A Review of the State-Level Advanced Utility Simulation Model

by

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BACKGROUND

This report presents a review of the state-level Advanced Utility Simulation Model (AUSM) that was developed for the Environmental Protection Agency (EPA) by the Universities Research Group on Energy (URGE). Our review focuses on the state-level AUSM consisting of six self-contained modules integrated into a single computer program generating annually recursive solutions.

The state-level AUSM includes only a subset of the capabilities planned for the final version of the AUSM. In particular, the interactions between states in electric capacity planning, pollution control, and dispatch, are not modeled by the state-level AUSM, and therefore must be separately analyzed and set by the model user. These state interactions are, broadly speaking, the subject of current modeling research by EPA and its contractors that will result in a regional AUSM in the near future.

While limited in terms of planned capabilities, the state-level AUSM is being used in research and simulation studies by the original modelers, is being readied for use by EPA for the National Acid Precipitation Assessment Program (NAPAP) and other air quality assessment programs, and is under review by some utilities and regulatory agencies. Hence, an independent review at this time seems appropriate, both to help potential users to understand the application possibilities of the state-level AUSM, and to contribute to the research agenda for continuing model development.

Our review is based on examination of the documentation and materials provided to us by EPA as of January 1, 1985, and supplemented by research materials provided by the modelers, and by published reports. Documentation of revisions to the model by EPA contractors in 1985 is not yet available for review. We have not examined in detail any model computer runs, asked that any particular runs be made, or tried to implement the model at MIT. Further, we have not attempted any systematic comparisons of the state-level AUSM with other models. All these steps are possible and potentially important in subsequent evaluation efforts, for example when new versions of the state-level AUSM are released, and when the regional AUSM is completed.

STATE-LEVEL AUSM DESCRIPTION

The state-level AUSM is intended to support studies of electric utility SO_2, NO_x, and TSP emissions, and to evaluate the economic costs and consequences of alternative emission control strategies. The model is also a key component in the integrated acid rain assessment system being developed by the National Acid Precipitation Analysis Program (NAPAP).

Two design features distinguish the state-level AUSM. First is the concept of the "state utility" establishing the state as the geographic area for capacity planning and dispatch. Second is the use of electric generating units as the organizing principle, allowing for the analysis of unit specific emission control decisions, either mandated or the result of utility decision making. This electric unit inventory data base is both central to AUSM, and has been employed in other models and scenario analyses requiring unit specific information.

The version of the state-level AUSM made available by EPA for review consists of six self-contained modules. These modules are combined in a computer program that generates annually recursive solutions; that is, modules solved earlier in the sequence do not require current year results from modeles solved later in the sequence. The solution sequence, and the major functions and data transfers for the six modules are:

1. Coal Supply Module that determines generating unit specific delivered coal prices. At present this module is run as a preprocessor, and is not part of the annually recursive solution;

2. Demand Module that determines current electricity rate schedules, and estimates state electricity demand by end use sector based on an econometric model (for Financial Module); adjusts state demands for interstate transfers and distribution losses to obtain estimates of state generation requirements and load characteristics (for Dispatch Module); and estimates long term electricity demand for each of the next 15 years based on an adaptive expectations model (for Capacity Planning Module);

3. Capacity Planning Module that schedules (i) planned plant construction, and (ii) new plants consistent with a specificed target generation mix (for Pollution Control, Dispatch, and Financial Modules);

4. Pollution Control Module that determines the least cost control technology investments required to meet generating unit emission constraints (for Dispatch and Financial Modules);

5. Dispatch Module that determines unit generation levels to minimize either state operating costs or emissions (for Financial Module); and,

6. Financial Module that determines state revenue requirements (for Demand Module), and income statements, and profitability measures consistent with each state's regulatory standards and procedures.

PRINCIPAL FINDINGS

The main work of this review has been to examine each of the state-level AUSM modules in detail to identify issues requiring further modeling research and analysis, and to provide potential users with information on the interpretation of model results. Before presenting these detailed results, however, we first discuss the implications of the state utility concept for model applications.

The state utility concept requires an "out of model" analysis by the user to set annual (i) interstate transfers of electricity, (ii) planned state construction schedules, and (iii) desired state target generation mix . The burden of this will depend upon the objectives of a particular application. For example, studies of the costs and effects of mandated control technology investments for specific units will be least burdensome in terms of user-model interactions. Then a knowledgable user (e.g. operating utilities, state regulatory agencies, or skilled modelers) can likely work out the policy induced effects on interstate transfers, planned construction, and target mix, perhaps with the aid of iterating the AUSM analysis to establish consistent results.

The burden will be much greater, however, for studies in which utilities and their interstate coordinating/dispatch authorities have some freedom in choosing control technologies and tactics to meet overall emission constraints. The more a particular state is involved in multi-state coordination/dispatch systems, the more complex will be its response to policies that permit the system some discretion in their choice of pollution control tactics. In these circumstances, substantial user-model iteration will be required, probably involving the use of other models to solve for consistent exogenous input data to the state-level AUSM.

We now summarize the main results from the review.

Module Interactions. There are two issues relating to the annually recurvsive structure of the state-level AUSM.

- An inconsistency exists between the actual revenues calculated in the Demand Module and required revenues calculated in the Finance Module. Actual revenues are calculated from the current estimates of electricity demand, last period's revenue requirements (from the Financial Module), and the rate schedule updated to reflect estimates of allowable variable and fixed costs. Current period required revenues, calculated in the Financial module, are based on actual allowable costs calculated from results provided by the the other modules.

No constraint ensures the consistency of these two revenue measures over time. Iterating the recursive solution until actual and required revenues are approximately equal may be one way to impose this consistency restriction. The importance of this inconsistency is unknown, and requires further analysis by the AUSM modelers.

- The recursive relation between the Capacity Planning and Pollution Control modules means that utilities are assumed to make their capacity choices for new plants independently of pollution control choices. Of course there is an intertemporal relation in that pollution control choices may affect future capacity requirements and choices, for example because of capacity penalties associated with particular control choices; but the assumption that utilities do not make capacity and pollution control choices simultaneously for new plants is unrealistic.

Pollution Control Technologies. The review of pollution control technologies has focussed on physical coal cleaning, and the wet limestone technology for the scrubbing of flue gases. For the latter, we find that the underlying cost and performance data is consistent with other information in the literature, and, as importantly, that these costs are not sensitive to the engineering parameters of the module. However,

- potential users should note that plant and site specific factors relating to the cost differences between old and new plants are treated as a scalar adjustment. Ensuring the appropriate choice of values for the retrofit factor is an important user responsibility.

The model for physical coal cleaning, included in the Coal Module, involves important improvements over previous representations of coal cleaning within coal market models. The core of the coal cleaning model consists of six regionally varying equations describing coal characteristics (e.g.pyritic sulfur fraction, maximum sulfur reduction, ash reduction, Btu content of cleaned coal, Btu yield and cost), all as functions of sulfur, ash and Btu content, and price of coal input to the cleaning process. The data base for estimation is a 1982 Bureau of Mines laboratory analysis of the washability characteristics of 710 specific coals. There are three issues requiring further analysis and research.

- New DOE data on washability characteristics, available since the original model was estimated, should be included in the estimation sample.

- The model is estimated with the ordinary least squares estimator (OLS) even though the equations involve endogenous variables as right hand side variables; in this case the OLS estimator provides biased and inconsistent parameter estimates. Further analysis with appropriate simultaneous equation estimators is necessary to establish a more credible statistical model.

- The coal prices used as input to the coal cleaning model are based on a statistical model of coal production costs that, according to the AUSM documentation, has performed poorly in historical forecasting experiments; in particular, the statistical model of coal prices significantly underestimated (overestimated) low (high) sulfur coal prices for 1980. Either a more credible statistical model of coal prices must be developed, or other methods of estimating these prices must be used.

Electricity Demand. The Demand Module plays a central role in the state-level AUSM, providing for estimating current electricity demand via an econometric model, adjusting these demand projections for interstate transfers and losses to provide estimates of state generation requirements and load characteristics, and providing demand projects for each of the next 15 years via an adaptive expectation model. An important option with this module is that users may provide their own demand estimates, either as a base case which is then adjusted by the modules elasticities in subsequent scenario analyses, or as a fixed project of current and future demand. The most important issues with this module include:

- As noted by the AUSM modelers, their estimated electric and fuel own-price elasticities are generally low when compared with related studies. For example, two of the long-run (Residential and Commercial) electricity own-price elasticity estimates are below the range of values in the studies considered in the recent extensive survey by Bohi, one of the short-run estimates (Commercial) is below that range, and the other electricity elasticities are generally toward the low end of the range. Further, several non-electric fuel long-run own-price elasticities are below the range of values for studies surveyed by Bohi. The validity of the AUSM estimates in comparison with the earlier studies needs to be argued and established by the AUSM modelers.

  Our review identifies and evaluates several conceptual and model implementation issues that may contribute to the typically low elasticity estimates, but no systematic biases could be identified. Priority should be given by the AUSM modelers to further research on the econometric demand model.

- The state-level AUSM employs separate models for estimating current demand (econometric model), and future annual demand (adaptive expectations model). The modelers argue that the adaptive expectations model "fits" the results of utility forecasting, and corresponds to utility practice. Recent surveys of utility forecasting methods and empirical studies suggest that, while this may have been true for pre-embargo period, it is presently inaccurate. The question of a suitable model for long-run electricity demand projections requires further consideration. From a policy modeling perspective, it is critically important to choose long-range forecasting methods that receive the endorsement of established utility forecasters and analysts.

Financial Module. This module provides impressive detail on state level regulatory and tax data, and probably represents the state-of-the-art for operational models of this type. The principal issues to consider in subsequent modeling research include:

- Plant capital and operating costs, including pollution control costs, are allocated to the state in which the plant is located. This is incorrect for plants that are jointly owned by utilities in different states. The modelers have considered alternative approaches to deal with this issue, and their ideas should be pursued in subsequent research. This issue is not trivial since some 36 plants are affected.

- Publicly and privately owned utilities are not distinguished in the current version of the AUSM. The modelers recognize this issue, and have set regulatory and financial parameters consistent with the mix of privately and publicly owned plants. The user should keep in mind, however, the fundamental regulatory differences between private and public firms, in particular, rate determination and costs of capital. The issue is more of less important depending upon the share of public power in a given state, and the importance in a particular study of accurate utility income and profitability measures.

- The module assumes a perfectly elastic supply of financial capital, regardless of the capital requirements. To the extent that capital costs increase with increases in demand for financial capital, this assumption will lead to an understatement of the cost of capacity and pollution control technology investments.

- It appears that the regulatory and financial parameters of the Financial Module are not used in the Pollution Control Module in determining least cost pollution control investments. If in fact different parameters are possible, the user should ensure they are equal or consistent, and subsequent versions of the AUSM should eliminate this possibility.

Capacity Planning Module. As discussed above under Module Interactions, the annually recursive structure requires that capacity planning for new plansts take place independently of pollution control planning. One other important issue relates to this module.

- Plant retirements are assumed constant in the current version of the model. In fact, optimal plant economic lives will be influenced by the relative economic values created, directly or indirectly, by control policies most importantly in terms of the relative values of existing versus new plants. While the existing model would support sensitivity studies of the effects of changing plant life, it provides no capability for economic analysis of of the costs/benefits of changing plant life assumptions, or of optimal plant lives in response to changing policy scenarios.

  In this regard, Argonne National Laboratory has developed a Retirement Module for AUSM that considers the economic costs and benefits of changes in plant lives. We have not reviewed that work, but note its importance in addressing, for example, the effect of plant life extension programs on emissions estimates.

Dispatch Module. As discussed above, the state utility concept requires the user to estimate interstate transfers, a task that will be increasingly difficult when a particular state is part of a multiple state coordination/dispatch authority, and when the pollution control policy in effect provides utilities with flexibility in their pollution control choices. Three remaining issues include:

- Maximum allowable capacity factors for existing plants are assumed to equal their 1980 maximum generation levels for the remaining plant life. This assumption seems inconsistent with recent studies of age-performance profiles for coal plants. Further, maintaining constant age-performance profiles is costless in the current version of the model since maintenance expenses during planned outages do not depend upon age.

It should be noted that the extent of the age-performance deterioration is controversial and not well established. To the extent that performance does deteriorate, however, the constant 1980 capacity factor assumption will overstate emissions. This issue, and more generally the economics of the coal generating unit age-performance relationship, should receive high priority in subsequent model research.

- Transmission and distribution system investments are specified by the user as part of the capacity planning process. This may be reasonable for least cost dispatch, providing that the air quality policies under investigation do not dramatically alter electricity distribution patterns within, and between, states. Substantial changes from historical patterns for least emissions dispatch, however, seem quite likely. Under these conditions, specifying the transmission investments in advance will be extremely difficult, and would almost certainly require "user-model" iterations.

It should be noted that analysis of the interactions between least emissions dispatch patterns and transmission system constraints and investment planning is probably beyond the capability of existing utility dispatch algorithms. Further research on this issue, and on algorithms for least emissions dispatch in general should be given high priority by the AUSM modelers. As a practical matter, it is important that these algorithms be credible to utility analysts and dispatch controllers.

- The use of an annual load curve characterized as a three or five segment function limits model applications in potentially important ways. For example, analysis of air quality policies affecting the seasonal use of generating units could not be considered with the present model. More generally, this seems an unduly restrictive approximation to the load curve for a model that is dispatching actual units.

<u>Coal Module</u>. In contrast with the other modules of the AUSM, this module is executed only at the beginning of an analysis for all time periods, not annually. Estimates of future coal requirements are, therefore, required as input (in the national model, they will be obtained from MPMS). The following issues are considered in our review:

- A user must ensure that coal demands resulting from an state-level AUSM solutions are consistent with the initial coal demand estimates required to estimate coal prices, or at least that equilibrium coal market prices are not likely to be much affected by differences between initial and estimated coal demands.

- The module assumes competitive markets for coal production and transportation. This may not be reasonable when railroads can extract monopoly rents, when intertemporal rents to coal producers are important or when other market imperfections exist. Previous studies have suggested the importance to equilibrium coal prices of both types of rents. This could imply that the delivered prices of premium low sulphur coals will be understated, thereby contributing to an overstatement of the switch from high- to low-sulphur coal.

The issue of monopoly and intertemporal rents should be addressed in subsequent AUSM modeling research.

- Two methods are provided for estimating coal production costs including (1) a statistical model, and (2) a process engineering model. The statistical model appears to have performed badly in forecasting 1980 coal prices by significantly underestimating (overestimating) low (high) sulphur coal prices. In our opinion the statistical model option should not be used until further modeling research produces a credible model with acceptable forecasting performance.

The process engineering model of coal production costs is based on the Resource Allocation and Mine Costing Model (RAMC) originally developed by ICF for the Federal Energy Administration. The model has relatively little economic behavioral content assuming, for example, a constant mine lifetime and constant recovery rates once a mine is opened. It should be noted that this model is probably the operational state-of-the-art, being essentially equivalent to that used at EIA and in the ICF Coal and Electric Utilities Model.

- The model employs transport cost estimates rather than transport prices in determining delivered coal prices. The documentation suggests that railroad costs are being underestimated, and water costs overestimated. Subsequent modeling research and data development should address this problem.

- An option is provided to operate the module without accounting for the effects of depletion on coal prices. Given the importance of depletion effects, this option should be employed only in sensitivity analysis, and not in actual studies;

- In addition to the Department of Energy's Demonstrated Reserve Base (DRB), an updated, more optimistic, coal reserve data base has been developed and may be used as an option. The procedures for updating the DRB are not sufficiently documented to permit review and evaluation. For this reason, the optimistic estimates should be employed only in sensitivity analyses, and not in developing base case policy scenarios.

Future work might focus on strengthening the documentation of this potentially useful reserve base and in developing a consensus for expanding the DRB to include inferred and subeconomic resources.

Section 1

BACKGROUND, MODEL DESCRIPTION, AND REVIEW SUMMARY

INTRODUCTION

This report presents a review of the Advanced Utility Simulation Model (AUSM). The AUSM has been developed by the Universities Research Group on Energy (URGE)[1] and sponsored by the Environmental Protection Agency (EPA).

The AUSM is intended to support state, regional and national studies of electric utility SO_2, NO_x, and TSP emissions, and to evaluate the economic costs of alternative emission control strategies, and is being designed to address the air quality policy issues summarized in Table 1-1. The model is also a key component in the integrated acid rain assessment system being developed by the National Acid Precipitation Analysis Program (NAPAP) as indicated in Figure 1-1.

The operational development and documentation of the AUSM had not been completed at the time this review was begun. However, a state-level version of the model was sufficiently developed so that the model sponsor, EPA, was willing to provide the documentation and related materials for review. Accordingly, we have focussed on the state-level AUSM consisting of six self-contained modules integrated into a single computer program generating annually recursive solutions. The modules and their relationships are summarized in Figure 1-2, and include:

Coal Supply
Demand
Capacity Planning
Pollution Control
Dispatch
Finance

Our review has been based on examination of the documentation and materials provided to us by EPA, and supplemented by published, and unpublished, reports and research materials provided by the modelers. We have not examined in detail any model computer runs, asked that any particular runs be made, or tried to implement the model at MIT. Further, we have not attempted to systematically compare the state-level AUSM with other models. All these steps are possible and potentially

[1]The URGE Consortium includes Carnegie Mellon University, Cornell University, and the University of Illinois. The Program Director is Professor James J. Stukel (Illinois), and the Senior Investigators include Professors Clark W. Bullard (Illinois); Duane Chapman (Cornell); Timothy D. Mount (Cornell); ; Edward S. Rubin (Carnegie-Mellon), and Sarosh N. Talukdar (Carnegie-Mellon); and **Edward H. Pechan** (E.H. Pechan & Associates, Inc.).

important in subsequent evaluation efforts, for example when the regional AUSM is completed.

This introductory chapter is organized as follows; in the next section we provide further background on the objectives and organization of the review. The remaining two sections provide an overview description of the state-level AUSM followed by a summary of the issues considered in the review.

BACKGROUND

The state-level version represents an intermediate stage in the development of the AUSM. Current and continuing research is developing a regional AUSM; but at the time we began our work only the state-level AUSM documentation and materials could be made available by the EPA for review.

It should be noted, however, that this version of the AUSM is being used by the modelers and other analysts in research and simulation studies. For example, Stukel and Bullard [1984] use the state-level AUSM in analyzing the emission and economic effects on midwestern states of selected air quality policies; and Bullard and Hottman [1984] employ the model in evaluating emission and economic effects of alternative policies affecting generating plants and coal producers in Illinois. These studies illustrate the applications that the modelers feel are supported by the state-level version of the AUSM.

Further, components of the state-level AUSM are being used in other models. For example, Skea and Rubin [1985] have developed the Utility Control Strategy (UCS) model to analyze the emission and economic effects of air quality control policies on states and groups of states. The UCS model combines AUSM Pollution Control Module and the electric generating unit inventory, together with (i) an exogenous plant construction sequence and dispatch module adopted from the AUSM, and (ii) exogenous electricity demand growth rates. The UCS is, therefore, quite similar to the state-level AUSM, except that the Demand and Financial Modules have been eliminated.

Finally, these early applications and the general increasing interest in how the AUSM will be used by EPA and by the NAPAP have stimulated interest in electric utilities, state regulatory agencies, and coal producing companies in learning more about the AUSM, and the possibilities for its use in their own air quality analysis studies. Thus, even though development of the AUSM continues, it was decided to undertake a review of the extant model made available by EPA as of 1 January 1985.

The review group, together with their affiliations and primary review responsibilities, include:

Martin L. Baughman: Professor of Electrical Engineering at the University of Texas-Austin, and President, Southwest Energy Associates (Financial Module).

Ernst R. Berndt: Professor of Applied Economics at the MIT Sloan School of Management (Demand Module).

James A. Fay: Professor of Mechanical Engineering at the MIT Department of Mechanical Engineering, and Director for the Energy Laboratory's Environmental Studies Program (Pollution Control Module).

Dan S. Golomb: Manager of the MIT Energy Laboratory's Environmental Studies Program (Pollution Control Module).

James Gruhl: President, James Gruhl Associates (Capacity Planning and Dispatch Modules).

Charles D. Kolstad: Assistant Professor of Economics at the University of Illinois, Urbana (Coal Supply Module).

Fred C. Schweppe: Professor of Electrical Engineering at the MIT Department of Electrical Engineering (Capacity Planning and Dispatch Modules).

David O. Wood: Associate Director of the MIT Energy Laboratory, and Senior Lecturer in the Sloan School of Management (Principal Investigator, and Demand Module).

Several features relating to the organization and conduct of the review should be noted. First, the review is based primarily on documentation and materials provided to us in late 1983 by John Milliken who at that time was the EPA Project Officer for the AUSM project. We then asked the modelers to review this list, and to add further documentation or other research materials which would facilitate the review. This produced several important additions to the documentation, and also some discussion of important modeling research decisions and issues with respect to the state-level AUSM, and the overall AUSM modeling project. Subsequently, we asked the EPA project officer to send us any new materials relating to the final version of the state-level AUSM delivered to EPA by the URGE group, and also for a copy of the computer code. (Wood [1985a, 1985b]); however, no additional materials were provided. This is of some importance since several comments from the URGE group reported in Section 8 imply that we have not considered all the documentation available. In fact, we have considered all the materials that EPA and the URGE group provided to us.

Second, in December, 1984, EPRI sponsored a Workshop for government, industry, and public interest group analysts to introduce the objectives and approach for this review, and to discuss model attributes and issues of importance to current and future air quality policy analysis. A report of this workshop (AUSM Review Group [1985]), including issues identified in the preliminary review of the state-level AUSM, was distributed for comment to the Workshop participants, and to EPA and the AUSM modelers. This produced several important suggestions for our subsequent work, and provided for some feedback from the modelers. A number of misconceptions and gaps in the documentation were clarified by this process.

Third, the draft report of the review was submitted to the URGE modelers, and to the EPA project officers

Finally, it should be noted that the AUSM modelers have been provided the opportunity to include their comments in the final chapter of this report. In this way, agreements, remaining controversies, and — most importantly — agendas for further research are presented in one report.

DESCRIPTION OF THE STATE-LEVEL AUSM

Figure 1-2 summarizes the six modules of the state-level AUSM. Detailed descriptions are presented in the subsequent chapters of the review. Here we indicate the major functions of each module, the important information transfers between modules, and the assumptions on module interactions required to implement the annually recursive solution algorithm.

Coal Supply Module: This module is operated as a preprocessor at the beginning of a model run to determine prices of coals delivered to specific generating units. In additional to estimating equilibrium coal market prices, the module also includes a model to estimate coal cleaning costs and characteristics based on equilibrium coal prices and the physical characteristics of "raw" coal. The primary method for estimating coal production costs in the module is based on a widely used economic/engineering model of coal production.

Demand Module: This module is the first to be solved in the annually recursive solution algorithm, and calculates state demand and generation requirements directly used in all other modules (except Pollution Control). In particular, the module updates the rate schedules for the Residential, Commercial, Industrial, and Transportation end use sectors based on last period's required revenues from the

Financial Module, and estimates of allowable fixed and variable costs. The rate schedule is characterized as a two-part tariff with fixed charges (intercept), and marginal electricity price (slope). The marginal electricity prices — together with other fuel prices, and economic and demographic variables — are used in an econometric demand model to estimate state electricity demand by end use sector for the current period. State electricity demands are then adjusted by estimates of net interstate transfers and distribution losses to obtain estimates of state generation requirements and load characteristics. Finally, estimates long term electricity demand for each of the next 15 years are estimated by an adaptive expectations model.

Capacity Planning Module: This module schedules plant construction sequences provided by the user. It has the capability, within limits, to slowdown or speed up construction based on information from the Demand Module on changing long-run generation requirements, and does all the "book keeping" regarding plant capacity characteristics and retirements.

Pollution Control Module: This Module determines the least cost control technology investments required to meet generating unit emission constraints. It is based on an economic/engineering model of pollution control technologies. The model chooses least cost combinations of permissible control options based on a levelized cost algorithm.

Dispatch Module: This module determines unit generation levels to minimize either state operating costs or emissions. It provides a merit ordering or a linear programing (LP) solution for choice of generating units. The modelers favor the LP option since it allows for incorporating various control policy specify restrictions in the solution.

Financial Module: This module determines state revenue requirements (for Demand Module), and utility income statements and profitability measures consistent with each state's regulatory procedures, and with state and federal tax laws. These calculations are based on information from each of the other modules in the state-level AUSM. An intertemporal feedback loop with the Demand Module exists via the use of revenue requirements for the current period in updating next period's rate schedules.

The concept of the state capacity planning and dispatch area, or state utility, is a key design feature of the state-level AUSM. This concept and the annually recursive solution algorithm depend upon the following "independence" assumptions:

- net interstate transfers and the state plant construction sequence are independent of any existing multiple state coordination/dispatch authority; and
- capacity planning is independent of the utilities' pollution control decisions.

The first assumption establishes the state as the geographical area for plant construction and dispatch decisions. It means that any changes in interstate transfers or plant construction due to, for example, policy induced changes in the economic and regulatory factors affecting decisions of a multiple state coordination/dispatch authority can be evaluated outside the model, and used in revising exogenous data. This assumption, and the general concept of a state utility is more or less plausible depending upon the existence of a multiple state coordinating/dispatch authority for states of interest in a particular study.

The second assumption ensures that capacity planning can precede pollution control planning in the solution sequence. Its plausibility is an empirical question of utility capacity and control planning, which in turn most likely depends critically upon the particular policy scenario. Policies providing considerable scope for utilities to choose between capacity types and control approaches are less well served by such an assumption than those where utility actions are essentially mandated. It should be noted that much of the current research to develop the regional AUSM is concerned with relaxing these assumptions.

REVIEW SUMMARY

Broadly speaking we find that, while possible, it is likely to be impractical to use the current version of the state-level AUSM for air quality policy studies. The impracticality arises when the state(s) of interest are involved in a multiple state dispatch area, due either to the fact that multiple state utilities and/or power pools are involved. In such cases, a considerable burden exists in specifying the interstate transfers, a specification which requires the solution to the multiple state dispatch problem. Even when an approximate solution exists for a base case scenario, any policy scenario affecting the base case solution will require a new approximation to interstate transfers. Further, significant changes in interstate transfers must be checked against available and planned transmission and distribution capacity, a capability not included in the state-level AUSM. Since the states of greatest interest, e.g. the north central states, tend to be in multiple state dispatch areas, the practical problems are obvious.

It is arguable, however, that for policies involving mandated control technologies on specific units, that the interstate transfer changes implied by such a policy could be worked out, and so the state-level model could be used. This would be most likely if the model user had intimate understanding of the multistate dispatch area, understanding that only the operating utilities, state regulatory agencies, or knowledgeable modelers are likely to possess. However, for policies in which utilities have some freedom in choosing control technologies and strategies to meet overall emission constraints, say by state or region, or in response to some economic cost or incentive (emission taxes, emission trading markets), then in its present form this state-level AUSM is surely impractical for use in operational studies.

Two caveats should be noted. First, the conclusion that it would be impractical to employ the state-level AUSM in operational air quality studies implies nothing about using the forthcoming regional AUSM when interstate capacity planning, emission control, and dispatch are important features of the problem. Second, the design of the state-level AUSM facilitates the use of individual components — in particular the Pollution Control Module, and the Electric Generating Unit data base — in conjunction with other models, or in supporting scenario calculations.

We now turn to a more detailed description of each module, and a summary of the the results of our review.

Coal Supply Module

Description. The purpose of the coal supply module is to determine a set of coal prices, delivered to power plants across the country, as a function of coal quality (heating content, sulfur content) and time. To accomplish this, the module finds an economic equilibrium, balancing demands for coal with the cost of coal mining, coal transport, and coal cleaning. The module is designed as a "shell," allowing users a great deal of flexibility in representing various methodological approaches to different components of coal supply.

The cost of coal mining is determined in one of two ways. One uses an exogenous extrapolation of past coal prices. A second method adopts the common approach of representing the cost of production by upward sloping coal supply curves, generated through an engineering analysis of costs. Coal transport costs are developed from an engineering model of rail and water coal transport. Coal cleaning costs are based on a detailed process model of coal benefication, using actual washability data.

The coal supply module operates somewhat separately from the rest of AUSM. Rather than iterate with the portion of AUSM determining electric utility coal demand, effectively solving for a supply-demand equilibrium, the coal supply module operates ahead of the rest of AUSM, using a separately generated forecast of regional coal demands. Given these demands, the coal supply module determines delivered prices for various types of coals in various regions of the country.

Issues. A fundamental criterion used in evaluating the coal supply module is how well it can be expected to resolve relative and absolute coal prices (eg, low vs high sulfur coal) and other similar factors which bear on the fuel choice decision for individual power plants. Coal prices will affect the scrubber/low-sulfur coal choice and thus the spatial pattern of coal supply and consumption and thus emissions. The module basically is sound, carefully implemented, and largely state-of-the-art; however, a number of major issues have been identified in this review of the coal supply module and are summarized below:

1. In AUSM, the basic approach to determining a set of coal prices and production/use patterns is to assume the market is competitive and solve for a competitive equilibrium. There has been significant concern in the policy and research community that this is an unwarranted assumption. As a prominent example, it has been suggested that some railroads are extracting monopoly rents. If western railroads are extracting rents, the AUSM coal prices may underestimate the delivered price of low-sulfur coal to the midwest and thus over-estimate the switch away from high-sulfur coal in response to acid rain legislation.

2. The decoupling of coal demand and supply in AUSM could lead to significant errors. Such errors could arise if the exogenously specified coal demands are inconsistent with demands generated by the rest of AUSM. While a careful analyst could always check for such inconsistencies, the decoupling does not appear to be a desirable feature of the module. The MPMS module (not covered in this review) has been designed to deal explicitly with this issue.

3. The AUSM coal supply module can be run without explicitly taking coal depletion into account by using exogenously-specified escalation rates. Depletion appears to be important enough, even for state-level analyses, that this option should not generally be used.

4. The computation of equilibrium prices, taking depletion into account, involves a number of simplifications for computational tractability. In particular, an option in AUSM is to truncate or eliminate many of the coal supply curves on the basis that the eliminated portions of the curves will never be reached. The truncation is based on current patterns of demand. This truncation appears to have been done carefully and accurately. However, since patterns of demand may vary significantly under different forms of acid rain legislation, and users may not all be equally experienced, such truncation appears undesirable, particularly since it does not appear necessary for computational tractability.

5. In AUSM, there are two basic approaches for determining the production costs for coal. One method is based on a statistical analysis of coal prices over the 1975–1980 period and appears to be so inaccurate that it should never be used. The other approach is an apparently solid implementation of an up-to-date version of a well-known mine cost model (RAMC). The primary criticisms of the AUSM implementation of the RAMC concern the assumed fixed mine lifetime (of 30 years), the computation of the mine operator's discount rate, and assumed mine recovery rates.

6. Several coal reserve bases are available within AUSM for computing coal mining costs. One set of reserves includes inferred economic resources. Despite the potential advantages of such an expanded reserve base, the method used for adding these inferred resources does not appear to be well documented and thus should be used with caution for AUSM analysis.

7. In contrast to most other coal market models, AUSM uses estimates of coal transport costs rather than prices for determining delivered coal prices. AUSM documentation indicates that this approach consistently underestimates rail prices and significantly over-estimates water movement prices. This portion of the model deserves additional attention before it is used.

8. The coal cleaning portion of the coal supply module appears to be a significant improvement over previous representations of coal cleaning within coal market models. However, there are two potential but modest problems with the coal cleaning cost estimates. One is statistical and relates to the estimation techniques and functional form for deriving the cost of coal cleaning. Another problem concerns the use of statistically estimated coal prices to determine the most efficient level of cleaning. As was pointed out above, the statistical estimates of coal prices developed for AUSM appear to be highly unreliable (although perhaps the best available), leading to questions about the accuracy of some of the coal cleaning costs.

Demand Module

<u>Description</u>. The Demand Module (DM) is the first module executed in state-level AUSM. The module performs three important functions including (i) estimating current electricity rates and electricity and other fuel demand by end use sector and state; (ii) estimating state generation requirements by adjusting state electricity demand for interstate transfers and losses, and then estimating load factors; and (iii) projecting state generation requirements for each of the next 15 years.

Rate schedules have been developed by state for the Residential, Industrial, Commercial, and Transportation end use sectors. These schedules are estimated as two-part tariffs including a fixed charge (intercept) and a marginal electricity price (slope) using data from Typical Electric Bills. These schedules are updated based on last period's required revenues (from the Financial Module) and estimates of allowable changes in variable and fixed costs.

The marginal electricity price, together with prices for competing fuels and other demographic and economic variables, are inputs to an econometric demand model, specified as a linear logit model, that is employed in estimating current period electricity and competing fuel demands. The econometric linear logit model was estimated based on data for a random sample of twelve states. Estimates of the current rate schedule and electricity demand for each end use sector are used in calculating actual revenues for the Financial Module.

The next step is to obtain estimates of state generation requirements and load characteristics. First, end use sector electricity demands are aggregated and adjusted by estimates of net interstate transfers and distribution and other losses to obtain an estimate of state generation requirements. At present, losses are estimated based on the 1980 national average loss factor, and net interstate transfers are based on the 1980 state relationship. Second, the load factor associated with each state's generation requirement is estimated based on the factors forecasted by the National Electric Reliability Council (NERC) for the NERC region in which that state is located. State generation requirements and load factors are inputs to the Dispatch Module.

The final step in the Demand Module is to estimate state generation requirements for each of the next 15 years as an input to the Capacity Planning Module. These estimates are based on an adaptive expectations model intended to capture the essential elements of utility forecasting practice and modeling. The adaptive expectations model was estimated using historical NERC ten year forecasts as endogenous variables, and lagged generation and a time adjustment for the 1973-1974 OPEC oil price shock as the exogenous variables.

An interesting feature of the DM is that users may choose to substitute their own demand forecast as a base case, and then choose whether or not to employ the DM's elasticities in scenario analyses run as changes to the base case. This flexibility should prove very valuable to users who have good independent information on likely demand levels.

Issues.

9. A potentially important issue concerns the relation between actual revenues — calculated from the updated rate schedule, the estimated demands, and estimated allowable costs — and the required revenues calculated in the Financial Module based on actual allowable costs. In particular, no constraint is imposed to ensure the consistency of actual and required revenues over time. This is partly due to the annually recursive solution procedure for the overall model, and might be rectified by iterating the recursive solution for each year. The importance of this inconsistency is an empirical question requiring further analysis.

10. Regulators are assumed to treat all end use sectors equally in allocating cost increases. The possibility that, for example, pollution control costs might be allocated differently between Residential and Industrial customers cannot be analyzed in the present version of the model. This seems unduly restrictive, given the policy interest in the possibility that state regulators may choose to discriminate between customer classes in allocating allowable costs from state and federal air quality regulations.

11. The AUSM econometric demand model is based on the linear logit specification, with some important improvements from earlier applications by other modelers. A serious issue with the currently estimated model is the extreme values of electricity and fuel own-price elasticities relative to other studies. Most importantly, in comparing the AUSM electricity own-price elasticities with those in Bohi's recent extensive survey of energy demand models, two of the long-run (Residential and Commercial) estimates are below the entire range of values in the studies surveyed by Bohi, and one of the short-run estimates (Commercial) is below that range. Several non-electric fuel long-run own-price elasticities are also

below the range of values for studies surveyed by Bohi. The validity of the AUSM estimates in comparison with the earlier studies needs to be argued and established by AUSM modelers.

12. The most important conceptual issue regarding the AUSM econometric demand model is that it satisfies the symmetry postulate of the basic economic theory of demand — namely, that technical substitution possibilities between factors are independent of the order of relative price changes — only at one data point, namely, the national historical sample average. The modelers could choose other data points at which to impose symmetry restrictions, but for the linear logit specification, symmetry restrictions can be imposed <u>only</u> at one data point in the estimation and forecast samples. The symmetry condition is essential to the economic interpretation of the model and its estimated elasticities. The implications of this deficiency for possible bias in the AUSM elasticity estimates are, however, unknown.

13. Other conceptual issues developed in this review include: (i) model parameter estimates are likely to be biased and inconsistent, since a right-hand variable (shares as components of the mean share) is stochastic and correlated with the equation disturbance term; (ii) the dynamic optimization problem underlying the linear logit specification is ad hoc; and (iii) in the Industrial and Commercial sector models, the procedure treating labor as an endogenous variable for estimation but an exogenous variable for forecasting violates the homogeneity assumptions built into the estimated model. Each of these issues should be addressed by the AUSM modelers in subsequent research.

14. Implementation issues considered by the AUSM modelers and reviewed here include, (i) appropriateness of the State Energy Data System data base on oil and coal product prices and consumption for use in econometric research; (ii) methods used for dealing with inconsistent oil products data; (iii) use of a 12 state sample rather than all states in estimation; (iv) use and interpretation of non-economic variables to eliminate bias and improve model fit; and (v) effects of omitted variables. While all these issues require further research and analysis, none can be shown to bias elasticity estimates in any systematic way.

15. Our analysis of the conceptual and implementation issues relating to the AUSM econometric demand model suggests that basic research is required by the AUSM demand modelers to reconcile their elasticity estimates with other studies, and to improve the AUSM demand model specification and implementation. Of considerable practical importance, seemingly arbitrary choices of, for example, data points for imposing

symmetry conditions and states used in the estimation sample should be eliminated. They leave the overall AUSM model unnecessarily vulnerable to the charge that results are being manipulated by these choices.

16. The calculation of distribution and other losses is based on 1980 average national relationships, while interstate transfers must be specified exogenously. These are clearly stop gap measures, and we interpret them as a means to permit the use of the state-level AUSM for research purposes and simulation experiments. A potential user considering the current model for policy studies should, however, keep these undesirable features in mind.

17. Annual demand projections for each of the next 15 years are made by an adaptive expectations model. This model incorporates no information on current and expected prices, costs, and operating conditions, other than that summarized in the generation history for four years prior to the forecast year. This approach is believed by the AUSM modelers to represent past utility methods and practice. Anecdotal evidence and recent empirical studies suggest, however, that utility forecasters are increasingly employing econometric and economic/engineering models for forecasting. Hence, even if time series forecasting methods were used in the past and "fit" historical forecasts, that is insufficient reason to employ them for future forecasting. As a practical matter, from a policy modeling perspective it is critically important to choose long-range forecasting methods that receive the endorsement of established utility forecasters and analysts.

Capacity Planning Module

Description. The Capacity Planning Module (CPM) is the second module executed in the state-level version of AUSM, following the Demand Module. "The central task of the capacity planning module is to maintain the schedule for the construction of generating units that best matches the capacity needs implied by the computer simulation in progress. Capacity requirements are based on the demand for electricity, which the demand module calculates on an annual basis over a look ahead horizon at least as long as the maximum plant construction." (Stukel, Bullard, 1984, p.3) This scheduling is accomplished by the CPM over a single state, or a "state utility."

"For each year that the planning module is run, a two part capacity needs test (available capacity and available energy) is performed successively for each year in the look ahead horizon. If both parts are passed, steps are taken to defer units under construction; otherwise, capacity augmentation is undertaken. Capacity augmentation occurs when any part of the capacity needs test fails." (Stukel, Bullard, 1984, p.3)

The CPM does not make any decisions about the capacity "types", i.e. baseload, intermediate, or peaking, that are needed. There are no pollution control or emission reduction considerations, and no retirement decisions. There is no interaction between CPM and the Dispatching Module or the Pollution Control Module except through the annual recursions.

It should be noted that the modelers of this CPM had identified a need for a functional, choice-making capacity planning optimizer (URGE, 1981, p. 5-20), and designed the CPM under the assumption such an optimizer would exist. Such a capability may yet be realized in the regional AUSM, but it is not yet available in the version of the model reviewed here.

Issues.

18. The CPM's very limited capabilities impose a considerable burden on the user, and as a practical matter suggests to us that only planners from affected utilities, regulatory agencies, or extremely knowledgeable analyst/modelers could seriously consider using the state-level AUSM for operational policy studies. The problem is that state construction schedules are strongly influenced by economic incentives at the level of the power pool or the multi-state utility. Interesting policy scenarios will almost certainly affect the relative economic valuation by the multi-state operation authorities of plant locations in the different states. The practical difficulty would be in analyzing and adjusting the state utility construction schedules for these interstate effects of particular policy scenarios. This is not impossible, but serious analysis would probably require use of the capacity planning system used by the utility or power pool for the multi-state dispatch area in which the state(s) of interest are located. Of course, dispatch area that correspond closely to the states would not present this problem, but most states of interest for air quality analysis are included in multi-state dispatch areas or power pools.

19. Plant retirements are assumed constant and equal to 45 years in the current version of the model. In fact optimal plant economic lives will be influenced by the relative economic values created, directly or indirectly, by policy scenarios, most importantly in terms of the relative values of existing versus new plants. While the existing model would support sensitivity studies of the effects of

changing plant life, it provides no capability for economic analysis of optimal plant lives in response to changing policy scenarios. In this regard, Argonne National Laboratory has developed a Retirement Module for AUSM that considers the economic costs and benefits of changes in plant lives. We have not reviewed that work, but note its importance in addressing, for example, the effect of plant life extension programs on emissions estimates.

20. The lack of documentation to aid the user in constructing input data and in conducting the consistency checks outlined above is disappointing, especially given the otherwise clarity of the state-level AUSM descriptive materials.

Pollution Control Module

Description. The AUSM Pollution Control Module (PCM) calculates the incremental cost of meeting selected emission standards for SO_2, NOx and particulate matter for both existing and new power plants. It selects the least costly technology for meeting the standards on a plant-by-plant basis within each state. For sulfur control, it selects either a lower sulfur fuel or the installation of equipment such as wet scrubbers. The fuel choice andcapacity penalty are transmitted to the Dispatch module and the technology costs to the Financial module.

The addendum to the PCM permits the calculation of the least cost allocation of sulfur emission reduction and its attendant pollution control choices for the population of power plants within a state such as that a selected aggregate emission reduction target for the state will be reached. This component is essential to the use of AUSM as an acid rain policy analysis tool.

Issues.

1. The heart of the AUSM PCM is the calculation of the levelized cost of meeting a posited emission standard (principally for sulfur) by all possible alternatives, including fuel switching and flue gas processing, so that the least costly alternative may be selected and its characteristics passed on to the other modules. The most likely alternatives to using lower sulfur fuels (whose costs are evaluated by the coal supply module) are physical coal cleaning and wet limestone scrubbing of the flue gases. We have evaluated the cost analysis of the latter technology, and are satisfied that it is consistent with other information in the literature. More importantly, these costs are not sensitive to the engineering parameters.

The hardware pollution control technologies (i.e., other than full switching) are capital intensive because they require processing the fuel of combustion gas stream. Their cost is mostly independent of the amount of sulfur removed, so they are most effective when applied to high sulfur fuels. It is likely that these costs are adequately estimated by PCM.

Switching to lower sulfur fuels is limited in the PCM to replacing coal by coal and oil by oil, but not oil by coal or either by natural gas. The latter options could be significant for east coast utilities.

22. In retrofitting existing plants with pollution control hardwired, a retrofit factor is applied to the costs to account for the plant-specific factors which will increase costs above a new plant baseline. This and other plant-specific information is required as exogenous data for the exercising of the PCM. The reliability of the module choices and output will depend upon the care exercised by the model operator in selecting this input information.

23. A PCM addendum (Simulating Market Management Systems) organizes the PCM calculation in a form suitable for analysis of sulfur control policies at the state level (and potentially at the national level when other AUSM modules are added). It calculates marginal costs of sulfur removal as a function of aggregate state emission reduction among state power plants. The methodology is appropriate to the use of AUSM as a policy evaluation tool, but the accuracy and sensitivity of this module component needs to be evaluated.

24. PCM is the entrance point for inserting a pollution control scenario to be evaluated. Since it is emission-oriented, these scenarios must be specified in terms of emission objectives in order to be translated subsequently into costs, fuel use, etc. Other scenarios (e.g., maximize reductions at a given cost) which cannot be cast in this form must be handled indirectly, if at all.

25. As presently constituted, the PCM can evaluate two intrastate pollution control strategies: (a) a common emission standard equally applicable to all in-state plants or (b) a least-cost plan for meeting an aggregate emission level for the state as a whole, based upon equal marginal cost for all plants which are needed in meeting the reduction goal. In both cases the module makes the individual plant choices regarding fuel or technology on the basis of minimum levelized costs. Any departure from these scenarios, such as restrictions on the choice of out-of-state fuels, limitation of employments effects, etc., must be taken into account by manipulating the exogenous inputs to this or other modules. There is no guidance on

how this might be done.

Dispatch Module

Description. "The purpose of the dispatching module is to find the allocation that minimizes a select quantity of concern (e.g., operating cost) while meeting constraints on the other quantities (e.g., various categories of air pollutant emissions) and keeping within the operating ranges of the generating units. The dispatching module can operate in either of two modes: merit order and linear programming dispatch. The linear programming mode which dispatches power plants according to a least-cost criteria was used in this study." (Stukel, Bullard, 1984, p.3)

The AUSM Dispatch module represents all of the load variations (hourly, daily, seasonally) in terms of a single 3 or 5 level annual load duration curve. The choice of units can apparently be based upon a least-cost or a least-emission criteria. When the linear programming format is used to simulate the results of this scheduling process, there are a number of constraints that can be imposed on the emissions. Apparently only the dollar cost or the sulfur oxide emissions have as yet been used in the performance measure of AUSM Dispatching, with NOx and TSP relegated to being regionally constrained.

The effect of generation outages are represented by derating the units. Purchases and sales with neighboring "utilities" are exogenous. It is assumed that there are no transmission limitations within the state utility region.

Issues.

26. The major burden of the "state utility" design decision for a user of AUSM materializes in this module. The biggest distortions between model results and actual utility performance are most likely when a single utility or a power pool is dispatching a multiple state system with significant capacity in the different states. Then the interstate transfer decisions of the utility and/or operating authority are most likely to change in response to changing economic and regulatory conditions. It should be emphasized that the AUSM modelers apparently agree with this assessment. Thus,

> If the AUSM is modified to operate for groups of states within a single power pool, the model will be much more representative of actual practices in the industry. .. If the model continues to operate exclusively at the state level,

there is no simple way to deal with interstate transfer of power in anything but a cursory manner.[2]

27. Capacity factors for existing plants are assumed to equal their 1980 maximum levels for the remaining plant life. This assumption seems inconsistent with recent studies of age-performance profiles for coal plants. Further, maintaining constant age-performance profiles is costless in the current version of the model since maintenance expenses during planned outages do not depend upon age. It should be noted that the extent of the age-performance deterioration is controversial and not well established. To the extent that performance does deteriorate, however, the constant 1980 capacity factor assumption will increasingly overstate emissions unless existing plants are retrofitted to NSPS. This issue, and more generally the economics of the coal generating unit age-performance relationship, should receive high priority in subsequent model research.

28. It should be noted that virtually all dispatching and production costing algorithms currently available are not well suited to simulate scenarios that are more than marginally different from "business as usual," "least cost" scenarios. Scenarios that would result in the generation or transmission systems operating far from those situations for which they were planned and constructed would require the use of a dispatching technique that could pick up a myriad of additional constraints and limitations of those transmission and generation systems. An especially important example is that the transmission system cannot be assumed to be capable of handling the very different transmission patterns that would result from a substantial emissions reduction scenario, or a least-emissions dispatch scenario. A dispatching technique with capabilities in these areas would possibly require an improvement to the state-of-the-art of dispatch modeling.

It is difficult to generalize on the type of bias that might be introduced by these issues of "detail." However, if the model is pushed into areas of substantial emissions reductions, or least emissions dispatching, in our opinion the AUSM Dispatching Module will substantially understate the costs and overstate the emissions reduction capabilities of the "state utilities."

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[2]Mount, Timothy D [1983], "Demand Module," Chapter 2 in The State-Level Advanced Utility Simulation Model: Program Documentation. URGE Project Office, University of Illinois at Urbana-Champaign, September, p. 2-36.

Financial Module

<u>Description</u>. The financial module is the last of the various modules of state-level AUSM to be executed. The module performs two main functions. It calculates the revenue accordance with the rules generally administered by the regulatory commissions in each state. The rate schedules that are used in the demand module to model electricity prices are recursively updated with information from this revenue requirements calculation. The financial module also tabulates and updates various financial statements, including the income statement, the balance sheet, and the sources and uses statement. It also calculates various interest coverage and profitability ratios from the financial statement data.

To make these calculations the financial module uses both exogenous financial data and information that it obtains from the other modules of AUSM. The information obtained from the other modules corresponds to

- purchased power costs and operating revenues from the demand module
- the construction program for generation, transmission, and distribution plant and equipment from the capacity planning module
- the costs of pollution control technologies (for both new and retrofit application) from the pollution control module
- the operating costs of the existing transmission and distribution network from the capacity planning module
- the fuel and operating costs of generation system from the dispatch module.

In computing the revenue requirements and financial statements, the financial module breaks the calculations into the following steps:

- It recursively updates the value of the rate base by adding in the value of new plant and equipment that enters commercial operation and deducting depreciation.
- It keeps track of construction cash flows for new plant and equipment and the corresponding values of the allowances for funds used during construction (AFUDC).
- It performs detailed depreciation calculations for regulatory and tax purposes, taking into account the depreciation laws that apply to various vintage assets and the peculiarities of the tax code that apply to special classes of utility assets.
- It calculates the income tax and other tax obligations of the industry, given a tabulation of actual operating revenue passed to the module from the demand module.

- It calculates total revenue requirements for the electricity sector in each state, given fuel and operating costs passed from the dispatch module, taxes and depreciation as computed above, and a return to capital consistent with the financial structure of sector and the rate base treatment of various tax allowances computed above.
- It simulates the financing of new plant and equipment to be consistent with a target capital structure for the firms operating within the state.
- It tabulates various common financial statements, including an income statement, a balance sheet, and a sources and uses statement for each state for each year of coverage and profitability ratios from the financial statement data.

