ENERGY LABORATORY

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

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David O. Wood
Michael Manove
Ernst R. Berndt

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Energy Laboratory
Energy Model Analysis Program

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David O. Wood
Michael Manove
Ernst R. Berndt

Contributors

Alan Cox
Ronald Krumm
Edward Mensah
Eric Shumabukuro
George Tolley

Prepared for:

Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, California 94304

EPRI Project Manager:

Richard Richels
Energy Analysis and Environment Division

NOTICE

Prepared by

Massachusetts Institute of Technology
Cambridge, Massachusetts 02139

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EXECUTIVE SUMMARY

The Mellon Institute's Energy Productivity Center (EPC) has recently completed a study asking the question, "How would the nation have provided energy services in 1978 if its capital stock had been reconfigured to be optimal for actual 1978 energy prices?"[1] Interest in this question is motivated by the unanticipated increases in oil prices since 1973. If policy makers are to learn from history it is important to know what would have happened if the increases in energy prices had been foreseen and if the nation had taken full advantage of that knowledge to minimize costs.

EPC concludes that if the 1978 capital stock had been transformed in conformance with a least-cost principal for providing energy services, then, given actual 1978 energy prices and energy service demands, per capita energy service costs would have been reduced by 17%. Market shares of the various energy types would also have been affected substantially. For example, while the gas share of total energy service demand would have increased slightly from actual 1978 levels, the share of purchased electricity would have fallen from 30% to 17% of total energy service demand, and improvements in energy efficiency would have increased from 10% to 32%.

EPC's findings have received considerable attention, both from the press and from policy makers. EPC interprets its results as indicating "... the direction in which we could move to begin realizing some of the benefits of a least-cost strategy."[2]

The purpose of this report is to assess and evaluate the EPC methodology, data base, and results. Here we briefly summarize our principal findings.

SUMMARY OF FINDINGS

1. The Energy Productivity Center's retrospective, "Least-Cost Energy Strategy" (LCES) study is provocative regarding the potential role of efficiency technologies in competition with energy supply technologies. Their decision to conduct a "what if" analysis for a recent year provides an historical context for interpreting and reviewing the results.

   1.1 As a result of its predication on known prices and technologies, the question posed by EPC avoids analysis of the difficult problems of uncertainty, shocks, and other "surprises," and instead focuses on the issue of optimal adjustment to higher energy prices.

1.2 The retrospective vantage of the LCES study helps us learn from history and has implications for optimal adjustment to future energy-price increases.

2. The LCES study is subtitled: "Minimizing Consumer Costs Through Competition." But the effects of competition are not explored in the body of the study. All of EPC's analysis is devoted to constructing a hypothetical optimal strategy and comparing that strategy to what actually occurred. EPC suggests, without substantiation, that competiton would cause an optimal strategy to materialize. It should be kept in mind that many economists, planners and regulators would argue that an optimal strategy can be implemented only with planning and regulation.

3. The methodology chosen by EPC to construct an optimal energy strategy is based on the least-cost energy-strategy (LCES) objective. This methodology has several advantages over other conventional policy objectives.

   3.1 Because of its general nature the least-cost objective function can simultaneously take account of many different kinds of issues. Matters such as resource limitations, environmental factors and national security can all be evaluated and compared within the framework of the least-cost method. This way of formulating policy is far more appealing than a method that takes account of only one significant issue (such as energy independence).

   3.2 Because costs must be quantified before they can be minimized, the least-cost method invites the analyst to use hard data when it is available. Vague judgments are thus discouraged.

4. Least-cost methodology is limited for several reasons, and it yields results which tend to overstate -- perhaps substantially -- the economic desirability of energy-efficiency improvements. Hence LCES implications for policy in this area may be misleading.

   4.1 There are many potential market responses to new energy price conditions:

      i. Consumers may substitute less energy-intensive consumer goods for more energy-intensive consumer goods.

      ii. Producers may substitute less energy-intensive inputs for more energy-intensive inputs in the production of a broad spectrum of commodities.

      iii. Producers may substitute more energy-efficient processes for less energy-efficient processes in the production of energy services.

iv. Secondary price changes may occur for many fuels and other energy rich commodities.

The least-cost methodology as applied by EPC takes account of only one of these market responses, namely, iii. above.

4.2 Least-cost methodology does not treat the level of benefits as a subject of consumer choice. Costs are permitted to vary as a function of the energy-service technologies selected, but the output of goods, and thus consumer benefits, are exogenously fixed. That is why the least-cost method cannot allow consumers to substitute less energy-intensive consumer goods for more energy-intensive consumer goods (e.g. i., above).

4.3 In contrast, the methodology of maximizing net benefits simultaneously chooses the appropriate bundle of outputs and the least-cost strategy for attaining that bundle. Maximizing net benefits and minimizing costs are equivalent only under restrictive and unlikely conditions. This raises important questions about the use of least-cost strategies for public and private policy formation.

4.4 When net-benefits maximization replaces cost-minimization as the policy objective, the indicated optimal improvement in the energy efficiency of capital goods is reduced. The interaction between the demand for services, capacity utilization and the optimal energy-efficiency of capital is an essential consideration in adjusting to higher energy prices. Ignoring this interaction biases LCES results toward excess efficiency. Some preliminary analysis suggests this bias may be substantial.

4.5 LCES strategies are deficient in that they recognize only the costs of energy-service inputs in the production of non-energy goods. They do not analyze the cost of other inputs to non-energy goods production, e.g. labor, capital, environmental conditions, non-energy materials, and primary resources. As a result, the LCES method cannot be used to analyze the substitution of less energy-intensive inputs for more energy-intensive inputs in general productive processes (e.g. ii., above). This omission further biases LCES results towards excess efficiency.

5. In constructing the LCES model, EPC described technologies for the production of energy services in great detail.

5.1 This detail is potentially useful in drawing conclusions about the future role of specific technologies in the production of energy services. EPC has advanced the state of the art of modelling energy-services production by integrating detailed information concerning a wide variety of energy services.

5.2 However, because of lack of attention to some of the broader issues discussed above, many of the detailed LCES results may be artifacts of methodology. Therefore, we believe it would have been more fruitful to distribute modelling resources more evenly among the issues listed under 4.1, to trade off detail for broader scope and a more appealing objective than least cost.

6. The EPC retrospective question can be stated succinctly: "How would the nation have provided energy services in 1978 if its capital stock had been reconfigured to be optimal for actual 1978 energy prices." We believe that the focus of this question is too restricted.

6.1 In fact, only a part of the capital stock is permitted to adjust. The least-cost strategy implicitly gives the gift of perfect foresight to end-use consumers of energy services but not to other decision makers, so that the least-cost strategy is a partial optimization.

6.2 Using actual energy prices rather than estimates of market prices greatly restricts the interpretation of the LCES study results as optimal. Further, the use of such prices, which include distortions due to regulation and market failures, is inconsistent with the spirit of a paper purporting to demonstrate the advantages of increased competition. We suggest that EPC should have used imputed free-market prices rather than "actual 1978 energy price."

7. We suggest an alternative retrospective question: "How would the nation have provided energy services in 1978 if cost-minimizing economic decision makers with perfect foresight had defined the domestic economic environment, constrained only by the domestic energy endowment and by world-market prices of energy resources abroad?" The answer to this question would be substantially different from the answer to the question posed by EPC, and, we think, more interesting.

7.1 With universal perfect foresight, public policies in the 1960's and 70's might well have mitigated the disruptive economic consequences of energy price shocks. A more fully adjusted macro-economy with greater economic growth and fewer recessions might have resulted.

7.2 With universal perfect foresight, investment levels and patterns of the energy-production, conversion, transportation and distribution industries would have been very different from their actual 1978 realization. For example, the electric power industry--with its long-lived capital and investment leadtimes --would have obtained a smaller and "optimally reconfigured" 1978 capital stock, resulting in lower electricity prices.

7.3 Governmental policy that allowed the deregulation of all fuel in the U.S. might have led to more rational fuel use and fewer shortages, as well as different energy service demand and prices in 1978

7.4 EPC argues that its optimization methodology is satisfactory for indicating "..the direction in which we could move to begin realizing some of the benefits of a least-cost strategy." But even the direction of change indicated by a partial optimization process may differ from the direction indicated by a complete optimization. Many of the opportunities for reducing the costs of energy services identified by LCES could disappear when the range of possible adaptations are increased.

8. LCES treats 1978 fuel prices as exogenous to the least-cost strategy. As a result, the fuel prices EPC uses in its simulations and computer runs, bias results towards increased use of natural gas, increased cogeneration of electricity, and substantially decreased use of purchased electricity.

8.1 Oil and natural gas prices are assumed to remain indefinitely at their below-market regulated 1978 levels.

8.2 Electricity prices are set at levels higher than would prevail if optimal reconfiguration of the utility capacity were allowed. This affects EPC simulations by making cogeneration more attractive to the industrial and buildings sectors than it otherwise would be.

8.3 Indicated optimal industrial cogeneration of electricity is dramatically higher than in any other study surveyed, and most significantly much higher than in other applications of ISTUM, the simulation model employed in the EPC study.

9. Several key results of the LCES study were imposed on the models, rather than being generated endogenously within the models as the outcome of an explicit optimization process. Hence prior judgment rather than integrated analysis significantly affected LCES results.

9.1 In the industrial sector, the second largest source of energy-efficiency improvement was the development and market penetration of the variable speed motor. As the recent history of the Reliance Company indicates, the time for the variable speed motor has not yet arrived.

9.2 In the transportation sector, the second largest source of improvement derives from the increased dieselization of the motor vehicle fleet. But the figures regarding penetration of diesel motored vehicles were imposed on the model exogenously.

9.3 In the buildings sector, the fourth most important source of efficiency improvement is cogeneration, a result introduced into the study via a side calculation.

10. The models used by LCES in their analysis have been found elsewhere to yield findings that are anomolous or inconsistent with LCES results. This complicates interpretation of LCES, and renders them less credible.

10.1 The Energy Modeling Forum studied aggregate energy demand-price elasticities using fourteen different models. They found that elasticities implicit in the ISTUM and BECOM models were by far the most volatile and sensitive to energy component price changes. For ISTUM, the demand ellipse had the wrong slope. It has been suggested that the EMF.4 price experiments were unintentionally biased against ISTUM; this conjecture needs to be evaluated by the modelers.

10.2 EPC uses a modified version of both the ISTUM and the BECOM models. The LCES reports contain no discussion of the sensitivity of ISTUM results to EPC model modifications.

10.3 Comparison of output from EPC runs of the BECOM model with base-case output presented in that model's documentation suggest very different patterns of adjustment to higher energy prices.

12. The use of ISTUM, BECOM and TECOM by LCES is poorly documented. Appropriate documentation would delineate each change in the base-case inputs of these models made for the LCES model runs presented. The lack of reasonable documentation aggrevates the problem of interpreting inconsistencies between LCES results and the base-case output of ISTUM, BECOM and TECOM.

TABLE OF CONTENTS

1. BACKGROUND AND ORGANIZATION

The M.I.T. Energy Model Analysis Program (EMAP) was organized in 1979 to conduct evaluations of important energy policy models and studies, and scientific studies bearing on important policy issues. Recent and current sponsors of the EMAP include the Electric Power Research Institute, the Energy Information Administration, the Office of Technology Assessment, and the Environmental Protection Agency.

In early March, 1981, EPRI invited the EMAP to conduct a review of the forthcoming Mellon Institute's Least-Cost Energy Strategy Study, tentatively titled "Eight Great Energy Myths." At the same time EPRI invited the Mellon Institute's Energy Productivity Center (EPC) to cooperate with M.I.T. in the review. After some discussion, EPC made clear that the new study would not be published until August, 1981, and that until then they would be unable to participate in any review activities beyond providing existing documentation and describing in general terms their current and proposed research study activities. In spite of this "timing problem", EMAP accepted EPRI's invitation to conduct an interim review to gain familiarity with the EPC's objectives and approach, and to review the initial EPC study, published in December, 1979.

The present study represents, therefore, an interim review of existing materials for EPC research and policy studies as of May 4, 1981, and concentrates on the objectives and approach of the EPC studies and on establishing a foundation for review of the current study.

2. DESCRIPTION OF THE ENERGY PRODUCTIVITY CENTER'S LEAST COST ENERGY STRATEGY STUDY AND PROGRAM

The Mellon Institute formed the Energy Productivity Center (EPC) in 1977 under the direction of Mr. Roger Sant. According to EPC's 1980 Annual Report, the Center's activities are organized into three areas including data gathering and analysis, institutional experiments, and public outreach.

Data gathering and analysis activities have been organized around three major research studies of energy service demand and supply. The first study--the subject of this review--was a retrospective study asking the question, "How would the Nation have provided energy services in 1978 if its capital stock had been reconfigured to be optimal for actual 1978 energy prices?"[3]

The second study, recently published by EPC, is "Eight Great Energy Myths", a prospective study (1980-2000) which employs the least-cost criterion in estimating capital and energy shares in providing the energy service demand predicted in the Energy Information Administration's ARC-1980, conditional upon EIA's estimates of equilibrium fuel prices.

The third EPC research study, a one-year effort beginning in the fall of 1981, will link the sectoral analysis characterizing the first two studies with a macroeconometric interindustry model, simultaneously determining equilibrium energy service uses, supply, and prices. According to EPC staff, the least-cost principles will continue to underlie the analysis, although the basis for comparisons has not yet been established.

2.1 Description of the EPC'S Least Cost Energy Strategy Study:

The starting point for the EPC studies is the idea that it is supply and demand for energy services which should concern both public and private decision makers, not primary energy itself and particularly not oil import dependence. Thus,

> The conventional import context in which the energy problem has been examined concentrates on the numbers of barrels of oil that can be produced or "saved" through new production or conservation. Within this framework, the competing elements include various fuels - oil, coal, natural gas, etc., - and various methods of "saving" energy - lower speeds on the highways, colder homes in winter and warmer homes in summer, etc. But production and conservation of a given number of barrels of oil or other quantities of energy only partially addresses the function of energy in our economy and our lives. A thriving economy and a materially rewarding life are dependent not on the given quantity of energy consumed but on the services or benefits that are derived from that consumption.[4]

Focusing on energy services has the immediate effect of explicitly coupling energy-using technologies with specific primary and intermediate energy forms. Providing a given level of energy service requires both the explicit consideration of alternative technologies and their various characteristics--including acquisition and operating costs, performance, and energy efficiency--as well as a criterion for choice. The EPC chooses a least-cost criterion, and that is the central theme of the EPC studies.

In this first EPC study, roughly half of the final report is devoted to a review of policy conflicts and failures of the 1970s, and to development of the concept of using least-cost principles to determine the shares of capital and energy in supplying energy services. The least-cost criterion is proposed as the organizing principle for identifying and evaluating both public and private energy policy alternatives. The second part of the report, supported by a technical appendix, presents and interprets the results of a retrospective study applying least-cost principles to answer the question, "How would the nation have provided energy services in 1978 if its capital stock had been reconfigured to be optimal for actual 1978 energy prices?"[5] The highly publicized answer is that such a "reconfiguration" would reduce per capita energy service cost by 17%, distributed by sector as shown in Table 2-1.[6]

TABLE 2-1

Summary Results from EPC's
Least-Cost Energy Strategy Study

Sector	% Reduction in Service Cost	2 Largest Contributing Technologies	Service Market Share
Buildings	23%	Structural Improvement, Residential Bldgs.	5.3%
		Improved HVAC, Bldgs.	2.0
Transportation	16%	Auto Weight Reduction, Power Train Improvement	3.2
		Auto Diesil Engines	.9
Industry	10%	Gas Turbine Cogeneration	1.6
		Variable Speed Motors	1.1

The total energy efficiency improvements equal 22% of energy service supply, purchased at an investment cost of 364 billion dollars. The sum of the two largest technology improvements in each sector is associated with least-cost estimation accounts for 14.1% of the 22% efficiency improvement.

The EPC least-cost energy strategy provides dramatic estimates of the potential for energy service cost reduction, and is interpreted by EPC as indicating "... the direction in which we could move to begin realizing some of the benefits of a least-cost strategy."[7] EPC employs the least-cost principle in order to identify opportunities for public and private policies to reduce energy service costs. One example of public policy cited by the study is the deregulation of fuel prices and fuel use in order to increase competitive forces in energy service markets. One example of private policy cited by the study is investment in the increased efficiency by private business organizations in the provision of energy services.

The EPC believes their analysis and results are sufficiently well-founded and credible to support rather wide-sweeping policy conclusions. Thus,

> Although the purpose of this analysis is to indicate the kind of changes tht could have taken place and <u>not</u> to project with statistical accuracy actual results that could have been attained, the hypothetical case will indicate that, <u>theoretically</u>, a least-cost strategy applied during the 10 or 12 years <u>prior to 1978</u> could have reduced the cost of energy services by roughly 17 percent in 1978 with no curtailment of services. We will then cite some conclusions based on this analysis which might help us realize the chief goal of a least-cost strategy - adequate energy services at a minimum cost. In addition, we will suggest that a least-cost strategy could also resolve many concerns that have appeared to be in conflict during most of the energy debate - concerns over nuclear power, oil imports, environmental integrity and so forth.[8]

Even setting aside "and so forth," a 17 percent reduction in energy service costs and the resolution of key energy related issues of the 1970's is an exciting prospect. It is not difficult to appreciate the sense of optimism which pervades the EPC study.

Next we describe the analytical apparatus, data, and procedures used by EPC in obtaining these results. EPC emphasizes that in this first LCES study they made "...maximum use of analytical techniques already developed."[9] In this spirit EPC employed three energy sector technology models[10] including,

- Industrial Sector - Industrial Sector Technology Utilization Model (ISTUM);
- Buildings Sector - Buildings Energy Conservation Optimization Model (BECOM);
- Transportation Sector - Transportation Energy Conservation Model (TECM).

Each of these models--ISTUM, BECOM, and TECM--is intended to support technology choice analysis employing the criterion of cost minimization. ISTUM and BECOM are both formulated as linear programming models, and TECM as a simulation model. Each model takes the relevant set of energy service demands, and a feasible set of energy service supply and efficiency improvement technologies as givens. Technologies are characterized by scale, costs (fixed and operating), and by efficiencies. In addition, emerging technologies are characterized by expected date of availibility. For emerging technologies, each of the three models "models" the penetration process, either through market share penetration functions, or by user constraints. The input variables, characteristics, and output variables for each of the three models is summarized in Table 2-2.[11]

The general assumptions regarding capital turnover in each sector and measurement of capital service cost are summarized in Table 2-3.

Table 2-2

Analytic Framework for Energy Productivity Analysis

Sector	Macro-Economic Output	Physical Service	Energy Service	Market Shares	Technical Efficiency	Economic Efficiency	Fuel Consumed
Buildings	Residential, non-residential construction dollar value 1	No. of residential units; Sq. ft. of Commercial floor space 2	Space heat air conditioning, thermal, lighting & appliances by bldg. type. 3	Market share by 4 service sectors & 9 bldg. types 3	Fuel used per unit of service sector & 9 bldg. types 3	Cost per unit of service sector & 9 bldg. types 3	Delivered fuel by 4 service sectors & 9 bldg. types 3
Industry	Output by SIC, dollar value 1	Tons of product *2	23 services by 24 SIC's 4	Market share by 23 service sectors and 24 SIC's 4	Fuel used per unit of service by 23 service sectors & 24 SIC's 4	Cost per unit of service by 23 service sectors & 24 SIC's 4	Delivered fuel by 23 service sectors & 24 SIC's 4
Transport	Disposable income, output by freight demand sector, dollar value 1	Ton miles or passenger miles by mode 2	Work at the flywheel by mode 5	Market share by 2 service sectors & 8 modes @5	Fuel used per unit of service by 2 service sectors & 8 modes @5	Cost per unit of service by 2 service sectors & 8 modes @5	Delivered fuel by 8 modes 5

Sources
1. Historic Data
2. Calculated from Historic Data
3. BECOM
4. ISTUM
5. TEC

Footnotes
* Not required by ISTUM
@ Calculated endogenously at a least cost basis for auto sector only at present

Source: Carhart [1979]

Table 2-3

Assumptions Underlying LCES Study

* The analysis described was performed using the Industrial Sector Technology Use Model (ISTUM), the Buildings Energy Conservation Optimization Model (BECOM), and the Transportation Energy Conservation Model (TEC). These models include all energy-using activities in the economy, and assumed the following conditions:

1. The transportation stock was permitted to completely turn over, buildings and industrial plants could be renovated or modified but not replaced structurally, and improved efficiency technologies in the industrial feedstock, construction and utilities sectors were excluded;
2. All decision-makers were assumed to minimize the discounted lifecycle cost of energy service capital investments.

   Capital was charged at an annual cost equal to the capital recovery factor times the installed cost.

   $$CRF = \frac{i}{1-(1+i)^{-n}}$$

   Where i is .05 and n is the lifetime of the equipment. With minor exceptions, equipment lifetime used were:

   Private vehicles: 10 years
   Commercial vehicles: 15 years
   Structural technologies: 20 years
   Industrial equipment: 25 years

   The total cost per unit of energy service is thus

   TC = CRF x Capital cost/unit of service
   + Fuel cost/unit of service
   + O-M cost/unit of service

   for each competing technology.
3. Capital was available in unlimited quantities at a real 5% cost to all:
4. The level of energy services in 1978 would remain constant, as would 1978 energy source prices. A marginal cost case was also analyzed but not included because it was even less reflective of a dynamic situation.

** Efficiency-improvement technologies were compared to a 1973 base year. In this case we compared energy use to an industrial output index in the industrial sector, total number of residences and commercial square footage in the buildings sector, and GNP in the transportation sector. A calculation of energy/GNP yields very similar results.

Source: Sant [1979].

3. CONCEPTUAL FOUNDATIONS OF THE LEAST-COST-ENERGY STRATEGY

In this chapter, we shall analyze the general concept of "least cost energy strategy" and the methodology associated with that concept. The least-cost concept was applied by the Energy Productivity Center in its retrospective study, "The Least-Cost Energy Strategy" (LCES). A review of the LCES study itself and of the question it posed is presented in the next chapter. In this chapter, however, we wish to step away from the details of any particular study, and consider at an abstract level the general issues involved in adopting the least-cost strategy. What are the important elements included in EPC least-cost analysis? Are important factors omitted? How does the concept of a least-cost strategy relate to competition? Is a least-cost strategy a good strategy? Is it "optimal" in some sense? Does a least-cost strategy correspond to our intuitive notions of a reasonable way to proceed? These are some of the areas explored below.

3.1 The Meaning of the Least-Cost Energy Strategy

EPC defines an "energy strategy" in terms of energy services and energy-service technologies. When we think of energy in economic terms, we usually think of physical commodities such as oil, coal, gasoline, uranium and electricity. These commodities are fuels. They can be converted into heat energy, electrical energy or mechanical forms of energy by a variety of technologies such as boilers, engines, motors, generators, wind-mills and nuclear reactors. Heat, electrical and mechanical forms of energy can be converted to energy services, energy delivered in a form which provides direct benefits to consumers or direct inputs in the production of non-energy goods. Some examples of energy services are space heating, transportation, electric service and steam for industrial uses. Energy-service technologies are technologies that are used in the transformation of fuels found in nature to energy services.

In the EPC study, an energy strategy is a prescription for producing a specified bundle of energy services by use of a specified set of energy-service technologies. Energy services are viewed as the ultimate output of an energy strategy, and energy-service technologies define the methods used in creating those outputs. A "Least-Cost Energy Strategy" for the production of a specified bundle of energy services is a strategy for producing the given services that incurs less economic cost than any other such strategy.

The EPC concept of a least-cost energy strategy, though not a new idea, represents an important step forward from the usual treatment of energy problems by laymen and policymakers.[12] EPC's approach begins from an attractive premise. In this view, there are only two aspects of energy that really matter to society: the benefits that energy yields and the economic costs incurred in the provision of those benefits. Energy services, rather than fuels, are viewed as the direct source of energy benefits. A warm livingroom (space heat) yields a certain benefit without regard to how that space-heating service was produced. The costs of a particular bundle of energy services are a function of the energy-service technologies adopted.

This type of analysis is appealing for several reasons. First of all, any least-cost strategy explicitly provides for some given level of energy benefits. We are reminded that such benefits are an end goal of energy production, while technological matters involving fuels, boilers, insulation and the like are but a means to that end. Policies which "tamper" with the means of energy-service production without regard to effects on energy benefits are discouraged by the EPC analytical framework.

Second, the evaluation of energy-service technologies in terms of economic costs seem much more reasonable than many of the single-issue approaches used in the past. When correctly defined, economic costs are a measure of the value of opportunities foregone when a particular course of action is adopted. In principle, many opportunities can be evaluated and compared on a common basis. Matters such as resource limitations, environmental factors and national security, as well as labor and capital requirements, can be considered simultaneously and traded off against one another within the framework of the least-cost method. This way of formulating policy is far more appealing than a method that takes into account only one significant issue (such as energy independence). Furthermore, because costs must be quantified before they can be totaled, the least-cost method encourages the analyst to use hard data when it is available, which tends to discourage vague judgements.

3.2 Competition and the Least-Cost Energy Strategy

The EPC study, "The Least-Cost Energy Strategy," is subtitled "Minimizing Consumer Costs Through Competition." Although EPC asserts that competitive forces would be a valuable tool for the implementation of least-cost energy strategies, the effects of competition are not analyzed in the body of the study. All of EPC's analysis is devoted to the construction of a hypothetical least-cost strategy and a comparison with what actually occurred. While the concept of cost minimization will play an important role in almost any economic system, it should be kept in mind that many economists, planners and regulators would argue that an optimal strategy can be implemented only with planning and regulation. Such views should be given serious consideration.

The LCES study may lead some readers to believe that competition would result in the adoption of the least-cost energy strategy. This is not so. In some cases a competitive strategy would be more desirable than a least-cost strategy; in other cases it would be less desirable. In any event, there are many reasons to expect that an EPC least-cost energy strategy and a competitive energy strategy would be substantially different.

Assuming a competitive market, one could expect to see a variety of economic responses to conditions of increased energy scarcity. These responses would probably include the following changes:

i. Consumers would substitute less energy-intensive consumer goods for more energy-intensive consumer goods.

ii. Producers would substitute less energy-intensive inputs for more energy-intensive inputs in the production of a broad spectrum of commodities.

iii. Producers would substitute more energy-efficient processes for less energy-efficient processes in the production of energy services.

iv. Secondary price changes would occur for many fuels and other energy rich commodities.

All of these market responses to increased energy scarcity would improve consumer welfare. All of the responses would be incorporated in a competitive-market energy strategy. But the least-cost energy strategy, as defined by EPC, incorporates only response iii. This is because EPC treats the demand for energy services, the configuration of production technologies for non-energy commodities, and the prices of fuels as exogenous parameters that must be specified in advance of least-cost analysis. Thus, with respect to consumer welfare, there are several ways that competitive-energy strategies would dominate least-cost energy strategies.

However, there are some areas in which least-cost energy strategies can be expected to perform better than any real-world competitive energy strategy. This is because competitive markets don't always work very well. EPC is well aware of this fact. The LCES study states:

> We have concluded that implementation of a least-cost strategy would utilize much of the traditional free market system. This conclusion arises not out of the belief that "free enterprise" can provide solutions to all of our problems. Indeed, such immense problems as world poverty and hunger and the burden of an escalating arms race will not yield to simple free market economics.[13]

Nevertheless, EPC asserts that the "most useful policy would be one that encourages the maximum number of competing elements".[14]

> Our conclusion about the value of market forces in the operation of the least-cost strategy arise from the evidence of our analysis that, in regard to most of our energy problems, a freely competitive environment would work, primarily because of the numerous, diverse and actually or potentially competitive technologies that can be brought into play in the energy economy.[15]

Their argument seems to be this: From a technological point of view, the least-cost strategy is highly varied and diffused. Competitive market forces work well in a varied and diffused technological environment. Therefore policies to promote competition should be adopted.

We are sympathetic to the general thrust of the EPC argument. However, many caveats should be attached to any general statement about the economic efficiency of traditional free-market mechanisms. The economic literature is rich with discussions of various forms of "market failure" and the causal conditions. These conditions are categorized under headings such as externalities, economies of scale and imperfect information. While many of the present institutions and regulations may not be serving the interests of society, many of the reasons regulation and planning were instituted are still valid. In principle, least-cost analysis can take into account these issues as well as concerns about the quality of the environment, present and future national security and the effect of particular energy strategies on the OPEC cartel. Free-market institutions, left to their own devices, are not able to do so.

3.3 EPC Least-Cost vs. Maximum-Net-Benefits

In the previous section, we noted that as a response to increased energy scarcity (and higher energy prices) consumers will substitute less energy-intensive consumer goods for more energy-intensive consumer goods. Consumers behave this way because the less energy-intensive goods become less expensive. In this situation, reducing the direct and indirect consumption of energy-services increases consumer welfare.

However, EPC least-cost analysis does not treat the consumption of energy services as a variable. When only costs are evaluated, the level of output must be specified in advance. In the LCES study, EPC assumes that the consumer will maintain his level of direct and indirect energy-service consumption. This behavior is clearly suboptimal.

We propose a criterion for evaluating energy strategies that incorporates explicit consideration of both the benefits and the costs associated with different levels of energy-service consumption. The strategy that maximizes net-benefits, the excess of benefits over costs, would be selected. The maximum-net-benefits strategy would create a higher level of consumer welfare than would the least-cost strategy.

Proponents of least-cost analysis might argue that it is not their intention to select a level of energy-service consumption. Consumers can make the selection unaided. Rather, it is their intention to discover how energy services ought to be produced. For this purpose, the specification of any reasonable bundle of energy services is sufficient.

We believe this argument is incorrect. The selection of a level of energy-service consumption and the method of producing those energy services form one simultaneous problem that cannot be partitioned in any simple way. For example, consider a consumer who is shopping for an automobile. The consumer is free to choose the automobile's fuel efficiency, but he is also free to decide how big the car will be and how much he will drive it. The values that a rational consumer assigns to each of these variables are interrelated and all will depend on the price of gasoline. Normally, it would not be rational for a consumer to consider the amount of his driving and the size of his car as fixed and to consider the price of gasoline only when choosing the appropriate level of fuel efficiency. Yet the design of a least-cost study postulates exactly that: the quantity of energy services to be produced and the productive capacity of the equipment are both specified exogenously; only the efficiency of energy-service production can be varied as a function of energy prices.

The technological configuration of an EPC least-cost strategy can markedly deviate from that of a net-benefits-maximizing strategy. In order to obtain a quantitative measure of the nature and degree of this deviation, Manove employs several elementary analytical models of the production of energy services.[16] The general setting for all of his models is the same: An energy service (e.g., space-heating, cooling, industrial steam, or transportation) is to be produced by some sort of equipment (furnace, boiler, air conditioner, automobile) that uses some form of energy input or fuel. Each strategy of energy-service production is described by three variables: the level of energy-service output, the productive capacity of the equipment and the energy-efficiency of the equipment. These three variables imply values for two other important variables: the capacity utilization rate and total use of energy inputs or fuel. The models differ from one another in their designation of which variables will be fixed in advance, and which may be set by the consumer or policy-maker.

The selection of the least-cost energy strategy is represented in one of the models, and the selection of maximum-net-benefits strategies is represented in three other models. The strategy selected by the representation of the least-cost model is compared to the strategies selected as optimal by the three net-benefits-maximizing models. In this way, conclusions can be drawn about the type and degree of distortion inherent in the least-cost model output because of its restrictive assumptions.

The results are striking. When the elasticity of equipment cost with respect to the level of energy efficiency is assumed to be unitary and the elasticity of consumer demand for energy services is conservatively assumed to be -.5, Manove's representation of the EPC least-cost strategy calls for an energy efficiency increase of 40 percent in response to a doubling in fuel price. But the maximum-net-benefits strategy, with capacity held constant, calls for an energy efficiency increase of only 29 percent. If the elasticity of demand for energy services is assumed to be unitary, then the least-cost efficiency increase is 40 percent, but there is no efficiency increase with the maximum-net-benefits objective.

Similar results are obtained for the maximum-net-benefits strategy when both demand and capacity are allowed to vary. The least-cost strategy tends to be a good approximation of the maximum-net-benefits strategy only when the capacity-utilization rates of service-producing equipment are fixed. But while fixed capacity-utilization rates may be a realistic description of certain sectors of the economy, one can safely assume that capacity-utilization rates for the economy as a whole will change in response to substantial changes in energy prices.

We must conclude, therefore, that a least-cost energy strategy may strongly overstate desired increases in energy efficiency. This occurs for two different reasons. First, there are many situations in which the capacity of equipment must remain relatively fixed, despite changes in the price of fuel. If, in such cases, the demand for energy services is price sensitive, then increased fuel prices will cause capacity-utilization rates to fall. Lower utilization rates reduce potential gain from increased efficiency without reducing the cost of obtaining that efficiency. Therefore, a smaller efficiency increase is desirable.

Second, there are many circumstances in which the level of productive capacity and the quantity of energy services demanded varies independently. In such cases, consumers or producers will tend to substitute additional capacity (and flexibility) for the energy service itself. This also lowers utilization rates and optimal efficiency.

It is a general principle of economics that the existence of substitutes in production and consumption tends to reduce the impact of external economic shocks. The methodology of least-cost analysis allows increased efficiency in the production of energy services to substitute for energy-inputs or fuels, as energy prices rise. However, that methodology excludes the possibility of substituting increased flexibility in the production of energy services for some portion of those services. Least-cost methodology also excludes the possibility of substituting the consumption of non-energy services for the consumption of energy services. Because of these characteristics, least-cost methodology will tend to overstate both the importance of increases in energy efficiency and the overall impact of high energy prices on the economy as a whole. Thus, the general perspective created by least-cost analysis may be seriously biased.

Even when we overlook this distortion in the least-cost analysis, we are left with a very difficult question: To what level of energy services should the least cost criterion be applied? For their analysis, EPC chose the level of energy services actually produced and consumed in 1978. But this bundle may be part of a transitional phase of consumption behavior that is inconsistent with least-cost or competitive energy strategies.

For all of these reasons we believe that a least-cost cost criterion will result in strategies that are inferior to those selected with a maximum net benefits criterion. We propose that EPC modify its least-cost concept. The consumption of energy services should be allowed to vary, and benefits as well as costs should be evaluated.

Some readers may be thinking, "easier said than done." But we believe this proposal is realistic and practical. This matter will be explored further in Section 3.6.

3.4 Least Cost of Energy Service vs. Least Cost of All Commodities

The EPC least-cost concept is concerned only with the cost of producing energy services. The non-energy input costs in general industrial production are not evaluated. It is simply assumed that the energy-service component of production inputs will remain fixed. In fact, as mentioned in Section 3.2, in response to increased energy prices, producers will tend to substitute non-energy inputs for energy inputs. This type of substitution will reduce production costs and thereby increase consumer welfare.

As an example, consider the plight of a national brewery facing sharply increased fuel costs for its transportation fleet. The brewery will respond in two ways. First, the configuration of the trucks owned by the brewery may be altered by the purchase of more fuel-efficient vehicles. This type of change will be captured by EPC least-cost analysis, because costs of producing transportation services are evaluated and analyzed.

The brewery may make a second potentially important adjustment. The brewery may gradually decentralize production by building a large number of relatively small brewing facilities, each one close to an important consumer market. On one hand, this decentralization will raise the unit capital and labor costs of beer production, because economies of scale will be lost. But on the other hand, the decentralized brewery will require fewer transportation services because of the market's proximity. The cost of transporting beer inputs is relatively minor, because water, the main ingredient of beer, can be purchased locally. Total costs will be reduced because when energy prices are sufficiently high, the reduced transportation costs will more than compensate for the increased energy costs. As the price of energy services increases, the least-cost configuration of the brewery will be more and more decentralized. In other words, capital and labor will be increasingly substituted for transportation services.

The EPC least-cost strategy does not include this type of substitution; the use of energy-services as inputs must be determined in advance, without regard to the prices of those services -- an output of EPC least-cost analysis. This means that the EPC least-cost strategy, while minimizing the cost of energy services for a particular level of energy-service production, does not minimize the cost of all production.

We propose that the EPC least-cost concept be revised. The quantity of energy services used as inputs should be permitted to vary, and all production costs, not just the costs of producing energy services, should be evaluated. The generalized least-cost strategy that could then be obtained would minimize the total cost of all production. In the next section, we comment on this proposal's practicality.

3.5 Issues in Model Design

Suppose that one accepts for the moment the EPC objective of choosing and specifying a least-cost energy-service strategy. Many decisions must be made to formulate a least-cost policy model, and most involve answers to the following questions.

- Which resource expenditures are counted as costs? At what prices are expended resources evaluated?
- What variables are endogenous to the cost-minimization process?
- What constraints are used in conjunction with the least-cost objective function?

In Appendix D, these questions and their possible answers are discussed in some detail. Here we note that the answers define the concept of optimality by which energy strategies are judged. Optimality can be defined in many different ways. It is appropriate in this context to narrow the domain of optimality by restricting attention to that which is economically optimal in a competitive market environment. This excludes from consideration, therefore, all energy-demand paths associated with national energy policy which are politically expedient but economically inefficient, or optimal from a solely engineering or thermodynamic vantage but is economically too costly. But even within the more limited domain of economic optimality, one can choose from a range of possible objectives.

We have already discussed several of these in previous sections. Here is a partial list:

(i) maximizing the net benefits of a country's entire resources in a given year, perhaps 1978;

(ii) maximizing the net benefits of a country's entire resources over a period of time, such as 1965-1978;

(iii) maximizing the net benefits of only the nation's energy consumption and production, either at a single point in time or over time;

(iv) minimizing the nation's social costs of all production at a given point in time, say, 1978, subject to certain overall level constraints;

(v) minimizing the nation's social costs of production over a certain period of time, say 1965-78, subject to certain overall output paths during this period, and subject also to certain end-of-period constraints (e.g., the nation's capital stock in the terminal year 1978 must not all expire on December 31, 1978);

(vi) minimizing the nation's social cost, either at a single point in time or over time, of producing and consuming a given amount of energy services.

While the above list is less than exhaustive, it suggests clearly that the notion of economic optimality is consistent with varying advance, without regard to the prices of those services -- an output of EPC least-cost analysis. This means that the EPC least-cost strategy, while minimizing the cost of energy services for a particular level of energy-service production, does not minimize the cost of all production.

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(vi) minimizing the nation's social cost, either at a single point in time or over time, of producing and consuming a given amount of energy services.

While the above list is less than exhaustive, it suggests clearly that the notion of economic optimality is consistent with varying objectives, and the corresponding optimal strategies can be very different from one another.

Which of these various possible notions of economic optimality is used by EPC, and what does this choice imply? To briefly review, EPC chose the objective of cost minimization of only energy services at a given point in time (1978), and does not specify any constraints as to what type of capital stock and what quantity of energy resources must still remain on January 1, 1979. Hence the EPC notion of "economic optimality" is one that minimizes energy costs rather than maximizes net benefits, and optimizes at a given point in time rather than over time.