These calculations, though sometimes quite complicated and complex as a result of the tax laws and regulatory practices that apply to this industry, appear to be carefully executed and, for the most part, documented quite clearly.

Issues.

29. As presently structured the module does not allocate the costs of plants jointly owned by utilities across the state lines to the states involved; rather the costs are attributed entirely to the state in which the plant is sited. Further, the overall model appears to be structured in a way that makes complicated the modifications that would be necessary to allocate the costs properly. This problem has received considerable attention from the modelers and the sponsors. The extent of the problem appears to be limited to 36 generating plants in the country, indicating that if special care is exercised in applying the model to analyses for the states affected, then the effects can be confined.

30. A shortcoming for at least some states is the assumption that the financial calculations in all states can be approximated by rules that apply to privately owned firms. The modeler principally responsible for specification of the financial module indicated that he attempted to select economic parameters for states with significant publicly owned segments which approximate public decision values, such as tax exempt, low interest debt, no preferred equity, and no corporate tax. Tennessee and Nebraska were specifically mentioned as states for which these approximations were adopted. The user should be aware that other states may require that care be exercised, in particular those that possess a substantial publicly owned industry segment.

31. A shortcoming for all states is that the financial module's financing calculations are premised upon there being no constraints on the amount of new external financing available. The requisites amount of external financing is

assumed to be available as needed with no constraints to maintain a target capital structure of the industry within the state. The effect is to overestimate the ease with which the industry can respond to any policy that requires more capital, such as more stringent pollution control policies, and understate the costs as a result.

32. As noted in issue (9) above, there is a question relating to the calculation of the actual operating revenue. The actual operating revenue is not tabulated in the financial module; it is passed to the module from the Demand Module. However, the rate schedules of the demand module are updated with the result of the revenue requirements calculation of the financial module, and the rate schedules are used to calculate the operating revenue in the demand module, which gets passed back to the financial module. Thus, though the operating revenue calculation is actually performed in the demand module, it is an integral part of the financial module's logical structure.

There appears to be an inconsistency between the actual revenue and required revenue calculations. It occurs by way of the update that is applied to the two part rate schedules that are used in the electricity demand module. The parameters of the rate schedules were estimated from historical data and their update is not necessarily consistent with their empirical definition. The result of it all is that it will bias the electricity demand growth outcomes of the model whenever electricity demands are being calculated endogenously. For any policy issue for which the absolute level of emissions is important this could be a serious shortcoming.

33. It appears that independent regulatory and financial parameters different from those employed in this module are used in the Pollution Control Module in determining lest cost pollution control investments. If in fact different parameters are possible, the user should ensure they are equal or consistent, and subsequent versions of the AUSM should eliminate this possibility.

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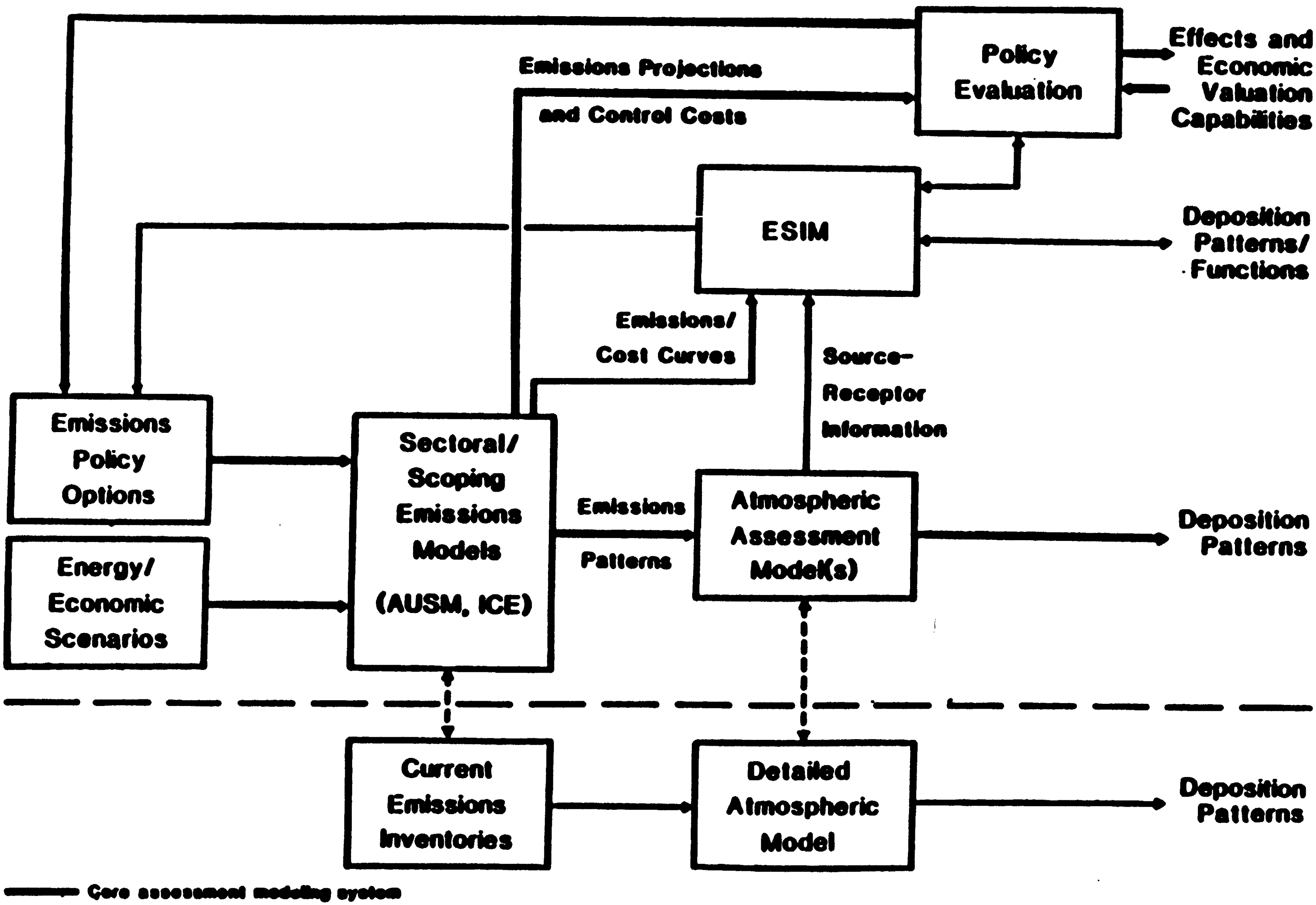
Figure 1-1



Policy Evaluation
Effects and Economic Valuation Capabilities
Emissions Projections and Control Costs
ESIM
Deposition Patterns/ Functions
Emissions/ Cost Curves
Source-Receptor Information
Emissions Policy Options
Energy/ Economic Scenarios
Sectoral/ Scoping Emissions Models (AUSM, ICE)
Emissions Patterns
Atmospheric Assessment Model(s)
Deposition Patterns
Current Emissions Inventories
Detailed Atmospheric Model
Deposition Patterns
Core assessment modeling system

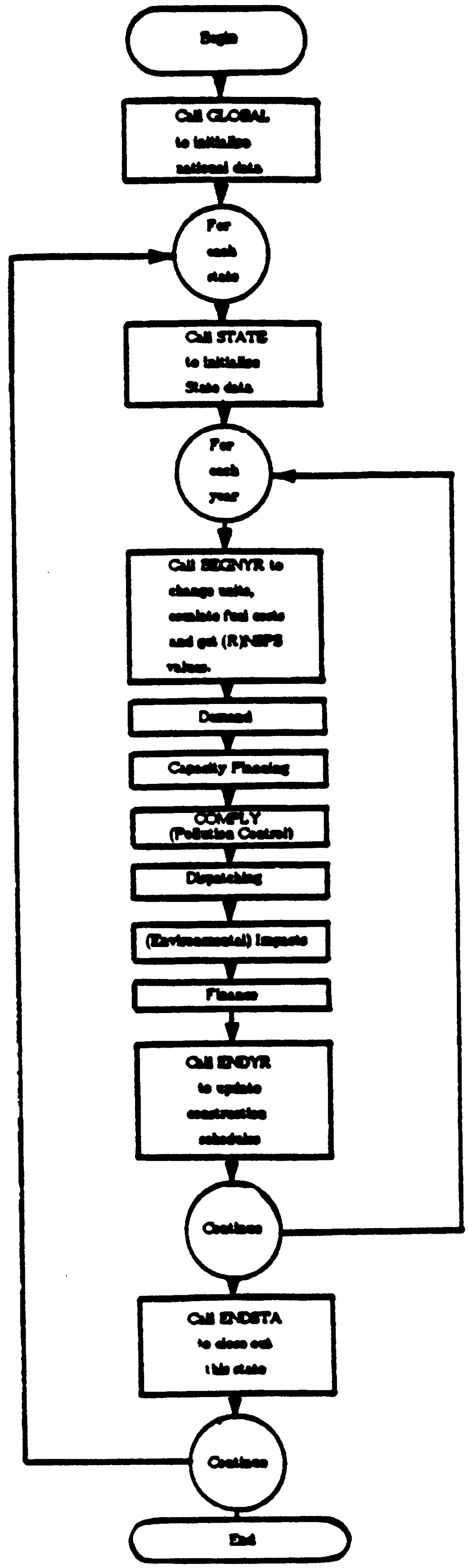


Figure 1-2 AUSM Logic Flow

Table 1-1

STRATEGIES: REGIONAL EMISSION CEILING POLICY FOCUS

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1. **Technical Regulatory Changes: Absolute Emission Limitations**

   1.1 By state
   1.2 By region
   1.3 By generating unit
   1.4 By type of unit (SIP and NSPS)

      1.4.1 Changes in averaging times of SIP units
      1.4.2 Redefinition of plant modification
      1.4.3 SIP rollback
      1.4.4 Nonenforcement of SIPs
      1.4.5 Emission charges-transferable discharge permits

2. **Financial Regulatory Changes**

   2.1 Revenue-setting policies
   2.2 Corporate income tax investment incentives
   2.3 Pollution control costs

      2.3.1 Changing investment tax credit
      2.3.2 Rate base treatment, tax depreciation
      2.3.3 Interest rates

3. **Control Options**

   3.1 Coal cleaning: a specific level of cleaning for all coals above a given sulfur content
   3.2 Coal blending
   3.3 Low-sulfur coal
   3.4 Local coal use
   3.5 Nuclear fuel
   3.6 Oil and gas fuel

4. **Technology-Based Regulatory Changes**

   4.1 Wet and dry FGD systems
   4.2 NOx control technologies
   4.3 Particulate control technologies: electrostatic precipitators and fabric filters

5. **System Operating Performance and Utility Behavior-Based Regulatory Changes**

   5.1 Least emission dispatch
   5.2 Shortening or prolonging of plant lifetime
   5.3 Utility strategy for least-cost compliance with regional emission ceilings

6. **Least-Cost Combinations of Fuel and Technology Choice**

Source: "The State-Level Advanced Utility Simulation Model: Analytical Documentation," prepared for the U.S. Environmental Protection Agency by URGE Project Office, c/o Public Policy Program, College of Engineering, University of Illinois at Urbana-Champaign.

Section 2

DEMAND MODULE

by

Ernst R. Berndt and David O. Wood

INTRODUCTION

This chapter reviews the Demand Module of the State-Level Advanced Utility Simulation Model (AUSM).[1] The Demand Module (hereafter DM) is the first module executed in the state-level AUSM. The three functions performed by this module include:

update rate schedules for each end use sector (residential, industrial, commercial, and transportation), and calculate marginal electricity prices for use in estimating current demand;

estimate current period demand and peak load demand net of interstate transfers and losses for the Dispatch and Financial Modules, and calculate the value of interstate transfers for the Financial Module;

estimate state-level generation and peak load net of losses and interstate transfers for each of the next fifteen years for the Capacity Planning Module.

The basic structure of the module is as follows. Current rate schedules and electricity prices depend upon a model of tariff structure reflecting demand and service charges (two part tariff), updated each period to reflect last period's required revenues as well as estimates of this period's changes in variable and fixed costs. Current period demand is estimated by an econometric model of end use sector fuel choice, employing the linear logit specification extended in certain important respects by Considine and Mount [1984]. Future electricity demand is based on an adaptive expectations model.

Our review follows closely the structure of the documentation, in particular Mount [1983]. We first present a description of the module, together with a summary of the important review issues developed in the subsequent Sections. Next we consider the estimation of marginal electricity prices and the updating of the end use sector

[1]This review is based primarily upon Mount [1983] and Czerwinski and Mount [1984]. Our understanding of the econometric demand model employed in estimating current demand, and the adaptive expectations model employed in projecting future demand, relies heavily on Considine and Mount [1984] and Vellutini and Mount [1983], respectively. We also gratefully acknowledge several discussions with Timothy Mount and Timothy Considine which significantly contributed to our understanding of the Demand Module.

rate schedules, followed by reviews the econometric demand model, the estimation of system load characteristics, and the long run electricity requirements, respectively. In a final Section, we present some recommendations for further demand model research, and for evaluation.

DEMAND MODULE DESCRIPTION AND REVIEW SUMMARY

Figure 2-1 summarizes the important data transfers and computations of the DM. The classification of end use sectors, fuels, and the independent variables are presented in Table 2-1. The DM operates as follows.

(1) The starting point in the DM is the rate schedule which determines average electricity prices for each end use sector. The rate schedule is characterized as a two part tariff, with the marginal electricity price and the fixed charge estimated by the slope and intercept coefficients of the schedule, respectively. Historical schedules have been estimated by state for each end use sector based on data from the Federal Energy Regulatory Commissions's Typical Electric Bills (TEB) file, with the resulting estimates reconciled to the Energy Information Administration's State Energy Data Base System (SEDS), the data base used in estimating the econometric demand model.

A central feature of the DM is the set of procedures for updating the rate schedules in forecasting applications. For the next period, say t+1, rate schedules are updated as a function of period t required revenue (from the Financial Module), and estimates of period t+1 allowable rate changes due to changes in variable and fixed costs. Since separate schedules are calculated for each end use sector, there is scope for allowing regulatory discrimination between end use sectors of changing costs; however, in the version of the model we have reviewed, only separate scalar adjustments for variable and fixed costs are provided for, and these scalars are equal and constant across end use sectors and time.

(2) Marginal electricity prices (the slope coefficients of the estimated rate schedules) plus non-electric fuel prices and the other exogenous variables of Table 2-1 are inputs to the econometric demand model that determines period t+1 electricity demand, as well as the demand for other fuels, in the Residential, Industrial and Commercial end use sectors. The econometric specification of the model is the so-called linear logit specification, with important extensions by the AUSM modelers to deal with some well known limitations of this modeling approach. The endogenous variables of the Residential equations of the model are the value

shares of electricity, the competing fuels, and all other expenditures, in total income. For the Industrial and Commercial equations, endogenous variables are value shares of electricity, competing fuels, and labor in the total expenditures on these inputs; hence, for these latter two sectors, inputs of capital and non-energy materials are excluded under the assumption that they are "weakly separable" from the included inputs in the underlying production function.

In forecasting, the levels of electricity and competing fuel demand in the Industrial and Commercial sectors are determined conditional on a user forecast of the quantity of labor demand, i.e. exogenous state industrial and commercial labor demand sets the scale of production for these sectors. Why labor quantity was chosen to scale these energy demands instead of the more traditional output variables is not clear. For the Residential sector, demand scale is set by a user forecast of state income levels. In the version of the model we have reviewed, Transportation sector electricity demand "... is determined as a fixed fraction of the commercial sector use .. where [the fixed fraction] is the observed ratio of sales in the transportation sector to sales in the commercial sector in 1980" (Czerwinski and Mount [1984], p. C4-9). The output of this part of the DM is, therefore, the estimated end use sector electricity demands and average prices by state for period t+1, which are then aggregated into state electricity demand quantity and value.

(3) The next step involves estimating state electricity generation quantities and values, and the load characteristics of state generation, in particular peak load demand. State generation requirements are based on adjusting the demand estimates for transmission and distribution losses and net interstate transfers of electricity. In the version of the model we have reviewed, losses are calculated using a constant national average loss factor. State load factors (defined as average annual kw/maximum annual kw) are taken from National Electric Reliability Council (NERC) projections for the council region including that particular state. Finally, interstate transfers " .. are treated as a constant, determined from the observed ratio of actual generation to required generation in 1980" (Czerwinski and Mount [1984], p. C4-9).[2] The output from this step is data on state-level generation requirements and characteristics that is input into the Dispatch Module.

[2]See Czerwinski and Mount [1984], p. C4-9, for discussion of the treatment of both losses and interstate power transfers. It should be noted that the documentation emphasizes the "stop gap" nature of these approximations, and that the development of the national model will provide the framework for a more satisfactory treatment of losses and transfers.

(4) The final DM activity is the projection of annual generation requirements and load characteristics for each of the next 15 years. For this purpose, an adaptive expectations model has been specified and estimated separate from the econometric model. This model was estimated using as the dependent variable NERC 10-year projections of electricity demand for the 9 NERC regions, and for the years 1974-1980, and as the independent variable actual generation for the previous 4 periods.[3] In forecasting applications the model employs the state demand requirements estimated by the econometric model, and then adjusts projected state demands for losses and interstate transfers to obtain the projection of state generation requirements for each of the next 15 years. The use of separate models for current period and future annual electricity demands is motivated by the AUSM modelers' view that the adaptive expectations model provides a better approximation than the economic model for representing actual utility forecaster practice and resulting projections.

An interesting feature of the DM is that users may choose to substitute their own demand forecasts as a base case, and then choose whether or not to employ the DM's elasticities in scenario analyses run as changes to the base case. This flexibility should prove very valuable to users who have independent information on likely demand levels, or wish to obtain state-level AUSM results calibrated to demand estimates employed in other analyses.

Before presenting the detailed results of the review, it seems useful to provide a "user's guide" to the main results.

Rate Schedule Estimation and Updating. DM procedures for calculating marginal electricity prices are straightforward and very convenient, for they approximate the rate schedule in terms of a two-part tariff representation. DM procedures for updating rate schedules are also relatively straightforward, and probably establish the current operational state of the art.

There is, however, one potential problem in ensuring that outputs of this part of the DM are consistent with those of the Finance Module. In particular, no constraint is imposed to ensure that the "next period" revenue requirement estimates used in updating rate schedules are equal to actual revenue requirements calculated in the Financial Module after receiving information on capital expansion (both generating capacity and pollution control) and generation from the Capacity

[3]See Vellutini and Mount [1983] for details, and Section 2.6 below for further description and discussion of this model.

Planning, Dispatch, and Polllution Control Modules. This means that the outputs of the Demand and Financial Modules in the current period may be inconsistent, and in particular that the rate schedule and "next period" demands may not be consistent with the actual average electricity price and with the various financial performance and profitability statements calculated in the Financial Module.

It appears to us that the extent of the disparity will vary with the size of the shift in relative fuel input prices and the amount of new capital formation between the current and next period. Because the AUSM model is large and contains numerous equations, however, it is difficult to esablish analytically how various factors will affect this consistency error. Note that the effect of the disparity may accumulate and could become substantial, since both the econometric demand and adaptive expectations models employ a lag structure in estimating current and future generation requirements. Also, both base case and scenario analyses are potentially affected by this problem. As a practical matter, we have no evidence as to the empirical significance of this problem, but note that it could be solved by appropriate iteration of the otherwise recursive structure.

Second, it should be noted that the user provided regulatory lag parameters are presently scalars for fixed and variable costs, and are constant across end use sectors and time. Hence, this version of the model provides no scope for analyzing implications for electricity demand of regulatory discrimination in passing through cost changes to end users, e.g. cost changes due to pollution control investments. This feature of the model seems excessively mechanical, given the distinct possibility that regulatory agencies will discriminate between end use sectors for perceived reasons of equity, economic development, etc.

Econometric Demand Model. This model is used in estimating next period demand primarily for use in the Dispatch Module. The specification is the so-called linear logit specification with some innovative modifications introduced by Considine and Mount [1984]. However, some very serious limitations of the linear logit specification remain, limitations which compromise the consistency of the model with the basic economic theory of demand carefully laid out by AUSM modelers. First, the specification satisfies symmetry conditions at only one point — for all other data points (states, years), the predictions of the model are inconsistent with the basic textbook theory of demand. The modelers attempt to deal with this awkward issue by imposing symmetry at the sample data mean of state electricity demand over time. This choice is, however, arbitrary, and so different parameters, elasticities, and forecasts would be obtained were a different "numeraire" chosen (e.g. state means at last sample point, the value for one very large state, means value for some grouping of most important states, and so on) This is an important practical issue, because the choice of the one data point for which the desirable economic properties will hold is truly arbitrary, and thus the empirical results of the model are unfortunately vulnerable to the charge that the "one economic data point" was "judiciously" chosen. Moreover, even if some rationale could be devised definding a particular choice of data point, results of model simulations for states with differing characteristics would be uninterpretable given the inconsistency with economic principles.

Second, and closely related, while the "sample mean" is constant, its components are the dependent input value shares which are stochastic variables. Hence there is likely to be correlation between this stochastic right hand variable and the disturbance term resulting in inconsistent and biased parameter estimates.

The operational significance of these inconsistencies in terms of forecasting implications have not been evaluated by the modelers. It should be noted, however, that price elasticity estimates associated with this model are low relative to other studies, including other studies by these modelers. Of the elasticity estimates which can be compared with the recent extensisve survey by Bohi [1981], 6 of the 11 comparable long-run own-price elasticities are outside the range of values in the literature (5 lower, 1 higher), and 3 of the 11 comparable short-run own-price elasticities are outside the range in the literature (1 lower, 2 higher). Most importantly, for the electricity own-price elasticities, 2 of the long-run (Residential and Commercial) estimates are below the range of values surveyed by Bohi, and 1 of the short-run estimates (Commercial) is below the range. If the electricity own-price elasticity estimates are, in fact, too low, then for rising electricity prices (the most likely case) demand estimates will be upward biased in both the base case and scenario analyses, thereby providing an upward bias to the estimates of generation, capacity expansion, and — most importantly — emissions.

Load Characteristics and Valuation of Interstate Transfers. As noted above, losses are computed based on a constant national average loss factor in 1980, and peak load demand is based on projected load factors for NERC regions. The documentation emphasizes that these are "stop gap" measures until such time as a regional model is developed. In the meantime a potential user must evaluate their appropriateness for a particular application. Changing these values is, apparently, not difficult.

Regarding interstate transfers, in the version of the model we have reviewed interstate transfers are calculated from the ratio of state actual generation and required generation in 1980, and then valued at the current average electricity price. This is clearly a "stop gap" measure, and presumably has been examined and suitably modified in any applications of the state-level AUSM (e.g. Stukel and Bullard [1984] and Peerenboom et al. [1984]). A user should be aware, however, of the need to ensure that reasonable estimates of interstate transfers are used. As emphasized in the review of the Dispatch Module, this is a serious and substantial undertaking.

Long-Term Demand Projections. Finally, long-run (1 to 15 years) demand projections are made by an adaptive expectations model employing current and lagged total generation requirements from the econometric demand model. The model depends only on lagged generation and years since 1973, and so is independent of any direct information of utility expectations regarding costs, prices, or other factors affecting utility operations and capacity planning. The modelers argue that this approach more nearly reflects actual utility forecasting practice and results. We are suspicious of this decoupling of short and long term demand projections; for example, a recent study by Nelson and Peck [1985] employing similar data used in the DM suggests that utility forecasts in recent years are consistent with dynamic economic models, and that the "failure" of utility forecasts to adjust more quickly to changing circumstances is more likely due to difficulties in forecasting exogenous variables, such as fuel prices and income, than to employing non-economic forecasting models. Hence, even if non-economic demand projection models typify utility forecaster behavior prior to, and immediately after, the 1974 embargo, that is not a sufficient reason to assume that such models are appropriate in the post-embargo era or will be so in the future.

We now turn to the details of our review of the AUSM Demand Module.

MARGINAL ELECTRICITY PRICES, AND THE RATE SCHEDULE

Marginal Electricity Prices. We begin our summary discussion by outlining how electricity prices are computed for use in the AUSM Demand Module. The principal structural innovation embodied in AUSM is that electricity prices are represented as being functions of a two-part tariff for each of the three sectors—residential, commercial and industrial. Use of the two-part tariff is very convenient because it permits a clear distinction to be made between marginal and average prices facing consumers, it allows capital (generation, transmission and distribution) and variable (especially fuel) costs to be allocated between the two parts of the tariff, and finally, it is computationally simple and therefore convenient for modelling.

Denote the quantity of electricity demanded in annual kilowatt hours during year t as KWH_t, and the average price of electricity as $\overline{P}_{ELEC,t}$. The revenue (R_t) derived by the utility from these sales at this average price equals

$$R_t = \overline{P}_{ELEC,t} \cdot KWH_t \quad . \tag{1}$$

In a two-part tariff, revenue is related to quantity sold as follows:

$$R_t = a_t + b_t \cdot KWH_t \quad . \tag{2}$$

When the "fixed" or "customer" charge a_t is positive, $b_t < \overline{P}_{ELEC,t}$, i.e., the "marginal" price of electricity is less than the average price; when $a_t = 0$,

$$b_t = \overline{P}_{ELEC,t} \quad .$$

The first task the AUSM demand modellers undertake is to obtain estimates of a_t and b_t for each of the three consuming sectors, each of the 48 states, and for the period 1967–1979. Since the "true" rate schedule is considerably more complex than that captured by a two-part tariff, use of the two-part tariff introduces an approximation errir. Based on data from the Typical Electric Bills (TEB) publication,[4] AUSM modellers estimate the a_t and b_t using least squares regression analysis. We denote these estimates as $\hat{a}_t$ and $\hat{b}_t$—which are computed separately for each year, sector, and state; parenthetically, it might be noted only three or four data points are used for each regression (See Mount [1983], p. 2-7, for discussion). It is therefore not not too surprising that linear and quadratic approximations were similar—for the degrees of freedom in estimation are already very small.
Using these parameter estimates, AUSM modellers calculated the implied revenue based on actual observed electricity demand as,

$$\hat{R}_t = \hat{a}_t + \hat{b}_t KWH_t \tag{3}$$

and compared this "predicted" revenue with the actual revenue (by state, sector and year) as found in the U.S. Energy Information Administration's "State Energy Data System" (SEDS).[5] Since the SEDS data base incorporated all-state consumption and revenue while the TEB data is based

[4]U.S. Department of Energy, Typical Electric Bills, published monthly.

[5]TEB data are monthly, while SEDS data are annual. Presumably the TEB data were in some sense "annualized" or "averaged," but how this was done is not clear.

only on that for urban customers, $\hat{R}_t$ differed from the observed R_t; as noted in Mount [1983], 2-7, 2-8, the differences were not great in the residential and commercial sectors, but discrepancies were more substantial in the industrial sector.

Because of this inconsistency between TEB and SEDS, and because the SEDS data base was to be used in estimation, it was necessary to modify the TEB-based parameters $\hat{a}_t$ and $\hat{b}_t$ so that $\hat{R}_t = R_t$ from SEDS. There are, of course, numerous ways in which this reconciliation could be done—indeed, there are an infinite number of possibilities. The procedure employed in AUSM is to take the ratio of the TEB-based "predicted" average price at the average (monthly) consumption level for each sector to the SEDS-based observed actual price—call this ratio z_t, i.e.,

$$z_t = \frac{\dfrac{\hat{a}_t}{KWH_t} + \hat{b}_t}{\bar{P}_{ELEC,t}} = \frac{\hat{\bar{P}}_{ELEC,t}}{\bar{P}_{ELEC,t}} , \tag{4}$$

and then simply define a new re-scaled two-part tariff as

$$\hat{R}_t = a_t^* + b_t^* \cdot KWH_t \tag{5}$$

$$\text{where } a_t^* = \frac{\hat{a}_t}{z_t} , \quad b_t^* = \frac{\hat{b}_t}{z_t} . \tag{6}$$

Note that with this new estimated two-part tariff, at the average level of consumption, $\hat{R}_t = R_t$, and moreover, the ratio of the original fitted average price to the original fitted marginal price based on (3) will be the same as the ratio of the new average fitted price to the new marginal price based on (5) and (6).

It is interesting to note that for the industrial sector, the difference between $\hat{b}_t$ and b_t^* was substantial, i.e., $\hat{b}_t > b_t^*$, which implies by (6) that $z_t > 1$ — the original fitted average price was considerably larger than the original actual average price paid by the industrial sector. Why this occurred and what it implies for the validity of the two-part tariff approximation in this sector is not discussed in the AUSM documentation.

These marginal electricity prices—the b_t^* —are then used by AUSM modelers to estimate demand elasticities. We will return later to a discussion of how these two-part tariffs are incorporated into the estimated demand equations.

Updating Rate Schedules. Having discussed how marginal prices and two-part tariffs are calculated for purpose of estimating demand responses, we now summarize our understanding of AUSM procedures for "updating" the rate schedules ". . . so that estimates of actual revenue and the 'required' revenue determined in the financial module can be used to set the customer charges and marginal prices in each sector for the following year" (Mount [1983], p. 2-9).

The issue we want first to address is, how is next year's expected electricity price determined? Note that this expected electricity price will then, together with the estimated demand curve, yield an estimate of next year's demand for electricity by sector and state.

Define the average electricity price at time t as the sum of the average fuel cost FC_t and the average non-fuel cost NF_t, i.e.,

$$\overline{P}_{ELEC,t} = \overline{FC}_t + \overline{NF}_t \tag{7}$$

Suppose that it is envisaged that fuel prices and therefore fuel costs will increase in the coming year. The expected amount of this increment to the average fuel cost associated with expected changes in fuel prices is calculated as

$$\Delta\overline{FC}_{t+1} = \overline{FC}_t(\text{Expected Average Fuel Costs}_{t+1}/\text{Actual Fuel Costs}_t) \tag{8}$$

where the ratio of expected average fuel costs in time period t+1 to actual fuel costs in year t is computed using the sum over fuels of expected fuel-specific prices in year t+1 (the source of these data is not given), each multiplied by current year consumption, all divided by current year costs, i.e.,

$$\frac{\text{Expected Average Fuel Costs}_{t+1}}{\text{Actual Fuel Costs}_t}$$

$$= \frac{P^E_{1,t+1}X_{1,t} + P^E_{2,t+1}X_{2t} + \cdots + P^E_{n,t+1}X_{n,t}}{P_{1,t}X_{1,t} + P_{2,t}X_{2,t} + \cdots + P_{n,t}X_{n,t}} \tag{9}$$

where the $P^E_{i,t+1}$ are expected fuel prices in year t+1, the $P_{i,t}$ are actual current prices, and the $X_{i,t}$ are current-year fuel demands required for current-year generation.

It should be noted here that use of (9) is appropriate only if possibilities for interfuel substitution in electricity generation will in no way be exploited by the utility in response to relative fuel-price changes; to the extent that such short-run fuel-switching substitution possibilities are exploitable, (8) and (9) will overstate potential average fuel cost increments. In terms of representing actual rather than economically optimal regulatory responses to expected fuel price changes, this representation may however be quite reasonable.

We now turn to the effects of expected changes in non-fuel costs in year t+1 on the expected rate structure for year t+1. It is assumed by AUSM that at year t regulators are fully aware of the current-year discrepancy between revenue requirements (RR_t) and actual revenue (R_t), and that this discrepancy per unit of KWH_t generated is expected to continue and thus is passed on by the proportional adjustment factor θ_1, i.e.,

$$\Delta RR_{t+1} = \theta_1(RR_t - R_t)/KWH_t \tag{10}$$

where θ_1 is a state-specific parameter that is assumed by AUSM to be equal across sectors and constant over time. It should be emphasized here that this θ_1 parameter is in fact a policy tool or instrument available to regulators and, perhaps, legislators; thus in a policy analysis context it should be viewed as variable rather than fixed, and also not necessarily equal across sectors. In particular, the amortized costs of pollution abatement capital could be passed on to consumers in different proportions—such as, for example, those corresponding to Ramsey pricing rules where the θ_1 might vary inversely with the price elasticity of demand.

The $\Delta\overline{FC}_{t+1}$ and ΔRR_{t+1} components are then used to update the two-part tariff as follows. If the original two-part tariff for year t is written as

$$R_t = \hat{a}_t + \hat{b}_t KWH_t \ , \tag{11}$$

then the updated or expected rate structure for year t+1 becomes

$$R_{t+1} = \hat{a}_{t+1} + \hat{b}_{t+1} KWH_t \tag{12}$$

$$a_{t+1} = a_t\left(\frac{\overline{NF}_t + \Delta RR_{t+1}}{\overline{NF}_t}\right) \tag{13}$$

and

$$\hat{b}_{t+1} = \hat{b}_t + \theta_2\, \Delta\overline{FC}_{t+1} + (\hat{b}_t - \overline{FC}_t)\, \frac{\Delta RR_{t+1}}{\overline{NF}_t} \tag{14}$$

where θ_2 is the (state-specific) fuel-adjustment flow through parameter. Apparently, AUSM treats θ_2 as constant over time and equal across sectors—the previous discussion on θ_1 being a policy instrument therefore also applies here.

In terms of interpretation, according to (12), the intercept or customer-charge term of the two-part tariff is updated by the proportional change in allowed expected non-fuel costs; similarly, the slope or marginal price term is updated by adding to the current year marginal price the allowed increase in average fuel costs ($\theta_2 \cdot \Delta\overline{FC}_{t+1}$), plus an amount representing the difference be tween the current marginal price and current average fuel costs ($\hat{b}_t - \overline{FC}_t$) times the percentage charge expected in allowed non-fuel costs ($\Delta RR_{t+1}/NF_t$). Note that this last term incorporates into the updated rate structure the effects of departures from marginal (average fuel) cost pricing.

Once this updated rate structure is calculated for each state and sector in year t+1, and after other appropriate forecasted variables are also forecasted (e.g., demographic, income, and GNP variables), the year t+1 rate structure (12) is inserted into the estimated demand equations, and "forecasted" demand in year t+1 is then obtained. Denote this expected year t+1 demand, forecasted in year t, as $E_t(KWH_{t+1})$.
The $E_t(KWH_{t+1})$ values are then passed on to other modules of the AUSM model where they are used to obtain estimates of, among other things, generation costs and a new estimate of year t+1 expected revenue requirements, denoted here as $RR_{t+1}[E_t(KWH_{t+1})]$. How possible discrepancies between these $RR_{t+1}[E_t(KWH_{t+1})]$ and those generated by (10) are recognized and accommodated is not stated inthe documentation, although it is obvious that an iterative technique could be employed to ensure consistency. For the moment, however, it is important to note that such a consistency is not ensured by the construction procedures outlined here, and that potential discrepancies caused by forecast errors could accumulate over time to become substantial.

In summary, the development and updating of rate schedules in the DM is quite impressive, and likely represents the state of the operational art in electricity demand modeling. We have noted two relatively minor points to keep in mind when using and interpreting DM results. First, the procedure by which the TEB and SEDS data base estimates of average electricity prices are reconciled in terms of fixed and marginal electricity charges is of necessity arbitrary. The scalar adjustment procedure is the easiest reconciliation procedure, available; however, some discussion of possible biases would be useful. For example, is the two-part tariff a reasonable approximation for the Industrial sector where demand charges often comprise a major portion of the customer's total charge? Might it not be better to estimate separately energy and demand components for this sector?

Second, it should be kept in mind that estimating fuel cost adjustments assumes, in effect, no substitution possibilities between different generation types, i.e. that merit ordering in dispatching is unaffected by changes in fuel prices. This is clearly wrong, but probably of small consequence unless dramatically large relative fuel price changes occur for generating types with a large share in total generation. We note that the "correct" weights could be found by introducing iterating methods into the otherwise recursive model.

Perhaps of greater potential significance is the lack of regulatory policy options for rate adjustment, and the difference between estimated and actual revenue requirements in the current period. The former can be handled by introducing sector- (and perhaps, time-) specific adjustment parameters — parameters that might in principle be estimable if appropriate data were available. The second problem — ensuring consistency — could be resolved by introducing an iterative method into the otherwise recursive model solution procedures.

We next turn our attention to the specification, estimation, and interpretation of the sector-specific electricity and other fuel demand equations.

SPECIFICATION AND ESTIMATION OF ENERGY DEMAND EQUATIONS

In the previous Section we have summarized AUSM procedures for calculating marginal electricity prices, and for updating the rate schedules to determine revenue requirements. While both of these procedures are very important in the AUSM model, they are nonetheless less central to electricity demand projections than are the basic energy demand equations which are specified and employed in AUSM. In this section, therefore, we devote considerable attention to these critically important electricity and other energy demand equations.[6]

[6] This discussion draws heavily on Considine and Mount [1984], as well as Mount [1983].

As the AUSM modelers note, a variety of approaches to demand response estimation have been developed and implemented in the last decade. AUSM modelers developed their own approach based on three principles:

i. The functional form chosen must be reasonable with common sense and with economic theory in that budget or cost shares must always be in the range of zero to 100% (this is not the case with the well-known constant elasticity of substitution functional form, for in such a case sustained price increases could result in expenditures that more than exhaust income); moreover, the implied demand functions must slope downward, must be symmetric, and must have the appropriate curvature;

ii. the demand equations must be consistent with the dynamic characteristics of energy demand, in that short-run responses should be more constrained than in the long-run, for in the long-run the energy-using equipment can be replaced with vintages embodying different energy-using designs and characteristics; and,

iii. the demand equations must not rely on capital stock data, for such data by sector are often not available at the regional or state level of detail.

To these three principles of AUSM, we find it useful to add the following:

iv. the estimated demand elasticities must be robust in the sense that elasticity estimates should not be affected by truly arbitrary decisions such as which price is used as the numeraire, or at which data point symmetry is imposed;

v. econometric estimation procedures employed should provide parameter estimates that, at least in large samples, are consistent and unbiased; and

vi. the model specification should employ the "best practice" procedures currently available, and estimates should be based on data including the most recent available.

The central novel contribution of the AUSM approach to demand model involves use of the linear logit model. Students of energy demand modelling might wonder, however, in what sense use of a linear logit model for explaining energy input demand shares constitutes a novel contribution, for the linear logit model was used more than a decade ago already used in the famous U. S. Department of Energy Project Independence report, in that context was severely criticized by Hausman [1975],[7] and was even more thoroughly discredited by Oum [1979]. It should immediately be noted, however, that Considine and Mount [1984] do deal with some (but not all) of the issues raised in the Hausman and Oum critiques of the linear logit specification.[8] Some background may be useful.

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[7] See especially Hausman's [1975] Appendix, pp. 549-551.

[8] It is surprising that in their otherwise careful study, Considine and Mount do not cite or address directly the Hausman [1975] and Oum [1979] criticisms.

In Oum's critique, two types of linear logit models were examined. Denote the cost or budget share of the ith good as w_i, $i = 1,2,\ldots,M$, its price as P_i, its quantity demanded as Q_i, and other exogenous variables affecting cost shares as X_n, $n = 1,2,\ldots.N$. In the Type 1 price-ratio linear logit model, the specification takes the form

$$\ln (w_i/w_M) = a_{io} + a_{i1}(P_i/P_M) + \sum_{n=2}^{N} a_{in} X_{in}, \quad i=1,\ldots,M-1, \tag{15}$$

while in the Type 2 price-difference linear logit model the form is

$$\ln (w_i/w_M) = a_{io} + a_1(P_i - P_M) + \sum_{n=2}^{N} a_{in} X_{in}, \quad i=1,\ldots,M-1. \tag{16}$$

Note that in the Type 2 specification, the a_1 is constrained to be equal across equations, while in Type 1 formulations this restriction is not typically imposed. In both cases, however, an additive disturbance term is appended to each of the M-1 equations, which is then typically estimated by the method of maximum likelihood. Oum notes that both Type 1 and Type 2 linear logit specifications have been used extensively in the literature, but that each has serious if not fatal flaws. Oum [1979, p. 381] summarized these problems as follows:

> The linear logit models of Type 1 ("price-ratio" model) have the following weaknesses as demand models:
>
> (1) The elasticities of substitution and the price elasticities are not invariant to the choice of base mode M.
>
> (2) A certain choice of base mode amounts to imposing rigid *a priori* restrictions on the relationships between the elasticities of substitution and the corresponding price ratios, and these restrictions are contradictory to the ones that would have been imposed under a different choice of base mode.
>
> (3) The preference (or technology) structure underlying the multinomial logit model of Type 1 is inconsistent and irregular because there are two different measures for the elasticitiy of substitution between any two non-base modes i and j: one when ith price is held constant and the other when jth price is held constant. Therefore, it is meaningless to measure the price responsiveness of demands using the multinomial logit model of Type 1.
>
> (4) All cross price elasticities with respect to the price of any given "nonbase" mode are restricted to be equal.
>
> Similarly, the linear logit model of Type 2 ("price-difference" model) has the following weaknesses as a demand model:
>
> (1) The technology (or preference) structure underlying both binomial and multinomial logit models of this type is inconsistent and irregular

because of the existence of two different measures for the same elasticity of substitution. Therefore it is meaningless to try to measure the price responsiveness of demands using the logit models of Type 2.

(2) All cross price elasticities with respect to the price of any given mode, including the base mode M, are restricted to be equal. This is also an extremely unrealistic restriction.

One advantage of the Type 2 (price-difference) model over the Type 1 (price-ratio) model is that neither the elasticties of substitution nor the price elasticities depend on the choice of "base" mode M in Type 2 models.

In summary, therefore, according to Oum, the linear logit model fails to satisfy the AUSM principle (i) — the lack of symmetry makes demand functions inconsistent with the basic economic theory of demand, fails to satisfy our principle (iv) — estimated elasticities lack invariance to the arbitrary choice of which good is "M", the "base" good, and by implication, fails to satisfy our principle (vi) — uses current "best practice" modelling and estimation procedures.

Fortunately, as was noted earlier, the AUSM linear logit specification differs both from the Type 1 and Type 2 linear logit formulations evaluated by Hausman and by Oum, although, as we shall see, some of their criticisms still apply to the altered linear logit specification. We now turn our attention to the AUSM formulation.

As stated in Considine and Mount [1984], consider the linear logit specification

$$\ln (w_i/w_M) = f_i - f_M , \qquad (17)$$

where

$$f_i = a_i + \sum_{j=1}^{M} c_{ij} \ln P_j + g_i \ln Y, \qquad (18)$$

and where the a_i, c_{ij}, and g_i are unknown parameters to be estimated, and Y is the level of output (or, in the case of the residential sector, the per capita level of income).

The first point to note is that (18) is very similar to the share equations obtained by logarithmically differentiating the well-known translog cost function. However, there is one very important difference. In the AUSM specification, f_i does not equal the share w_i, but rather is related to the logarithm of w_i,

$$w_i = \frac{e^{f_i}}{\sum_{j=1}^{M} e^{f_j}} \quad . \tag{19}$$

This formulation has important implications for imposing the homogeneity and symmetry conditions which are required by the economic theory of utility, cost and production. Specifically, although it is simple to impose constant returns to scale (set $g_i = 0$ for all $i = 1,\ldots,M$) and linear homogeneity in prices ($\sum_j c_{ij} = 0$ for all i), the symmetry of demand functions in prices can be imposed only by constraining

$$w_j \, c_{ij} = w_i \, c_{ji} \quad \text{for all } i \neq j. \tag{20}$$

What is significant about (20) is that the imposition of symmetry — a constraint absolutely critical for the model to make any economic sense — involves the cost shares w_i and w_j, which vary of course from one observation to another. Since the imposition of symmetry involves not only parameters but also data that varies from one observation to the next, there is no way symmetry can be imposed globally, unless of course it is done trivially by setting $c_{ij} = c_{ji} = 0$. Rather, symmetry can only be imposed locally — at one selected data point.

AUSM modelers attempt to handle this awkward situation by selecting particular values for the w_j. A large number of possibilities are available, at least as many as there are data points. In addition, one could use the mean cost shares across states at the first annual (1967) observation in the sample, or one could use the mean cost shares across states of the most recent annual observation (1979), or one might even use the sample arithmetic means over all states and years. AUSM modellers employed this last option, and then inserted these mean values in (20) to impose symmetry. When this was done, the c_{ij} parameters were redefined as

$$c^*_{ij} = c_{ij} \,/\, \bar{w}_j \text{ , where } \bar{w}_j \text{ is the sample mean of } w_j \text{ .} \tag{21}$$

Note that the c^*_{ij} in (18) were then estimated econometrically rather than the c_{ij}.

A number of comments are in order concerning implications of this AUSM procedure. First, note that such a procedure implies that symmetry is valid only at one point — that of the arithmetic means of the historical sample. For all other data points, including of course the data involved in projections, or for states that are large or small relative to the historical mean, the AUSM specification is inconsistent with the economic theory of demand, for symmetry cannot be imposed. This implies of course that projections or sensitivity analyses involving estimated responses to alternative electricity prices resulting from, say, installation of pollution abatement capital, will not be consistent with the most basic and fundamental aspects of the economic theory of demand. This inconsistency is a very basic and serious flaw of the AUSM specification of the linear logit model, and in fact violates their own principle (i). Its practical significance should not be underestimated, since any analysis of distributional effects of electricity price changes will be uninterpretable if the state happens to have shares that differ from this historical national average.

Second, since the data on $\bar{w}_j$ are employed in imposing the local symmetry restriction, it is of course the case that all estimated parameters and elasticities will differ depending on which data point is used in (20) and (21). For example, if AUSM modelers had chosen the sample over states for the last year in their historical data set (1979) — that corresponding most closely to the most recent environment faced by utilities, the estimated parameters and elasticities would differ from those reported in their documentation. Similarly, if the sample were instead weighted by expenditures or volumes (thus allowing the larger states to have a greater impact than their $(1/50)^{th}$ weight given by AUSM), parameter estimates would differ.

How much the results would change is of course unknown at this point. However, if someone took a particular disliking to the simulation results generated by AUSM, that individual could arbitrarily choose a different data point for imposing symmetry, re-estimate the model econometrically using the same historical data, and obtain different results, perhaps more in line with prior beliefs and/or preferences held by that individual, or the organization he/she represented. This lack of invariance of the estimated AUSM linear logit specification to the arbitrary choice of data point at which symmetry is imposed is unfortunate, is inconsistent with principle (iv) mentioned at the beginning of this section, and reduces of course the reliability and credibility of any simulation results. Moreover, if the model were used in a regulatory or other adversarial setting this lack of invariance to a truly arbitrary choice of numeraire could lead to distractions and unproductive disputes.

Third, even if one would ignore both of the above problems — that the estimated model is inconsistent with the economic theory of demand at almost all data points, and that its results lack invariance to the choice of point at which symmetry is imposed — there is another econometric problem. Specifically, since in the AUSM linear logit specification and implementation the imposition of symmetry involves using the sample means of the cost shares as in (21), the estimated model has the logarithm of the cost share ratio as a left-hand or endogenous variable, and the arithmetic mean of the same endogenous cost share as a right-hand or exogenous variable. Hence the cost share appears in one form or another on both sides of the estimating equation. Note that while the mean of the cost shares is constant over a given sample, this mean is still stochastic in that the data can be viewed as being a sample from a larger population. As a result, there is likely to be a correlation between this stochastic right-hand variable and the disturbance term, resulting in inconsistent and biased parameter estimates. In this sense, therefore, the AUSM linear logit specification violates principle (v) mentioned above.

Fourth, we note that while the AUSM linear logit specification is dynamic in that lagged quantities appear as a right hand variable, there are problems with it. Contrary to the Considine-Mount [1984] claim that their seemingly ad hoc model is identical to one based on sophisticated dynamic optimization, it should be noted that this equivalence holds only for the quasi-fixed input equations (such as that for capital input), and not for the variable input equations such as that for electricity, oil, gas, etc. (Note also that not all inputs can be quasi-fixed — there needs to be at least one variable input.) For the equation specification to be consistent with dynamic optimization, levels of capital stock must appear as a right hand variable in the variable input demand equations. Hence the AUSM dynamic specification is in fact ad hoc.

Further, since the partial adjustment matrix in the AUSM dynamic specification is diagonal with equal elements along the diagonal, a feasibility problem emerges. Specifically, let production be characterized by constant returns to scale (as is assumed in AUSM) and suppose output doubles. In the AUSM specification, all inputs adjust upward by a proportion λ, $0 < \lambda < 1$. But how can production double when all of the inputs less than double? This output feasibility problem can be handled at least in principle by permitting the adjustment matrix to be non-diagonal, so that some short-run overshooting is possible, as was argued by Nadiri-Rosen in the article cited by Considine and Mount. Provided that the adjustment matrix were non-diagonal, at least in principle the output feasibility restriction could be approximated. However, full consistency with the output feasibiility restriction requires a more explicit specification of a short-run production or cost function. For further discussion, see Berndt, Fuss, and Waverman [1977].

Finally, there is an issue regarding the manner in which the estimated share equations are employed in forecasting quantities of electricity, fuels, and other inputs. Recall from (17) that the estimated model may be written as,

$$\ln (w_i/w_M) = g_i \tag{17'}$$

where $g_i = f_i - f_M$. Noting that $w_i = e^{g_i} \cdot w_M \longrightarrow w_M = 1 - \Sigma\, w_i = 1 - \Sigma\, e^{g_i} \cdot w_M$, we may solve (17') for w_M and w_i as,

$$w_M = 1 \,/\, (1 + \sum_{i=1}^{N-1} e^{g_i}), \qquad w_i = e^{g_i} \,/\, w_M \qquad (i = 1, .., M-1) \tag{17''}$$

Given the factor expenditures shares and factor prices, the factor quantities in AUSM are calculated either by specifying exogenously the expenditure total (income in the Residential model), or one of the factor quantities (labor in the Industrial and Commercial models). This second method — fixing labor quantity inputs — is inconsistent with sequential decision making process implied by the model. To see this, note that the solution for any endogenous factor quantity is,

$$q_i = (e^{g_i} \cdot p_L \cdot q_L) \,/\, p_i \quad .$$

Since the p_i are given, this implies that total expenditure on electricity, fuels and labor is now endogenous. But the sequential decision making process assumed in specifying the estimation models is that industrial and commercial firms first allocate input expenditures for a given level of production into two bundles including (i) electricity, other energy inputs, and labor, and into (ii) a bundle consisting of capital and non-energy material inputs. Given that only expenditure shares of the first bundle are modeled, the natural variable to set the scale of production would be the total expenditure on electricity, fuels, and labor.