In addition to making choices regarding the particular definition of economic optimality to be adopted, and the mix of markets and regulatory constraints in which firms will function, decisions must also be made regarding the types of models to be used in the simulation experiments. One possibility is to construct general equilibrium models for various sectors of the U.S. economy, using either statistical- econometric, engineering, or judgmental methods. Regardless of which method is chosen, it is important to ensure that the integrated model faithfully reproduces the actual set of events occurring over the 1965-78 time period.

The EPC chose a very different approach. The LCES model is focused on the technologies for producing (and conserving) energy services. The primary function of the model is to select energy-service technologies in order to minimize the costs of providing a specified set of energy services at given prices. Energy-service technologies within the model are represented in disaggregate form. Engineering data incorporated in BECOM, ISTUM and TECOM is used to describe those technologies.

Thus, as we have noted, the LCES framework is well suited for detailed analysis of the production of energy services. Data, as well as analytical judgement is brought to bear on the problem. This is an advantage that we have already discussed. Just as the LCES model considers combined economic costs of energy services rather than a single goal (such as energy independence), the least-cost strategy is likely to be more appropriate than one-issue alternatives.

Nevertheless, we believe that the focus of the least-cost concept is inappropriately narrow. Highly detailed data is useless if results are substantially (and unpredictably) distorted by the focus of a model. Therefore, we would urge that the focus of LCES be broadened and that, if necessary, some of the high level of detail in LCES be sacrificed to that end.

Some readers may feel, of course, that the level of detail in LCES is one its crucial distinguishing features. We do not agree, believing that the real strength of the LCES concept lies in its concept of an economically based national energy strategy. We need to know only the general characteristics of that energy strategy. If EPC is correct, then traditional free-market institutions will "define the details." At any rate, once the general nature of the optimal strategy is determined, general parameters from that strategy can be iterated with the sectoral results from ISTUM, BECOM and TECOM; the detailed output from these models would then undoubtedly be more reliable than the output in the current LCES study.

It has been suggested that such a scheme is impractical and beyond the current state of the modeling art. Although this review does not compare the EPC model/study with others, it is important to note that technology choice models have been integrated with general equilibrium economic models, and employed in studies similar to EPC's. One of the most prominent examples is the Hoffman-Jorgenson effort to integrate the Brookhaven Energy Optimization System (BESOM) with the Hudson-Jorgenson Dynamic General Equilibrium Model (DGEM); this integrated model was then employed in a series of studies for DOE and its predecessor agencies, and in various Energy Modeling Forum studies. Another example is the Wharton Annual Energy Model developed at the University of Pennsylvania under EPRI sponsorship. This model integrates the Wharton Economic Model with technology models via the summary of the process models in the use of "pseudo data" techniques developed and employed for this purpose of Professor James Griffin. While it is beyond the scope of this review to compare those efforts with that of EPC, it should be noted that these integrated models, which incorporate many of the features we feel are relevant to EPC's question, were available to EPC when they began their study.

What are the variables and dimensions of a model relevant to the question posed by EPC? Following is a broad outline of the basic variables and dimensions of a model appropriate for a response to EPC's question. Formulating an optimal energy strategy is a grand idea, and we would give our model a very grand scope indeed. We would use aggregate variables, and would drop non-essential details. The following types of variables and parameters would appear in the model:

- o Output of energy services (in 5-10 categories): 10 variables.
- o Capital stocks for energy-service production (2-3 technology types for each category of energy service): 30 variables.

- Capacity utilization rates of the various stocks of energy-service capital represented: 30 variables.
- Energy efficiency of the represented capital stocks: 30 variables.
- Innovation (efficiency increases) in the energy area: 30 variables.
- Consumer demand (benefits) functions for energy services and non-energy commodities: 150 parameters.
- Consumer purchases of energy-services: 10 variables.
- Domestic supplies of energy inputs (described by 3-5 supply curves): 25 parameters.
- Derived demand for energy inputs (a function of the variables describing the energy-service industry): 5 variables.
- Prices of energy inputs, with some modelling of their determination: 5 variables.
- Non-energy industrial production, by major sector (perhaps 3-5 sectors would do): 5 variables.
- Final and intermediate demand for the output of these non-energy sectors (a very small input-output table might be helpful here): 10 variables, 25 parameters.
- The derived demands of the non-energy industrial sectors for various energy services: 50 variables.
- Several important macroeconomic variables: (GNP, C, I, G, r, etc.): 8 variables.

For each of these categories, our estimated maximum number of required variables is given. However, the model we propose would necessarily be a dynamic one, perhaps with five five-year periods. Therefore, the maximum number of variables given above would have to be multiplied by five. This comes to a grand total of about 1100 variables. (Of course, many of these variables would be identically zero.) This is by no means a small model, yet it is but a small fraction of the size of a detailed model like ISTUM. And its scope is very broad. As noted, many of the ingredients required to build such a model are already available in medium and large size macroeconomic forecasting models.

Aside from its broad scope, an important advantage of the sort of model we propose is that it provides an integrated framework for the construction of an optimal strategy. One disadvantage of LCES is that it is basically a collection of detailed models without an explicit organizing framework. As a result much is lost.

3.6 Conclusion

In conclusion, we would like to emphasize the following points.

The LCES study is subtitled: "Minimizing Consumer Costs Through Competition." But the study does not explore the effects of competition. All of EPC's analysis is devoted to the construction of a hypothetical optimal strategy and a comparison between the strategy and what actually occurred. EPC simply assumes that competiton would cause an optimal strategy to emerge. It should be kept in mind that many economists, planners and regulators would argue that an optimal strategy can be implemented only with planning and regulation.

Because of its general nature, the least-cost objective function can simultaneously take into account many different kinds of issues. Matters such as resource limitations, environmental factors and national security can be evaluated and traded off against one another within the framework of the least-cost method. This policy-making formula is far more appealing than one that takes into account only one significant issue (such as energy independence).

Least-cost methodology is limited for several reasons, such as its tendency to produce results that may substantially overstate the economic desirability of energy-efficiency improvements. EPC least-cost methodology can take into account only one (number iii.) of the following predictable market responses to higher energy prices:

i. Consumers may substitute less energy-intensive consumer goods for more energy-intensive consumer goods.

ii. Producers may substitute less energy-intensive inputs for more energy-intensive inputs in the production of a broad spectrum of commodities.

iii. Producers may substitute more energy-efficient processes for less energy-efficient processes in the production of energy services.

iv. Secondary price changes may occur for many fuels and other energy rich commodities.

Least-cost methodology does not treat the level of benefits as a subject of consumer choice. Costs are permitted to vary as a function of the energy-service technologies selected, but the output of goods, and thus consumer benefits, are exogenously fixed. In contrast, maximum-net-benefits methodology would simultaneously choose the appropriate bundle of outputs and the least-cost strategy for attaining that bundle.

However, the least-cost methodology does have the advantage of avoiding all of the problems attendant to benefits computation. This is an argument in its favor. But, in the context of selecting a national energy strategy we do not find this argument convincing. As the discussion in this chapter makes clear, the concept of cost has critical subjective elements, as does the concept of benefits. The analyst's decisions regarding expended resources evaluation can have a critical impact on the cost figures obtained.

LCES strategies are deficient because they recognize only the costs of energy-service inputs in the production of non-energy goods. They do not analyze the cost of other inputs to non-energy goods production, e.g. labor, capital, environmental conditions, non-energy materials, primary resources, etc. As a result, the LCES method cannot be used to analyze the substitution of less energy-intensive inputs for more energy-intensive inputs in general productive processes (number ii., above). This omission further biases LCES results towards excess efficiency.

In constructing the LCES model, EPC described technologies for the production of energy services in great detail. This detail is potentially useful insofar as it permits conclusions about the future role of specific technologies in the production of energy services. However, because of lack of attention to some of the broad issues discussed above, many of the detailed LCES results may be spurious artifacts of LCES methodology. Therefore, we believe it would have been more fruitful to use modelling resources in a fashion such as we proposed in Section 3.6.

The subjective elements in least-cost analysis impose a number of obligations on the analyst: his approach must be consistent, his decisions must be appropriate for the purpose of the analysis, but most importantly, the analyst's subjective input and assumptions must be meticulously documented. The lack of such documentation prevents other parties from interpreting the results of the analysis in a meaningful way and can cause those results to be confusing or misleading. On the whole, we found LCES documentation to be unsatisfactory.

4. REVIEW OF THE "LEAST-COST ENERGY STRATEGY" STUDY

We now turn to a detailed examination of the retrospective question posed by EPC in the LCES study. In section 4.1, we evaluated the EPC question and proposed several alternative questions. Now we set aside these alternative questions, and concentrate upon EPC's approach and the interpretation of their results; in particular we will be concerned with the extent to which EPC's results are likely to coincide with those of cost-minimizing decision-makers with perfect foresight.

The conceptual experiment proposed in the LCES study is, "How would the nation have provided energy services in 1978 if its capital stock had been reconfigured to be optimal for actual 1978 energy prices." This is a question about "what could have been." Such questions are interesting to curious people everywhere, and if we are to learn from history, they are important as well. In defining "what could have been," we can abstract from the influences of various constraints that complicate interpretation of past events. The resulting projection can then be compared with the actual data to identify opportunities for public and private sector policies, including new market initiatives for economically efficient supply of energy services.

Unfortunately, defining "what could have been" is not as simple as it may at first seem. This is because such a question is invariably associated with a hypothetical premise. The premise is usually set off by the word "if." For example, we might ask: "How would the nation have provided energy services in 1978 <u>if</u> our national leaders had promoted policies to stimulate free-market competition in the energy field?" Or, we might ask: "How would the nation have provided energy services in 1978 if each of our citizens were intelligent, perspicacious, frugal and public spirited?" In order to interpret the answer of a "what-could-have-been" question, it is important to understand the question's explicit and implicit premise. Therefore, we will examine the premise in EPC's question, and compare it to plausible alternatives.

4.1 Alternative Questions

Here is the EPC question with the explicit part of the premise underlined:

> EPC: How would the nation have provided energy services in 1978 if its capital stock had been reconfigured to be optimal for actual 1978 energy prices?

We now proceed to define a series of alternative questions that are obtained by modifying the premise of the original EPC question. In the remaining sections of this chapter, we will examine each of the alternative questions to see how its answer would differ from that of the EPC question:

In the first alternative question, we ask about economic behavior in an environment of free-market prices. We call this alternative the market-price (MP) question:

> MP: How would the nation have provided energy services in 1978 if its capital stock had been reconfigured to be optimal for imputed 1978 free-market domestic energy prices?

The market-price question differs from the EPC question by presupposing imputed domestic free-market prices rather than actual prices. This allows us to abstract from government price controls and other domestically caused price distortions. (Presumably, we wouldn't want to abstract from OPEC-caused price changes.) In addition, we believe that use of regulated prices is inconsistent with the spirit of a study purporting to demonstrate the advantages of increased competition.

Our second alternative question modifies the meaning of an optimally configured capital stock. We call it the dynamic optimization (DO) question:

DO: How would the nation have provided energy services in 1978 <u>if its capital stock had been reconfigured to be optimal for the trajectory of imputed domestic free-market energy prices from 1960 to the year 2000?</u>

The dynamic-optimization question refers to a trajectory of prices, while EPC refers to prices for the single year, 1978. This places our own hypothetical decision-maker in a more realistic situation than the EPC's hypothetical decision-maker. The EPC notion of an optimally configured capital stock seems predicated on a set of prices that never changes, present, past and future. When EPC asks a question about "what could have been" in terms of such a myopic hypothetical decision maker, the answer will have very little connection with real-world possibilities.

We will argue below that the dynamic-optimization question is more interesting and applicable to current problems than is the EPC question. However, we are not satisfied with the dynamic-optimization question. We believe that interest in the EPC study is largely stimulated by curiosity about the answer to a question with a broader premise than any of those given above: "What would have occurred if economic decision makers had correctly foreseen the energy-price increases of the 1970's and had used this information to minimize production costs?" We call this the perfect-foresight (PF) question. The perfect-foresight question can be stated formally as follows:

PF: How would the nation have provided energy services in 1978 if cost-minimizing economic decision makers with perfect foresight had been constrained only by the domestic energy endowment and by world-market prices of energy resources, and had made their decisions accordingly?

The premise of the perfect-foresight question includes a number of elements:

i. Cost-minimizing economic decision makers (in the 1960's and 70's).

ii. Perfect foresight.

iii. A wide range of domestic economic variables subject to adjustment. These include:

   a. configuration of the entire domestic capital stock
   b. domestic energy prices.
   c. domestic economic policies.
   d. direct and indirect demand for energy services by end-use consumers.

iv. Only the domestic endowment of energy resources and world prices of foreign resources are absolute constraints on the economic decision makers.

In Sections 4.4 and 4.5, we will suggest how the answers to the EPC question and the perfect-foresight question might be expected to differ.

4.2 Price Concepts in the LCES Study

Chapter 3 and Appendix D make clear that the results of a least-cost calculation depend critically upon the concept of price employed. EPC asks us to consider a world with an optimally configured energy-using capital stock. But their notion of optimality is based on actual energy prices. These prices do not reflect economic scarcity or other constraints beyond our control. We find it rather incongruous to speculate about optimality in the capital stock without allowing prices to adjust appropriately. Furthermore, EPC insistence on the use of actual 1978 prices in their hypothetical world seems to violate the spirit of the subtitle of their study: "Minimizing Consumer Costs Through Competition." In a study which emphasizes the role of competitive forces, we would expect that actual or estimated competitive market prices would be employed.

We believe that the market-price question is both more interesting and more relevant to the goals of the EPC study than the EPC question is. Actual prices of natural gas, petroleum, and electricity reflect the results of institutional factors such as taxes and regulation. As a result, actual prices are a poor measure of true economic scarcity. In our opinion, it is important to know what configuration of capital and energy input would be associated with a more competitive market for energy services. Serious questions regarding the treatment of natural monopolies, the transmission of electricity, environmental costs, and taxes would all need to be specifically considered.

How would the substitution of "imputed market prices" for "actual prices" in the EPC question affect EPC's results? The single price that most shapes EPC results is probably the price of natural gas. The regulated price of natural gas appears to contribute dramatically to the increased use of natural gas in EPC's least-cost scenario, a full .8 Quads above the actual 1978 level of consumption. In addition, the use of this price resulted in an increase in the market share for natural gas. In the least-cost scenario, 35% of all BTU's derived from fuel comes from natural gas, compared to 25% in the actual 1978 situation. We believe that natural gas would play a much less important role if the optimal configuration of capital were determined in a competitive domestic energy-price environment.

In fact, the 1978 actual natural gas price is likely to be highly atypical of future gas prices, for in that year the United States committed itself to a specific phased decontrol plan for natural gas. Thus, capital investments based upon natural gas prices remaining at 1978 relative levels will certainly not be least-cost investments for years beyond 1978.

A more subtle point concerns the treatment of taxes in the LCES study. The Technical Appendix of the study makes clear that

> For purposes of calculating the Least-Cost energy strategy, a more basic approach was appropriate. The costing conventions used represent a normative approach based on a pure capital charge independent of assumptions concerning government policies, such as mandatory of certain fuels or taxes. Capital charges per unit time are thus calculated as the present value of a dollar's investment given the real long term discount rate and the service life of the investment. The real long term discount rate used in all technology investment evaluations is i = .05, with the notation that this estimate '...is consistent with the recommendations which will be summarized in the forthcoming extensive treatment of this subject edited by Professor R. C. Lind of Cornell University.' (Technical Appendix, p. 3).

Setting aside for the moment the issue of the appropriate long-term real discount rate, and the question whether the same rate is appropriate for all sectors in the economy, consider the EPC view that private economic cost is the appropriate concept in least-cost calculations. Two questions must be raised. First, if private cost is the appropriate concept, why are regulated prices used for energy inputs, represented by 1978 actual prices? This seems an inconsistent treatment, and at minimum requires discussion and justification.

Second, if taxes are to be excluded, shouldn't they be excluded from all input costs? Apparently exclusion of taxes is restricted only to depreciation allowances and investment tax credits for capital goods represented by the competing technologies in the models employed in the EPC study. We find no evidence that taxes have been excluded from the price of assets -- for example, corporate profits taxes passed through to purchasers, etc. -- or excluded from the cost of energy forms combined with this capital. Clearly, if taxes are to be excluded from capital goods comparisons, then consistency requires their exclusion from energy costs, even if a case could be made for using regulated energy prices.

Another point relating to prices used in the LCES study concerns the distribution of the actual 1978 average prices to the regions required by the models underlying the study. One question is: how were national average prices distributed to regions, and does the distribution method have any significant effect upon the results? More fundamentally, if energy prices consistent with full anticipation of the events of the 1970s were used, the adjustment process would almost certainly have resulted in regional shifts in demographics and economic activity, towards both less energy-using regions of the country and less energy-using activities. Thus, the relationship between the regional pattern of energy prices and the national average would be very different in a fully anticipated calculation compared to one which considered the Least-Cost of producing a given level of energy demand.

We could analyze the implications of some of these questions with more detailed investigation of the LCES study, especially by examining the models and data bases underlying the study. However, our main concern is to point out that there are fundamental inconsistencies in the LCES study's treatment of different prices and costs, which at minimum require much more motivation and rationalization than is provided in their Technical Appendix.

Recognizing the difficulty of estimating market prices associated with a fully adjusted economy, our preference would have been for some "best estimates."

4.3 Configurations of the Capital Stock: Dynamic vs. Static Optimality

Because capital goods are relatively long-lived, the cost of operating a given unit of capital can change significantly over the lifetime of that unit. As a result, an optimizing decision maker will not base the purchase of a unit of capital on current energy prices. Instead, he will consider the trajectory of future energy prices. He will search for a compromise between the units that would be optimal for each energy-price level that can be foreseen over the lifetime of the unit purchased. For example, a businessman may decide that a truck with a high-powered engine is optimal when fuel prices are low, while a truck with a low-powered engine is optimal when fuel prices are high. If this businessman decides that fuel prices will be low early in the lifetime of the truck and high later in the lifetime of the truck, he would probably choose a medium-powered engine as a compromise.

Furthermore, optimal purchase decisions at a given time depend not only on currently available technologies, but on technologies that are expected to become available in the future. Our businessman may put off his purchase of a new truck if he expects a truck with substantially increased fuel efficiency to become available the following year.

In a dynamic setting (one with market characteristics changing over time), the optimal configuration of the capital stock at a given time cannot be determined by reference to current energy prices and current technologies alone. Past and future energy prices and technologies are relevant as well. In particular, the optimal composition of capital stock in 1978 depends on prevailing prices and available technologies before, during and after 1978.

To see why this is true, consider the 1978 capital stock. The stock will consist of (i) new capital goods put in place in that year; (ii) capital goods from previous years whose characteristics have been modified via additional retrofit investments in the current year; (iii) unmodified capital goods from previous years. The characteristics of the new and newly modified capital goods will depend on expected future prices, on current and expected future technologies and on the characterisitics of the stock of old capital goods. The characteristics of the old capital goods, must also depend on prevailing energy prices and available technologies during their lifetimes.

To talk about "what could have been" in connection with 1978 energy prices and technologies alone, is to talk about what could have been in some imaginary land where price and technology never change. The EPC question compares what actually happened in 1978 with what could have happened in such an imaginary land. For this reason, we believe that the answer to the dynamic optimization queston is more important than is the answer to the EPC question.

4.4 Perfect Foresight and EPC Concept of Capital Reconfiguration

Let us consider the perfect-foresight question. Compared with its premise (see section 4.1), the premise of the EPC question allows only a very narrow scope for adjustment. Adjustments to the configuration of the capital stock are the only adjustments permitted. Energy-service demand and energy-input prices are held constant by the EPC premise. Furthermore, although it is not explicitly stated in the study, EPC concentrates on only one type of adjustment to the capital stock: changes in shares of the various end-use technologies and fuels in the production of energy services. Shares of non-end use technologies including those used to produce, convert and transport energy for end-use purposes are not permitted to adjust.

If we categorize the EPC question in terms of perfect foresight, we are led to the conclusion that EPC gives the gift of perfect foresight to some categories of decision makers while denying it to others. Perfect foresight is a powerful fantasy, and once unleashed may introduce more complications than it eliminates. In the case of the LCES study, the most serious complications arise because of restrictions on which groups in the economy and society adjust with perfect foresight, and which continue to make decisions based on a lack of knowledge and uncertainty about both future events and the adjustments of those who are gifted with perfect foresight. The premise of selective perfect foresight can significantly bias results, because the extent of action appropriate for those who have it tends to be exaggerated. For example, those who know that the price of oil is about to increase will have a greater scope for action, while the larger segment is ignorant.

Two groups that lack perfect foresight in the LCES study are the public sector and the private energy production, conversion, transport and distribution industries. How, we ask, would perfect foresight in these sectors affect the planning data and decisions of those purchasing end-use energy services?

First, let us consider public sector response to perfect knowledge of energy-related events in the 1960's and 70's. Certainly we would expect that public policies would have been implemented to mitigate the economic and political consequences of the now fully anticipated OPEC embargo and related events. Thus, the major energy policy problem of the 60's would have been the same as that for the period beginning in October, 1973; namely, how to reduce the economic and social costs of an OPEC "tax" on U.S. oil consumption.

Given the policy conflicts and problems of the post-embargo period in dealing with this tax, it is somewhat fanciful to project with any specificity just what policies might have been implemented. Perfect foresight does not rule out possibilities for political conflict, bungling, and confusion. For example, it took until 1978 to establish that deregulation of energy prices was an important instrument of national policy in order to reduce the OPEC tax first imposed in October, 1973. Thus, what particular policies might have evolved, given perfect foresight, is uncertain. For our present purposes, and with hindsight, the main line of public policy response to perfect foresight of the energy-related circumstances of the 1960's and 70's would probably have been some deregulation of energy prices, perhaps with taxes on the economic rents accruing to domestic producers, purchase of a strategic petroleum reserve of reasonable size, increased public expenditures on research, development, and demonstration (R,D&D) where competitive markets did not produce the known desired result.

A stylized account of the consequences of such a policy would include at least two kinds of results. First, the economy would have optimally adjusted to the "shock" of 1973-74 since it would now have been fully anticipated. The most important consequence of this adjustment would be elimination of the costs of uncertainty, lack of knowledge, and economic disruption associated with the energy conditions of the 1970's. Thus, to the extent that the lower productivity and growth of the economy in the 70's is traceable to energy conditions, these losses would be recovered. In general, given the opportunity to adjust appropriately to our national energy fate, we would expect greater growth and prosperity.

It follows that one consequence of public policy adjustment would be a higher rate of economic growth, with a concomitant increase in the demand for energy services, and a reconfigured capital stock composed of appropriate shares of new, retrofitted, and old capital.

A second result of public sector policies aimed at mitigating the economic and social consequences of adverse energy conditions would be a gradual increase in energy prices prior to the precipitous event of the OPEC embargo, either influenced or not by domestic energy taxes. Of course, perfect foresight in the private sector would also cause such price increases. If it had been known in the early 1960's that oil prices would definitely increase in 1973, there would have been hoarding of oil by potential suppliers in years prior to 1973. This hoarding would have taken the form of reduced levels of production by producers, conservation of supplies by those involved in refining and distribution, and stock building by consumers and speculators. This would have reduced the supply available on the market and, as a consequence, oil prices would have begun increasing well before the 1973 OPEC tax came into effect. Since deregulation of natural gas would likely have occurred as well, its price would have been rising in a sympathetic relation with its close substitute, oil, over this period.

A second consequence, then, of likely public policies, given perfect foresight, would have been that consumers would face gradually increasingly higher energy prices in the 1960's and early 70's so that the OPEC tax on world oil consumption announced in October, 1973, would have been fully anticipated in the price of U.S. energy products.

Let us continue, now, with the effects on the private sector of the assumption of perfect foresight. The LCES study concentrates upon adjustments by private consumers of energy services in choosing between end-use technologies and energy forms. We now ask how the energy industries would have reconfigured their own capital stock, if industry decision makers had perfect foresight. Would an appropriately reconfigured energy industry have changed the planning data used by consumers of energy services in consumption decisions? How would perfect knowledge of the competition that the energy industry faced from the "efficiency" industry have influenced energy industry decisions?

Consider the effects of perfect foresight on energy production, transportation, conversion, and distribution activities. There are two important types of adjustment here, including changes in levels and patterns of investment on infrastructure for providing energy forms, in addition to changes due to perfectly anticipated competition from improvements in capital efficiency. In the first instance, the deregulation of oil and gas prices would have stimulated investments in exploration and development to a greater or lesser extent depending on government policies with respect to allowable returns for this activity. Deregulation of natural gas prices, and their rise in sympathy with oil prices, would lead to increased use of this resource when excess demand due to regulation eroded. This would mean new investments in transmission-delivery systems and in hook-ups -- investments which should be counted in a least-cost calculation of a fully anticipated adjustment.

Second, we would expect pronounced effects on the level and pattern of investments in the energy conversion industry, in particular, the electric utility industry. Certainly the level of investments in the 60's and early 70's would generally have been reduced by the anticipation of higher energy prices and reduced demands. Also, the pattern of investments would have adjusted to reduce expansion in oil and gas capacity, substituting coal and nuclear. It is likely that this development would have accelerated the consideration of environmental concerns about expanded coal use. Thus another problem of the 70's would have been transferred back in time to the 60's. The net effect of these adjustments would probably have been reflected by somewhat higher electricity prices in the 1960's and early 70's and markedly lower prices in the post-embargo period.

Another aspect of adjustment with perfect foresight would be the response of intermediate energy-form suppliers to competition from energy efficient capital. In the LCES study, the implications of these adjustments for the energy prices used in least-cost calculations are ignored. A prominent example is the role of cogenerated electricity in the industry and buildings sectors. If the economics of the competition between self-cogenerated and purchased electricity were, in reality, the ones portrayed in the LCES study results, then a fully anticipating electric utility industry would have had a much different pattern of capacity investment. In particular, fully anticipating electric utilities would have adjusted their capacities to reflect loads net of cogenerated electricity either internally consumed or distributed via the utilities grid. The exact adjustments would depend upon which segments of the utilities' load curve cogeneration effectively supplies. The details of such competition would depend upon the nature of the industries cogenerating and the load characteristics for each utility.

Whatever the outcome of this competition, a perfectly anticipating utility would have adjusted its capacity level and mix so as to acquiesce gracefully when cogenerated electricity was economically superior. Almost certainly, especially considering the results of the EPC study, this behavior would have resulted in a much lower electricity price in 1978, even setting aside the consequences for electricity price of all the other adjustments in a fully anticipating economy.

When we consider the implications of perfect foresight in the public and private sectors, other than just the end-use sectors, many more opportunities for minimizing costs are available than have been considered in the LCES study. Most important are the macroeconomic costs of the OPEC tax and the costs associated with inefficient capital stock in the energy supply industries. The LCES study, by focusing on such a narrow range of adjustments, omits many of the actions that "could have" been taken. Our brief review suggests that these actions may be quite significant.

There is an important argument that should be made here in support of the narrow focus of the LCES study. The types of adjustments admitted by LCES can be easily and precisely quantified, while many of the adjustments we have discussed here in connection with perfect foresight are qualitive in nature and have uncertain quantitative implications. By restricting itself to adjustments in the configuration of the capital stock, the LCES study avoids a nasty morass of guesses and value judgments.

We do not dispute this argument. But in spite of it, we believe that a broader focus in the LCES study is warranted. This is our reason: by omitting government policy and other variables from consideration, the LCES study may significantly alter the outcome of adjustments it does allow. The use of natural gas and cogenerated electricity is a prominent example.

4.5 The Demand for Energy Service

As noted, the premise of the EPC question explicitly requires the level of energy services consumed to equal the actual 1978 level. Given this level of services, consumers choose that combination of technologies and energy forms which minimize their service costs. This is equivalent to saying, for example, that there is no elasticity of substitution in manufacturing between the capital and energy aggregate versus labor and other inputs; or that the demand for vehicle-miles traveled is completely insensitive to price; or that demand for space conditioning (heating and cooling) in residences is completely independent of the delivered service price.

Clearly, we expect some price elasticity in energy service demand. It would have been entirely consistent with the EPC strategy of "employing existing methods of analysis and data" to have considered use of such elasticities as a means of obtaining a first order approximation to the adjustment from 1978 actual service demands that the change in service price implied by Least-Cost calculations would indicate.

That such an adjustment might be significant can easily be illustrated. The "first iteration" of the LCES procedure provides estimates of the reduction in energy service costs associated with the implementation of the LCES (Table 4-1, Column 1). As seen there, industry, building and transportion costs of delivered energy services are reduced by 10, 23, and 17% respectively.

Table 4-1

Percentage Increase in Energy Service Demand for Alternative Service Price Elasticities Conditional on LCES Estimated Cost Reductions

	LCES Service Cost Reductions	Alternative Energy Service Elasticities			
		.25	.50	.75	1.0
Industry	10%	2.7	5.4	8.2	11.1
Buildings	23	6.8	14.0	21.7	29.9
Transporation	17	4.8	9.8	15.0	20.5

Assume the range of own price elasticities for energy service demand of .25 to 1.0. Then the percentage increase of energy service demand associated with the estimated price reduction corresponding to each elasticity is given in the body of Table 4-1. The most dramatic effect is in the building sector, where an increase of as much as 30% in energy service demand might occur at the high range of elasticities.

Such information could be employed in a second (and subsequent) iteration(s) in which the revised energy-service demands were analyzed in each of the three sectoral models, revised service price adjustments were calculated, and the process iterated until it converged. Provided that such an iterative process converged (and this would depend in part on parameter values within the model), we do know that at the final iteration; both energy demand and energy-service demand would be at least as large as that at the first iteration. Therefore, eliminating disequilibrium effects associated with the assumption of constant energy service demand would result in higher energy-service demand, and lower energy-service costs, with equilibrium energy-service price somewhere between the LCES estimate and the 1978 actual price.

Another consequence of the partial equilibrium nature of LCES results is the implicit elimination of supply constraints. This problem is pervasive in the study, but is most dramatically illustrated by natural gas. Since the regulated price is lower than estimates of market price, excess demand exists in natural gas markets. However, EPC implicitly assumes that natural gas is supplied with infinite elasticity at the regulated price. This naturally results in increased use of natural gas up to that point on the gas demand curve associated with the regulated price. The increase in gas consumption in the LCES study over and above the actual 1978 consumption (constrained by supply) is .8 quads. Unless we find some method for producing more domestic gas and deliver it at that price, the only source for this additional supply is international purchases. But clearly such purchases are not available at the 1978 regulated price.

If the decision to utilize a regulated price is justified, then a necessary implication is that excess demand must be allocated to other fuels. In the LCES study this might be accomplished by imposing a restriction on the use of natural gas equal to the 1978 actual use. This is equivalent to continuing the supply restriction which has constrained natural gas use in the past.

The consequence of not imposing this restriction is clear when the LCES results are examined. Underpriced, unconstrained natural gas now takes over an increasing share of energy service markets. The LCES study dramatically highlights this increased share of gas. This is a consequence, in part, of their use of a regulated gas price, unconstrained by any supply restriction.

A similar disequilibrium problem exists with the electric utility sector. One of the most prominent, and highly publicized, study results is the considerable role for cogeneration found in both the industrial and building sectors. As shown in Appendix C, and summarized in section 5.2, the amount of cogeneration projected in the LCES study is much larger than by any other study with which we are familiar, even studies which employ the same models. If supportable, the EPC finding is an extremely important and significant result. If EPC is correct, what factors have other studies ignored?

One consequence of the very large contribution of cogenerated electricity is that the demand for purchased electricity is considerably reduced. As previously noted, LCES fails to consider the details of the effects of the electric utility industry's adjustment to successful competition from cogeneration. Therefore, an important area for additional work by the EPC is the reconciliation of their cogeneration results with those of other studies, and the provision of a more detailed and credible interpretation of equilibrium between purchased and cogenerated electricity.

One of the important differences between the premises of the EPC question and the perfect-foresight question is that the latter permits adjustment in the demand for energy services. In this section, we have considered the possible effects of allow such adjustment and have tried to show that these effects would be significant.

5. OVERVIEW OF MODELS EMPLOYED IN THE LCES STUDY

We now turn to a very selective review of the models employed in the LCES study. In Appendix A we present information obtained from each of the three modeling groups (EEA, BNL, JFA) using the EPRI/MIT Model Description Questionnaire. The questionnaire asks for information in 5 broad areas including;

General Information,
Administration data,
Model Characteristics, Description, and Documentation,
Model Development and Applications, and
Model Assessment.

Also included in Appendix A are the EPRI/MIT Energy Model Notebook entries for each model, as well as some additional descriptive information compiled from the model documentation, the LCES Study Technical Appendix, and conversations with the modelers and the EPC staff.

A more systematic description of each of the models as employed in the LCES study is provided in Appendix B, together with an overview of some issues concerning the use of these models in the context of the EPC study objectives.

In addition to the issues raised in Appendix B, we address four points which suggest questions and directions for more detailed analysis and review. These include,

some anomalous results from the Energy Modeling Forum "Aggregate Demand Elasticity Study" (EMF.4) for the ISTUM and BECOM models;

some as yet unreconciled differences between the LCES study results from the BECOM model, and a related base case analysis conducted by the Brookhaven National Laboratory;

unreconciled differences in estimates of industrial cogeneration potential between the LCES study and previous applications of the ISTUM model;

a problem of accounting consistency in the ISTUM treatment of capital stock component in the measure of industrial output used by ISTUM (value added) versus the capital stock obtained as the Least-Cost optimal estimate.

5.1 Review of Comparative Model Evaluation Results in EMF.4 for ISTUM and BECOM

In this section we review some recent results in which the aggregate demand elasticities implied by the ISTUM and BECOM models are calculated and compared with other industrial and residential/commercial energy sector models. These comparisons, while not specific evaluations of ISTUM and BECOM, do provide some disquieting information regarding model performance, and suggest that a more indepth investigation of these models is warranted.

ISTUM: While it would clearly be desirable to perform a detailed and systematic analysis of the ISTUM model -- a modified version of which was employed by the Least Cost Strategy study -- both the limits of available documentation and time permit us only to conduct a somewhat brief "first round" comparison of ISTUM with other models of the industrial sector. Such a comparison is possible because of recent work published by the Energy Modeling Forum.[17]

A principal focus of the EMF4 (Energy Modeling Forum) Working Group at Stanford University was the measurement and comparison, across sixteen detailed models, of the aggregate price elasticity of demand for energy.

Although the industrial sector model used by Least Cost Strategy was not included among those examined by EMF4, the ISTUM model was evaluated and compared with others.

Within the industrial sector, EMF4 considered five models: Baughman-Joskow (BJ), the combined Brookhaven Energy System Optimization Model/Hudson-Jorgenson (BESOM/HJ), the U.S. Department of Energy Mid-Range Energy Forecasting System (MEFS), the Lawrence Livermore Laboratory Energy Policy Model (EPM), and the Energy and Environmental Analysis, Inc. Industrial Sector Technology Use Model (ISTUM). Statistical and econometric methods underlie the BN, BESOM/HJ and MEFS models, engineering analysis forms the basis of the ISTUM model, while EPM relies primarily on judgmental methods.

In terms of implicit aggregate price elasticity of demand for energy, EMF4 undertook extensive simulations of the various models using common assumptions on exogenous variables, and then measured price responsiveness both at the primary and secondary energy level. Because of additive mark-up policies, price elasticity estimates at the primary level are always smaller than at the secondary level. Once price simulations with respect to various fuels were undertaken, the various energy quantities were aggregated using four indexing procedures: Paasche, Laspeyres, BTU aggregation, and Tornquist. The Paasche and Laspeyres indexes have a long history in national income accounting, while the Tornquist has been shown to have very desirable theoretical properties and has been used increasingly over the last decade. Although BTU aggregation is very common in the energy analysis literature, EMF4 follow other analysts in arguing that BTU aggregation is undesirable, since implicitly it assumes that the various energy types are perfectly substitutable with one another. Moreover, there is considerable ambiguity in determining how to measure the BTU content of electricity. In their summary of results, EMF4 report aggregate elasticity estimates for energy, using in most cases the Paasche index.

At the secondary demand level, based on the Paasche index, the 25-year demand elasticity (a reasonably close approximation to the long run price elasticity) runs from a high estimate of 0.7 (EPM), mid-range values of 0.5 (BESOM/HJ) and 0.4 (BJ), to a low value of 0.2 (ISTUM and MEFS).[18] Hence within the various industrial sector models, ISTUM lies on the relatively low end of the scale for price elasticity estimates. A rather strange feature of the ISTUM model, however, is its sensitivity to the choice of index. While aggregate price elasticity estimates for the other models show only limited sensitivity (for example, the Paasche and BTU-weighted price elasticity estimates for BESOM/HJ across all sectors are .42 and .46, respectively), the price elasticity estimate for ISTUM drops from .24 to .01 when BTU rather than Paasche indexing is used.

More generally on the issue of instability, EMF4 note that elasticity estimate results were occasionally quite sensitive to the specific composition of the price changes. As noted by Sweeney, it is not necessarily the case that the demand function for energy in aggregate is single-valued; different combinations of fuel price changes, each corresponding to an equal change in the aggregate energy price, can have very different aggregate energy quantity impacts.[19] In such cases the demand function for energy is an ellipse rather than a single valued straight-line function. Sweeney notes, incidentally, that a sufficient condition for the aggregate energy demand function to be single-valued is that the various types of energy are weakly homothetically separable from all other inputs or commodities.

EMF4 report in their study that of the fourteen models evaluated (five of which were in the industrial sector), elasticity estimates from the ISTUM model were extremely unstable and sensitive to compositional changes.[20] Moreover, when the ISTUM price elasticity estimates were averaged over all possible component price directions, the average elasticity had the wrong sign, implying that the demand function not only was a very wide ellipse (rather than a narrow ellipse converging to a straight line), but that it was upward, rather than downward, sloping.

Precisely how one interprets these peculiar results from ISTUM is not clear. However, several points should be made. First, among the industrial sector models, the point estimate of the secondary aggregate energy price elasticity is within the range of others, albeit at the low end. Griffin and Wood have noted that engineering models such as ISTUM have traditionally exhibited less price responsiveness than statistical or econometric models such as Hudson-Jorgenson and MEFS.[21] Hence that ISTUM produces a low estimate is not that surprising.

Second, since the ISTUM model generates elasticity estimates very sensitive to the particular indexing procedure employed (for example, BTU versus Paasche), it follows that a great deal of inter-fuel substitution must be implicit in the ISTUM model, far more than in other models. For only if the fuel composition is changing substantially will weighted aggregation methods produced such divergent results. This feature of ISTUM merits further examination. Incidentally, as shown in the paper by Alan Cox, included as Appendix C of this report, the Least Cost Strategy analysis of industrial cogeneration exhibits even greater sensitivity to interfuel prices than the already volatile ISTUM model.

Finally, while it clearly is not necessary that demand functions for aggregate energy be single-valued, the extreme width of the energy demand function ellipse with the ISTUM model and its "incorrect" upward slope suggests that ISTUM differs quite considerably from other industrial sector models, be they engineering, econometric, or judgmental. Why these differences occur merits additional attention.

BECOM: For the residential sector, EMF4 compared five models in terms of aggregate energy demand elasticities: the Hirst model (H), the OECD model of James Griffin (G), the U.S. Department of Energy Mid-range Energy Forecasting System (MEFS), the model by Robert Pindyck (PIND), and the Brookhaven Energy Conservation Optimization Model (BECOM). Several additional models were considered by EMF4 for the combined residential/commercial sector. It should be noted that the least cost strategy (LCS) adopted a slightly modified version of the BECOM model.

In terms of the implicit long-run (25 year) secondary aggregate energy demand elasticities, BECOM falls in the middle of the range of estimates: 1.0 (PIND), 0.9 (G), 0.6 (BECOM), 0.5 (MEFS) and 0.4 (H).[22] It is noteworthy, however, that the BECOM aggregate energy elasticity estimate is by far the most sensitive to the choice of indexing procedure used (e.g., Paasche, Laspeyres and BTU-weighted), among the residential models considered. For example, while the Hirst Paasche and BTU-weighted elasticity estimates were 0.44 and 0.47, respectively, and the Pindyck estimates were 0.70 and 0.66, the BECOM point estimate varied by a factor of two from 0.51 to 1.00 when BTU rather than Paasche indexes were used.[23] As noted earlier, such sensitivity to choice of aggregation procedure is disturbing, and may reflect extremely high inter-fuel substitution elasticities. This issue merits further examination.

Interestingly, BECOM also shares with ISTUM an extreme sensitivity of aggregate elasticity measure to the choice of component fuels. As noted in the EMF4 report, of the fourteen models examined by EMF4, the two most volatile in terms of average elasticity estimates are ISTUM and BECOM.[24] Coincidentally, variants of these two models are employed by Least Cost Strategy. Additional analysis should be undertaken to examine implications of the extreme elasticity volatility in BECOM and ISTUM reported results.

5.2 Comparison of LCES Buildings and Brookhaven Base Case for Northeast Residential and Commercial Buildings

The BECOM model documentation provides as illustration results from a base case analysis for residential and commercial buildings in the Northeast region, 1990.[25] The base period is 1975, and the analysis is conducted based on 1990 estimated prices, technologies, and service demands. Thus this illustrative base case differs from the LCES study case because full adjustment and retrofit has probably not taken place, meaning that the extent of capital stock turnover in the two cases is not comparable, different service demands are being considered (1978 versus 1990), and different energy prices are used (actual 1978 versus estimated 1990).

Nevertheless, by scaling the BNL 1990 base case to approximate 1978 building units in place, and by considering the pattern of techology units and energy demands, it is possible to measure approximately just how important the other differences might be.[26] We would not expect the two sets of results to be exactly comparable, but some consistency in patterns between the two studies might reasonably be expected.

The results of this comparison are summarized in Tables 5-1,2 for the residential buildings, and Tables 5-3,4 for commercial buildings. Perhaps most striking is the fact that while the residential building results differ significantly, the commercial building results seem similar.

Residential Buildings:

The major differences in the residential sector are a shift from oil furnaces and greater retrofitting in the Least-Cost case. The Least-Cost case has 5.5 million fewer oil burning furnaces. In thermal heat all the oil burners are scrapped and no new ones are introduced. Instead, the Least-Cost study shows an increase in gas furnaces and electric heat pumps. These changes result in the residential Least-Cost case using 1/3 less fuel than the base policy case.

The Least-Cost technological mix is quite different from the base case. Electric heat pumps make a large penetration into the retrofit market, amounting to 25T of the heating units. However, they make zero penetration into the new home market. Instead almost all the new homes are heated by gas burners. Why there would be more electric heat pumps than new gas furnaces used in retrofitting and none in new housing is perplexing, particularly given that the base policy case has electric heat pumps in the new structures.

We have not been able to reconcile differences between the two sets of residential results, but we believe two sets of factors are at work.

First, while the energy prices used in the BNL Base case are not documented, almost certainly, natural gas prices were higher, relative to other energy prices, than in the LCES case. Hence the "reconfiguration" to gas based technology seems likely to be due to this fact.

Second, the LCES study does not include as part of capital cost the economic depreciation associated with early retirement of old capital. Only incremental costs are evaluated.[27] As the tables indicate, the LCES study "turns over" a great deal of HVAC equipment.[28] If this equipment is retired prematurely, then the incremental capital cost method is incorrect because it doesn't account for the economic value lost in prematurely retiring capital. The most probable reasons for the difference in the number of oil burners between the Least-Cost and base policy case is that the Least-Cost study simply retired them faster than the base-case did, without correcting capital costs.

This leads us into the question of perfect foresight in fuel prices. If we know infinitely in advance what fuel prices would be, it would pose no problem to choose the correct technologies under a given decision criterion. If we reduce this period to 25 years, we still have a enough time to make fairly optimal decisions. However, if we reduce this period to 10-15 years as suggested by the Least-Cost study, it would be difficult to make some of the changes suggested by the Least-Cost study, for some capital lifetimes are longer than 10-15 years. Some of the procedures used in the Least-Cost study suggest that foresight longer than 10-15 years is needed.

However, even if we could have this long foresight, there is no reason to believe that minimizing a specific year's costs would be an optimal strategy. Why would anyone in 1963 act so that they would minimize their costs in 1978 rather than minimizing the costs over the life of the equipment, or maximizing net benefits obtained from their investment choice? Not only would 1978 fuel prices be considered, but also all the fuel prices in all the other years of the equipment life would be relevant.

This point is stressed here because of its relationship to the housing results. The high price of oil relative to other fuels is probably the driving force in the move away from oil burners. But in the sixties oil was not as highly priced. Thus if one was going to buy a heating unit in 1963, the fuel savings in 1978 of not having used oil may not have offset the savings of burning low-cost oil in the sixties and any other additional equipment costs. Thus, minimizing 1978 costs may not have been an optimal decision criterion since costs changed over the period before 1978 and continued to change after 1978.

The Least-Cost study also consistently invokes a higher retrofit and new equipment conservation level than does the base policy case. In the LCES case all old equipment is retrofitted, while in the base policy case about 1/3 is not retrofitted to any level. The majority of new technology is entered at the second level of conservation in the LCES study while in the base policy case most is entered at the first level.

<u>Commercial Building:</u>

The commercial sector results appear to be similar for the two cases. The notable exceptions are that in the Least-Cost case, there are no oil or electric thermal units and very few electric space heaters. One fact that should be noted is that there are no oil or electric thermal units in the entire building sector of the Least-Cost study. Almost all thermal demand is met by gas units with the small remainder going to solar. As well, all the thermal units are new. This means that the entire stock has been turned over, which does not seem unreasonable. But to replace it entirely with gas and a few solar units is more unlikely.

Electric thermal units that are used in the base policy case appear to be replaced by gas units in the Least-Cost case. Again, retirement procedures are likely to account for differences.

One interesting note in thermal and space heating of new commercial structures is that solar collectors supply the majority of the demand in the Least-Cost case. This holds true not only at the national level, but also for the Northeast, which one would expect to be less favorable to solar technologies. Solar is easily the dominant technology for supplying space and thermal heating of new commercial buildings.

Table 5-1

Northeast Residential (E6 Physical Units)

	Space Heat	AC	Thermal	Appliance
Gas L-C	9.8381	.0211	17.5000	
BPC	7.1868	.6646	8.8048	
Oil L-C	2.7510			
BPC	8.3328		5.1585	
Elect L-C	4.9110	6.6769		17.9000
BPC	1.9149	5.9976	3.1593	17.2513
Solar L-C	.1917		.3078	
BPC	.2573	.2573	.2573	

Table 5-2

Northeast Residential Total Fuel Use (E15 Btu's)

	Space Heat	AC	Thermal	Appliance
Gas L-C	.6413	.0001	.6506	
BPC	.5013			
	.8067	.0024	.3921	
Oil L-C	.2307			
BPC	.6850			
	1.3653		.2858	
Elect. L-C	.0597	.0117	.0009	.2963
BPC	.0589	.0138	.0837	.3442
Solar L-C	.0025		.0030	
BPC	.0019	.0003	.0013	

Table 5-3

Northeast Commercial (E6 Physical Units)

	Space Heat	AC	Thermal	Appliance
Gas L-C	3.0520		5.7510	
BPC	2.4244	.6500	2.2333	
Oil L-C	2.6500			
BPC	2.1308		2.9412	
Elect. L-C	.0490	2.9519		6.1430
BPC	1.1609	2.1861	.3020	5.6918
Solar L-C	.3920		.3920	
BPC	.4307	.2962	.4307	

Table 5-4

Northeast Commercial (E15 Btu)

	Space Heat	AC	Thermal	Appliance
Gas L-C	.2337		.0222	
BPC	.1422	.0149	.0120	
Oil L-C	.2884			
BPC	.2316		.0193	
Elect. L-C	.0048	.0356	.0003	.3383
BPC	.0231	.0325	.0007	.3204
Solar L-C	.0040		.0011	
BPC	.0055		.0010	

5.3 The LCES and the Economics of Cogeneration.

Until now, we have accepted the EPC cogeneration results at face value. However, it is important to note that the EPC results are dramatically higher than those for other cogeneration studies. We have not conducted a comprehensive survey of such studies, but have summarized those with which we are familiar in Table 5-5. As is apparent, the production of cogenerated electricity is dramatically higher for the EPC study than for other studies included in the table.

Most importantly, the EPC study results for the industrial sector differ significantly from those based on another application of ISTUM, the same model employed by EPC. In Table 5-5 we compare the results between the two studies, as well as the assumptions concerning technology costs and fuel prices. ISTUM results for the year 2000 (with a much higher steam service demand than actual 1978) are substantially lower than the EPC results; the pattern of supply between the competing cogeneration technologies is also much different. Most dramatically, natural gas fired turbines are the sole source of supply for industrial cogeneration in the EPC study, whereas in the ISTUM study their role is much reduced.

The main differences between the two studies appear to be that EPC uses a much lower price of natural gas, and uses much higher investment costs for coal-fired boilers and steam generating equipment. In addition, the EPC study uses an annual capital recovery factor that is one half that of the ISTUM report.

With their set of assumptions, the EPC report's technology costs show that gas turbines are a cheaper way to produce steam than coal boilers; and that coal-fired topping cycles are more expensive than

Table 5-5

Estimates of Cogeneration Penetration

Total U.S. cogenerated electricity as a percentage of total electricity production, 1975 (Pickel, 1978)	4%
Massachusetts estimate of profitable cogeneration in state as a percentage of 1977 electricity consumption. Base Case. (Massachusetts, 1978)	19%
Resource Planning Assoc.[1]	5.5-16.4%
Dow (1975)[1]	18.2%
Thermo-Electron (1976)[1]	7.7%
ISTUM[1]	5.9%
Least-Cost(a)[2]	59.6%
Least-Cost(b)[3]	37.7%

[1]As percentages of 1985 demand projected by DRI. Adapted from Joyce (1978) using 65 percent utilization rate.

[2]Industrial cogeneration as a percentage of 1978 industrial demand. Estimated from gas consumption figures. Tables III.3.3 of LCES technical appendix. Total gas use for electrolyte and machine drive demand = 2.95 Quads. At 60% efficiency this gives 1.75 Quads of electricity. Percentage cogeneration is then (1.75/(2.21 + 1.18) where 1.18 is industrial demand for purchased electricity.

[3]Total cogeneration as a percentage of total 1978 demand. Estimated as in (a) plus oil consumption for diesel cogeneration in buildings times 40% efficiency. Oil use in diesel cogeneration in buildings (from Table III.4.1) 2.29 Quads. At 40% efficiency, this gives .916 Quads of electricity. Total electric purchases in LCES study is 4.4 Quads. (1.75 + .916)/(1.75 + .916 + 4.4) = .377.

purchased electricity. We have corrected the EPC technology costs and find that coal is actually cheaper than gas turbines for providing steam and that the mean cost of coal topping is cheaper than purchased electricity.

These corrections notwithstanding, it is unlikely that the cost per Btu calculations are an accurate reflection of the costs of cogeneration. While the ISTUM methodology does utilize a distribution of costs, some factors are not included in the estimation of the distribution. Cogenerators face the problem of oscillating steam demand which will increase the capital costs of cogeneration. In addition some cogeneration options, particularly gas turbines, require the scrapping of a great deal of capital which has both economic and financial consequences.

The unreasonable cost assumptions, coupled with the inconsistent way in which cogeneration technologies are handled in ISTUM, results in gas turbines capturing a significant proportion of the steam market and, automatically, the electricity market. The inconsistency is that gas turbines receive a credit for their electricity production, reducing the cost of providing steam, while coal boilers receive no such credit. The incremental cost of adding cogeneration equipment to a coal boiler is then used to compare this form of cogeneration with purchased electricity in a competition for whatever is left of electricity demand after the gas turbine contribution has been removed.

While the levels of cogeneration predicted in the EPC study are very large, no attempt has been made to assess the impact of so massive a reduction in demand on the elctric utility industry. Increased production of electricity not under the control of a utility will alter the capital choices and operating costs of the utility. Significant reductions in electricity production costs will reduce the value of cogeneration, while increased capital requirements for cogeneration back-up will also be assessed against cogeneration. However, the effect of large amounts of cogeneration on the electric utility has not been studied and the disequilibrium consequences are simply unknown.

5.4 Accounting for Capital in ISTUM

There is a question regarding the procedure by which energy service demand is estimated in the ISTUM model. The ISTUM documentation makes clear that energy service demands are calculated proportional to a value added measure of output by industry sector. The proportion used is calibrated using data for 1974, and projections are based on the DRI industry model, although other projections of sector output (value added) could be used.

Value added measures payments to primary factors of production including capital, labor, and land. Thus a projection of value added implicitly (hopefully explicitly) includes a projection of payments to capital. But the ISTUM model itself purports to calculate optimal capital in minimizing cost of providing energy services. Nothing in the procedure ensures consistency between capital implicit in the projection of value added, and capital explicitly estimated by ISTUM.

We note that this inconsistency does not affect the LCES study results since actual 1978 service demands are employed. However, in future EPC studies which are prospective in scope, some attention should be given to the implications of this inconsistency.

FOOTNOTES

1. See Sant [1979], p. 27.

2. See Sant [1979], p. 38.

3. See Sant [1979], p. 27.

4. See Sant [1979], p. 4.

5. See Sant [1979], p. 27.

6. See the EPC Annual Report [1980] for discussion of the publicity.

7. See Sant [1979], p. 38.

8. See Sant [1979], p. 5.

9. See Carhart [1979], p. 1.

10. An EPRI Energy Model Notebook entry was prepared for each of these models by the respective modeling group. See Appendix A.

11. An overview of each of the three models is presented in Appendix B.

12. The notion that it is energy services, not energy products, that should be the focus of analysis has been suggested and pursued by, among others, the modeling group at Brookhaven National Laboratory, initially by Kenneth Hoffman, and more recently by the Technical Director of the EPC study, Steve Carhart.

13. See Sant [1979], p. 5.

14. See Sant [1979], p. 43.

15. See Sant [1979], p. 5.

16. See Appendix D. Note that this problem is not specific to the EPC study. See McFadden [1981].

17. See EMF4 Working Group, "Aggregate Elasticity of Energy Demand", The Energy Journal, Vol. 2, No. 2, April 1981, pp. 37-75. Hereafter, called EMF4.

18. EMF4, Table 6, p. 59.

19. J. L. Sweeney, "Price and Quantity Change Decomposition for Aggregated Commodities", EMF Working Paper 4.7, Draft 2, January 1980.

20. EMF4, Table 7, p. 62.

21. J. M. Griffin and D. O. Wood, "Explaining Intermodel Differences in the EMF Aggregate Energy Demand Elasticity Study," EMF Working Paper 4.11, Draft 1, August, 1980.

22. EMF4, Table 6, p. 59.

23. EMF4, Table 5, p. 57.

24. EMF4, Table 7, p. 62

25. In a telephone conversation, Steven Carhart gave his assurances that the results were based upon reasonable inputs and were meaningful, although not all the inputs were available for review.

26. Base policy case results were multiplied by .902 for residential and by .706 for commercial. This factor equalizes the number of space heating units in each case. Problems exist with some of the BECOM base policy case results. These numbers are taken from Carhart, Steven C.; Mulherkar, Shirish S.; and Sanborn, Yasuko. The Brookhaven Buildings Energy Conservation Optimization Model, BNL50828 Brookhaven National Laboratory, January 1978. Some of the fuel use values do not add to the totals given in the summary tables. The numbers listed in Table II correspond to the aggregated fuel totals listed by type of technology.

    It should be noted that tables III.3.2 and III.3.3, page 89 of the Least-Cost Energy Strategy Technical Appendix do not correspond because of off-line changes. These changes are referred to on page 102 of the Technical Appendix.

27. Capital costs are difficult to account for in the housing sector. While page 118 of the Technical Appendix lists $147.6 billion as the required capital investment, costs listed in tables III.6.1-.5 on pages 117-118 add to only $103.7 billion.

28. The tables are taken from pages 96 and 111 of the Least-Cost Energy Strategy Technical Appendix and from pages 35-37 and 47-49 of Carhart, Steven C.; Mulherkar, Shirish S.; and Sanborn, Yasuko; The Brookhaven Buildings Energy Conservation Model, BNL 50828, Brookhaven National Laboratory, January 1978. The upper number in a row refers to the Least-Cost case and the number beneath it to the comparable figure from the BECOM base-policy case. See also footnote 23.

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CHAPTER 6

RESPONSE OF THE ENERGY PRODUCTIVITY CENTER

Steven C. Carhart
William R. King

Energy Productivity Center
Mellon Institute
January, 1982

Chapter 6

Response of the Energy Productivity Center
Steven C. Carhart

Introduction

Participation in the modeling review process proved to be an extremely valuable experience for us. Any time another research group takes this degree of interest in our work, we consider it a high compliment indeed. In going into such a high degree of depth concerning our approach with the MIT group, we raised and fruitfully discussed many fundamental issues. Throughout the process our EPRI project manager, Richard Richels, provided steady, unobtrusive support which made possible a fruitful exchange of views. For our part, we gained many useful perspectives on alternative approaches to some of the issues we have pursued, as well as some ideas for future work.

In our discussions with the review team, we endeavored to impart our broader perspective on the study. We have reviewed their final report and find it does not fully reflect the perspective we feel should be taken for productive use of our results. Our difference in perspective primarily concerns the contribution which the least-cost approach has made and can make to understanding energy markets.

The Least-Cost Perspective

The modeling system developed at the Energy Productivity Center represents a fundamentally different conceptual approach to energy issues than has traditionally been taken in most other studies: The purpose of this system is to assess the market shares and relative competitiveness of different means of supplying energy services - the heat, light, mobility, and other useful functions provided by energy. It is not the purpose of the system to forecast energy use or develop policies for reducing oil imports. It is important to emphasize this, because most energy modeling activity has been directed at the latter two objectives.

Many of the comments of the review team reflect a concern with energy use forecasts and oil import policies--and suggestions about how to "improve" the least-cost analysis that changes it into a forecast. We wish to emphasize at the outset that while these are worthwhile issues to address, they were not our purpose in this exercise. A major contribution of the least-cost exercise was to highlight the value of analyzing the energy system from a totally different perpective. We do not, therefore, consider these comments to be responsive to the study.

The second point of emphasis in our study is the need-given our purpose of assessing technologies - to work from a sufficiently rich engineering data base. To do this, we used the three engineering-economic models which represented the state of the art in this field when the study was done in 1979 - the Industrial Sector Technology Use Model (ISTUM), the Buildings Energy Conservation Optimization Model (BECOM) and the Transportation Energy Conservation Model (TEC). Use of these models allowed an in-depth assessment of which technologies made the most sense as means of reducing consumer costs.

Many of the review team comments criticized the choice of models, and suggested different models or model improvements they claim would be better suited to the task. Yet, given our technology focus, we feel our choice of models provided the best analytical approach available.

The review also states that our assessment of a 1978 optimal reconfiguration of the energy system was "motivated by the unanticipated increase in oil prices since 1973." On the contrary, our interest was motivated by a desire to understand energy markets and the relative competitiveness of different fuels and technologies, not by any special concern about oil prices or imports.

Detailed Commentary

This section responds point by point to the discussion in the MIT Executive Summary. The section is arranged so that the reader is first presented with a point made by

MIT in the Executive Summary. Each point is followed by our comments concerning the validity of the conclusions MIT draws in their analysis of the Least-Cost modeling results. The reader should note that the points presented by MIT represent a mixture of critique of our study and exposition regarding issues MIT believes are relevant. The concluding section discusses in detail the issue of cogeneration modeling, which was a major focus of in-depth review by the MIT team. Our comments focus on these points we feel are most controversial, and ignore statements on which we concur or statements of fact.

Executive Summary:

1. The Energy Productivity Center's retrospective, "Least-Cost Energy Strategy" (LCES) study is provocative regarding the potential role of efficiency technologies in competition with energy supply technologies. Their decision to conduct a "what if" analysis for a recent year provides an historical context for interpreting and reviewing the results.

   1.1 As a result of its predication on known prices and technologies, the question posed by EPC avoids analysis of the difficult problems of uncertainty, shocks, and other "surprises," and instead focuses on the issue of optimal adjustment to higher energy prices.

   1.2 The retrospective vantage of the LCES study helps us learn from history and has implications for optimal adjustment to future energy-price increases.

Response:

1. We appreciate MIT's comment regarding the value of retrospective studies; however, we believe the utility of the results lies more in the area of understanding market trends in the near future.

1.1 Our choice of prices and avoidance of "shock" issues reflects our feeling that analysis of long term equilibrium is a better guide to business and government planning, apart from the development of insurance policies for special contingencies (such as the Strategic Petroleum Reserve).

Executive Summary:

2. The LCES study is subtitled: "Minimizing Consumer Costs Through Competition." But the effects of competition are not explored in the body of the study. All of EPC's analysis is devoted to constructing a hypothetical optimal strategy and comparing that strategy to what actually occurred. EPC suggests, without substantiation, that competition would cause an optimal strategy to materialize. It should be kept in mind that many economists, planners and regulators would argue that an optimal strategy can be implemented only with planning and regulation.

Response:

2. We might distinguish here between technology competition and competition between different business organizations. The formal analysis demonstrates the results of technology competition by choosing the technologies which provide energy services at the lowest cost. The corollary is that enhanced market competition achieved through deregulation of prices, elimination of barriers to market entry, and enforcement of anti-trust statutes will produce more technology competition, and hence lower consumer prices. We consider this corollary to be intuitively obvious. Attempts in centrally planned economies to implement optimal schemes have generally failed to achieve lower consumer prices relative to economies with market competition. Empirical verification of this axiom most likely can be found in economic research comparing price levels with market concentration.

Executive Summary:

3. The methodology chosen by EPC to construct an optimal energy strategy is based on the least-cost energy-strategy (LCES) objective. This methodology has several advantages over other conventional policy objectives.

   3.1 Because of its general nature, the least-cost objective function can simultaneously take account of many different kinds of issues. Matters such as resource limitations, environmental factors and national security can all be evaluated and compared within the framework of the least-cost method. This way of formulating policy is far more appealing than a method that takes account of only one significant issue (such as energy independence).

   3.2 Because costs must be quantified before they can be minimized, the least-cost method invites the analyst to use hard data when it is available. Vague judgments are thus discouraged.

Response:

   3.1 It is generally true that a cost minimization function can facilitate simultaneous study of issues, although for clarity we should note that in the study we focused only on cost minimization without explicitly treating environmental or oil import concerns. The favorable results in these areas were an unintended result of the economic optimization.

   3.2 The importance of quantifying technology costs cannot be overemphasized.

Executive Summary:

4. Least-cost methodology is limited for several reasons, and it yields results which tend to overstate -- perhaps substantially -- the economic desirability of energy-efficiency improvements. Hence LCES implications for policy in this area may be misleading.

4.1 There are many potential market responses to new energy-price conditions:

i. Consumers may substitute less energy-intensive consumer goods for more energy-intensive consumer goods.

ii. Producers may substitute less energy-intensive inputs for more energy-intensive inputs in the production of a broad spectrum of commodities.

iii. Producers may substitute more energy-efficient processes for less energy-efficient processes in the production of energy services.

iv. Secondary price changes may occur for many fuels and other energy rich commodities.

The least-cost methodology as applied by EPC takes account of only one of these market responses, namely, iii. above.

4.2 Least-cost methodology does not treat the level of benefits as a subject of consumer choice. Costs are permitted to vary as a function of the energy-service technologies selected, but the output of goods, and thus consumer benefits, are exogenously fixed. That is why the least-cost method cannot allow consumers to substitute less energy-intensive consumer goods for more energy-intensive consumer goods (e.g. i., above).

4.3 In contrast, the methodology of maximizing net benefits simultaneously chooses the appropriate bundle of outputs and the least-cost strategy for attaining that bundle. Maximizing net benefits and minimizing costs are equivalent only under restrictive and unlikely conditions. This raises important questions about the use of least-cost strategies for public and private policy formation.

4.4 When net-benefits maximization replaces cost-minimization as the policy objective, the indicated optimal improvement in the energy efficiency of capital goods is reduced. The interaction between the demand for services, capacity utilization and the optimal energy-efficiency of capital is an essential consideration in adjusting to higher energy prices. Ignoring this interaction biases LCES results toward excess efficiency. Some preliminary analysis suggests this bias may be substantial.

4.5 LCES strategies are deficient in that they recognize only the costs of energy-service inputs in the production of non-energy goods. They do not analyze the cost of other inputs to non-energy goods production, e.g. labor, capital, environmental conditions, non-energy materials, and primary resources. As a result, the LCES method cannot be used to analyze the substitution of less energy-intensive inputs for more energy-intensive inputs in general productive processes (e.g. ii., above). This omission further biases LCES results towards excess efficiency.

Response:

4. Methodological limitations in the study nonetheless reflect the state of the art at the time. We do not agree that the methodology - taken with the caveats originally provided in the study - overstates the desirability of efficiency. Moreover, the principal policy conclusion we reach - that enhanced competition is the key to improving the operation of the energy system - would only be enhanced by extension of the methodology.

4.1 - 4.2 Certainly Least Cost work does concentrate on one facet of consumer substitution response. This choice was a conscious one since the other facets of substitution are far less relevant to our purpose in the study, i.e. to identify market directions for fuels and technologies As a point of general model development, we certainly agree that these issues should be treated. In defense of our modeling methodology, it should be pointed out that no other methodology exists which treats these issues at the level of detail we felt necessary in our study using empirical data.

4.3 Net benefit maximization is certainly desirable in theory but has not been implemented with empirical data at a disaggregated level. For our purpose - identifying directional trends in energy markets - we do not feel that there is any important difference between analyses applying a cost minimization criterion and analyses applying a net benefit maximization criterion. The comment indicating that least-cost strategies are not useful for public and private policy formation is highly misleading and out of context, especially since MIT does not define the policy questions for which this approach is considered inappropriate. The only major policy recommendation we reach is that more competition in energy markets will reduce consumer costs without compromising social objectives. A net benefits calculation would not affect this conclusion.

4.4 Use of a net-benefits maximization function, if such a function could be applied to empirical data, might reduce the magnitude of energy-efficiency achieved. However, this comment presupposes that we are calculating a "recommended" level of energy efficiency, which we were not doing. Our emphasis was on testing the consequences of increased market competition. The relevant lessons to be drawn from the analysis are concerned with market competition, not absolute efficiency levels, as we have repeatedly emphasized.

4.5 An analysis allowing for a broader scope of substitution, including substitution of energy-service production inputs with non-energy service production inputs is certainly desirable. It is, however, beyond the scope of any general energy use model presently available. Ironically, if the range of possible substitution were broadened, we could only imagine a broader range of substitutions for energy in the production process, which implies that the potential for increased efficiency is understated by this methodological limitation.

Executive Summary:

5. In constructing the LCES model, EPC described technologies for the production of energy services in great detail.

5.1 This detail is potentially useful in drawing conclusions about the future role of specific technologies in the production of energy services. EPC has advanced the state of the art of modelling energy-services production by integrating detailed information concerning a wide variety of energy services.

5.2 However, because of lack of attention to some of the broader issues discussed above, many of the detailed LCES results may be artifacts of methodology. Therefore, we believe it would have been more fruitful to distribute modelling resources more evenly among the issues listed under 4.1, to trade off detail for broader scope and a more appealing objective than least cost.

Response:

5. - 5.1 Detailed technology characterization was essential to our attempt to understand the economic competitiveness of these technologies. A primary goal of the modeling effort was to advance technology characterization to a level not attained in other modeling systems.

5.2 Certainly our analysis was not concerned with a broad scope of substitution; however, to suggest we should have used our limited resources to develop a broader substitution spectrum is to comment on the value of the question we addressed rather than on how well we performed the task we chose for ourselves. Our view was and is that identifying growth markets for fuels and technologies is by far more useful for practical business and government planning than calculating the most accurate fuel use forecast.

Executive Summary:

6. The EPC retrospective question can be stated succinctly: "How would the nation have provided energy services in 1978 if its capital stock had been reconfigured to be optimal for actual 1978 energy prices." We believe that the focus of this question is too restricted.

6.1 In fact, only a part of the capital stock is permitted to adjust. The least-cost strategy implicitly gives the gift of perfect foresight to end-use consumers of energy services but not to other decision makers, so that the least-cost strategy is a partial optimization.

6.2 Using actual energy prices rather than estimates of market prices greatly restricts the interpretation of the LCES study results as optimal. Further, the use of such prices, which include distortions due to regulation and market failures, is inconsistent with the spirit of a paper purporting to demonstrate the advantages of increased competition. We suggest that EPC should have used imputed free-market prices rather than "actual 1978 energy prices."

Response:

6. These points suggest further refinements of our methodology which are in fact reflective of directions we have taken since the 1979 study.

6.1 This is true of the best methodology we could apply in 1979. We do not consider these results directionally misleading concerning market trends from 1978, however, because the marginal costs of new energy sources were higher than the actual prices used. Thus, we understated the attractiveness of marginal productivity investment versus energy supply investment.

6.2 Since our purpose was to identify growth markets and assess the consequences of increased competition in energy markets rather than to do a forecast, this point is quite distant from the central focus of the study. We did, in fact, do a sensitivity case using replacement prices for fuels to reflect fuel price increases as low cost supplies are depleted. This case showed greatly increased efficiency technology penetration (44% vs 32% in the average cost case). These results were covered briefly in section V of the Technical Appendix, rather than presented prominently, precisely to avoid the charge of overstating the economic potential of efficiency technologies which MIT attributes to our controlled price analysis.

Executive Summary:

7. We suggest an alternative retrospective question: "How would the nation have provided energy services in 1978 if cost-minimizing economic decision makers with perfect foresight had defined the domestic economic environment, constrained only by the domestic energy endowment and by world-market prices of energy resources abroad?" The answer to this question would be substantially different from the answer to the question posed by EPC, and, we think, more interesting.

7.1 With universal perfect foresight, public policies in the 1960's and 70's might well have mitigated the disruptive economic consequences of energy price shocks. A more fully adjusted macro-economy with greater economic growth and fewer recessions might have resulted.

7.2 This statement is probably true, although if the electric power system were deregulated and priced at the margin, the electricity price would probably been higher rather than lower.

7.3 A partial derivative of a function with respect to a certain variable is necessarily taken at certain values for other independent variables. Given that we started from actual 1978 conditions, and that the process we have performed is essentially taking the partial derivative of market shares with respect to price, no other result could emerge.

In previous points the effects of expanding the range of substitution was discussed (i.e., Point 4). In response to these points we showed that with an expanded range of substitution there should not be a significant decrease in opportunities for reducing costs of energy services. Indeed, we suspect the range of opportunities would <u>increase</u>.

<u>Executive Summary</u>:

8. LCES treats 1978 fuel prices as exogenous to the least-cost strategy. As a result, the fuel prices EPC uses in its simulations and computer runs, bias results towards increased use of natural gas, increased cogeneration of electricity, and substantially decreased use of purchased electricity.

8.1 Electricity prices are set at levels higher than would prevail if optimal reconfigurations of the utility capacity were allowed. This affects EPC simulations by making cogeneration more attractive to the industrial and buildings sectors than it otherwise would be.

8.2 Indicated optimal industrial cogeneration of electricity is dramatically higher than in any other study surveyed, and most significantly much higher than in other applications of ISTUM, the simulation model employed in the EPC study.

Response:

8. The run is not "biased" except insofar as the results follow from the explicit assumptions. If this statement is made relative to a free market, marginal price case (exhibiting even higher prices), the analysis greatly overstates the role of electricity and understates the market for productivity investment.

8.1 It is not clear that electric prices are set too high. Marginal electric prices in 1978 were for higher than the average prices used in the analysis. To the extent that it could be demonstrated that a reconfigured deregulated electric system would have lower rather than higher prices, the directional interpretation is correct.

8.2 The cogeneration result is principally a function of the spread between gas and electric prices in the analysis.

Executive Summary:

9. Several key results of the LCES study were imposed on the models, rather than being generated endogenously within the models as the outcome of an explicit optimization process. Hence prior judgment rather than integrated analysis significantly affected LCES results.

9.1 In the industrial sector, the second largest source of energy-efficiency improvement was the development and market penetration of the variable speed motor. As the recent history of the Reliance Company indicates, the time for the variable speed motor has not yet arrived.

9.2 In the transportation sector, the second largest source of improvement derives from the increased dieselization of the motor vehicle fleet. But the figures regarding penetration of diesel motored vehicles were imposed on the model exogenously.

9.3 In the buildings sector, the fourth most important source of efficiency improvement is cogeneration, a result introduced into the study via a side calculation.

Response:

9. This statement is unfair and misleading in the extreme. As with all models, there are always a few features or technologies one wishes to assess which are not endogenous to the model at any particular state of its development. In view of the purpose of our study-i.e, to assess the market potential of key energy technologies - a conscious decision was made to introduce a few key technologies into the model which were not formally represented. These were introduced to the model via side calculations performed using exactly the same calculation procedure the model would have used. These changes were fully and explicitly documented. This analysis was thus fully consistent with the calculations used for other technologies, was not in any sense "imposed," and was integral to the optimization process. In fact, the technologies have performed pretty much as one would expect in the market place.

9.1 Motor controls have performed exceedingly well, and are marketed by numerous manufacturers. The Reliance situation was atypical and arose from business rather than technical circumstances. Other firms, such as Barry-Wright, are doing very well.

9.2 Diesel automobiles are becoming increasingly popular, as projected.

9.3 Oil-fired cogeneration in buildings has not done well because the world prices of oil used in this system has gone from $14 per barrel assumed in the study to $34 per barrel or more.

Executive Summary:

10. The models used by LCES in their analysis have been found elsewhere to yield findings that are anomolous or inconsistent with LCES results. This complicates interpretation of LCES, and renders them less credible.

10.1 The Energy Modeling Forum studied aggregate energy demand-price elasticities using fourteen different models. They found that elasticities implicit in the ISTUM and BECOM models were by far the most volatile and sensitive to energy component price changes. For ISTUM, the demand ellipse had the wrong slope. It has been suggested that the EMF.4 price experiments were unintentionally biased against ISTUM; this conjecture needs to be evaluated by the modelers.

10.2 EPC uses a modified version of both the ISTUM and the BECOM models. The LCES reports contain no discussion of the sensitivity of ISTUM results to EPC model modifications.

10.3 Comparison of output from EPC runs of the BECOM model with base-case output presented in that model's documentation suggest very different patterns of adjustment to higher energy prices.

Response:

10. We find all of these differences easily explainable in light of the case assumptions.

10.1 The volatility of elasticity stems simply from the fact that both BECOM and ISTUM are engineering-oriented optimization models designed to study capital substitution rather than econometric behaviour. Consequently, their capital stock is more malleable; hence, they should naturally have more volatility in their elasticity. It is not an issue of bias; it is simply that these models use a fundamentally different analytic construct than econometric models of fuel use because they address a fundamentally different set of issues not usually raised in typical fuel projection studies. This point is still not fully appreciated by the review team.

10.2 Extensive sensitivity analyses, while always desirable, were simply beyond the resources available to us for the study.

10.3 This is because the run compared was from an early development version of BECOM (Spring, 1977) which used a much higher discount rate and did not permit furnace fuel switching in existing structures. The issue of base case comparisons should be made relative to the 1978 base case presented in our documentation rather than earlier model runs under different assumptions.

Executive Summary:

11. The use of ISTUM, BECOM and TECOM by LCES is poorly documented. Appropriate documentation would delineate each change in the base-case inputs of these models made for the LCES model runs presented. The lack of reasonable documentation aggravates the problem of interpreting inconsistencies between LCES results and the base-case output of ISTUM, BECOM and TEC.

Response:

11. Our applications were extensively documented. The Technical Appendix included all input data, algorithm descriptions, and output printouts in full. Each change in the models was meticulously described there - as evidenced by the ease with which the review team identified and discussed these changes in point 9. The concerns expressed about discrepancies between this application of these models and others are readily explained on the basis of different input assumptions and straightforward changes in the models which are fully described in the documentation. The review team inexplicably uses as its point of reference "base case" model runs presented in documentation of earlier versions of these models rather than the 1978 base case developed specifically for this study using current versions.

Comments Concerning Treatment of Cogeneration in the Least-Cost Studies

William R. King

Introduction

The MIT critique of the Energy Productivity Center Least-Cost work contains a detailed review of cogeneration in the industrial sector which we feel deserves a detailed response. The concentration on cogeneration modeling was prompted by the MIT observation that Least-Cost projections of cogeneration penetration were far greater than estimates developed by MIT and other sources. In our response to the MIT critique, we first discuss the rationale for cogeneration modeling in the industrial sector. This discussion is followed by comments regarding MIT's critique of our capital costing for coal boilers in coal topping cogeneration systems and its critique of our penetration results.

Industrial Cogeneration Modeling

Three kinds of cogeneration are modeled in the industrial sector. Topping cycles are modeled for steam-intensive industries. In these cycles, a boiler is fueled to provide steam at a higher heat content than is required in the process. The steam is run through a turbine/generator system to produce electricity. "Waste" steam goes to the plant process.

Diesel and gas turbine cogeneration systems are modeled for other industries, and electricity is treated either as a primary output or a byproduct. In cases where electricity is a primary output, a "no-export" technology is used. In cases where electricity is a by-product, an "export" technology is used. In either case, the turbine is fueled by either diesel or gas. Turbine exhaust gas runs a waste heat boiler to provide process steam.

Contrary to statements made in the MIT review, the two forms of cogeneration are consistently modeled. Both are competed first in the steam sector. For the topping cycles, the user is really making a boiler choice, so boiler capital cost is the relevant cost to reflect in steam sector competition. For turbine cycles, the user reflects the full system cost (boiler and turbine/generator) in the steam sector with a capital cost credit for electricity used in Machine Drive. Thus, the steam sector capital cost for turbine systems is sensitive to the value of the electricity credit; however, the accounting for capital in the steam sector is consistent for both topping and turbine cycles in that both systems show only the capital the manager would attribute to steam production. In the Machine Drive sector, the cost of the cogenerated electricity is used for both topping and turbine cycles. The differences in costing between topping and turbine systems arise because the modeler is reflecting differences in the decision processes used by managers to choose a system (i.e., in steam intensive industries, the manager is primarily choosing a boiler, not a cogeneration system).