Why is it important to maintain the same exogenous and endogenous variables in the estimating and forecasting models? The reason is that the homogeneity restrictions are not invariant to a change in endogenous variables. In particular, linear homogeneity in factor prices implies that,

$$\sum_{j=1}^{M} \epsilon_{ij} = 0$$

Fixing L independently is equivalent to setting $\epsilon_{LL} = 0$. Continuing to employ the estimated ϵ_{iL} introduces non-homogeneity into the forecasts, and so the forecasting model is inconsistent with the estimated model.[9]

It should be noted that this problem is not easily corrected. Projecting expenditures for the electricity, fuels, and labor subfunction without information on the underlying production function that relates output to capital, non-energy materials, and the factors included in the subfunction is, at best, problematic. This is not a problem with the linear logit specification, but rather an issue of data availability.

In summary, therefore, while the AUSM modification of the linear logit model incorporates innovations which circumvent some of the criticisms articulated by Hausman [1975] and Oum [1979], this modified linear logit specification is seriously deficient in that, (i) it is consistent with the most basic postulates of economic theory of demand at only one point in the sample, and in particular is inconsistent with the symmetry property for any states that differ from the national historical average — a very serious deficiency if the model is to be used to determine geographic distributional consequences of alternative policies; (ii) its parameters and elasticity estimates will depend on the truly arbitrary choice of which particular data point is chosen to be the sole one at which properties of the model will be consistent with the basic theory of demand; (iii) its parameter estimates are likely to be biased and inconsistent, since a right-hand variable is stochastic and correlated with the equation disturbance term; (iv) the dynamic optimization problem underlying the linear logit specification is ad hoc; and (v) at least for the Industrial and Commercial models, the procedure for employing the model in forecasting exercises violates the homogeneity assumptions built into the estimated model.

While further evidence concerning the empirical significance of these deficiences might be provided by undertaking well-documented sensitivity analyses, within adversarial or political environments the model might still be vulnerable to the charge that its results were based on otherwise arbitrary criteria that were "judiciously chosen" in support of some desired policy outcome. Hence, even good empirical performance in well-designed forecasting experiments would not alleviate the problems that this model is likely to encounter in policy applications.

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[9]A related, and probably minor, point is that no information from the estimated model's error structure is employed in making the forecasts. Taub [1979] has developed the prediction formula for the variance components model specification employed by Mount and his associates.

We now turn to a different set of issues relating to the implementation and estimation of the econometric demand model. We begin with a brief description of the data, estimation methods, and problems dealt with in the modeling research process.

The model is estimated by pooling state cross sections of time series data for the years 1967-1979. The variables are defined in Table 2-1, with oil and coal fuel quantity and price data from the Energy Information Administration's State Energy Data System (SEDS), electricity and natural gas prices and quantity data from the Edison Electric Institute and the American Gas Association, respectively, and other data from Bureau of Economic Analysis publications. While data were compiled for all 48 contiguous states, model parameters are estimated using a randomly selected sample of 12 states.[10]

Two types of non-economic variables were included in the estimated model, so-called because they do not enter into the homogeneity and symmetry conditions discussed above. These non-economic variables are summarized in Table 2-2. Dummy variables were used in selected equations to account for certain episodic events including (i) the oil embargo in 1974, (ii) natural gas supply constraints reportedly in effect for 1973-1976, and (iii) relaxed air quality standards in 1967-1970. In addition, other "indicator" variables including numbers of customers and prices for automobiles and appliances were included in selected equations.

Model parameters were estimated by the iterative generalized least squares method, allowing for contemporaneous covariance between the equations in the system. Fixed effects by state were accounted for by subtracting out state means for each variable. This transformation is equivalent to introducing a state specific intercept term in each equation. The actual intercepts, required in forecasting applications, are recovered from the endogenous variable means and the estimated slope coefficients.

Initial parameter estimates for the model were unsatisfactory in that some own-price elasticity estimates were positive, and so violated condition (i) mention above. The problem was traced to inconsistencies in the construction of the oil data, in particular redefinition of oil product categories in 1979 by the Department of

[10]The states included in the estimation sample are Alabama, Indiana, Iowa, Michigan, Minnesota, Nebraska, Nevada, New York, North Dakota, Pennsylvania, Wisconson, and Wyoming.

Energy.[11] Since the underlying data could not be corrected the modelers adopted the strategy of relaxing the symmetry restrictions associated with the oil product equations. This results in additional estimated parameters which when constrained to equal zero re-impose the symmetry conditions. These zero restrictions are imposed in forecasting applications of the model.

The effects of this procedure on elasticity estimates is significant. The initial and final own-price elasticities are summarized in Table 2-3. There it can be seen that all the positive own-price elasticities are eliminated. Note in particular that for the Industrial sector, only one of the initial elasticity estimates had the correct sign.

We now turn to the final version of the estimated model itself. The specific form of the estimation equations, and the parameter estimates are reported in Tables 2-6 through 2-8 in Mount [1983]. Rather that repeat those tables, we present instead in Table 2-4 of this report an enumeration of the types of parameters estimated and the number that are statistically significant. It is of some interest to note that many parameters are not statistically significant (45/76 significant at $t = 1.96$). While coefficients required to impose symmetry and homogeneity conditions are included for economic, not statistical reasons, the non-economic variables, especially coefficients for the time epoch variables, are intended to remove effects which would bias parameter and subsequent elasticity estimates. If the coefficients of these variables are not statistically significant, then some argument deriving from economic theory is required if they are to be included in the final model.

The starting point for evaluating the estimated model is to consider how the final short- and long-run own price elasticities compare with similar modeling efforts.[12] Mount notes that in general the elasticity estimates of the state-level AUSM Demand Module ".. are at the low end of the range of values estimated in other studies.., and are smaller in absolute terms than earlier estimates that we have made using single equation models." (Mount [1983], p. 2-32).[13] The survey of demand elasticities to which Mount refers is due to Bohi [1981]. Since the Mount [1983] and Considine and Mount [1984] studies were completed after Bohi's survey, it is useful to add these new studies into the comparative analysis. Table 2-5 summarizes the elasticity estimate ranges by fuel and end use sector for the studies surveyed by

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[11]See Mount [1983], pp. 2-22 and 2-41, for further discussion.

[12]We note that the income elasticity for the Residential sector is 1.07, and seems reasonable.

[13]The reference for other studies is to Bohi [1981]. The reference to earlier single equation studies is to Mount, Chapman, and Tyrell [1973].

Bohi, as well as the more recent estimates of Mount and his associates. Several points should be noted.

First, the AUSM demand model has several electric and fuel own-price elasticities which are outside the range of values in Bohi's literature survey. Most importantly, the long-run electricity own-price elasticity in the Residential and Commercial sectors are some 50% and 54%, respectively, below the lowest values in the surveyed studies, while the value for the Industrial sector is only 7% above the lowest value recorded in the survey. Short-run electricity own-price elasticities tend to be close to the mid-points of the range for the Residential and Industrial Sectors, but well below the range of the estimates for the Commercial Sector in the literature.

Second, for both the Residential and Commercial sectors, the short- and long-run natural gas own-price elasticities are within the ranges encountered in the literature, but toward the low end. Matters for the Industrial sector are, however, quite different. There the short- and long-run natural gas own-price elasticities are some 57% and 12% above the largest values found in the literature.

Third, fuel oil own-price elasticities have a pattern similar to that found for electricity in the Residential and Commercial sectors, with Industrial long-run estimates within and toward the low side of the range in the literature, and short-run estimates slightly above the highest values found in the literature.

Fourth, long-run gasoline elasticity estimates for the Residential sector are slightly below the lowest value, while the short-run elasticities are near the mid-point of estimates in the literature. Industrial sector coal short- and long-run own-price elasticities are well within the ranges of the literature reviewed by Bohi.

Fifth, while not included in Table 2-4, note that the Mount [1983] electricity short- and long-run own-price elasticity estimates for the Commercial sector differ significantly from those in Considine and Mount [1984]. In particular, Mount's [1983] Commercial sector electricity short-run own-price elasticity is slightly less than one-half that of Considine-Mount [1984] (-0.10 versus -0.18, respectively), while the long-run elasticity is about one-third higher (-0.65 versus -0.92, respectively). This is puzzling since the model specification and presumably the data sources are quite similar. Possible explanations include:

- effects of using different set of states in estimation (CM use 14 "Northeastern" states whereas M uses 12 states identified in footnote above);

- effects of choosing a different data point as "numeraire;"

- effects of dropping out the labor input factor;

- differences in basic data sets used in estimation; and

- effect of dropping out non-economic variables.

We do not have sufficient information and documentation to pursue this further, but note that all these possibilities raise questions about the stability and interpretation of the Commercial sector elasticity estimates even with a similar model specification and data.

Finally, while we have emphasized the electricity and fuel elasticities, it should be noted that the long-run own-price elasticities for labor in the Commercial and Industrial sectors are extremely small (-0.02 and -0.01, respectively), with even smaller implied short-run elasticities. These are extremely low estimates; long-run labor own-price elasticities for manufacturing industry would typically be above -0.30.

The results of the above analysis are puzzling. As seen Table 2-5, six out of eleven of the comparable long-run own-price elasticities in the AUSM econometric demand model are outside the range of values for all the studies surveyed by Bohi, while two of the eleven comparable short-run own-price elasticities are outside that range. Further, except for natural gas in the Industrial sector, all the new boundary values introduced into the literature by the AUSM econometric demand model are on the low side of the range. Unless there is reason to believe that the AUSM estimates improve the state-of-the-art, these low estimates imply that AUSM will tend to understate the effects of price changes upon demand. Most importantly, for example, the effects of rising relative electricity prices upon electricity demand will be understated, implying that emissions estimates will be overstated. Validating and/or improving the AUSM econometric demand model elasticities should, therefore, have a very high priority in future demand research modeling.

We now consider several issues which might contribute to these low estimates, none of which, unfortunately, can be shown to have specifically biased elasticity estimates in one direction or the other. Nonetheless, the following points should be considered thoroughly in subsequent modeling research:

- appropriateness of the SEDS data on oil and coal products for demand model estimation,
- procedure adopted for dealing with inconsistent oil products classification;
- use of data for 12 states rather than the full sample in parameter estimation;
- use and interpretation of non-economic variables; and
- effect of omitted variables on elasticity estimates.

We now briefly consider each of these issues in turn.

Appropriateness of SEDS Data Base. Perhaps the first point to note in considering why the AUSM price elasticities are so unrepresentative of the extant literature is that none of the studies surveyed by Bohi have employed the SEDS data base, either for oil and coal as in the AUSM Demand module, or for other fuels; in fact, we have been unable to find any published econometric study that has used this data. One reason for the lack of interest in the SEDS data may be that much of the data is based on surveys intended to track fuel supplies, not end use. The SEDS methodology involves various assumptions and transformations by which measures of so-called apparent consumption (production minus changes in net fuel inventories plus net fuel imports) are transformed into estimates of end use consumption. These procedures in effect are a model, and so some question exists as to the appropriateness of using this transformed data in an econometric model without paying attention to the statistical properties of the underlying procedures used in generating the data. Relating issues in the construction of the SEDS data to the low elasticity estimates provided by the current version of the AUSM econometric demand model is, however, likely to be a difficult task, and is certainly beyond the scope of this review. Careful attention, however, should be given to an analysis of the appropriateness of this data for future versions of the AUSM econometric demand model, and other data sources such as the Bureau of Census fuel and electricity survey for manufacturing industries, and the EIA Residential Energy Consumption Survey for the household sector should be considered.

Inconsistent Oil Data. Dropping the symmetry conditions in the oil product equations seems an unusual, if not inspired, solution to the problem of a changing oil product classification in 1979. There is no logical reason that we can see as to why this procedure resolves the curvature problem with the original estimates (i.e. positive own-price elasticities) noted in Table 2-3. Further, there are three reasons for continued concern, even though the procedure "worked" in that all own-price elasticities are now of the correct sign.

First, dropping the oil product equation symmetry restrictions in estimation eliminates even the tenuous claim of economic interpretation at the national mean of the sample.

Second, the procedure is only partially successful since while the own-price elasticities are all correctly signed, many of them — in particular the Residential and Commercial long-run electricity elasticities — fall outside the range of any related estimates available in the literature.

Finally, and perhaps most important, this procedure for dealing with changes in oil product classification in 1979 leaves open the question of just what definition applies to oil product projections from these equations. Apparently, it is some mixture of the pre-1979 and the 1979 definitions. Clearly this is an unsatisfactory state of affairs.

Alternative possibilities might have been (i) to drop 1979 from the estimation sample, or (ii) employ a dummy variable in 1979 to capture the effect of the changed definition. The latter approach seems promising since then the model could be set to forecast "1979 defined" oil products by an appropriate setting of the dummy variable.

Of course, we have no way of knowing in advance just what effect changing the procedure for dealing with the "oil product classification" problem would have on the estimated elasticities; that is an empirical issue. Note, however, that if curvature problems still remain, a more natural solution would be to impose curvature restrictions on the estimated parameters. While these restrictions — in this case concavity in the factor input prices is required — have not yet been worked out for the linear logit specification, a likely starting point is the approach developed by Jorgenson and Fraumeni [1981] for the translog cost function.

<u>Use of 12 State Estimation Sample</u>. Mount [1983] makes the following two arguments for employing a sample of 12 states in estimating model parameters:

> First, since each system of equations is estimated simultaneously, the implied sample size (number of equations x number of years x number of states) is large, and computational costs would be substantial. Second, the form of the equations is based on the logarithm of expenditure shares. If shares are very small, large proportional changes can be implied in the data that may distort the results. To avoid this problem, some states were eliminated for estimation purposes, typically because the use of natural gas or of coal was very small (Mount [1983], p. 2-22).

It is unclear as to why adding states increases computational costs. While the number of raw observations will be larger when all states are included in the estimation sample, it is the dimension of the cross product matrices that matter, and since state specific intercepts are not directly estimated, these dimensions are invariant to the number of states.

The second issue — small expenditure shares — seems a potentially more serious problem. For cases where some shares in the full sample are zero in some years, the dependent variable (logarithm of the share ratios) will be undefined, and so could not be included in the estimation sample. If only a few zero violations occur for a given state, then it seems extreme to drop that state completely from the estimation sample. Three alternatives are possible.

First, just the offending observations could be dropped (e.g. if natural gas share in state j in 1969 is zero, then drop all observations for that state in that year). Since a pooled model is being estimated, use of unequal time series causes no problems.

Second, and much more elaborate, it might be possible to derive expressions for the shadow price of the offending input in terms of estimated parameters and data which could then be used in constructing an equality constraint in which the value of the shadow price was just sufficient to ensure a zero solution for the offending input.[14] That is, offending observations are dropped from the estimation sample, but are added in equality constraints on the estimation problem.

Third, a different functional form that permitted legitimate zero factor quantities might be considered. Given the difficulties of imposing natural economic restrictions such as symmetry on the linear-logit specification, the "zeros" problem seems just one more reason why an alternative functional form might be considered. Note, however, that if the zeros problem is significant, then the translog functional form is also eliminated since it also employs logarithms of factor quantities.

If the problem is only small shares, not zero shares, then we are unaware of any studies that analyze or provide evidence relating to the "distortion" of parameter estimates in the presence of small shares. Woodland [1979] has considered the issue of assuming a joint normal distribution in share models, in particular the fact that

[14] See Diewert [1977] for the development of this idea in the context of accounting for "new goods" in constructing index numbers.

this distribution violates the condition that shares sum to one by giving positive probability to shares outside the [0,1] interval. He provides, however, no evidence of the significance of this issue when shares are "small." It may be that Mount and his colleagues have unpublished results bearing on this problem.

Mount [1983] evaluates the effect employing a 12 state sample by calculating root mean square errors (RMS) and pseudo-R^2 statistics associated with actual and predicted state factor inputs separately, for states included and excluded in the estimation sample. The results suggest that, especially for electricity, the prediction errors are similar between the included and excluded states.[15] Hence it seems unlikely that low elasticity estimates can be traced to the use of a sample of states rather than all states in the estimation sample.

Inclusion of Non-Economic Variables: As noted above, the econometric demand model includes a number of non-economic variables so-called because they do not enter directly into the homogeneity and symmetry restrictions. The motivation for including these variables is as follows:

> Another feature of the models is that certain additional variables have been included to account for non-economic factors. In particular, an effort was made to remove the unusual effects of the oil embargo in 1974, constraints on the supplies of natural gas in 1973-76, and the more relaxed standards that existed for air quality prior to the Clean Air Act in 1968-70. In the equations for electricity and natural gas, the number of customers per capita is included to account for the effects of changing the classification scheme for customers. Finally, price indices for appliances and automobiles are included in the residential sector. The underlying purpose for including all these variables is to try to improve the estimates of the price effects by removing possible sources of bias (Mount 1983:2-18).

Table 2-2 indicates that while many of the coefficients for the episodic dummy variables are not statistically significant, the price and customer variables are, with one exception, all significant. We have two types of concerns about the inclusion and interpretation of these variables. Regarding the appliance and automobile prices, since these goods are part of the non-fuel component of expenditures, shouldn't they be introduced explicitly into the set of factors being modeled?

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[15] There is an ambiguity between the description of these tests in the text (p. 2-34) which implies that predicted and actual state observations are used, and the formulas (p. 2-35) and footnote 15 (p. 2-34) which indicate that averages of state predicted and actual observations are used. The former method, which we assume was used, allows expression of both "poor" and "good" state predictions; the latter permits cancellation of over- and under-predictions.

In particular, the assumption underlying the aggregation of all non-energy factors into the non-fuel expenditures bundle is that components of that bundle are "separable" from factors outside the bundle, implying that within bundle factors have the same elasticity of substitution with each of the factors outside the bundle. Introducing the prices of automobiles and appliances, which are components of the non-expenditure bundle, as separate unconstrained explanatory variables contradicts the separability assumption. Either separability of the components of the non-fuel expenditures bundle is maintained, or automobiles and appliances are introduced as separate factors that then enter into the symmetry and homogeneity restrictions and as separate share equations in the system.

Regarding the "customer" variables, we are uncertain about the meaning of ".. changing the classification scheme for customers." A number of issues should be addressed in subsequent versions of the AUSM documentation;

- what are the sources of these changes;
- are they continuing or episodic;
- do they affect prices as well as quantities (i.e. do they need to be considered in estimating the histrocial rate schedules, and, if so, were they.

The second area of concern relates to the treatment of the episodic events, e.g. oil embargo, gas curtailments, and the relaxed air quality standards. As summarized in Table 2-2, dummy variables are used to measure the influence of these episodic events. There are several issues to note here. First, presumably episodic events reflect disequilibirum in factor markets. That is, firms/consumers would choose different factor combinations if these events had not occurred. Why, then, wouldn't these disequilibrium effects extend to all competing imputs?

For example, if natural gas curtailments indicate that consumers/firms were not able to obtain as much natural gas as they wanted to purchase at prevailing prices, then doesn't that mean that they purchased more competing fuels than they really wanted to at these same prices? Measuring the effects of natural gas curtailments requires that dummies appear in all equations, not just the natural gas equations. A similar argument applies to the inclusion of a "relaxed air quality standards" dummy in only the industrial coal equation; why isn't this dummy also included in the other industrial electricity and fuel equations? Note that so-called oil embargo dummies are included in the non-petroleum, as well as the petroleum product equations, a procedure that seems to us to be preferable.

Second, when two episodic events overlap — e.g. oil embargo (1974) and natural gas curtailment (1973-1976) — how should the interactions be treated? In the natural gas equations of the present model, effects of curtailments and the oil embargo are assumed to be additive, and are not separately identified. Perhaps this is reasonable, but it might be worthwhile to test a more general model allowing for interactions against the restricted (i.e. zero interaction effects) model.

Third, and perhaps most serious, the model as specified assumes that episodic events had equal effect in all states. This seems unreasonable, especially for natural gas curtailments. For example, states with intra-state natural gas markets for which prices are not regulated are unlikely to have experienced disequilibrium in natural gas purchases at prevailing prices. That suggests that either state specific episodic event dummies be considered, or that dummies for state groupings such as "no access to intra-state" versus "gas producing states" be considered.

Finally, it should be noted that less than one-half of the episodic event coefficients in Table 2-2 are statistically significant (13 out of 29). Why are they included in the final version of the model?

Effects of Omitted Variables. It should be noted that especially for the industrial sector, the effects of omitted variables on the derived elasticity estimates may be quite substantial.[16] In a different context, Berndt-Wood [1979] have shown that omitted variable effects depend upon the share of the input of interest in a subfunction, and the own price elasticity of that subfunction. Recall, for example, that the Mount specification for the industrial sector is equivalent to,

$$Y = f[\text{capital, non-energy materials, } g(LB, EL, NG, OL, OM, CL)]$$

The subfunction, $g(\cdot)$, is what is being estimated by Mount, and so elasticities do not take into account adjustments due to variations in capital goods (K) and their energy efficiency characteristics, and in non-energy materials (M). These omitted variable effects are measured as follows;

$$\epsilon_{EL,EL} = \epsilon^{*}_{EL,EL} + \epsilon_{gg} \cdot S_{EL}$$

*

[16]Omitted variables cannot, however, explain the results in the elasticity comparisons discussed above, since most of the studies surveyed by Bohi [1981] also exclude the non-energy related inputs, such as capital and labor, in a manner similar to Mount [1983].

where ϵ is the gross elasticity of electricity calculated holding the output of the function g constant, ϵ_{gg} is the own-price elasticity of demand for the output of the subfunction g, S_{EL} is the value share of the electricity in the total value of output for g, and $\epsilon_{EL,EL}$ is the so-called net elasticity calculated with gross output Y held constant, but the output of g allowed to adjust along with changes in K and M. Keeping in mind that we (Mount) do not have the data to estimate f and so cannot estimate ϵ_{gg}, what are the implications for $\epsilon_{EL,EL}$ of plausible estimates of ϵ_{gg}?[17]
Note that $\epsilon_{gg} = 0 \longrightarrow \epsilon_{EL,EL} = \epsilon^*_{EL,EL}$. Then assuming alternative reasonable values of S_{EL} and ϵ_{gg} we have, e.g.,

Illustrative Gross and Net
Electricity Price Elasticities
(in absolute values)

Share Values	Absolute Values of ϵ_{gg} 0.0	0.25	0.50	0.75	1.0
.10	.550	.575	.600	.625	.650
.20	.550	.600	.650	.700	.750
.30	.550	.625	.700	.775	.850

The documentation provides no information on the value share of energy purchases in total expenditures for the DM end use sectors. We note, however, that energy's value share in gross output for U.S. Manufacturing industry is about 10% in 1981, and estimates of energy's own price elasticity range from 0.5 to 0.9. The above tabulation suggests, therefore, that for Manufacturing industry, gross elasticity estimates of 0.55 would understate net elasticities by about 10-15%; while not dramatic, these biases are large enough to be of some concern.

In summary, we are puzzled as to why the AUSM econometrically estimated own-price elasticities tend to be so much outside the range of values obtained in similar studies, and in particular, tend to be so low. In this Section we have gone to some lengths to identify the conceptual and implementation issues regarding the current version of the model that might account for these anomalous elasticities. In an important sense, our investigation has been unsatisfactory since, while many issues of potential importance have been raised, nothing that definitely "explains" the

[17]The omitted variable effects are not likely to explain differences in the studies of Table II-2-5 since these studies all exclude capital and other variables as well.

elasticity results has been identified. This greatly complicates our ability to make constructive suggestions for to improving the econometric demand model.

What might instead be done? In our judgment, it does not seem to make sense to alter this demand module model marginally by making adjustments here and there. Rather, unfortunately, the whole demand model must be reformulated and re-estimated, preferably using more recent data (beyond 1979), and perhaps a new data set if a review of the SEDS data base finds it inadequate for use in econometric modeling.

The starting point for continuing demand modeling research should be a careful review of the SEDS data base, as well as other data bases available at the appropriate regional, fuel, and end use levels of detail which might complement, or substitute for SEDS. Also, the various micro-region modeling efforts that have been completed/initiated since the AUSM effort should be evaluated for potential contributions to continuing AUSM modeling research. Data sources that might complement or replace SEDS include:

- the Energy Information Administration's Residential Energy Consumption Survey;
- Bureau of Census Electricity and Fuel Consumption and Expenditure data; and
- Bureau of Census Longitudinal Establishment Data File.

Three related modeling efforts should also be evaluated for possible contributions of data, ideas, or model components. First, Goett and McFadden [1984] report on a major micro-regional electricity demand modeling project which appears to possess many of the features desired by the AUSM modelers. Most important, this effort deals with many of the data issues raised by the AUSM modelers, in particular the development of durable goods data at the micro-regional level of detail. Second, EPRI is now supporting a large project at Battelle Columbus on manufacturing industry electricity demand by detailed SIC industries, and by utility service areas.[18] Third, we understand that the Energy Information Administration is undertaking source data development and a modeling research effort for Commercial Sector electricity and fuel demand. These efforts, and quite likely other modeling research projects, should be evaluated and, if possible, exploited in subsequent AUSM electricity and fuel demand modeling research.

[18] A more modest effort of modeling industrial factor demands is due to Alt [1982], who has constructed capital input data at the state level of detail.

Regarding functional forms, of which much has been said above, we have the following observations.[19] Since the AUSM linear logit specification is closely related to the well-known translog function and in fact involves estimation of the same number of parameters, one could specify and estimate a translog model that at least was consistent with the economic theory of demand.

The translog, however, is but one of many possibilities, and may not be the best option. In this context it is useful to recall principles (ii) and (iii) enunciated by AUSM, namely, that the model distinguish between short- and long-run, and that it not require use of capital stock data by state and sector, which are frequently unavailable. As is noted in Considine and Mount [1984], the translog model in its pristine form is not particularly adaptable to dynamic or partial adjustment, since it involves shares, and partial adjustment by shares can lead to violation of the well-known Le Chatelier principle that short-run own-price responses are smaller (in absolute value) than long-run responses. A more attractive procedure might therefore involve specification and estimation of a generalized Leontief model, for with it one can easily specify partial adjustment of input-output coefficients or of input levels.

LOAD CHARACTERISTICS

The Demand Module next calculates state generation requirements by adjusting total state electricity demand for distribution and other losses, and for net interstate transfers. These adjustments to convert state demand into state generation requirements currently rely on certain 1980 scalar relationships. In particular,

$$g_i = \alpha \cdot \beta_i \cdot q_i$$

where,

g_i = generation requirements in the ith state;

q_i = total demand in the ith state;

$\alpha = \dfrac{\text{national sales net of exports}}{\text{national generation net of imports}}$ in 1980 (loss factor); and,

[19]In earlier versions of this evaluation, AUSM modelers apparently believed we recommended but one general functional form, namely, the translog. This was not our intention. There are a variety of second-order functional forms — the translog, generalized Leontief, generalized Cobb-Douglas, biquadratic, generalized Box-Cox — that might be appropriate. We do not advocate a particular flexible function, but emphasize the need to employ forms that are economically meaningful, e.g. that are globally consistent with the symetry property of demand theory.

$$\beta_i = \frac{\text{actual generation}}{\text{required generation}} \text{ in the ith state for 1980 (transfers factor).}$$

The documentation is unclear regarding the ease by which the loss and transfer factors can be adjusted, especially regarding the possibility of making them time dependent.

It should immediately be noted that the modelers intend this as a stop gap measure, presumably permitting them to solve the state-level AUSM as a research model until such time as the operational capability for a regional model is available.[20] Mount [1983, pp. 2-35, 2-36) summarizes the issue as follows:

> Many states belong to a power pool, and all plants in the pool are dispatched centrally. Since plans have been discussed to adapt the AUSM so that major dispatching regions can be used for dispatching and planning purposes, most effort has gone to getting suitable information about dispatching regions. The analysis at the state level is relatively simple.
>
> If the AUSM is modified to operate for groups of states within a single power pool, the model will be much more representative of actual practices in the industry. Interstate transfers within a dispatching region would then be determined by the model. If the model continues to operate exclusively at the state level, there is no simple way to deal with interstate transfers of power in anything but a cursory manner.

A potential user of the state-level AUSM should keep this skepticism in mind when considering any applications where interstate transfers are likely to be important, and in particular when these transfers are likely to be adjusting in response to changing economic and regulatory factors. Note, however, that this is not an issue in the demand model per se, but rather involves the need for further development of the overall AUSM.

DEMAND PROJECTIONS

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[20]Timothy Mount has pointed out to us that this procedure was revised in the final version of the model/program submitted to EPA. We have not been able to review the revised documentation. According to Mount [1985], however, for the revised procedure, "the quantity and corresponding costoftransfers can now be specified each year throughtout the forecast period (i.e., two series with 30 entries each). The logic of operating the model is that interstate transfers are determined prior to running the state models, and are treated exogenously at the state level." This is more reasonable that relying on 1980 relationships, but does not change the basic logic of treating interstate transfers.

We now turn to the AUSM Demand Module procedures for the projection of long-run electricity demand.[21] Although development of the econometric demand model emphasized the dynamics of demand, in fact that model is not used in projecting the demand levels employed in the capacity scheduling process. Instead an adaptive expectations model relating forecasted growth rates in the current period, say period t, to the "actual" growth rates for the past four periods is employed. The model reflects atypical behavior immediately following the first oil embargo by introducing "slope shift" adjustments, whose effects then decrease inversely with the passage of time.

The model is formulated as,

$$ER_t = \sum_{i=1}^{4} \alpha_i \cdot AR_{t-i} + \sum_{i=1}^{4} \beta_i \cdot (AR_{t-i}/t) + \sum_{j=1}^{8} \gamma_j \cdot D_j + \gamma_0 + u_t \qquad (24)$$

where,

- ER_t – expected electricity growth rate projected in period t;
- AR_{t-i} – actual electricity growth rate in period t-i, (i=1, 2, 3, 4);
- D_j – NERC region zero/one dummy variables (j = 1, .., 8);[22]
- t – index of time, 1973 = 0; and
- u_t – an error term assumed to be distributed $N(0,\sigma^2)$.

α_i, β_i, γ_j, and γ_0 are parameters to be estimated subject to the restriction that,

$$\sum_{i=1}^{4} \alpha_i = \sum_{i=1}^{4} \beta_i = 1 \qquad (25)$$

The first set of terms in (24) is the "normal" adaptive expectations, while the second set accounts for the influence of the embargo via an inverse relation with time. The third set of terms provides for fixed effects associated with the NERC region location.

The data base used in estimating (24) is based upon the ten year forecasts prepared by NERC for its nine regional councils for the years 1974-1981, and actual state-level electricity requirements aggregated to the NERC regions using fixed population density weights. These data are expressed in annual growth rates (expected growth rates over the next 10 years for ER_t, and actual growth rates from year t-i to year t for AR_{t-i}).

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[21] See Vellutini and Mount [1983] for details on the formulation and estimation of this model.

[22] Note that the effects of the 9th NERC region are absorbed into the constant term. We have been unable to find in the documentation the order in which NERC regions are indexed in this equation.

The estimated model parameters are reported in equation (26) with the restriction of (25) eliminated, and t-statistics in parentheses;[23]

$$FR(t) - AR(t-4) = \qquad (26)$$

$$\underset{(7.14)}{0.500} * [AR(t-1) - AR(t-4)] + \underset{(3.20)}{0.250} * [AR(t-2) - AR(t-4)]$$

$$+ \underset{(2.47)}{0.141} * [AR(t-3) - AR(t-4)] - \underset{(3.92)}{(0.730/t)} * [AR(t-1) - AR(t-4)]$$

$$- \underset{(1.02)}{(0.242/t)} * [AR(t-2) - AR(t-4)] - \underset{(1.53)}{(0.284/t)} * [AR(t-3) - AR(t-4)]$$

$$\underset{(0.85)}{-0.384} * D_1 - \underset{(3.30)}{1.540} * D_2 + \underset{(1.02)}{0.447} * D_3 + \underset{(1.14)}{0.515} * D_4 - \underset{(0.05)}{0.026} * D_5$$

$$+ \underset{(1.65)}{0.753} * D_6 + \underset{(0.41)}{0.181} * D_7 - \underset{(0.73)}{0.319} * D_8 + \underset{(1.34)}{0.415}$$

$$R^2 = 0.94 \qquad SER = 0.80 \qquad SSR = 27.25$$

In actual forecasting, this part of the DM calculates generation net of transfers for each of the next 15 years based on last period's actual generation, the annual growth rate from (26) for the NERC region in which the state is located, and current period transfers. Growth rates for "actual" generation for the past 4 periods required in (26) are based on the econometric estimates adjusted for losses. Specified future load factors are taken from the NERC forecasts and/or supplied by the user.

Several points should be noted regarding both the estimated model and its justification and use in forecasting. First, there are some minor ambiguities in the documentation; for example, why are current period values used as forecasts of future transfers; what load factors are used for years beyond which the NERC forecasts are available; and why and how are the regional intercept coefficients of (26) ".. reduced to 0 over the first five years of simulation run?"[24]

Second, and more important, while the coefficients of (26) on all the "normal" expectation terms are statistically significant, for the time dependent terms only the coefficient on the AR(t-1) - AR(t-4) term is significant. Further, with one

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[23]We reproduce the model from Vellutini and Mount [1983], Table B.3. Note there are some typographical problems in Mount [1983]; in particular, the constant term and regional effect terms are omitted, and the t-statistics are written as multipliers rather than in parentheses as was intended.

[24]See Czerwinski and Mount [1984], p. C4-10.

exception, none of the coefficients for the regional intercept terms is statistically significant. While Vellutini and Mount [1983] provide an interesting discussion of alternative estimators, and in particular, of the use of regression diagnostic techniques to identify influential data points, they provide little discussion and justification of the statistical properties for their preferred version of the model.

Third, and much more critical, we confess to some surprise that AUSM adopts different modeling approaches for the analysis of current period demand (the econometric model), and annual demand for each of the next 15 years (adaptive expectations). The motivation for this strategic choice is that the adaptive expectations model is believed to better reflect actual utility forecasting practice, or at least that such models adequately approximate utility forecasts as summarized in the NERC regional projections. This raises at least three issues including,

- the validity of assuming that NERC projections represent utility forecasts used in capacity planning;
- whether utility forecasting practice in fact relies heavily on time series methods; and
- whether utility forecasting results as summarized in the NERC projections are more nearly consistent with time series rather than economic models.

Regarding the first point — do NERC projections accurately reflect forecasts used in capacity planning — the general impression is that they are probably reasonably accurate, given that they are produced by regional committees working with individual utility estimates. It should be remembered, however, that utilities most likely have many forecasts, and so the specific connection between what is being used in planning and what is communicated via the NERC process is probably ambiguous. To the best of our knowledge, no studies have been conducted on the integrity of the NERC forecasts in terms of correspondence with actual utility forecasts used in capacity planning.

The second issue — the extent to which utility forecasters rely on time series methods — is less problematic. We note that the AUSM documentation provides relatively little justification for this view. It is our impression that both anecdotal evidence and the literature support the notion that economic models of electricity demand are being developed and being used. For example, casual conversations with utility analysts suggests that even if non-economic models (or no models at all) characterized the pre-1970 utility forecasting process, that is certainly not the case in the 1980's.

Further, studies of current utility foreasting practice, such as Burbank [1979], emphasize the use of market penetration and saturation analyses, and other economic/engineering methods for residential electricity demand analysis. Current modeling efforts such as that of Goett and McFadden [1984] emphasize the use of integrated process engineering/econometric models to capture both technical and engineering characteristics of electricity use, as well as the economic behavior underlying choices of technology and utilization rates. Finally, large-scale modeling efforts for utility service area modeling of manufacturing industry electricity demand is currently underway at EPRI, with strong support from the Utility Advisory Committees under which EPRI establishes its research priorities and programs. Hence, we are not aware of any empirical support for the notion that current utility forecasting practice relies on non-economic, time series methods, and in fact find evidence suggesting otherwise.

Regarding the third issue, it might be argued that what utility forecasters say they do, or examples of modeling research efforts, are less important than how well a particular model fits the data and corresponds with underlying economic theory. On these grounds there is still reason to be skeptical that the adaptive expectations model represents a good approximation to utility foreasting practice. A recent study by Nelson and Peck [1985] has compared time series versus economic model estimates of U.S. electricity demand with NERC projections. Table 2-3 summarizes these results. Each model type was estimated with data through the year noted in the first column, and then used to make a 10-year forecast over the period noted in the second column, with the results reported in columns (4) and (5). NERC projections are given in column 3, with differences between NERC and model forecasts given in columns (6) and (7).

Which model most closely approximates the NERC forecasts? The answer turns critically upon treatment of the energy price shock years, 1973-1974 and 1979-1980. For the entire period 1973-1982, the mean absolute percent differences are 0.49 and 0.72 for the time series and economic models, respectively, suggesting that on average the time series model more nearly approximates the NERC forecasts. This would support the suggestion by Mount and his associates that time series models provide a good approximation to utility forecasting results.

If, however, we drop the oil price shock years 1973-1974 and 1979-1980, then the mean average percent differences rise for the time series model to 0.67 and drop for the economic model to 0.38, suggesting that in "normal" times economic models provide the better approximation to the NERC forecasts. Further, examining the percent differences in the most recent 1981-1982 era indicates dramatically superior performance by the economic model in approximating the NERC performance.

Further, although not reported in Table 2-6, Nelson and Peck evaluate the contribution of errors in forecasting the input variables (prices and GNP) versus errors in estimated parameters. When actual price and GNP values are used in their model, they find that the economic model (estimated with data through 1973) predicted an average growth rate for U.S electricity of 2.5% for 1973-1982 versus the actual rate of 2.2% for that period. They conclude that, "it is clear, then, that it was not the parameter values estimated as of 1973 that were in error, but rather the underlying projections of electricity cost and eocnomic growth" (Nelson and Peck [1985], p. 184).

Thus, both anecdotal and research evidence raise questions about the claim that time series models approximate NERC forecasts better than do economic models. These results suggest that perhaps more consideration be given to the choice of the annual modeling approach. The first step should be to undertake further analysis of the three propositions outlined above. In particular, it seems prudent to inquire in a systematic way as to the views of utility forecasters and analysts on these matters. The credibility of the AUSM and AUSM-based studies will require that these analysts generally concur in the assumptions being made concerning behavior and practice.

We expect one outcome of such a review would be the conclusion that economic models should be employed in both short - and long-run electricity demand forecasting. This would require adopting/developing a suitable economic model along the lines suggested above as the means of obtaining annual forecasts. Such a task would be non-trivial, involving both (i) the need for the user to project independent economic variables (prices, income, employment, etc.) developing the base case and scenarios, and (ii) extending the model's capability to project the rate schedule to provide estimates of marginal electricity prices in each forecast year. The result, however, is likely to be a more credible and defensible forecast of long-run annual electricity demand.

CONCLUDING REMARKS

We have presented a summary and recommendations in each of the above major sections, and will not repeat them here. We have concentrated our effort on the econometric demand model, in large part because the estimated own price elasticities based on that model seem so at odds with the extant literature. We had hoped to contribute evidence on the direction and magnitude of biases in these elasticity estimates.

This has not proven feasible, however, and instead we have contributed a list of conceptual, implementation and data issues which we feel Mount and his colleagues should pursue in subsequent demand modeling research.

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TABLE 2-1

AUSM Demand Module Fuel Types Projected and Independent Variables

SECTOR	FACTOR INPUTS	INDEPENDENT VARIABLES
Residential	Electricity (EL)	Marginal Price of Electricity
	Natural gas (NG)	Price of Natural Gas
	Oil (light) (OL)	Price of light oil
	Oil (motor) (OM)	Price of motor oil
	Employment (LB)	Personal Income
	Non-Fuels (NF)	Population
		Price of appliances index
		Price of new cars index
		Number of electricity customers
		Number of natural gas customers
Commercial	Electricity (EL)	Marginal Price of Electricity
	Natural gas (NG)	Price of natural gas
	Oil (light) (OL)	Price of light oil
	Oil (heavy) (OH)	Price of heavy oil
	Employment* (LB)	Wage rate
		Number of electricity customers
		Number of natural gas customers
		Population
Industrial	Electricity (EL)	Marginal price of electricity
	Natural gas (NG)	Price of natural gas
	Oil (light) (OL)	Price of light oil
	Oil (heavy) (OH)	Price of heavy oil
	Coal (CL)	Price of coal
	Employment* (LB)	Number of electricity customers
		Number of natural gas customers
		Wage rate
Transportation	Electricity	(Unknown since model not yet estimated)
	Oil (light)	
	Oil (heavy)	
	Oil (motor)	
	Oil (aviation)	

Source: Adopted from description in Mount [1983], and various tables and discussion in Czerwinski and Mount [1984].

* Note that employment is endogenous in the estimated model, but is set exogenously in forecating applications.

TABLE 2-2

Non-Economic Variables Included in Estimated Models

Event/Variable	Sector: Residential	Industrial	Commercial
Embargo (1974	EL, NG, OL, OM	EL, NG, OL, OH, CL	EL, NG, OL, OH
Nat. Gas Constraint	NG	NG	NG
Relaxed Air Qual.		CL	
Per Capita Cust.	EL, NG	EL, NG	EL, NG
Appliance Price	EL		
Automobile Price	OM		

Equation codes in this Table are defined in Table 2-1.

TABLE 2-3

Comparison of Initial and Final Own-Price Elasticties
by End Use Sector

Fuel	Residential Initial	Residential Final	Commercial Initial	Commercial Final	Industrial Initial	Industrial Final
Electricity	-0.32	-0.30	-0.51	-0.65	0.42	-0.55
Natural Gas	-0.03	-0.21	0.26	-0.31	-1.42	-1.70
Oil (Light)	0.22	-0.34	-1.46	-0.60	2.24	-0.86
Oil (Heavy)			-0.53	-0.59	0.45	-0.83
Oil (Motor)	0.38	-0.33				
Coal					0.84	-0.75
Non-Fuel	-1.05	-1.01				
Labor			-0.01	-0.02	0.02	-0.01

Source: Mount [1983], Tables 2-5 and 2-10.

TABLE 2-4

Enumeration of Coefficients by Type and Statistical Significance

Coefficients by Type	Residential Total	Residential Statistically Significant	Commercial Total	Commercial Statistically Significant	Industrial Total	Industrial Statistically Significant
Price	13	7	15	10	20	5
Non-Economic						
Episodic	7	3	9	3	13	7
Other	4	4	2	1	2	2
Lagged Endogenous	1	1	1	1	1	1
Totals	25	15	27	15	36	15

Based on enumeration of coefficients from Mount [1983], Tables 2-6, 2-7, and 2-8, with t statistics greater than or equal to 1.96.

TABLE 2-5

Comparisons of Short- and Long-Run Own-Price Elasticity Estimates,
Bohi [1981] Survey Versus Mount [1983]
(in absolute values)

Sector/ Fuel	Range in Literature Short-Run	Long-Run	Mount [1983] Short- Run	Long-Run
		Residential		
Electricity	.06 - .49	.45 - 1.89	.17	.30
Natural Gas	.03 - .40	.17 - 1.00	.12	.21
Gasoline	.11 - .41	.36 - .77	.19	.33
Fuel Oil	.13 - .30	1.10 - 1.76	.20	.34
		Commercial		
Electricity	.17 - .25	1.00 - 1.60	.10	.65
Natural Gas	.03 - .40	.17 - 1.00	.05	.31
Fuel Oil	.07 - .20	1.10 - 1.76	.09	.59 - .60*
		Industrial		
Electricity	.04 - .22	.51 - 1.82	.16	.55
Natural Gas	.07 - .21	.45 - 1.50	.49	1.70
Fuel Oil	.11 - .22	.80 - 2.82	.24 - .25*	.83 - .86*
Coal	.10 - .49	.49 - 2.07	.22	.75

Source: Bohi [1981], Table 7-1, p. 159.
*Note that Mount[1983] reports separate elasticities for light and heavy fuel oils, while only a total fuel elasticity is reported in Bohi [1981]. Here we report the light and heavy fuel oil range for Mount.

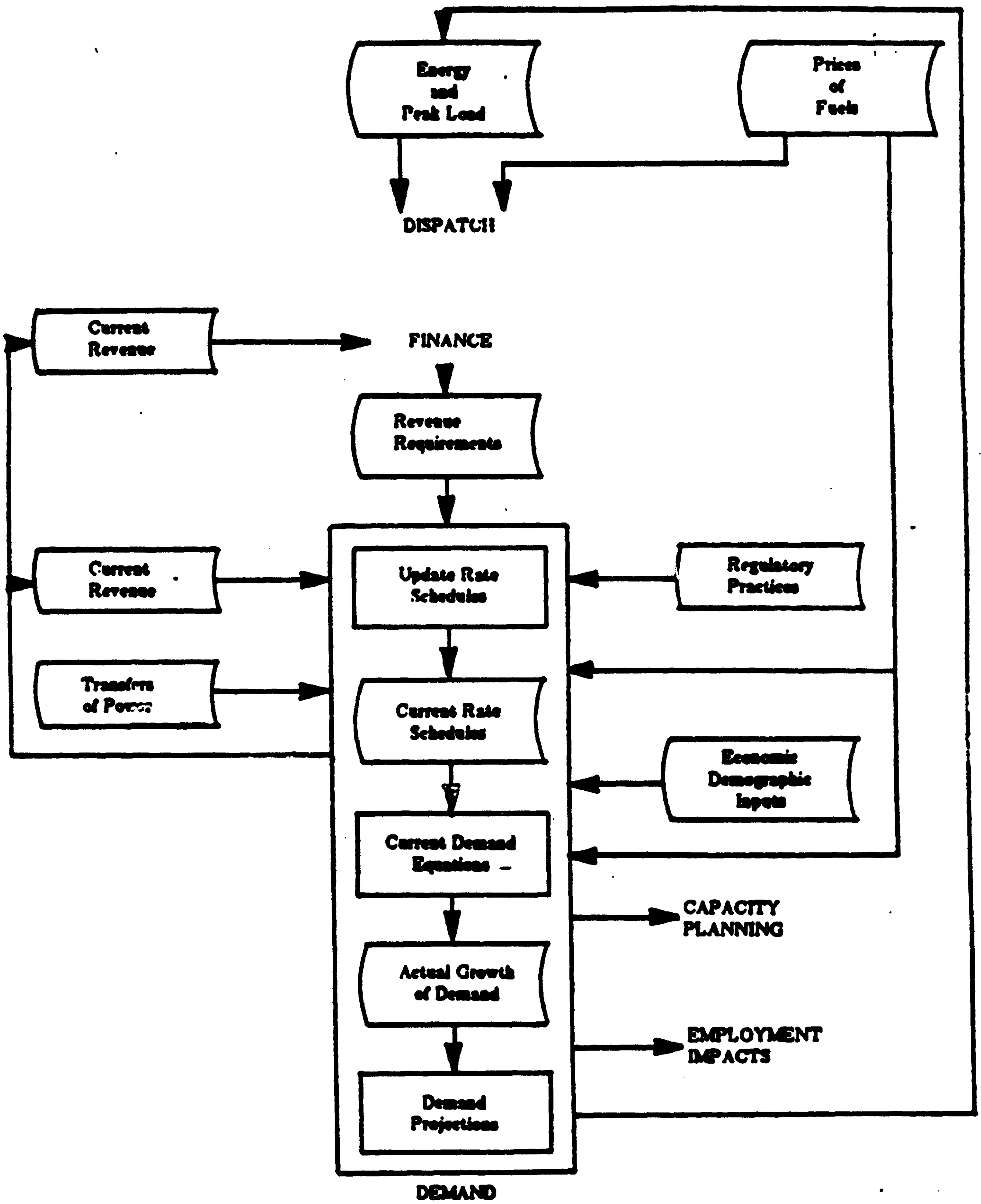
TABLE 2-6

Comparison of Time Series and Economic Demand Model Forecasts with NERC 10-Year Projections of Electricity Demand, 1973-1982

(1) Using Data Through	(2) 10-Year Forecast Period	(3) NERC 10-Year Forecasts	(4) Time Series Forecasts (%)	(5) Demand Model Forecasts (%)	(6) (3)-(4) (%)	(7) (3)-(5)
1973	1974-1983	7.5	7.5	6.8	0.0	0.7
1974	1975-1984	6.7	7.1	4.8	-0.4	1.9
1975	1976-1985	6.3	5.4	5.3	0.9	1.0
1976	1977-1986	5.8	5.7	5.2	0.1	0.6
1977	1978-1987	5.3	5.4	5.2	-0.1	0.1
1978	1979-1988	4.8	4.9	4.9	-0.1	-0.1
1979	1980-1989	4.1	4.3	5.0	-0.2	-0.9
1980	1981-1990	3.7	3.4	5.1	0.3	-1.4
1981	1982-1991	3.3	2.5	3.7	0.8	-0.4
1982	1983-1992	3.2	1.2	3.1	2.0	0.1

Source: Extracted from Nelson and Peck [1985], Tables 2 and 3.

Figure 2-1


Energy
and
Peak Load
Prices
of
Fuels
DISPATCH
Current
Revenue
FINANCE
Revenue
Requirements
Current
Revenue
Update Rate
Schedules
Regulatory
Practices
Current Rate
Schedules
Economic
Demographic
Inputs
Current Demand
Equations
CAPACITY
PLANNING
Actual Growth
of Demand
EMPLOYMENT
IMPACTS
Demand
Projections
DEMAND

Section 3

FINANCIAL MODULE

BY

MARTIN L. BAUGHMAN

INTRODUCTION[1]

The first sentence of the Introduction and Overview of the Analytical Documentation for AUSM states:

> The Advanced Utility Simulation Model (AUSM) is a policy analysis tool designed to analyze the implications for the U.S. electric utility sector of alternative strategies for reducing air pollutant emissions in the generation of electricity." [ref. 1, p. 1-1]

In the words of the modelers:

> The primary function of the financial module in the Advanced Utility Simulation Model is to provide quantitative responses to the kinds of questions: How much will air quality control costs affect rates and usage for consumers of electricity? How will they affect the financial condition of electric utilities?" [ref. 1, p. 3-1]

It goes on to state:

> Thus, a financial module should compute the revenue requirement by which regulators determine rates and the financial statements that measure a utility's economic health." [ref. 1, p. 3-1]

Interestingly enough, the financial module does the latter, i.e., computes the revenue requirement and the financial statements, but it does not calculate rates or usage of electricity. In fact, the calculation of rates and usage are done in the demand module.