Industrial Cogeneration Capital Costing

MIT makes two observations regarding our capital costing. First, they observe we used a capital recovery factor of 0.07. This factor was derived assuming an industrial equipment life of 25 years at a five percent real discount rate. The original ISTUM runs done by Energy and Environmental Analysis, Inc. (EEA) used a capital recovery factor of 0.14 for cogeneration, compared to a factor of 0.11 for most other technologies. They based their factor on very similar assumptions (25 year life and 7.9 percent real discount rate). The difference between the factors employed at EEA and at the Energy Productivity Center is due to the use of an after tax capital recovery factor formula by EEA. The Energy Productivity Center study employed a simple capital recovery factor excluding tax effects. This factor was developed for each sector studied (industry, buildings, transportation) and was applied consistently to all sectorial technologies.

Second, MIT believes that coal boiler costs may be overstated, contributing to coal topping cogeneration's inability to gain market share. We used capital cost data current to the ISTUM model at the time of our runs. The model data base will be updated as more accurate capital cost data becomes available for a given technology.

Penetration of Industrial Cogeneration

The magnitude of the cogeneration penetration is a result of the spread between gas and electric prices assumed in the analysis. Thus, since the gas price is low relative to the electric price, it can be expected that gas cogeneration technologies might produce less-expensive electricity. The question of fuel pricing has been addressed in previous sections of this chapter. If one believes the spread between gas and electric prices should be narrower, then the cogeneration penetration would naturally diminish. Testing this hypothesis is a straightforward sensitivity analysis using this methodology.

Cogeneration capital costing would also affect penetration relative to noncogenerating technologies. However, since MIT agrees that the cogeneration costs used are in agreement with those cited in other sources, with the exception of coal boiler costs, only the mix of cogeneration technologies should be affected with a change in capital charges (i.e., more gas cogeneration instead of coal cogeneration). Furthermore, since the same capital recovery factor was applied to all technologies in the Energy Productivity Center, ISTUM analyses, the relative levels of technology capital costs were preserved in ISTUM competition. Therefore, the magnitude of the capital recovery factor does not bias cogeneration competition.

Massachusetts Institute of Technology

Energy Laboratory

Energy Model Analysis Program

Appendix A

Energy Model Analysis Notebook Entries and Background Information on the ISTUM, BECOM, and TEC Models Employed in The Mellon Institute's *The Least-Cost Energy Strategy: Minimizing Costs Through Competition*

Eric Shimabukuro*

June 25, 1981

*Morehead Fellow in Economics, University of North Carolina, and Visiting Research Scholar at the MIT Energy Laboratory.

TABLE OF CONTENTS

1. Introduction

The three energy technology models employed in the Mellon Institute's Least-Cost Energy Strategy Study: Minimizing Costs Through Competition, include the Industrial Sector Technology Use Model (ISTUM) developed by Energy and Environmental Analysis, Inc.; the Buildings Energy Conservation Optimization Model (BECOM) developed by the Brookhaven National Laboratory; and the Transportation Energy Conservation Model (TEC) developed by Jack Faucett Associates. In this report, we present background information for each of these models including the modeler's response to a questionnaire asking for descriptive information, the translation of the questionnaire information into an entry for the EPRI/MIT Energy Model Analysis Notebook, and some additional information and comments bearing on the use of these models in the Mellon Institute study.

2. Industrial Sector Technology Utilization Model (ISTUM)

Energy Model Analysis Notebook Entry

MODEL NAME: Industrial Sector Technology Use Model ISTUM

ANALYTIC TECHNIQUES:
- o Static Optimization
- o Stochastic Techniques
- o Descriptive Simulation

ISSUES ADDRESSED:
- o Demand for Electricity and Non-Electric Energy
- o Regulatory Behavior
- o Other Industry Behavior
- o Economic Impact of Energy Policies
- o New Technology Assessment
- o Conservation Assessment

DEVELOPED: o 1977-1978

RESOLUTION:
- o Geographic: U.S. as a whole
- o Temporal: Medium term 1980-2000 in 5-year steps

ASSESSMENT: Not Assessed

MODELER CONTACT:
Samir Salama
Michael Lerner
Energy and Environmental Analysis, Inc.
1111 N. 19th St.
Arlington, VA 22209
703-528-1900

SPONSOR: ERDA/HOPPS

MODEL DESCRIPTION:

The Industrial Sector Technology Use Model (ISTUM) focuses on the market penetration potential of conventional and emerging energy technologies, providing projections of market shares to the year 2000. The ISTUM methodology has three basic components. The first component represents the inputs required by the model. These include the basic characteristics of the technologies considered by the model, macroeconomic and fuel price forecasts, and a methodology for estimating baseline energy requirements. The second component is the market competition logic. This is a four-stage procedure designed to simulate financial decision making. The third component is the output procedures which permit the data to be aggregated for detailed analysis of particular issues. Each component is described briefly below.

Over 200 technologies are presently considered in ISTUM. Included among them are: conventional oil and natural gas boilers and furnaces; coal, fluidized bed, and coal gasification (e.g., MBG, LBG) technologies, energy conservation equipment, and other energy conversion devices.

The technology characterization is designed to serve three functions:

- o Specify which technologies are being permitted to compete for market shares in the industrial sector.

- o Specify application cost variability for each technology based on experience with conventional technologies, and

- o Specify the percentage of each market where the technology is capable of satisfying the technical process requirements.

This model, therefore, limits competition to those technologies for which sufficient information is available to specify performance, provides a range of costs for each technology based on specific application cost considerations, and limits the market for which each technology is allowed to compete to that fraction in which technical feasibility is assured.

Industrial energy demand in ISTUM is represented through the concept of service demand. Service demand is the amount of useful work required for a particular process. Each industrial process's energy requirements are grouped into one of the service demand categories tracked in the model.. Examples of these categories include steam, direct heat, machine drive, and internal electricity generation. Service demand is partitioned into a variety of sub-categories in order to isolate homogeneous energy services. Disaggregation includes: 26 industries split into two-, three-, and four-digit standard industrial classification codes (paper, chemicals, aluminum, etc.), 23 energy service sectors (steam, electrolytic, machine drive, etc.), hours of operation per year, combustor size (e.g., 50 million Btu/hr boiler vs. 250 million Btu/hr boiler), and five time periods.

The fundamental assumption underlying ISTUM is that a decision to invest in industrial equipment is based on choosing the hardware which performs a given task at the lowest cost. However, the decision to invest is subject to behavioral constraints which serve to restrict the market penetration rate of emerging technologies, even though they may be superior.

ISTUM considers the total cost of technology in its comparative assessment, including capital costs, maintenance costs, fuel costs, and non-fuel operating costs. Technology costs within a cell are represented as a range rather than as point estimates and are annualized so as to provide a basis of comparison. The distribution attempts to pick up the effects of site specific variability, differences in equipment costs, etc. Various tax credits, depreciation and discount rate assumptions can be simulated in this step.

The determination of the initial market penetration potential is based on the life-cycle costs calculated in the previous section. Cost distributions representing each technology competing for a market cell are compared. The market share of each technology is determined through a sophisticated statistical algorithm which determines the probability that the technology is the least-cost option being considered. The results of this step provide the economic market penetration potential.

The market competition analysis assumes that firms have access to all existing information regarding prices and availability of the alternative technologies and fuels. However, in reality there are several "behavioral" factors which limit a new technology's market penetration. These include:

- o lags in the transfer of information,
- o decision maker aversion to risk, and
- o vendor and distribution network and "supply side" restrictions.

These factors are explicitly modeled in the behavioral analysis and the results are used to adjust the market penetration rates of the respective technologies. The outcome is to slow the penetration of new technologies to a rate somewhat lower than what a strictly economic analysis would indicate.

Capital turnover in a given year is calculated as the sum of projected equipment retirement in the previous period and increased energy demand due to growth in product output. This figure is calculated for each cell and is multiplied by the market shares for each relevant technology to project capital requirements and energy demand.

ISTUM provides projections of service and fuel demands at five-year intervals through 2000. Energy demands are broken down by energy service sector, technology, fuel type, industry and technical characteristics. Estimates of aggregate capital costs, as well as several relative measures of market share projections, are also available.

COMPUTING ENVIRONMENT:

- o Machinery - IBM/AMDAHL
- o Languages - APL*PLUS
- o Approximate cost - $500 per solution
- o Code is available on tape
- o Model is non-proprietary
- o Model has been transferred

MODEL DEVELOPMENT AND APPLICATIONS:

A second version of ISTUM is being developed. It should be operational in the fall of 1981 and available to the public in the beginning of 1982.

Partial description of each significant application of the model, including dates of usage	Ref. No. from Bibliography describing each application	Sponsor/ client for each application	Model operated by:	Scenarios supplied by:
			*M = modeler S = sponsor O = other	
Impacts of tax incentive on Energy Conservation (Feb. 1980)	-	Private	M	M
Impact of financial incentives on Industrial use of oil/gas (October 1979)	-	DOE	M	M
Conservation Technology Assessment (1/79-current)	-	DOE Office of Industrial Programs	M	S
Impact of prices economic growth on industrial energy conservation (10/80)	-	Private	M	M/S
Natural Gas Demand (1/79,1/80)	-	AGA	M	S

MODEL ASSESSMENT:

The model has been described in the literature, but has not been subjected to either in-house or external assessment.

BIBLIOGRAPHY:

1. Industrial Sector Technology Use Model (ISTUM): Industrial Energy Use in the United States, 1974-2000; 4 volumes, DOE; October 1979; DOE/FE/2344

   i. Volume 1 - Primary Model Documentation
   ii. Volume 2 - Results
   iii. Volume 3 - Appendix on service and fuel demands
   iv. Volume 4 - Technology Appendix

2. The Least Cost Energy Strategy; Energy Productivity Center, Carnegie Mellon University Press, 1979.

   ISTUM Technology Evaluation for the EIA Annual Administration Report to Congress and the National Energy Supply Scenario, DOE, June 19, 1979.

ENERGY MODEL ANALYSIS PROGRAM
Energy Laboratory
Massachusetts Institute of Technology
Cambridge, Massachusetts 02139

QUESTIONNAIRE FOR ENERGY POLICY MODELERS

The M.I.T. Energy Model Analysis Program (EMAP), under sponsorship from the Electric Power Research Institute, is developing a directory of energy models and assessments, to be published in the fall of 1980. The directory will be distributed widely to government departments, academic institutions, and private industry, and will be an extremely useful reference tool for model developers, assessors and users. We would very much like to include your model in this directory, and therefore are requesting that you complete the following form to provide the information needed. We will then compile your responses into a standardized format, which will be sent to you for review prior to publication.

Please answer the questions below as completely as you can; we are particularly pleased to be able to present in this directory the kind of meaningful and interesting information and perspective that only modelers and model assessors themselves can provide. We are interested in anything you have to offer about your model, and encourage you to use extra sheets of paper where necessary. If you are extremely short of time, please answer the questions marked with an asterisk.* Martha Mason and Kelly Morgan of the EMAP will be happy to answer any questions and offer assistance; they may be contacted at (617) 253-8318.

Thank you for your assistance — the directory will not be complete without an entry on your model!

GENERAL INFORMATION

*1. What is the name of the model? Industrial Sector Technology Use Model

*2. By what acronym, nickname, or other name(s) is it known? ISTUM

*3. Where, and under what auspices, was the model developed.
Version I developed by EEA under funding by ERDA/HOPPS.
Version II developed by EEA under funding by DOE Conservation and Solar Division of Industrial Program.

*4. Over what time period was the model developed? V-I 1977 to 1978; ~~V-II 10/80~~ to ~~9/81~~ (mo./yr to mo./yr.)

*5. Who is the person filling out this questionnaire?
Name: Harold Kalkstein
Address: EEA Inc., 1111 N. 19th St., Arlington, VA. 22209
Telephone: 703-528-1900
Relationship to model: Developer of ISTUM Version-II

*6. Who is (or are) the key modeler contact(s)?
Name: Samir Salama
Address: EEA Inc., 1111 N. 19th St., Arlington, VA 22209
Telephone: 703-528-1900
Relationship to model: ~~Project Manager~~

Name: Michael Lerner
Address: EEA Inc., 1111 N. 19th St., Arlington, VA 22209
Telephone: 703-528-1900
Relationship to model: Project Director

*7. Who is (or are) the key contact(s) in the organization(s) that sponsored the model development?
Name: Thomas Gross, Conservation and Solar
Address: 100 Independence Ave., N.W. ~~Washington, D. C. 205085~~
Telephone: 202-252-2890
Relationship to model: Project Officer

Name: Cyril Draffins, Fossil Energy (Version I)
Address: 100 Independence Ave., N.W., ~~Washington, D.C. 20585~~
Telephone:
Relationship to model: Project Officer

MODEL CHARACTERISTICS

The following questions are designed to provide understanding of the fundamental technical characteristics of the model. The multiple-choice options are provided for your convenience; however, we understand that models vary significantly, and these choices may not be suited to your model. Please add categories, phrases, or sentences, as applicable.

In Question 18 we will ask about different operating versions of the same basic model. If there has been more than one version, please indicate here which one you are describing. If the versions are significantly different, you may find it necessary to fill out a complete questionnaire for each unique model version.

*8. What keywords characterize the issues the model addresses?

- ☐ Supply of fuels & resources
- ☒ Demand for electricity
- ☒ Demand for non-electric energy
- ☒ Regulatory behavior
- ☐ Electric utility behavior
- ☒ Other industry behavior
- ☒ Economic impacts of energy policies
- ☐ Environmental impacts of energy policies
- ☐ Demographic/social impacts of energy policies
- ☒ New technology assessment
- ☒ Conservation assessment
- ☐ Other (specify) ____

*9. What analytic techniques are used in the model? (If appropriate, check more than one, and indicate which subsection of the model uses which technique.)

- ☐ Linear programming
- ☐ Nonlinear/integer programming
- ☒ Other static optimization
- ☐ Dynamic optimization
- ☒ Stochastic techniques
- ☒ Descriptive simulation
- ☐ Allocation & equilibrium
- ☐ Input/output
- ☐ Regression, econometric
- ☐ Expert opinion, non-quantitative
- ☐ Other (specify) ____

*10. a) What geographic resolution does the model cover?

- ☐ Site-specific (specify) ______
- ☒ Regionwide (specify) Version II, 10 Federal Regions
- ☐ Statewide (specify) ______
- ☒ U S as a whole Version I
- ☐ International (specify) ______
- ☐ Other (specify) ______

b) If regional information is aggregated before reporting results, what is the level of aggregation? ______

*11. a) What temporal resolution does the model cover?

- ☐ Short term (5 years or less) ______
- ☒ Medium term (6-20 years) 1980/2000
- ☐ Long term (over 20 years) ______

b) If there are discrete time steps, what is their typical length? 5 years

12. Aside from their use as input, were data used during calibration/development of the model?

X yes ______ no (skip to ques. 13)

If yes, how were the data used?

- ☐ for coefficient/parameter determination
- ☒ for structural form determination
- ☐ for assessing the accuracy of model results
- ☒ other (specify) Baseline Technology and Energy Consumption Characterization

*13. In the space below (or on extra sheets) please provide a complete technical description of your model, discussing when applicable:

- model structure and methodology
- significant equations
- parameters
- variables (endogenous & exogenous)
- input data
- output data

When discussing input data, please differentiate between those data that serve as input assumptions imbedded in the model and those that are frequently changed during model runs

Please attach a flow chart or other diagram of the structure of the model, if possible.

The Industrial Sector Technology Use Model (ISTUM) focuses on the market penetration potential of conventional and emerging energy technologies, providing projections of market shares out to the year 2000.

The ISTUM methodology has three basic components each of which is shown in Figure 1. The first component represents the inputs required by the model. These include the basic characteristics of the technologies considered by the model, macroeconomic and fuel price forecasts, and a methodology for estimating baseline energy requirements. The second component is the market competition logic. This is a four stage procedure designed to simulate financial decision making. The third component is the output procedures which permit the data to be aggregated for detailed analysis of particular issues. Each component is described briefly below.

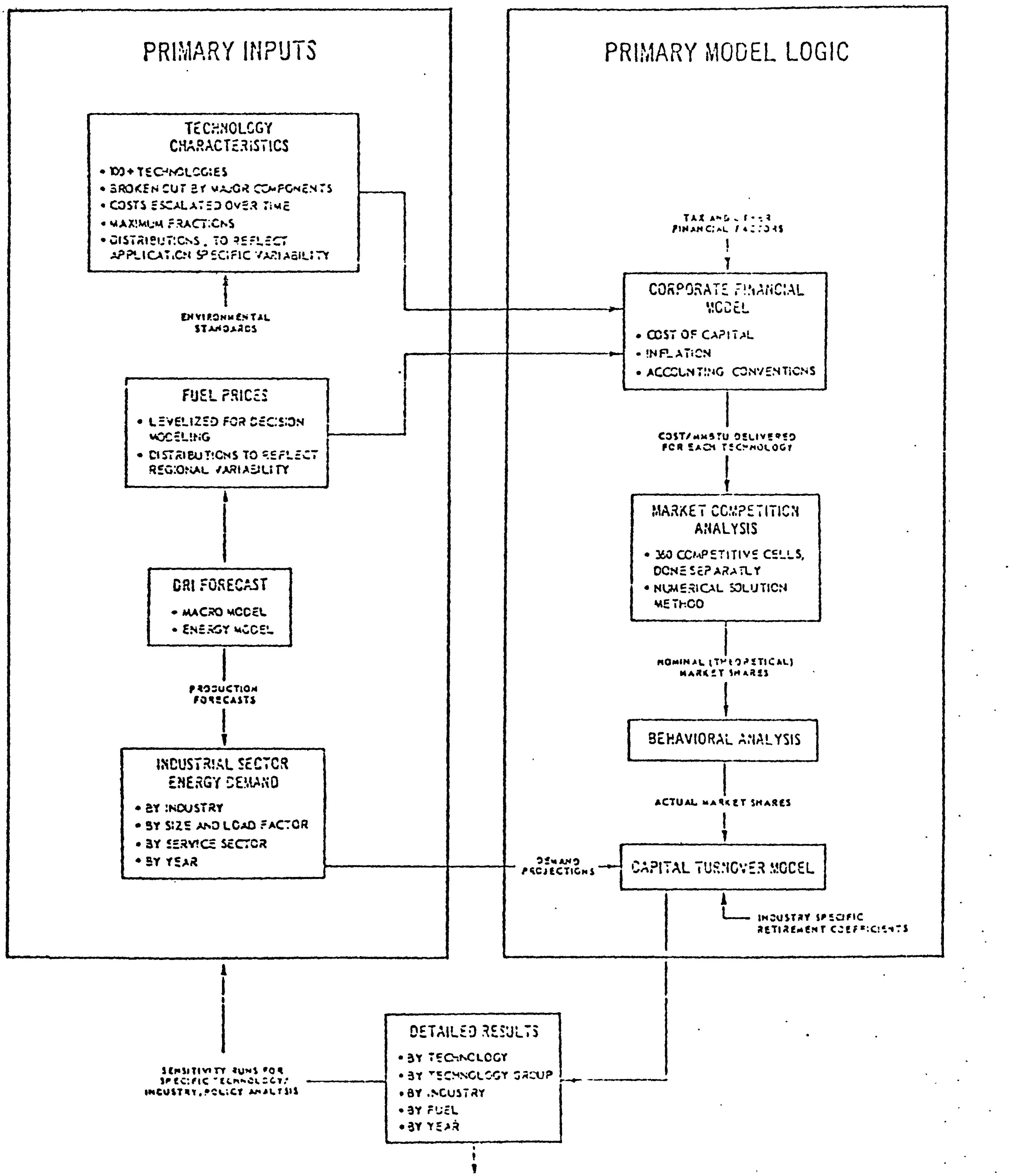
Over 200 technologies are presently considered in ISTUM. Included among them are: conventional oil and natural gas boilers and furnaces; coal, fluidized bed, and coal gasification (e.g., MBG, LBG) technologies, energy conservation equipment, and other energy conversion devices.

The technology characterization is designed to serve three functions:

- o Specify which technologies are being permitted to compete for market shares in the industrial sector.
- o Specify application cost variability for each technology based on experience with conventional technologies, and

FIGURE I

SCHEMATIC OF INDUSTRIAL SECTOR TECHNOLOGY USE MODEL



- Specify the percentage of each market where the technology is capable of satisfying the technical process requirements.

This model, therefore, limits competition to those technologies for which sufficient information is available to specify performance, provides a range of costs for each technology based on specific application cost considerations, and limits the market for which each technology is allowed to compete to that fraction in which technical feasibility is assured.

Industrial Sector Energy Demand

Industrial energy demand in ISTUM is represented through the concept of service demand. Service demand is the amount of useful work required for a particular process. Each industrial process's energy requirements are grouped into one of the service demand categories tracked in the model. Examples of these categories include steam, direct heat, machine drive, and internal electricity generation.

Service demand is partitioned into a variety of sub-categories in order to isolate homogeneous energy services. Disaggregation includes: 26 industries split into two, three, and four digit standard industrial classification codes (paper, chemicals, aluminum, etc.), 23 energy service sector (steam, electrolytic, machine drive, etc.), hours of operation per year, combustor size (e.g., 50 million Btu/hr boiler vs. 250 million Btu/hr boiler), and five time periods.

PRIMARY MODEL LOGIC

The fundamental assumption underlying ISTUM is that a decision to invest in industrial equipment is based on choosing the hardware which performs a given task at the lowest cost. However, the decision to invest is subject to behavioral constraints which serve to restrict the market penetration rate of emerging technologies, even though they may be superior.

Corporate Financial Model

ISTUM considered the total cost of technology in its comparative assessment, including capital costs, maintenance costs, fuel costs, and non-fuel operating costs. Technology costs within a cell are represented as a range rather than as point estimates and are annualized so as to provide a basis of comparison. The distribution attempts to pick up the effects of site specific variability, differences in equipment costs, etc. Various tax credits, depreciation and discount rate assumptions can be simulated in this step.

Market Competition Analysis

The determination of the initial market penetration potential is based on the life-cycle costs calculated in the previous section. Cost distributions representing each technology competing for a market cell are compared. The market share of each technology is determined through a sophisticated statistical algorithm which determines the probability that the technology is the least-cost option being considered. The results of this step provide the economic market penetration potential.

Behavioral Lags

The market competition analysis assumes that firms have access to all existing information regarding prices and availability of the alternative technologies and fuels. However, in reality there are several "behavioral" factors which limit a new technology's market penetration These include:

- o Lags in the transfer of information,
- o Decision maker aversion to risk, and
- o Vendor and distribution network and "supply side" restrictions.

These factors are explicitly modeled in the behavioral analysis and the results are used to adjust the market penetration rates of the respective technologies. The outcome is to slow the penetration of new technologies to a rate somewhat lower than what a strictly economic analysis would indicate.

Capital Turnover Model

Capital turnover in a given year is calculated as the sum of projected equipment retirement in the previous period and increased energy demand due to growth in product output. This figure is calculated for each cell and is multiplied by the market shares for each relevant technology to project capital requirements and energy demand.

Model Outputs

ISTUM provides projections of service and fuel demands at five year intervals through 2000. Energy demands are broken down by energy service sector, technology, fuel type, industry and technical characteristics. Estimates of aggregate capital costs, as well as several relative measures of market share projections are also available.

*14. The following questions concern the computing environment required by the model.

a Brand of machines, IBM/AMDAHL
b Language(s) employed APLPLUS (Version I); VSAPL (Version II
c Approximate cost per solution cost $500 or time ______ per solution
d Is the model linked with other models or software packages?
X No ______ Yes (specify) ______
e Is the code available on tape X cards ______?
f Are any parts of the model proprietary?
X No ______ Yes (specify) ______

*15. Bibliography (partial)

We would like to include a bibliography for your model. Therefore in the following space, or on an attached sheet, please list all references in which the model has been described or cited including documentation, journals, publications, and reports on model applications. Please number each item for easy reference later in the questionnaire.

1. Industrial Sector Technology Use Model (ISTUM): Industrial Energy Use in the United States, 1974-2000; 4 volumes, DOE; October 1979; DOE/TE/2344

   i. Volume 1 - Primary Model Documentation
   ii. Volume 2 - Results
   iii. Volume 3 - Appendix on service and fuel demands
   iv. Volume 4 - Technology Appendix

2. The Least Cost Energy Strategy; Energy Productivity Center, Carnegie Mellon University Press, 1979

3. ISTUM Technology Evaluation for the EIA Annual Administration Report to Congress and the National Energy Supply Scenario, DOE, June 19, 1979

4. EMF-2; energy demand elasticities (cannot locate exact reference

16. Which documents listed in Question 15 are references for the model's data sources?

Reference numbers 1

MODEL DEVELOPMENT AND APPLICATIONS

In this section we are interested in tracing how the model has been used. In the first column, please describe each application of the model. uses might include both academic study and specific problem solving. In the following columns please indicate which reference number from Question 15 describes the application, who the sponsor was for that application, who actually operated the model, and who suggested or supplied the scenarios implemented in the application.

	Partial *Description of each significant application of the model, including dates of usage	Ref. # from Question 15 describing each application	Sponsor/client for each application	Model operated by: M = modeler S = sponsor O = other	Scenarios supplied by: M = modeler S = sponsor O = other
1.	Impacts of tax incentive on Energy Conservation (Feb. 1980)	-	Private	M	M
2.	Impact of financial incentives on Industrial use of oil/gas (October 1979)	-	DOE	M	M
3.	Conservation Technology Assessment (1/79 - current)	-	DOE Office of Industrial Programs	M	S
4.	Impact of prices economic growth on industrial energy conservation (10/80)	-	Private	M	M/S
5.	Natural Gas Demand (1/79, 1/80)	-	AGA	M	S

17. As the table above suggests, an important factor in model development and documentation is whether or not the model has ever been installed and operated by someone other than the modeler.

a) Can the model be transferred for use by someone other than the modeler?
__X__ Yes ______ No If no, why not? ______

b) Has the model ever been transferred for use by someone other than the modeler?
______ No __X__ Yes If yes, please indicate where the model was transferred and briefly describe the transfer process Transfer of Version I to DOE computer for planned use by Fossil Energy Division was completed and model was successfully run.

c) Do you have any plans to transfer the model in the future?
__X__ No ______ Yes If yes, to where? ______

18. One factor sometimes complicating model assessment is that one-time or on-going changes to a model's structure have led to more than one version of that model. In this question we are interested in finding out how many discrete versions of the model have been developed, and which, if any, are currently operational.

a) Has the model undergone any major structural changes since its original finished form?
______ No (skip to Ques 19) __X__ Yes If yes, please briefly describe any significant differences between the versions and the reasons motivating the changes. ______

b) Which version(s) of the model are currently operational, and where are they maintained?

Version 1: Maintained on STSC computer system; is operational.

Version 2: Maintained on EIA/DOE computer; will be operational in the fall.

MODEL ASSESSMENT

*19. Has the model ever been subjected to an in house assessment by the modelers?

X No (skip to Ques. 20) (not formally)

____ Yes a) If yes, which elements listed below received emphasis during the modeler assessment?

- ☐ Model validity
  - ☐ Structure
  - ☐ Content
  - ☐ Prediction
- ☐ Data validity
- ☐ Verification of the model's expression in the computer code
- ☐ Usability
  - ☐ Documentation
  - ☐ Efficiency
- ☐ Model applications
- ☐ Other (specify) ____

b) Please briefly describe the techniques utilized in the modeler assessment.

*20. Has the model been made available for assessment by external parties?

- ☐ No (skip to Question 21)
- ☒ Yes, through publication of model descriptions in the literature.
- ☐ Yes, through a formal external assessment
- ☒ Yes, through other means (specify) ____

If the model was assessed by an individual, group or organization other than the modeler(s), please answer the questions below.

a) Who was the assessor for the model?

Organization Technokron
Name of contact ____
Title ____
Address ____
Telephone ( ) ____
Title of Report ____

b) Who sponsored the assessment?

Organization Fossil Energy Division, DOE
Name of contact Cyril Draftin
Title ____
Address 1000 Independence Avenue, N.W.
Washingoth, D.C. 20585
Telephone ( ) ____

c) What assessment approach(es) were employed by the assessors?

- ☒ Review of the literature, not including the computer code
- ☐ Evaluation of the detailed documentation, including the code
- ☐ Audit of the model's performance, using test problems
- ☐ Evaluation of the model using experiments designed by the assessors, but implemented by the modelers
- ☐ In-depth assessment, in which the assessors themselves implemented experimental runs of the model
- ☐ Comparative evaluation of two or more models
- ☐ Other (specify) ____

d) Which elements listed below received emphasis during the external assessment of the model?

- ☒ Model validity
  - ☒ Structure
  - ☐ Content
  - ☐ Prediction
- ☐ Data validity
- ☐ Verification of the model's expression in the computer code
- ☐ Usability
  - ☐ Documentation
  - ☐ Efficiency
- ☐ Model applications
- ☐ Other (specify) ____

e) Do you have any comments on the external evaluation of the model?

21. a) Please discuss the accessibility of the model for initial or further assessment. If the model has not been assessed, do you have any plans concerning future assessment? Do you feel it should be considered for an assessment?

Version II of the Model will be in the public domain, fully documented and available for review by the beginning of 1982. No extensive external review is presently planned. However, model outputs will be reveiwed by industry experts as part of a validation task in the project.

22. We would be interested in any other aspects of the model that you would like to discuss. How does it compare with other models in terms of structure or coverage? Were there any interesting ramifications resulting from use of the model?

Additional Information and Comments on ISTUM

ISTUM computes energy demand and technological market shares from technological costs and efficiencies, service sector demand, and fuel prices.

Fuel prices are built into ISTUM, but can also be input by the user. Fuel prices are entered as distributions as opposed to point estimates in ISTUM. Thus they are characterized by their mean, variance, and minimum values. This is done to capture regional differences in prices. The ISTUM fuel prices were provided by Data Resources, Inc. from the DRI U.S. Annual Energy Model. Fuel prices are input adjusted to the specific technology with which the fuel is used. This is done by dividing the fuel price by the conversion efficiency of the technology. This is done so that all fuel prices reflect the cost of the energy produced that is usable to industry in a constant manner.

In order to determine total energy demand, ISTUM must first determine the demand for each of the 23 service sectors. To do this ISTUM divides industrial demand into 26 Standard Industrical Classifications (SICs). Each of these SICs has a certain demand for each service sector. These demands are then aggregated to determine total service sector demand. To project future service demand ISTUM assumes that service demand grows at the same rate at which the industry does. These projections were also made by DRI on their Quarterly Macroeconomic Model. Since there are differences in ISTUM's and DRI's industrial classifications, surrogates for service sectors are used in some projections.

ISTUM divides industrial use of energy into 23 service sectors. Of these, thirteen actually compete technologies to fill the demand. The other ten are sectors such as feedstocks that are included in the model

Table 1

ISTUM SUBDIVISIONS

List of Competing Service Sectors:

1. Steam
2. Direct Heat--Intermediate
3. Direct Heat--Dirty
4. Indirect Heat--Coal Based
5. Machine Drive
6. Electrolytic
12. Space Heat
13. Indirect Heat--Not Coal Based
14. Calcining
15. Glass Melting
16. Brick Firing
17. Iron Making
19. Steel Reheating

List of Non-Competing Service Sectors:

7. Liquid Feedstock
8. Natural Gas Feedstock
9. LPG Feedstock
10. Metallurgical Coal Usage
11. Miscellaneous Energy and Lubricants
18. Steel Making
20. Internal Generation
21. Captive Electricity
22. Captive Direct Heat
23. Coke Consumption

Listing of SIC Classifications:

1. Food
2. Tobacco
3. Textiles
4. Apparel
5. Lumber, Wood
6. Furniture
7. Paper, Allied Products
8. Printing, Publishing
9. Chemicals
10. Petroleum Refining
11. Rubber, Miscellaneous Plastics
12. Leather
13. S, C, G, Concrete
14. Steel
15. Aluminum
16. Other Primary Metals
17. Fabricated Metals
18. Machinery (Not electric)
19. Electric Machinery
20. Transportation Equipment
21. Measuring Equipment
22. Misc. Manufacturing
23. Crops
24. Livestock
25. Metal Mining
26. Non-Metal Mining

to insure that total industrial energy usage is accounted.

A problem with this service sector approach is that the service provided by an individual service sector is not totally homogeneous. One solution to this problem is to increase the number of service sectors. ISTUM service sectors calcining, glass melting, brick firing, iron-making, steel-making, and steel reheating are separated from the direct heating sectors because of such problems.

A similar type of problem was solved by using size and load factors in the ISTUM service sectors. It is reasonable that technologies will be more or less competitive depending upon their size or load factor. Size refers to the MMBtu's produced per hour and load factor to the number of hours per year a technology is in use. Part of this size and load effect is captured by the use of cost distributions. However, for more accurate predictions up to two size and two load factors for each service sector are used. More precision might have been available by using more sizes and load factors, but at a trade-off in model costs.

Technologies are the third important input in determining final energy demand. Good descriptions of the engineering processes of the technologies can be found in the ISTUM documentation.

Like fuel prices, technologies are represented by cost distributions. The use of a distribution more accurately portrays costs than single point estimates. Costs vary for a number of reasons. Construction costs vary according to site specifications and labor costs. Also the quality of the service (e.g., evenness of heat) needed by different industries may vary costs. To calculate capital costs, the costs are broken down into components, estimated, and then aggregated. The components are:

1) site preparation and power house
2) primary systems and controls
3) fuel handling
4) environmental controls and waste handling
5) utility and feedwater systems
6) indirect capital costs
7) installation costs.

When technology costs are finally input into ISTUM they are given in \$/MMBtu's and annualized. The capital charge rate not only takes capital lifetime and rates of return into consideration, but also the effects of tax laws and depreciation accounting procedures.

Originally ISTUM was to look at different costs depending upon whether a new or old plant was implementing the technology. The empirical data suggest that a great difference in costs does not exist, so the distinction was not included in the model.

Technologies are given a maximum market penetration. This figures may be 100% of the service sector. Maximum shares exist for many reasons. A technology may not provide the correct quality of service across the whole sector. Steam is an example. Solar technologies cannot provide the higher-pressure steam needed by some industries. Thus it has a maximum market share. Environmental constraints may also limit a technology's market share.

ISTUM only competes technologies to fill incremental service demand. This is demand created by increases in service demand plus demand created by retirement of capital. The retirement schedule is based upon historical trends. In general, the older the capital, the higher its retirement rate. ISTUM does not allow for early retirement of uneconomic capital.

In competing technologies to fill the service demand, it is important to remember that costs are represented by distributions. By taking annualized capital and operating costs and adding them to fuel costs, ISTUM produces a total cost distribution. Since distributions tend to overlap, a combination of technologies will capture shares of the market. The minimum total cost value is important here. Otherwise all technologies would capture a non-zero market share.

The market shares thus obtained are then modified by the behavioral lag component. This component reduces the introduction of new technologies. The newer a technology, the greater the lag will be.

After accounting for this behavioral lag, the market shares are recalculated. These shares are turned into actual capital investment by multiplying by the incremental energy demand. Total fuel use is then calculated from the technologies in use.

3. Transportation Energy Conservation Model (TEC)

Energy Model Analysis Notebook Entry

MODEL NAME: Transportation Energy Conservation Model TEC

ANALYTIC TECHNIQUES:
- o Linear Programming
- o Regression, econometric

ISSUES ADDRESSED:
- o Demand for Non-Electric Energy
- o Regulatory Behavior
- o Other Industry Behavior
- o New Technology Assessment
- o Conservation Assessment

DEVELOPED:
- o 1976-1978

RESOLUTION:
- o Geographic: U.S. as a whole
- o Temporal: long term 1975-2025;
  single year up to 2000;
  five year steps to 2025

ASSESSMENT: Partial - Automobile sector forecasting model - independent assessment by University of Michigan Highway Safety Research Institute

MODELER CONTACT:

Mike Laurence
Jack Faucett Associates
5454 Wisconsin Ave.
Chevy Chase, MD 20015
301-657-8223

Gary Kaitz
Stanford Law School
Palo Alto, CA 94305

SPONSOR: Department of Energy - Applied Analysis

MODEL DESCRIPTION:

TEC is designed to compute energy usage in the transportation sector between the years 1975 and 2025. The model is divided into nine transporation modes - air, automobile, truck, bus, motorcycle, rail, marine, and pipeline. The modes are independent and can be run together or in any combination of the nine. TEC is a demand for transporation services model in which the manufacturers minimize the lifetime vehicle costs to the consumer. The model can consider factors such as fuel prices, vehicle miles demanded, cost of improved efficiency, environmental and safety factors, tax effects, and the introduction of new technologies.

The automobile mode is the most complex of the nine modes. The model classifies autos into three weight classes and projects a demand for each

A-22a

ENERGY MODEL ANALYSIS PROGRAM
Energy Laboratory
Massachusetts Institute of Technology
Cambridge, Massachusetts 02139

QUESTIONNAIRE FOR ENERGY POLICY MODELERS

The M.I.T. Energy Model Analysis Program (EMAP), under sponsorship from the Electric Power Research Institute, is developing a directory of energy models and assessments, to be published in the fall of 1980. The directory will be distributed widely to government departments, academic institutions, and private industry, and will be an extremely useful reference tool for model developers, assessors, and users. We would very much like to include your model in this directory, and therefore are requesting that you complete the following form to provide the information needed. We will then compile your responses into a standardized format, which will be sent to you for review prior to publication.

Please answer the questions below as completely as you can; we are particularly pleased to be able to present in this directory the kind of meaningful and interesting information and perspective that only modelers and model assessors themselves can provide. We are interested in anything you have to offer about your model, and encourage you to use extra sheets of paper where necessary. If you are extremely short of time, please answer the questions marked with an asterisk.* Martha Mason and Kelly Morgan of the EMAP will be happy to answer any questions and offer assistance; they may be contacted at (617) 253-8318.

Thank you for your assistance — the directory will not be complete without an entry on your model!

GENERAL INFORMATION

*1. What is the name of the model?

Transportation Energy Conservation Model

*2. By what acronym, nickname, or other name(s) is it known?

TEC

*3. Where, and under what auspices, was the model developed.

Developed by Jack Faucett, Associates under funding from ERDA Conservation and Solar Applications, Office of Transportation Programs

*4. Over what time period was the model developed? 1976 (mo/yr.) to 1978 (mo/yr.)

*5. Who is the person filling out this questionnaire?

Name: Michael F. Lawrence
Address: ~~5454 Wisconsin Ave., Chevy Chase, MD 20015~~
Telephone: 301-657-8223
Relationship to model: ______

*6. Who is (or are) the key modeler contact(s)?

Name: Michael F. Lawrence	Name: Gary Kaitz
Address:	Address: Stanford Law School, Palo Alto, CA 94305
Telephone:	Telephone:
Relationship to model:	Relationship to model: programmer

*7. Who is (or are) the key contact(s) in the organization(s) that sponsored the model development?

Name: Jerry Peabody	Name:
Address: DOE-Applied Analysis, Washington, D.C., 20461	
Telephone: 202-633-8508	Telephone:
Relationship to model: project supervisor	Relationship to model:

MODEL CHARACTERISTICS

The following questions are designed to provide understanding of the fundamental technical characteristics of the model. The multiple-choice options are provided for your convenience; however, we understand that models vary significantly, and these choices may not be suited to your model. Please add categories, phrases, or sentences, as applicable.

In Question 18 we will ask about different operating versions of the same basic model. If there has been more than one version, please indicate here which one you are describing. If the versions are significantly different, you may find it necessary to fill out a complete questionnaire for each unique model version.

*8. What keywords characterize the issues the model addresses?

- ☐ Supply of fuels & resources
- ☒ Demand for electricity
- ☒ Demand for non-electric energy
- ☐ Regulatory behavior
- ☐ Electric utility behavior
- ☒ Other industry behavior
- ☐ Economic impacts of energy policies
- ☐ Environmental impacts of energy policies
- ☐ Demographic/social impacts of energy policies
- ☒ New technology assessment
- ☒ Conservation assessment
- ☐ Other (specify) ______

*9. What analytic techniques are used in the model? (If appropriate, check more than one, and indicate which subsection of the model uses which technique.)

- ☒ Linear programming
- ☐ Nonlinear/integer programming
- ☐ Other static optimization
- ☐ Dynamic optimization
- ☐ Stochastic techniques
- ☐ Descriptive simulation
- ☐ Allocation & equilibrium
- ☐ Input/output
- ☒ Regression, econometric
- ☐ Expert opinion, non-quantitative
- ☐ Other (specify) ______

*10. a) What geographic resolution does the model cover?

[ ] Site-specific (specify) ______
[ ] Regionwide (specify) ______
[ ] Statewide (specify) ______
[X] U S as a whole ______
[ ] International (specify) ______
[ ] Other (specify) ______

b) If regional information is aggregated before reporting results, what is the level of aggregation? ______

*11. a) What temporal resolution does the model cover?

[ ] Short term (5 years or less) ______
[ ] Medium term (6-20 years) ______
[X] Long term (over 20 years) 1975-2025

b) If there are discrete time steps, what is their typical length? single year steps up to 2000, five year steps up to 2025

12. Aside from their use as input, were data used during calibration/development of the model?

X yes ______ no (skip to ques. 13)

If yes, how were the data used?

[X] for coefficient/parameter determination
[ ] for structural form determination
[X] for assessing the accuracy of model results
[ ] other (specify) ______

*13. In the space below (or on extra sheets) please provide a complete technical description of your model, discussing when applicable:

- model structure and methodology
- significant equations
- parameters
- variables (endogenous & exogenous)
- input data
- output data

When discussing input data, please differentiate between those data that serve as input assumptions imbedded in the model and those that are frequently changed during model runs.

Please attach a flow chart or other diagram of the structure of the model, if possible.

see attached

MODEL DESCRIPTION

TEC is designed to compute energy usage in the transportation sector between the years 1975 and 2025. The model is divided into nine transportation modes - air, automobile, truck, bus, motorcycle, rail, marine and pipeline. The modes are independent and can be run together or in any combination of the nine. TEC is a demand for transportaion services model in which the manufacturers minimize the lifetime vehicle costs to the consumer. The model can consider factors such as fuel prices, vehicle miles demanded, costs of improved efficiency, environmental and safety factors, tax effects, and the introduction of new technologies.

The automobile mode is the most complex of the nine modes. The model classifies autos into three weight classes and projects a demand for each weight class. It then determines the demand for new cars by calculating the scrapage rate of the existing fleet and by finding the difference between fleet demand and number of cars in the fleet minus scrappage. The model then fills the new car demand with the cars that minimize the total of the initial costs and the discounted operating costs over the first owner's lifetime of the car. The car life for the first owner is assumed to be approximately 52,000 miles. Future costs are discounted at 10% for 80% of the car buyers. The other 20% are assumed not to consider operating costs when making their purchase. The costs of increased fuel efficiency are built into the model and the fuel prices may be changed for all years of the run. The costs of the technologies to improve fuel efficiency are considered seperately for three time blocks within the model. The model also includes different safety and emitions scenarios and can check the effect of MPG requirements and penalties for non-compliance.

The truck and air modes are similar in design to the auto mode. Trucks are divided into light, medium, heavy and heavy-heavy weight classes. Airplanes are divided into six categories for commercial flight and one general aviation class.

The other modes are simpler in design than the first three. This is due largely to data constraints.

TEC offers output on fuel consumption and costs, vehicle costs and vehicle market shares.

14. The following questions concern the computing environment required by the model.

a. Brand of machinery IBM 370 A-22e

b. Language(s) employed FORTRAN

c. Approximate cost per solution cost ________ or time 2½ minutes ________ per solution

d. Is the model linked with other models or software packages?

X No ______ Yes (specify) ________

e. Is the code available on tape yes ______ cards yes ______?

f. Are any parts of the model proprietary?

x No ______ Yes (specify) ________

*15. Bibliography

We would like to include a bibliography for your model. Therefore, in the following space, or on an attached sheet, please list all references in which the model has been described or cited, including documentation, journals, publications, and reports on model applications. Please number each item for easy reference later in the questionnaire.

1. Jack Faucett Associates, TEC: Transportation Energy Conservation Model, Washington, D.C. JFA, 1978

2. Jack Faucett Associates, TEC: Transportation Energy Conservation Model-User's Guide Washington, D.C., JFA, 1978

3. The Energy Productivity Center, Least-Cost Energy Strategy-Technical Appendix , Carnegie-Mellon University Press

4. Shackson, Richard H. and Leach, H. James, Maintaining Automotive Mobility: Using Fuel Economy and Synthetic Fuels to Compete with OPEC Oil, Interim Report, Carinegie-Mellon University Press, 1980

5. Jack Faucett Associates, Automobile Sector Forecasting Model Documentation, Washington, D.C. JFA, 1978

16. Which documents listed in Question 15 are references for the model's data sources?

Reference numbers: ________

MODEL DEVELOPMENT AND APPLICATIONS

In this section we are interested in tracing how the model has been used. In the first column, please describe each application of the model, uses might include both academic study and specific problem-solving. In the following columns please indicate which reference number from Question 15 describes the application, who the sponsor was for that application, who actually operated the model, and who suggested or supplied the scenarios implemented in the application.

*Description of each significant application of the model, including dates of usage	Ref. # from Question 15 describing each application	Sponsor/ client for each application	Model operated by: M = modeler S = sponsor O = other	Scenarios supplied by: M = modeler S = sponsor O = other
Least-Cost Energy Strategy Study	3,4	Mellon Institute EPC	S	S

17. As the table above suggests, an important factor in model development and documentation is whether or not the model has ever been installed and operated by someone other than the modeler.

a) Can the model be transferred for use by someone other than the modeler?

__X__Yes _____No If no, why not? __________

b) Has the model ever been transferred for use by someone other than the modeler?

_____No __X__Yes If yes, please indicate where the model was transferred and briefly describe the transfer process. model was transfered to Carnegie-Mellon University

c) Do you have any plans to transfer the model in the future?

__X__No _____Yes If yes, to where? __________

18. One factor sometimes complicating model assessment is that one-time or on-going changes to a model's structure have led to more than one version of that model. In this question we are interested in finding out how many discrete versions of the model have been developed, and which, if any, are currently operational.

a) Has the model undergone any major structural changes since its original finished form?

__X__No (skip to Ques. 19) _____Yes If yes, please briefly describe any significant differences between the versions and the reasons motivating the changes. __________

b) Which version(s) of the model are currently operational, and where are they maintained?

MODEL ASSESSMENT

*19. Has the model ever been subjected to an in-house assessment by the modelers?

_____ No (skip to Ques. 20)

_X_ Yes

a) If yes, which elements listed below received emphasis during the modeler assessment?

- [X] Model validity
  - [X] Structure
  - [X] Content
  - [X] Prediction
- [X] Data validity
- [X] Verification of the model's expression in the computer code
- [ ] Usability
  - [ ] Documentation
  - [ ] Efficiency
- [ ] Model applications
- [ ] Other (specify) ____

b) Please briefly describe the techniques utilized in the modeler assessment.

*20. Has the model been made available for assessment by external parties?

- [ ] No (skip to Question 21)
- [ ] Yes, through publication of model descriptions in the literature.
- [X] Yes, through a formal external assessment assessment done of Automobile sector
- [ ] Yes, through other means (specify) ____

If the model was assessed by an individual, group or organization other than the modeler(s), please answer the questions below:

a) Who was the assessor for the model?

Organization University of Michigan Highway Safety Research Institute
Name of contact Barbara Richardson
Title ____
Address University of Michigan HSRI
2901 Baxter Road
Ann Arbor, Michigan 48109
Telephone (313) 763-1276
Title of Report due to be published fall 1978

b) Who sponsored the assessment?

Organization Motor Vehicle Manufacturers Association
Name of contact Dick Shackston
Title ____
Address ____
Telephone ( ) ____

c) What assessment approach(es) were employed by the assessors?

- [ ] Review of the literature, not including the computer code
- [X] Evaluation of the detailed documentation, including the code
- [X] Audit of the model's performance, using test problems
- [ ] Evaluation of the model using experiments designed by the assessors, but implemented by the modelers
- [X] In-depth assessment, in which the assessors themselves implemented experimental runs of the model
- [ ] Comparative evaluation of two or more models
- [ ] Other (specify) ____

d) Which elements listed below received emphasis during the external assessment of the model?

- [X] Model validity
  - [X] Structure
  - [X] Content
  - [X] Prediction
- [X] Data validity
- [X] Verification of the model's expression in the computer code
- [ ] Usability
  - [ ] Documentation
  - [ ] Efficiency
- [ ] Model applications
- [ ] Other (specify) ____

e) Do you have any comments on the external evaluation of the model?

21. a) Please discuss the accessibility of the model for initial or further assessment. If the model has not been assessed, do you have any plans concerning future assessment? Do you feel it should be considered for an assessment?

22. We would be interested in any other aspects of the model that you would like to discuss. How does it compare with other models in terms of structure or coverage? Were there any interesting ramifications resulting from use of the model?

weight class. It then determines the demand for new cars by calculating the scrappage rate of the existing fleet and by finding the difference between fleet demand and number of cars in the existing fleet minus scrapage. The model then fills the new car demand with cars that minimize the total of the initial costs and the discounted operating costs over the first owner's lifetime of the car. The car is assumed to last 52,000 miles. Future costs are discounted at 10% for 80% of the car buyers. The other 20% are assumed not to consider operating costs when making their purchase. The costs of increased fuel efficiency are built into the model and the fuel prices may be changed for all years of the run. The costs of the technologies to improve fuel efficiency are considered separately for three time blocks within the model. The model also includes different safety and emissions scenarios and can check the effect of MPG requirements and penalties for non-compliance.

The truck and air modes are similar in design to the auto mode. Trucks are divided into light, medium, heavy and heavy-heavy weight classes. Airplanes are divided into six categories for commercial flight and one general aviation class.

The other modes are simpler in design than the first three. This is due largely to data constraints.

TEC offers output on fuel consumption and costs, vehicle costs and vehicle market share.

COMPUTING ENVIRONMENT:

- Machinery: IBM 370
- Language: FORTRAN
- Approximate time per solution: 2 1/2 minutes
- Model is non-proprietary
- Model can and has been transferred
- Model is available on tapes and cards

MODEL DEVELOPMENT AND APPLICATIONS:

The TEC model was developed around the Jack Faucett Associates' Automobile Sector Forecasting Model. The Automobile Sector Forecasting model is now a fully integrated part of the TEC model; however, like all the sectors of TEC, it may be run separately.

The only current application of the TEC model is its use in the Mellon Institute's Least-Cost Energy Study.

Description of each significant application of the model, including dates of usage:	Ref. No. from Bibliography describing each application	Sponsor/ client for each application	Model operated by:	Scenarios supplied by:
			*M = modeler S = sponsor O = other	
Least-Cost Energy Strategy Study	3,4	Mellon Institute EPC	S	S

MODEL ASSESSMENT:

Assessor: Barbara Richardson
University of Michigan Highway Safety Research Inst.
2901 Baxter Road
Ann Arbor, Michigan 48109
313-763-1276

Sponsor: Motor Vehicle Manufacturers Association

An in-house assessment of the TEC model was performed. The validity of the model's structure and content were checked. Tests were also run to check the model's predictions. The in-house assessment also verified the computer code.

An in-depth external assessment of the Automobile Forecasting Sector of the TEC model was performed by the University of Michigan Highway Safety Research Institute. This work included recalculation of the data inputs and the parameters of equations used in the model. Test data were run to check the accuracy of the model's forecasts. This assessment also examined the model's computer code.

No other assessments are planned at this time.

BIBLIOGRAPHY:

1. Jack Faucett Associates, TEC: Transportation Energy Conservation Model, Washington, D.C., JFA, 1978.

2. Jack Faucett Associates, TEC: Transportation Energy Conservation - User's Guide, Washington, D.C., JFA, 1978.

3. The Energy Productivity Center, Least-Cost Energy Strategy - Technical Appendix, Carnegie-Mellon University Press.

4. Shackson, Richard H. and Leach, H. James, Maintaining Automotive Mobility: Using Fuel Economy and Synthetic Fuels to Compete with OPEC Oil, Interim Report, Carnegie-Mellon University Press, 1980.

5. Jack Faucett Associates, Automobile Sector Forecasting Model Documentation, Washington, D.C., JFA, 1978.

Additional Information and Comments on TEC

The TEC model used in the Least-Cost Strategy Study is on the Carnegie-Mellon University computer. Thus it is possible that changes were made to the model which may make it different than the description below. Recently, an evaluation of the Automobile Sector Forecast Model (the automobile sector of TEC) was performed by the University of Michigan Highway Safety Research Institute. This report should be available in the fall. The report did suggest changes that must be made in the model to insure reliability of the results. When this report becomes available, it should provide valuable insights into the rest of the TEC model and the Least-Cost Study. The Least-Cost Study only appears to use the aircraft, automobile, and truck sectors of TEC. Thus they will be the only ones discussed here.

The aircraft sector is divided into two parts: air carrier and general aviation. The Least-Cost Study does not appear to consider general aviation in its analysis. The air carrier sector is further divided into two components, domestic and international travel. This is because the two types of travel have somewhat different characteristics. However, the methodology involved in calculating fuel use is the same.

TEC divides aircraft into six categories according to number of engines and body type (i.e., narrow or wide). Current aircraft are placed into these groups. Fuel efficiency gains are made by replacing existing planes with more efficient planes. The more efficient planes are phased in according to a schedule based on various studies. TEC contains two alternative schedules which may be used. One is based upon the assumption that research being done by NASA will become available. This schedule is considerably more optimistic about fuel efficiency increases than the other schedule that does not assume the NASA research will be available.

The aircraft sector first projects total passenger-miles for a given year. These estimates are based upon an FAA study. However, passenger-miles can be input by the model user. Passenger-miles are then converted to seat-miles by dividing by load factor. TEC assumes a constant load factor of .55. This figure can also be changed by the user.

Seat-miles are then allocated into each of the different aircraft groups. The percentages to each category are held constant by the model. Within each category seat-miles are then allocated to specific aircraft. To do this a retirement schedule based upon assumed aircraft lifetime is applied to the fleet to determine size of existing fleet. Seat-miles are first distributed among the existing fleet. Remaining seat-miles are then allocated to new planes. It is assumed that the most fuel-efficient planes available will be purchased. From this information fuel consumption can then be determined.

The automobile sector begins by projecting a demand for automobiles in a given year. This is done as a function of household income. Different household income levels are assumed to have different demand levels. The parameters were developed from historical data. Total automobile fleet demand is figured by aggregating the number of automobiles demanded by each income level. The demand for new cars is then determined by subtracting current fleet size from the total automobile demand plus scrappage. The scrappage schedule is based upon historical trends. The effect of new car prices and the unemployment rate on scrappage is also added for automobiles nine years or older.

The new car demand is filled by cars that minimize the total discounted costs to the first owner, or about 52,000 miles. The data on costs of increasing fuel efficiency were taken from a Hittman Associates, Inc. study. The study looks at different technologies and estimates their cost and fuel savings. Future costs are discounted at 10% for 80% of car buyers. The other 20% are assumed not to consider future costs in their purchase decision.

TEC divides the automobile market into three groups depending upon weight. Market shares of each of the three weight classes are based upon historical data and are a function of the relative prices of cars of different weight classes and the market share of the weight class in the previous time period.

TEC also computes vehicle miles traveled per year per household. This is a function of disposable income, number of automobiles owned, and the real price of fuel. From the information on weight class, fuel economy of cars, and vehicle miles traveled, TEC calculates fuel consumption. In this calculation an adjustment is made to simulate the fact that as a vehicle gets older it is used less often.

The light truck sector is modeled in a similar way except no competition exists among fuel-saving technologies. Yearly fuel economics are simply put into the model.

The trucking sector is also similar to the automobile sector. The trucks are divided into three types: medium, heavy, and heavy-heavy. The trucks are also divided into seven categories according to their use (e.g., construction, agriculture). Demand for truck use in each of these categories is predicted. This demand is a function of growth in GNP. New truck demand is figured from demand, existing fleet, and scrappage.

Vehicle miles traveled are then calculated and fuel efficiency can be calculated. The fuel efficiencies of different model years are taken from earlier research by Jack Faucett Associates. From information about vehicle miles traveled, fuel efficiencies and the age mixture of the truck, fleet fuel consumption is calculated.

4. Buildings Energy Conservation Optimization Model (BECOM)

Energy Model Analysis Notebook Entry

MODEL NAME: Brookhaven Buildings Energy Conservation Optimization Model BECOM

ANALYTIC TECHNIQUE:
- o Linear Programming

ISSUES ADDRESSED:
- o Demands for Energy
- o Regulatory Behavior
- o Economic Impacts of Energy Policies
- o New Technology Assessment
- o Conservation Assessment
- o Federal Energy Policy

DEVELOPED:
- o 1/77-1/78

RESOLUTION:
- o Geographic: 4 U.S. census regions; U.S.
- o Temporal: 6-20 years

ASSESSMENT: Not Assessed

MODELER CONTACT:
Peter T. Kleeman and Chip Balzer
Building 475
Brookhaven National Laboratory
Upton, NY 11973
617-426-5844

SPONSOR: Department of Energy

MODEL DESCRIPTION:

The Brookhaven Buildings Energy Conservation Optimization Model (BECOM) is designed to provide a tool for projecting, analyzing, and evaluating the energy implications of conventional and proposed energy-related technologies in buildings. Starting with detailed cost and performance data for individual building technologies, the model assembles alternative combinations of these technologies within a linear programming framework. BECOM explicitly models 25 energy conversion technologies and 8 structural technologies that can be used by 9 building types in each of 4 regions. BECOM is designed as an extension of the Brookhaven Energy System Optimization Model (BESOM).

Structure. BECOM is formulated as a modified transportation/transsshipment problem. The aggregated demand points of BESOM for residential/commercial space heat, air conditioning, water heating, and appliances are the sources for the transshipment problem. The destinations are the different building markets. Shipments from source to destination are made through intermediate transfer points: conversion devices and thermal shells. Associated with each node (technology or transfer point) is an efficiency coefficient and a cost. The objective is to minimize cost.

Equations

I) BESOM
   1) Supply equations - limit amount of a given resource available
   2) Demand equations - specify energy requirements of a given sector
   3) Electrical supply and peaking constraints - limit capacities of plants and account for peak demands
   4) Environmental constraints - limit emissions into environment
   5) Market penetration equations - limit technology penetration of markets

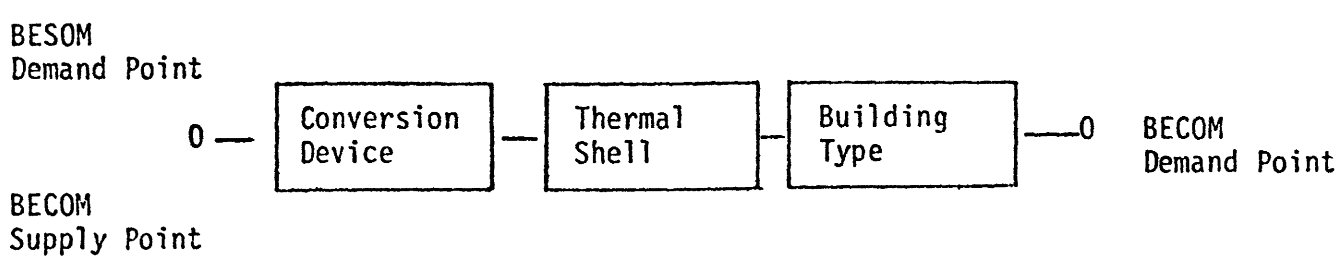
II) BECOM Constraints
   1) Demand constraints for each type of demand and building type
   2) Minimum constraints on residual stock
   3) Seasonal load balance
   4) Fuel mix in new construction
   5) Seasonal operation constraints on heat pumps
   6) Solar back up constraints
   7) Solar AC constraints
   8) Solar water heating

Data Inputs
   1) Building stocks including inventory data for 1975, removals in 1976-2000, and new construction during 1976-2000
   2) Theoretical building loads specified for space heating, air conditioning, hot water, lighting plus power, and auxiliaries in commercial buildings
   3) Shell efficiencies
   4) Conversion device efficiencies
   5) Technology costs

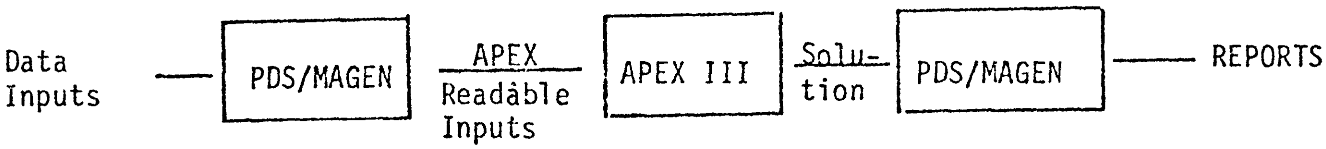
Inputs come from Arthur D. Little data base for buildings.

Outputs. Output for each region is displayed on three levels. The first shows energy demand by building type. The second sums the energy flows separately in residential and commercial buildings. The third presents net energy demand by fuel and end use for each region.

In addition, the results of each run are presented in terms of physical units which use each technology combination. The investment in energy-related devices and structures during the period from 1976 to the case year is summarized.



Model Operation. The model is set up using a general-purpose problem-description system (PDS/MAGEN) which is interfaced to the CDC APEX III linear programming system. Runs for each region are independent of each other. BESOM and BECOM are run simultaneously as a cost-minimization problem.



COMPUTING ENVIRONMENT:

- o CDC 7600
- o Languages employed are PDS/MAGEN, and APEX
- o Linked with BESOM (Brookhaven Energy System Optimization Model)
- o Code available on tapes and cards
- o Non-proprietary

MODEL DEVELOPMENT AND APPLICATIONS:

- o Model is transferable but has not been transferred
- o Replacement model is currently under development under the name KB-1 at Brookhaven National Lab
- o Developed from 1/77 to 1/78 under contract to DOE, Division of Buildings and Community Systems

Description of each significant application of the model, including dates of usage:	Ref. No. from Bibliography describing each application	Sponsor/ client for each application	Model operated by:	Scenarios supplied by:
Assessing market potential of gas powered air-cond. technologies under various fuel & technology price assumptions 9/80-pres.	Work is currently in progress	American Gas Ass'n Arlington, VA	M	S

*M = modeler
S = sponsor
O = other

Assessment of alternative building energy policy options for New York State Energy Office 1979, 1980	4	New York State Energy Office	M	S
Investigation of elasticity of demand for energy 1978, 1980	6,7	Energy Modeling Forum	M	S
Identifying energy conservation strategies in residential and commercial buildings 1979	2,3	Mellon Institute	M	S

MODEL ASSESSMENT:

The modeler conducted an in-house assessment. Although this model has been used, it has not been submitted to formal third-party assessment.

BIBLIOGRAPHY:

1. The Brookhaven Buildings Energy Conservation Optimization Model. Steven C. Carhart, Shirish S. Mulherkar, and Yasuko Sanborn. BNL 50828, Brookhaven National Laboratory, 1978.

2. The Least-Cost Energy Strategy. The Energy Productivity Center, Mellon Institute. Carnegie-Mellon University Press, 1979.

3. The Least-Cost Energy Strategy: Technical Appendix. The Energy Productivity Center, Mellon Institute. Carnegie-Mellon University Press, 1979.

4. Analysis of New York State Energy Office Conservation Programs in Buildings. Peter T. Kleeman and Doreen Schneider. BNL 28523, Brookhaven National Laboratory, 1980.

5. A Simulation Model for Assessing Building Energy Conservation Policies. Peter T. Kleeman in Modeling and Simulation, Volume II, Proceedings of the Eleventh Annual Pittsburgh Conference, Pittsburgh, PA, May 1-2, pp. 1133-39, Instrument Society of America, Research Triangle Park, N.C., 1980.

6. Aggregate Elasticity of Energy Demand. Energy Modeling Forum, EMF report 4, vol. 1, August 1980.

7. Aggregate Elasticity of Energy Demand. Energy Modeling Forum, EMF report 4, vol. 2, in preparation.

ENERGY MODEL ANALYSIS PROGRAM
Energy Laboratory
Massachusetts Institute of Technology
Cambridge, Massachusetts 02139

QUESTIONNAIRE FOR ENERGY POLICY MODELERS

The M.I.T. Energy Model Analysis Program (EMAP), under sponsorship from the Electric Power Research Institute, is developing a directory of energy models and assessments, to be published in the fall of 1980. The directory will be distributed widely to government departments, academic institutions, and private industry, and will be an extremely useful reference tool for model developers, assessors, and users. We would very much like to include your model in this directory, and therefore are requesting that you complete the following form to provide the information needed. We will then compile your responses into a standardized format, which will be sent to you for review prior to publication.

Please answer the questions below as completely as you can, we are particularly pleased to be able to present in this directory the kind of meaningful and interesting information and perspective that only modelers and model assessors themselves can provide. We are interested in anything you have to offer about your model, and encourage you to use extra sheets of paper where necessary. If you are extremely short of time, please answer the questions marked with an asterisk.* Martha Mason and Kelly Morgan of the EMAP will be happy to answer any questions and offer assistance, they may be contacted at (617) 253-8318.

Thank you for your assistance — the directory will not be complete without an entry on your model!

GENERAL INFORMATION

*1. What is the name of the model? Brookhaven Buildings Energy Conservation Optimization Model

*2. By what acronym, nickname, or other name(s) is it known? BECOM

*3. Where, and under what auspices, was the model developed. Developed at Brookhaven National Laboratory under contract to the U.S. Department of Energy, Division of Buildings and Community Systems.

*4. Over what time period was the model developed? ~ 1/77 (mo/yr.) to 1/78 (mo/yr.)

*5. Who is the person filling out this questionnaire?

Name: Dr. Peter T. Kleeman
Address: Building 475, Brookhaven National Laboratory, Upton, NY 11973
Telephone: (516) 345-2116
Relationship to model: Have used and modified model for expanding its capabilities.

*6. Who is (or are) the key modeler contact(s)?

Name: Dr. Peter T. Kleeman
Address: Bldg. 475, Upton, NY 11973
Telephone: (516) 345-2116
Relationship to model: as above

Name: Chip Balzer
Address: Bldg. 475, Upton, NY 11973
Telephone: (516) 345-2256
Relationship to model: Data base and model maintenance

*7. Who is (or are) the key contact(s) in the organization(s) that sponsored the model development?

Name: Mr. Peter Back
Address: U.S. DOE, Washington, D.C. 20585
Telephone: (202) 252-9426
Relationship to model: program sponsor

Name: Mr. Steven Lee
Address: U.S. DOE, Washington, D.C. 20585
Telephone: (202) 252-9426
Relationship to model: Program sponsor

MODEL CHARACTERISTICS

The following questions are designed to provide understanding of the fundamental technical characteristics of the model. The multiple-choice options are provided for your convenience; however, we understand that models vary significantly, and these choices may not be suited to your model. Please add categories, phrases, or sentences, as applicable.

In Question 18 we will ask about different operating versions of the same basic model. If there has been more than one version, please indicate here which one you are describing. If the versions are significantly different, you may find it necessary to fill out a complete questionnaire for each unique model version.

*8. What keywords characterize the issues the model addresses?

- ☐ Supply of fuels & resources
- ☑ Demand for electricity
- ☑ Demand for non-electric energy
- ☑ Regulatory behavior
- ☐ Electric utility behavior
- ☐ Other industry behavior
- ☑ Economic impacts of energy policies
- ☐ Environmental impacts of energy policies
- ☐ Demographic/social impacts of energy policies
- ☑ New technology assessment
- ☑ Conservation assessment
- ☑ Other (specify) Federal energy policy assessment

*9. What analytic techniques are used in the model? (If appropriate, check more than one, and indicate which subsection of the model uses which technique)

- ☑ Linear programming
- ☐ Nonlinear/integer programming
- ☐ Other static optimization
- ☐ Dynamic optimization
- ☐ Stochastic techniques
- ☐ Descriptive simulation
- ☐ Allocation & equilibrium
- ☐ Input/output
- ☐ Regression, econometric
- ☐ Expert opinion, non-quantitative
- ☐ Other (specify)

*10. a) What geographic resolution does the model cover?

- [ ] Site-specific (specify) ______
- [x] Regionwide (specify) ______ four U.S. census regions
- [ ] Statewide (specify) ______
- [x] U S as a whole ______ as union of four regions
- [ ] International (specify) ______
- [ ] Other (specify) ______

b) If regional information is aggregated before reporting results, what is the level of aggregation? ______

*11. a) What temporal resolution does the model cover?

- [ ] Short term (5 years or less) ______
- [x] Medium term (5-20 years) ______
- [ ] Long term (over 20 years) ______

b) If there are discrete time steps, what is their typical length? ______

12. Aside from their use as input, were data used during calibration/development of the model?

______ yes ✓ no (skip to ques. 13)

If yes, how were the data used?

- [ ] for coefficient/parameter determination
- [ ] for structural form determination
- [ ] for assessing the accuracy of model results
- [ ] other (specify) ______

*13. In the space below (or on extra sheets) please provide a complete technical description of your model, discussing when applicable:

- model structure and methodology
- significant equations
- parameters
- variables (endogenous & exogenous)
- input data
- output data

When discussing input data, please differentiate between those data that serve as input assumptions imbedded in the model and those that are frequently changed during model runs.

Please attach a flow chart or other diagram of the structure of the model, if possible.

see attached report (reference 1 in bibliography)

*14. The following questions concern the computing environment required by the model.

a. Brand of machinery ____Control Data Corp.__CDC 7600______
b. Language(s) employed __PDS/MAGEN, __APEX____
c. Approximate cost per solution cost __$50_____ or time ______ per solution
d. Is the model linked with other models or software packages?
_____No _XX__Yes (specify) Brookhaven Energy System Optimization Model (BESOM)
e. Is the code available on tape __XX______ cards ____XX____?
f. Are any parts of the model proprietary?
_XX_No _____Yes (specify) ______

*15. Bibliography

We would like to include a bibliography for your model. Therefore, in the following space, or on an attached sheet, please list all references in which the model has been described or cited, including documentation, journals, publications, and reports on model applications. Please number each item for easy reference later in the questionnaire.

1. The Brookhaven Buildings Energy Conservation Optimization Model. Steven C. Carhart, Shirish S. Mulherkar, and Yasuko Sanborn. BNL 50828, Brookhaven National Laboratory, 1978.

2. The Least-Cost Energy Strategy. The Energy Productivity Center, Mellon Institute. Carnegie-Mellon University Press, 1979.

3. The Least-Cost Energy Strategy: Technical Appendix. The Energy Productivity Center, Mellon Institute. Carnegie-Mellon University Press, 1979.

4. Analysis of New York State Energy Office Conservation Programs in Buildings. Peter T. Kleeman and Doreen Schneider. BNL 28523, Brookhaven National Laboratory, 1980.

5. A Simulation Model for Assessing Building Energy Conservation Policies. Peter T. Kleeman. in Modeling and Simulation, Volume 11, Proceedings of the Eleventh Annual Pittsburgh Conference, Pittsburgh, PA, May 1-2, pp. 1133-39, Instrument Society of America, Research Triangle Park, N.C., 1980.

6. Aggregate Elasticity of Energy Demand. Energy Modeling Forum, EMF report 4, vol. 1, August 1980.

7. Aggregate Elasticity of Energy Demand. Energy Modeling Forum, EMF report 4, vol. 2, in preparation.

16. Which documents listed in Question 15 are references for the model's data sources?

Reference numbers 1, 3.

MODEL DEVELOPMENT AND APPLICATIONS

In this section we are interested in tracing how the model has been used. In the first column, please describe each application of the model, uses might include both academic study and specific problem solving. In the following columns please indicate which reference number from Question 15 describes the application, who the sponsor was for that application, who actually operated the model, and who suggested or supplied the scenarios implemented in the application.

*Description of each significant application of the model, including dates of usage:	Ref. # from Question 15 describing each application	Sponsor/client for each application	Model operated by: M = modeler S = sponsor O = other	Scenarios supplied by: M = modeler S = sponsor O = other
Assessing market potential of gas powered air-cond. technologies under various fuel and technology price assumptions 9/80 - pres.	work is currently in progress	American Gas Association, Arlington, VA	M	S
Assessment of alternative building energy policy options for New York State Energy Office 1979,1980	4	New York State Energy Office	M	S
Investigation of elasticity of demand for energy 1978,1979	6, 7	Energy Modeling Forum	M	S
Identifying energy conservation strategies in residential and commercial buildings 1979	2, 3	Mellon Institute	S	S

17. As the table above suggests, an important factor in model development and documentation is whether or not the model has ever been installed and operated by someone other than the modeler.

a) Can the model be transferred for use by someone other than the modeler?
XX Yes ______No If no, why not? ____________

b) Has the model ever been transferred for use by someone other than the modeler?
XX No ______Yes If yes, please indicate where the model was transferred and briefly describe the transfer process. Sponsor used BNL installation but worked independently

c) Do you have any plans to transfer the model in the future?
XX No ______Yes If yes, to where? ____________

18. One factor sometimes complicating model assessment is that one-time or on-going changes to a model's structure have led to more than one version of that model. In this question we are interested in finding out how many discrete versions of the model have been developed, and which, if any, are currently operational.

a) Has the model undergone any major structural changes since its original finished form?
______No (skip to Ques 19) XX Yes If yes, please briefly describe any significant differences between the versions and the reasons motivating the changes
new version (or replacement model) currently under development under the name KB-1 at Brookhaven National Laboratory

b) Which version(s) of the model are currently operational, and where are they maintained?

MODEL ASSESSMENT

*19. Has the model ever been subjected to an in house assessment by the modelers?

__✓__No (skip to Ques. 20)

_____Yes   a) If yes, which elements listed below received emphasis during the modeler assessment?

- ☐ Model validity
  - ☐ Structure
  - ☐ Content
  - ☐ Prediction
- ☐ Data validity
- ☐ Verification of the model's expression in the computer code
- ☐ Usability
  - ☐ Documentation
  - ☐ Efficiency
- ☐ Model applications
- ☐ Other (specify) ____

b) Please briefly describe the techniques utilized in the modeler assessment.

*20. Has the model been made available for assessment by external parties?

- (✓) No (skip to Question 21)
- ☐ Yes, through publication of model descriptions in the literature
- ☐ Yes, through a formal external assessment
- ☐ Yes, through other means (specify) ____________

If the model was assessed by an individual, group or organization other than the modeler(s), please answer the questions below:

a) Who was the assessor for the model?

Organization ____________
Name of contact ____________
Title ____________
Address ____________

Telephone (   ) ____________
Title of Report ____________

b) Who sponsored the assessment?

Organization ____________
Name of contact ____________
Title ____________
Address ____________

Telephone (   ) ____________

c) What assessment approach(es) were employed by the assessors?

- ☐ Review of the literature, not including the computer code
- ☐ Evaluation of the detailed documentation, including the code
- ☐ Audit of the model's performance, using test problems
- ☐ Evaluation of the model using experiments designed by the assessors, but implemented by the modelers
- ☐ In-depth assessment, in which the assessors themselves implemented experimental runs of the model
- ☐ Comparative evaluation of two or more models
- ☐ Other (specify) ____________

d) Which elements listed below received emphasis during the external assessment of the model?

- ☐ Model validity
  - ☐ Structure
  - ☐ Content
  - ☐ Prediction
- ☐ Data validity
- ☐ Verification of the model's expression in the computer code
- ☐ Usability
  - ☐ Documentation
  - ☐ Efficiency
- ☐ Model applications
- ☐ Other (specify) ____

e) Do you have any comments on the external evaluation of the model?

21. a) Please discuss the accessibility of the model for initial or further assessment. If the model has not been assessed, do you have any plans concerning future assessment? Do you feel it should be considered for an assessment?

This model is not a good candidate for assessment since a model is currently being developed that will in effect replace this model with one of superior quality. ~~This model is currently known as KB-1 and may be implemented and documented~~ sometime within the next several months.

22. We would be interested in any other aspects of the model that you would like to discuss. How does it compare with other models in terms of structure or coverage? Were there any interesting ramifications resulting from use of the model?

This model indicated in several applications that aggressive policies on the part of the federal govt. could encourage large energy savings in both residential and commercial sectors. The bulk of these savings would occur through building envelope improvement rather than conversion device retrofit or replacement when real fuel prices paid by consumers increases.

References

1. Jack Faucett Associates, Inc. TEC: Transportation Energy Conservation Model, Jack Faucett Associates, Inc., August 1979.

2. Energy and Environmental Analysis, Inc., Industrial Sector Technology Use Model (ISTUM): Industrial Energy Use in the United Syayes, 1974-2000, Vol. I, EEA, Inc., June 1978.

3. Carhart, Steve C. The Least-Cost Strategy--Technical Appendix (Carnegie-Mellon Unvirsity Press), 1979.

4. Conversation with Samir Salama, Harold Kalkstein, and Tim Hogan, Energy and Environmental Analsyis, Inc., May 29.

5. Conversation with Mike Laurence, Jack Faucett Associates, Inc., May 29.

6. Telephone conversation with Barbara Richardson, University of Michigan Highway Safety Research Institute, June 16.

Massachusetts Institute of Technology

Energy Laboratory

Energy Model Analysis Program

Appendix B

An Evaluation of the Mellon Institute Least Cost Energy Strategy

by

George Tolley*
Ronald Krumm *
Edward Mensah*

June 1981

*Department of Economics, University of Chicago

Table of Contents

INTRODUCTION AND OVERVIEW

The Mellon Institute Least Cost Energy Strategy (LCES) is an attempt to examine how the effects of higher world energy prices can be partially mitigated through the introduction of more efficient technologies. The approach taken in the LCES is to consider competition between alternative new technologies to determine their adoption patterns. Very detailed breakdowns according to technology type, and energy service demand by industry, transportation, and housing sectors are provided.