The calculations of the financial module are performed at the state level of aggregation. The analytical documentation states:

> A major advantage of the AUSM approach is that it reflects state-level activities. This is particularly important when dealing with state regulatory and/or environmental regulations. Models that aggregate to a multistate level, such as the CEUM, cannot treat these issues unambiguously. For example, under the CEUM approach it is not clear how one treats an aggregated set of utilities in which different state accounting or regulatory procedures are in effect. [ref. 1, p. 1-9]

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[1] I want to acknowledge the generous help of Professor Duane Chapman in providing unpublished materials relevant to the design of the Finance Module, and for detailed discussion of this review.

Though the state level of aggregation is an advantage for the reasons stated, it also presents significant problems in allocating costs of environmental control when generating units are jointly owned by utilities in more than one state. This topic will be returned to later.

In computing the revenue requirements and financial statements, the financial module breaks the calculations into the following steps:

- It recursively updates the value of the rate base by adding in the value of new plant and equipment that enters commercial operation and by deducting depreciation.

- It keeps track of construction cash flows for new plant and equipment and the corresponding values of the allowances for funds used during construction (AFUDC).

- It performs detailed depreciation calculations for regulatory and tax purposes, taking into account the depreciation laws that apply to various vintage assets and the peculiarities of the tax code that apply to special classes of utility assets.

- It calculates the income tax and other tax obligations of the industry, given a tabulation of actual operating revenue passed to the financial module from the demand module.

- It calculates total revenue requirements for the electricity sector in each state, given fuel and operating costs passed from the dispatch module, taxes and depreciation as computed above, and a return to capital consistent with the financial structure of sector and the rate base treatment of various tax allowances computed above.

- It simulates the financing of new plant and equipment to be consistent with a target capital structure for the firms operating within the state.

- It tabulates various common financial statements, including an income statement, a balance sheet, and a sources and uses statement for each state for each year of the simulation. It also calculates various interest coverage and profitability ratios from the financial statement data.

These calculations, though sometimes quite complex as a result of the tax laws and regulatory practices that apply to this industry, appear to be carefully executed and, for the most part, documented quite clearly.

The data of this part of the model are also very clearly presented and quite completely documented. For example, a survey of regulatory practices in all 48 states was completed to establish the regulatory data for this part of the model [ref. 2]. The data for generation, transmission, and distribution costs are clearly presented in other sections of the analytical documentation [see ref. 1, pp. 7-20 to 7-25], and all the initializing financial statement data are given [ref. 2, Appendix

C]. However, the financial calculations are done consistent with the notion that all utilities are privately-owned companies, and the initializing financial statement data are for only the privately-owned sector of the industry. How representative the financial calculations will be for states with a large publicly-owned sector is open to question at this point.

Aside from the shortcomings and one unanswered question discussed in a succeeding section, the module seems well conceived and implemented. The major strengths of the AUSM approach are:

- The specification of a number of regulatory parameters is eased since the regulatory unit in the model is the state;
- The module contains a state-of-the-art treatment of the tax and depreciation rules that apply to this industry;
- The module contains a thorough treatment of the options for handling construction work in progress (CWIP) in the rate base and the associated non-cash AFUDC credits.

The next section presents an overview of the module's calculations.

INFORMATION FLOWS AND CALCULATIONS

Figure 3-1 is a modification of Figure 3-1 of the analytical documentation(ref. 1); it is modified to illustrate the flow of information from the other modules of AUSM to the financial module and vice versa. It illustrates that the principal input information, in addition to a variety of initializing and logical data not shown, corresponds to:

- purchased power costs and operating revenues from the demand module;
- the construction program for generation, transmission, and distribution plant and equipment from the capacity planning module;
- the costs of pollution control technologies (both for new and retrofit application) from the pollution control module;
- the operating costs of the existing transmission and distribution network from the capacity planning module; and
- the fuel and operating costs of generation system from the dispatch module.

The figure also illustrates that the principal output information of the financial module is:

- the revenue requirements, which gets passed to the demand module (for updating the rate schedules); and

-the financial statements and profitability and coverage ratios that are printed as part of the standard output from a model simulation.

To produce these results the module does a number of calculations.

A large portion of the computer code actually deals with filling out a number of initializing arrays necessary to establish the future depreciation profiles from historical investment programs. This part of the module's calculations seems very reasonable and will not be further described here. Since, however, the principal outputs of the financial module are the revenue requirements and the financial statements, we can illustrate the complexity and thoroughness of the approach by reporting some of the intermediate steps of the calculations as the financial statements get recursively updated.

Consider the changes that would occur on the financial statements after one year's lapse of time. First, all existing asset accounts experience one additional year's depreciation. A large portion of the computer code for the financial module is designed to make these depreciation calculations, with proper care and attention to the IRS guidelines and tax allowances that apply to assets of different vintage and type. This part of the module's calculations accommodates the most recent changes in the tax law, as stated in the analytical documentation, as well as the depreciation schedules that apply to older vintage assets. This part of the module's calculations is impressive in its detail.

Second, there are additions to the asset accounts corresponding to the new capital spending for plant and equipment being constructed or completed. The financial module aggregates the assets into seven asset types, and new assets are added to one of these seven accounts. These seven asset accounts are an aggregation of what really corresponds to 23 generating technology alternatives, 3 control technology alternatives corresponding to retrofit SOx, NOx, and TSP control, and 3 transmission and distribution equipment aggregates. The financial module is designed to keep track of the CWIP and to tabulate the AFUDC for each of the asset accounts. The AFUDC credits, of course, feed through to the income statement calculations. The module is capable of accounting for the variety of rate basing procedures used by states for CWIP and the variety of AFUDC compounding procedures that are also employed.

The regulatory treatment of investment tax credits is varied and complicated, as are the effects of accelerated depreciation and the accounting for AFUDC credits. Also, the tax treatment of investment in pollution control technologies is quite complicated. The AUSM financial module appears to have adeptly negotiated this regulatory and federal tax maze. In fact, the documentation may be one of the more careful and complete presentations available of this very complicated subject material.

Before reporting the logic for simulating new financing, consider the effects of the year's lapse of time on the income and expenses of the industry.

The operating revenues of the industry are passed to the financial module from the Demand Module, as are the purchased power costs. The fuel costs and operation and maintenance costs of the generation system are passed to the financial module from the dispatch module. The operation and maintenance cost for the transmission and distribution system, and the general and administrative costs are calculated in the planning module and passed to the financial module from there. The financial module calculates the depreciation, federal, state, and local taxes, along with the appropriate deferrals and credits, and the interest obligation. These components of revenue and costs are then tabulated in the financial module to yield net income. Out of net income the dividends are paid on common stock and preferred stock, and the remainder is transferred to the balance sheet as end-of-year retained earnings. (The proportion of net income paid out as common dividends is apparently based upon a fixed proportion of the beginning-of-the-year retained earnings. This formulation is unique—unfortunately no quantitative results are available to review its performance.) After the retained earnings calculation, the financial module's calculations return to balance sheet related items.

The external financing of new plant and equipment is simulated at this stage. Remember that the asset side of the balance has already been updated for the year (see above), and after the retained earnings have been added to the liabilities side of the balance sheet, what remains is the update of the new issues of debt, common equity, and preferred stock. The calculations are rather standard; they are designed to maintain a target capital structure for the firms in each state. There is no feedback of the financial condition of the industry upon the costs of new external financing, nor upon the availability of new external financing. So long as the policy scenarios being analyzed by the model are such that the financing requirements do not change significantly (i.e., no more than a few percent from the base case), this formulation is passable. For scenarios in which the financing requirements change significantly, however, this formulation will understate the financial costs/benefits.

After updating the balance sheet, the module then calculates the revenue requirements using the updated balance sheet items (to determine required return to capital) and also using the actual taxes, fuel, and operation and maintenance expenditures for the period. The components of the revenue requirements are also calculated. Both the total and the components are then passed to the demand module and become the basis for updating the rate schedules (see Figure 3-1). The module then calculates various interest coverage and profitability ratios for information purposes only.

This then completes one year's worth of calculations done by the financial module.

The above calculations are done assuming the economic unit is the state. Standard financial statements, including the balance sheet, income statement, and a sources and uses statement are available for each state for each year of a simulation.

FINANCIAL DATA

The data used in the financial module's calculations are, with one exception, clearly and completely presented. The exception is the data on the costs of pollution control. This is considered serious given the intent of the overall model. All other costs and financial/regulatory parameters appear to be clearly presented and documented.

The detailed state regulatory data on such things as treatment of CWIP in the rate base, AFUDC compounding procedures, normalization versus flow-through conventions for the states, rate base definition, state tax rates, etc., are documented in a separate report [ref. 2]. The initializing financial statement information is given in the same report [ref. 2, Appendix C]. The capital costs of new generation alternatives are reported in the analytical documentation in another chapter, as are the transmission, distribution, and general plant investment requirements [see ref. 1, Tables 7-2, 7-3, and 7-4]. All the financial module's calculations are, as a result, easily traceable to basic data except for the pollution control costs. The control technology costs are presented in Chapter 5 of the analytical documentation. The outcome of the cost calculations reported there is not apparent.

MODULE LIMITATIONS

The most significant limitations of the financial module appear to be the following. First, as presently structured, the module does not allocate the costs of plants jointly owned by utilities across state lines to the states involved; rather, the costs are attributed entirely to the state in which the plant is sited. Furthermore, the architecture of the calculations is such that it appears to be complicated to modify the calculations to allocate the costs properly. This is a topic recognized by the modelers; it is addressed at some length in correspondence among the models and the sponsors [ref. 3]. The difficulty arises as a result of the fact that the basic unit of productive capital is considered to be a generating unit. As AUSM performs its dispatch and financial calculations, the economic consequences of the plant's activity is assigned totally to the state to which it is assigned in the database. The correspondence referenced above suggests two approaches to overcoming this allocation problem, but either would require significant alterations to the logical organization of the existing documented model. As a result neither of the approaches have been tested by the modelers. Since it is the case that the effects of various pollution control strategies on the revenue requirements and financial condition of the electric utilities in a state is an important measure of the consequences of a strategy, this modeling problem needs attention.

A second deficiency is that the measure of actual operating revenue (as calculated in the demand module) is inconsistent with the fundamental revenue requirement calculation of the financial module, placing in question the outcome of the tax calculations, profitability ratios, and interest coverage ratios calculated within the module.

The actual operating revenue is not tabulated in the financial module; it is passed to the module from the demand module. However, the rate schedules of the demand module are updated with the result of the revenue requirements calculations of the financial module, and the rate schedules are used to calculate the operating revenue in the demand module, which gets passed back to the financial module. Thus, though the operating revenue calculation is actually performed in the demand module, it is an integral part of the financial module's logical structure. The problem here is that consistency between the actual revenue and required revenue is not maintained, given the two-part rate schedule formulation in the demand module and the dependence of the operating revenue calculation on the number of customers.

A third problem, for at least some states, is the assumption that the financial calculations can be approximated by rules that apply to privately owned firms. This is significant for states with a large publicly owned sector, such as Tennessee, Nebraska, and Oregon.

A fourth problem is that the financing is done independent of any financial constraints that might arise. In other words, the requisite amount of external financing is assumed to be available in each state as needed with no constraints. This may overstate the ease with which the industry can respond to various pollution control policies and understate the costs as a result.

A fifth problem is that there is no feedback from the financial module to the economic calculations of the planning and pollution control modules. This is potentially significant because the economic comparisons drawn in these two modules are dependent upon a number of financial parameters in common with the financial module. For example, if one hypothesizes a change in tax policy that gives preferential treatment to certain generating types or pollution control technologies, this does not automatically feed through to the economic calculations of the planning and pollution control modules. Consistency must be assured by the model user.

EVALUATION ISSUES

In this section we attempt to address the question: How significant are the financial module's limitations to the use and application of AUSM as a policy analysis tool? The answer depends upon the question being asked and the measures of merit/impact that are deemed most relevant.

This assessment is based upon the notion that normal use of the model in a policy analysis mode will entail the two-step procedure of, first, running a base case of the model with status quo data and parameters, and, second, simulating a perturbation of the base case to represent the features of the policy being analyzed. The results of the two simulations then get compared to quantify the costs/benefits of the policy change. Of the limitations mentioned in the prior section, only one seems to have the possibility of affecting the terms of the base case outlook. The others appear more limiting in a policy analysis mode, and may or may not be significant depending on the context.

The limitation that might affect the base case results is the problem with the revenue calculation cited earlier. Since the demand module uses the prospective prices of electricity as an independent variable in the electricity demand calculation, if there existed a bias in the electricity price calculation, it would evidence itself in the model results as a bias in the demand outcomes. The level of electricity demand as a function of time governs the amount of new electricity generating capacity needed in the future to meet that demand, and also governs the amount of emissions that are present in the base case. Several legislative proposals speak specifically of limiting emissions of one or another pollutant to an absolute upper bound. For any issue in which the absolute level of emissions is important the absolute level of demand will also be important. If the overall AUSM is being used with endogenous electricity demand, then the price series of electricity needs to be consistent with the revenue requirements calculated in the financial module, and for this to occur the operating revenue calculated in the demand module needs to reflect the full average costs of service. As presently configured, the marginal electricity prices in the rate schedule formulation are updated with only the fuel costs, and the update in customer costs of the rate schedule formulation reflects all other fixed and variable costs [ref. 1, p. 2-111]. Since this is not necessarily consistent with the empirical parameters of the rate schedules, the result will be an evolution of the rate schedules that is biased from what one would expect in reality. This will result in a biased electricity demand growth projection. The magnitude of the quantitative effects must await further analysis.

The other limitations mentioned in the previous section are more limited in impact and more clearly traceable. For example, the problem of properly allocating control costs to the states involved when generating units are jointly owned across state lines has received considerable attention from the modelers and the sponsors [ref. 3]. It can also be said that if the interstate sales of electricity (these data are supplied exogenously) are accurately specified, both in terms of quantity and price, then the financial impacts are properly handled. The difficulty with this is that one must know the answer to the question beforehand to be able to specify the data. The extent of the problem appears to be limited to 36 generating plants in the country [ibid., Table 2], indicating that if special care is exercised in applying the model to analyses for the states affected, then the effects can be confined. If care is not exercised, then the result will be to assign the full costs of control to the state in which the plant is sited.

The third shortcoming noted in the prior section has already been indicated to be important only in those states with a relatively large publicly owned electricity sector. The modeler principally responsible for the specification of the financial module states in recent correspondence on the topic [ref. 4]: "For the financial module, I've tried to select economic parameters which do the best job of approximating public decision values: tax-exempt, low interest debt, no preferred equity, no corporate tax. This was done for the two public power states: Tennessee and Nebraska. I don't know if the other modules use different interest rates or tax rates for these states in their investment analyses."

The fourth problem is the assumption of no limitations on financing outside the capital structure constraints. The effect here is to understate the costs of any measure that will require more capital than the base case, and to understate the benefits of measures that require less capital.

The problem concerning consistency between the financial parameters used in the financial module and the same parameters used in the planning and pollution control modules is potentially quite significant. If one hypothesizes a change in financing or tax policy that offers preferential treatment to selected technologies, the effects could significantly alter the economics of technology choice. As presently configured, the model is not integrated to the point where a change such as that hypothesized will automatically "feed through" to the other modules. As a result, the user should be aware that consistency among data used by the various modules is an important user responsibility.

SUGGESTED FURTHER RESEARCH

The results of this evaluation suggest two topics for further inquiry. Both are linkage and consistency issues. The first of these is further inquiry into the revenue requirements, rate schedule update, demand, operating revenue, and financing sequence of calculations. A few simulations of the model in which the allocation of costs is varied from that used in the present rate schedule updating procedure would provide very useful information on how robust the demand and financial calculations of the model are. Though these modelers have an excellent historical record of forecasting electricity demand [ref. 5], the quantitative significance of the formulation used in this context merits scrutiny.

The second area of suggested further inquiry requires a complete examination of the data linkages between the financial, planning, and pollution control modules. This should be done via the program documentation [ref. 6],and also through a complete review of the computer code.

REFERENCES

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[2] Hindman, Sally, Duane Chapman, and Kathleen Cole, "State Regulatory Policies for Privately Owned Electric Utilities in 1981," A.E. Res 82-31,University Research Group on Energy, October, 1982.

[3] Chapman, Duane, and Tim Mount, "Proposed Modifications to the URGE/AUSM to Assign Control Costs Among States Correctly," Memo dated July 20, 1984, Cornell University, New York.

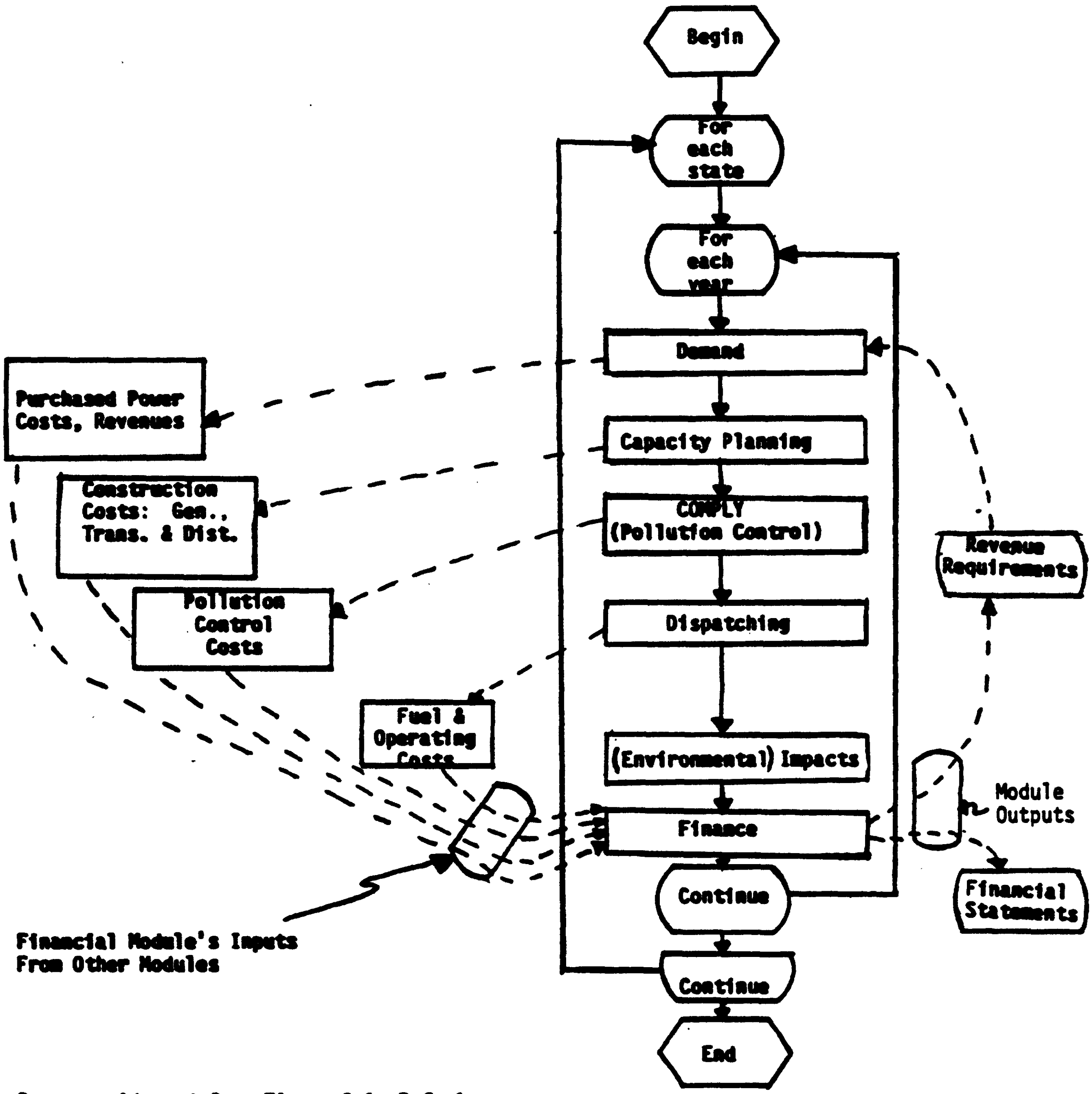
[4] Chapman, Duane, Letter to David O. Wood, M.I.T. Energy Laboratory, dated March 18, 1985, Cambridge, Massachusetts 02139.

[5] Chapman, Duane, T. Tyrrell, and T. Mount, "Electricity Demand in the U.S.: An Econometric Analysis," Oak Ridge National Laboratory Report (ORNL-NSF-49),Oak Ridge, Tennessee, June 1973.

[6] URGE Project Office (University of Illinois Urbana-Champaign), "The State-Level Advanced Utility Simulation Model: Program Documentation," prepared for the U.S. Environmental Protection Agency, Research Triangle Park, North Carolina.

Figure 3-1

AUSM LOGIC FLOW DIAGRAM MODIFIED TO ILLUSTRATE INFORMATION FLOWS TO/FROM THE FINANCIAL MODULE



Source: Adapted from Figure 3-1, Ref. 1

Section 4

CAPACITY PLANNING MODULE

BY

JAMES GRUHL AND FRED SCHWEPPE

INTRODUCTION

The capacity planning process for electric utilities faced with a change in air quality policy regulations is summarized in Figure 4-1. The electric utilities will first look to their state regulatory commissions to see what their response to federal legislation will be. For example, will additional costs be allowed to be passed through directly, will new construction costs be automatically allowed into the rate base, etc.? The utility will then make strategic planning choices among a wide variety of options such as:

- Retire Existing Plants
- Convert Existing Plants
- Change the Fuels Used in Existing Plants
- Build New Coal, Nuclear, Natural Gas, or Oil Plants
- Enter into Long-Term Buy/Sell Contracts with Neighbors
- Rely on Short-Term Market Buy/Sell Purchases from Neighbors
- Embark on Major Conservation Load Management and Customer Owned Cogeneration Plants

The utility's choice between these strategic options will not necessarily be made in terms of the classic "minimum cost criteria" based on deterministic present worth. Instead, these "choice" decisions will often be heavily influenced by the nature of past and expected future regulatory treatment, on the utility's financial conditions, and on the need to hedge against uncertainty.

After the above "choices" have been made, the electric utility will make "scheduling" decisions about which explicit years the various strategic options chosen are to be implemented. For example, on what year to retire a given plant, build a new plant, conduct a coal conversion, etc.

The outputs of Figure 4-1 are determined primarily by the "choices" and only slightly by the "scheduling." The Capacity Planning module of AUSM:

- has no internal generation or transmission "choice" capabilities, and
- has a simplified representation of the "scheduling" process.

Since state-level AUSM has no internal "choice" capability, all of the utility's strategic plans have to be provided to AUSM as exogenous inputs. Thus, on any single AUSM run, the outputs will be determined primarily by the model operators' opinions of what strategic decisions or "choices," the electric utility's would make.[1]

The AUSM documentation describes the central task of the Capacity Planning Module as "to maintain a schedule for the construction of generating units" (URGE, 1984, p. 7-2). It uses an operator-supplied inventory or planned or otherwise specified candidate units for addition to the "state utility." Decisions about the timing of these additions are made based upon the states' requirements for additional energy and additional peak capacity in order to preserve "safe" levels of reserve margins. That is, given the decisions that lead up to the maintenance of a generation construction schedule, and without concern for decisions that follow that schedule, the AUSM capacity planning module has been constructed to consider:

- capacity needs at each year and in future years,
- "current" changes to construction schedules, and
- next plant relation to long-term prespecified target mix.

This is a very restricted view of capacity planning.

The existing documentation of the Capacity Planning Module provides discussions of both a "current version," using heuristic algorithms, and a "next version," that will employ "aggregated optimization methods," this apparently being the regional AUSM. Only in this "next version" will it be possible "to simulate and quantify such tradeoffs as scrubber retrofit versus early plant retirement, coal conversion, and out-of-state siting to meet regional emission limits" (URGE, 1984, p. 7-2). It is our understanding that the current version was not designed to "stand alone" but was explicitly designed to be only a support to the more comprehensive regional AUSM. Since we had no access to any detailed information on this regional AUSM, we could only review the available material. We have no reason to believe or

[1]By exploring an extremely wide range of potential "choices," it is conceptually possible to use AUSM to partially remove this dependence on personal opinions. However, the wide range of possible utility strategic options means that a very large number of AUSM runs could be required for even a minimal study.

disbelieve that an effective regional AUSM exists or can ever exist. If an effective regional AUSM existed, our opinion of the Capacity Planning Module might be completely changed.

Several important problems with the CPM have been identified, which will likely have very important effects on the base case and any scenario applications. An attempt has been made to predict the potential bias that may be introduced by these problems.

DESCRIPTION AND SUMMARY

The Capacity Planning Module (CPM) is the second module executed in the state-level version of AUSM, following the Demand Module. "The central task of the capacity planning module is to maintain the schedule for the construction of generating units that best matches the capacity needs implied by the computer simulation in progress. Capacity requirements are based on the demand for electricity, which the demand module calculates on an annual basis over a look ahead horizon at least as long as the maximum plant construction." (Stukel, Bullard, 1984, p.3) This scheduling is accomplished by the CPM over a single state, or a "state utility."

"For each year that the planning module is run, a two part capacity needs test (available capacity and available energy) is performed successively for each year in the look ahead horizon. If both parts are passed, steps are taken to defer units under construction; otherwise, capacity augmentation is undertaken. Capacity augmentation occurs when any part of the capacity needs test fails." (Stukek, Bullard, 1984, p.3)

It should be noted that there are a number of features and capabilities that the CPM does not have. The CPM does not make any decisions about the capacity "types", i.e. baseload, intermediate, or peaking, that are needed. It does not decide what the plant-types will be; these are to be supplied by the user in an inventory of new generation and the order or emission reduction shall come on-line. There are no pollution control or emission reduction considerations, and no retirement decisions. There is no interaction between CPM and the Dispatching Module or the Pollution Control Module, except through the annual recursion.

The entire function of the CPM is then to speed up, slow down, or otherwise "to maintain a schedule for the construction of generating units" (Bullard, 1983, p. 7-2), a schedule which the user is required to provide. It should be noted that the modelers of this CPM had identified a need for a functionsl, choice-making capacity planning optimizer (URGE, 1981, p. 5-20). Due to limitations within AUSM, as a whole, and the stated, but not yet realized, intents of a regional AUSM, these capabilities were not included in the CPM.

We now summarize the important issues affecting the use and interpretation of the Capacity Planning Module.

State Utilities. The operation of these Modules as if they were a single utility with state boundaries, and without any interactions with other "state" utilities, has many important implications. The very different planning and costing of privately-owned versus publicly-owned utilities presents one set of problems. "Multiple utilities within a single state" also presents problem situations. However, the "single utility in multiple states" is particularly inappropriately modeled by these AUSM Modules. It is true that interstate transfers of power can be input exogenously by the user, but it doesn't appear that the user is given enough information with which to make these iteratively changing sets of interstate transfers.

The problems associated with these "state utilities" have been recognized by the modelers, and they have proposed a multi-state "power pool" approach. The errors that result from this approach are difficult to generalize.

Missing Interactions. Closely related to the above, the CPM is not coupled automaticaly, and as stated earlier, virtually impossible to couple manually, to the Dispatch and Pollution Control Modules, except through the annual recursion. The relegation of respective quotas for emission reductions from among these various Modules is apparently left to the user, and any search to manually make "marginal emission reduction costs" equal across different Modules is not aided by useful outputs.

Retirements. Forecasting retirements requires close interaction between Dispatching, Pollution Control, Financing, and Capacity Planning, interaction which is not present. The inflexibility of the 45-year retirement exogenously set on coal-fired plants, may understate costs, relative to a more optimal choice of plant lifetime.

Data Validity. We were unable, from the documentation, to assess the value of the data that drives these modules. There apparently exists a "data manual" but we were not provided a copy. Without examples or sources of the data, and with only hypothetical data used in the report, there is no evidence of the extent to which enormous data collection effort was conducted. No results from this model ought to be reported until such an accounting is made.

We feel that these major assessment issues are very important and must be addressed before this Module can be used in any analysis intended for policy use.

User Responsibilities. The user must provide most all the information that otherwise might be expected to be endogenously provided by such a module. The user must provide the bulk power interchanges, unusual transmission costs, and sequence of plant additions for each state that is consistent with demand, pollution controls and other states' activities. The fact that the user is not warned of the need and importance of this data, and the fact that the user can most easily proceed with the "default" data, leads to a situation of virtually certain misuse.

REVIEW ISSUES

We now consider in some detail the major issues associated with the state-level AUSM Capacity Planning Module. The Introduction to this Section and Figure 4-1 describes the decisions that utilities must make in response to air quality control policies. Implementing these decisions requires that generation capacity planning be responsive to pollution control alternatives, fuel switching options, plant retirement options, and power purchase possibilities. AUSM's capacity planning module is, however, not responsive to these key tradeoff possibilities. In particular, the state-level AUSM requires new generators to go into construction with the pollution control devices unspecified, either by the model or the model user. The statement that someday the regional AUSM "can optimize" these types of "economic tradeoffs" (URGE, 1984, p. 7-24) is hopeful, but not relevant to the currently available model. The current capabilities of the Capacity Planning Module only include the bookkeeping with regard to generation capacity construction schedules.

Some peak demand multipliers are used to cost transmission expansion in this module, triggered by changes in power demands. There is no mechanism within this module for handling interstate energy exchanges. Such exchanges must be foreseen and handled exogenously by the user as demand modifications.

Perhaps an even more serious deficiency in AUSM is the presumption that the transmission network will be capable of handling changes in transmission usage patterns that might develop. For example, substantial retrofit costs, or the use of least-emission-dispatch scenarios, are presumed not to change transmission usage patterns beyond current capabilities. In fact, however, current transmission capabilities might be quite inadequate for such scenarios. With no transmission modeling, these complicated network simulations would have to be conducted by the user before a simulation could be labeled viable or feasible.

<u>State Utilities</u>. It is important to comment on the "boundaries" of the "utilities" in AUSM. By defining the "utility" as including all the units in a state, AUSM is not able to consider many key issues. A map showing actual utility service territories in the United States will quickly show two cases of concern:

- Multiple Utility States: A single state that is served by several utilities that lie solely or mostly within that state. New York state is an example.

- Multiple State Utilities: Utilities which serve multiple states. Often these are holding companies or similar corporate structures which have subsidiary companies located within state boundaries. However, the planning is integrated. American Electric Power (AEP) which serves seven midwestern states is an important example.

AUSM's use of a fictitious state utility may be satisfactory for "multiple utility states" (or a state covered by a single utility) when all of the utilities have somewhat homogeneous characteristics in terms of generation mix, financial position, and other planning features. The effect in the Planning Module of aggregation to a single state utility of several nonhomogeneous utilities (such as Consolidated Edison and Long Island Lighting in New York) is not clear. It may yield unacceptable distortions. However, we presently believe it can probably give satisfactory results relative to the problem of Figure 4-2 and considering AUSM's very limited planning capabilities (that is, all planning decisions "choices" being exogenous inputs) and assuming the input data is correctly constructed.

The use of "fictitious" state utilities for simulating the planning of "multiple state utilities," such as AEP, produces many more potential distortions. We believe that AUSM outputs for such regions of the country should not be considered valid unless the users of AUSM provide satisfactory numerical documentation that such distortions have not occurred. One specific problem involves so-called "entitlements,- that is ownership of plants outside the state where power is used, which is becoming increasingly common. In some models these "entitlements" can be simulated by interstate transfers of power, and apparently with some special effort on the user's part, this might be accomplished in AUSM. Clearly beyond the resolution of AUSM, however, are the differences in expansion actions and costs of private, versus public, utilities. Regulatory, financial and cost allocation problems also occur when state boundaries are used as the boundaries of utilities. Some states will also be too small to make large new capacity additions as cost effective as they are when power sales across state lines can be conducted. AUSM, without interstate power transfers, will thus incorrectly build and cost this capacity.

Plant Retirement. In the AUSM we reviewed, plant retirements are assumed constant and equal to 45 years. Historically, this is probably reasonable, but recent and potential air quality legislation is likely to create major economic incentives affecting plant lives. In particular, optimal plant economic lifes will be influenced by the relative economic values created, directly or indirectly, by changing economic and regulatory factors — most importantly state and federal air quality policies —in terms of the relative values of existing versus new plants. While the existing model would support sensitivity studies of the effects of changing plant life, it provides no capability for economic analysis of the costs and benefits of changing plant lives in response to changing economic and policy scenarios.

Of course, the user could adjust the plant service life according to independent analysis of the consequences of changing conditions. This imposes still another burden on the user that might better be the subject of modeling analysis. In this regard, Peerenboom et al. [1984] at the Argonne National Laboratory have developed and applied a Retirement Module in the state-level AUSM to consider the economic costs and benefits of changes in plant lifes. The Argonne Retirement Module is operated as an optional preprocessor, similar to the Coal Supply Module, that can be executed prior to the recursive solution of the state-level AUSM. The other modules, in particular the Capacity Planning Module, have been modified to account for the retirement logic of new plant additions, and the output files also suitably modified.

Peerenboom and his associates have applied their augmented state-level AUSM for four retirement scenarios, including the default value current in the model, an accelerated retirement program (40 years), and two life extension programs (50 and 60 years). As expected, the effects on new capacity additions and emissions are significant, suggesting that plant life assumption, together with assumptions about nuclear plant construction and availability, are perhaps the most important factors a user must consider in developing policy scenarios for analysis by the state-level AUSM.

We have not reviewed the Argonne group's Retirement Module, or its integration into the state-level AUSM. We note, however, its importance in expanding and extending both the state-level and regional AUSM capabilities.

User Responsibilities. In an assessment of the USM, conducted by the URGE group to provide guidance for their AUSM efforts, they concluded the following, concerning the Capacity Planning Module (URGE, Dec. 1981, pp. 5-20-21): "heavy reliance on user-specified inputs to determine the mix of generating technologies constructed, and the schedule for retiring old plants and for converting existing plants to alternative fuels, were identified as serious weaknesses. Strengthening these aspects of the model by allowing for economic decision criteria is receiving top priority in the design of the capacity planning module for the advanced model."

AUSM makes substantial demands of the user, and these demands are in some sense "hidden." That is, nowhere is there an attempt made to thoroughly discuss these demands, nor the potential consequences of using at-hand defaults. And these are just the user responsibilities with respect to the operation of the Capacity Planning Module. Since the control instruments are all multi-dimensional and interconnected, the possibility must be discussed that a user, even a careful, patient, and sophisticated user, may not be capable of adequately handling all the required responsibilities.

AUSM does not make it easy for the user to anticipate these responsibilities either. One look at the short list of scenario parameters would give any user a false sense of security about his/her responsibilities, versus the model's capabilities.

In a related matter, any number of cross-cutting factors must be made readily visible to users so that they can approximately tailor and re-calibrate the Capacity Decision inputs. We do not know whether these feasibility checks and cross-cutting factors are or are not made accessible to the user in real-time operations, but knowledge of them is imperative. Some of these complex interconnecting issues that are left to the user's oversight and adjustment are: nuclear power as an emission control option, retirement or derating as control measures, retrofitting versus new generation as control measures, changes in regulatory postures, fuel selections, generation selection and timing, transmission feasibilities and cost, and many other interconnected issues.

The user should be made aware of the fact that the Capacity Planning Module is primarily an exogenously fed bookkeeping program. Module decisions are limited to feasibility checks on the user-supplied, ordered lists of units to be built in each state.

Data Concerns. Cost and construction data, largely from EPRI and Bechtel, are not well documented (as mentioned before, there apparently exists a data manual which we were not furnished). The URGE group in their USM assessment showed some excellent sensitivity with regard to the predominant role of "uncertainty" in this area of modeling. However, they did not carry through on either the reporting or the modeling of such uncertainty in their advanced version of that model. Cost and construction data would have been an excellent place to at least report some of these uncertainties to users, rather than leaving them as seemingly precise data. Without any information on the run times and usuability of AUSM, we cannot project whether or not alternative cost figures could ever be considered in AUSM sensitivity analyses.

Data Concerns. A county-level siting algorithm that existed in earlier model versions (using a directed random selection approach) is not included in AUSM, but may be "developed next year" (URGE, 1984, p. 7-24).

The crudeness of the 3 to 5-level load duration curve makes the model inappropriate for looking at storage, cogeneration, and certain load modifying techniques. These must be treated in very approximate ways by user modifications to the demand projections.

The choice of new technologies, the same as the choice of old technologies, is the responsibility of the user. Market penetration and cost-effectiveness must be forecast in light of the user's understanding of the unfolding situations in each scenario.

The capacity, and energy (and plant availability) effects, of various compounded pollution controls, must also be specified exogenously.

Summary. The Capacity Planning Module has apparently been modeled and programmed to adequately serve in the annually recursive mode required in the AUSM. This in itself was a significant undertaking. However, we have a major concern about the usability and accuracy of the Capacity Planning Module. In particular, without a regional AUSM the user of AUSM information ought to be aware that he/she is primarily looking at model results that have been the product of the operator's exogenously fed information.

We share the modeler's concerns that the principal area of AUSM's applicability, acid rain regulations, may be dominated by uncertainties. What "dominated by uncertainties" means bears some discussion. It apparently means is that the present models or the present data are not good enough to deal with the key issues. It argues for finding and including new variables in the model, or for the development of an understanding of the importance of those uncertainties by use of sensitivity analyses. Neither of these seem to have been undertaken, and thus we must conclude that the area of "uncertainty" was not dealt with in the AUSM.

The absence of the regional AUSM leaves a very weak connection between Dispatching and Planning, or Control and Planning, or between other major portions of AUSM. Such weak connections ought to be carefully checked out in AUSM runs, and might be identified by inappropriate insensitivities between importantly coupled decision areas.

Of concern here, and in other parts of AUSM, is the manner in which this Module's decisions will replicate the process and scope of the "actual" decisions. One of the important factors in this decision-making is the <u>size</u> of the decision units: are model decisions made to "minimize" the costs at a unit, a utility, a state, a region, or the nation? And on what scale will these decisions actually occur: on a utility level? There could very likely be significant differences between the results for decisions made over different sizes of decision units. Without development of a regional AUSM, the models's capabilities are limited to unrealistic decision units rather than at the actual utility level.

The capabilities and ingenuities of the user apparently will be severely taxed in long-range model runs. The longer the application's horizon, the more important the expansion patterns would be, and the more difficult it would be for users to unravel the compounding effects. In some scenarios, with major cost or generation changes, the limits of even the most foresighted users would likely be exceeded in fewer than 10 or 15 year simulations.

We agree with the modelers that the "serious weakness" of the Capacity Planning Module was, and we think still is, the enormous responsibility that has been put on the user. A clear statement of the qualifications of the model, and the qualifications and responsibilities required of the user, must be made. Even with our examination of the model to date, we could only make an inadquate attempt at such a list. It is unfair to expect a potential user to make the commitment of time necessary to discern what those qualifications and responsibilities might be, they ought to be provided with the model. We feel that anyone who can, or wishes to, measure up to those qualifications and responsibilities will likely have to make a full-time commitment to that job. This will make the usability, "ventilation," or the credibility of the AUSM and its results an uphill struggle.

RECOMMENDATIONS FOR FURTHER RESEARCH AND EVALUATION

The recommendations and comments discussed in Section 5 are also applicable here, namely:

- further methodological investigations are not necessary unless the Capacity Planning Module is integrated into a regional AUSM;
- the usability, transferability, and user responsibilities involved in operating the Capacity Planning Module must be investigated, and
- the detail and resolution of the data, and its easy availability, and updating, must be evaluated.

These last two issues relate to the same important question: whether or not the user will have the time and information necessary to "lead" the module in the right "direction," as well as to "check"" the results afterwards for consistency with his/her input "estimates" and make any necessary iterative runs of the module and model. It seems, from what is in the documetnation, that this very difficulty and necessary task, is not facilititated in any way by the operating procedure or outputs from the model.

Also clearly needed is a statement of these tasks that are expected of the user, as well as the limitations imposed upon AUSM applicability because of the Capacity Planning Module. The user of AUSM generated policy information <u>must</u> ask for assurances that the user and the modules are operating within their limitations. As a first step toward assuring proper uses of AUSM, a clear statement of the qualifications of AUSM and the responsibilities required of users ought to be generated by the modelers, an outside group of analysts, or better, by both.

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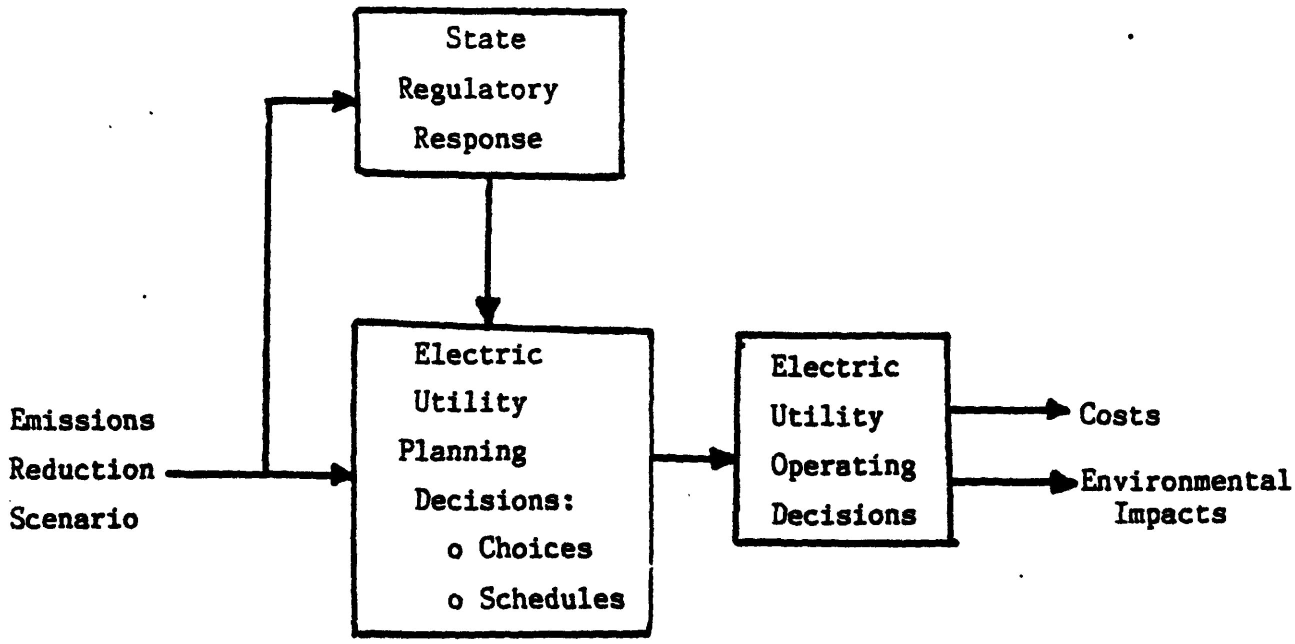

Figure 4-1 Process to Which AUSM Is Intended to be a Simulator

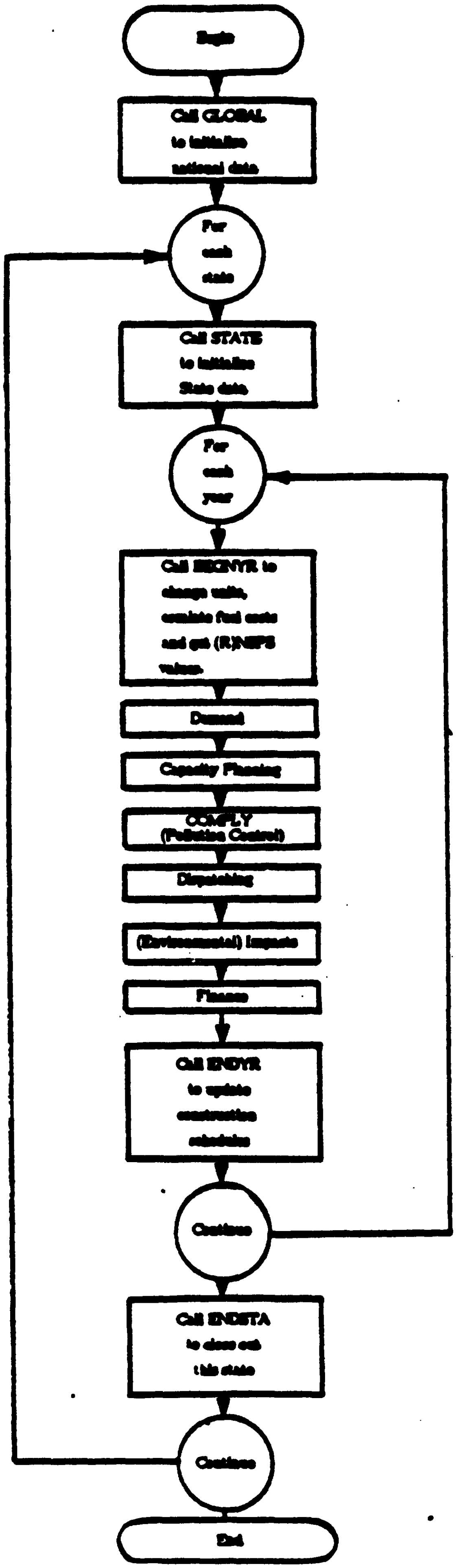

Figure 4-2 AUSM Flowchart (from URGE, 1983, App. A, Figure A-2)

Section 5

DISPATCHING MODULE

BY

JAMES GRUHL AND FRED SCHWEPPE

INTRODUCTION

Actual utility dispatching operations include the following functions:

- Economic Dispatch: Optimization of operation every five minutes.
- Unit Commitment: Hour-by-hour commitment of steam units, use of hydro resources, etc. for one day to several weeks.
- Maintenance Scheduling and Nuclear Fueling: Week-by-week decisions out to one to several years.
- Purchase and Sale Agreements with Neighbors: Purchase and sale of actual and rights to capacity on time scales ranging from hours to years.
- System Security Assessment and Control: Continual monitoring of transmission line flows and voltages to detect unsatisfactory conditions combined with evaluation of potential contingencies to deter mine future possible problems with network transmission capability. Results of these studies place limits on the unit commitment and maintenance scheduling logics and can severely restrict purchases and sales.

The costs, environmental impacts, etc. of these decisions vary widely over time depending on weather conditions, days of the week, seasons of the year, etc. They are also heavily dependent on random generation and transmission line outages.

The AUSM Dispatch module represents all of the load variations (hourly, daily, seasonally) in terms of a single 3 or 5 level annual load duration curve. The utility operations decisions are then simulated by the use of either of two logics:

- Heuristic merit order loading
- A linear programming optimization

The choice of capacity types can apparently be based upon a least-cost or a least-emission criteria. When the linear programming format is used to simulate the results of this scheduling process, there are a number of constraints that can be imposed on the emissions. Apparently only the dollar cost or the sulfur oxide emissions have as yet been used in the performance measure of AUSM Dispatching, with NO_x and TSP relegated to being regionally constrained.

The effect of generation outages are represented by derating the units. Purchases and sales with neighboring utilities are exogenous inputs. It is assumed that there are no transmission limitations within the utility region.

The principal assessment issues with this type of dispatching module relate to:

- detail, resolution, and accuracy of the methodology,
- feasibility of the simulators,
- accuracy and updating of the data,
- computer operating times, and
- ease of input and output procedures.

In the size of problem being investigated by AUSM, the last point is of considerable importance. Unfortunately, we do not currently have any information related to these input and output procedures. Aside from this major issue there are several other key, or high priority, assessment issues, which are also presented in the executive summary to this review.

DESCRIPTION AND SUMMARY

"The purpose of the dispatching module is to find the allocation that minimizes a select quantity of concern (e.g., operating cost) while meeting constraints on the other quantities (e.g., various categories of air pollutant emissions) and keeping within the operating ranges of the generating units. The dispatching module can operate in either of two modes: merit order and linear programming dispatch. The linear programming mode which dispatches power plants according to a least-cost criteria was used in this study." (Stukel, Bullard, 1984, p.3)

The AUSM Dispatch module represents all of the load variations (hourly, daily, seasonally) in terms of a single 3 or 5 level annual load duration curve. The choice of units can apparently be based upon a least-cost or a least-emission criteria. When the linear programming format is used to simulate the results of this scheduling process, there are a number of constraints that can be imposed on the emissions. Apparently only the dollar cost or the sulfur oxide emissions have as yet been used in the performance measure of AUSM Dispatching, with NOx and TSP relegated to being regionally constrained.

The effect of generation outages are represented by derating the units. Purchases an sales with neighboring "utilities" are exogenous. It is assumed that there are no transmission limitations within the utility region.

The AUSM Dispatching Module has the capability of handling 1-year or multiple-year periods, individual units or aggregate units, and 3- or 5-step load duration curves. Such flexibility implies either a very sophisticated modeling procedure, or a great deal of manual setup. It is not clear from documentation which is the case, although the only example given being a hypothetical system of 20 different generators, where all over $57.30 per MWhr are not used, does not display any sophisticated automated dispatching procedure.

The information presented to the Dispatching Module apparently requires only generator capacity, availability, (constant) emissions rates, fuel type, heat rate, and (constant) operating cost. Without emission constraints, filling a 3- or 5-stem load duration curve could be easily handled in an "optimum" way by a very simple heuristic, or "merit order," algorithm. With the emissions constraints, apparently, the "merit order" algorithm available in AUSM is not workable, and the "linear programming" algorithm is needed.

Figure 4-1 shows the position of the Dispatching Module in relation to the other modules in the AUSM flowchart. It can be seen that the Demand Module has previously been operated so as to estimate the growth in electricity requirements, Capacity Planning has tracked the schedule for new plant construction, and Comply has determined the pollution control devices to be attached to the generating units. The Dispatching Module, thus, follows these important parts of AUSM, but cannot feedback any of its information to these modules. Essentially the only output from the Dispatching Module is the operating levels of the generating units.

We now summarize the review issues associated with the state-level AUSM Dispatch Module.

<u>State Utilities</u>. As discussed in the review of the Capacity Planning Module, the use of the "state utilities" is artificial and compromising. It obviously contributes to the "misbehavior" that has been noted in the testing of the Dispatching Module. Those states that export large quantities of power will show capacity factors much lower than the historical, if the Dispatching Module is left to seek its own operating levels. Here again, with the capacity factor constraints more or less fixing the dispatch solutions, changes from a base case would not be adequately picked up by the Dispatching Module. Substantial changes in operating

conditions, such as in response to substantial emission reduction constraints, or using least emissions dispatching, should not be attempted until the Dispatching Module can forecast operating levels without "forcing constraints" aiding it.

Capacity Factors. Apparently because of the crudeness of the structure and data of the Dispatching Module, and because of the highly artificial "state utilities", the Dispatching Module did not yield reasonable or realistic results. Capacity Factors were then, and apparently still are, constrained at maximum levels of their 1980 historical values. Such a constraint virtually fixes the output of the Dispatching Module at 1980 levels, and means that this Module is essentially non-functional.

Several researchers have looked at this issue and concluded that there is no "quick fix". Realistic utility or power pool boundaries apparently must be introduced as well as more detail about the systems and the units. The error introduced by this assumption is that results will, or course, be closer to 1980 base year results than they ought to be. The error will grow with time and by bout 1990, without a general decline of capacity factors with age, the use of these old plants will be overstated and emissions will be overestimated.

Missing Interactions. Essential feedbacks and interactions with all the other AUSM Modules, in particular with the Capacity Planning and Pollution Control Modules, do not currently exist. This means that the relegation of respective quotas for emissions reductions has to be made by the user, from among the reduction possibilities within the various Modules. The Pollution Control Module, the Capacity Planning Module, the Dispatching Module, and the Demand Module can each play important roles in emissions reductions. The user is unfortunately not even given "marginal emission reduction cost" information with which to manually search out these respective roles.

Missing Details. Again, likely contributing to the problem mentioned in issue #1., there are several other areas where the Dispatching Module is missing substantial and essential detail. One is in the load duration curve, in generation construction or operation, (although this kind of detail is not inconsistent with the very crude assumption that the load shapes do not change over time). Such lack of detail argues for the use of the Dispatching Module only as a placeholder, and not the object, itself, of any new investigations. Another example of lack of detail in the Dispatching Module is inherent in its assumptions of a relatively unchanging generation and transmission scenario. Virtually all dispatching and production costing algorithms currently available are inappropriate for simulating scenarios that are more than marginally different from "business as usual," "least cost" scenarios. Scenarios that would result in the generation or transmission systems operating far from those situations for which they were planned and constructed would require the use of a Dispatching technique that could pick up a myriad of additional constraints and limitations of those transmission and generation systems. For example, the transmission system cannot be assumed to be capable of handling the very different transmission patters that would result from a substantial emissions reduction scenario, or a least emissions dispatch scenario. A dispatching technique with capabilities in these areas would possibly require an improvement to the state-of-the-art of dispatch modeling. AUSM's dispatching technique is perhaps the most simplistic placeholder imaginable, and would be wholly inadequate for simulating radically different operating scenarios.

It is difficult to generalize on the type of bias that might be introduced by these issues of "detail." However, if the model is pushed into areas of substantial emissions reductions, or least emissions dispatching, it seems clear that the Dispatching Module will substantially understate the costs and substantially overstate the emissions reduction capabilities of the "state utilities."

User Responsibilities. Especially if the Dispatching Module continues to be operated with substantial pre-specification of capacity factors, but in other model runs as well, the user is responsible for providing tremendous amounts of data, and for checking the consistency of a great many outputs, in the dispatching of the "state utilities." The input information (on interchanges, retirements, load shapes, and so on) must change with any new scenarios. There is a "default" base case data set, but we were unable to find enough information about it to evaluate its accuracy. The real danger inherent in such a default data base is that it will be misused as the data base for new scenarios. The Dispatching Module neither warns of the needs for new data sets consistent with new scenarios, nor does it provide any mechanism for simplifying the horrendously difficult task of providing new data consistent with each new scenario.

If the user does not take the time and effort to develop appropriate inputs and check the consistency of the outputs then there will be substantial biases introduced into the results. If the same "default" inputs are used for new scenarios that were used for the base case, then it is likely that the differences between the base case and the scenarios will be understated, both in costs and emissions reductions.

It is very difficult to estimate what type of bias will be introduced by these Dispatching Module issues. Of course, there seem to be some more or less dominant effects, and these are that the base case will not change as much as it should, with time, and the variations from the base case will likely be understated, again both in costs and emission reductions.

There have apparently been some recent efforts to improve the Dispatching Module. One effort that was proposed would have the "capacity factor limit" decrease with the age of power plants. Major "fixes" to the Dispatching Module would take a considerable amount of time, and would be faced with the difficulty of a limited amount of "size, space, and complexity" that could be added to the already taxed AUSM.

REVIEW ISSUES

The usefulness of the AUSM Dispatch Module obviously depends upon the application. The evaluation that follows applies to the case where AUSM is being used to predict the output of the sequence illustrated in Figure 4-2 wherein

- A certain emission reduction legislative action relating to acid rain reduction is imposed.
- The electric utilities make generation/transmission equipment <u>choices</u> and <u>schedules</u> to respond to the legislative action and corresponding state regulatory decisions.
- The electric utilities make operating decisions under the new rules and changed plans.
- These new plans and operating conditions result in changes in costs, rates, and environmental and social impacts.

The evaluation criteria is

- Can the AUSM Dispatch module be used to predict the Figure 1 outputs accurately enough to help determine whether the legislation is desirable?

The following evaluation is based only on the available documentation of the Dispatch Module, and does not consider the regional AUSM that will add to the capabilities of both the Capacity Planning and Dispatch Modules. From the general description of the regional AUSM that we have seen, it probably will change our evaluation of AUSM's capabilities.

The following sections discuss the major assessment issues.

Modeler-Noted Limitations and Issues. Before construction of the AUSM Dispatching Module was begun, the URGE group conducted a detailed assessment of the USM Dispatching Module. Some of their conclusions are still relevant to AUSM Dispatching (URGE, December 1981, p. 6-11): "Costs and emissions are sensitive to . . . uncertainties (in exogenous variables), and it is reasonable to expect that the uncertainties will be large. A few of the uncertain parameters can be dealt with through the study of different scenarios. However, the number of scenarios grows very rapidly, much faster than linearly, with the number of uncertain parameters. Since the number of uncertain parameters is large, the scenario approach is not practicable for handling all of them." We agree, and this deficiency has not been addressed in AUSM.

Also from the URGE assessment (URGE, December 1981, p. 6-10-11): "A second major deficiency in the TRI model (USM) is that it contains no procedures for feedback from the dispatching module to the planning module. Particularly when emission constraints are present, dispatching can have a major impact on decisions concerning hardware." Again we agree, and, if anything, feel that the importance of this point has been understated. The "current version" of the AUSM, without a regional capability, does not allow for this feedback and so this "major deficiency" also remains unresolved.

The URGE assessment lists several "less serious limitations," none of hich have been resolved in AUSM:

1. "the model uses constant costs . . . causing errors both in the computed operating costs and in the order in which the plants pick up load,"

2. "forced outages are included inaccurately - that is, by derating rather than by a probabilistic method,"

3. "there are no provisions for handling the effects of maintenance scheduling and unit commitment,"

4. "Finally, load management is not included" (URGE, December, 1981, p. 6-11).

The URGE team did attempt to address the first of these "less serious limitations" using a quadratic programming method that did not work out. All in all, these lesser points are probably overshadowed by related deficiencies in available data and lack of interconnections between modules. The modelers did not document any statements about the range of applicability of this Dispatching Module.

State Utilities. Now consider the Dispatch module of AUSM relative to the use of "fictitious" state utilities. By analogy with the Planning discussions, there are two cases of interest:

- Multiple Dispatch Area States: A state with several independent dispatch areas such as California. New York is a state with a single dispatch area.
- Multiple State Dispatch Areas: A dispatch area covering several states. Examples are AEP and Southern Services, where a single company covers several states, and the New England and PJM power pools, where independent utilities in different states are under a single pool dispatch.

Use of the AUSM Dispatch module for "fictitious" state utilities may be acceptable for "multiple dispatch area states" provided the results are carefully scrutinized to make certain that no major transmission limitations are being violated.

Use of the AUSM Dispatch module on "fictitious" state utilities for regions of the country with "multiple state dispatch areas" introduces so many potential distortions that the results should not be considered valid without an independent demonstration of their validity. It is conceptually possible for the impacts of multiple state dispatch areas to be represented within AUSM by very careful exogenous specification of interstate power transfers. But it is not at all clear how this can be done in practice.

Least Emissions Dispatching and Emissions Constraining. Of greatest concern, we feel, is the "least emissions dispatch" mode of operating the Dispatching Module. The modelers seem to give the Dispatching Module significant credibility in investigating this particular issue. What the modelers discuss in the AUSM documentation (URGE, 1984, p. 6-13) could at best be described as a theoretical possibility for investigating "least emissions dispatch." There is no discussion of the source or extent of non-linearity of the emission data, for say NO_x. Of greater importance is the fact that the patterns of generation and transmission would be so different in a least-emissions scenario, that many of the assumptions underlying the dispatching algorithms would not hold.

First, AUSM (apparently to provide realistic results) has constrained the maximum capacity factor at the historical levels. The fact that a user can go in and use better limits if he wants, is not relevant since the URGE group with greater resources and time, attempted to find better numbers but apparently found them unworkable in the model and gave up.

Second, the transmission network cannot be presumed away in a "least emissions" scenario as it can in a "least cost" scenario. The transmission network was constructed to meet the system needs in "least cost" dispatching strategies. Any change from that would require an examination of the additional costs and delays necessary to meet the different transmission requirements.

Third, the patterns of generation would be so different as to make for substantial changes in interregional power transportation, generation planning, fuel switching, and other pollution control options. Feedbacks from the Dispatching Module to these other sections of AUSM are up to the user's intuitions, which we would claim cannot be sufficiently developed in these new areas.

There are other concerns, such as whether or not the Planning and Control Modules have "least emission" capabilities. These concerns must be considered, in degrees, depending upon the extent to which the Dispatching Module is constrained away from the "least cost" scenario. The user ought to be made aware of the potential biases and inaccuracies involved in these scenarios.

Capacity Factors. Capacity factors for existing plants are assumed to equal their 1980 maximum levels for the remaining plant life. This assumption seems inconsistent with recent studies of age-performance profiles for coal plants. For example, a recent econometric study by Schmalensee and Joskow [1985] of coal burning units finds that both the heat rate and availability deteriorates significantly as units age. Corio [1982] reports similar results. Finally, Heiges and Stoll [1984] report that analysis of industry data show a distinct increase in forced outage rates for plants older than 20 years.[1] These studies suggest that fixing capacity factors for existing plants at there 1980 maximum levels will increasingly overstate plant availability with the passage of time.

It should be noted that the extent of the age-performance deterioration is controversial and not well established. To the extent that performance does deteriorate, however, the constant 1980 capacity factor assumption will overstate emissions. This issue, and more generally the economics of the coal generating unit age-performance relationship, should receive high priority in subsequent model research.

[1]Doug Carter of DOE pointed out this last reference to us, and indicates that further studies of the age-performance characteristics of coal generation units are underway at DOE.

It should also be noted that in the current state-level AUSM, maintaining constant age-performance profiles is costless since maintenance expenses during planned outages do not depend upon age.

Data and Documentation Issues. Many possible data concerns cannot be checked due to the lack of adequate documentation about their sources. The URGE assessment, oddly, also was concerned with "the absence of detailed documentation" (URGE, Dec. 1981, p. 5-5), but we have had to go back to that USM documentation to get ideas about what unit-specific data sources might have been used in AUSM.

"Precise data on the shape of the load duration curve is unavailable . . . therefore the AUSM . . . load curve is extremely coarse" (URGE, 1984, p. 7-16). This does not yield any insight into the care or accuracy of the collection and use of such data. Of significant concern are statements (again on p. 7-16) which state that capacity factor constraints are difficult to obtain, "therefore, the 1980 actual capacity factors . . . were selected as default values for the AUSM" capacity factor constraints. The user should be cautioned that if such defaults are not changed, least-emission-dispatch scenarios cannot be modeled with any accuracy.

Cost and construction data, largely from EPRI and Bechtel, are documented. The URGE group in their USM assessment showed some excellent sensitivity with regard to the predominant role of "uncertainty" in this area of modeling. However, they did not carry through on either the reporting or the modeling of such uncertainty in their advanced version of that model. Cost and construction data would have been an excellent place to at least report some of these uncertainties to users, rather than leaving them as seemingly precise data. Without any information on the run times and usability of AUSM we cannot project whether or not alternative cost figures could ever be considered in AUSM sensitivity analyses.

The only indication of the quality of the data that feeds the Dispatching Module is a very hypothetical example (where more than 1/3 of the generators do not get used). This is unfortunate because of the extent and importance of data to the operation of this Module. A few of these following concerns ought to be addressed before the AUSM is used in policy analysis.

Plant characteristics must be changed when pollution controls are added, or when fuels are changed. Capacities must be derated; forced outages must be accounted in further deratings; and operating costs must be increased. Whole computer languages have been created just to facilitate the automatic handling of data changes and other inputs to large LP formats. The capabilities that AUSM has in this area should be reported.

Since older, higher-emission, plants are often the last in the loading order, the peak and shape of electric demand can be of heightened importance to emission projections. How well this demand-to-dispatch connection is modeled should be addressed by the modelers.

There are many regional and intrastate emissions that are not readily amenable to modeling with state emissions dispatch constraints. These ought to be listed and discussed in the context of AUSM's capabilities.

The data sources and the construction of the load factors and load duration curves will have to be reported and assessed. Especially under major electric price changes it is important that the Dispatching Module sees the right characteristic of the demand. The evaluation of the quality of the data, a task that cannot be adequately covered without great effort, must precede any policy uses of the model.

User Responsibilities. The available documentation on the Dispatching Module (URGE, 1984, chap. 6) reads almost as a hypothetical discussion of the feasibility of the techniques. This is fine, and important, but it does not yield any information about the "product," that is, the actual model, its data, and the internal interconnections with the other AUSM Modules.

The modelers should be commended for providing a "mathematical formulation" of the Dispatching Module. The bulk of the Dispatching report, however, ought to deal with files available, codes and (LP) packages included, scenario parameters, information categories, output report capabilities, and so on. There should be block diagrams of the flow of information through this Module. Without this information the user, and assessor, cannot evaluate the "usability" of the Module.

Summary. The user needs more material in-hand to be assured that the inputs and outputs are digested and formulated in a reasonable way within the Dispatching Module. The so-called easy upward mobility of the code will require some documentation. Such flexibility is only possible with a carefully structured and very modularized approach, for which there is no immediate evidence. The limits, stability, and rigidity of what is in AUSM must be reported.

The Dispatch module of AUSM is an extremely simplified version of production costing programs used by electric utilities when they conduct their own studies. Utility studies use much more detailed load representations, explicit treatment of generation outages using probabilistic methods, and other complex modeling methods using voluminous data.

Our opinions on the validity of the AUSM dispatching module relative to the problems illustrated by Figure 4.2 are as follows:

- The use of a unit derating approach rather than probabilistic representation is satisfactory as long as issues of reliability and the use of gas turbine peaking plants do not become concerns.
- The use of an annual load duration curve is satisfactory but a three-level representation can be too "lumpy" for many applications and can lead to abrupt changes in output which should not exist.
- For minimum cost dispatch strategies, either the heuristic or linear programming algorithms should be satisfactory (in fact should yield essentially the same answers).
- Results from the minimum emissions dispatch of the linear program cannot be trusted until an independent study is made to determine that the transmission can actually handle the changes in dispatch patterns.
- Storage or reliability are not represented in the Dispatch Module and thus could not be the subject of any AUSM investigation.
- With the lowest level of regional resolution being the state, it seems also clear that most results at the state level would not stand up to scrutiny.
- Interstate transfers of power are also not included (with one state per AUSM "region"), or are made perfect and free (with two or more states in an AUSM "region") limiting many types of investigations.

There are many more such statements, which may seem obvious to the modelers, but which they ought to state in a "statement of qualifications" of AUSM for any potential users. Potential users are probably not in a position to make judgments of the importance and sensitivity of certain features in, or not in, AUSM with respect to decisions and results they wish to investigate.

As mentioned previously, a "serious limitation" with regard to this Module's capabilities for handling probabilistic or uncertain information was expressed by the AUSM modelers when they assessed the USM, and we see no reason to believe this limitation has been removed. If anything, the AUSM LP format is less easily parameterized than was the USM heuristic format. The modelers claimed "the scenario approach" was "not practicable," but now say it can be handled "without undo strain." Such changes in views, and claims, ought to be accompanied by evidence or examples.

As far as the types of scenarios that might be investigated, without some arguments to support other uses, it would seem that significant emission constraints, or "least emissions dispatching," would be out of the range of applicability of the Dispatching Module. This opinion is stated and founded based upon two observations:

1. the Dispatching Module has not been directed at any of the concerns or limitations that exist away from the usual "minimum cost" scenarios, or

2. without a detailed and substantial regional AUSM there are none of the feedbacks from Dispatch to either Planning or Pollution Control that would have to be in place in order to operate away from "conventional" scenarios.

RECOMMENDATIONS FOR FURTHER EVALUATION AND RESEARCH

In many ways the usefulness of AUSM will depend upon the capabilities of the Dispatch and Planning modules in adequately simulating the utility systems. These modules must have some decision-making capabilities, as well as interconnections, or feedbacks, to other key AUSM modules. From a methodological viewpoint it is clear what is contained in the Dispatch Module, and approximately how well it will perform in certain applications, as has been discussed. If, however, a regional AUSM is somehow coupled to the Dispatch Module, this would require some additional, and more detailed, methodological investigations.

Outside of the "methodological" areas, two key assessment issues remain unresolved. First, what is the usability, transferability, and user responsibility in the operation of this module? Second, what is the quality of the data that is available with this module, and how easily or often is it changed? It is our opinion that these two issues, and particularly the second, <u>must</u> be investigated before any results from this module, or AUSM, are made public.

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Section 6

POLLUTION CONTROL MODULE

by

James A. Fay and Dan Golomb

INTRODUCTION

If AUSM is to be used as an aid to policy analysis, it is necessary to determine what kinds of information it can or cannot supply to the policy analyst, how reliable is this information, and how relevant it is to the policy alternatives being examined. In particular, acid rain policy studies would place great emphasis on the costs of emission control technology and the changes in fuel use that might accompany an emission reduction requirement, both of which would imply consequences for prices, demand, employment, and other variables of policy importance. In this linear chain of causes and consequences, the AUSM pollution control module (PCM) plays a vital role because it determines what can be done to attain a desired emission reduction goal, at what cost, and in what manner. The attendant consequences of the technical pollution control choices are evaluated by the other AUSM modules.

There are many possible acid rain control strategies worth assessing. Current legislative proposals would specify, in effect, state-by-state (or plant-by-plant) reductions in sulfur emissions below historic levels. Interstate trading and substitution of NOx for SO_2 emission reduction might be permitted. These are principally "bubble" concepts which would permit a choice by states as to how to achieve the statewide goals, although constraints on fuel substitution may be invoked. Other alternatives have been advanced, such as minimizing aggregate national costs while achieving a given aggregate national emission reduction goal or optimizing the emission reduction to achieve desired deposition reductions in environmentally sensitive areas. But given the long-range transport aspects of acid rain precursors, it is permissible to aggregate the emissions within each state as contributing to the state "bubble" and therefore to retain for each state the option for choosing how best to meet the bubble requirements.

States may choose different methods for achieving an emission reduction goal (e.g., a statewide cap on emissions per unit of fuel heat, least cost control) and may apply various constraints (e.g. limited substitution of low sulfur fuels, required use of scrubbers). States will want to examine the consequences of the alternative policies open to them within the constraints imposed by a national plan.

The AUSM PCM is the starting point for converting a perceived acid rain control strategy into a set of policy outcomes. This is accomplished primarily through the determination of the control costs that flow from the details of the strategic choices made or implied by whatever nontechnical constraints are invoked. These costs and choices are then used in the other components of AUSM to develop the policy consequences of interest.

In subsequent portions of this section we consider the current ability of AUSM PCM to provide the requisite information for policy evaluation. We further review in some depth the cost analysis for wet scrubbers as indicative of the sensitivity of the calculated costs to user specified information.

A SYNOPSIS OF AUSM PCM

Cost Calculation. AUSM PCM is structured to determine the annualized cost of meeting exogenously specified emission standards for NOx, TSP, and SO_2 at an existing or new plant. (The requisite plant characteristics are obtained from the AUSM unit inventory files for each state.) In considering how to meet these standards, the following alternative technologies are considered:

a. NOx: Low NOx burners and overfire air.
b. TSP: Electrostatic precipitators and fabric filters.
c. SO_2: Wet limestone FGD system, lime spray dryer FGD system, direct limestone injection, coal cleaning, substitution or blending of a lower sulfur fuel (including the requisite upgrading of the TSP control where necessitated by the change in fuel ash and sulfur contents).

The cost of each technology that meets the specified emission standard is calculated in the form of an annual revenue requirement covering the fixed and variable costs. The fixed costs depend upon a capital recovery factor calculated from the financial module. When lower sulfur fuels are considered, their cost is obtained from the coal supply module. The levelized cost of each technology is then calculated and the least costly (i.e., lowest levelized cost) is selected as the "best" strategy for that plant by the pollution control strategy component of the module. The corresponding capital and variable costs are transmitted to the financial module for use in determining revenue requirements and price estimation.

A capacity penalty is calculated for each technology, as determined by the requirements for electric power and steam needed for that technology. The cost of power and steam are included in the technology costs, while the capacity penalty is reported for use in the dispatch module.

AUSM PCM does not permit the substitution of lower sulfur oil or gas for coal as a means of meeting emission standards. For existing oil-fired plants, the use of lower sulfur oil at a price premium is the only method considered for reducing sulfur emissions.

There are many factors in the cost calculation which must be entered exogenously when different from the default values. Among the more important of these are the indirect cost factor and the retrofit factor (applied to the direct capital cost). The latter takes into account the plant-specific cost increases above those expected for a new plant that will be incurred when retrofitting an existing plant with new pollution control equipment. Other factors, such as the cost of electric power (which determines the energy cost) and the cost of lower sulfur fuel, are determined from other AUSM modules.

Minimum cost strategies. If a state were required to reduce aggregate SO_2 emissions by a specified amount, it would likely allocate individual plant reductions so as to satisfy certain criteria, such as minimizing cost or prices, not exceeding an emission cap, limiting employment effects, etc. If cost were the only criterion, then technologies would be chosen so as to minimize the average cost per ton of SO_2 removed. In general, this would lead to installing scrubbers on the higher sulfur fuel plants and less intensive removal technology (e.g., coal cleaning) on the lower sulfur fuel plants, so that an equal cost per ton of sulfur removed is obtained at the margin.

An addendum to AUSM (Diemer, 1984) provides a procedure for determining the least cost method of achieving a selected value of aggregate reduction of sulfur emissions within a state. It first determines approximately the least marginal cost of sulfur emission reduction at each plant (for selected levels of emission) and then subsequently assigns the level of control needed for each plant so that equal marginal costs are experienced at all controlled plants, the common marginal cost being selected to meet the aggregate emission goal for the state. (A similar scheme for setting a common interstate marginal cost and emission reduction allocation could be used when the MPMS module becomes available). The method is approximate. Individual plant marginal cost functions are replaced by a stepwise function. What effect this approximation has on the aggregate costs for the state is not shown, but supposedly is minor.

As presently constituted, the PCM can evaluate two intrastate pollution control strategies: (a) a common emission standard equally applicable to all in-state plants, or (b) a least-cost plan for meeting an aggregate emission level for the state as a whole, based upon equal marginal costs for all plants that are needed in meeting the reduction goal. In both cases the module makes individual plant choices regarding fuel or technology on the basis of minimum levelized costs. Any departure from these scenarios, such as restrictions on the choice of out-of-state fuels, limitation of employments effects, etc., must be taken into account by manipulating the exogenous inputs to this or other modules. There is no guidance on how this might be done.

AUSM COSTING OF FUEL GAS DESULFURIZATION USING THE WET LIMESTONE PROCESS

Costing Methodology. The AUSM PCM documentation (Bloyd et al, 1984) explains the method of calculation of the costs of flue gas desulfurization (FGD) by use of the wet limestone process (Section 2.6). The costs are divided among four categories: capital costs (2.6.2), variable costs (2.6.3), energy costs (2.6.4) and solid waste disposal costs (2.6.5). Each component of cost is calculated for any plant whose characteristics (e.g., power rating, capacity factor, fuel properties, emission limits, etc.) are separately given. These characteristics become the exogenous parameters of the cost calculation.

The very large number of the input parameters and the aggregated costs calculated by AUSM make it difficult to determine which are the most important variables and components of the overall cost. This section explains a method of presenting the scheme of the cost calculation which emphasizes the critically important parameters and eliminates the inconsequential ones, simplifying the resulting calculation with little loss of accuracy.

For the purpose of making decisions about the control of sulfur emissions in the context of a national or state acid rain control program, the most important output variable of the cost calculation should be the specific sulfur removal cost (denoted herein as SSRC); i.e., the cost of each ton of sulfur dioxide which is not emitted because of the installation of the FGD system. As will be seen below, this variable is mostly dependent upon the amount of sulfur in the fuel: It is less costly to remove a ton of SO_2 from a high sulfur fuel than from a low sulfur fuel. It turns out that the best variable for measuring fuel sulfur is fuel sulfur dioxide (denoted by FSO2), expressed as pounds of SO_2 formed per million Btu's of fuel heating value.

The specific sulfur removal cost can be expressed as the sum of three terms: capital cost, variable cost and energy cost:

$$SSRC = SSCC*TF + SSVC + SSEC*E \tag{1}$$

Here the capital cost factor TF is the product of the indirect cost multiplier (1 + f), a retrofit cost factor RF and the fixed cost factor F as used in AUSM:

$$TF = (1 + f)*RF*F \tag{2}$$

The energy cost factor E in (1) is the cost of electricity in units of cents/kWh (AUSM uses $/kWh). The solid waste cost of AUSM is included in the capital and variable cost terms.

The component term SSVC and the component factor terms SSCC and SSEC depend principally upon the fuel sulfur variable FSO2 and to a much lesser extent on the plant capacity MW (megawatts), the sulfur removal efficiency of the scrubbers η, the plant capacity factor CF, the limestone reagent cost RC($/ton), and the unit cost of disposal land ULC ($1000/acre), more or less in order of importance. The dependence upon fuel heating value is implicitly included in the variable FSO2. These terms can be explicitly approximated by:

$$\begin{aligned} SSCC\ [\$/\text{ton } SO_2] = 25.6 + (172 + 3.1*ULC)/CF \\ + \{1750 + (174{,}000/MW)\}/\eta\ *FSO2 \end{aligned} \tag{3}$$

$$SSVC\ [\$/\text{ton } SO_2] = 19 + 2.37*RC + \{262 + (56{,}100/MW)\}/\eta\ *FSO2 \tag{4}$$

$$SSEC\ [(\$/\text{ton } SO_2)/(\text{cents/kWh})] = 2.17 + 68.6/\eta\ *FSO2 \tag{5}$$

In arriving at these forms through use of the AUSM PCM formulae, minor components of these costs involving variables such as fuel heating value were replaced by typical values. The equations (3) - (5) duplicate the sample calculations of AUSM PCM Section 4 to within a few percent.

(The fuel sulfur variable FSO2 is related to the percent of sulfur in the fuel %S and the fuel heating value FHV [Btu/lb] by:

$$FSO2 = \%S(20{,}000/FHV) \tag{6}$$

Since a typical fuel heating value is about 10,000 [Btu/lb], FSO2 is generally about twice %S.)

To display the dependence of SSRC on FSO2, Equations (3) - (5) were evaluated for typical values of capacity factor CF = 0.65, scrubber efficiency η = 0.9, land cost ULC = 10 [$1000/acre] and limestone cost RC = 8.5 [$/ton]. The components SSCC, SSVC, and SSEC are plotted in Figure 6-1 as a function of fuel sulfur FSO2 [$/ton SO_2] for two plant sizes, 200 and 1000 megawatts.

The most noticeable feature of Figure 6-1 is the strong inverse dependence on fuel sulfur. For low sulfur fuels (FSO2 = 10), these functions vary nearly as the reciprocal of FSO2 and therefore the sulfur removal cost per million Btu of fuel heating value approaches a constant. This limit is logical in that the cost of a FGD system is not much dependent on the amount of sulfur being removed but is proportional to the amount of fuel being burned, the latter determining the size of the components, the electric power consumed, the operating labor needed, etc. On the other hand, for high sulfur fuels (FSO2 = 10) the costs proportional to the amount of sulfur being removed begin to assume some importance, but they do not entirely determine the SSRC. Thus, over the entire practical range of fuel sulfur, the cost of constructing and operating the FGD system are not dominated by the amount of sulfur removed, and may even be little affected by the latter. The effect of power plant size is not very great, especially when the three components of SSRC are added together.

To compare the relative contributions of the three components of SSRC, we must assume typical values of TF and E. Assuming that (1 + f) is 1.8, RF is 1.6, and F is 0.15, then TF becomes 0.43; further assume E is 5 [cents/kWh]. Using these values, we find that for a 5% sulfur fuel, the sulfur removal cost is $416 per ton of SO_2, of which 64% is capital, 24% variable and 12% energy cost. This distribution of costs is relatively insensitive to the amount of fuel sulfur.

Cost Comparions. As an independent check, we have compared the cost functions of Figure 6-1 with equivalent values taken from two illustrative examples of cost evaluation of FGD retrofit systems contained in the EPRI Retrofit FGD Cost-Estimating Guidelines (1984). This comparison is shown in Table 6-1. The variable and energy costs are remarkably close, but the AUSM PCM capital costs are 20% higher than those of the EPRI examples. In this comparison, we have factored out the retrofit and indirect cost factors of the EPRI examples to derive the cost values comparable to those of Figure 6-1 and Equations (3) - (5). These factors are derivable in the EPRI Guideline procedure but are exogenous values in the AUSM PCM computation.

We also compared the AUSM cost of wet limestone scrubbers with some historical records of large plants with high sulfur removal efficiencies exceeding 80%. PEDCo (1980) collected and reported data on practically all scrubber units installed on U.S. power plants before 1980. Tilly (1983) analyzed the PEDCo collection by stratifying the data for new and retrofit units, as well as by the type of scrubber (lime, limestone, wet, dry, etc.). Since the AUSM and PEDCo/Tilly cost components are somewhat different, a convenient comparable cost unit is the capital cost per kW of installed capacity. PEDCo defined capital cost as direct cost, indirect cost and other capital costs. Direct costs include the cost of the equipment (scrubber train), the cost of installation, and the site development (including land for waste disposal). Indirect costs include interest during construction, taxes, insurance, allowance for start-up and shake-down and spares, and contingency costs (malfunctions, equipment alterations, unforeseen sources). Other associated pollution control capital costs (e.g. TSP) are not included. In the Tilly study, all historic costs are adjusted to 1981 dollars.

Eq. (3) above can be recast in the following form, using nominal values of the insensitive parameters:

$$DCC[\$/kW] = 47.3 + (4706/MW) + 8.23*FSO2 \qquad (7)$$

This direct capital cost DCC does not include indirect costs, which in AUSM are modeled "as a single user specified parameters, with a default value of 0.8". If interest during construction is accounted for elsewhere (financial module?), the default value is reduced to 0.57 (see Section 2.6.2.3).

The result of this comparison is as follows:

1. <u>PEDCo/Tilly</u>

Number of new wet limestone scrubbers	4
Average capacity	482 [MW]
Average capital cost (direct + indirect)	132 [$/kW]

2. AUSM (Equation 7)

Assumed capacity	482 [MW]
Assumed FSO2	5 [lb SO_2/MBtu]
Average direct capital cost	93 [$/kW]

This comparison shows fairly good agreement if the PEDCo indirect costs are about 35%. As indirect costs were probably higher than this, it would appear that the AUSM capital costs are somewhat higher than historic experience indicates.

AUSM capital costs (Eq. 7) show a declining unit cost with increasing plant size. The PEDCo/Tilly study did not indicate a monotonic dependence on plant size, but rather a normal distribution around a central value with a standard deviation of 15%.

Without having examined in similar detail the other AUSM sulfur removal systems (lime spray dryer, direct limestone injection, and coal cleaning) that involve the processing of the gas or fuel streams, one can expect that the SSRC will depend upon FSO2 in the inverse manner shown in Figure 6-1 for the wet limestone system. Of course, the magnitude of SSRC will be different for each process, but the general shape of the SSRC vs. FSO2 relation should be similar. For these processes, the cost curves should form a hierarchy with the flue gas processes at the top (most costly) and the fuel cleaning processes at the bottom (least costly).

HISTORICAL PERFORMANCE RECORD OF SCRUBBERS

In the AUSM PCM, costs are computed on the basis of design efficiency and other characteristics of a scrubber, which are exogenous parameters of the calculation. In calculating emissions reduction to be used in other modules, it is assumed that the system will perform as designed.

In examining the records of 26 large scale FGD installations, Tilly (1983) found that the design performance frequently was not met in service. If this were true for future installations, the emissions reductions calculated by AUSM would be an overestimate. Tilly defined four performance indices:

1. Availability Index

$$A(\%) = \frac{\text{available FGD hours}}{\text{hrs in period} \quad x \quad 100}$$

This is the number of hours the FGD system is available for operation (whether operated or not) divided by the number of hours in a period (e.g., 8760 for a year). For 13 new FGDs, this index was 86.7 15.1%. However, this parameter tends to overestimate the availability because the FGD system may have been declared available when in fact it was not required for operation because the boiler was down.

2. Reliability Index

$$R(\%) = \frac{\text{actual FGD hours}}{\text{called upon FGD hours}} \times 100$$

For nine new plants, R = 94.3 19.8%. The main problem with this index is the definition "called upon." Suppose the FGD was not called upon because of chemical shortages, lack of manpower, short duration boiler operations, etc. This would have a tendency to inflate R. Also, the records of "called upon to operate" were not always accurate.

3. Operability Index

$$O(\%) = \frac{\text{actual FGD hours}}{\text{actual boiler hours}} \times 100$$

For 11 new plants, O = 95 18.3%. This parameter can also be overestimated when the FGD system is recording operation while the boiler is not. For example, in order to prevent sludge formation, the FGD may be kept in operation when the boiler is down.

4. Utilization Index

$$U(\%) = \frac{\text{actual FGD hours}}{\text{hrs in period}} \times 100$$

For 11 new plants, this index was 63.9 13.0%. This index can be underestimated because it does not allow for the potential utility of the FGD when it was not operated for external reasons, such as boiler outage.

It is difficult to select the most reliable performance index. Tilly (1983) placed greatest trust in the Operability and Utilization indices. For the purpose of determining the actual reduction in emissions which would be experienced when plant power is dispatched, a factor of less than unity should be applied to the design reductions if it is assumed that plants can or will be permitted to operate with inoperative or malfunctioning scrubbers. Otherwise, the dispatch module would consider the plant to be unavailable whenever the FGD system is not fully operable.

Based on the historical evidence, about 10% reduction in availability or emissions control, on average, would be expected.

These operating deficiencies will be reflected in a higher total cost of achieving a required emissions reduction within a state or region because a greater degree of reduction will have to be installed to reach the average performance needed. Such slippage factors should be included as exogenous parameters in the dispatch module of AUSM.

SUGGESTIONS FOR FURTHER WORK

Apart from questions relating to the performance of AUSM as a whole, there are several aspects of PCM that should be evaluated in more detail if it is to be a reliable source of information in evaluating acid rain control options. The first concerns the adequacy of detail in determining individual plant marginal costs as the basis for exercising the market management component of PCM and whether the state-level pollution control costs are sensitive to the plant-level technology choices made in this calculation. A second question is the ability of AUSM to cope with control strategies other than those based on emission standards or least cost, particularly where constraints (such as fuel switching limitations) may need to be evaluated. Finally, further review of the costs of control technology would help to further validate the output of the PCM.

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Table 6-1

Comparison of EPRI Retrofit FGD Cost Guidelines Case Studies with AUSM-Derived Formulae[a]

	EPRI Case No. 1	EPRI Case No. 2
Rated Power [MW]	450	525
Fuel Sulfur [lb SO_2/Million Btu]	6.48	3.15
Capital Cost [1983 \$y/t SO_2]	600[b] (720)	1000[b] (1200)
Variable Cost [1983 \$/t SO_2]	123[c] (120)	199[c] (190)
Energy Cost [1983 \$/t SO_2]/[¢/kWh]	16[d] (14)	31[d] (27)

Notes

a. Values shown in parentheses, taken from Fig. 1, use 1980 \$.
b. After dividing out the retrofit factor.
c. Fixed and variable O & M, but excluding steam and power, and after dividing out the levelizing factor.
d. After dividing out the levelizing factor and energy cost of 45 mils/kWh.

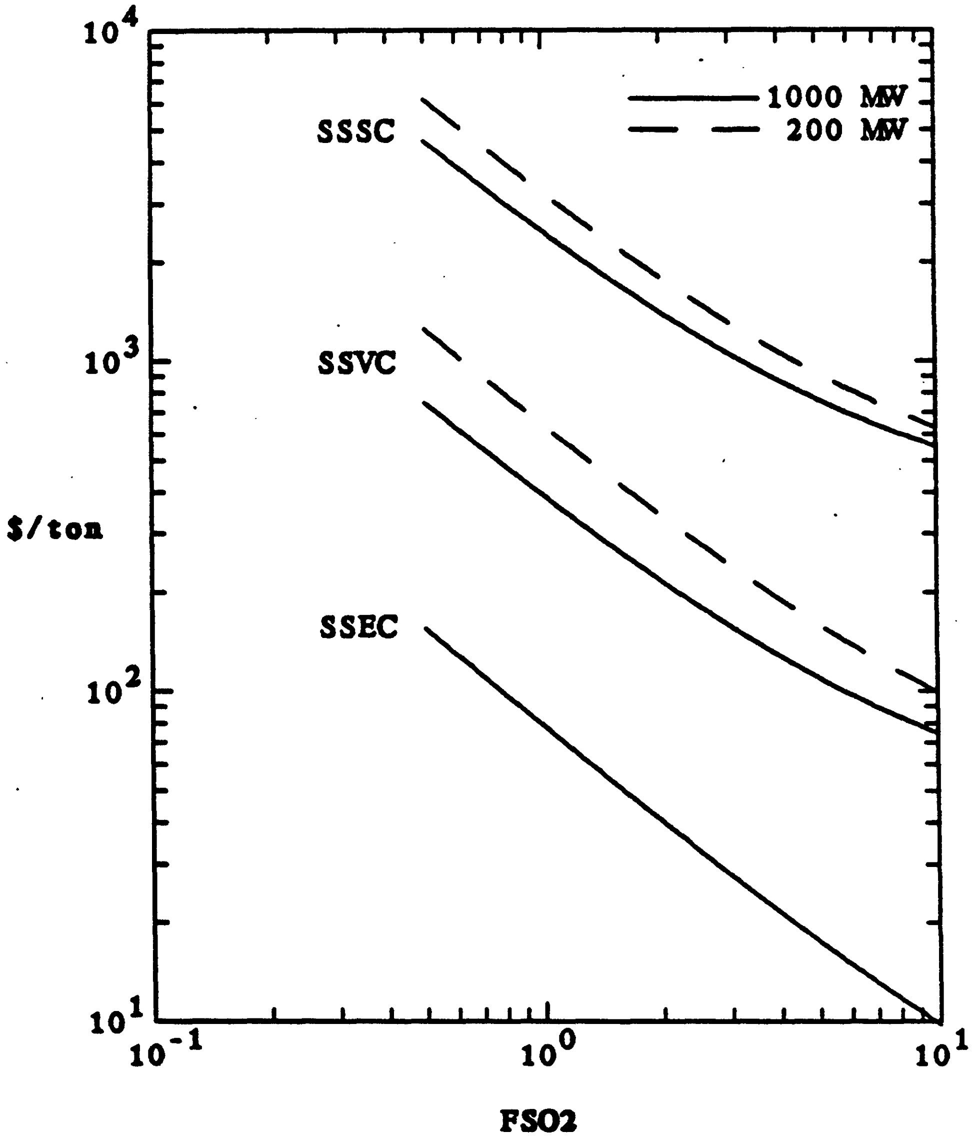

Figure 6-1

Cost Functions for Wet Limestone FGD System

Section 7

COAL SUPPLY MODULE

by

Charles Kolstad

INTRODUCTION

A critical component of any model of the electric power industry which is to be used for evaluating environmental regulations is an appropriate representation of coal supply, including delivered prices, characteristics of delivered coal and the spatial pattern of supply and consumption. Recognizing that a significant defect of the original Utility Simulation Model was its under-emphasis on coal supply, the AUSM developers sought to include a state-of-the-art model of coal supply within AUSM. This seems to have been achieved to a large extent. The module is carefully and seemingly accurately implemented and offers a number of new and attractive features to the user. However, there are a number of questions which remain about coal supply in AUSM, questions which are addressed in this chapter.

OVERVIEW OF COAL SUPPLY MODULE

The purpose of the coal supply module is to determine a set of coal prices, delivered to power plants across the country, as a function of coal quality (heating content, sulfur content) and time. To accomplish this, the module is concerned with the costs of coal mining, coal transport and coal beneficiation (cleaning). Each of these submodules is quite large and complex.

In developing the coal supply module, the AUSM modelers sought to allow users a maximum amount of flexibility in adopting various approaches to representing portions of coal supply. The developers called the module a "shell" within which the user can choose from a variety of submodules to represent different portions of coal supply. For example, the user can choose among different types of mine cost equations, different estimates of coal reserves, and different representations of depletion. This flexibility is a virtue which should be attractive to a wide variety of users.

The cost of mining can be computed in several ways within the coal supply module. One is to exogenously specify mine-mouth coal price escalation by coal type, using the module only to add transport costs and compare various coals for delivery to a specific destination, determining the least cost coals for specific consumers. A second method for computing coal costs (apparently more central to the coal supply module) is very similar to that used by ICF in the Coal and Electric Utilities (CEUM) model and by the Department of Energy (DOE) in their National Coal Model (NCM). Coal supply curves are developed based on model mines and an interpretation of the reserve base of coal by region of the US. These coal supply curves are for specific types of coal and give the long-run marginal cost of producing coal as a function of the production rate in a region.

Coal transport costs are developed from an engineering model of rail and water coal transport costs. A transportation cost per ton of coal is generated for each combination of thirty-five origins for coal and forty-eight destinations. This method contrasts to the use of actual rail tariffs in some coal supply models.

Coal cleaning costs and performance characteristics are based on a detailed engineering model of coal beneficiation. Data on actual washability of coals around the country have been statistically reduced to equations describing four washing levels. The equations give washing yield, sulfur and ash removal efficiency and costs.

The coal supply module operates somewhat separately from the rest of AUSM. Rather than iterate with the portion of AUSM determining electric utility coal demand, effectively solving for a supply-demand equilibrium, the coal supply module operates ahead of the rest of AUSM, using a separately generated forecast of regional coal demands. (It appears that eventually the coal supply module will iterate with the MPMS planning module.) Given these demands, the coal supply module determines delivered prices for various types of coals in various regions of the country, taking into account the cost of mining, the cost and performance of washing technologies and transportation cost. Two methods for computing these prices are available. One method, termed the "unconstrained" algorithm ignores depletion by assuming an infinite amount of any existing coal type can be produced. A second method, termed the "constrained" algorithm, involves finding a market equilibrium, using conventional mathematical programming techniques, between the set of coal supply functions and the exogenously specified set of demands.

The final output from operation of the coal supply module is a set of coal prices in each coal consuming region, by grade of coal and origin of coal. This information, generated for ten year intervals, serves as input to the rest of AUSM which is concerned with the operation of the electric power industry. Since AUSM operates in an annual mode, annual coal prices are obtained by linear interpolation between the prices computed at ten year intervals.

COAL PRICE FORMATION

As will become clear in the discussion below, there are a number of fundamental questions about how the coal market operates which bear directly on the appropriateness of the AUSM method of computing delivered coal prices. The gist of the following discussion is that the assumption of competitive coal markets implicit in AUSM is probably the best a priori assumption about coal market behavior. Most, if not all, other coal market models assume perfect competition. However, there are enough doubts about such an assumption to make it highly desirable for the AUSM developers to explicitly address the importance of the various non-competitive aspects of the market. In fact, given the large literature on coal market modeling, the burden of proof is beginning to shift to the modeler to justify his assumptions about market conduct. Without such justification, there would appear to be significant uncertainties about the validity of coal price and quantity forecasts produced by the AUSM coal supply module. The AUSM developers have indicated privately that they have explored this question informally; if so, their analysis should occupy a prominent place in their report.

Determining Market Equilibrium. The basic idea behind computing an equilibrium in a spatial market like the coal market is to represent coal supply by an upward sloping curve giving the marginal cost of supply for a particular type of coal as a function of quantity and to represent demand by a downward sloping (perhaps vertical) curve. A separate curve would represent the marginal cost of producing each particular type of coal in each specific mining region. In AUSM these coals would be defined by their thermal content and sulfur level. AUSM regions consist of thirty-five different coal producing districts and forty-eight coal consuming regions.

To illustrate how a market equilibrium is obtained, consider the case of a single coal, produced in a single location and used by a single consumer. In Figure 7-1, curve MM' represents the marginal cost of producing that coal. Each step of the supply curve represents a different coal deposit or mine. Mines are arranged in ascending order of costs to form the supply curve MM'. Transportation costs from this mining region to the coal-consuming region are given by t ($/ton). Thus the supply curve for delivered coal of this type is obtained by shifting upwards MM' by t to obtain SS'. Demand for this type of coal in the destination region is given by DD' which is often vertical (inelastic demand) in a model such as this, as indicated by the alternate demand curve, II'. Thus DD' gives quantity of this type of coal from this particular supply region as a function of price including prices of other, competing coals. For the case of II', the indicated quantity of coal will be demanded, independent of price. Where either demand curve intersects SS' determines the equilibrium price and quantity in the market. Operationally, this equilibrium is obtained by maximizing economic surplus, SED (shaded area). For inelastic demand, this is equivalent to minimizing cost, SEI', consisting of mining costs (stipled area) and transport costs (t*OI'). For multiple coal types and regions, maximizing surplus (or minimizing costs) over all coal types and regions, a multi-commodity, multi-region spatial equilibrium is obtained.

There are several key assumptions which underlie this approach to finding a set of market clearing prices and quantities. A basic assumption is that the market is competitive: coal producers offer their coal at the market price and are willing to sell provided the market price is at least as great as marginal costs; consumers choose how much to consume, for a given market price, solely on the basis of their demand curve. In particular, their choice of coal is dictated purely by coal characteristics and cost. This leaves no room for market manipulation (e.g., monopoly) nor for other noncompetitive behavior on the part of buyers, sellers, transporters or regulators. Further, as represented above and in AUSM, coal price formation is a purely static phenomenon. Expectations about price do not enter into price formation. We consider these issues below.

<u>Monopoly Rents</u>. Perhaps the most prominent distortion in the US coal market concerns rail transportation. It is often suggested that railroads take advantage of their market position in certain regional markets, such as from the Powder River Basin of Wyoming and Montana, to destinations in the Southeast (Oklahoma, east Texas) and the Midwest, charging rates in excess of marginal costs. In an analysis of rail rates for coal competing with natural gas (in the days of cheap gas), Zimmerman (1979) measured significant monopoly rents accruing to railroads. Further, Tennican et al (1984) argue that Illinois Central Gulf's coal tariff is one of the lowest in the nation
because of the significant competition it faces from barges. Also, rail rates on the Burlington Northern from the Powder River Basin have reportedly been significantly reduced recently due to increased competition from the Chicago and Northwestern railroad. Whenever increased competition results in a long-term lowering of rates, one must suspect that monopoly rents had been accruing prior to the increased competition.

Another potential capturer of monopoly rent is the state governments in areas with attractive coal deposits. Most well-known is the 30% severance tax on coal levied by Montana. It has been argued that this tax represents more than just compensation for externalities of coal production and includes rent extraction due to the favorable position of Montana coal (see Kolstad and Wolak, 1983). Wyoming also has a high severance tax although significantly lower than Montana's. If these taxes can be taken as given for the purposes of analysis, then whether or not they represent monopoly rents is immaterial. It is easy to input different taxes into AUSM; however, if they may change during the course of an analysis, due to market forces, then they can no longer been viewed as exogenous.

A third and less frequently discussed extractor of monopoly rents is the coal consumer, the electric utility. In locations where a single electric utility is the principal buyer of local coal, the potential exists for the utility to act as a monopsonist, extracting rent from the coal producers. Zimmerman (1979) found some evidence that in fact railroads and utilities were sharing some of the monopoly rents associated with coal. Whether or not an electric utility acts as a monopsonist is probably unimportant for long-distance coal movements such as those out of the Powder River Basin. But for certain regional markets, particularly those for which it may not be economic to ship coal very far (such as the Dakotas, New Mexico/Arizona, and parts of Appalachia), monopsony power may exist.