The scenario explicitly considered by the LCES is what technologies and energy inputs would have been adopted in 1978. Actual energy service quantities in 1978 are determined and then, not allowing for changes in these quantities, the cost savings associated with adoption of least cost technologies to meet these these energy service quantities are determined using existing, large scale computer algorithms for each of the industrial, transportation, and housing sectors. The industrial sector analysis makes large use of the Industrial Sector Technology Utilization Model which is not part of the LCES report but was partially available to us for examination. The building sector analysis relies heavily on the Building Energy Conservative Optimization Model and the transportation sector relies on the Transportation Energy Conservation Model. Documentation of neither of these models was available to us for evaluation. Below, our evaluations of the LCES are presented based on the LCES reports and other limited material available to us but not included as documentation to the Mellon Institute reports.

MARKET ADOPTION IN THE LCES

The methodology employed in the LCES is to consider energy efficiency improvements in three sectors of the economy: industrial sector, buildings sector, and the transportation sector. While improved efficiency in each of these sectors had been substantial up through 1978, as pointed out by the authors of LCES, the approach taken by them is to consider more completely further efficiency improvements and the potential cost-savings associated with their adoption. The question they wish to provide insights on is "How would the nation have provided energy services in 1978 if its capital stock had been reconfigured to be optimal for the actual 1978 energy prices?" In essence, their answer to the question involves comparison of costs of providing energy services among alternative technologies in various sectors of the economy. This section examines the methodologies used in this attempt and evaluates them in the hope of providing a more appropriate approach.

A. Industrial Sector Analysis

The first step in analysis of the industrial sector is to determine the quantity of energy services demanded to produce given output levels based on actual 1978 levels of economic activity. Given these quantities as inputs, the Industrial Sector Technology Utilization Model (ISTUM) is used to calculate the lowest cost combination of fuel and efficiency improvement technologies to meet these quantities demanded. The average cost of fuel prices in 1978 were used in this cost determination approach. No changes potentially induced by lower cost alternatives, on economic output levels or the distribution of economic activity are permitted. Turnover of the capital stock in which technologies are embedded includes equipment used in generation or conversion of energy but not other items.

The exercise considers 23 energy service sectors (e.g., machine drive, space heat,etc.) in 26 industrial catagories. Within each service sector technologies were adopted on the basis of the ISTUM lowest service cost algorithum. The least cost estimates are based on an assumed constant (1978 actual) quantities of service demanded and energy prices through the year 2000, but allow for full turnover of energy using durable goods taking into account replacement through the year 2000. The authors suggest that limitations in the approach such as process changes due to changing costs of energy services are not serious because the analysis is only for one year, 1978. Numerous technologies are considered for each of the 23 service sectors with competition between technologies conducted separately for each service sector.

Market Share Projections

Market share projections in the LCES are determined by use of ISTUM. The discussion presented here is based in large part on documents referred to in the LCES pertaining to ISTUM but not developed by the LCES. The basic approach is to characterize the cost of a technology in terms of capital costs and costs associated with the utilization of the durable good in generation or conversion of energy services. With different costs associated with alternative technologies and utilization rates the objective is to determine the least cost technology that would be adopted. The cost of each technology is determined by adding up (using a discounted cash flow technique) capital costs, fuel costs, and operating and maintenance costs. That technology with the lowest total cost is then the appropriate technology to be adopted.

The procedure to determine the total cost associated with each technology is to assume distributions of fuel costs, capital costs, and operating costs. For a particular type of plant this includes site preparation, start-up costs, and other capital costs as well as refined breakdowns for operating and maintenance costs. Appropriately, ISTUM realizes that these costs may vary by plant for a variety of reasons (included are site-specific valuations and firm-related variation). Hypothetical ranges associated with cost variation due to these factors are then used to determine distributions of costs associated with all factors that figure into total cost determination. These distributions are then added together (assuming independence) to arrive at total cost distributions for each technology. Each technology is assumed to have a maximum market share in each service sector with some technologies excluded (zero market share). The exact procedure for this determination, however, is not explicitly addressed in the available documents. In addition to these considerations, often some technologies are limited in application because of restrictions in size either because of technical factors or through regulation. The cost associated with a particular technology may also depend on the extent of utilization. Thus load factor categories are used within each service sector in analysis of competition among alternative technologies.

Competition between alternative technologies is examined in five-year intervals (1980-2000) with only those technologies available in a given year able to compete. Thus, for example, a technology that is expected to be developed in 1985 will have no effect on the technologies available in 1980 and adopted in 1980. The nominal market share is "...that fraction of the market segment in which that technology will be able to supply energy to the final process more cheaply than any other competitor."

Since the nominal market share determines the fraction of the market in which any technology is theoretically preferable to any alternatives, based on the cost of the alternatives, it is most probably the market ceiling for the particular technology. It is realized that the acceptance of a given product or process in a market place is not dependent on cost considerations alone. Factors such as consumer risk aversion, lags in transfer of information concerning the technology, role of governments, etc., all affect the rate at which a product/process is adopted.

In the original industrial sector technology utilization model (ISTUM) these factors are termed behavioral lag factors. ISTUM defines behavioral lag as the amount of time in years required for actual market shares to equal the nominal market shares (the market ceiling). It is supposed to be a time lag function controlling the rate at which the actual market shares approach the market ceiling. ISTUM concentrates only on costs and does not consider the effect of net benefits of a particular technology on its adoption. To get around this point, the ISTUM methodology uses the ratio of the nominal market share (NMS) to maximum market fraction (MMF) as a measure of the perceived profitability of a technology (PTP) and in turn the expected length of the behavioral lag. The assumption is that the higher this ratio, the higher the perceived profitability of a technology and hence the shorter the behavioral lag time.

The behavioral lag time (BLT) is modeled as the product of the initial technology behavioral lag time, ITBLT, and the behavioral lag multiplier. The ITBLT is defined as the maximum number of years one could imagine that risk aversion and information transfer constraints which delay the commercial acceptance of a product/process could be overcome. ISTUM sets the upper limit of this number to be 15 years.

A risk aversion multiplier (or lag time slope) is defined as the slope of a downward sloping straight line which depends on the nominal market share relative to the maximum market fraction. This slope is set equal to 5.0. After calculating the behavioral lag time for each technology, the actual market share (AMS) is computed according to the following procedure:

$$AMS = \begin{cases} 0, \text{ where } t - YTA < 0 \\ NMS(t) \times (t - YTA(t)), \text{ where } 0 \leq t - YTA(t) \leq BLT(t) \\ NMS(t), \text{ where } t - YTA(t) > BLT(t) \end{cases}$$

where YTA = Year technology is available

BLT = Behavioral time lag

t = Time in calendar years

The assumption is that once time t exceeds the year technology is available, (YTA), by the technology behavioral lag time, actual market share will be equal to the nominal market share. Since this model does not take into consideration the probable appearance on the market of more superior technologies, it is not clear whether the nominal market share or the market ceiling will ever be approached by most of the technologies.

Results

In the industrial sector, technological improvements in energy efficiency accounted for 22% of the industry energy service market in 1978 in the absence of least cost strategy. However, the results also show that if least cost strategy had been applied in 1978, technological improvements in the energy efficiency would have accounted for 33% of the energy service market. Oil utilization in industry contributed to 18% of the energy service market in 1978 and in the hypothetical situation, oil would have accounted for only 11% of the energy utilization in industry. Another important difference in energy utilization in industry was in the area of natural gas usage. The results show that while natural gas accounted for 22% of the energy service market in 1978, if least cost strategy had been employed natural gas would have accounted for 37% of the energy service market in 1978. Purchased electricity would have captured 11% of the market for energy services in industry in the presence of least cost strategy in 1978 but the actual share of the market captured by purchased electricity in 1978 was 26%. Industrial coal utilization would have dropped from 10% in the actual 1978 situation to 7% in the hypothetical case.

On the whole, energy cost per capita which was $257 would have decreased to $232 if least cost strategy had been employed in 1978. This is a 10% drop in the actual 1978 situation.

Evaluation

Table 1 presents the major comments of our evaluation of the LCS modeling effort.

First, the modeling effort provides a detailed breakdown of energy service demand sectors and industrial catagories. This disaggregation effort is an important step forward in analysis of market adoption of new innovations. They have provided a model that brings to light some of the effects of competition between new technologies on the extent of adoption which are essential ingredients in understanding adjustment to the changing world energy situation.

Second, the demands for energy sources in each sector are assumed fixed at their 1978 levels, not responsive to price or expected growth

TABLE 1

COMMENTS ON THE LCES INDUSTRIAL SECTOR ANALYSES

1. The detailed breakdown of energy service demand sectors and industry categories is a necessary step forward in the modeling of market adoption of new technologies.

2. Effects of energy service cost reductions due to adoption of new technologies on costs of outputs and input quantities demanded need to be considered to determine total market adoption patterns.

3. The LCES results are relevant for comparison of cost savings associated with adoption of new technologies only in the sense that they compare actual costs to what costs could have been if adoption of new technologies took place in a non-dynamic setting without uncertainty. A more realistic approach is needed that takes into account market adoption decisions in a world where future changes in prices and economic conditions are uncertain.

4. Costs of adjustment are not explicitly modeled in the LCES market adoption methodology. Factors that alter the rate of adoption of new technologies should be viewed in the same manners as other costs and explicitly included in the LCES analysis.

TABLE 1 (con't)

COMMENTS ON THE LCES INDUSTRIAL SECTOR ANALYSES

5. The level of existing durable good stock structure, embodying older technologies should be explicitly considered in the determination of adoption of new technologies. Replacement of existing technologies will depend on the age and efficiency structure of capital goods in which technologies are embedded and thus will alter the rate of adoption of a new technology depending on this structure.

6. Effects of expectations of introduction of newer technologies in the future on current adoption patterns of new technologies in the current period need to be explicitly treated in the LCES analysis. The age structure of existing capital stock, the life terms of alternative new technologies and the extent of expected future cost reductions will play important roles in determination of market adoption patterns of existing new technologies.

7. The approach taken in the LCES through use of ISTUM is to consider dispersion of elements of costs associated with purchase and utilization of new technologies. The economic reasons for this dispersion need to be explicitly incorporated into the cost structure analysis instead of relying on mechanistic procedures to determine cost dispersion and the maximum market penetration of new technologies. Variation in labor costs and other input costs as well as output market conditions need to be included in a more complete analysis.

TABLE 1 (con't)

COMMENTS ON THE LCES INDUSTRIAL SECTOR ANALYSES

8. A least cost of production strategy could include substantial relocation of industry to areas where fuel costs are lower and climatic conditions are such to lower demand for energy servies in heating and cooling capacities. However, the benefits to the population may be more substantially decreased because of higher costs of transportation and/or costs associated with population relocation. Instead of relying on cost of production decreases as the LCES, a more appropriate approach would be to consider reduced costs of population consumption of all goods and services.

9. The cost savings associated with adoption of a technology that provides two distinct services is the sum of the savings in each category. The appropriate comparison between alternative technologies, some of which provide multiple services, should take into account such joint cost savings. The current cost comparison algorithms, to the best of our knowledge do not take into account these properties.

10. The year of availability of new technologies, just like costs of existing technologies, should be allowed to depend on economic factors.

or decline in demand. Further, reduced costs of production in one sector of the economy due to adoption of new technological innovations do not affect production costs in other sectors. For example, reduced steel prices would not reduce the cost of automobiles. People often consume not the output of metal fabrication industries but rather services from goods they directly purchase. A direct measurement of the benefits to society of adopting new technologies is the ability of people to purchase goods and services they directly consume and not the changes in costs associated with intermediate goods used in production.

Third, although the LCES results are only meant to relate to what happened in 1978 relative to what could have happened if the LCES were followed, it is not clear that given the information available in 1978 and earlier, the LCES results may not have been appropriate, even with perfect foresight with respect to new technologies. For example, great uncertainty with respect to future energy prices may optimally lead to less investment in new technologies that would have large benefits associated with their adoption only if fuel prices did not decline.

Fourth, costs of adjustment are not explicitly treated in this modeling effort. If all relevant capital was to turn over immediately in 1978, the cost of producing all the durable goods that embody the new technology may increase in cost. Thus the cost distribution associated with supply of one type of technology will not be independent of the quantity of other technologies supplied. More explicit treatment of the aggregate implications of the model results and their appropriateness is needed.

Fifth, the role of the existing capital stock and cost of utilization relative to that associated with the new technologies needs to be more completely developed. The efficiency of the existing capital stock may depend significantly on its age structure and thus the technology imbedded in it. It appears there is an asymmetry between competition between existing (old) technologies and that between new technological innovations. Our understanding of the model is that all old capital is replaced by improved existing technologies as of 1978 and this old capital has no value. An economic treatment of this subject would not lead to this result and that it is not likely to be a least cost strategy. In order to carry a more sound economic analysis along these lines it would be necessary to compare costs of utilizing existing durable goods that embody old technologies with both costs of new durable goods containing new technologies and their costs of utilization.

Sixth, the expected introduction of a new technology in the future does not affect what technologies are adopted in the current period. Even abstracting from the existence of current old technologies that are in place, the choice between two equal-cost technologies available in the current period, but with different lifetimes, will not be adopted at the same rate if it is expected that in two years a new, dominant technology will become available. In addition, in some cases it may be least costly not to replace an old technology with a new, more efficient technology, if it is expected that an even more efficient, less costly technology will be developed in the near future. These trade-offs need to be more explicitly dealt with in the Mellon Institute study.

Seventh, the approach taken in the LCES through the use of ISTUM is to consider dispersion of elements of costs associated with the purchase and utilization of new technologies. The economic reasons for this dispersion need to be explicitly incorporated into the cost structure analysis instead of reliance on mechanistic procedures. For example, variation in labor costs and other input costs will alter the variation in cost in a systematic manner that should be included in the cost structure analysis.

Eighth, a least cost strategy could involve the relocation of all industry to regions where energy costs are minimized and/or where climatic conditions are such as to require very little heating services. This may lead to very low costs of production but an overwhelming decrease in the benefits that stem from the consumption of the goods purchased. In other words, the resulting increase in costs of transporting goods and services where people live would outweigh the savings achieved by production relocation. Moreover, such considerations suggest that the effects of energy cost changes in production and distribution (the transportation sector) cannot be developed independently. Optimal adjustment to higher energy prices thus involves comparison of <u>both</u> benefits and costs associated with the adoption of new technologies in a spatial context.

Ninth, the cost savings associated with adoption of a technology that produces two distinct services is the sum of the cost savings in each category. The appropriate comparison, for adoption purposes, between technologies that have such characteristics should take into account these joint cost savings amounts. The current cost comparison algorithms, to the best of our knowledge, does not take into account this property.

Tenth, the year of availability of new technologies depends on differences between regions, prices, labor ayailabilities, site-specific factors as well as qualitative service demand differences such as product/process reliability. The model should include the effects of interactions between these factors on the availabilities of new and improved technologies and make new technology development a result of economic determinants.

B. Building Sector

The LCES for the building sector focuses on the lowest cost combination of energy technologies that would satisfy the actual 1978 quantities of a variety of service demands. Nine building types were considered under the residential and commercial building categories; the residential category had four building types--single-family detached, low density, multi-family, and mobile homes. The commercial buildings category is made up of the following: office, retail, school, hospital, and miscellaneous. Service demands in a building category are broken down into four types: 1) space heating, 2) air conditioning, 3) thermal demands (water heating, cooling, drying), and 4) lighting/appliances. An example of a space heating demand for a single-family house is the energy required to maintain a reference house, defined explicitly in terms of its thermal characteristics, at a reference temperature for one year. Fuel demand is then derived from service demand by adjusting for fuel conversion efficiences.

Service demands were derived for new and existing buildings for each of the four end uses--space heating, air conditioning, thermal, lighting/appliances--in each of the nine building types in the four specified regions of the U.S. The LCES uses the Building Energy Conservation Optimization Model (BECOM) which derives the least cost mix of capital and fuel required to meet all service demands. However, no documentation of this model was available.

Model Formulation

The model is formulated as a trans-shipment problem with energy as the commodity to be shipped from the supply nodes (fuel sources) to the demand nodes (building service demands). All the possible ways of satisfying the service demand for each building type in each region are specified. Each procedure is likely to incur a different cost. The components of the costs are 1) fuel cost, 2) capital cost amortized over the lifetime of the equipment, and 3) the capital cost of the structural improvements, also amortized. The costs are represented as costs per unit of service adjusted for efficiency.

Given the efficiencies of the equipments and the structural technologies and the associated costs, the preferred mode for the provision of a service demand is one that provides the energy service at the lowest cost. A discount rate of 5% is used in the LCES. The model is basically a cost minimization linear programming algorithm which seeks to achieve the least cost of provision of a specific level of service demand in a given building type in all four regions of the U.S.

Results

According to the LCES modeling effort, building energy service markets would have shown a 23% reduction in the cost of energy services per capita if the least cost strategy had been employed in 1978. Technological improvements in energy efficiency accounted for only 2% of the energy service market in the building sector in the actual 1978 situation. But in the least cost case , a hypothetical 1978 case, improvements in energy efficiency would have contributed 35% of the market for energy services.

The shares of oil, natural gas, and purchased electricity in the buildings' energy service would have declined if least cost strategy had been followed in 1978. Oil would have accounted for 12% of the building sector energy service market in the hypothetical case compared to 16% in the actual 1978 situation. The share of natural gas in the energy services market would have decreased from 56% in the actual 1978 situation to 37% in the hypothetical situation.

Intensive retrofitting of residential and commercial structures would have been mostly responsible for the difference between the two cases, contributing to over 8% of the aggregate energy service market. It was also found that under the 1978 hypothetical case, the introduction of more energy-efficient appliances would have occurred.

Evaluation

Table 2 gives our major comments on the LCES modeling in the building sector.

First, regional representative technologies are described in much detail for all building types. Most of the refined breakdowns deal with alternative technologies and associated costs. This is a necessary first step in analysis of adoption of alternative technologies in the housing sector.

Second, documentation of the procedures used in the LCES is not complete so that comment on the underlying determinants of market penetration cannot be clearly presented.

Third, homogeneous conditions are assumed within each broad regional category although very substantial variations in climatic conditions, structural characteristics, and energy prices exist. A need is to consider more completely this intra-regional variation in the above factors.

Fourth, the 1970's were characterized by substantial regional and intra-regional change in location of population. To the extent that differential energy costs played a role in these patterns, market penetration results in the buildings sector may not affect the least cost strategy.

Fifth, similar to the modeling for the industrial sector, no consideration is given to the role of existing technology age structure, or age structure of the housing unit itself. Issues associated with adoption of new technologies in existing buildings need to be examined more completely before the LCES results can be useful in describing potential cost savings.

Sixth, sensitivity analysis with respect to assumptions made would be useful in establishing the stability of the results and indicating which assumptions need to be more fully addressed.

TABLE 2

COMMENTS ON THE LCES BUILDING SECTOR ANALYSIS

1. Very refined breakdowns of alternative technologies are presented and provide a necessary first step in market adoption analysis.

2. Documentation of analytical procedures used limits comment on the methodology.

3. More refined intra-regional breakdowns would enhance the usefulness of the modeling effort.

4. Substantial movement of population between and within regions in the period analyzed needs to be included in the analysis of housing demand and associated energy use.

5. The role of age structure of existing housing stock and technologies needs to be more fully incorporated into the new technology adoption process.

6. Sensitivity analysis to the assumptions made would be useful in indicating which assumptions need to be more fully explored.

C. Transportation Sector

The approach taken in the LCES for the transportation sector was to make use of the Transportation Energy Conservation Model (TEC), for which documentation was not available.

Model

Specification of service quantity demanded (passenger miles of service to consumers) was determined through historical correlation with disposable income and other variables, although the nature of this relation is not presented. Principle modes of transportation are examined with aging and retirement of vehicle types, although the procedures used are not documented. However, no switching between modes is allowed. Moreover, it "assumed that development of technologies planned for introduction within the next ten years would have been advanced to make them available in 1978."

For each mode, transportation source demand is held constant. The LCES then makes use of TEC to determine the least cost mix of technologies. Apparently, a variety of alternative technologies were considered in each mode.

Results

The results showed that in the transportation sector significant technological improvements in energy efficiency in automobiles would have contributed to 29% of the energy service market shares in the hypothetical least cost case in 1978 compared to the 3% shares captured by improved energy efficiency in the actual 1978 case. Oil consumption would have accounted for 69% of the energy service market in the hypothetical case compared to 94% in the actual 1978 case. Most of the improvements in efficiency in the hypothetical situation in the transportation sector were expected to result from improved fuel economy, increased use of diesel engines in light and heavy-weight trucks, reductions in vehicle weight through material substitution, and substitution of advanced wide-body for narrow-body airplanes. Under the hypothetical 1978 least cost situation, deregulation of the airline and trucking industries was expected to have led to further improvements in efficiency.

The study also found that even though efficiency improvements and fuel substitutions occurring in the hypothetical situation would have required $364 billion (1978 prices), it would have cost a lot less than the $401 billion invested in power plants and the oil import bills actually required in past years.

Evaluation

Table 3 summarizes our evaluation of the LCES transportation sector analysis.

First, unlike the analysis for the industrial and buildings sectors, it appears that the analysis for the transportation sector does take into account the influence of existing durable goods and retirement rates in determining adoption of new technologies. This is an important element in the analysis and should be addressed and documented more completely.

Second, mode switching, especially within urban areas, is likely to have a major impact on demand for transportation services of each mode even though demand for transportation services may not change in all modes.

TABLE 3

COMMENTS ON THE LCES TRANSPORTATION SECTOR ANALYSIS

1. The role of age structure and retirement rate associated with existing durable goods is included in analysis of new innovation market penetration, but needs to be more completely documented.

2. Mode switching as a result of changing costs needs to be included in the analysis as it has been found in a variety of studies of urban travel demand to be an important element in transportation analysis.

3. Effects of transportation cost changes on location of population and production need to be addressed.

4. More complete documentation of effects of environmental and government regulatory activity on the transportation sector should be included.

Mode switching due to cost changes has been well-established in studies of urban areas and needs to be included in the LCES modeling effort. Further, the historical correlations used to determine mode demand should include such interactions.

Third, transportation costs have played an important historical role in determination of location of population and jobs. Regional growth and change as a result of transport cost changes is not included in the modeling effort but is likely to be a long-term result of such transportation cost changes, thus altering regional demand for transportation services. A need is to more fully develop these issues in a least cost energy modeling effort.

Fourth, environmental factors and government regulatory changes have been included in the model and are likely to be of substantial importance. However, to evaluate precisely the effects of these conditions on penetration of new technologies a more complete documentation is necessary.

SUMMARY AND SUGGESTIONS FOR AN IMPROVED METHODOLOGY

The Mellon Institute study is an attempt to examine how effects of higher world energy prices can in part be lessened by adoption of more efficient technologies that compete with each other on a cost basis. The economic basis for these adjustments is recognized by the LCES but rigorous economic analysis of the adjustment process is seriously lacking in the LCES modeling effort.

The mechanistic approach taken by the LCES needs to be altered so that the underlying economic principles affecting market adoption of new technologies is explicitly included in the process of adjustment to changing world energy process. Serious analysis of this adjustment and the process of new technology adoption must address the manner in which existing and new technologies embedded in durable goods compete both at any point in time and over time. Such analysis needs to be based on a framework that considers relationships among the level of adoption of alternative technologies and the rate at which these change. In essence, market adoption of innovations is a dynamic process that must be examined in that context, including uncertainty with respect to future conditions. Market adoption patterns of a single new technology will depend on how costs and benefits of adoption of that technology over time are related to costs and benefits of adopting alternatives over time and the replacement process now and in the future. The mechanistic algorithms used in the LCES are not sufficient to accurately reflect the complicated dynamics of change involved. In addition, analysis of market adoption of new technologies must be viewed in a setting of a dynamic economy with changes in industrial composition and location of production and population in addition to changes in world energy prices.

Massachusetts Institute of Technology

Energy Laboratory

Energy Model Analysis Program

Appendix C

The Least-Cost Energy Strategy and the Economics of Cogeneration

Alan J. Cox*

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*The author is currently a student in the Graduate School of Business Administration, University of California, Berkeley. This paper has benefited from comments by Ernst Berndt, Roger Bohn, Paul Joskow, Michael Manove, Fred Pickel and David Wood.

TABLE OF CONTENTS

This paper is a review of the assessment of cogeneration in the Mellon Institute Energy Productivity Center's report "The Least Cost Energy Strategy" (the LCES Study). LCES results show far greater penetrations of cogeneration than are found in other literature on the subject. Some of these differences can be explained by merely examining the input assumptions of the relative costs of investing in the various cogenerating technologies and of the relative costs of fuels. However, the biases that result from these assumptions can only be clearly understood through a detailed examination of the methodology.

Cogeneration is conventionally defined as the joint production of heat and electricity. The joint production can be thought of as reducing the costs of producing each of the outputs through the "writing-off" of part of capital and operating costs to each of the outputs. The costs of producing electricity will then be the residual of the net cost of producing steam, or the cost of producing steam can be the residual of the net cost of producing electricity.

The plan for this paper is, first, to compare the LCES results with those found in other reports. The input assumptions that lead to the divergence of the LCES results from the other reports are reviewed briefly. The methodology of the LCES report is then reviewed in some detail. That description, drawing heavily on documentation provided by the creators of the model utilized for the LCES report, is followed by a discussion of the estimation of the capital costs of cogeneration. The emphasis in that discussion is on the problems of trying to predict the total of individual investment decisions using aggregate energy demand data. The purpose of that discussion is not so much to criticize the model, which in many respects is satisfactory, but to outline the limitations of the aggregate approach that it utilizes.

The simple economics of cogeneration are reviewed in the appendix C.1 to this paper. Particular weight is placed on the complexities of estimating the capital costs of cogeneration systems and of the estimation of an optimum investment in these systems. Those not familiar with cogeneration or not familiar with the impact of such considerations as utilization factors and its effects on the estimation of capital costs may find it helpful to review the appendix before proceeding. Other papers that discuss the economics of cogeneration include Cox and Helliwell (1980), Helliwell and Cox (1979), Helliwell and Margolick (1980), Pickel (1978), and Joskow and Jones (1981). The appendix and the text draw heavily from these papers.

Two technologies will be discussed in this paper, both of which provide process heat in the form of steam.[1] They are: steam-topping cogeneration and gas-turbine, combined-cycle cogeneration. Diesel-motor cogeneration is occasionally referred to.

The Least-Cost Results

Table 1 compares the LCES results with those found in other reports and with the actual situation in 1975, as reported by Pickel (1978). The most striking feature of this table is the large amounts of cogeneration found in the LCES results, far greater than those found in the other studies. In fact, the LCES penetrations are so great that estimates previously considered outliers now appear to be fairly reasonable.

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[1]"Process" will describe an input to all non-electricity production; f or instance, process steam for the production of paper.

TABLE 1

Estimates of Congeneration Penetration

Total U.S. cogenerated electricity as a percentage of total electricity production,1975 (Pickel, 1978)	4%
Massachusetts estimate of profitable cogeneration in state as a percentage of 1977 electricity consumption. Base Case. (Massachusetts, 1978)	19%
Resource Planning Assoc.[1]	5.5-16.4%
Dow (1975)[1]	18.2%
Thermo-Electron (1976)[1]	7.7%
ISTUM[1]	5.9%
Least-Cost(a)[2]	51.6%
Least-Cost(b)[3]	37.7%

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[1] As percentages of 1985 demand projected by DRI. Adapted from Joyce (1978) using 65 percent utilization rate.

[2] Industrial cogeneration as a percentage of 1978 industrial demand. Estimated from gas consumption figures. Table III.3.3 of LCES technical appendix. Total gas use for electrolytic and machine drive demand = 2.95 Quads. At 60% efficiency this gives 1.75 Quads of electricity. Percentage cogeneration is then (1.75/(2.21 + 1.18) where 1.18 is industrial demand for purchased electricity.

[3] Total cogeneration as a percentage of total 1978 demand. Estimated as in (a) plus oil consumption for diesel cogeneration in buildings times 40% efficiency. Oil use in diesel cogeneration in buildings (from Table III.4.1) 2.29 Quads. At 40% efficiency, this gives .916 Quads of electricity. Total electric purchases of LCES study is 4.4 Quads. (1.75 + .916)/(1.75 + .916 + 4.4) = .377.

This is not the only unusual result. The LCES report shows all industrial cogeneration coming from gas turbine systems. This result is not found in any other study and is not even found in the original report on ISTUM, the computer model upon which the LCES industrial results were based and which is described below. Table 2 has been drawn up to indicate this divergence. It presents two estimates of the fuels consumed in the production of steam and cogenerated electricity by predicted levels of investment in different technologies. The fuel consumption figures are in percentages. Each percentage is the proportion of the total fuel consumed to meet either steam or electricity demand. The first of these results is from the original report on ISTUM. The second set of results is the LCES result. The fuel cost input assumptions are also listed for both studies.

While gas turbines provide very little steam in the ISTUM study, this technology provides almost half the steam in the LCES study and meets about half the demand for electricity. Similarly, while coal provides large amounts of steam in the ISTUM study and some electricity, it provides none of either in the LCES study.

The major reasons for these results were found to be:

i) The low price of natural gas assumed in the LCES study, a price consistent with the average price in 1978, but not representing its true value as a substitute for oil, nor its likely level in the gradually deregulated future. Natural gas is the presumed fuel for gas turbines in the LCES study, while ISTUM assumed the turbines to be fired by oil. Thus, the cost of fuel for the gas turbine is \$2.50/MMBtu for ISTUM and \$1.55/MMBTU in the LCES study.

ii) Capital costs were generally found to be understated in the LCES

Table 2

Steam penetrations %		Electricity Penetrations[1] %	
ISTUM			
Coal (New)	26.9	Coal Topping	2.69
Gas Turbine	.06	Gas Turbine	9.2
Diesel	.02	Diesel	11.00
Natural Gas Boilers (New)	16.35	Electricity Purchases	69.42
LCES			
Coal (New)	0.0	Coal Topping	0.0
Gas Turbine (WHB)*	45.62	Gas Turbine (ORB)[2]	4.3
Diesel	0.0	Gas Turbines	64.62
Natural Gas Boilers (New)	42.84	Diesel	0.0
		Electricity purchases	31.05

Price Input Assumptions

in $/MMBtu

	ISTUM (1980 prices in 1978$)	LCES (1978 prices in 1978$)
Coal	1.20	1.10
Oil	2.50	2.49
Gas	2.30	1.55
Electricity	7.10	8.12

This does not include electrolytic demand for electricity[1]

[2]Organic Rankine cycle.

study, with the exception of coal boilers, which were assumed to be about twice as expensive as their current cost.

The primary consequence of this particular set of assumptions is that investment in gas-turbine technologies are made to appear cheaper than investment in steam-topping systems or to purchasing electricity. However, gas turbines produce about four times as much electricity per pound of steam than topping technologies. Thus, the apparent biases in the cost assumptions lead to the choosing of a technology that produces far more cogenerated electricity than found in other studies.

To see the manner in which these input assumptions affect the choice of technology and the amount of cogeneration it is necessary to review the methodology employed in the LCES paper.

Review of Least-Cost Strategy Procedure

The model upon which the Least-Cost Energy Strategy report depends is an adaptation of ISTUM, which itself was developed for DOE and is documented in Department of Energy (1979). Figure 1 is a flow diagram that illustrates some of the steps in this process. The model takes as inputs fuel prices, technology capital costs, and energy demand data. It evaluates a set of technologies to find the combination of them that meets fixed energy service demand at lowest cost. The penetrations of some technologies are limited by technical constraints. "Energy demand" is separated into 26 industries, each with up to 23 energy service demands. Two of these service demands are relevant to cogeneration; machine drive demand and steam demand. These services are the only two that will be considered in this review.

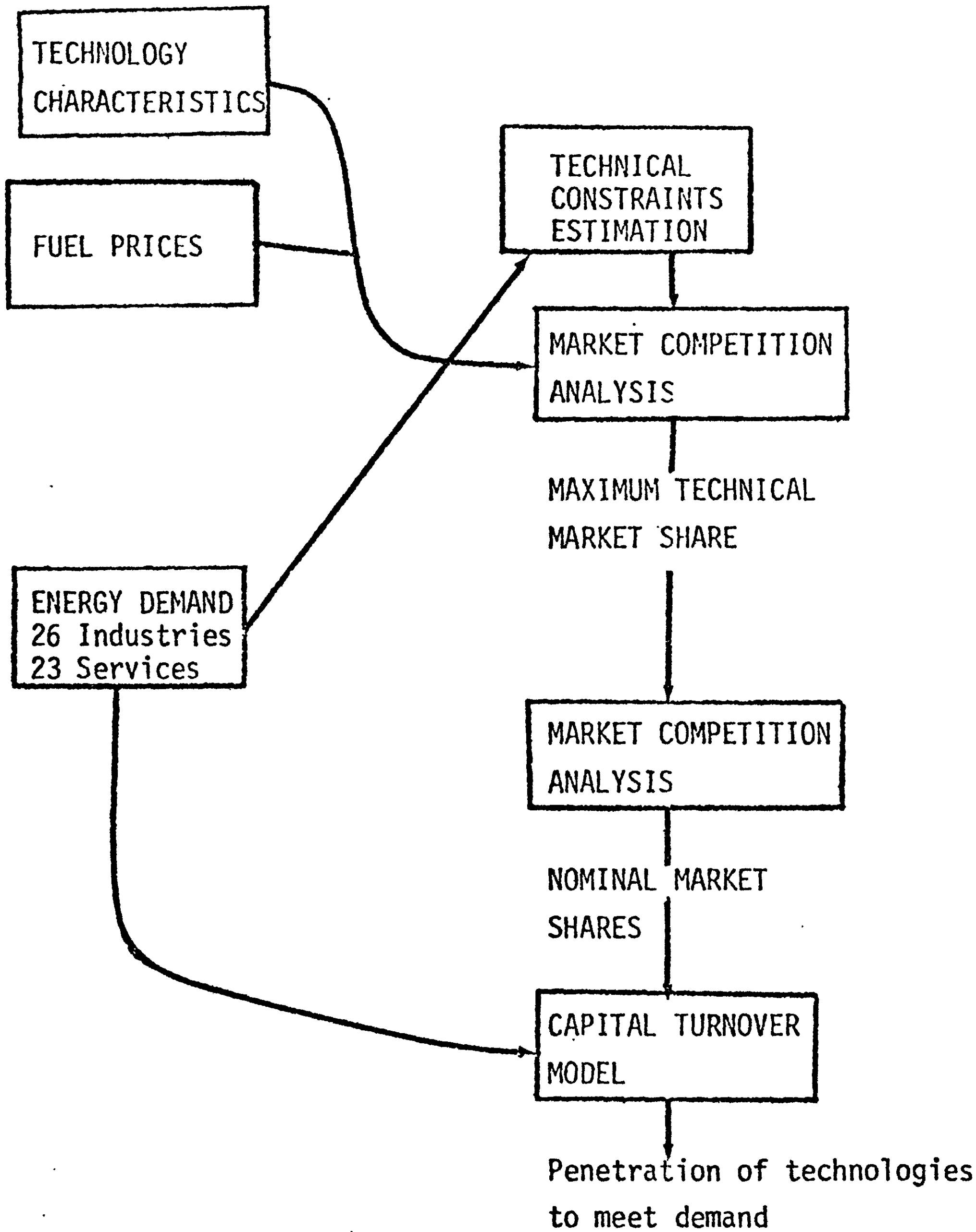
TECHNOLOGY CHARACTERISTICS
FUEL PRICES
TECHNICAL CONSTRAINTS ESTIMATION
MARKET COMPETITION ANALYSIS
MAXIMUM TECHNICAL MARKET SHARE
ENERGY DEMAND
26 Industries
23 Services
MARKET COMPETITION ANALYSIS
NOMINAL MARKET SHARES
CAPITAL TURNOVER MODEL
Penetration of technologies to meet demand

Figure 1

Technical Constraints Estimation

Cogeneration systems can only produce a certain number of kWh per pound of process steam demand. For instance, a steam-topping system with a boiler pressure of 1250 p.s.i., a heat content per pound of steam of 1375 Btu, and a process requiring steam at 150 psi, can produce about 55 kWh of electricity per thousand pounds of steam generated to meet process heat requirements. The steam-topping maximum market share is estimated as:

$$S_{T,t} = \frac{M_{C,t} \cdot \rho_T \cdot \rho_g(-\Delta h_3)}{M_{T,t}} \qquad (1)$$

where $S_{T,t}$ is the maximum share of machine drive energy demand that coal-topping can meet,

$M_{C,t}$ is the total amount of new coal-fired boiler capacity installed in year t, in Btus,

$M_{T,t}$ is the total demand for electricity, in Btus.

ρ_T, ρ_g are turbine and generator efficiencies ($\rho_T \cdot \rho_g = .7$), and

Δh_3 is the change in Btus per pound of steam as it expands through the turbine, as a percentage of Btu/lb, as steam exhausts the turbine.

This can be converted to an equation to estimate the amount of cogeneration potential available in kilowatts by replacing $M_{T,t}$ with 3412, the number of Btus per kilowatt hour.

Market Competition Analysis

ISTUM takes the costs of providing an energy service from the range of possible technologies and picks the lowest cost system to meet that demand. However, instead of using point estimates of the cost of each technology's services (which would result in a single technology capturing the whole market or up to the maximum allowed by its technical constraint) the model utilizes a range of per-Btu costs for each of the technologies.

The costs of meeting steam- and machine-drive service demands through cogeneration are estimated in two inconsistent ways. To understand this problem it is helpful to review the capital costs involved in cogeneration systems.

The major investments that are incremental to providing steam and are due solely to the decision to cogenerate electricity from a steam topping system include:

i) the cost of the turbo-generator,

ii) the cost of the additional boiler capacity necessary to produce the greater output of steam necessary to make up for the heat converted to electricity,

iii) the additional boiler cost resulting from a boiler of a pressure higher than that necessary to provide process steam alone, if the investor is considering increasing cogeneration capacity in this manner, and

iv) the cost of any condensing capacity.

While the isolation of the incremental cost of producing electricity from a coal topping cycle is straightforward, the same cannot be said of the other two technologies. In fact, both diesel and gas-turbine cogeneration could be considered primarily electricity-generating technologies, with steam being a by-product. However, the ISTUM methodology requires that these technologies compete in well-defined service sectors, either steam services or electricity services. All three technologies must first compete to meet industrial steam demand. The capital costs of meeting steam demand with a coal system is merely the cost of a conventional coal boiler. However, the cost of providing steam from the gas turbine and diesel technologies is deemed to be the total cost of the systems, minus the benefits to the firm of producing electricity for its own use and for sale to the local utility. The average cost of providing process steam fom a gas turbine could then be represented as

$$AC_S = (K + F_S + F_T - B_E)/Btu \tag{2}$$

where AC_S is the average cost of a Btu of steam,

K is the total annual capital and operating cost,

F_S is the cost of fuel consumed to raise steam to meet process heat requirements,

F_T is the additional fuel required to produce electricity from any steam topping system,

B_E is the annual benefit due to reduced electricity purchases and due to sales of surplus electricity, and

Btu is the annual process heat production.