The importance to AUSM of monopoly rents is, of course, not that some producer or consumer is being gouged or that some injustice is occurring. Rather, the assumptions of price formation in the coal market just do not apply when such noncompetitive behavior exists. Generally, prices, and particularly quantities, associated with a surplus maximum or cost minimum will correspond to a market equilibrium only when behavior by all agents is competitive. The AUSM modelers have pointed out informally that many consumers have multiple suppliers with very similar costs and thus that competition would ensue. This is useful information. However, identifying a cap on monopoly rents by looking at the cost of various coals supplied to a particular consumer, gives some evidence regarding the competitiveness of the market, but does not resolve the problem. There may be concentration in transport, mine ownership, labor supply, regulation, or other portions of the market; thus market manipulation may still occur. Further, some consumers do not have much choice in coal supply. Only by accurately representing the behavior of consumers, producers and other actors in the coal market can one solve the complex and difficult coal allocation problem.

As an example of the importance of either explicitly considering monopoly rents or at least verifying that they do not exist at significant levels can be appreciated by considering the Powder River Basin—Midwest coal haul. If railroads are extracting rents, prices of low-sulfur coal in the Midwest will be higher than if no rents were extracted. If rents are modest, price patterns will probably not be dramatically different from the competitive case; however, spatial patterns of coal use may be very different. Suppose we are considering the effect of an acid rain bill which mandates that SO2 emissions be rolled back. If low-sulfur coal is high-priced, more utilities will choose to scrub and buy high-sulfur coal than if low-sulfur coal were cheap. Thus if an analysis ignores monopoly rents, for example by using transport costs as proxies for rail rates, an analysis of such an acid-rain bill will overemphasize the switch to low-sulfur coal and overemphasize the loss in high-sulfur coal production, politically a tremendously important variable. It should be pointed out that these factors are of particular importance in considering coal allocation patterns. If coal prices or utility costs are the dominant concern, then the question of monopoly behavior is less important since it is unlikely that coal rents are very large.

Coal Buyer Behavior. Aside from the issue of monopsony power on the part of coal-buying utilities, is the question of what other biases may enter into coal-buyer behavior, biases away from the simple model of price-taking, competitive behavior as assumed in AUSM.

There are a variety of factors which enter into a coal-buyer's decision of how much coal to buy and from whom. Certainly cost is important. But other factors such as past experience with the seller, uncertainty regarding future prices, variability of coal quality, reliability of supply, or political factors (such as pressure to buy in-state rather than out-of-state) may also enter into the decision. Some of these factors (such as local coal preference) may be exogenously imposed in AUSM. This does not solve the model-user's problem of how important these factors are and how they influence prices. For instance, should acid-rain legislation mandate a reduction in SO2 emissions, many observers in the Midwest suspect that local utilities would be directed by regulatory bodies to favor local high-sulfur coal even if that favoritism resulted in higher generating costs.

The simple characterization of a coal in terms of its heating value and sulfur content may not be precise enough to uniquely characterize a coal from the point of view of a coal-buyer. As is becoming increasingly clear (see Tennican et al, 1984 and Klein and Meany, 1984), the desirability of a particular coal depends on a host of physical characteristics of the coal, including heat, sulfur and ash content, but also factors such as grindability, volatility, moisture content, ash fusion temperature and chlorine content. While it is impractical to include all of these factors in a national model of the coal market, the question remains as to how much error is introduced by neglecting such detail. AUSM deals with this by considering three types of coal and restricting switching from one coal type to another. It might appear that the choice of three levels for heating content of coals in AUSM is an unwarranted oversimplification of coal characteristics. However, because of the large number of sulfur categories in AUSM and their use of the actual heat content of coal in a specific deposit, this seems like a reasonable assumption.

There is a long and controversial literature about the behavior of regulated monopolists, beginning with the paper of Averch and Johnson (1961) concerning over-capitalization in the presence of a rate-of-return constraint. A variety of other models have appeared showing similar or even opposite results. Some empirical work has detected an Averch-Johnson bias, other studies have not. For our purposes, the important point is that regulated utilities cannot necessarily be assumed to behave as cost-minimizers. While an Averch-Johnson or similar bias may not directly effect coal choices, if there is a bias for or against capital, then there may be a bias regarding the low-sulfur coal—scrubber decision.

Market Dynamics. The coal price formation process in AUSM is fundamentally static. While the user may choose to escalate various cost components over time, there is no endogenous recognition of spot vs. long-run markets, coal contracts, producer or consumer inventories, or price expectations. The coal industry, as most capital intensive industries, is characterized by periods of boom and bust. During a boom, mines produce at or near capacity and new mines open up as conditions warrant. In hard times, mines stay open as long as variable costs are covered, even though they do not realize a full return on fixed costs. Currently, the coal industry is in a state of over-capacity. Prices are depressed, having declined in nominal terms in 1983. In real terms, prices at the mine peaked in 1975, have been declining ever since (excepting 1978) and in 1983 were lower than in 1974 (Slatick, 1985). In response to coal market uncertainties, many coal transactions are in the form of long-term contracts. In 1983, nearly 87% of all coal moving to power plants was under long-term contract. However, to maintain flexibility, among other reasons, in certain regions of the country, a significant portion of coal is sold in spot markets. In 1981, nearly a third of all coal sold to power plants in the important markets of Ohio, Pennsylvania and Maryland were spot sales (Energy Information Administration, 1982). Understandably, spot and long-run prices may diverge considerably. From the perspective of AUSM, it is unclear how the spot and long-run markets interact in terms of being able to predict prices for particular demand levels.

Within the AUSM coal supply module, long-run coal contracts are represented by prohibiting an existing coal plant from switching coals unless environmental regulations force it to do so. This representation of contracts probably understates the flexibility such plants have regarding coal-switching in response to changing market conditions. However, accurately representing the sale of contracts in a coal market model is difficult. While a sizeable portion of coal moves in long-run contracts, should market conditions change dramatically, producers or consumers usually have ways of renegotiating or voiding such contracts. If market conditions do not change significantly, then the contracts remain in place. In either case, they have little effect on market prices, at least in the long-run. One would expect that the shorter the time frame of an analysis, the more important would be the existence of coal contracts. Over the long term, the AUSM approach should be acceptable in terms of projecting prices. However for coal distribution patterns the story in somewhat different. As is well known, delivered prices in an equilibrium model such as the AUSM coal supply module tend to be relatively insensitive to small perturbations of the parameters, whereas quantities moving between specific origin-destination pairs are highly sensitive to perturbations. If there is very little difference in price between two coals provided by different suppliers then the quantity supplied by each supplier will be highly sensitive to parameter values. The existence of coal contracts can be very important in distinguishing one spatial pattern of transactions from another. The difficult question is how to represent coal contracts without overly constraining the coal allocation problem. A related issue concerns captive mines: What is the behavior of regulated firms, which may have a financial incentive to buy coal from a subsidiary?

<u>Other Issues</u>. In contrast to most other models of the coal and electric power industries, AUSM has decoupled, to a certain extent, coal supply from coal demand. Coal demand, for the purposes of the coal supply module, is not demand as calculated by the electric power portion of AUSM, but rather an exogenous set of demands originating in the MPMS module, which is not reviewed here. We have significant reservations about this decoupling and would caution potential users to carefully examine the relationship between coal demands as generated by the AUSM electric power modules and coal demand as used by the coal supply module.

Another feature of the coal supply module that we have concern about is the ten-year time span between coal price computations. Perhaps the coal market is stable enough to warrant this level of temporal aggregation. However, a criticism of other coal models has been that five years is too long between price calculations. A discussion of the importance of the length of the time interval would be useful.

Increasingly, the southeast is importing coal from Colombia and South Africa. Such imports do not appear to be a included in AUSM. Since these coals tend to be low in sulfur and they often displace higher sulfur Illinois basin coal, this may be significant, at least on a regional basis.

DEPLETION AND SUPPLY CURVES

Depletion is one of the major issues in coal price analysis. How significant will be depletion of coal deposits over the coming years and how can it be quantified? Will depletion, if any, be offset by increases in productivity? Will depletion, if any, effect all regions similarly? This is a controversial issue and obviously an important one to the AUSM developers. One of the major criticisms of AUSM's predecessor, the USM, was that no coal resource depletion was considered. With no depletion, infinite amounts are available at a fixed price for any particular type of coal. Not only does this often lead to perverse coal supply patterns, but resulting patterns and prices will not change over time as deposits are worked out and new, more costly deposits developed.

The AUSM coal supply module operates in two modes with respect to depletion. One mode, termed the "unconstrained" mode, neglects depletion. It would appear that this mode is particularly designed for the state-level AUSM. The other mode, the "constrained" mode takes depletion into account and appears to be the preferred mode for operating the national-level AUSM. In this section we review the importance of including depletion in an AUSM-type model and review the two AUSM methods for computing equilibrium prices: one with depletion and one without.

The basic conclusion of this section is that considering depletion is very important, even for state-level analyses and consequently, the "unconstrained" mode should rarely, if ever, be exercised. Further, there are a number of simplifications which have been made in the "constrained" supply mode, apparently for computational convenience, which may lead to inaccuracies unless the user of the model is very experienced and careful.

The Significance of Depletion. In a recent study for the Electric Power Research Institute, ICF, Inc. (whose model, the CEUM, it should be noted, is a potential competitor to AUSM) examined the effects of depletion on future coal prices (Klein and Meany, 1984). Using their representation of coal supply economics, they estimated that coal prices in Central Appalachia will rise 1.3 to 1.4 % per annum over the 1990-2000 period due to depletion, at 2.7% per annum in Texas, 0.2% in Illinois and less than 1% per annum over the remainder of the country. The fact that depletion will force prices up (by as much as 30% over ten years) is an important conclusion. Perhaps more important is that depletion may not occur uniformly; some regions will experience significantly more depletion than others. Thus even if technical change moderates any increase in the overall price of coal, production patterns can be expected to shift significantly due to depletion alone. It should be pointed out that there is some contention about the extent of future depletion. The AUSM modelers argue, for instance, that use of an excessively restrictive coal reserve base unnecessarily exaggerates depletion. However, even if one disagrees with the ICF analysis, the evidence would seem to indicate that the burden of proof lies with those who wish to neglect depletion rather than vice-versa.

What is the empirical significance of depletion for policy analysis? Based on the ICF analysis, over a twenty year period, low-sulfur Appalachian coal can be expected to rise in price more than ten dollars per ton relative to the price of high-sulfur Illinois coal due to depletion alone, resulting in significantly different scrubber and fuel-choice decisions for Midwest utilities than if depletion were not considered. Thus an analysis of an acid-rain bill would overstate the switch away from high-sulfur coal to low-sulfur coal should depletion be neglected.

In summary, depletion would seem to be important enough to raise the question of when, if ever, it should be ignored by using the "unconstrained" coal supply algorithm. Even if one is examining a single state, coal prices at some future point in time can only be gauged by considering depletion of resources which may occur between now and then. In a national analysis, clearly the extent of regional depletion can be very much endogenous. One policy may emphasize low-sulfur coal resulting in long-term price rises in compliance coal; another policy may emphasize scrubbing leading to different relative prices. However, even if the model is only used for state-level analyses, if a national policy is being considered then the coal prices that state faces will be a function of the national policy under consideration. Thus it would appear that if the unconstrained mode (no depletion) were used for any analyses, save very short-term analyses, significant biases would be introduced by ignoring depletion.

Unconstrained Algorithm. Despite the apparent inappropriateness of ignoring depletion, there are a number of points to be made regarding the "unconstrained" (no depletion) algorithm for computing delivered coal prices. The basic idea is that each step of all coal supply curves is assumed to be infinite. Thus, the first and cheapest step will be the only step supplied for each coal type. In addition, for the period 1980—1990, it appears that prices are linearly interpolated between actual 1980 prices (which are difficult to obtain, mine-mouth by coal type) and the 1990 first step of the coal supply curve. Thus, by 1990 prices correspond to the fully allocated (variable plus fixed) costs of a new mine. If demand keeps growing, this may be reasonable (although the choice of 1990 is arbitrary). However, if demand for a coal type remains slack, then variable costs will best reflect long-run prices. Since this problem is probably most severe for regions with slack demand, which are therefore less important regions, this representation of interim prices may be adequate.

Constrained Algorithm. The constrained algorithm for computing coal prices takes the well-known approach of representing supply of different coals by upward sloping step function supply curves. The problems with this approach were reviewed in the previous section on price formation. The primary deviations from conventional supply curve analysis in the AUSM coal supply module have to do with simplifying assumptions which have been made to reduce the computational complexity of the module. The appropriateness of these assumptions is the primary focus of this section. Our main finding is that while the simplifications are reasonable and probably do not introduce much inaccuracy, they do not appear necessary. Since the coal supply module is only solved once, at the beginning of each AUSM run, from an approximate starting solution, computationally the problem is already relatively simple without the additional baggage of a variety of heuristic simplification techniques. Further, the supply curve truncation simplification requires a high degree of user involvement and vigilance, an undesirable feature for a model designed to be transportable and used by a variety of people. Since the supply curve truncation is an AUSM option, we would recommend that it not be used, except by the most experienced user, or by users who wish to minimize computing costs for sensitivity analyses.

The basic problem confronted by the coal supply module is to solve, for each time period, the following linear program (actually a generalized transportation problem):

$$\min \sum_{iksmj} c_{iksmjt} \; x_{iksmjt}$$

$$\text{subject to} \quad \sum_{iks} x_{iksmjt} = d_{mjt} \qquad \text{for all } m,j$$

$$\sum_{mj} a_{ikm} \; x_{iksmjt} \leq q_{ikst} \qquad \text{for all } i,k,s$$

$$x_{iksmjt} \geq 0 \qquad \text{for all } i,k,s,m,j$$

where c is the delivered cost ($/million Btu) for coal of type k, step s of the coal supply curve, cleaned to type m, in region i and shipped to region j in time period t. If all possible combinations of i, k, s, m, j and t are permitted there would be hundreds of millions of variables in the above problem and tens of thousands of constraints—clearly an unmanageable problem. Even considering only the feasible combinations of indices, the problem is very large. The AUSM developers have taken a very innovative approach to solving this problem by re-writing a_{ikm} as $\alpha_{ik}\,\beta_m$ which permits the problem, after an appropriate change of variable, to be rewritten as a conventional transportation problem with several thousand sources and destinations. Such problems can be solved much more easily than a generalized transportation problem or a generic linear program.

We have no quarrel with the assumption that a_{ikm} can be decomposed in this manner; it would seem necessary for computational tractability. However, the method of decomposition is puzzling. First of all, the module developers describe a heuristic procedure for computing α_{ik} and β_m. Why was a conventional statistical technique not used? Perhaps more to the point, the a_{ikm} are statistically estimated in the coal cleaning submodule. Since the coal supply module is the only user of the cleaning information, and it was developed specifically for this project, why was a_{ikm} estimated in the cleaning submodule instead of estimating α_{ik} and β_m directly? This coefficient, relating tons of uncleaned coal to Btu's of cleaned coal is a fairly critical variable. It is comforting that the heuristic approximation was very good most of the time; however, some of the time the approximation was poor, particularly for deep cleaning. Does this mean that deep cleaning costs are significantly over- or under-stated?

Two other simplifications are made in the supply curves in order to reduce computational complexity. One is to reduce the number of steps on individual supply curves by aggregating steps with prices within 10% of each other. The documentation is not clear as to precisely how the aggregate steps were chosen, although the precise method is not important. Considering the other uncertainties involved in estimating coal supply costs (a very useful discussion of which is contained in the AUSM documentation), this aggregation of steps seems entirely appropriate.

Another simplification is to eliminate or truncate certain supply curves based on an analysis of "price-setting" coals. The idea is that there are abundant reserves (relatively flat supply curves) for certain coals. Prices will rise little for these coal and this will act to cap depletion of substitute coals from other sources. Price-setting coals are defined as those coal deposits for which reserves are sufficient for 45 years of 1980 demand for all coal of that type. Some coals meeting this criterion are eliminated from consideration by assuming that bituminous and subbituminous coals are substitutes over the long run and that lower sulfur coal can be substituted for higher sulfur coal. Using the resulting 29 price-setting coals, and assuming 1980 demands, a set of delivered prices is determined for the price-setting coals. Returning to the full set of coal supply curves, supply steps are eliminated which result in delivered prices in excess of the price-setting coals for all delivery regions and cleaning levels. By this procedure, supply curves are truncated and some supply curves are eliminated entirely.

This approach to supply curve truncation seems reasonable, given the assumed level of coal demand. For a particular spatial pattern of demand, it is certainly true that some coals will dominate supply and others will never be produced. However, coal demand is not fixed. In particular, demand for certain types of coals is highly uncertain and dependent on environmental and other policies which are likely to be examined using AUSM. For example, sulfur regulations have a tremendous effect on relative demand for Illinois (high-sulfur) and eastern Kentucky (low-sulfur) coals. This problem could be ameliorated somewhat by setting reference level demands for the price-setting coals at the highest conceivable demand levels for each coal type throughout the analysis period. However, defining such a highest conceivable demand level would seem to be difficult and might result in such a high level of demand that few steps could be eliminated from coal supply curves. The AUSM developers seem aware of the potential problem with truncating supply curves when they point out that the model can flag any supply curves which are being exhausted so that the user may add some more steps. True enough, but this requires the model user to be familiar with this feature of the model and be prepared to intervene should a curve be exhausted. This would seem to be an undesirable feature since the coal allocation problem appears to be computationally tractable without this truncation because the module is only executed once per AUSM run, in ten year intervals, from a reasonable starting basis. However, a very useful application of the truncated curves would be for modest sensitivity analysis. Provided the curves are carefully truncated, this approach should permit a reduction in computational overhead without any sacrifice of accuracy.

There are several other points which should be mentioned regarding the constrained algorithm for computing coal prices. One concerns the assumption of a uniform distribution of lifetimes for existing mines. This assumption is used for retiring existing mines over the first thirty years of the analysis. One third of the existing (1980) capacity is retired in each of the first three ten-year time periods. Lacking any other information, an assumption of uniform lifetimes for existing mines might seem reasonable. However, if one examines a time series of regional or even national production levels over the past few decades, there have been dramatic increases in production of some coals, decreases in others and stability in others. Nationally, underground production has been stable for decades whereas surface production has tripled in the last twenty years and now constitutes over 60% of total production. On a regional level, the obvious example is capacity in the Powder River Basin, nearly all of which has become operational only in the last decade. An inappropriate assumption regarding the distribution of existing mines will result in an over- or under-emphasis on depletion over time.

In a related vein, there is a need to estimate the variable cost of producing coal from the mines existing in 1980; these variable costs constitute the first step of all supply curves, with the length of the step corresponding to the size of committed reserves. In the AUSM coal supply module, the assumption is made that variable costs for existing mines can be set equal to variable costs associated with the first new mine for a coal type. While conceptually this may seem reasonable, the result is that the supply curves are nowhere pegged to actual prices of coal. Thus the prices for "existing" mines could bear very little resemblance to actual prices. To address this, AUSM interpolates coal costs in the 1980s between the estimated 1980 price (the problems with which we have already noted) and 1990 supply curve marginal costs.

COAL PRODUCTION COSTS

Perhaps the most crucial part of the entire coal supply module is the computation of the costs of producing coal. In AUSM, there are two basic approaches for determining the production costs of coal. One method is based on a statistical analysis of coal prices over the 1975—1980 period. The other method involves dividing the coal reserve base into homogeneous deposits and then costing each deposit using engineering relationships between deposit characteristics and costs. The latter approach appears to be most prominent in AUSM but we consider both approaches here.

Our basic conclusions are that the statistical price analysis should not be used. The engineering cost approach appears to be a fairly solid implementation of a well-known mine cost model (a model with problems and virtues which have been widely discussed), although there are some procedures and data assumptions which we question.

Statistical Price Analysis. This approach to developing mine-level costs was developed by John Green and Ari Michelson of the US Department of Agriculture. Using data on coal deliveries at power plants during 1975—1980 from FERC form 423, mine-mouth coal prices are estimated by subtracting an estimate of transport costs from the reported delivered prices (excluding spot purchases). These mine-mouth costs were regressed on UMW wages, oil prices, ash content, shipment size and other variables.

Although there is not a great deal of discussion of this approach in the AUSM documentation, it would appear that there were significant problems in explaining coal prices. For instance, there is an indication that about half the variation in prices was explained by the statistical model. If this is a short-hand for stating that the regression resulted in an R^2 of .5, then the fit was not good at all. The documentation states that when forecast prices for 1980 were compared with actual prices for 1980, extremely large discrepancies were observed: most prices were off by at least 15% and many by over 50%. Furthermore, the method tended to underestimate low-sulfur coal prices and over-estimate high-sulfur coal prices. In other words, the statistical estimates of the determinants of coal prices are poor and should probably not be used.

Engineering Estimates of Mine Costs. The more central method in AUSM for computing coal production costs is a refinement of the Resource Allocation and Mine Costing Model (RAMC) originally developed by ICF, Inc. for the Federal Energy Administration in the mid-1970's. The US Department of Energy has subsequently undertaken considerable updating of the RAMC and AUSM builds upon the latest version (SAI, 1983a,b). The basic idea behind the RAMC is to divide up the national reserves of coal into deposits consisting of coal homogeneous in physical characteristics (e.g., sulfur level) as well as mining characteristics (such as seam thickness). A number of typical or "model" mines are costed out as a mining engineer would do but with some critical variables such as seam thickness parameterized. These model mine equations are then applied to the individual deposits to determine the cost of producing coal from these deposits.

The advantages, problems and appropriateness of an engineering-costing approach to mine-mouth coal costs have been the subject of much debate over the past decade. As in any production analysis, there are basically two ways to determine production costs: engineering estimates for hypothetical new facilities or econometric estimates for existing or past facilities. The engineering approach has the advantage of being able to vary design characteristics at will, limited only by the skill of the cost engineer. The econometric approach has the advantage of being based on actual costs, not estimated or approximate costs for some idealized or generic facility. A complicating factor regarding coal supply curves developed under either approach is how estimates of costs for mines with well-defined characteristics interact with the regional or national base of undeveloped reserves of coal to yield an industry supply curve. We will say no more about the relative advantages of engineering vs. econometric costing methods except to note that econometric techniques, particularly in conjunction with geostatistical techniques, have probably not be explored as fully as they should be in order to conclude that engineering methods are superior.

The RAMC as originally implemented by ICF was the subject of a thorough review by the MIT Model Analysis Program several years ago (Wood et al, 1981). That review identified four potential problems with the RAMC, some of which were remedied when the RAMC was updated. The most serious, as judged by MIT, was the assumption of a uniform mine lifetime. Since the AUSM coal supply module also assumes a uniform 30-year lifetime, this criticism can presumably also be leveled at AUSM. The basic point was that mine lifetime is an extremely important variable and consequently that the assumption of a constant mine life is unrealistic. A second criticism concerned the reliability of the reserve base for coal, an issue we will return to later. A third criticism concerned the treatment of intertemporal rents (they are not considered in the ICF model or in AUSM). A fourth criticism concerned the antiquity of the model mines and the fact that the form of the mine-costing equations resulted in an indeterminate optimal mine size. The model mine equations used in AUSM are more detailed and up-to-date than those considered by the MIT review but the form of the equations still is such that mine size is indeterminate. Rather than repeat the previous MIT critique, we will focus on other issues in the discussion below.

One of the assumptions of the RAMC is that reserves can be partitioned according to seam thickness or overburden ratio into distinct deposits. Mining one deposit has no effect on the other deposits. In some cases, this is an oversimplification of reality. Surface deposits sometimes consist of multiple seams of varying thickness occurring anywhere from close to the surface to quite deep. The cost of mining deeper surface reserves clearly depends on whether or not the more shallow reserves are extracted at the same time. If the shallow reserves are extracted first and the overburden replaced, it will be much more costly to mine the deeper reserves at a later date than if they are mined simultaneously with the shallower reserves.

A related issue concerns the recovery rates of mines, i.e. how much of the deposit is actually recovered. Reserves left in the ground in a worked out deposit are effectively excluded from future extraction—thin seams may be mixed in with overburden in surface mines or mine conditions may deteriorate in abandoned underground mines. By assuming that recovery rates are fixed, and effectively independent of economic conditions, one may be distorting (in either direction) the amount of particular types of coals available for development. Just as mine lifetimes should be treated as endogenous variables (as suggested in the MIT critique), recovery rate too should probably be considered an endogenous variable.

As was discussed in the MIT review of the RAMC, mine lifetime assumptions are critical to the estimated production costs. The more steeply sloped a supply curve, the more important is the assumption about mine lifetime. Although there does not appear to be a reference to the mine lifetime assumed in AUSM, thirty years is assumed in the development of the mine costing equations (SAI, 1983a,b). Interestingly, SAI reports in the same volume that surface mine lifetimes in the east rarely exceed five years, often exceed twenty or thirty years in the Midwest and are up to fifty years in the west. Thus there seems to be a certain amount of inconsistency within the RAMC model mine cost equations. Mine lifetimes appear in the AUSM model in two places. One is implicit, through the use of the RAMC mine cost equations developed by SAI. Secondly, the AUSM calculates a levelized cost for all the components of production costs. This levelization requires an assumption of a mine lifetime. The mine lifetime assumed seems to be a user specified input, specified in the PARMS file for the routine QUANT. For consistency with the RAMC, it would seem that this should not be user specified but set to thirty years. The use of thirty years as a single mine lifetime exposes the AUSM module to the same criticism leveled at the RAMC by MIT.

Another set of comments concerns the mine operator discount rate. The AUSM developers quite appropriately focused attention on this variable, taking some pains to develop an estimate that reflects the characteristics of the mining industry rather than the electric power industry. The mine operator's discount rate is defined as:

$$r = (1-T)\ D\ r_d + (1-D)\ r_e$$

where r_d and r_e are the interest rate on debt and the after-tax return on equity; T and D are the income tax rate and the debt-equity ratio; r is the resulting mine operator's discount rate. Inflation is considered in AUSM but is neglected in our discussion here. This discount rate is used to compute a levelized cost including "fair" payments to equity holders. The values used for return to equity, debt cost and debt-equity ratio are averages for all large corporations. While these values can be chosen by the user, it would seem that large corporation rates and ratios would not correspond at all to relatively high-risk mining companies and thus the computed costs would understate the minimum acceptable selling price. More realistic data could be developed from published sources such as Standard and Poor's Stock Reports, although conglomerate ownership of mining companies may make this difficult.

A related issue concerns eqn. (12) in the coal module documentation. That equation defines the present value per ton of output for a particular mine:

$$PV = PV(costs)/(S\ L)$$

where S is mine capacity in tons per year and L is lifetime of the mine. It is stated that this equation determines the order in which mines are opened. This is only true under very special circumstances. In particular, it requires that lifetimes for all mines are the same or, alternately, that the price of coal rises at precisely the discount rate. The reason for this is that the viability of a mine depends on the overall net present value of costs and income and the present value of income depends on the time profile of prices. This may be a minor point because for most of the remainder of the documentation, reference is made to levelized costs, a more appropriate criterion, rather than a present value of costs per ton.

COAL RESERVES

In order to estimate supply curves for specific coals, one needs estimates of mining costs as a function of characteristics of a coal deposit as well as information of the distribution of various deposits of coal throughout a coal basin and throughout the country. The estimation of the amount of coal in deposits of different types is probably the weakest link in all models of coal supply. To a very large extent, the AUSM developers have utilized almost exactly the approach of the DOE to dividing and categorizing coal reserves for use in generating supply curves. A major departure was in expanding the number of sulfur categories from six to eleven. A significant portion of the documentation of the reserve allocation is concerned with aggregating or disaggregating DOE data which is in terms of National Coal Model coal types and regions. One reason for this is the desire for AUSM to be able to replicate the NCM.

The US Department of Energy is responsible, within the Federal Government, for maintaining an estimate of coal reserves in the US. The Demonstrated Reserve Base (DRB) is developed from numerous field measurements of coal in place, measurements taken by geologists over the years, primarily from the early part of this century (Klein and Meany, 1984). One of the problems in using the DRB is that the last detailed DRB was published in 1974. The 1974 DRB contained information on reserves by sulfur level, coal bed, county and seam thickness. Since then, only aggregate summaries of the DRB have appeared. In particular, no more recent breakdown by sulfur level or seam thickness is available, despite the fact that the DRB has changed significantly (at least in some regions) since then.

In developing an up-to-date estimate of coal reserves by sulfur level, the AUSM developers took the 1974 detailed DRB, categorized coals of unknown sulfur content and "adjusted" detailed entries to make them more consistent with the 1980 DRB (the latest DRB is now for 1982). The first step involved the assignment of 1974 reserves of unknown sulfur level to one of the sulfur categories, following an approach similar to that adopted by the DOE in developing the inputs for the National Coal Model (SRC, 1982). The approach used to do this is well-documented and basically consists of applying the distribution of sulfur content for known-quality reserves to unknown-quality reserves, doing the assignment at the highest level of disaggregation possible. This seems reasonable and the only way of dealing with missing data. However, in moving from the 1974 DRB to the 1980 DRB, all that is said in the AUSM documentation is that it was "necessary to go back to the [1974 DRB], extract data according to the various DRB reserve categories, adjust for depletion, and then assign sulfur content" (Appendix B of AUSM Documentation). This is insufficient documentation for a fairly important assignment of reserves. Nationally, the difference between the 1974 and 1980 DRB's is not great but for some regions, the difference is marked. An additional point is that the sulfur categories as defined in the Appendix documenting the generation of the AUSM DRB do not correspond exactly to the sulfur categories in the AUSM coal supply module documentation and the AUSM coal cleaning documentation (there is a discrepancy regarding the break-points between sulfur categories).

Another set of reserves are developed by E.H. Pechan & Associates for the AUSM project. The Pechan reserves involved adding inferred economic resources to the reserve base which only includes measured and indicated economic resources.[1] The idea of including inferred resources (and even subeconomic resources) is a good one. As the AUSM modelers point out, by excluding inferred reserves, supply curves may end up being too steep, resulting in exaggerated coal price rises due to depletion. However, the addition of such inferred resources should be done carefully and in a well documented fashion. The documentation in the AUSM report (Appendix B) on the development of the Pechan extension of the reserve base is rather sparse. This is unfortunate. We conclude that this reserve base should be used with caution given the current state of documentation. If it is relatively easy to expand the documentation, this should be done so that this potentially useful reserve base may be used with more confidence. Apparently the AUSM developers agree since they state that they plan to use the EIA Demonstrated Reserve Base for base case runs, either as developed for the National Coal Model or the variant developed for AUSM.

A fundamental step in moving from an estimate of reserves to supply curves is in allocating reserves to categories of overburden ratio (for surface mines), seam depth and thickness (for underground mines) and mine size in terms of annual output capacity. The DOE approach is to examine the characteristics of existing mines and essentially apply the distribution of characteristics to all reserves. This approach seems to have been adopted by AUSM although technically the user can input any distribution of reserves. Thus the distribution of overburden ratio in producing mines of a particular district will be applied to all potential new mines for that district. Since currently operating mines are supposedly working the best reserves, this seems to be a peculiar and biased way of allocating reserves. Some examination of its appropriateness for a region or two where detailed information is available would be useful in order to validate the approach.

A final point concerns the determination of committed reserves for existing mines. The DOE uses the same data for computing committed reserves that they use for determining the distribution of deposits by overburden ratio, seam thickness, etc. The AUSM developers seem to prefer to assume that all existing mines have fifteen years of life remaining. This would seem to be an unnecessary approximation, considering the availability of the more realistic DOE information.

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[1]Actually, E.H. Pechan and Assoc. developed both sets of coal reserves used in AUSM. However, it is the set of reserves which include inferred resources which represent a dramatic departure from past practices; we thus refer to them as the "Pechan" reserves.

COAL TRANSPORTATION

The cost of coal transportation is AUSM is represented by costs per ton of coal for each transport link between a supply region and a demand region. Because of the use of these costs in AUSM, one must conclude that they are used as proxies for deregulated rail tariffs, an appropriate assumption for a competitive market.

These transport costs were developed by Ken Ebeling of North Dakota State University using a model of the nation's rail and water transportation network. By using estimated transport costs rather than actual transport rates, this model represents a divergence from the approach of other coal models. In fact the primary review issue here regarding coal transportation concerns the potential bias which may be introduced by using cost estimates as proxies for deregulated rates. As was discussed earlier, there is a strong possibility that railroads have been extracting some monopoly rent over certain routes. Such rents would be reflected in rates but not in costs. Further, with the deregulation of railroads, such rent extraction may occur even more frequently than in the past. Further, the railroads have a considerable amount of flexibility in how to allocate fixed costs to various commodities. This presents difficulties for a cost-based analysis since it is difficult to determine a priori how fixed costs will be allocated. The one exception to using costs to reflect rates is given by the Staggers Act which limits rates to 160—180% of variable costs (without rate hearings), although this limit may only be appropriate where the market power of railroads is high.

The excellent documentation of the rail transport cost work for AUSM (Ebeling, 1983) attempts to defuse some of this criticism by performing a detailed comparison of costs as computed with transportation costs computed by three other groups, all based on coal tariffs: the National Coal Model, ICF's CEUM and a Carnegie-Mellon statistical analysis of coal and barge rates. Ebeling reports that average rail rates per ton-mile from the tariff analyses are consistently higher the computed costs: 36% higher for the National Coal Model, 7% higher for the CEUM and 8% higher for the Carnegie- Mellon analysis. Except for the National Coal Model, these differences are surprisingly small; nevertheless, the cost approach does seem to consistently under-estimate coal tariffs, despite the fact that the costing methods are supposedly the same as those used by the ICC. In fairness, this does not mean that these costs will be inappropriate for estimating post-Staggers Act rates; that issue remains open. In addition to providing a comparison of national average rates under the various approaches, it would be interesting to analyze differences for certain types of movements, such as out of the Northern Great Plains or in the Midwest.

The comparison of water rates is more disconcerting. The Carnegie-Mellon analysis involved a statistical estimation of a barge rate equation by regressing tariffs for water movements on distance. The cost calculations for water movements per ton-mile were 50% higher than the tariffs. Perhaps this lower accuracy is not surprising, since the coal transport model used to develop transport costs appears to be basically a railroad model with much more limited capabilities for costing barge movements.

One portion of the coal transport cost documentation concerned validation of the rail transport distances as computed by the costing model. Using a rough check on these distances (comparing "crow-flies" distances with rail distances), a number of apparent errors in the costing model were uncovered by Ebeling. This is somewhat disturbing. If further checks were made, would other errors be detected. For example, why is there a preponderance of the cost of $1.51 per ton-mile for rail movements (in Appendix C, the variable TCOST)?

COAL CLEANING

The coal cleaning portion of the coal supply module was developed as a stand-alone analysis by James Skea and Ed Rubin of Carnegie-Mellon University. The basic problem with representing coal cleaning in a model such as AUSM is that coal washability is highly variable, depending on a variety of factors in addition to the sulfur and heating content. Skea and Rubin's approach is to utilize a DOE data base consisting of laboratory washability characteristics for 710 specific coals. Their characterization of coal cleaning consists of two steps. First, they apply three models of coal cleaning, ranging from medium to deep cleaning, to the DOE washability data, generating a set of pseudodata giving the characteristics of the washed coal for a variety of cleaning intensities for each of the coals in the sample. Using this pseudodata, they estimate equations on a regional basis giving cleaning yield in terms of sulfur, ash, heat content and weight as a function of the characteristics of the input coal. The approach appears to be a significant improvement over the representation of coal cleaning in other coal market models; however, there are a number of issues that remain which are discussed below.

The first point concerns the data base used for the washability analysis. The source of the washability data is cited as a 1976 Bureau of Mines publication. Since that report was published, an additional set of washabilities have been generated by the Bureau of Mines (now part of the DOE). Have those been included?

A large portion of the documentation of the coal cleaning model concerns the statistical estimation of six regionally varying equations describing pyritic sulfur fraction, maximum sulfur reduction, ash reduction, Btu content of cleaned coal, Btu yield and cost, all as a function of the sulfur, ash and Btu content of the coal input to the cleaning process. Since most of the equations involve endogenous variables on the right-hand sides, it would seem that statistically it would be more appropriate to estimate the equations simultaneously rather than using single-equation ordinary least squares. Also, t-statistics are not reported for the intercept terms in the equations. And, as pointed out by Resource Dynamics Corp. (1984), the t-statistics may be misleading since the equations are estimated from pseudodata. Also, what other functional forms could be utilized to improve fit? Also, the cost of basic preparation seems to be absent from the documentation.

For each cleaning level, there is a need to choose a most economical process for achieving the given level of cleaning. This choice is not independent of the price of the input coal. Consequently, the cleaning module uses the statistically estimated prices generated by Green and Michelsen. As we pointed out in our earlier discussion of these price estimates, they appear to be highly unreliable. Consequently, it is disturbing that they are being used to choose the most economical method of coal cleaning. Further, even if the Green and Michelsen prices were reliable for 1980, it is likely they would not be appropriate for representing prices at some future time point. Perhaps the assumed coal input price is not very important; if so that should be indicated in the cleaning module documentation. If the coal input price is important then there is a potential problem. Perhaps what is needed is a more conventional economic cost function in which the cost of cleaning is a function of input prices, input characteristics and output characteristics. This would be quite compatible with the coal price and allocation algorithm.

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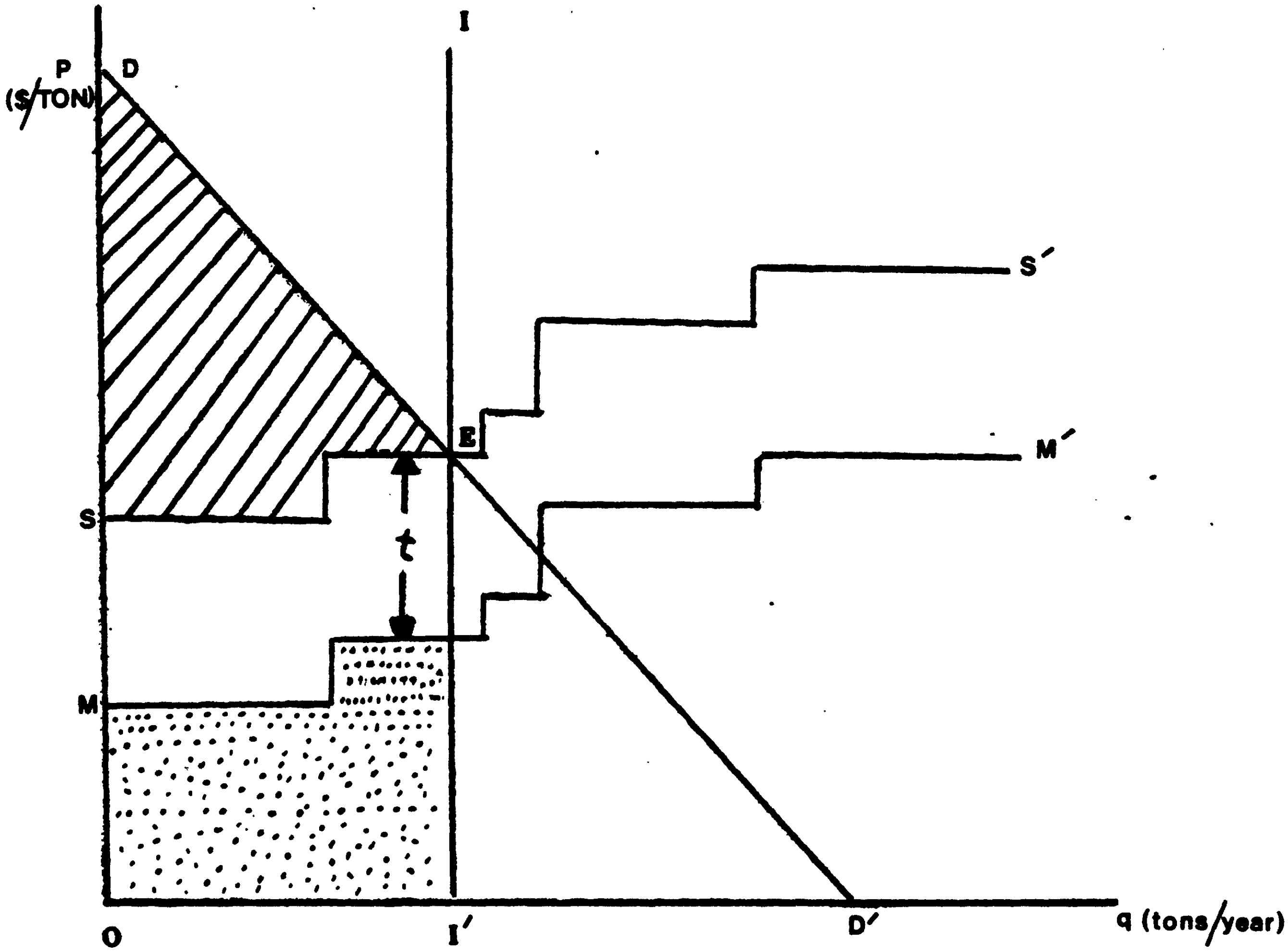

Figure 7-1

Illustration of Coal Market Equilbrium Calculation

Section 8

COMMENTS ON REVIEW ISSUES

INTRODUCTION

As discussion in Section 1, the URGE group, and the EPA project officers were invited to prepare comments on the state-level AUSM review. Those providing written comments to be included in the report were:

Professor Clark Bullard, University of Illinois
Professor Duane Chapman, Cornell University
Dr. Richard Edahl, Carnegie-Mellon University
Mr. Larry Jones, Environmental Protection Agency (current AUSM project officer);
Professor Timothy Mount, Cornell University
Professor Edward Rubin, Carnegie-Mellon University
Mr. Edward Pechan, E. H. Pechan & Associates;
Mr. Paul Schwengels, Environmental Protection Agency (former AUSM project officer);
Professor James J. Stukel, University of Illinois.
Professor Sarosh N. Talukdar, Carnegie-Mellon University;

GENERAL COMMENTS (Larry Jones)

Thank you for the opportunity to review your draft report of the M.I.T. Energy Laboratory's review of a component of the Advanced Utility Simulation Model (AUSM) currently under development by the U.S. Environmental Protection Agency. This report will assist us as we complete development of the AUSM model.

As you know, your report addresses a component of AUSM (i.e., the "state-level model") that was developed by the Universities Research Groups on Energy (URGE) and delivered to the U.S. EPA in December of 1984. The remaining components of AUSM, the "national loop," have been under development by EPA during 1985. Several of the deficiencies identified have been corrected by extensive modifications by EPA to the "state model" component this year. However, we intend to give each comment attention in our continuing program to complete the AUSM model.

We, of course, want you to emphasize that this report is not an end-point in review of the AUSM model's capabilities, but rather is a beginning step in this process. The capabilities of AUSM will become clearer once the entire integrated model has completed development and testing in 1986. EPA plans to submit test results and revised documentation to third-party reviewers upon its completion. At that time we expect to have the capabilities of the AUSM model assessed relative to its intended purpose. It should be noted in your report that the AUSM model is intended to approximate the annual average operating characteristics of a utility and not simulate its day-to-day operations. From this perspective, it is not of paramount importance how exact the "nuts and bolts" of each module describe actual utility operations. Although we are giving careful attention to "nuts and bolts" issues and do not want to minimize their importance in reaching our final goal, it is equally or more important to assess how well the entire integrated model approximates, on an annual basis, the results of utility operations in terms of construction schedules, costs, and emissions. Obviously this type of assessment must await the model's completion and the preparation of test results and therefore is beyond the scope of this review. We feel this perspective should be recognized in your report.

Your report takes issue with using the "state model" component of AUSM in a stand-alone mode. Obviously the inputs to the "state model" from the "national loop" are not available in a stand-alone mode and must be independently supplied by the analyst using the "state model" component. Although this would place greater demands on the analyst to supply data and to describe the inherent limitations of this approach, we do not agree with the draft reports conclusion that it is impractical to use the "state-model" in a stand-alone mode. It would be more constructive for the report to describe the inventory of data that would be required to operate the "state model". Listing of the not inconsequential amount of data and effort required to operate the "state-model" in a stand-alone mode would provide the appropriate perspective on this approach.

The following section contains responses to each of the 33 issues identified by the draft report. Issues are identified by number, using the same numbering scheme as the report. Several of the issues are fairly complex, requiring careful analysis. In the interest of providing a timely response, we have not had sufficient time to address the more complex issues. We have, however, indicated those issues which would be studied in more detail and responded to at a later time.

As was noted above, several of the issues have been dealt with through introduction of new or revised AUSM components. In particular, the "national loop" will address issues related to interstate transfers of electricity, coal demand/supply interaction and coal depletion effects. We have noted where model development activities in 1985 have resolved issues identified by your review.

Issue No. 1: Delivered coal prices in the national loop, which replaces the coal supply component of the "state model," are determined for each state and are made up of mine-mouth costs, preparation costs, and transportation costs. Competitive effects among coal producers are accounted for. Profitable producers realize rents. Other producers "squeezed" by competitive pressure of a shifting demand scenario may realize no rents, selling at cost.

Transportation costs are determined by solving a transportation problem to find the least cost routing of coal deliveries using per unit costs of carrying coal. While the dynamics of the transportation/coal market are not treated directly, there is a capability for using exogenous escalation of rates. Exogenous rates can be specified to reflect anticipated excess rents due to monopolistic transportation business practices.

Issue No. 2: Decoupling of coal demand from coal supply was a feature of the state model. Coupling of supply and demand is achieved by the national loop, in which partial equilibrium of the coal/electric utility market is modeled.

Issue No. 3: Lack of depletion effects on coal supply was a feature of the "state model." The "national loop" includes depletion effects. When the "state model" is used alone, it is incumbent upon the analyst to independently determine future coal prices for the particular policy option analyzed.

Issue No. 4: Whether truncation will materially impact coal prices as forecast by the national loop is an empirical issue. EPA plans on subjecting this issue to sensitivity testing during 1986.

Issue No. 5: EPA will use the RAMC approach to determining coal prices. The impacts of assumptions about parameter values or about fixed parameter values will be explored empirically.

Issue No. 6: EPA has planned on updating all AUSM documentation, including documentation of methods for calculating various components of the coal reserves data base.

Issue No. 7: EPA has planned on evaluating the effects of this mis-estimation empirically. Adjustments may be incorporated after evaluating results.

Issue No. 8: As indicated under issue number 5, the RAMC method will be used to determine mine-mouth prices.

Issues Nos. 9 through 17: EPA has not completed its evaluation of the demand module, preferring to concentrate resources on parts of the model required for NAPAP assessments and similar work. Those assessments will rely on exogenous demand from the Department of Energy, obviating the need for the demand module. Evaluation of the demand module is planned for 1986. Each of the demand-relating issues will be used in guiding that evaluation.

Issue No. 18: The "national loop" will remove the need for exogenous construction sequences and interstate electricity transfers by providing forecasts of announced units and transfers for the state model. However, where the "state model" is used for an individual state study, announced units or some particular build mix and a schedule of interstate electricity transfers can be supplied by the analyst. EPA feels that in such a situation it is incumbent upon the analyst to justify his/her choice of mix and transfers.

Issue No. 19: The present version of AUSM does not explicitly model lifetime extension programs. Early retirements are dealt with indirectly when uneconomic units are not dispatched. Retrofits can be dealt with indirectly by including special "retrofit generating units" as technology options. Little testing has thus far been directed to this approach or to the approach suggested by Argonne.

Issue No. 20: Revised documentation will be prepared in the future. However, it should be noted that the documentation is oriented towards operation of the entire integrated AUSM model. Operation of the "state model" in a stand-alone mode is expected to have more limited applications.

Issue No. 21: This module has not been examined by EPA since priority has been placed on resolving issues in areas that appear to have problems.

Issue No. 22: The need for care in selecting parameter values throughout the model is recognized. It is incumbent upon the analyst to justify parameter value choices. However, other research currently underway at EPA will serve to better identify reasonable choices for site-specific retrofit factors.

Issue No. 23: Some testing of this addendum was conducted by the developer. Additional testing and evaluation by EPA are planned.

Issue No. 24: In general, this comment is correct. However, using the addendum to the PCM (see issue number 23), emissions reduction can be maximized subject to a cost per ton removed limit.

Issue No. 25: Once the entire integrated AUSM model is constructed, optimum ways of attaining these goals will be investigated. There are enough "handles" built into this model to analyze virtually any scenario specified.

Issue No. 26: While the dispatch module provided as part of the December 1984 version of AUSM is being replaced, the points raised in this and succeeding issues remain important. The assumption of state level dispatch was partially tested by Bullard and Hottman. Their work, done in conjunction with a major electric utility, found that the assumption was justified. This does not justify the assumption for all cases, but it does lend credence to the assumption. Further testing will be directed to this issue.

Issue No. 27: Recent work on the dispatch module has resulted in the elimination of fixed capacity factors and the substitution of maximum capacity factor based on historical usage. Further work to analyze aging effects must be coupled with refurbished potential to provide a balanced perspective on this issue.

Issue No. 28: As indicated above, EPA has replaced the dispatch module. The magnitude and direction of any bias inherent in the present version is clearly an empirical question requiring actual model runs. Although additional constraints on capacity factors may be needed to reflect transmission capacity for existing units, the model does consider the cost of new transmission capacity for new units.

Issue No. 29: EPA has previously identified this as an important issue. Ways of dealing with this problem by revisions to the Finance Module are currently under active consideration.

Issues No. 30 through 33: EPA recognizes that these issues require careful exploration. As indicated in the response to issues numbers 9 through 17 work has concentrated on NAPAP assessments, which will make no immediate use of the finance module. However, an evaluation of the finance module is presently underway.

GENERAL COMMENTS (Paul Schwengels)

Thank you for the opportunity to comment on your September, 1985 draft report entitled A Review of the State-Level Advanced Utility Simulation Model. It is clear that you and your colleagues have made a major effort in producing this report, and that these findings and subsequent discussions will make a positive impact on the on going model development and testing effort. Nevertheless, I find this draft disappointing and frustrating in several respects. We have discussed a number of my concerns previously, and they may be partially addressed in the revisions to the draft report. I do not believe that my basic concerns about the way the review was conducted have been or could be addressed by simply editing the final report. Therefore, I am taking this opportunity to try to state my concerns more coherently and completely. I hope these comments will serve as a basis for further discussion leading to more constructive and relevant model assessment efforts in the future.

I believe a fundamental problem is that the criteria used for review and the resulting comments are not tied to a clear picture of the context in which this model was designed to function. The AUSM was designed as a tool to be used in environmental policy analysis, most importantly at the national level, and to a lesser extent at a state or multi-state regional level. To my knowledge this is the dominant potential use which drives interest in the model and its review. This implies that some, if not all, of the reviewers must be extremely familiar with the objectives and current practice in this type of analysis. Unfortunately there is very little evidence in the review draft of this perspective on the part of the review team. Although a workshop was conducted to help identify important policy uses for the model, results are not reported and do not appear to have been used in the review.

The AUSM or any other model should be considered on tool to be used in analysis of any particular policy problem along with other relevant models and analytic tools and considerable expert judgement. Several statements in the report imply that the reviewers see a tradeoff between model complexity and analyst judgement. For example on page II 1-7 it is stated that despite deficiencies, in some circumstances "the state level model could be used...if the model user had intimate understanding of the multistate dispatch area, understanding that only the operating utilities, state regulatory agencies or knowledgeable modellers are likely to possess. The implication is that if the identified deficiency (lack of multistate dispatching) were corrected, the model could be used without such understanding. In fact, whether the model deals endogenously with interstate power transfers or not, any serious policy analysis at the state or national level would have to involve very knowledgeable individuals and contact with the groups mentioned (operating utilities, state regulatory agencies).

The discussion of "independence assumptions" in the executive summary (p.I-2) also implies much greater role for the model than is normal or desirable in policy analysis. If one actually viewed the state-level AUSM as the only available tool, and as containing all the available information for an analysis, then one would have to accept the independence assumptions in order to proceed. In fact, as stated, these independence assumptions are something of a red herring. If a model like the state-level AUSM were used in policy analysis, it would have to be supplemented in areas outside the boundaries of the model. This is true of any policy analysis model. A more constructive and relevant way to express these points would be to discuss them as information needs or calculations which must be supplied outside this model in order to do specific types of analysis credibly.

The report cites as deficiencies the facts that plant retirement age (p.II - 1-16) and monopoly rents for western railroads (p.11-1-9) would have to be treated as inputs to the model. This implies that the reviewers believe these decisions should be determined endogenously by the model. Policy analysts would undoubtedly be interested in what the model might predict, if it had these capabilities. They would certainly view any such model calculations with a healthy degree of skepticism, however. In fact, even if a model were available which calculated economic retirement age and monopoly rents extracted by railroads, a good policy analyst would override this with carefully thought out alternative assumptions. In the analysis of alternative policies, it is quite likely that the range of outputs, or sensitivity, would be as important as any single estimate.

A stated objective of AUSM development was to produce a model which is simple and transparent enough in its components to be understandable and reviewable by a side range of interested analysts. I believe that these attributes are important to many policy users. Throughout the development process there have been difficult compromises to be made between simplicity and additional sophistication. The reviewers do no6t seem to have considered these constraints in their comments. Many of the criticisms of the model imply that additional and more complex decision logic needs to be incorporated.

A related concern of the model developers and sponsors is that the model be designed to be efficient, economic to operate and maintainable on a national level. This requires that computational complexity be avoided when possible and that publicly available , regularly updated, automated data sources be used. Again, comments seem to be made in the abstract without any sense of how they relate to these constraints. For example, the reviewers suggest that a better approach to demand modeling might...." involve specification and estimation of a generalized Leontief Model..." without any discussion of the computational, data, and maintenance requirements of such an approach.

It is clear from considering these constraints that many otherwise desirable modeling approaches could not be incorporated. Given these constraints, it is unlikely that a level of sophistication can be incorporated in each component of the model which will be considered satisfactory by utility personnel familiar with much more detailed models used at the company level. The important issue is how to provide the most reasonable approximation of the net effect of actual utility decision making within the inherent constraints of a national environmental policy model.

The review was obviously carried out by evaluating the individual components of the model separately and compiling the resulting comments as a review of the whole model. This does a disservice to the model and to the potential users who are the audience for your review. Evaluating the demand module, for example, relative to the universe of possible demand forecasting models, results in a long list of concerns about the model's performance. It is not clear whether these are real concerns given the role and levels of emphasis of this module within the larger, annually recursive system. For those concerns which may be "real" in this sense, it is not clear whether the suggested alternatives are "feasible" in that they could be implemented within the constraints of the larger model.

For all of the above stated reasons, I believe that the draft review is of questionable value to to potential policy users. I understand your desire to avoid being drawn into a model comparison exercise as opposed to an individual model evaluation. However, I believe the abstract theoretical perspective reflected in the current draft report is largely irrelevant to the real world policy process. If future review activities are to be relevant and constructive, some discipline needs to be imposed on the review process. Comments must be grounded in the current state-of-the-art for national-scale, environmental modeling, must be sensitive to the inherent constraints in th8is type of modeling, and must relate to the model as a whole not to components in isolation.

I would also like to recommend that any future review activities incorporate more communication with modellers and users early on. I recognize that there have been problems on both sides in communication during the preparation of the current draft report. However, it is important to note that the interaction between reviewers and model developers has not been as extensive as would be desirable. In addition, a great deal more interaction with model sponsors and possible policy users during the review process would be helpful. Such successive interactions could assist in providing focus and relevance to the review criteria used in evaluating the model.

I look forward to discussing these issues further with you and your colleagues in the future. Again thanks for your efforts to incorporate alternative points of view in the review process.

COMMENTS ON THE MIT REVIEW OF THE AUSM MODULE (James J. Stukel)

My comments will be brief since most of the detailed criticisms have been addressed by the module developer in their responses. I would, however, like to reinforce a few of their comments.

As you know, I felt that one of the fundamental problems with the review was that it did not address the integrated model characteristics. Rather, it focused on the individual modules. Also, the reviewers did not seem to be aware of or chose to ignore the programmer design specifications agreed to by EPA concerning computer storage space, computer protocol and the like. These decisions were extremely important because they imposed design constraints on the module developers. I would like to review these design specifications as outlined in the programmer documentation before making additional comments.

System design and operation issues usually are not given as much explicit attention in model development efforts as are analytical capabilities. Probably the most serious deficiencies of the current generation of utility models fall into the design category. Current models that are detailed enough for regulatory analysis are uniformly cumbersome and frequently require excessive computer resources and inordinate amounts of contractor-supplied analyst time to set up, to run, and to interpret the output of scenarios. This results in inordinately long turn-around time - sometimes a matter of weeks for a complete scenario run - and excessive costs. A major criterion of the AUSM system design was that improved state-of-the-art analytical capabilities be provided at reasonable cost.

Another common flaw in existing models is that they are structured and documented (or undocumented) so that their internal operations are virtually impossible to understand by anyone except the contractors who developed them. Embedded assumptions and idiosyncrasies make it difficult to trace the relationship between a change in an input parameter and changes in model outputs. Thus some models can be run successfully only by the contractor organization that developed them. A second criterion of the AUSM system design was that it be a contractor-independent model, one that could be operated and understood by any interested organization.

Large computer programs are often intended to be operated on a specific type of machine. Even when a model is not proprietary, much time and effort may be required to make it operational on another machine. A third criterion of the AUSM design was that it be as machine independent and thus as transferable as possible.

The last major objective of the AUSM system design was that the model be independent of its developers.

Because the project team and project officer recognized that system design improvements are at least as important as enhanced analytical design, significant project resources were allocated to system design and integration efforts in an effort to meet those criteria. Thus, in making decisions about specific system design features, the attempt was to develop features to fulfill all four criteria: efficiency, contractor independence, transferability, and developer independence. Some of these features are presented below in terms of the four criteria.

After assuring that the model accurately provided the analytical capabilities promised by the developers, the most important objective of system design was cost savings. In the case of the Utility Simulation Model at least, the computer costs associated with the final execution of the computer model to simulate a desired scenario were often negligible compared with the analyst and programmer costs and with the computer charges incurred in defining the scenario, revising the data base and code to implement that scenario, and testing and debugging the modified model.

Because data handling often consumes more computer resources than computational tasks within a large simulation model, particular effort went into the design of data-handling procedures. Other efficiency features are designed into the model. For example, data generated for reports and graphs are simply dumped into binary format disk files for later processing by a specialized report-writing program. Not only does this drastically cut the costs associated with abortive test and developmental runs, it also allows different (or reformatted) sets of reports to be generated later from the same scenario, often without re-executing the model. A standard method also has been devised for modules optionally to specify varying levels of additional model output needed only for tracing potential errors and for validating the results of the model. Since these printed data are produced only when specifically requested, normal runs are relatively inexpensive.

Finally, unnecessary computations are avoided. For example, it was recognized that the coal supply module need not be solved simultaneously with the detailed utility sector simulation. Therefore, this module was broken off as a preprocessor to the AUSM and is rerun only when the user wishes to change coal-related scenario parameters for a specific series of AUSM runs.

Through the careful design of scenario-specific parameters and the detailed analytical and programmer documentation, it was hoped that the contractor-independent criterion will be met.

Particular effort was expended to assure that the third criterion, transferability, was met. First, very rigid structural and coding standards were maintained during the module development. All code was written in a subset of 1966 ANSI Fortran. The subset was selected based on a comparison of the Fortran compilers provided by three major vendors. All library routines included with the model are Fortran callable, in the public domain, and available for both CDC and IBM systems.

While transferability was a consideration in selecting many of the individual design elements, one element in particular should be noted: The control program was the only segment of the model with direct access to physical data files. Analytical modules were completely "unaware" of the physical structure of the data base; they locate and retrieve data via the control program by describing the logical attributes of the data desired. Although input-output procedures in Fortran programs can never be made completely machine independent, the routine conversion tasks necessary to transfer the model between the University of Illinois CDC computer and the Environmental Protection Agency IBM computer are now confined to this one program. Virtually no modifications will be required in the analytical modules.

To further assure transferability to the EPA system, the Project Office staff periodically tested the complete model on the IBM 3431 located on the University of Illinois campus.

The final criterion, developer independence, was assured by both a detailed documentation series and the use of automated, easily obtainable data sets whenever possible. These data sets are compatible with those used by other agencies that could also employ the AUSM, notably the Department of Energy.

It was recognized that the objectives discussed above were extremely ambitious. Many were very difficult to achieve, but the project team and project officer dedicated much time and effort toward meeting them. In order to identify the most productive approaches to achieving these goals and evaluating progress toward them, substantial involvement was sought from individuals working on related federally supported projects and from a very active working group of potential government users of an advanced model (principally EPA and DOE regulatory and policy analysis staffs). In addition, an ongoing technical review process involved recognized experts in various aspects of utility and coal supply modeling from academe, research and environmental organizations, and industry.

Given the philosophy outlined above, I was surprised to learn in reading the critiques that very little discussion was directed toward the basic model design or the documentation. The most important EPA design criteria were that the model be transparent, transportable, and very well documented. EPA put a very high priority on these issues. Yet, in the review process, no mention was made of these important characteristics of AUSM.

Another troublesome aspect of the review was that none of the unique attributes of AUSM were discussed. It was not pointed out, for example, that it was the only model which attempts to treat coal and utility sectors in similar detail. The reviewer did not point out that this was the only model that tries to capture the interaction between the higher cost of energy and the demand for energy in an annually recursive manner.

The decision to use the state as opposed to the dispatching region as the basic geographical unit for the AUSM model was a joint decision made by the core team members and EPA. The rationale for the decision was that EPA felt that it was more important to get accurate estimates of state emissions and the associated capital costs for various abatement options than to get accurate representations of the financial data. It should be noted, however, that if we had utilized the dispatching region as the basic geographical unit for AUSM, we would have had difficulty trying to assign emissions, capital costs, and expansion plants to the proper states within the dispatching region.

Many of the reviewers made suggestions for expanding the scope of the AUSM model. Although these suggestions were generally very interesting, most of them could not have been implemented without major additional data acquisitions. In addition, many of the model refinements would have required data which either was not collected on an annual basis by a public entity or did not exist. A major design criteria for data used in the AUSM development was that only data which was available on an annual basis from public sources could be used in the development of each of the modules.

Another problem that would have been encountered, if many of the reviewers' suggestions were implemented, was that the size of the program and the concomitant storage space required would have been quite large. As noted above, a major design criteria of this current model was that a limited amount of storage space be made available to the module developers. This was done to allow the AUSM model to be transportable as possible. For example, by keeping the size of the AUSM reasonable, the state level model could be used by state agencies with modest computer resources with little or no modification. As has been pointed out by the module developers, relaxation of the memory constraint could be achieved in a straight forward manner.

Finally, many of the "limitations" of the model which were uncovered by the review team were pointed out to EPA in a letter to the EPA by the Project Director at the conclusion of the project.

The most troublesome aspect of the review was its preoccupation with the negative aspects of the model. Ideally, the review would have identified both the positive and negative aspects of the model. This lack of balance causes me a great deal of concern.

COMMENTS ON COAL SUPPLY MODULE (Clark Bullard)

In general, the review reflects a careful assessment and critique of the documentation provided. The principal shortcoming of the review is its lack of context. It is one thing to simply list the ways in which the module falls short of a perfect representation of reality; it is quite another to assess the extent to which the model represents advancement of the state of the art, in light of the design constraints.

The purpose of these comments, therefore, is to address the contextual issues in order to give the reader a better appreciation of issues the reviewer found to be puzzling or troublesome. The context in which the AUSM coal supply module was developed can be summarized as follows. In 1981 EPA was primarily dependent upon two proprietary models; one that ignored depletion, and another that had been derived from an early version of the DOE/IEA/NCM (National Coal Model). The NCM was already large and costly to run, and would have become prohibitively costly to operate if it were modified to met the types of additional needs EPA required (e.g. simultaneous optimization of coal cleaning and allocation, more detailed representations of coal characteristics and producing regions). The AUSM coal supply module was therefore constrained to operate using public domain data alone, to achieve a level of analytical complexity at least five to ten times greater than that of the NCM, and to accommodate a wide range of alternative data and algorithms available in the literature: coal reserve data bases, seam thickness and depth distribution, mine costing algorithms, etc.

The AUSM not only represents an advancement in the state of the art, but it was also designed to facilitate the types of sensitivity analyses needed to focus future data and algorithm work cost effectively. Therefore, the model was designed as a "shell" which could accommodate a variety of alternative data bases, mine costing algorithms, etc. The reviewer's comments on the relative advantages and disadvantages of econometric versus engineering cost methods are well taken, but the review fails to emphasize the model's strength in this respect. The user can easily employ each methodological approach (or alternative data bases) to assess their impact on the results of interest. If policy analysis results are unaffected, then the critiques of alternative data of algorithms may be moot. On the other hand, if key results are found to be sensitive to such assumptions, the sensitivity analyses lead directly to the identification and improvement of specific data elements and analytical assumption. Without this "shell" framework, it is difficult to isolate the effect of a change in a single data base or a single analytical assumption.

When two or three different models are compared, it is virtually impossible to hold all but one thing constant.

The review also downplayed the computational simplifications made in the AUSM, questioning whether they were necessary for a pre processor that only needed to be run once prior to a set of AUSM simulations. In response, I can only emphasize that advancements in the state of the art in coal supply modeling to date have been retarded by two factors that the AUSM is designed to alleviate: 1) many existing models are not available in the public domain, and 2) all the detailed models are extremely costly to run. The AUSM contains far more detail than any existing model, and can run for six time periods (1980-2040) without user intervention. Other models (e.g. CEUM, NCM) are designed to run only one to three periods without user intervention. Unfortunately, the review does not acknowledge the fundamental improvement that AUSM provides in this respect. It literally makes the difference between extensive sensitivity analyses being feasible and infeasible. A cost comparison with NCM may help emphasize this point. The AUSM coal supply module costs less than $20 (on the US DOE computer) to simulate the 1980-2040 period. To run the NCM for six time periods would cost more than $100, and requires user intervention to rebuild the data base after the first three time periods. If the number of constraints in the NCM were quadrupled to match the analytical capability of the AUSM, the cost of sensitivity analyses would be prohibitive.

Two other contextual issues need to be clarified, so readers will not be misled by the review. The first concerns the relation of the AUSM coal supply module to the MPMS. The review refers to "an exogenous set of [coal] demands originating in the MPMS module." In fact, coal demands are endogenous to the MPMS, and then serve as inputs to AUSM. Significant differences can be resolved through iteration, because of the extremely low cost of running the model. The second issue concerns the role of the "unconstrained algorithm" in the coal supply module. The reviewer recommends against its routine use, because it ignores depletion. The documentation, however, makes it clear that its principal use was for identifying price setting coals and truncating the supply curves so the constrained-supply algorithm could run more efficiently. It can also be used as the baseline for sensitivity analyses aimed at developing a better understanding of the effects of various depletion-related assumptions.

Minor Comments

1. The review suggests that the question of coal market competitiveness be revisited. However, it does not inform the reader of a unique feature of the

module's solution algorithm and report generator, a feature that facilitates verification of the assumption of competitiveness. After each simulation, the report generator shows not only the optimal allocation, but about 10 or 15 of the nearest competitors to this optimal solution for each of the 35 supply regions and 48 demand regions. The base case results show that for almost every optimal allocation there are about 10 alternative suppliers who could meet the specified demand at a delivered price within about 10% of the optimal one. In nearly all such cases, the alternative suppliers are widely distributed geographically, so they are unlikely to be subject to monopoly pricing either at the mine mouth or along the transportation routes. While these results do not prove that the coal market competitiveness assumption is a reasonable one, they provide a substantial amount of evidence to that effect. Moreover, such results can lead the user to investigate particular routes and particular allocations for potentially noncompetitive situations. Without this feature of the model, such investigations should not be cost effectively focused. It is correct, as the review points out, that "there may be concentration in transport, mine ownership, labor supply, regulation and other areas which still result in market manipulation." It is precisely because of the impracticality of modelling the US coal industry at this level of detail, that we designed the AUSM with the algorithms and report generators needed to identify areas in which such expenditures might be worthwhile.

2. The review states "from the perspective of the AUSM, it is unclear how the spot and ling run markets interact in terms of being able to predict prices for particular demand levels". Since the AUSM is primarily a long term model, and it is not possible to predict the behavior of spot markets five to ten years in advance, the model does not attempt to deal with spot markets.

3. The report states: "The difficult question is how to represent the coal contracts without overly constraining the coal allocation problem." The documentation demonstrates that, given the uncertainty in coal data and mine costing algorithms and transportation costs, combined with the competitiveness of the coal market, predicting actual allocation patterns is impossible. Since these uncertainties make predictions of coal allocation patterns unknowable, it is inappropriate to worry about the representation of coal contracts "overly constraining the coal allocation problem."

4. The review states: "Another feature of the coal supply module that we have concern about is the ten year time span between coal price computations. Perhaps the coal market is stable enough to warrant this level of temporal aggregation." Actually, the results show that prices vary quite slowly over time. The percentage

variation lies well within the envelope of other uncertainties which are discussed throughout the documentation.

5. The review questions the use of a heuristic procedure for calculating and , and asks "Why was a conventional statistical technique not used?" A heuristic technique was favored because it made it easy to force the transformation error to be zero on the diagonals of the matrices, corresponding to allocations of raw coal. Thus for the overwhelming number of allocations, the transformation introduced no error. While this could have been done using a conventional statistical technique, the computational complexity probably would not have been worth it. This assumption, too, is also subject to ex-post evaluation. Since deep cleaning pathways are almost never used, and the heuristic technique forced the largest errors (positive and negative) to occur there, the results were quite accurate; only a few allocations were subject to actual errors exceeding 1%.

6. The review expresses concern over the fact that mine lifetimes are specified exogenously, and points out that this may not be appropriate for surface mines. However, inspection of the SAI mine cost equations shows that most of the costs of surface mining are operating costs, and most of the capital costs are for equipment that is replaced every five or ten years. Thus the levelized cost of coal is rather insensitive to mine lifetime. Since public domain data are inadequate to support endogenous determination of mine lifetime, this additional complexity was not added to the model.

7. The review states that "The estimation of the amount of coal in deposits of different types is probably the weakest link in all models of coal supply." However, it does not give the AUSM credit for being the only detailed model of the US coal industry that lends itself to inexpensive and straightforward testing of the tremendously uncertain data on such parameters.

8. The review raises a number of issues concerning the treatment of coal cleaning. For a response to this part of the review, the reader is referred to the comments of Edward S. Rubin, developer of the pollution control module and the coal cleaning data.

COMMENTS ON "A REVIEW OF THE ADVANCED UTILITY SIMULATION MODEL" (Timothy Mount)

This report is a response to the September, 1985 review of the URGE/AUSM[1] conducted by the MIT Energy Laboratory under the sponsorship of EPRI. There are three sections. The first discusses the review of the overall model. The second responds to the review of the Demand Module made by Ernst Berndt and David Wood, and the third presents some concluding remarks.

I. Review of the Structure of the URGE/AUSM

This section could be very short because there is essentially no review of the overall model. The reviewers have chosen the much easier task of focusing on the individual modules one by one. While this is a convenient device for allocating tasks among the review team, it hardly does justice to one of the main distinguishing features of the URGE/AUSM which is that it is a fully integrated model.

Most planning models used by the utility industry provide detailed information about one of the components of operating a utility system. Linking these components together in practice is a difficult thing to do, and consequently, it is not done on a regular basis. When models are run separately, it is quite possible for important logical inconsistencies to exist in the economic implications of results from different models.

a) Some Perspective on Electric Utilities

In the past, a common mistake made by most utilities was to underestimate the effect of higher prices on levels of demand. This led to consistent errors in forecasting and the construction of a substantial amount of excess generating capacity, particularly in the northeast and midwest (see Table 1). Since reserve margins of about 20% can provide adequate reliability, it is clear from Table 1 that actual reserve margins which are greater than 30% for seven of the nine reliability regions, are indeed excessive. In fact, the two regions with margins less than 30% correspond to only three states (TX, IL, WS). Paying for additional unneeded

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[1]Some of the reviewers' concerns relating to the overall structure of the URGE/AUSM have been modified in later versions of their report. [NOTE FROM EDITOR: This disclaimer by Professor Mount relates primarily to minor changes in some quotations, and to pagination changes.]

capacity has placed a tremendous financial burden on utilities and ratepayers, and the problem has been exacerbated by the incredibly high costs of new nuclear capacity. This is the underlying situation which must be face if one is to consider implementing potentially expensive new initiatives for reducing emissions of pollutants from power plants.

The objective of this discussion is to emphasize that there is considerable virtue in the annually recursive structure of the URGE/AUSM. By modelling the market for electric power in an internally consistent manner, the model provides a much sounder basis for the EPA to evaluate the effects of environmental policies than, for example, conventional production models of a utility system.

While this conclusion is clearly my own, it would be helpful if the review team identified in some detail what type of model they consider appropriate for the EPA to use for policy analyses. It really is essential to decide whether one wants to purchase a sports car or an all-terrain vvehicle before getting into an extensive discussion of the features of a certain type of tire. However, the review of the URGE/AUSM does not discuss the appropriateness fo the overall model structure.

b) Requirements for a Viable Policy Model

It is very easy to criticize any model. Constructive criticism, however, requires offering suggestions for better alternatives. Once again, this is generally not done in the review. No model works as well as one would like it to, and all models perform certain tasks better than others. By not defining the structure of a "better" model, the review team is not limited to the logical constrains of the structure. Consequently, it is not clear from the Review how much the cited "problems" with the model really matter in terms of providing the EPA with a viable policy tool. Many criticisms relate to an ideal model which, in addition to being undefined, is almost certainly unattainable. In reality, many objectives compete with each other. If one accepts the criterion that a relatively compact model is desirable, for example, then one has to accept the corollary that the level of detail must be restricted (e.g., a decision to treat the dispatch of plants on an annual basis).

The most surprising omission in the Review is some discussion of the policies which the model is designed to address. Although a table listing the policies considered in the URGE/AUSM is presented (Review, p. II.1.1 and Table II.1.1), no further comment is made. Of course, this omission may reflect some important decisions or restrictions placed on the review team which are not mentioned explicitly in the

Review. Nevertheless, by providing no perspective on desired policy objectives in the Review, it is impossible to take seriously the Review's main conclusion that it is "impractical to use the current version of the state-level AUSM for air quality policy studies" (Review, p. I-3). For example, the same model structure has been used successfully to address issues relating to the State Acid Deposition Control Act (SADCA) in New York State.

Given the fact that a substantial effort has been spent at Cornell over the past two years on developing a state-level model of the New York Power Pool, it is relevant for this report to discuss what modifications were found necessary in adapting the model's structure. It should, however, be noted that this work was not based strictly on the URGE/AUSM. It represented a cooperative effort between Cornell and Carnegie-Mellon Universities using the same basic analytical capabilities as the URGE/AUSM for demand, dispatch, finance and pollution control. Capacity planning and coal supply are treated exogenously in this model, which is appropriate for a model of a single state with a reserve margin of over 40%.

There were three major modifications which had to be taken to improve the model's accuracy and to incorporate appropriate policy capabilities. There were:

1) Relax the constraints on the size of the linear programming algorithm (LP) for dispatching plants (attaining reasonably accurate predictions of plant-level capacity factors requires that "must-run" restrictions are imposed, for example).

2) Correct and enhance the input data bases, particularly those relating to the initial plant characteristics and to scheduled changes in existing plants (e.g., in the availability of natural gas for boiler use in dual oil/gas plants).

3) Add additional analytical capabilities relating primarily to policy issues of relevance to the state. The two most important of these deal with specific characteristics of SADCA, such as restricting deposition levels at certain environmentally sensitive sites, and modelling the contracts for economy imports from Canada to determine both the cost and quantity of these imports within the model.

The first of these modifications (enlarging the LP for dispatch) simply reflects the lifting of an artificial constraint placed on the model's size. Once this is done, it is relatively straightforward to get better accuracy and to incorporate additional policy capabilities (this point is also made in the response to the Review by Sarosh Talukdar and Richard Edahl, who developed the Dispatch Module).

The second modification (using more accurate data) is very important. Reconciling differences between the model's data from state agencies took a great deal of time, even when there were legitimate reasons for these differences. In practice, the need to establish the integrity of data bases for a model is not given sufficient attention. For example, data issues relating to the URGE/AUSM are not discussed systematically in the Review. The third modification (enhancing the policy capabilities) is not really relevant for this report because the capabilities relate primarily to state rather than national policies.

When these three modifications are made, the resulting model can be used to conduct policy analyses. In particular, the annually recursive structure, and the associated internal consistency of costs, sales and revenues stand in distinct contrast to other planning models used by the state's agencies and utilities. The point to emphasize is that the model does work well, and that there is nothing intrinsically wrong with it's structure. Presumably, those now responsible for managing the URGE/AUSM have made similar efforts to improve the model's performance, although I have not seen the results from any such effort.

c) The Reviewer's Concerns about the Model's Structure

With this background, it is now possible to address the specific concerns raised in the Review about the overall structure of the state-level version of the URGE/AUSM. These are the two "independence" assumptions between 1) net interstate transfers and plant construction, and 2) capacity planning and pollution control (Review, p. I-2), and that "an inconsistency exists between the actual revenues .... and required revenues" (Review, p. I-4). It is convenient to deal with these three issues in reverse order.

With regard to required revenues (I prefer the term "allowed" revenues), there is no real guarantee that allowed rates of return determined using conventional regulatory mechanisms are achieved in practice. This is particularly true when large cost increases are passed into the rate base as they are at the present time. To illustrate this point, data on allowed and actual rates of return are summarized for companies in New York State in Table 2. The mechanism for setting rates in the URGE/AUSM ensures that actual revenues follow allowed revenues, but not that they equal each other every year. This is, in my view, a reasonable approximation to what actually happens. In fact, it would be interesting to develop better explanations for observed differences between allowed and actual rates of return if suitable data on allowed rates of return were available.

The reviewers also point out, correctly, that allowed and actual revenues could be equated by running a number of iterations of the model each year. They also recognize that this would be expensive in terms of computations. One possible compromise would be to perform this type of iteration only in years when a major change occurs in the supply system (e.g. when a new nuclear plant is brought on-line).

The second and third issues both involve capacity planning, but the implications of existing reserve margins on their importance are not reflected in the Review. Given the high levels of reserves mentioned above, capacity planning will not be a major issue in most states for the next 10 or 15 years. The biggest uncertainty that currently exists is whether the nuclear plants under construction will operate or not, and how much of the cost will be passed on to customers. Since these decisions are largely political, it is appropriate to treat them exogenously.

Keeping up-to-date with current plans for new plants will be an important task for anyone operating the URGE/AUSM. In the model for the New York Power Pool, for example, the capital accounts for Shoreham and Nine Mile Point II (two nuclear plants under construction) are both treated separately so the atypical accounting procedures can be used (e.g., using economic depreciation, adding the capital cost incrementally over a number of years, or disallowing some fraction of the cost).

It is important to remember that decisions affecting new nuclear power plants will have major effects on emission levels from power plants as well as on electric rates charged to customer. Any analysis of emission policies will have to be conditional on these decisions. In many cases, changing the assumptions about whether a nuclear plant will operate or not will have a greater effect on the results than the alternative control policies considered (see Chapman et. al., 1983). In this important sense, pollution control and capacity planning are independent. For the next 15 or so years, policy initiatives for pollution control in most states will have to be focused primarily on existing generating capacity (e.g., delaying retirement) and capacity under construction. Consequently, the structure of the URGE/AUSM is considerably more appropriate than the conclusions of the Review imply.

The final issue relates to the fact that the cost and quantity of net interstate transfers of power are specified as exogenous inputs for each year of a forecast (note that this feature is more flexible than the one described in the Review, and presumably the final draft of the Review will reflect this correction). Consequently, the state-level model operates conditionally on these inputs. If control policies affect interstate transfers are the same in all scenarios. In other words, operation of the state-level model assumes that an additional mechanism will be available to determine the cost and quantity of interstate transfers for any scenario. This is hardly a surprise to the model's developers, and in fact, a quote from the documentation of the Demand Module is used in the Review as a reference (Review, p. II-20). Hence, any evaluation of the state-level model should take this two-step procedure into account, and at the very least, consider the implications of the case in which interstate transfers can be specified exogenously in different scenarios.

By not recognizing the implications of existing high reserve margins on capacity planning or of specifying interstate transfers exogenously as inputs, the review team concludes that the range of appropriate policies which can be addressed by the URGE/AUSM is severely limited. To quote "For most policy scenarios, checking the consistency of model solutions ...would probably require the use of still other models akin to the capacity planning and dispatching models used by utilities" (Review, p. I-3). In my view, it would be particularly unwise to return to planning models which are not fully integrated. Use of these models, after all, is closely associated with the current problem of excess generating capacity in the utility industry. A far better solution would be to maintain the integrated structure of the URGE/AUSM. If existing mechanisms for determining interstate transfers are found to be inadequate, the state-level model should be modified so that it can operate at a multi-state or regional level. While specific suggestions for modifying the model are outside the scope of this report, one might have expected some constructive proposals from the reviewers along these lines.

II. Review of the Demand Module

The review of the Demand Module is very detailed, and a large number of issues are raised. The tone of the review is generally critical, but at the end of it all the Demand Module remains intact with no major damage sustained. Given the critical tone and sheer bulk of the review (it is almost twice as long as any of the others), it is important to remember that the Demand Module performs well, and has many desirable characteristics which are not found in other models. Furthermore, the alternatives suggested by the reviewers for modelling demand have obvious deficiencies for a policy model such as the URGE/AUSM.

The Demand Module contains three components relating to 1. Rate schedules, 2. Demand equations, and 3. Demand projections. The demand equations, which determine current levels of sales of electricity each year, are the main focus of the Review. Of the nine issues raised about the Demand Module in Chapter II of the Review, six deal with the demand equations, two with rate schedules and one with demand projections. This report will reflect the same emphasis. Given the central role of the system of demand equations in determining the structure of the module, issues relating to these equations will be discussed first.

a) Characteristics of the Demand Equations

While the reviewers find fault with number of features of the demand equations used in the URGE/AUSM, they do not begin by reviewing the underlying rationale for the model. Hence, it is sensible to consider the major choices made in developing the specific form used for the demand equations.

i) Use an econometric approach.

Given the integrated structure of the URGE/AUSM and the need for a compact model, a decision was made prior to beginning the project to use an econometric approach rather than a detailed end-use analysis.

ii) Use a national data base.

Since the model was to be developed for individual states on an annual basis, estimation of the demand equations should be based on state-level data. These data would also be used to demonstrate how well the model performed as part of the process of validating the model.

iii) Use a system of demand equations.

Recent studies in econometric modelling have established the inadequacies of single equation, constant elasticity models. Although single equation models are still used (e.g., Taylor et. al., 1984), it is clearly preferable to have price elasticities reflect the importance of each commodity in a budget. Typically, price responsiveness is greater when expenditures on a commodity represent a larger share of total expenditures.

iv) Use a dynamic model.

The dynamic nature of adjustments to price changes, for example, is well established in the literature on modelling the demand for electricity. However, formal economic models of demand systems are still largely based on static models. Efforts have been made by a number of people, including the reviewers, to extend standard theory to include explicit adjustment mechanisms. Nevertheless, these efforts have not yet yielded a tractable approach which is suitable for a policy model.

v) Use marginal prices.

Most recent studies of the demand for electricity advocate the use of marginal prices rather than average prices. For example, Acton et. al. (1980, p. 159) summarize the current view succinctly,

The presence of declining-block rates in the sale of electricity gives rise to potentially strong biases in empirical investigations of demand which are based on the average price of electricity. However, the theory .... establishes that the quantity demanded is correctly specified as a function of the marginal price and major exogenous variables.

The main difficulty for modelling is that data for average prices are easy to get, but deriving data for marginal prices at the state level requires a great deal of effort.

The reviewers would almost certainly accept the rationale for these five fundamental decisions which determine the basic structure of the demand equations. Given these criteria, the primary objectives for the project were to establish an accurate data base at the state level, and to derive corresponding marginal price data for electricity. Both of these tasks involved a substantial amount of effort.

b) The Choice of Functional Form

Most econometric studies of the demand for electricity are based on dynamic single equation models. Whereas, most applications using systems of demand equations are based on static models. Hence, the specification of a dynamic system of demand equations in the URGE/AUSM represents an innovative departure from standard models. It is the choice of functional form at this step which is severely criticized by the reviewers. Since a great deal of space is spent on this subject in the Review, I will try to do what the reviewers did not do, which is to identify the key area of disagreement.

A number of desirable properties, which should be exhibited by any functional form chosen for a system of demand equations, are given in the Analytical Documentation for the Demand Module and augmented by the reviewers (Review, p. II-2-15). Among these are that the demand functions must slope downward (i.e., have negative direct price elasticities) and be symmetric (i.e., weighted cross-price elasticities should be equal in different equations). The reviewers place a great deal of weight on the symmetry condition, and state it is a "constraint absolutely critical for the model to make any economic sense" (Review, p. II-2-19). Since the choice of linear logit model as the functional form in the URGE/AUSM implies that symmetry is not exhibited globally, it is viewed by the reviewers as unsatisfactory. Their preference is emphatically for the translog model or similar system which does exhibit global symmetry.

It would be nice if a model possessed all desired properties, but such a model does not exist. In practice, a decision has to be made about which undesirable properties are acceptable. My own view is that if a choice had to be made between symmetry and negative price elasticities, the latter is more important. In other words, I would not choose a model which could lead to positive direct price elasticities. Nevertheless, price elasticities are unstable and may even be positive using a translog model. This problem manifests itself when expenditure shares are small, because, unlike the linear logit model, predictions of the demand for a commodity may be negative (i.e. illogical) with a translog form. Energy data at the state level contains many examples with small expenditure shares in one or more sectors.

This point can be illustrated by considering the expressions used to derive price elasticities. If S_i represents the share of expenditures on a commodity (i.e., price x quantity/total expenditures), and c_{ij} is the estimated coefficient for the logarithm of the jth price in the equation for the ith commodity, the direct price elasticities for the ith commodity can be written as follows:

Linear logit model

$$c_{ii} - \sum_j S_j c_{ij} - 1$$

Translog model

$$c_{ii}/S_i + S_i - 1$$

The linear logit expression implies that the elasticity is a linear function of all shares. In contrast, the elasticity is inversely related to the commodity's share with the translog model. Consequently, as the share approaches zero, the elasticity in the translog model explodes, and prior to this, may change sign from negative to positive and violate the most fundamental characteristic of a demand equation.

A typical econometric model based on pooled data from different states would have the same slope coefficients for regressors in the model and different intercepts for each state. This type of model (an analysis of covariance model with fixed effects) can account for the substantial differences that exist in the patterns of energy use in different states, and avoid the inefficiency of estimating a new set of slope coefficients for each state. In other words, the slope coefficients (c_{ij}) would be the same in every state, but the expenditure share (S_i) would vary, implying that the corresponding price elasticities would also vary. Typically, direct price elasticities would get smaller, in absolute terms, as the expenditure share gets smaller.

Assume that the linear logit and translog models imply identical elasticity values of $-.5$ with a 4% expenditure share ($S_i = .04$). The corresponding value of the price coefficient, $c_{ii}z$, is .0184 in the translog model ($.0184/.04 + .04 - 1 = -.5$). If it is assumed, for simplicity, that there are only two commodities, then the same elasticity value for the linear logit model is obtained when the two relevant price coefficients for $i = 1$ are $c_{11} = .5$ and $c_{21}z = -.02/.96 = -.02083$ ($.5 - .04 \text{x} .5 + .96 \text{x} .02083 - 1 = -.5$). The implied price elasticities for a realistic range of expenditure shares are summarized in Table 3.

The results in Table 3 show that both models give the same elasticity value of $-.5$ when the share is 4%. Both models also show greater price responsiveness when the share is larger (i.e. at 8%), as one would expect. When the share gets smaller, however, the elasticity value for the translog model changes dramatically and reverses sign. The behavior of the elasticity for th linear logit model is quite stable in comparison. Even though the computation of elasticities with a linear logit model is generally more complex in a real application than the example implies, the overall conclusions are not affected. As shares get smaller, elasticities behave very erratically with a translog model. This is not the case with a linear logit model.

Problems with the properties of translog models have been cited by others. For example, Christensen and Caves (1980) derive explicit conditions which determine when the economic logic of the translog and generalized Leontief models breaks down. Lutton and LeBlanc (1984) discuss the problem of generating "theoretically implausible negative shares during simulation" from a translog model. Finally, there are others (e.g., Deaton and Muellbauer, Chapter 6, 1980) who argue that it is generally inappropriate to impose restrictions derived from microeconomic relationships on aggregate data. In other words, it simply is incorrect for the reviewers to treat global symmetry as the most important criterion for selecting a demand system. For a policy model based on state-level data, the linear logit model is preferable to the translog model.

There is still another outstanding issue concerning the functional form of the demand equations, and this is whether a static or dynamic model should be used. As stated earlier, most models of demand systems are static. One reason, which is recognized by the reviewers, is that it is impractical to adapt the translog model to a dynamic form. They suggest using a Generalized Leontief model instead of the translog model because it can be made dynamic. However, this alternative suffers from the same problem of instability of elasticity values when expenditure shares are small as the translog model. Furthermore, it is not possible to account for interstate differences in patterns of energy use by specifying state-specific intercepts. Consequently, using the Generalized Leontief model implies estimating a complete set of slope parameters for every sector in every state. Not only is this expensive in terms of the large number of parameters needed to specify models for 48 different states, but in addition, the information contained in the data set is almost certainly insufficient to obtain reliable estimates of the parameters.

An attractive feature of the linear logit model is that it can be made dynamic in a relatively tractable way (see Considine and Mount, 1984). While the dynamic structure corresponds to the familiar partial adjustment model, it is still better, in my view, to include this type of adjustment process rather than ignore the distinction between long-run and short-run responses. Furthermore, the use of a dynamic system (as opposed to a single equation) has very important implications for the relative magnitudes of short-run and long-run income elasticities (see next section). Once again, the linear logit form provides a viable and innovative structure for modelling a dynamic demand system.

c) The Unsuccessful Search for Bias

The reviewers spare no effort in their attempt to discredit the procedures used ot estimate the linear logit model. At the end, they are at least honest enough to admit that in spite of the number of issues they raise "none can be shown to bias the coefficients in any systematic way" (Review, p. II-1-14). Among all of these issues are the two really important ones, which are both discussed in detail in the Analytical Documentation for the Demand Module. To provide a better perspective on the estimation problems for others, the focus of this section will be these two key issues.

i) Problems with the sample data.

The first issue is that the estimated coefficients were found to be sensitive to the presence of data from regions with small expenditure shares. It is important to understand the distinction between this problem and the sensitivity of elasticities to small shares, which was discussed in Section II b. With the logit model, small shares create a problem for estimation but not for the computed elasticities. For the translog model, the opposite is true. Small shares do not create problems for estimation (unless one takes the stochastic specifications and the implied constraints on the values of residuals seriously, which most people tend to ignore), but elasticities are very sensitive. In other words, the economic characteristics of a logit model in a simulation are not adversely affected when small shares are predicted, but the translog model does not perform well in this type of situation because direct price elasticities may be positive and predicted shares negative.

The reason for the sensitivity of the estimated logit model to the existence of small shares in the sample is the the dependent variable is a function of the logarithm of a share. Small shares tend to exhibit large relative changes from year to year, which result in large changes in the dependent variable. For example, a change from .1% to .2% is a very small absolute change but a large relative change. Relative changes will rarely be this big when shares are large. In other words, the use of coal in Pennsylvania is unlikely to double in one year, but this can happen in Maine. With a translog model, the share itself is used as the dependent variable, and consequently, absolute changes matter for estimation and not relative changes.

The second data issue is more important, and it relates to the quality of the oil data in the sample. sectoral data on oil use at the state level are not available from industry sources as they are for electricity and natural gas. One of the main promises when the State Energy Data System (SEDS) was developed by the U.S. Department of Energy (DOE) was to provide these important missing values. Without a doubt, collecting and processing the data for oil quantities took the largest share of effort in creating the overall data base for the project. unfortunately, these data are erratic throughout the sample period for both distillate (light) and residual (heavy) oil. Eventually, the adverse effects of using these data had to be circumvented. In fairness, these data problems nave been recognized within DOE, but so far, insufficient resources have been made available to rectify them.

ii) Solving the data problems.

Initial estimates of the logit model were very unsatisfactory because, for example, many of the direct price elasticities were positive. Since the estimation of a system of demand equations involves cross-equation constraints on the coefficients, problems in one equation (i.e. the oil equation) affect the whole system. The oil equations were identified as the major source of the problems with the initial set of estimates.

The reviewers refer to the chosen solution to these data issues as "inspired". However, like most new developments, the reality is that it was 1% inspiration and 99% perspiration. Trying to reconcile these data issues required far more effort than originally planned. The eventual solution was to limit the number of states used for estimation, and to disengage the oil equations from the system. The rationale for the first step was to estimate the coefficients using data from states in which all fuels are relatively important (i.e. avoid having Maine dominate Pennsylvania in the coal equation). The second step was simply to avoid distortions due to the erratic nature of the oil data. Obviously, it would have been far better, particularly for those working on the project, if these steps had not been necessary.

Basing the estimation on a subset of the sample raises some issues which must be addressed. The most important is whether the final model is truly representative of the whole nation. To investigate this issue, a comparison was made of the explanatory power of the model for the 12 states used for estimation, the other 36 states, and all 48 states. The results for electricity demand are summarized in Table 4 in terms of predicting the annual use of electricity per capita in each state. These results show that the model does fit the data extremely well for all states, and not just for those states used for estimation. The corresponding results for natural gas and coal are equally as good, but as expected, the derived equations for oil do not perform very well (Analytical Documentation, Table 2-11 on p. 2-35).

iii) The estimated price elasticities.

The most important parameters in the model are the direct price elasticities for electricity. Compared to other studies, the long-run elasticities are relatively low. The values are -.30, -.65 and -.55 for the residential, commercial and industrial sectors, respectively. The reviewers are unable to provide any explanation for these low values. Given the thoroughness with which they dissect everything else, it is surprising that they do not discuss some obvious points.

First, a distinguishing feature of the demand equations is that they are estimated using marginal rather than average prices for electricity. Rate schedules are represented by two-part tariffs (a marginal price and a customer charge) for every sector, state and year in the sample. Most published studies, particularly early ones, are based on average prices. Marginal prices increased faster than average prices during the sample period because rate schedules generally became flatter over time (see Table 2-1, p. 2-8 of the Analytical Documentation). Consequently, the use of marginal prices would be expected to lead to lower elasticities than models based o average prices.

It is interesting to note that a low long-run elasticity of -.56 for the commercial sector was reported by Halversen (but is not included in the table presented by the reviewers). This estimate was obtained using marginal price data from Typical Electric Bills, which is the same source used in the Demand Module. Bohi also attributes this low elasticity value to the use of marginal prices (Bohi, p. 82, 1981).

Although the use of marginal prices is generally favored in recent studies. It is fair to point out that there is relatively little information on the effects of using average and marginal prices as alternatives in the same model. Since this topic is more controversial than I had realized, it would be an interesting area for further research.

A second issue relates to the use of a dynamic system fo equations rather than a single equation model. This has important implications for the value of the long-run income elasticity in the residential sector. The conventional wisdom is that income elasticities, like price elasticities, are larger in the long-run. All of the studies reported by Bohi exhibit this feature. However, some long-run income elasticities must be smaller than the short-run elasticities to ensure that expenditures always sum to income. This requirement has been recognized for a long time (e.g. see Phlips, 1972), and is a characteristic of the demand equations in the URGE/AUSM (Analytical Documentation, p. 2-17). The implied behavior of the logit model is interesting. In the short-run, income elasticities tend to be relatively close to one. In the long-run, the elasticities diverge from one, implying that the distinction between luxuries and necessities gets greater. Since electricity is a necessity, the long-run elasticity (.07) is smaller than the short-run elasticity (.46).

The elasticities for different prices and income sum to zero in each demand equation to ensure that they exhibit zero degree homogeneity in income and prices, and consequently, elasticity values are linked together. In this sense, a high income elasticity is typically associated with a large negative price elasticity. Since the long-run income elasticity is small using the logit model, a small price elasticity is to be expected in the residential sector.

The overall conclusion is that the use of a dynamic system of demand equations based on marginal prices represents an improvement over most existing studies. It is not surprising that the characteristics of this type of model are different from other more simplistic models. The main difficulties encountered in estimating the logit model were associated with the poor quality of data on oil use. If better oil data become available, it would be highly desirable to re-estimate the complete system of equations. At the same time, a more extensive comparison of the effects of using marginal and average price data could be undertaken.

d) Rate Schedules and Projections

Two issues are raised in the Review about the mechanism for setting new rate schedules each year. The first concerns the fact that actual and allowed (required) revenue are not equated each year in the model. Evidence had already been presented in this report showing that the restriction proposed by the reviewers is not really warranted in practice (see Table 2 on p. 9).

The second issue relates to enhancing the model's capabilities to allow for greater discrimination in the way cost increases are passed on to different classes of customers. This, at least, is an area of agreement between the reviewers and myself. Given the large increases in costs associated with completing new unneeded generating capacity (see Section I a), and the competing objective of making a region attractive for new industries, it is inevitable that attempts will be made to pass a larger share of costs on to the residential sector. Whether this is sound economics is another matter. However, it would be interesting to evaluate the effects of alternative mechanisms for setting rates.

The Demand Module also contains a component which computes a projection of energy requirements 15 years ahead. This projection, which may vary from year to year, is used as an input for the Capacity Planning Module. A four year moving average process is used to model how projections of future demand adapt over time. This provides the model with an interesting feature.

When demand growth departs from an established trend, realistic problems are generated for capacity planning. For the past few years, for example, actual demand growth has been relatively low and in some cases negative. Consequently, utilities' expectations of future growth have been revised downwards. If demand increases faster than expected, projections will be revised upwards. It is possible, however, that insufficient lead times will be given to get new base-load plants constructed in time to meet higher levels of demand. This possibility can be modelled with the URGE/AUSM. Generally, the projections of demand growth used for a policy scenario will follow a relatively smooth growth path. As a result, the problems associated with overshooting or undershooting future capacity needs will not occur.

It is true that the forecasting methods used by utilities have become more sophisticated, and that simple time series models are no longer used. The reviewers are concerned that the adaptive expectations model used in the URGE/AUSM to project future demand for planning purposes does not reflect current industry practices. This criticism misses an important point. The forecast of demand which matters for a given scenario is determined each year by the complete system of demand equations. This is the forecast which would be scrutinized by other analysts when evaluating a particular scenario.

An attractive feature fo the URGE/AUSM is that a base forecast can be specified exogenously. When this is done, it is possible to select an option in the control program which ensures that the 15-year projections of demand used for planning purposes always correspond to the exogenously specified growth path. In subsequent sensitivity runs, however, it is possible to allow demand to respond to price changes. Consequently, the important annually recursive feature of the URGE/AUSM can be maintained, and at the same time, a base forecast can be calibrated to any desired growth path. It is this set of features which allows analysts to incorporate forecasts obtained, for example, from industry sources, and to reconcile any discrepancies between these forecasts and those derived within the model.

III. Summary and Conclusions

Given the length and technical nature of the proceeding two sections, it is sensible to summarize the general conclusions of this report. The overall impression of the Review of the URGE/AUSM is that it does not provide fresh insight into how a policy model for the EPA should be structured. Given the innovative work done at the MIT Energy Laboratory in the past, this is disappointing. After all, the annually recursive structure of the URGE/AUSM follows in the tradition established by Baughman, Joskow and Kamat (1979). Trying to determine the appropriate blend of engineering and economic capabilities is a central issue for any modelling effort of this type, but it is never addressed by the review team. Consequently, there is no unifying theme to the Review, and reviewers of individual modules are free to pick on whatever takes their fancy.