Thus the greater the price of electricity the lower is the cost of steam used in production. Also, the lower the cost of the fuel burned to produce both steam and electricity, the greater will be the net benefits of producing electricity and hence, the lower will be the cost of producing steam.

Coal boilers with no cogeneration capacity then compete with gas-turbines and diesel cogenerators to meet steam demand on the basis of their average costs of steam. Once the amount of steam generated from gas turbines and diesels is estimated, the amount of electricity produced can be computed. This electricity production is then subtracted from that required by the machine drive sector. The remaining machine drive demand is met by steam topping and purchased electricity, whichever is cheaper.

Thus, three cogeneration technologies are evaluated in two contradictory ways. The ISTUM modelers no doubt felt that, since there was no way to isolate a steam-producing segment of the gas-turbine system or the diesel system, they had to think of the steam generating investment as being incremental to the electricity generating system. However, it is incorrect to assume that the incremental cost of producing electricity is embodied in one technology. Consider the case of a plant manager evaluating the purchase of a new steam generating system and faced with the choice of the three technologies. The cheapest way to produce steam alone will probably be the coal system since the other two systems produce the steam merely as a byproduct. Suppose the manager then considers the possibility of cogenerating electricity. The incremental cost of cogenerating by steam-toppping is, as we saw, the additional boiler cost plus the cost of turbo-generator. The incremental cost of producing electricity from a gas-turbine or a diesel system would be the total cost of those systems, minus the total cost of the coal boiler large enough to provide steam requirements alone. In this manner all technologies could compete on the same basis in order to meet electricity demand.

Conversely, the method applied by ISTUM for gas turbines and diesels (equation 2) could be applied to the coal-topping system as well. The credit to be applied to the cost of process steam production would be the value of electricity produced.

Once the net steam costs had been evaluated for all possible topping designs this technology could compete with gas turbine or diesel cogeneration systems on the same basis. This sort of approach has been suggested by the developers of the ISTUM model. (See Olson and Kalkstein, 1980.)

Even if these methodologies had been applied consistently to all technologies, however, it is unlikely that they would result in an optimum investment strategy. The only way to do that would be to calculate the net present value of the whole range of possible technology options, including conservation possibilities. More specifically, that means subtracting the capital, fuel, operating and maintenance costs for the entire investment (i.e. not broken into their component parts) from the present value of electricity savings. The project which supplies steam requirements with the smallest negative value should be the one undertaken. However, in a system that chooses technologies by minimizing costs instead of maximizing benefits, such a procedure, though correct, cannot be undertaken.

In summary, the amount of machine drive demand satisfied by each technology is based upon each technology's penetration into the steam market. The cost of steam from coal is merely the cost of a coal boiler. The cost of steam from a gas turbine is the total cost of that system, minus the benefits of electricity production. With the very low prices for natural gas and the realistic prices for electricity found in the LCES study the gas turbines take a very large share of the steam sector market. The amount of electricity generation that this gas-turbine steam penetration implies is so large that there is little left for any other technology to capture.

To see how the results of Tables 1 and 2 come out of the LCES study it is useful to look at the assumed capital and fuel costs for each technology. The first part of Table 3 displays the LCES cost assumptions (in dollars per MMBtu) for the technologies. It clearly demonstrates the economic advantage that gas turbines enjoy under the LCES scenario. The costs shown are after electricity benefits have been subtracted. The electricity savings are somehow allocated over both the capital and fuel costs of the gas-turbine system. In some cases the fuel costs are reduced to a negative number. The credits earned from electricity generation are $6.76/MMBtu for electricity (about 2.3¢/kWh) and the cost of the fuels are $1.55/MMBtu for natural gas and $2.49/MMBtu for diesel. (The fact that the minimum costs under the "fuel" and "total" headings are higher than their mean costs may indicate that the cost distribution of the ISTUM system have been replaced by using the mean as a point estimate.)

As Table 2 indicates, the natural gas price assumptions are clearly very low, resulting in the low net fuel prices for gas turbines on column 3 of Table 3. The 1978 prices are much lower than those that one could reasonably expect after natural gas deregulation. The LCES study implies that investors will be very myopic in their decisions to invest in cogeneration,even though the life of this equipment is very long.

What if potential cogeneration investors had not had as myopic a view of the price of natural gas and expected to face the marginal cost of natural gas by 1985? In the second and third sections of Table 3 are represented some of the LCES cost assumptions adjusted to take into account different possible prices for natural gas. In the second section we add an additional $0.75/MMBtu to the cost of gas to bring it up to the

Table 3

Technology Costs
Steam Service

$/MMBtu
LCES Cost Assumptions

From Table II 2.5

Technology	Capital + O&M Mean	Capital + O&M Min	Fuel Mean	Fuel Min	Total Mean	Total Min
Steam						
Gas Turbine	3.2	2.1	-.4	1.2	2.8	3.3
New Coal	3.4	2.7	1.25	.97	4.7	3.6
Machine Drive						
Coal topping	7.9	4.2	1.8	1.4	9.7	5.6
Purchased Electricity	0.27	0.15	7.6	1.5	7.87	2.8
ISTUM Price Assumptions						
Steam						
Gas turbine	3.2	-	.4	-	3.6	-
Deregulated Case Cost Assumptions						
Steam						
Gas turbine	3.2	-	2.26	-	5.46	-
New Coal	3.4	-	3.06	-	6.46	-
Machine Drive						
Coal topping	7.9	-	3.6	-	10.7	-
Corrected Coal Costs with Deregulated Fuel						
Steam						
New Coal	1.82	-	3.06	-	4.88	
Machine Drive						
Coal Topping	2.76[1]		3.6	-	6.36	

[1]From page II-98, Vol. 1 of ISTUM reported, corrected for different interest rates and for inflation.

ISTUM case. In that scenario the difference between the cost of steam from a gas turbine and the cost of steam from a coal boiler is reduced from $1.9/MMBtu to $1.1/MMBtu.

For a "deregulation" scenario all prices are set on the basis of the cost of oil in 1980 when residual oil was priced at an average of $4.27/MMBtu. Coal is assumed to have a long-run price of one half of the price of residual oil. (It was actually about one third the price of oil in 1980, but the one half proportion is closer to the historic situation.) Natural gas is priced at 85 percent of oil. Under this set of assumptions the cost of new coal steam is $1.00/MMBtu above that of gas-turbine steam.

With these fuel cost adjustments the coal technology still costs more than the gas turbine technology but the reduction in the differences between the mean prices could well have resulted in some coal being used to generate both steam and electricity. However, a further adjustment must be made to the LCES cost assumptions. The assumptions of investment costs for coal systems are too high. The discrepancy between the LCES assumptions and currently listed prices is discussed below, under "Capital Cost Issues." Corrected coal cost estimates are listed in the last section of Table 3. The additional adjustment to capital costs results in the cost of coal being below that of the gas turbine in providing steam.

The annual holding cost of capital utilized in the LCES study is also too low. The LCES formulation for estimating the annual cost of capital includes no consideration of taxes and assumes a discount rate of 5 percent. Even if the discount rate were acceptable, the inclusion of taxes would almost double the cost of holding capital. Since gas turbines have a higher capital cost than coal boilers, this correction would make gas-turbines even less attractive for the production of steam.

With fuel and capital costs adjusted to be more realistic, the LCES results would have shown far greater production of steam from coal boilers. The biased input assumptions combined with the ISTUM methodology result in the gas turbine technology capturing most of the steam market. With less gas-turbine steam production, far more of the machine drive demand would have remained to be competed for by coal-topping cogeneration and by purchases. Furthermore, coal-topping would not have captured as high a percentage of electricity demand. With the cost assumptions of the last row of Table 3 coal would have captured a substantial portion of this market. The appendix and the capital cost section contain discussions of the reliability of these cost estimates.

Electricity Prices and Utility Operations

The electricity prices used are about the same as the average U.S. industrial price in 1978. A valid objection to the use of these prices lies in considering the relative costs of capital to the utility and the potential cogenerator. Utilities clearly expect a higher rate of return than the 5 percent real rate enjoyed by the LCES investors and pay some taxes that are not accounted for in the LCES study. A more reasonable (i.e. higher) cost of capital faced by cogenerators would reduce the amount of cogeneration in the LCES study. On the other hand, the average industrial rate charged for electricity is based on the historic book value of the utilities' capital stock. A socially optimal level of cogeneration can only be found if the price of electricity is based on the costs of new capital to utilities. In most cases this would result in a higher price of electricity and, therefore, increased cogeneration. Any study that purports to estimate the socially optimum mix of energy technologies should do so on the basis of the marginal costs of all energy, including the marginal cost of electricity.

Furthermore, the estimate of the marginal cost of electricity should take into account the large amounts of cogeneration that are being projected. There are two primary concerns of having large amounts of generation connected to the utility grid but not under the control of the utility; the reliability of the dispersed systems and the effect on these systems on operating costs.

Figure 2 outlines a simplified flow structure for modeling these effects. A utility's hour-by-hour demand for electricity is collapsed into a cumulative distribution of demand (referred to as a Load Duration Curve) which is then fed into a production costing model. The minimum cost of meeting the demand for electricity is estimated taking full account of the reliability of each unit owned by the utility. The overall reliability of the system is also measured. The operating costs are passed on to a rate-setting model which utilizes information on the investment history of the utility to estimate regulated rates and also calculates rates based upon the long-run marginal costs of the utility.[2] Both sets of rates should be used to compute the level of cogeneration; one in response to current regulatory practice, the other in response to socially optimal prices.

The amount of investment in cogeneration should provide a time profile of the production of cogenerated electricity which can be

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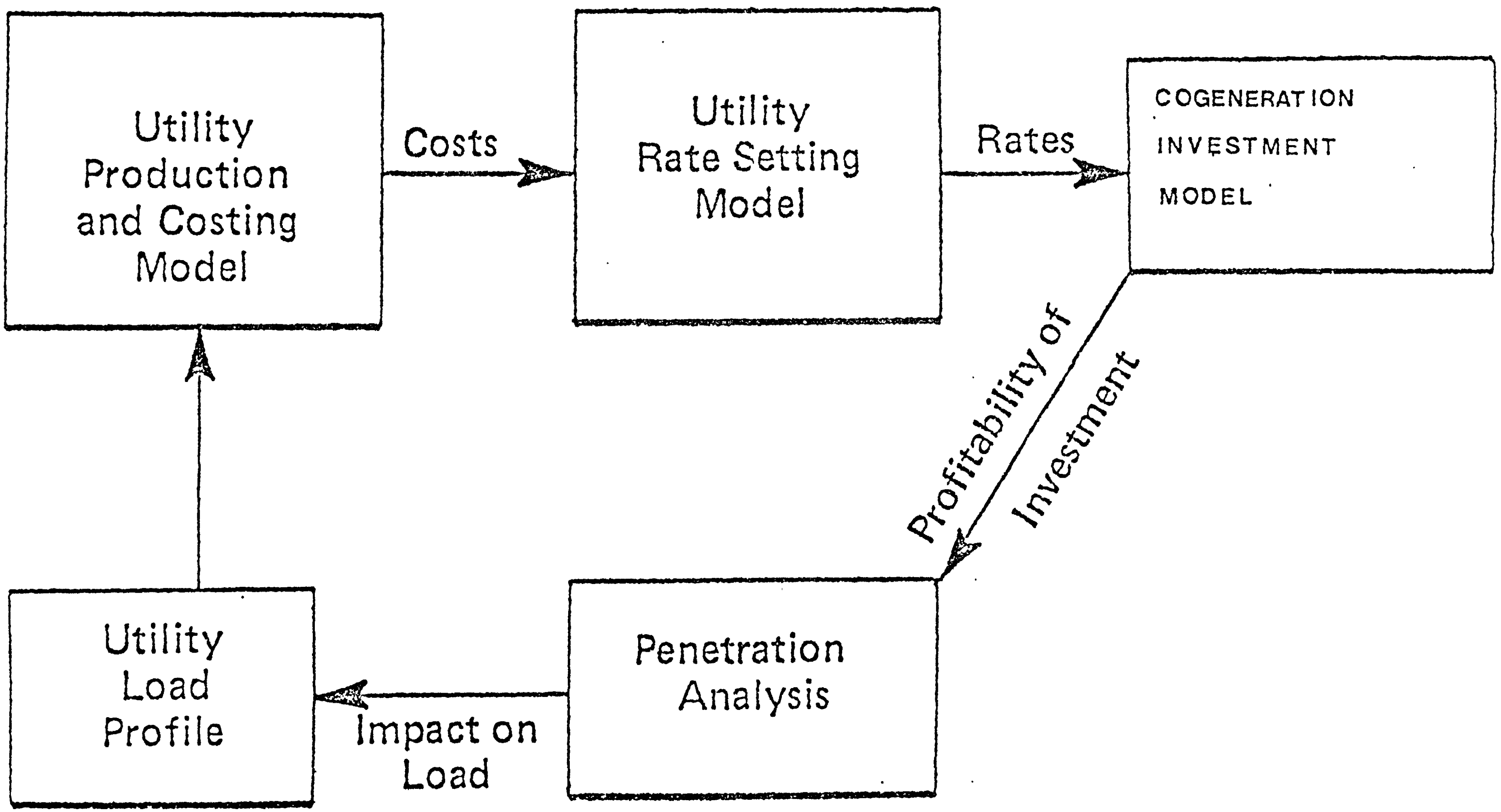
[2]Both sets of rates include prices of electricity both for sale and for purchase by the utility.

Figure 2

MODELING SYSTEM



subtracted from the original load duration curve. The new load-duration curve is then run through the production costing and reliability model and the rate-setting model. Depending upon the effects of cogeneration on net load, the operating costs of meeting the new demand will be less than, equal to, or greater than during the first iteration. A revised set of rates is then estimated to pass on to the cogeneration investment model, revised levels of cogeneration investment are calculated, and a new load duration curve is fed back into the system.

No work has been done to examine the effects of large amounts of cogeneration on the operating and capital costs of a utility. Work reported in Cox (1981), Tabors, et al. (1981) and Finger (1981) on the effect of large amounts of photovoltaic producers connected to the utility grid indicate that, for this technology, the operating costs of the utility are reduced. As more and more electricity is fed into the grid the utility shuts down some of its most inefficient plants. With increased penetration of these dispersed generating systems cheaper and cheaper electricity is displaced. Thus additional dispersed units provide lower benefits.

The strong correlation between peak demand and maximum photovoltaic output (which may also exist between peak demand and maximum cogeneration), allows the utility to reduce its capital requirements and maintain its reliability requirements. On the other hand, Lee and Yamayee (1980) predict increases in spinning reserve requirements with levels of photovoltaic penetration greater than 6 percent of a utility's peak demand.

Either increasing or decreasing costs to the utility through large penetrations of decentralized generation will result in a reduced value for cogeneration. Reduced total utility costs due to production savings will be passed on as lower rates to customers reducing cogeneration benefits. Increased costs (e.g., for spinning reserve) due to cogeneration alone will be assessed against cogenerators and will also result in lowered profitability.

On page 36 of the summary LCES report, gas turbine cogeneration is shown to save 1.6 percent of the 1978 U.S. energy consumption. This result can be approximately replicated from the information provided in the LCES technical report[3]. It is important to note, however, that the LCES authors are implying a substitution away from oil, coal, nuclear, hydro and some natural gas-fired utility generators. The savings are thus not necessarily in oil and natural gas.

Problems with the the relative prices of electricity and natural gas account for a large part of the surprising results of the LCES study. However, the estimation of relative capital costs also has an impact on both the choice to cogenerate and the choice of technology with which to cogenerate.

Capital Cost Issues

The investment costs quoted in the ISTUM reports seem to be fairly consistent with costs published elsewhere. A standard design for a 108 MW gas-turbine combined cycle system, according to Pickel (1978), costs $455/kW. ISTUM uses a mean price of $444/kW (Vol 1, p. II-99). Cox and

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[3]4.18 Quads of steam generated times .4562 of this steam coming from gas turbines times .82 Quads of electricity per Quad of steam produced by gas turbines divided by 79 Quads of energy consumed in the U.S. gives .0198. To save 1.6 percent indicates that for every Quad burned to produce electricity by cogeneration a utility would have to burn 2.2 Quads.

Helliwell (1978) report an average capital cost of electricity production of 1.0¢/kWh (1978 Cdn. $) for cogeneration from wood-fired topping system in British Columbia whereas the ISTUM document reports a capital cost of .78¢/kWh (1978 US $) for coal-fired cogeneration. The LCES study seems to have retained the same investment costs as those found in ISTUM for the gas turbine systems. For instance, the ISTUM report states a total cost for gas turbines as $11.16/MMBtu, which, after subtracting fuel costs gives $5.41/MMBtu. After correcting for changes in the fixed charge rate used in the LCES study, the ISTUM result transforms to $3.79/MMBtu. The equivalent capital cost quoted in the LCES study is about $4.5/MMBtu. (This interpolates between two capacity factors presented in the LCES study.)

There is one glaring inconsistency between the capital cost estimates of the LCES study and the ISTUM study; the capital costs of coal-topping. An estimate of the mean cost of capital for this technology in the ISTUM study (p. II-98 of Vol. 1 of Department of Energy (1979)) is one half that found in LCES study. An overestimation of coal capital costs was also found in the steam demand sector. Pickel (1978) reports (on p. 217) that the cost of a typical field-erected coal boiler is .0315 $/Btu/hr. For a 300 thousand pound boiler this coverts to about $10.4 million (1975 $), which would be about $12.94 million in 1978 current year dollars.[4] Assuming a load factor of .457, this gives an annual cost of $879,160. The operating and maintenance costs for this system with the same load factor would be $792,000. This becomes $990,000 in 1978 dollars. Dividing capital, operating and maintenance

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[4]This conversion is made using the Handy-Whitman index of electric utility costs. See Whitman, Requardt and Assoc. (1980).

costs by the expected annual heat production gives $1.416/MMBtu. The LCES study uses a value of $2.996/MMBtu for the same sized boiler, utilized at the same 46 percent rate. Thus we find that coal consumption is understated partly because the LCES workers utilize a cost that is twice as high as that found in other reports.

There are, in addition, two issues in the estimation of capital costs that neither ISTUM nor the LCES study take into account. These issues are better addressed by studies that examine individual plants instead of whole industries. Pickel (forthcoming) shows that past predictions of cogeneration based on aggregate studies have overestimated the levels of cogeneration. This is partly due to important details being excluded, details that must be dealt with by surveying plants separately. Pickel (forthcoming) and Helliwell and Cox (1978) show the advantages of this approach.

The first of these capital cost considerations has to do with economic retirement of older plants. ISTUM assumes that the rate of retirement in the past will continue into the future. This is hardly a reasonable assumption for energy generating and consuming equipment. As an example, consider a plant with several boilers, and with annual production expected to remain constant. Each time there is an increase in energy prices a plant manager examines the stock of boilers, with a view of replacing that equipment. If the present value of savings due to the installation of a new, more efficient boiler is greater than the cost of installing that boiler, then a new boiler should be purchased. Thus the rate of replacement is a function of the rate of change of the relative costs of energy and capital. If energy prices increase on a sustained basis more rapidly than they have in the past, then replacement rates will be greater. As the ISTUM documentation states, these factors are not taken into account (Vol. 1, p. IV-103). The data upon which the retirement rates are based are ten five year periods from 1926-1975. Thus, the data on retirement rates are based on a period of decreasing real costs of energy, except for the last 5-year observation.[5] Premature retirements will impose additional costs on a firm. The writing-off of large amounts of undepreciated capital, while having no economic consequences, will have an impact on the firms ability to raise the capital necessary to make the economically efficient investment.

But the zero economic cost of discarding undepreciated capital is not entirely a correct assumption to hold for cogeneration investments. Imagine a potential investor in cogeneration who has a boiler which currently has 10 years of economic service remaining. An estimate of the net benefits of adding cogeneration equipment to the current boiler indicates that the project would result in losses. A possible alternative is to scrap the boiler for one designed to provide more electricity per pound of steam or to invest in a gas-turbine system. In this case, the cost of cogenerating electricity must include the value of the discarded boiler in order to cogenerate electricity. Thus, the prospect of producing electricity may result in early retirement of capital, but the costs of such a retirement would tend to push the retirement date back towards the date that it would have been retired had there been no increase in electricity prices. These scrapping costs are not taken into account in the ISTUM cost distributions. They probably

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[5]However, instantaneous and unexpected changes in the price of energy, spaced with intervals of real price declines will have no effect on survivorship rates. There will be rapid adjustments in the capital stock with retirements proceeding at their previous rate.

cannot be measured in an aggregate model of this sort, again pointing to the preference to individual plant modeling.

The ISTUM methodology measures capital costs as a function of the projected capacity factors of the equipment used. However the average costs of energy from a new system may not be the same as the marginal cost of producing energy from the total energy producing plant (i.e., with both old and new capital). With indivisibilities of capital and economies of scale matched against continuous increases in steam demand, a firm will purchase equipment in such a way that some of its capital will be redundant. Thus, some investments that may seem attractive on the basis of the average cost of energy with a fixed capacity factor will not be so when the marginal cost of energy production is used as the investment criteria.

In addition to the problems of indivisibilities it is important to consider the complexities of the cogeneration investment that are outlined in the appendix. Firms faced with base load demand for steam plus a highly oscillating demand above that base will not purchase a cogeneration system to capture all of that peak, but may utilize an array of technologies that will efficiently utilize the varying demand for steam. The perspective of the individual investor is much different from that implied by a model that optimizes upon a national steam demand. The smaller systems that such considerations would lead to will also significantly reduce efficiencies, particularly for gas turbines.

Conclusions

The results of the Least-Cost study indicate levels of cogeneration far greater than those predicted elsewhere. The LCES study also indicates that all industrially cogenerated electricity should ideally come from gas turbine systems. The penetration of cogeneration is much greater than even that found in the report of early results from ISTUM, the model upon which the Least-Cost report is based.

There are four major weaknesses of the LCES study. The first of these is the unrealistically low price of natural gas which fuels the gas turbine technology. Secondly, this low price results in gas turbines capturing a large share of the demand for steam, an outcome of the ISTUM methodology which was found to be inconsistent in the way it treated different technologies. The large amounts of cogeneration that the LCES study predicts arise from this bias towards gas turbines because this technology produces about four times as much electricity per pound of steam than topping systems.

Thirdly, the large penetrations of cogeneration have profound implications on electric utilities' costs of production. These issues are not addressed anywhere in the Least Cost study.

Finally, capital costs of technologies were often incorrect.

The cogeneration submodel suffers from the problem of trying to model very complex individual investments in an aggregated manner. Considerations raised in this paper and in the appendix indicate that such an effort is likely to miss key considerations that must be taken into account and that will vary from plant to plant.

Appendix C.1

Brief Review of Cogeneration

Figure A1 provides a diagramatic representation of the three technologies discussed in this paper and which are described below. The Least-Cost study also includes a fourth technology for on-site generation of electricity, a gas-turbine combined with an organic rankine cycle. This technology produces electricity only, and will not be discussed.

Steam-Topping Technologies

The standard method of producing steam for process requirements is to combust fuel below a boiler in which steam is raised. In order to assure a constant supply of steam, the boiler pressure is significantly greater than that which is required at the process site. The steam can be passed from the boiler through a pressure-reducing valve to the production site where it is required at from 60 to 150 pounds per square inch (p.s.i.). As heat is transferred to the production site the steam condenses and is pumped back into the boiler.

Electricity can be jointly produced with steam by dropping the steam pressure from boiler to process through a turbine attached to a generator. The energy cost of producing this electricity is only the energy loss in converting the steam into electricity in the turbine. At a typical electric utility plant a considerable amount of energy is lost to the environment in order to condense the steam after it leaves the last turbine. With a cogenerating system the heat loss in condensing is actually recovered in the production site. What otherwise would have been a heat loss can be thought of as being written off as a cost of producing the plant's non-electric output.

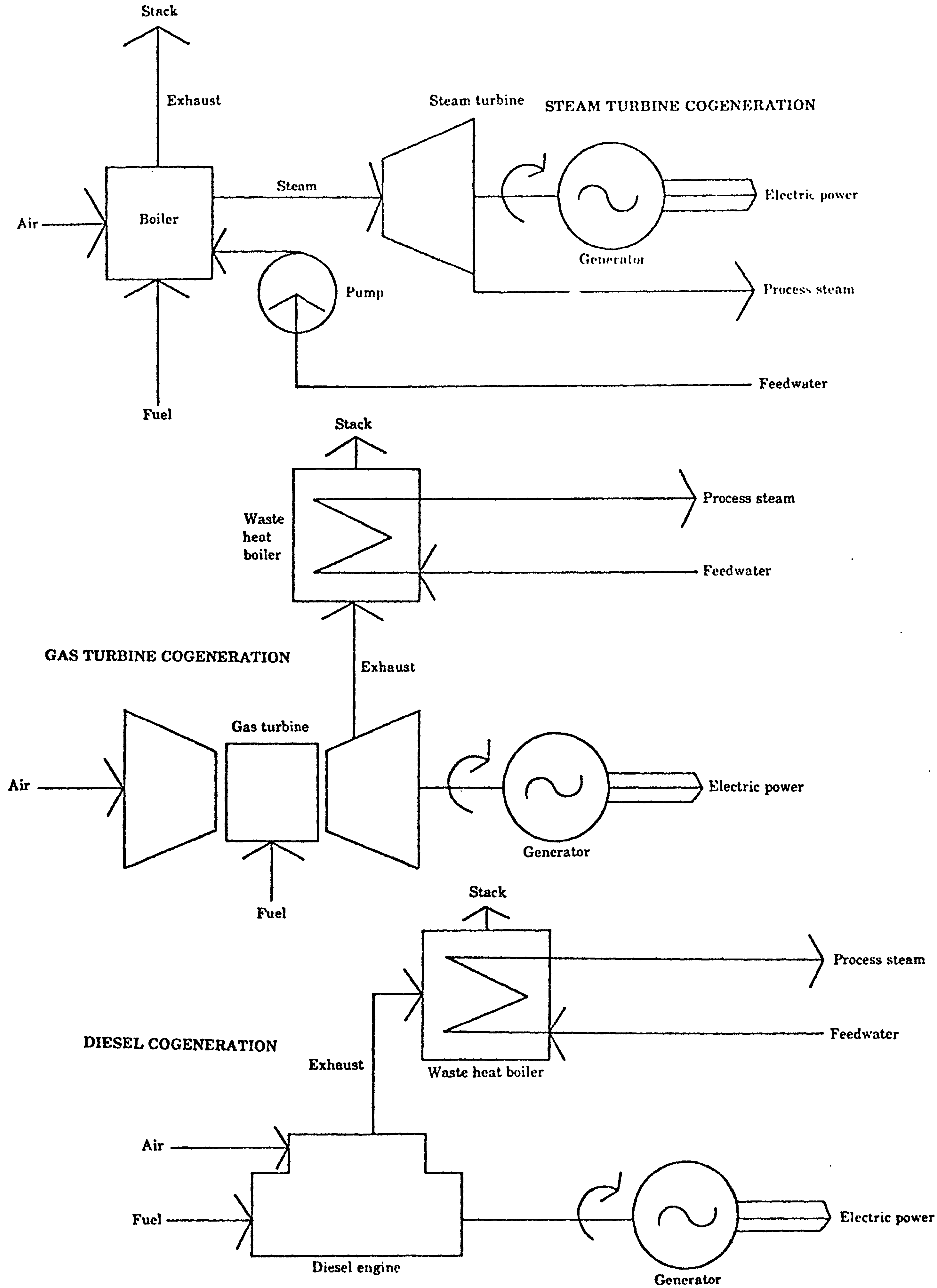


Figure A-1 Schematic of Cogeneration Technologies

The amount of electricity that can be produced by cogenerating is limited by the demand for steam and by the temperature and pressure drop across the turbine. (See equation 1.) For a given steam flow, therefore, the amount of electricity cogenerated at a particular site can be increased by building a boiler of greater pressure and temperature.

Figure A2 shows a transform from steam demand to electricity cogeneration potential. (Equation 1 is the exact formula for the transform.) Figure A2a represents a hypothetical steam demand for a plant over one year. This demand shows seasonal fluctuations but assumes the hour-to-hour demand to be constant.

Figure A2b represents the same steam demand of the plant as a cumulative distribution. It expresses the probability that any level of steam demand, in thousands of pounds per hour, will be experienced by the plant at any point in time. Figure A2c is the cumulative distribution of possible cogenerated electricity production that arises from the steam demand of Figure A2a, assuming the same set of boiler and process pressures and also assuming the installed capability to harness all the cogeneration potential. This capability includes, as we see later, the existence of excess capacity in the boiler.

Thus, at an installed cogenerating capacity X* kW, the plant will be able to fully utilize the turbo-generator 50 percent of the time and will be able to produce, per year, a number of kilowatt hours equal to the area under the curve below X*AB times 8760, the number of hours per year (see Figure A2c).

The components of the capital costs of cogenerating by steam-topping vary with the exact configuration of the system. One possible design would size the boiler(s) to be just large enough to provide the maximum

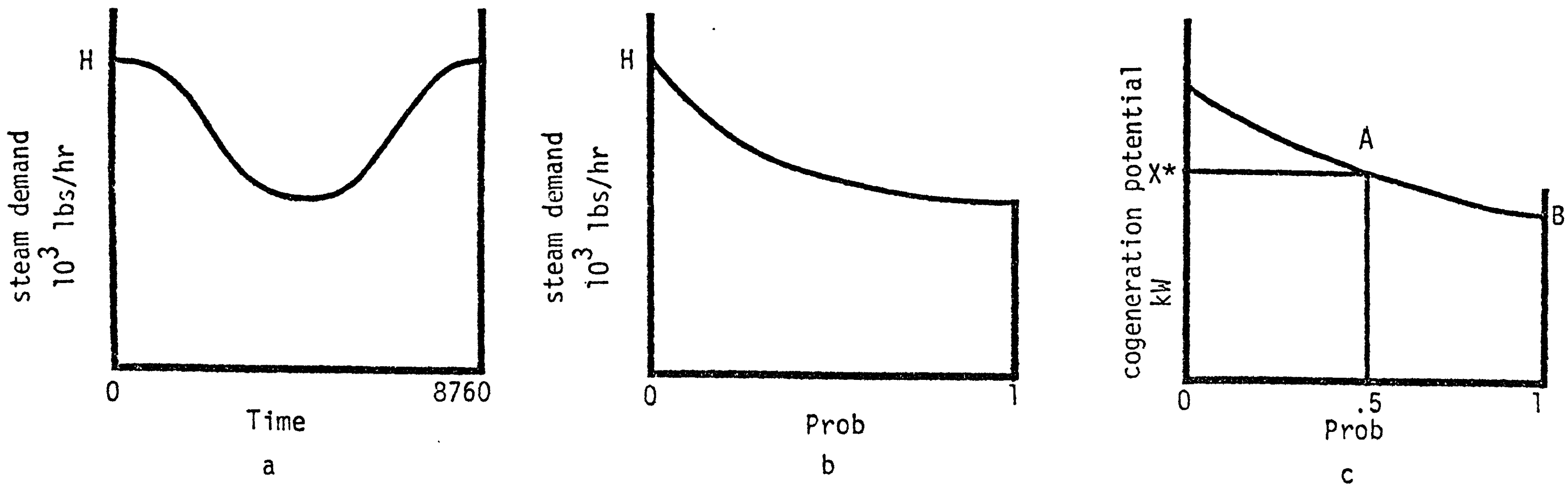

steam demand
10^3 lbs/hr
H
0
8760
Time
a
steam demand
10^3 lbs/hr
H
0
1
Prob
b
cogeneration potential
kW
X*
A
B
0
.5
1
Prob
c

Figure A-2

steam necessary for all non-electricity production. Since some heat energy is converted to electricity, this heat must be made up with additional steam from the boiler over that required for non-electrical production. If the boiler is just large enough to provide peak process steam demand then no energy will be available for electricity production during periods of peak process requirements.

Figure A3 shows the derivation of the cumulative distribution function of cogeneration capability for such a system. In Figure A3a we again show a seasonally fluctuating demand for process steam. The shaded area indicates the amount of steam available for cogenerating electricity, with the maximum steam available for cogeneration, H', occuring during some summer hour. Figure A3b shows the cumulative distribution function for process steam demand. Figure A3c is the cumulative distribution for electricity that can be generated from the steam available in the shaded area.

The depiction in Figure A3 implies that there is enough turbine capacity to convert all excess steam to electricity by cogeneration. If this is not the case then excess steam is used for cogeneration until the maximum amount of electricity production is attained. At that point total steam demand continues to go down at about the same rate as process steam demand.

This situation is depicted in Figure A4. The result of this situation is a flat portion of the cumulative distribution function for electricity generation. This sort of profile and distribution function would result if the potential cogeneration investor wanted to improve the utilization of the turbo-generator even though process steam demands would allow higher amounts of cogenerated electricity.

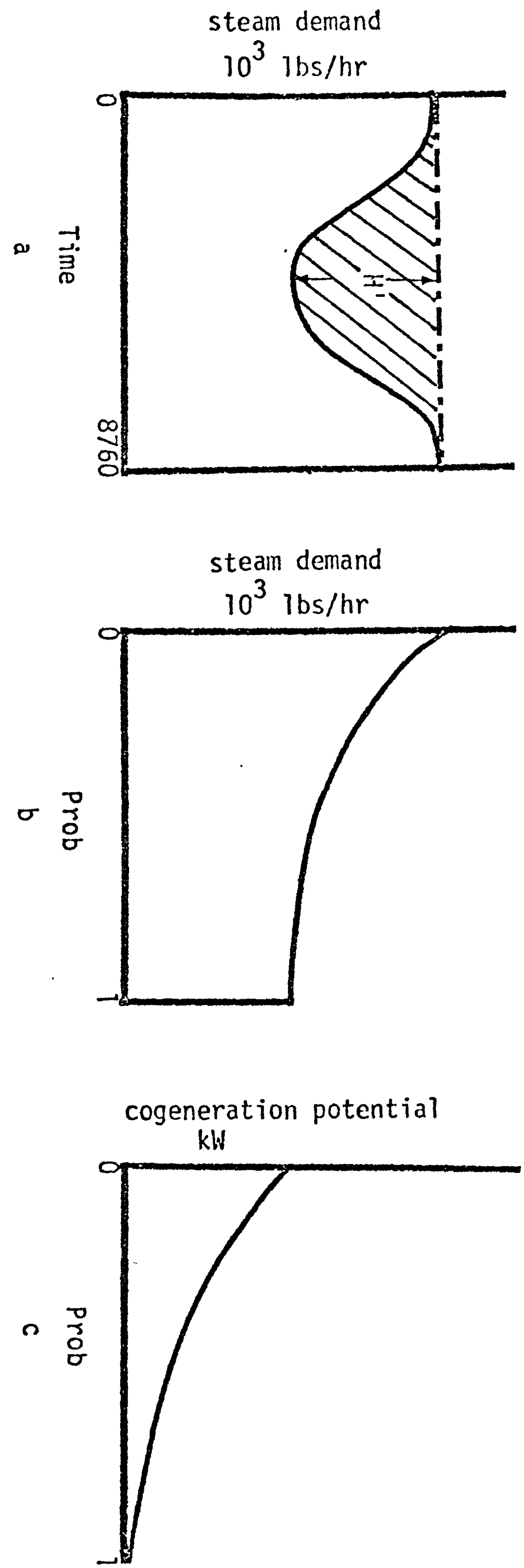

steam demand
10^3 lbs/hr
0
Time
a
8760
H'
steam demand
10^3 lbs/hr
0
Prob
b
1
cogeneration potential
kW
0
Prob
c
1

Figure A-3

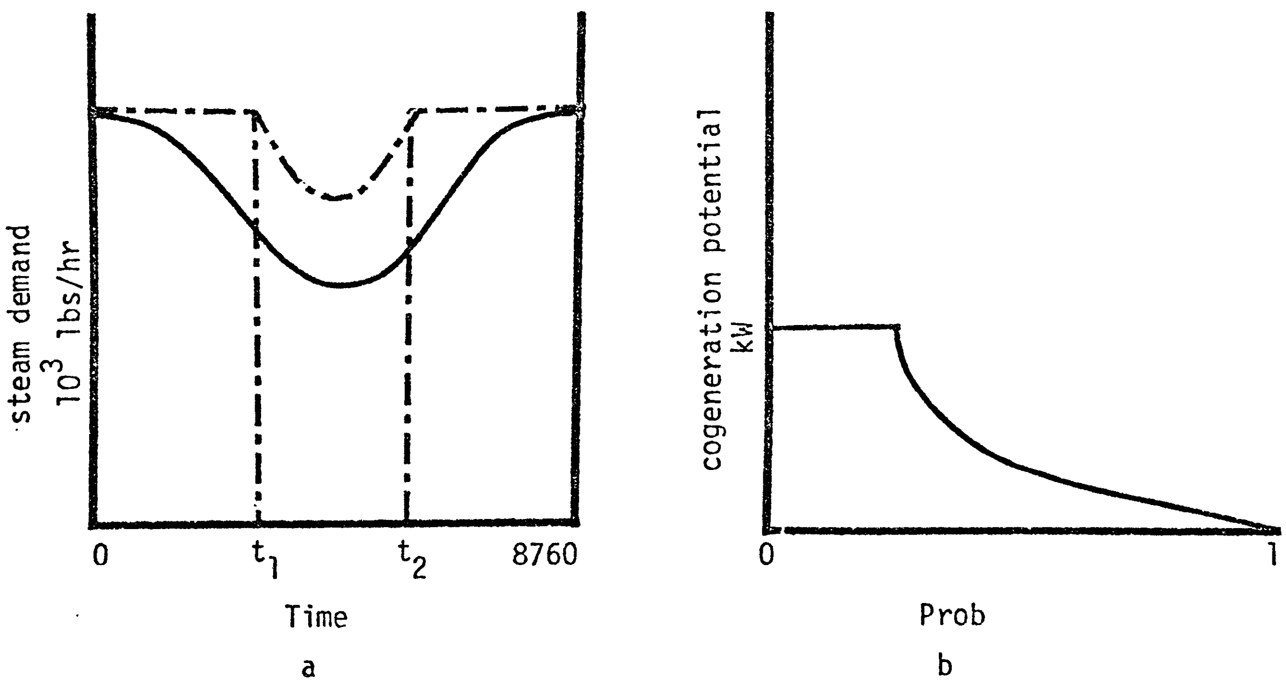

steam demand
10^3 lbs/hr
0
t1
t2
8760
Time
a
cogeneration potential
kW
0
1
Prob
b

Figure A-4

If the plant designs that gave rise to Figures A3 or A4 were employed, the additional capital cost of producing electricity would be merely the cost of the turbo-generator alone since the boiler(s) would have been necessary for process steam requirements. The total production of electricity and, hence, average cost of capital per kilowatt-hour of electricity would depend upon the number of hours that the boiler would have spare capacity. The percentage utilization will also depend on the size of the turbine generator. The larger the turbine, the fewer will be the number of hours during which there will be enough spare boiler capacity to use the turbo-generator to full capacity.