The review of the Demand Module by Berndt and Wood is generally critical. They raise a large number of issues, but do not focus on the requirements for a model used in a policy environment. Many of the "problems" cited in their review are simply not related to the Demand Module. The most blatant example is their discussion of two models criticized by Oum (1979). A full two pages of text are assigned to repeating in detail the deficiencies of these models (Review, p. II-18,19). The two models are, however, completely different from the one used in the Demand Module. The reviewers do recognize this, but they are extremely vague in defining which, if any, of their list of problems apply to the actual model used. For any reader who is unfamiliar with the technical issues, this discussion will almost certainly raise unwarranted concerns about the overall merits of the model. In my view, there is no excuse for this type of misleading tactic. There are enough real problems without bringing in a lot of irrelevant ones (see Section II c).

Berndt and Wood dismiss the use of a linear logit structure for the demand equations primarily because this structure does not exhibit "global symmetry." Their recommendation is that the logit system should be replaced by a translog system (Review, p. II-2-37). In Section II b, it is shown that their suggestion is particularly inappropriate given the nature of energy data at the state level.

In many states, the use of one or more fuels in a sector is quite limited, and expenditure shares on these fuels form a very small part of total expenditures. Under these circumstances, price elasticities derived from a translog model are very unstable. Although the translog model does exhibit symmetry, this does not provide any guarantee that other more important economic characteristics will be maintained. For example, direct price elasticities may be positive (i.e. illogical) when expenditure shares are small. Given the fact that the URGE/AUSM must work for all states, and the widespread existence of small expenditure shares throughout the data set, the translog model (as well as the Generalized Leontief model) would simply not be reliable in this environment.

One of the virtues of the linear logit form is that elasticities are not adversely affected by small expenditure shares. In general, it's economic characteristics are robust to the wide diversity of situations found in different states. In simple terms, the alternative models place different weights on the importance of global symmetry versus logical responses to prices changes. There is no doubt in my mind that the latter is more important for a policy model, and that the logit structure is a better choice than the alternatives advocated by Berndt and Wood.

The most important conclusion reached by the review team about the overall structure of the URGE/AUSM is that it is impractical to use the model for policy analyses, and that the EPA should rely on existing models used by utilities (Review, p. I-3). This sweeping conclusion is based largely on perceived problems with the model which were all considered at length by the developers of the URGE/AUSM. In other words, no additional insight into how the model should be structured has been provided by the reviewers. It is surprising that they did not spend more effort on determining why key decisions were made about the structure of the model. Given this superficial treatment, the reviewers have been unable to identify more constructive ways for modifying and improving the model so that it could deal more effectively with policy issues (some suggested modifications are discussed in Section I of this report).

My own experiences using a model with the same basic structure as the URGE/AUSM is that it compares very favorably with other models. In particular, the integrated structure is a valuable analytical feature which is not exhibited by most existing planning models. This does not mean that the URGE/AUSM is ready for immediate action in the policy arena. A number of technical and administrative issues will have to be dealt with first. However, this is a very different conclusion from the one reached in the Review.

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COMMENTS ON CAPACITY PLANNING MODULE (Clark Bullard)

The review of the Capacity Planning Module is extremely misleading. It provides the reader with only a selective and incomplete description of the module's operation, and evaluates the model from a sterile, academic perspective that reflects little awareness of the ways in which the AUSM represents an advancement in the current state of the art.

The review states in several places that the user is required to specify the "sequence of plant additions for each state that is consistent with demand", and concludes that the module represents "a very restricted view of what capacity planning ought to include for a model such as an AUSM." In fact, the review's assertion is totally incorrect. It is the Capacity Planning Module (CPM), not the user, that determines the sequence in which plants are constructed. What the user defines is a "target mix". The review did not describe this process, which is in fact the heart of the CPM.

The review suggests that the CPM be modified to include an extremely complicated representation of intrastate transmission systems, utility-specific demand forecasts, etc. However, it does not suggest how such data might be obtained within the design constraints imposed upon the AUSM, namely that such data be uniformly available and regularly updated for 48 states, and available in the public domain. A key problem with many policy analysis models is their inscrutability and reliance on data that are either proprietary or prohibitively costly to verify or update. AUSM was designed to deal with that issue, but the review finessed it.

The review is critical of the burden placed on the user to provide significant amounts of input data. In fact, the AUSM was intentionally designed to receive such inputs from the MPMS module, which operates at a more highly aggregated level where economic tradeoffs and decisions can be more realistically modelled using available public domain data. Moreover, state agency personnel and electric utilities who have used the model view this so-called "burden" as an opportunity. In general, they have exploited almost every opportunity the CPM provides to exogenously specify such parameters as plant retirement schedules, interstate power transfers, etc. The reader should be aware of the fact that such data were intended to come from the economic optimization performed in the MPMS module at the regional power pool level, but that the AUSM makes it easy to override these results at the generating unit level of detail in cases where data are available and users are interested in doing so.

Finally, the review was superficial, in that it addressed only the analytical documentation of the CPM. If the review had been based on an examination of the volumes describing the overall AUSM system design, the programmer documentation for the CPM, and code itself, it is unlikely that the review would have asserted in several places that the outputs reported by the module were inadequate. All modules of the AUSM, the CPM included, compute a wide range of results, only a few of which are included in the formal reports printed as part of a routine model run. Additional formal reports are available if the user specifies they are wanted, and in addition, each module produces a set of "trace" reports, which are extremely useful for sensitivity analyses, as well as debugging. It is also unfortunate that the review did not reflect the existence of the data maintenance volume for the CPM; or it would not have raised questions about the sources and credibility of much of the input data.

Specific Comments

1. Besides omitting discussion of the way in which the CPM builds towards a user-specified "target mix" generating capacity, the review blurs the distinction between the data base that contains planned additions of generating units, and the new units constructed by the CPM as it builds towards the "target mix". It further states that "decisions made about the timing of these additions are made based upon the state's requirements for additional energy and additional peak capacity..." That is true but misleading in that the CPM is free to change the sequence of these capacity additions depending on which type of technology (i.e. peak or base load) is most needed. In most annually recursive simulations, the CPM changes the sequence frequently.

2. The review states that "...Given the decisions that lead up to the maintenance of the generation construction schedule, and without concern for decisions that follow that schedule, the [CPM] has been constructed to consider..." This is particularly misleading because the CPM alters the construction schedule annually to reflect a variety of decisions that follow its initialization. Examples include the addition of pollution control equipment that reduce the available capacity, and alterations in the demand forecast that can result from a variety of "decisions that follow that schedule." Examples include rate increases that result from changes in dispatch patterns induced by construction or pollution control actions, rate increases resulting from new capacity added to the rate base, etc.

3. Next, the review states "This is a very restricted view of capacity planning...Only in [MPMS] will it be possible to simulate and quantify such tradeoffs as scrubber retrofit versus early plant retirement , coal conversion, and out of state siting to meet regional emission limits". The review presents this situation as a serious shortcoming of the AUSM. However, it does not indicate what might be gained by handling these issues at the generating unit level in the CPM versus treating them at the aggregate level in the MPMS module. Since the appropriate data are not available in the public domain at the generating unit level, nothing would be gained by placing these algorithms in the CPM, nothing except computational complexity. That is why the decision was made to conduct the economic optimization in the MPMS module rather than embed them in the CPM of the annually recursive AUSM.

4. The review states "It is our understanding that the current version was not designed to "stand alone" but was explicitly designed to be only a support to the more comprehensive [MPMS]". That is backwards. The MPMS is designed to "support" the annually recursive AUSM, by providing it with input data. The state-level AUSM, however, is designed to accept data either from the MPMS or from users who wish to override it with unit-specific data. For example, some policy analysts from government agencies or electric utilities might wish to let MPMS define such input parameters as from the target mix of generating capacity additions. Other (in fact most) users may wish to specify the mix themselves rather than believe the results of an optimization. The chief advantage of the AUSM is that if offer the user both options. It is unfortunate that the review was conducted in the absence of a written description of the way in which the MPMS module relates to other modules of the AUSM. Nevertheless, the reader should be advised that electric utility personnel who have used the model have expressed a desire for more ability to override these types of inputs, not less [1]. The review seems to imply that the user would be better off if he/she were deprived of the flexibility that the AUSM provides in this respect.

5. The review cites the absence of any mechanism within the model to make marginal emission reduction costs equal across three modules: planning, dispatch and pollution control. There are two reasons for this model design decision. First, policies are not often designed to achieve such an objective, therefore a model which forced such an outcome would be irrelevant for analyses of many types of policies. Second, the MPMS module was designed to perform precisely that function (forcing marginal costs to be equal), and define inputs to those three modules accordingly. Of course, such input would be subject to user override for particular types of policy analyses.

6. The review refers to the "inflexibility of the 45-year retirement exogenously set on coal fired plants". In fact, there are two ways in which this provides an example of the flexibility and uniqueness of the AUSM. First, no other state of the art model available for national emissions policy analysis is sufficiently detailed to deal with retirement dates of specific generating units. This is an important issue because many of the proposed pollution control policies are targeted towards specific units. Second, the user is free to specify (with ease) different retirement dates for individual units, coal and otherwise. This flexibility has been exploited by state agencies and electric utilities that have used the model [1,2].

7. In describing the responsibilities of the user the review states "The fact that the user is not warned of the need and importance of this data [on bulk power interchanges and the sequence of plant additions for each state], and the fact that the user can most easily proceed with the default data, leads to a situation of virtually certain misuse." In fact, the nature, extent and sources of such data are documented better in the AUSM than in any other state of the art model. Moreover, data on planned additions of generating capacity are well documented (they are obtained from the North American Reliability Council) and can be easily modified by users who have more recent knowledge of specific utility expansion plans. The review does not balance this criticism with an explanation of how a model might represent the electric utility system in as much detail as an AUSM, provide the user with the ability to override default data as easily as in the AUSM, provide an interface with an economic optimization model like the MPMS, and do all this without creating a situation of "virtually certain misuse". Users who desire all these advantages must be expected to do more than simply skim the analytical documentation. It is unfortunate that the review does not refer to the model design document, the programmer documentation for the CPM.

8. The review identifies as a shortcoming of the AUSM its requirement that "New generators go into construction with the pollution control devices unspecified either by the model or the model user." In fact, compliance with the new source performance standards is modelled in the pollution control module, to account for the economic tradeoffs between percentage removal and the delivered price of coal of varying sulfur content. It would have been unwieldly and unreasonable to simulate this tradeoff in the CPM.

9. The review state that "Some states will also be too small to make large new capacity additions as cost effective as they are when power sales across state lines

can be conducted". That is precisely why the CPM was designed to interface directly with the MPMS module. It is also why the user is allowed to easily override the default value for the size of new generating capacity additions.

10. The review dedicates an entire paragraph to describing the results of analyses conducted by Argonne National Laboratory using a separately developed plant retirement model which can operate as a preprocessor to AUSM. The AUSM team decided it would be much more cost effective to invest limited funds in the development of MPMS, rather than a separate retirement model with such limited capabilities. Moreover, the review does not note that the Argonne sensitivity analyses would have been virtually trivial to conduct using the AUSM (by simply changing the default plant lifetime from 45 years to the 40, 50 and 60 year lifetimes assumed by Argonne).

11. The review points out that a county level siting algorithm was scheduled to be developed in the future. The reader should be made aware of the fact that the siting module was developed and delivered to EPA in August 1985.

12. The review cites the "crudeness" of the 3-5 segment load duration curve, pointing out that it make the model inappropriate for looking at storage, cogeneration and load management techniques. The issue here is not one of model capability, rather it concerns the availability of public domain data. Insufficient data were available to characterize load shapes for 48 states to any greater degree of accuracy, therefore it would have been wasteful to use load duration curves having more than five segments. In specific instances where more detailed data are available, the dispatch module can be easily modified to accommodate more steps.

13. The review states that "the capacity and energy effects of various compounded pollution controls must also be specified exogenously." That is incorrect, and reflects a misunderstanding of the annually recursive nature of the AUSM structure, and the way in which information is passed between modules. Such effects are in fact computed endogenously in the pollution control module. It is unfortunate that the review was conducted on a module by module basis, rather than focusing on the design tradeoffs that dictated the appropriate modules in which to deal with phenomena.

14. The review states "...We must conclude that the area of "uncertainty was not dealt with in the AUSM". In fact, the CPM was designed to facilitate sensitivity analyses, both by minimizing computational complexity and by making it easy for the

user to easily alter the well documented default data inputs. Moreover, many of the model "improvements" suggested by the review would seem to increase uncertainty: e.g. separately modelling public and private utility expansion when demand data are unavailable below the state level; letting unit level retirement decisions be made by endogenous economic calculations when no reliable data exists at the unit level to support such calculations; letting endogenous economic algorithms determine the amount of new nuclear capacity to be added, etc.

References for Comment by Professor Clark Bullard

1. Hottmann, H., "Evaluation of the Advanced Utility Simulation Model: Data and Modeling Assumptions," Masters Thesis, University of Illinois at Urbana-Champaign, September 1985.

2. Bullard, C.W. and Hottmann, H., "Strategies for Reducing Acid Emissions from Illinois Electric Utilities: A Preliminary Assessment," Report to the State of Illinois: Environmental Protection Agency and Energy Resources Commission; Springfield, Illinois, September 1984.

COMMENTS ON POLLUTION CONTROL MODULE (Edward Rubin)

These comments address the 1985 report by Baughman, et.al of the Massachusetts Institute of Technology (MIT) Energy Laboratory, prepared for the Electric Power Research Institute (EPRI). The MIT report presents a review of the state-level Advanced Utility Simulation Model (AUSM) developed for the U.S. Environmental Protection Agency upon completion of the project (November 1984), plus supplemental materials acquired by MIT during the course of their review.

Comments on the MIT review are organized into two parts. The first part addresses the overall conclusions of the report as reflected in the Executive Overview and in the section on Background, Model Description and Summary. The second part addresses the reviews of the specific AUSM components developed by my colleagues and I, namely the Pollution Control Module and parts of the coal supply module dealing with pollution control options (specifically coal cleaning).

Comments on the Overall Findings

In general, the MIT group is to be complemented for a careful and thorough review of the material at hand, and for their efforts to thoughtfully identify and discuss key limitations and issues surrounding the AUSM and its individual components. The principal flaw in the review, however, is a failure to adequately address issues related to the integration of model components in framing a set of overall findings and recommendations. Thus, in considering the AUSM as a whole, the review was disappointingly shallow, at times misleading or in error, and often painfully silent on workable ways to improve upon a number of the areas that were criticized.

The issue of context is particularly important in a review like this. Overall, I believe that someone reading this report with no prior knowledge of the AUSM would come away with an overly negative impression that does not correctly portray the potential for overcoming many of the current difficulties. The review also leaves one with the impression that the improvements suggested for some of the individual modules could be incorporated with no serious consequences to the feasibility or cost of running an overall integrated model, which is clearly not the case. Thus, the weaknesses of the AUSM must be judged against the opportunities (and cost) for improvements, and most importantly, against the state-of-the-art of comparable models for policy analysis. While the reviewers may not see this as part of their task, the absence of such context is nonetheless a major deficiency in the present document. Thus, the review really needs to begin by addressing a few key questions. For instance:

> In the context of the "acid rain" problem, what are the major issues that need to be addressed by a model dealing with the electric utility sector?
>
> How are these issues currently being dealt with (if at all)? What alternative approaches or models are available?
>
> Is the conceptual design of the AUSM appropriate for getting better answers to any of these issues? Does the notion of a state-level model make any sense? If so, how should it relate to a national model? Is the AUSM design reasonable is this regard?
>
> Is there an _a priori_ expectation that any single model can adequately address all issues of concern? If not, what are the most important things to get right? How does the AUSM stack up against other models in these areas?

Without at least some attempt to deal with these questions up front, many of the detailed as well as general criticisms that are make maybe extremely difficult for a reader to evaluate.

The following comments touch briefly on some of the specific statements appearing in the Executive Overview and the Summary chapters of the text.

1. There are frequent statements in the review about the use of AUSM for "air quality" studies. To avoid any possible confusion, it should be made clear that the AUSM has nothing to do with predictions of air quality. Rather, it deals with power plant _emissions_. Any link to air quality would require coupling such emissions with an atmospheric transport model.

2. The background description of the state-level AUSM calls attention to two "independence assumptions." One is a statement that "capacity planning is independent of the utilities pollution control decisions," which is only partially correct. Information on plant derating due to pollution control decisions is passed to both the dispatch and planning modules, and is thus accounted for in the planning of future capacity requirements. Other types of planning decisions, however, are not explicitly coupled to emission reduction requirements in the state-level model, though such considerations _are_ included in the regional AUSM framework.

3. It was somewhat disappointing that the summary of principal findings did not address critical areas and capabilities of the overall model before launching into a discussion of its individual components. In this context, there are a number of strong points and features well worth calling attention to that the review fails to acknowledge or highlight.

4. In the principal findings for individual components, the discussion of pollution control technologies contains several erroneous or misleading statements. The statement that "costs [of wet limestone scrubbing] are not sensitive to the engineering parameters of the module" simply isn't true. This is explained in later comments dealing with the review of that module. With regard to the model for physical coal cleaning, the most recent DOE data on washability characteristics (as of 1982) have been included in the analysis. No new data were contemplated at that time. The method for estimating minemouth coal prices has nothing to do with the coal cleaning model, as is implied, though it may be relevant to the discussion of coal supply. The points on statistical methods and "exogenous variables as right hand side variables" (which I suspect most readers won't understand) sound much more ominous than they are. These points too are discussed more fully later.

5. A conclusion for the Financial Module is that its regulatory and financial parameters appear to be different from those used in the Pollution Control Module. To the best of my knowledge this is not true (though it may have been a bug at some earlier time).

6. The section on Background compares the Utility Control Strategy (UCS) model to the state-level AUSM. While these are conceptually very similar, the review omits some important differences in the USC module and data base designs. These include a substantially revised electric generating unit inventory (and multi-unit aggregations); different coal supply and transportation models (based on price); a larger number of coal demand regions; a state or regional least cost option; and a much more refined dispatch model. Differences in the output reports also are significant. As with the AUSM, the UCS model is used to study policies for emissions control, not "air quality" control.

7. Item 8 in the Review Summary of coal supply issues again erroneously relates the incremental cost of coal cleaning to the price of raw coal. The point being made actually concerns the total cleaned coal cost, not the incremental cost of coal cleaning (see later comments).

8. There again are a few minor errors in the Review Summary of issues related to the pollution control module. These are covered in the discussion that follows.

Comments on the Pollution Control Module Review

The review by Fay and Golomb of the AUSM Pollution Control Module does not raise any serious areas of disagreement. However, several of the points in their discussion, and several of the conclusions, do merit some correction or clarification.

1. On p.6-2, it should be made clear that the control technologies listed apply only to coal-fired power plants. In the paragraph following this, the statement regarding fixed costs is in error, in that all such costs are calculated wholly within the pollution control module (though the calculation uses a number of the same parameters as in the financial module). The recovery of capital is the principal (but not only) element of these fixed costs.

2. Page 6-3 incorrectly states that the cost of electric power used to estimate the energy cost of pollution control systems is determined from other AUSM modules. Rather, it is an exogenous (user-specified) variable (together with a variable cost escalation rate). A detailed discussion of appropriate energy costs for pollution control cost estimation appears in the AUSM documentation.

3. The statement on p.6-4 that the option of evaluating emission standard strategies requires "a common emission standard equally applicable to all in-state plants" is not correct. (This statement also is repeated in the review's Summary section.) Any set of user-specified standards for individual units can be evaluated. However, my understanding is that the current version of the AUSM scenario generator (which is not part of the pollution control module) is most easily able to handle scenarios involving common standards or fractional reductions.

4. As to scenarios "such as restrictions on the choice of out-of-state fuels, limitations of employment effects, etc." the review correctly notes that this requires manipulating the inputs to other modules (to the extent various options of this sort are incorporated). Thus, "guidance on how this might be done" should be sought in other parts of the model documentation.

5. The discussion of costing methodology which begins on p.6-4 makes extensive use of three equations which Fay and Golomb have derived by simplifying the AUSM cost algorithms for wet limestone scrubbers. The equations are intended to represent the principal determinants of capital cost, O&M costs (excluding utilities), and energy costs, which together determine the total cost of FGD. This approach is a nice way of gaining insight into a complex model with a large number of parameters, which could be difficult to deal with otherwise in a review such as this. However, several misleading or erroneous conclusions have been drawn from these equations that need to be corrected. The following points elaborate.

6. The principal problem is that the review talks about "cost" when it means "cost effectiveness." The two are very different and need to be carefully distinguished. All of the simplified equations used in the MIT analysis give a measure of cost-effectiveness, i.e., dollars per ton of SO_2 removed. The review correctly points out that the principal determinant of this is the normalized fuel sulfur content (lbs SO_2 per million Btu). Other factors affect the cost-effectiveness to a much lesser extent, as the review also notes correctly. But it is not correct to conclude that this also applies to costs (as in the Principal Finding that "costs [emphasis added] are not sensitive to the engineering parameters of the module"). Indeed, it is this very feature of AUSM which distinguishes it from most other models whose representation of pollution control costs are relatively simple, and insensitive to potentially important site-specific factors.

A simple example illustrates this point. Consider two identical plants using FGD to get 90% sulfur removal. One plant burns coal with 4%S while the other uses 1%S. If the total annual FGD cost and annual generation for the two plants were identical (i.e., no effect of other plant parameters), scrubbing the high sulfur coal plant would be four times (400%) more cost-effective than at the low sulfur plant. In practice, however, the cost of FGD for the high sulfur plant is likely to be at least 50% higher because of the higher expenses for reagent, materials handling, waste disposal, and other engineering factors. The AUSM correctly models this, using plant-specific data. Even so, the cost-effectiveness of sulfur removal for the high sulfur plant would still be nearly 300% less than for the low sulfur plant, compared to "only" 50% higher costs due to other engineering factors (i.e., sulfur content remains the most dominant term for this measure). But it is the cost—and not the cost-effectiveness—that utilities and consumers must pay for to control emissions. While cost-effectiveness is indeed a critical measure for minimizing th is cost, the implication that many of the site-specific model parameters make little difference is incorrect and misleading.[1]

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[1]An earlier paper (Ref.1) included a sensitivity analysis of AUSM pollution control models as they stood at that time (a number of additional refinements were made subsequent to that). As is generally known, the cost of FGD depends most significantly on the volume of gas being scrubbed. This, in turn, depends on several site-specific plant and fuel parameters included in the model (in the MIT equations, this is reflected simply in the plant size parameter, MW). The ratio of operating to spare FGD trains is another important engineering design parameter not normally found in policy models. The plant capacity factor and the fixed charge rate are the key determinants of annualized costs since they reflect the power production and remaining lifetime over which costs are amortized for the specific facility.

7. Consistent with these comments, some statements in the MIT review should be revised to avoid the possibility of a reader mistaking the simplified MIT equations for the actual AUSM algorithms. For instance, the text on p.6-8 refers to "AUSM capital costs (Eq.7)," which may be mistakenly taken to mean that Equation 7 is indeed used in the AUSM.

8. Figure 1 nicely shows how the elements of cost-effectiveness depend on fuel sulfur content for selected values AUSM parameters. To help keep this figure and the equations from which it was derived from being misinterpreted or misused, it would be helpful to also include, (i) the year dollars are reported in (constant 1980 $), and (ii) a table summarizing all AUSM parameter values used to derive Equation (3) - (5) and Figure 1. It would also be better to modify the equation for SSCC (and its plot in Figure 1) to make it the total capital cost rather than just the direct cost component. (I believe it's very likely to be mistaken for the total capital cost as the text now stands.) This would simply involve putting the indirect and retrofit cost factors explicitly into Eq. (3). The factor F left in Eq. (2) then represents the net fraction of total capital which must be paid back each year, which depends primarily on interest rate, tax policy and plant lifetime assumptions.

9. The cost comparisons summarized in Table 1 are interesting, but must be interpreted rather carefully. First, the capital and variable costs for the EPRI and AUSM cases are presented in different years dollars, so the AUSM figures would have to be inflated by about 20% to make them comparable. The "energy cost" figures (where the agreement is quite good) do not require this adjustment since they are normalized in a way that makes cost drop out altogether (i.e., the units given can be rewritten as 100 kWh/ton SO_2, which is simply a measure of energy use, not cost). For the direct capital cost, adjustments for inflation would leave the AUSM figures about 40% (rather than 20%) higher than the EPRI figures, which I just don't believe. It appears much more likely that these figures simply are not really

comparing the same things.[2] Whether this also might affect the comparison of variable costs is hard to say without knowing the details of what was done. The fact that all costs are normalized on the sulfur removal rate introduces still another uncertainty since it is not clear whether capacity factor and sulfur removal in bottom ash have been treated consistently.[3] All this is simply to say that comparing costs from different source remains a messy business, and even favorable comparisons must be viewed rather carefully.

10. The same obviously applies to comparisons with the PEDCo/Tilly data on p.6-7. These data are for scrubbers installed on U.S. power plants before 1980, hence, represent the first generation of this technology to be used in this country. Design changes which have evolved over this first decade of experience have resulted in higher costs for new systems to improve their performance and reliability. Thus, the statement that "AUSM capital costs are somewhat higher than historic experience indicates" is certainly true. So too are the capital cost estimates of EPRI, TVA and anyone else in the business.

11. The specific numbers on p.6-7 again must be viewed with care. First, they appear to be in different years dollars (1981 for PEDCo/Tilly vs. 1980 for AUSM), so that an adjustment for inflation seems needed (which would make the difference somewhat larger in comparing total rather than direct capital costs.). Since the "AUSM cost" is actually derived using the MIT model (Equation 7), it does not reflect some of the engineering parameters that also could be important is a comparison like this (such as scrubber redundancy, use of partial bypass, etc.). Nor is it clear whether the specific parameter values assumed by MIT correspond

[2]The text indicates that the EPRI costs were adjusted to factor out the retrofit and indirect cost factors in order to arrive at the capital costs which are presented. (Footnote b of Table 1 is inconsistent with this, but we assume the text is correct.) Thus, the figures would reflect the "direct" capital cost, not the total cost. Our own experience in trying to compare elements of EPRI cost figures with those of the Tennessee Valley Authority (whose detailed cost estimation model is the basis for the AUSM wet FGD cost algorithms) is that this is very difficult to do since EPRI and TVA use different conventions and nomenclature. Thus, items categorized as "direct costs" or "indirect costs" by TVA (and AUSM) are different from cost categories such as "process capital" or "general facilities" ad used by EPRI. This makes it very difficult to correctly compare intermediate cost results, as the MIT review attempts to do. On the other hand, we have found that total capital costs are quite comparable when based on identical assumptions. In general, it is the detailed assumptions and judgments employed, rather than the "models" that are used, that gives rise to discrepancies in cost estimates.

[3]EPRI studies usually assume no sulfur removal in the bottom ash, while the AUSM uses EPA emission factors. Depending on the coal type this could have a negligible to significant effect on the FGD sulfur removal rate required to meet a particular emission standard. Capacity factor has an obvious inverse relationship to cost-effectiveness.

rigorously to the four PEDCo/Tilly plants (the assumed value of FSO2 seems partially critical). Overall, however, the qualitative conclusion drawn from this comparison, i.e., that average capital costs today are somewhat higher than for pre-1980 plants, is quite correct, for the reasons cited earlier.[4] Note also, however, that a user-specified parameter in the AUSM can allow the future cost of FGD to decrease as well as increase in real terms, according to expectations.

12. The paragraph on page 6-7 regarding AUSM's default values for indirect costs needs some clarification. Interest during construction is always calculated separately in the AUSM (within the pollution control module, not the finance module) to insure a consistent treatment of interest and inflation rate assumptions, and to reflect different (user-specified) expenditure schedules for each control technology. Thus, results of the TVA model had to be adjusted to remove interest during construction as an item of indirect cost. This lowered the typical indirect cost factor for FGD systems from 0.8 to 0.57 (which is the default value used in AUSM).

13. The discussion on page 6-9 of whether FGD systems will actually perform as designed is an interesting one that merits careful consideration in future AUSM development. The reviewers point out that "historical evidence [suggests] about a 10% reduction in availability or emissions control, on average," and suggest adding an exogenous parameter to the AUSM to reflect this (which is the case typically modeled with the AUSM). The working assumption has been that many of the design changes which have produced higher FGD costs (including the use of redundant trains and spare equipment) are intended to bring FGD system reliability up to the level of an unscrubbed plant, so that future availability will not be affected significantly. The option to relax this assumption by modifying the current model nonetheless remains a worthwhile goal to pursue in future developments.

14. Several other suggestions for further work are made on p.6-10. The first concerns a closer examination of the "market management" component of AUSM for determining plant-level marginal costs and statewide least cost solutions. Since this was developed at the University of Illinois, detailed comments on it would be more appropriately provided by other AUSM modelers (our own responsibilities were limited to developing cost and performance models for various technologies, plus selection algorithms based on least levelized cost for a single facility). As to

[4]Note also that the TVA model upon which the AUSM FGD costs are based was substantially revised in 1982 to reflect a new set of design premises based on industry experience. These resulted in higher costs than the system design in earlier versions of the model.

the question of whether state-level pollution control costs are sensitive to the plant-level technology choice made in a regional least-cost formulation, our experience with the Utility Control Strategy model (which also employs a least-cost option) shows that this indeed is the case.[5] Qualitatively similar results would be expected for the AUSM, though quantitative results might differ since the AUSM uses a less rigorous to evaluate plant-level strategies and marginal costs.

15. The related point regarding AUSM's ability to deal with control strategies other than those based on emission standards or least cost requires further elaboration. It is certainly possible to constrain the model in various ways (e.g., to limit certain types of fuel switching), but —as in all other models we are familiar with— the ultimate decision criterion is still based on cost (for whatever options are permissible). The incorporation of other criteria (though it's not clear what the reviewers have in mind) would require further development.

Comments on the Coal Supply Module Review

These comments deal principally with the section on coal cleaning (p.7-22 to 7-23). They incorporate responses to the MIT review by Dr. James F. Skea, an AUSM co-author and principal developer of the coal cleaning model (now at the University of Sussex in England). Additional comments relate to other work performed at Carnegie-Mellon.

First, we do appreciate what appears to be the overriding conclusion with respect to coal cleaning, namely that, " the approach appears to be a significant improvement over the representation of coal cleaning in other coal market models". The review then goes on to raise seven points requiring further attention. These are discussed below.

1. The first point concerned whether post-1976 data had been included in the washability analysis. Yes. The USBM Report RI-8118 published in 1976 contained 587 coals. The 710 coals referred to here included data subsequently added to the USBM computer database, which is what was used in 1982 when the analysis was carried out. No additional tests were planned at that time.

2. The review notes that since endogenous variables appear on the right-hand side of the regional regression equations, simultaneous estimation of the system of equations would have been more appropriate. This criticism is partially (and

[5]Results on this were recently presented at the 1985 EPA/EPRI FGD Symposium (Ref.2).

theoretically) correct, though we believe it is not likely to be of significance. Looking at the system of physical washing equations (Eqs. (26)-(35) in the AUSM report), the only endogenous variable used on a RHS is $\underline{p}$, the pyritic sulfur fraction. Note also that the only estimated equations involving this are Eqs. (26), (27), (30), (32), and (35). The remainder are identities, while the variables ΔS, S_R, A_R and H_R are all exogenous. Thus, the "endogeneity" of the variable $\underline{p}$ was ignored primarily on the grounds that it would make little difference to the final results.[6] We do note that if the system of equations is extended to include the cost equation, (36), then the criticism would hold, as Y, the process yield (and an endogenous variable) is the only one on the RHS. However, in this case, the goodness of fit is so high (R^2 in excess of 99%) that the bias in the estimates of the coefficients is negligible.

3. We believe the point that t-statistics are not reported for intercept terms in the equations is not really significant. The point of showing t-statistics is to indicate how significant particular variables are in explaining the observed results. The t-statistic for the intercept term indicates the likelihood that this term is other than zero. Since there is no reason, given the functional forms, to assume that any intercept would be zero, the t-statistic effectively provides no information. While the values were not recorded systematically, in most cases they had 2 or 3 digits, indicating the term to be highly significant.

4. There is some truth to the point that the t-statistics may be somewhat misleading since the analysis was performed on pseudo-data; but it is not nearly as significant as some have suggested. We discussed this point fully in responding to a 1984 critique of the coal cleaning model performed by SAI, Inc. for the U.S. Environmental Protection Agency. The subsequent critique for DOE by Resource Dynamics Corp., referred to in the MIT review, repeated essentially the same points raised by SAI. (Unfortunately, we were never given an opportunity to read or comment on that report before it was published.) The main point not to loose sight of in all this is that the need to use pseudo-data arises in the first place because of major shortcomings in current way of handling coal cleaning in the context of large-scale models used for policy analysis. The original USBM data for each coal sample consists of washability characteristics for three different size fractions

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[6] It's also important to note that the system of equations (26)-(35) also are extremely non-linear. While methods are readily available to cope with the simultaneous fitting of systems of linear equations, it is far more difficult to deal with systems of non-linear equations. Altering the specification of the model to remove the non-linearities (a common way out of such problems) was rejected, as the particular functional forms were chosen carefully because of the nature of washability curves (see point 5).

tested under laboratory conditions. A real prep plant washes these fractions separately and blends them together. The model used to create the pseudo-data optimizes these processes and allows for the inefficiencies of commercial washing processes. For this reason, it would not be possible to make a meaningful statistical analysis of the raw data. In addition, it is important to note that the original USBM data would not even qualify as a proper statistical database, since the same specific gravities were selected every time, giving a biased sample. The next point to consider is where the unexplained variance in the regression equations comes from. The equations chosen can simulate washability curves for individual coals with great accuracy. Hence, most of the unexplained variance derives from differences among coals.

5. The MIT review also asks what other functional forms could have been utilized to improve fit. None that we know of (or tried). The forms chosen were selected carefully on the basis of a priori knowledge about the general properties of washability curves. First, they are very non-linear. This required the selection of a log-log or log-linear formulation. The log-log formulation was chosen. Second, it is known that the pyritic sulfur content of a coal represents an upper bound on sulfur removal through physical cleaning. This determined the choice of the transform, $\log(\Delta S/(p-\Delta S))$, as the chief explanatory variable in the washing equations. In additions, the facts that the maximum ash removal is 1 and the maximum yield is 1 determined the choice of the endogenous variables $\log(\Delta A/(1-\Delta A))$ and $\log(1-Y)$.

6. The review notes that basic preparation costs are absent from the documentation. This does need to be clarified. In fact, the basic preparation levels and yields given at the top of page C-52 of the model documentation serve as inputs to the engineering cost models described in Section C-2.6. The results of this are then used in the subsequent analysis.

7. The final point raised concerned the coal prices used to determine coal preparation paths. As we've noted earlier, this is really a question about the coal proprocessor methodology in general, rather than specifically about washing. However, it does potentially affect the prices of washed coals used in the AUSM. The major problem raised is the use of Green and Michelsen 1980 coal prices as input to the coal washing algorithms. This methodology was chosen in conjunction with the coal supply modelers because it allowed the cleaning analysis to be carried out in a stand-alone fashion (at a time when the model mine option also was still under development). However, there would be little difficulty, in principle, in repeating the exercise with a different set of coal prices. Whether this would significantly

change the optimal choice of coal cleaning technology (and incremental cost) for a given level of sulfur reduction can't really be foretold since it would depend on the particular choice of alternative prices. Based on our own sensitivity analyses, however, we would expect the differences to be minimal for the cases where it matters the most —i.e., for low to moderate sulfur reduction levels where washed coals compete most effectively with unwashed coals of equivalent sulfur content. Here, overall yields are still fairly high so that the simpler plant configurations are generally the most economical. More importantly, the effect of input coal price on the value of coal refuse is unlikely to be severe. (It is this cost of lost coal which eventually makes higher levels of cleaning become uneconomical.) The subsequent effect on delivered coal prices, affecting power plant economics would be even smaller in light of added transportation costs, and the relatively large number of alternative coals considered in AUSM.

The second part of the question is whether any 1980 coal prices, however accurate, would be appropriate for subsequent years. The answer to this is, "it depends." The current methodology is satisfactory if no significant changes occur in the price premiums for low sulfur coals in a particular supply region. (It would not matter if the general price levels for coals in two different supply regions diverged.) Should future AUSM developments warrant it, there is no reason, in principle, why the coal cleaning methodology could not be completely integrated with the preprocessor to re-estimate cleaned coal prices for each projection year (including the effect of changing economic parameters affecting the cleaning plant itself). But this would also mean slowing the model down, making it bigger and increasing the cost of its use. Nonetheless, when the review closed by saying, "perhaps what is needed is a more conventional economic cost function in which the cost of coal cleaning is a function of input prices, input characteristics and output characteristics," we thought this summed up nicely what was done in any case.

8. Finally, we note that the discussion of coal transportation costs (p. 7-21) makes several references to analyses and models of rail prices and barge rates developed at Carnegie-Mellon, though no specific sources are included. Refs. 3-5 below provide citations to this work by Dr. Michael Morrison.

References for Comment by Professor Edward Rubin

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2. Rubin, E.S., M. Cushey, R.J. Marnicio, C.N. Bloyd and J.F. Skea, "The Role of FGD in SO_2 Reduction Strategies for Coal-Fired Power Plants," Proc. of Ninth

Symposium on Flue Gas Desulfurization, USEPA, Research Triangle Park, NC and EPRI, Palo Alto, CA, June 1985.

3. Morrison, M.B., "Coal Transportation Rate Models," International J. of Energy Systems, Vol. 3, No. 2, 1983.

4. Morrison, M.B., "Transportation of U.S. Western Coals: The Impact of Deregulation on Unit Train Rates," Energy Policy, June 1985.

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COMMENTS ON DISPATCH MODULE (Sarosh Talukdar and Richard Edahl)

Two points must be kept in mind when considering the dispatch module. The first is that the module can assume several configurations.. The version in the official copy of the AUSM is a minimal configuration. It has been compacted, with many features disabled or removed, so that it will fit in an amount of memory that is small by today's computing standards. The reason will be discussed later. Our own unofficial versions of the dispatch module run in more reasonable amounts of memory and are far more powerful than the official version. Sophisticated users should be able to make simple modifications to Dispatch in order to achieve similar increases in power.

The second point is that there is a companion program to the AUSM called MPMS (Multi-Period, Multi-State) whose purpose is to coordinate generation planning, transmission planning, pollution control, fuel scheduling, and dispatching over time horizons of about 25 years and geographic regions covering several states or several interconnected utilities. MPMS takes a broad, undetailed view, and is intended to provide input data for its more detailed and narrower companion, AUSM.

We have found MPMS particularly useful in calculating inter-state energy flows and in coordinating the emissions of states. In many studies, MPMS and AUSM should be used as a matched pair. Unfortunately, MPMS may not receive widespread distribution. Its algorithms were designed by members of the AUSM team who also wrote a prototype code. But responsibility for further progress was transferred to other developers. The testing, adjusting, and refining needed to convert a prototype into a finished program suitable for mass distribution requires intimate familiarity with all the design decisions and planning that went before. Since the new team does not have this familiarity, we suspect that the EPA version of MPMS will remain in its present state —— an unsupported program useful to researchers who have the time to learn how to use it, but not a program for general distribution.

Let us now turn to the specific criticisms made by the MIT reviewers. They are:

1. "Capacity Factors were then, and apparently still are, constrained at maximum levels of their 1980 historical values. Such a constraint virtually fixes the output of the Dispatching Module at 1980 levels,..."

There seems to be some confusion between maximum capacity factors and actual capacity factors. The maximum allowable values of the capacity factors are provided as inputs. (The historical 1980 values for capacity factors are <u>not</u> used as these maximum values by the dispatch module.) Dispatch then calculates the actual capacity factors to be used for each year. Depending on conditions, very different dispatches may be obtained for different years.

2. "Capacity factors are assumed to equal their 1980 maximum levels for the remaining plant life. The assumption seems inconsistent with recent studies of age-performance profiles for coal plants."

Actually, the dispatch module has been designed to work with maximum-allowable capacity factors that vary year by year. If data on these variations are provided by the user, they will be taken into account. (The responsibility for obtaining or calculating these data lies with other EPA contractors.)

3. "Transmission and distribution system investments are specified by the user as part of the capacity planning process... Under these conditions (least emission dispatch) specifying the transmission investments in advance will be extremely difficult, and would almost certainly require 'user model' iteration."

This criticism is warranted especially if MPMS or an MPMS-like program is not used to preprocess data for the AUSM.

4. "The use of an annual load curve characterized as a three or five segment function limits model applications in potentially important ways."

We agree that three segments may be too few. However, very small and quickly accomplished programming changes can increase the number of segments. These changes will require more memory, but not an unreasonable amount. For instance, the memory for ten segments is easily provided by most minicomputers and even many personal computers. To understand why the official version of the dispatch module is limited to three segments, we must go back to the memory restrictions placed on its developers, namely that the module be capable of dispatching 400 independent plants (the largest number in any state) and, when combined with the rest of the AUSM, be transportable, without modification, to virtually every mini- and main-frame computer. This limited the dispatch module to about 60,000 words of memory. To fit it into this space, we had to cut it down to the bone. We also had to disable or eliminate features that have been retained in our "unofficial" versions. Virtually all users can afford much more than this 60,000 word limit, and hence can add more segments to the load duration curves.

One point to note is that it may be difficult to predict future demands with accuracies that justify using more than three segments. (For example, in AUSM, only the yearly peak levels and total annual sales are predicted by the DEMAND module. Using only this provided information, one would be hard-put to defend the construction of a more detailed load curve.)

5. The Dispatch Module uses "the very crude assumption that the load shapes do not change over time".

It seems that there is the perception that the load duration curves used by the Dispatch Module are even cruder than is the case. While it is true that mainly a three segment load curve is used, the shape of the load curve does vary. While the lengths of the segments generally remain constant, the relative heights are not kept constant (i.e. the shape of the load duration curve does change).

6. "Especially if the Dispatching Module continues to be operated with substantial pre-specification of capacity factors, but in other model runs as well, the user is responsible for providing tremendous amount of data.."

As pointed out above, while the values of the maximum capacity factors are inputs, the Dispatch Module computes the capacity itself.

The Dispatch Module requires little information that is not also required by the other modules in AUSM. The Dispatching Module essentially gets all of its data from the Unit Inventory database (which is part of AUSM) and from the other AUSM modules. For example, the operating cost of a generating unit (which is assumed to be linear in operating levels) consists of an Operations and Maintenance part (which is from the inventory database), a fuels cost (which is provided both by the coal module and the pollution control modules for a fuel mix), and a pollution control cost (of scrubbers, provided by the pollution control modules).

7. "Plant characteristics must be changed when pollution controls are added, or when fuels are changed. Capacities must be derated; forced outages must be accounted in further deratings; and operating cost must be increased ... The capabilities that AUSM has in this area should be reported."

The Dispatch Module does not assume constant plant characteristics for varying fuel mixes, pollution technologies, etc. To some extent, these changes are calculated by other modules in AUSM. The variations are passed on to Dispatch which takes them into account.

COMMENTS ON COAL RESERVE DATA BASE (Edward H. Pechan)

This letter comment on the revised Coal Supply Module materials transmitted by your letter of November 27. These comments supplement those I made on the prior draft that were transmitted directly to Charles Kolstad.

Background

Production of the augmented reserve base for AUSM (described in the Coal Supply Module chapter as the Pechan reserve base) was a spinoff from our work to produce a coal reserves estimate, utilizing AUSM coal quality and geographic categories, consistent with the Demonstrated Reserve Base (DRB) published by the U.S. Department of Energy. To do this work, we obtained the detailed coal resource data originally developed by the U.S. Geologic Survey. In reviewing these data, it became clear that a substantial quantity of coal that is economically recoverable under current conditions had been omitted from the DRB simply because the core samples from which resource estimates are calculated were more than 1.5 miles apart. Discussions with DOE staff revealed that the DRB was never designed to support long term modeling needs such as those of AUSM. The "Pechan reserve base" was an initial attempt to quantify additional coal resources available for development over the AUSM forecast horizon.

Response to AUSM Review

The basic criticism of our work in your report seems to concern its documentation rather than its concept. In 1982, our coal reserves work was reviewed by the URGE team, executive branch and congressional agency staff, and representatives from industry. These reviewers did not identify deficiencies in the documentation. Obviously, since documentation adequacy is in the eye of the beholder, some will find the documentation of our work inadequate. To the extent that this is the case, it should not detract from the significance of our major finding regarding the inadequacy of DRB-type estimates for long-term modeling. Our work to develop an augmented resource estimate represented a first step in a process to address underlying assumptions (e.g., the utility of the DRB in long-term modeling) that had not previously undergone scrutiny.

Since AUSM is designed to generate a 30 year projection (and some have suggested using it for 50 year projections), it is surprising that your review did not comment extensively on the inadequacy of the Demonstrated Reserve Base (DRB) to support such long term modeling.

Summary

Our coal resource analysis work has produced the only available quantitative data base that augments the DRB by including coal resources that can be economically developed under current conditions. Although the quantity of the economically recoverable resources is not as precisely known as the resources in the DRB, inclusion of the economically recoverable resources is at least as important to long-term modeling as is the depletion effect. If AUSM testing reveals that depletion is important, we would recommend that additional research into coal resources be conducted. At that time, it would be appropriate to modify the documentation so that all readers comprehend the significance of our findings and the details concerning how they were developed.

COMMENTS ON THE FINANCIAL MODULE Duane Chapman)

The financial module is logically simple but technically complex in some areas. Its conceptual simplicity is its reporting function: it does no work other than report financial data generated in other modules, and process these data according to accepted regulatory and financial practice. Hence, the simplicity of format for the reports' income statement, balance sheet, cash flow, tax account, and revenue allowance.

The complex facets of the financial module are wholly internal and self-contained: tax calculations, regulatory normalization of tax incentives, and system revenue requirements.

Of course, the strength of the financial module is its ability to estimate the total revenue requirement. This gives, theoretically, the capability of showing prices paid by customers (as distinctive from levelized cost) for the full array of possible pollution control policies, whether capital intensive or fuel intensive.

However, the simplicity of the financial module reports means that problems which exist in overall AUSM design or in other modules often become evident only as they become reflected in the financial modules reports.

The significance of this is that some AUSM problems which give bizarre financial results can only be rectified by modifying either the external module or the AUSM integration linkage which is the locus of the problematic assumption. AUSM users should understand this point carefully before planning either modification or use of the model.[7]

Two important illustrations of this locus problem merit discussion. First: consider coal plant "M", located in West Virginia, owned by an out of state utility "V" whose service area includes suburban Washington, D.C. The financial module correctly includes the "M" plant cost in "V"s rate base and charges this cost to "V"s customers. However, the plant data base and the dispatching module assign "M"s production costs to West Virginia and its customers. Similarly, the planning and pollution control modules will unfortunately assign future costs for "V" and its customers to West Virginia. The financial module is conceptually correct, and the problem can only be corrected by rectifying other modules. Dispatch, plant data, planning, and pollution control hypothesize a non-existent West Virginia dispatching

[7]*AUSM is coded in 1980 Fortran with special GET-PUT subroutines additional to the standard Fortran information transfer statements.

entity. In fact, about 75% of the electricity generated in West Virginia is used by and paid for by utilities and customers in other states. West Virginia is the worst case of a general AUSM problem.

Second: the publicly owned utilities are not identified in an module. This is probably unimportant for New York where the State Power Authority is essentially a wholesaler to the privately owned utilities. However, the Tennessee Valley Authority covers 6 states and operates as an integrated and separable entity for dispatching,. planning, and pollution control. In the West, the major Federal utility systems are regional and multi-state, and have complex sales and dispatching agreements with both public and private retailing systems. The retailing systems +for this Federal power almost always have generating plants themselves. Obviously, any attempt at modelling public-private interactions in AUSM must begin on the ground, so to speak, with multi-state plant data, dispatching, planning, and pollution control modules.

A third problem arises from the lack of integration of economic data within AUSM. This is most evident in the discontinuity in revenue treatment between the finance and demand modules. Formally, the problem arises within the demand module in the Update Rate Schedule segment. My perception is that this is a difficult problem, and I think Tim Mount's discussion merits careful consideration.

In addition, it must be noted that the base year data is now 6 years of age, that the corporate income tax provisions affecting electric utilities are undergoing major revisions in 1985 and 1986, and that many state regulatory commissions are making substantive innovations in their cost of service methodologies in response to the high cost of nuclear plant investment. Similar data problems exist for plant data and the other modules.

Overall, considering these problems in AUSM design and data, I do not think the AUSM model itself is useful for studying any single state, or for national analyses of pollution control policies. It can be modified to study most individual public or private utilities, and single-state power pools, as has been done by several investigators.

In the review, there is some discussion of joint cost allocation for jointly owned plants. For the financial module, there is no initial problem here because in the module's data base, assets, debts, and rate base allowances are correctly allocated by the original financial data to the owners and their customers. These initial values will be correctly apportioned between states in the financial module.

However, as the other modules analyze the operations of a jointly owned plant, these subsequent cost all go to the state of location regardless of actual ownership or customers.

The review gives too much emphasis to demand function specification. AUSM was intended to evaluate air pollution control policies. I think it improbable that over the domain of observed and predicted data, functional form itself could have any noticeable significance for any variables of interest. The question of logit versus translog function will not impact estimated sulfur emissions, demand projections, control costs, dispatching, or revenue requirements. Accurate information on power plants operations and fuel use is more important by an order of magnitude. The major AUSM problems, as noted, arise from the overall design concept of separable, independent, geographically bounded states for planning, dispatching, and operating costs.

As far as I know, the anticipated MPMS national model has not been successfully developed. In my judgement, AUSM as it exists cannot be used or revised to undertake accurate analyses of national policies for air pollution control. If I am to take seriously the EPA quest for a useful tool for empirically correct policy work, then I must continue to suggest that such modelling must recognize regional dispatching and planning power pools and planning groups, and state responsibility for rate regulation. Such a model must be built upon real world utility systems to give information which is useful about those real world systems.