A profit-maximizing firm would probably find the design strategies discussed above to be sub-optimal if they provide any profit at all. Larger turbo-generators could be built and their utilization could be increased by building a larger boiler and continuously feeding some steam to the production site through the turbine. The degree of utilization would depend upon the size of the boiler and of the turbine. These systems relax the constraint of steam availability and are faced with only the constraint of a sufficient heat sink at the production site for cogeneration to take place.

Figure A5a shows, as a solid line, the process steam demand of Figure A4a. The vertical distance between the solid line and the dashed line is the additional steam necessary to make up the heat losses due to cogeneration when all the cogeneration potential is utilized. The vertical distance is greater during the winter due to the large potential available at that time. Figure A5b translates the total steam production into a cumulative distribution function for steam demand; Figure A5c illustrates the transformation of steam demand to a cumulative

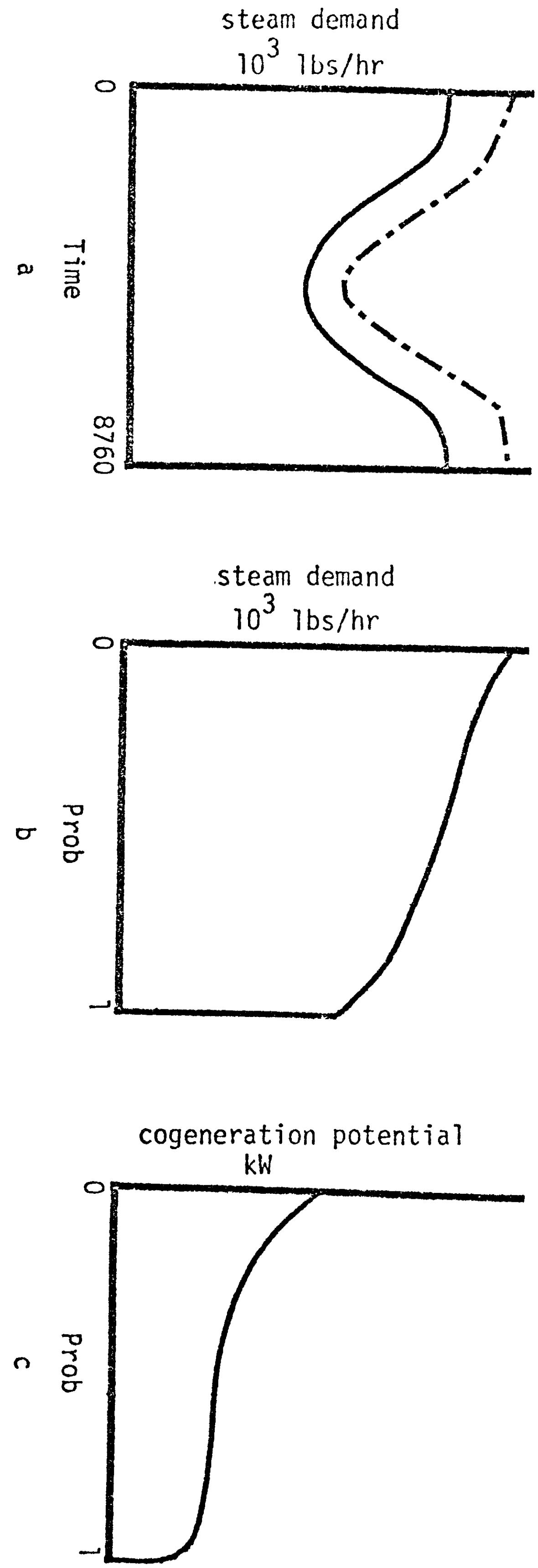

steam demand
10^3 lbs/hr
0
Time
8760
a
steam demand
10^3 lbs/hr
0
Prob
1
b
cogeneration potential
kW
0
Prob
1
c

Figure A-5

distribution of cogeneration potential. The peak cogeneration potential is greater than that depicted in Figure A4 because the steam producing capability of the boiler has been removed as a constraint.

The utilization of both the turbo-generator and the boiler can be improved by reducing the capacity of both. This is depicted in Figure A6.

For the situation in which only excess steam demand is used to produce electricity the only capital cost of cogeneration is just the cost of the turbo-generator. With some steam always being made available for cogeneration there is added a second component of the capital cost, the cost of building a boiler of capacity greater than that required for process requirements alone.

There is an additional incremental cost that can arise in steam-topping cogeneration. As noted above, more electricity can be produced per pound of steam by using a boiler of a higher pressure and temperature rating at some additional cost. Furthermore, the boiler will have to provide more steam to make up for the increased energy loss in the additional electricity production. These supplementary costs can be partially offset against the economies of scale captured with the larger boiler and turbo-generator.

A final possibility is the inclusion of some condensing capability to the electricity generation equipment. This will augment the production heat sink when the production demand for steam is low. Figure A7 shows steam demand profiles for such a system. The shaded area in Figure A7a is the additional capacity that is available for condensing generation. The area between the solid and dashed lines of Figure A7a is the steam utilized for cogeneration, that below the solid line steam for process requirements. Figure A7c shows the electricity production profile for

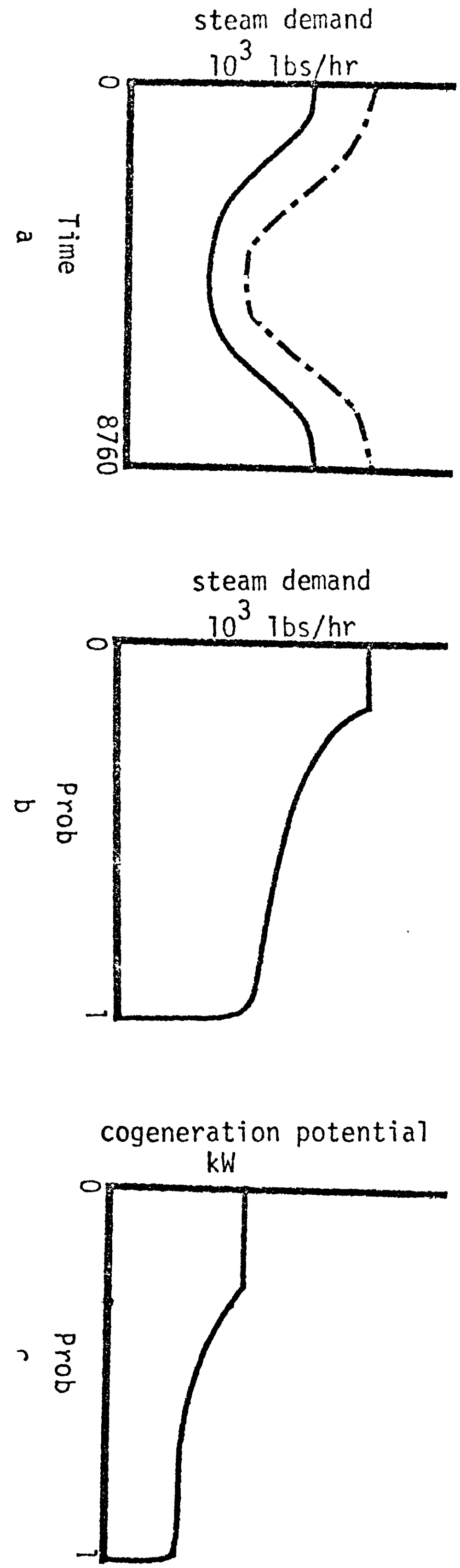

steam demand
10^3 lbs/hr
0
8760
Time
a
steam demand
10^3 lbs/hr
0
1
Prob
b
cogeneration potential
kW
0
1
Prob
c

Figure A-6

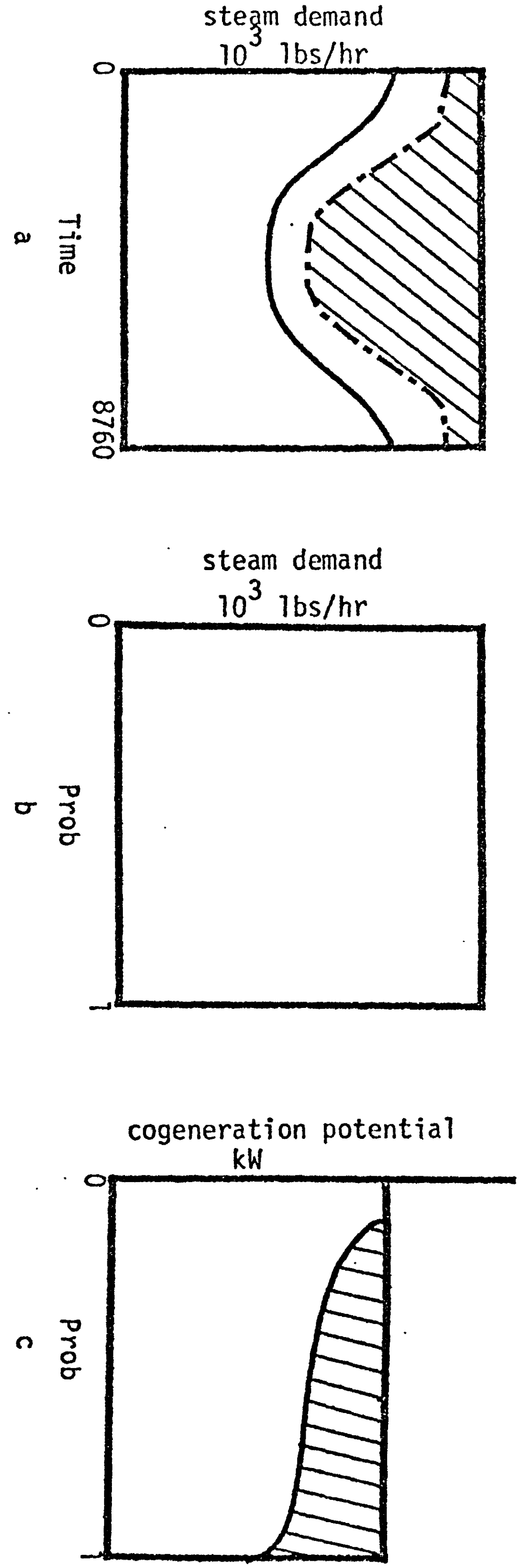

steam demand
10^3 lbs/hr
0
8760
Time
a
steam demand
10^3 lbs/hr
0
1
Prob
b
cogeneration potential
kW
0
Prob
c

Figure A-7

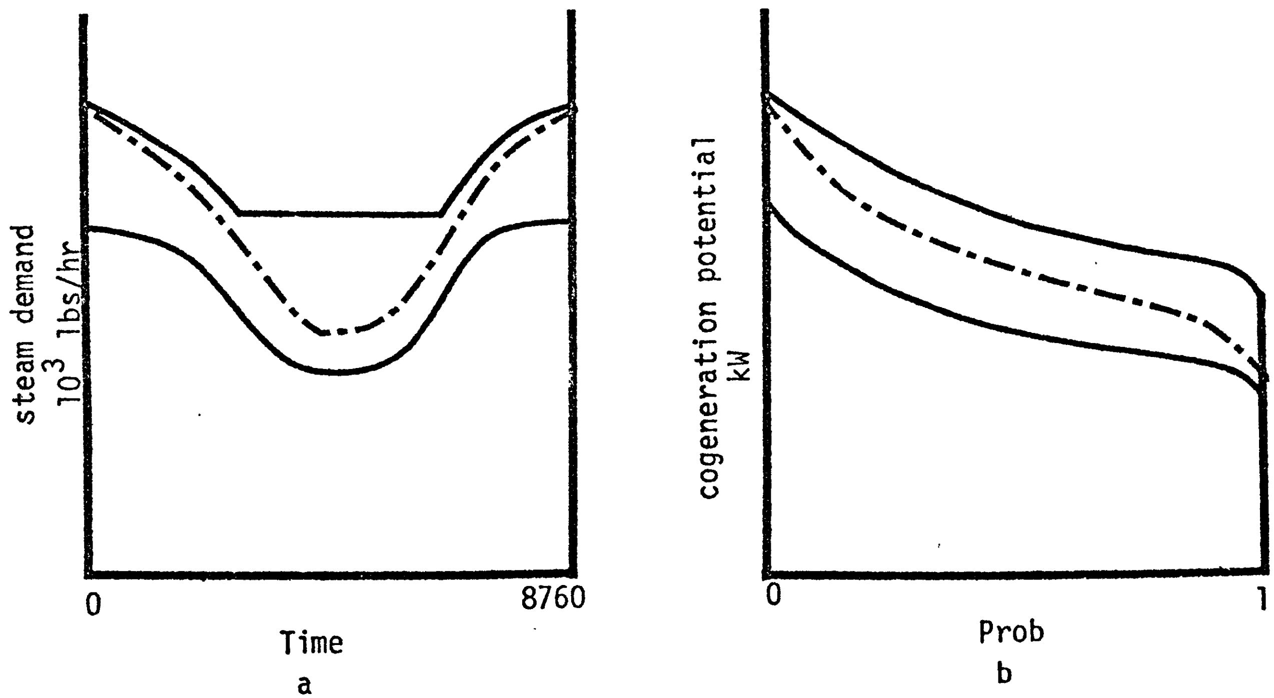
this system, with the shaded area being that due to condensing steam.

Generation of electricity through the use of a condenser would have a higher fuel cost since no useful heat will be recovered outside the turbine. However, this additional cost will be offset by the increased utilization of the boiler and the turbo-generator. The investment with the highest present value will depend upon the relative prices of capital and energy. For a rigorous derivation of this trade-off, see Helliwell and Margolick (1980).

Gas Turbine Combined Cycle

The gas turbine technology is depicted in Figure A1b. It utilizes the expansion of gases released by combusting fuel to drive a turbine. The gas exhausting from the turbine is then channelled through a waste-heat boiler in which steam is raised. This steam can be delivered to the process site through a topping turbine (not shown in the diagram) or a pressure reducing valve. Again, flexibility in the ratio of electricity to steam production can be maintained through the use of condensors.

The possible steam demand profiles and cumulative distribution profiles are portrayed in Figure A8a. Three profiles are shown. The lower solid line is the demand for process steam. That steam is provided from the exhaust gases which first produces the electricity. The dashed line indicates the additional steam demand for electricity production by steam topping cogeneration. The topping generation strategy implied by this steam demand profile is one in which the topping turbine is utilized at full capacity at all times. Additional capital costs to provide this steam would be a larger combustor and a larger gas turbine. The higher



steam demand
10^3 lbs/hr
0
8760
Time
a
cogeneration potential
kW
0
1
Prob
b

Figure A-8

solid line is a possible profile to provide added steam to be put through a condenser. Again, the advantage of being able to run steam through a condensor would be increased utilization of both the gas turbo-generator and the steam-topping turbo-generator.

The electricity generation load duration curve is found in Figure 8b. The lower solid line is, of course, the electricity production from the gas turbine. The height between the lower solid line and the dotted line represents the additional capacity generation that results from adding a topping turbine. There are two components to this additional power, the first being that which arises from the topping turbine. The second component arises from the extra steam that will be required to make up for heat lost in the topping turbine. That heat will have to be raised in the fuel combustor, the gases from which will be passed through a gas turbine larger than the one indicated by the lower solid line. A large waste-heat recovery boiler would also be required.

A cogenerating strategy does not have to include full use of the topping turbines. The gas turbine and waste-heat recovery boiler could be sized just large enough to meet peak process steam requirements with the topping turbine only large enough to generate electricity from excess steam. (This is a strategy similar to that described for the situation in Figure A4.)

The capital costs of these gas turbine cogeneration options are slightly more complicated to assess for the joint products than the simple topping cycle. The smallest system possible results in an investment in a gas turbine and a waste heat recovery boiler. An additional investment can be made in a steam topping turbine up to a size large enough to utilize excess process steam requirements. Topping capacity larger than that will require further investments in a larger gas turbine and a larger waste heat recovery boiler. The thermal efficiency of the gas-turbine-boiler system can be improved with a balancing condensor to dampen any remaining fluctuations in the steam requirements.

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Massachusetts Institute of Technology

Energy Laboratory

Energy Model Analysis Program

Appendix D

An Analysis of 'Least-Cost' Methodology

Michael Manove*

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*Professor of Economics, Boston University

TABLE OF CONTENTS

Appendix D

An Analysis of 'Least-Cost' Methodology

by

Michael Manove

Minimizing energy costs seems, on a superficial level, to be a worthwhile objective of energy policy. It has more appeal than various all-or-nothing alternatives such as a strategy of energy self-sufficiency. The Carnegie-Mellon Energy Productivity Center (EPC) describes the least-cost idea with great enthusiasm:

> The nation has been on an unproductive course; it has looked at energy as a diminishing domestic commodity instead of a service which could be provided by many competing sources. We have been developing a least-cost strategy which, we believe, could unleash new competitive forces, multiply consumer choices, force down the real cost of energy services over the long run, cut the demand for energy supplies, and make a substantial contribution to the nation's economic health. [Emphasis added.]

Unfortunately, as a bit of thought will reveal, the least-cost-energy strategy is generally not optimal; nor is it easily defined. In this Appendix, I will examine least-cost methodology with regard to its limitations and its use within these limitations.

1. Is the "Least-Cost Energy Strategy" the Best Strategy?

Least-cost energy strategies are generally not the best strategies, for two different reasons. First, benefits are not explicitly considered in the selection of least-cost energy strategies; only costs are recognized. Second, it may not be reasonable to minimize energy costs alone, for energy costs are often linked to other costs of production. I will discuss the first of these problems here.

When a consumer goes to the store to buy an item, he often does not pursue a least-cost strategy. Taken literally, the least-cost strategy would require the consumer to buy the cheapest brand. But a consumer is not interested in cost alone; rather, he is interested in net benefits, the surplus of benefits over cost. Therefore, consumers are willing to buy expensive brands provided that the added cost is justified by the increased quality of the product.

The concept of a least-cost strategy is meaningful only when some details concerning the output (or benefits) produced by that strategy have been specified in advance. "Least-cost for what?" we must ask. If desired benefits can be specified in advance, then the search for the least-cost strategy is a useful one. In most situations, however, consumers are as free to determine the level of benefits as they are to determine cost. In such cases, the benefits and costs of each alternative strategy must be evaluated simultaneously.

Consider, for example, a consumer who is shopping for an automobile. The consumer is free to make his/her decision on the basis of fuel efficiency, but is also free to decide on the size of the car and amount of driving. The values that a rational consumer assigns to each of these variables are interrelated and all will depend on the price of gasoline. Normally, it would not be rational for a consumer to take the amount of his driving and the size of his car as fixed and to consider the price of gasoline only in choosing the appropriate level of fuel efficiency. Yet the design of a least-cost study postulates exactly that: the quantity of energy services to be produced and the productive capacity of the equipment are both specified exogenously; only the efficiency of energy-service production can be varied.

The least-cost strategy identified in this way can markedly deviate from the optimal (net-benefit-maximizing) strategy. In order to obtain a quantitative measure of the nature and degree of this deviation, I shall employ several elementary analytical models of the production of energy services. The models I use here were inspired by the more complex and general models presented by McFadden [2].

1.1 General Setting

The general setting for all of the models presented here is the same. Some energy service (space-heating, cooling, industrial steam, transportation) is to be produced by some sort of equipment (furnace, boiler, air conditioner, automobile) that uses some form of energy input or fuel. Each strategy of energy-service production is described by three variables: the level of energy-service output, the productive capacity of the equipment and the energy efficiency of the equipment. These three variables imply values for two other important variables: the capacity utilization rate and total use of energy inputs or fuel. The models differ from one another in their designation of which of these variables are fixed in advance, and which may be set by the consumer or policymaker.

Our first model will represent the selection of the least-cost energy strategy: the least-cost level of energy efficiency is chosen for a given output of energy services and equipment capacity. The second model will represent the selection of the maximum-net-benefits strategy when both the level of energy services and the energy efficiency of the equipment can be varied. The third model represents the selection of the maximum-net-benefits strategy when energy services, equipment capacity and equipment efficiency can all vary, but where the capacity utilization rate is fixed. Finally, we shall construct a model of the selection of the maximum-net-benefits strategy when energy service, equipment capacity and equipment efficiency can all be varied independently of one another.

The properties of the strategy selected by our representation of the least-cost model will be compared with those of strategies selected as optimal by our three net-benefits maximizing models. In this way, we shall reach some conclusions about the type and degree of distortion inherent in the least-cost model output because of its restrictive assumptions.

It is important for the reader to keep in mind that all models contain simplifying assumptions and that their outputs necessarily deviate from reality. These simplifications cannot and ought not be avoided if the model is to have significant explanatory and predictive value. In fact, most policy model failures occur because of models that are cluttered with complex, poorly represented and poorly understood detailed depictions of the real world. Many models would be greatly improved if they were cast at a simpler, more highly abstract level. Thus, we are not objecting to the fact that a least-cost study contains simplifying assumptions; rather, we are asking when the particular simplifications made are the appropriate ones for the purposes to which the study is to be applied.

1.2 Our Modelling Framework

The fundamental policy variables of our models are the level of energy services, X, the capacity of the service-producing equipment, K, and the equipment energy/service ratio (ESR), denoted by H. The variable H is defined by the identity

$$(1) \quad H = E/X$$

where E is the total quantity of energy used as an input to the productive process. Thus the reciprocal of H is a measure of energy efficiency.

The capacity utilization rate, U, is defined by the identity

$$(2) \quad U = X/K$$

When cost is the same, consumers prefer lower utilization rates to higher ones, because lower rates afford the consumer more flexibility in the production of energy services.

In all of our models, equipment costs will be assumed proportional to equipment capacity. This is because we are trying to depict the production of energy services in the aggregate. Equipment capacity is visualized as being determined by the number of units of equipment available rather than by the size of each unit. The cost per unit of equipment is denoted by the function C(H). We assume that lower ESR values (greater efficiency) are more costly to achieve than higher ESR values (lesser efficiency), and that there is increasing marginal cost of increasing efficiency. Thus $C'<0$ and $C''>0$.

The price of energy inputs or fuel is denoted by P. In the models below, we shall examine how the value of P effects the optimal value of the other variables.

1.3 The Least-Cost Strategy of Producing Energy Services

Let the output of energy services, X, be fixed and, for simplicity, assume that the equipment capacity, K, is fixed at K = 1. Then, total cost of producing energy services is given by

$$(3)\ T = C(H) + PXH$$

Note that HX is the quantity of fuel consumed in the production process, so that PHX is the total cost of fuel consumed. The cost-minimizing strategy is determined by the energy/service ratio, H, that minimizes T. This first-order condition for the optimal value of H is given by

$$(4) \quad \frac{-C'(H)}{X} = P$$

Suppose, now that C(H) is defined by

$$(5) \quad C(H) = c_0 + mH^{-\mu}$$

for $\mu \geq 1$. The parameter c_0 represents the base price of a unit of capacity, and the parameter μ represents the elasticity of additional equipment cost with respect to energy efficiency.

Differentiating (5), we have

$$(6) \quad C'(H) = -m\mu H^{-\mu-1}$$

Subtituting (6) into (4) yields

$$(7) \quad \log(m\mu/X) - (\mu+1)h = p$$

where h and p are the respective logarithms of H and P. By differentiating (7) with respect to p and solving for h' we obtain

$$(8) \quad h' = -\frac{1}{1+\mu}$$

Note that h' is the elasticity of the least-cost H with respect to the price of fuel, P. Thus -h' is the elasticity of energy efficiency of the least-cost production strategy with respect to the price of fuel. If, for example, $\mu = 1$, then a doubling of the price of fuel will cause the energy efficiency of the least-cost strategy to increase by about 40 percent. We will show that this figure substantially exceeds the analogous figures obtained from some of the maximum-net-benefits models.

1.4 The Production of Energy Services with Fixed Capacity

In this model, we shall assume K is exogenously specified at K = 1, and allow both X and H to vary. As an example, think of a consumer that must have a two-ton truck in order to haul large fixtures. The consumer can select the efficiency of his truck and can determine the extent of its use. The consumer derives benefits (revenue) from the services provided by the truck, but must pay both capital costs and mileage costs.

Let B(X) denote the benefits to the consumer of the level of service X. We assume decreasing marginal benefits, i.e. $B'>0$ and $B''<0$. The net benefits associated with any values of X and H is the difference between the benefits of the energy service and its costs. This is given by the function $\pi(X,H)$ where

$$(9) \quad \pi(X,H) = B(X) - C(H) - PHX$$

The maximum-net-benefits strategy is given by the solution of the following problem:

$$\max_{X,H} \pi(X,H)$$

The first-order conditions for the maximum-net-benefits strategy are given by (4), repeated here,

$$(4) \quad \frac{-C'(H)}{X} = P$$

and by

$$(10) \quad \frac{B'(X)}{H} = P$$

A second-order condition sufficient to guarantee that the solutions of (4) and (10) describe a maximum-net-benefits strategy is given by

$$(11) \quad -B''(X)C''(H) > P^2$$

We now find the solutions of (4) and (10) for particular specifications of benefits and cost functions. Let B(X) be defined by

$$(12) \quad B(X) = \frac{b\alpha}{\alpha-1} X^{(\alpha-1)/\alpha}$$

for $\alpha > 0$, $\alpha \neq 1$. This benefits function was chosen because it implies a demand function for X with a constant own-price elasticity of $-\alpha$.

Let C(H) be given by (5), as before.

Differentiating (12), we have

$$(13) \quad B'(X) = bX^{-1/\alpha}$$

Let x, h and p denote log X, log H and log P, respectively. Substituting (6) and (13) into (4) and (10) and taking logarithms yields the logarithmic form of the first-order conditions for the maximum-net-benefits strategy:

$$(14) \quad \log(b) - \frac{1}{\alpha} x - h = p$$

and

$$(15) \quad \log(m\mu) - (\mu+1)h - x = p$$

Equation (15) is equivalent to (7), but in (15) X is not a constant. The second-order condition (11) will hold if and only if

$$(16) \quad 1 + \mu - \alpha > 0$$

Therefore, a maximum-net-benefits strategy will exist at positive values of X and H if and only if (16) is true.

Equations (14) and (15) implicitly define x and h as functions of p. Differentiating (14) and (15) with respect to p and solving for x' and h', we have

$$(17) \quad x' = - \frac{\alpha\mu}{1 - \alpha + \mu}$$

and

$$(18) \quad h' = - \frac{1 - \alpha}{1 - \alpha + \mu}$$

The logarithmic derivatives x' and h' are the elasticities of X and H with respect to P, the price of energy inputs. Because the demand for energy is given by $E = XH$ the own-price elasticity of the demand for energy is given by $e' = x'+h'$, so that

$$(19) \quad e' = -\frac{1 - \alpha + \alpha\mu}{1 - \alpha + \mu}$$

Condition (16) implies that both x' and e' will be negative. But, we can see from (18) that h' will be positive if $\alpha > 1$. Thus, as Khazzoom[1] and McFadden [2] observe, it may be desirable for consumers to decrease the efficiency of their equipment when the price of energy rises! In our model, this somewhat surprising behavior will occur whenever consumer demand for energy services is price-elastic. The intuitive reason for this phenomenon is easy to understand. A consumer with an elastic demand for energy services responds to an increase in energy price with a very large decrease in the use of his equipment. Therefore, he no longer needs to have equipment that is as energy efficient. Of course, his total energy use will still decline.

By comparing (18) to (8), we can estimate the overstatement of optimal equipment efficiency associated with least-cost analysis when demand for services can vary. If the true price-elasticity of demand for energy services is zero, then (18) becomes the same as (8) so that cost minimization will identify the appropriate energy strategy. But if the price-elasticity of the demand for energy services is non-zero, cost minimization yields an exaggerated result. Recall that for $\mu = 1$ cost minimization (8) yields $h' = -.5$, so that optimal efficiency increases by about 40 percent when the price of energy inputs doubles. But if the elasticity of demand for energy services is .5, then the maximum-net-benefits strategy described by (18) calls for an efficiency increase of only 29 percent. And if the elasticity of demand is unitary, then the maximum-net-benefits strategy calls for no change in efficiency of energy-service-producing equipment, only a reduction in the quantity of services consumed. Because the demand for energy service is certainly sensitive to the price of that service, we are confident that in cases where equipment capacity is fixed, least-cost strategies will reflect a significant bias toward increased efficiency of energy-using equipment.

1.5 The Production of Energy Services with Fixed Capacity Utilization

In the previous section, the stock of equipment was assumed to be constant, and the production of energy services was varied by varying the utilization rate of that constant stock. In this section we fix the capacity-utilization rate, and allow the capacity of the equipment to vary. When capacity utilization is fixed, the ratio of equipment capacity to the output of energy services must be constant.

As before, we let B(X) represent the benefits of X units of energy services and C(H) represent the cost per unit of capacity of equipment with an energy/service ratio of H. The net-benefits function is given by

$$(20) \quad \pi(X,H) = B(X) - C(H)K - PHX$$

Using (2), we can rewrite (20) for the case of fixed capacity utilization as follows:

$$(21)\quad \pi(X,H) = B(X) - \frac{1}{U}C(H)X - PHX$$

where U is the constant capacity-utilization rate. The first-order conditions for the maximization of (21) are given by

$$(22)\quad B'(X) = \frac{1}{U}C(H) - PH$$

and

$$(23)\quad C'(H)X = UPX$$

If X is positive, (23) reduces to

$$(24)\quad C'(H) = UP$$

Let us now specify the function C(H) by equation (5), so that C'(H) is given by (6). Substituting (6) into (24) and taking the logarithm of each term in the resulting equation, we get

$$(25)\quad \log(m\mu/U) - (\mu+1)h = p$$

where h and p are the logarithms of H and P, respectively. Differentiating (22) with respect to p and solving for h' yields

$$(26)\quad h' = -\frac{1}{1+\mu}$$

But (26) is identical to (8). This means that if the capacity-utilization rate is fixed, as we have assumed for this model, the least-cost strategy is a good approximation for the maximum-net-benefits strategy with regard to the energy-efficiency of equipment. This is true even if the demand for energy services is price elastic. Of course, because least-cost analysis contains no counterpart of equation (22), it cannot tell us anything about the output of energy services.

1.6 The Production of Energy Services with Variable Capacity Utilization

In this section, we allow both productive capacity (for producing energy services) and capacity utilization to vary. In other words, the level of the production of energy services and the capacity to produce those services can vary independently. It is important to understand that the presence of productive capacity creates benefits even when it is not being used. This is because excess capacity allows increased flexibility in the rate that services are created. Because of the need for flexibility, people are often willing to pay for capacity in excess of minimum production requirements. Therefore, in this section, we will consider the benefits of energy services to be an increasing function both of the level of services and the amount of capacity available to produce those services. Benefits will be denoted by B(X,K). This will make our model a bit more complicated than the previous models in which benefits were functions only of the level of services, X.

In this model, net benefits are given by

(27) $\pi(X,K,H) = B(X,K) - C(H)K - PHX$

First-order conditions for maximizing π are given by

(28) $\frac{\partial B}{\partial X} = PH$

(29) $\frac{\partial B}{\partial K} = C(H)$

and

(30) $-C'(H)K = PX$

In order to present one example of how X, K and H might depend on the price of energy, P, we will specify the following form for B(X,K):

(31) $B(X,K) = bX^{\gamma}K^{\beta} \qquad \gamma,\beta > 0,\ \gamma,\beta < 1$

This particular functional form (Cobb-Douglas) is a plausible, but by no means general, benefits function. The value $\gamma+\beta$ is the elasticity of benefits with respect the the level of energy services when the capacity-utilization rate is held constant.

We specify the cost-of-efficiency function, C(H), by (5), as before. Differentiating (31) and (5), substituting the results into (28), (29) and (30) and taking logarithms yields

(32) $\log(b\gamma) + (\gamma-1)x + \beta k - h = p$

(33) $\log(b\beta/m) + \gamma x + (\beta-1)k - \log(C(H)) = 0$

(34) $\log(m\mu) - x + k - (\mu+1)h = p$

Differentiating these equations with resect to p yields the equations:

$$(35)\quad (\gamma-1)x' + \beta k' - h' = 1$$

$$(36)\quad \gamma x' + (\beta-1)k' + \mu S h' = 0$$

$$(37)\quad -x' + k' - (\mu+1)h' = 1$$

where S is the ratio of efficiency costs to total capacity costs given by

$$(38)\quad S = \frac{mH^{-\mu}}{c_0 + mH^{-\mu}}$$

These equations can be solved for x', k' and h', the elasticities of X, K and H with respect to P. The solutions are:

$$(39)\quad x' = -\frac{1-\beta}{1-(\gamma+\beta)}$$

$$(40)\quad k' = -\frac{\gamma}{1-(\gamma+\beta)}$$

and

$$(41)\quad h' = 0$$

Equation (41) implies that for the Cobb-Douglas benefits function, the optimal energy efficiency of productive equipment is <u>independent</u> of the price of energy. How can this be so From (2) we know that u', the elasticity of the utilization rate with respect to the price of energy, is given by u' = x' - k', so that by (39) and (40), u' = -1. Thus, as the price of energy increases, productive equipment is used less intensively. Although increased energy prices tends to increase optimal efficiency, the accompanying reduction in utilization rate negates that optimal-efficiency increase.

Suppose, for example, that $\gamma = -1/4$ and $\beta = 3/4$. From (39) and (40), we have $x' = -1/2$ and $k' = 1/2$. Therefore, if fuel prices double, the demand for energy services will fall by about 30 percent. The capacity of the equipment, however, will increase by about 40 percent. This increase comes about because consumers find equipment has become less expensive as compared with the cost of energy services. Thus, for example, after an increase in the price of gasoline, consumers may choose to own more cars on the average, even if they decrease their total mileage. Each car would be used significantly less, so that consumer willingness to pay for increased fuel efficiency would be less than it otherwise might be.

This model brings out a very important aspect of the production of energy services. Increases in energy prices tend to decrease optimal equipment utilization, and decreased utilization decreases optimal efficiency. Thus, optimal efficiency is bound to be less than would be indicated by least-cost analysis, in which productive capacity and the rate of capacity utilization are both held fixed. The distortion associated with least-cost analysis might be less (or more) dramatic than the distortion that appears with the Cobb-Douglas benefits function, but some distortion will be present. This type of distortion is independent of the elasticity of demand for the energy service, and it will exist even if that demand is perfectly inelastic!

1.7 Conclusion

In Section 5, we suggested that least-cost analysis tends to be a good approximation of maximum-net-benefits analysis whenever capacity-utilization rates of service-producing equipment are fixed. But while fixed capacity-utilization rates may be a realistic discription of certain sectors of the economy, it is unreasonable to assume that capacity utilization rates for the economy as a whole will remain unchanged when energy prices are drastically increased.

We must conclude, therefore, that a least-cost energy strategy may strongly overstate desired increases in efficiency. This can occur for two different reasons. First, there are many situations in which the capacity of equipment must remain relatively fixed, despite changes in the price of fuel. If, in such cases, the demand for energy services is price sensitive, then increased fuel prices will cause capacity-utilization rates to fall and least-cost analysis will overstate optimal efficiency increases. This tendency was demonstrated in Section 1.3. Second, when the level of productive capacity and the quantity of energy services can vary independently, consumers (or producers) will tend to substitute additional capacity (and flexibility) for the energy service itself. This lowers utilization rates and optimal efficiency. This tendency was demonstrated in Section 1.6.

It is a general principle of economics that the existence of substitutes in production and consumption tends to reduce the impact of external economic shocks. The methodology of least-cost analysis allows increased efficiency in the production of energy services to substitute for energy-inputs or fuels, as energy prices rise. However, that methodology excludes the possibility of substituting increased flexibility in the production of energy services for some portion of those services. Least-cost methodology also excludes the possibility of substituting the consumption of non-energy services for the the consumption of energy services. Because of these characteristics, least-cost methodogy will tend to overstate both the importance of increases in energy efficiency and the overall impact of high energy prices on the economy as a whole. The general perspective created by least-cost analysis may be seriously biased.

2. The Formulation of the Least-Cost Concept

Having already raised some questions about the desirability of the least-cost approach, I would like to consider the meaning of the terms "cost" and "least-cost," and discuss the different ways in which the concept of least cost can be formulated. The task of adding up the costs of providing energy services to the entire nation is extremely broad and varied. In pursuit of this endeavor, even the most detached analyst will be forced to make a long series of decisions entailing value judgments and predictions. These decisions will constitute an implicit definition of what the analyst means by the cost of a strategy and will ultimately affect choice of which strategy is the least-cost strategy.

Here are some examples of decisions that must be made in computing the cost of a national energy strategy: Should payments for already-existing capital goods be counted as costs? What value should be placed on environmental quality? Should the actual price of natural gas be used to evaluate the cost of gas? Or, should the analyst use some estimate of the price of gas that would prevail in the absence of regulation? What are appropriate minimum ambient temperatures for various categories of buildings? If a strategy includes governmental regulations, should costs be computed on the assumption of complete compliance with those regulations? If not, how should the costs of cheating be evaluated? Will a particular strategy induce innovation and market penetration of new, more efficient technologies? Should the quantity of available oil be constrained to equal known reserves? Or should the discovery of new deposits be assumed?

It should be obvious, I think, that there are no clear-cut right or wrong answers to these questions. Many of the answers ought to turn on the purpose of the cost calculations. But one point is clear: The identification and description of the least-cost strategy will be of little value unless the analyst diligently communicates his answers to all of these questions and many others. In fact, any depiction of a least-cost strategy without careful documentation of these decisions may prove to be seriously misleading.

Each of the cost-defining decisions tends to answer one of the following four general questions: Which resource expenditures are counted as costs? At what prices are expended resources evaluated? What variables are endogenous to the cost-minimization process? What constraints are used in conjunction with the least-cost objective function? One of the sections below is devoted to each of these general questions.

2.1 Which Resource Expenditures Are Counted as Costs?

Answering this question requires a number of careful value judgments. Below, I discuss some general points that arise in connection with costing out all resources, and then I discuss costing-out specific resources.

2.1.1 Money Expenditures vs. Resource Expenditures

It is important to consider as costs the real use or expenditure of scarce economic resources rather than money payments. Sometimes the two go together, but sometimes they do not. For example, federal, state and local taxes are money costs that do not, in themselves, involve the expenditure of scarce economic resources. Thus, taxes normally should not be counted as an economic cost. However, when a specific energy strategy requires the government to provide a certain service, the value of that service should be counted as a cost.

The degradation of the environment is an example of a resource expenditure usually not associated with a money payment. It is important to count all such costs, even though it may be difficult to assign a value to them.

2.1.2 Point of View

This brings us to a closely related and equally general point: From whose point of view are costs defined? From the point of view of corporate stockholders, the corporate income tax is a cost, because it gives the government, an 'outsider,' a claim on the real resources owned by those stockholders. But from the point of view of the nation as a whole, the corporate income tax is not a cost. It is simply a transfer of resources from one group of citizens to another; both groups are 'insiders.' No resources are actually expended in that transfer.

We are frequently concerned about costs from the national point of view. Thus, for example, all of the funds paid to foreign governments for oil are considered to be costs. This makes sense because those funds give foreigners (outsiders) a claim on our own real resources. It should be understood, however, that it would be perfectly valid for an analyst to be concerned with costs from the point of view, say, of all of humanity. In that case, the profits paid to an OPEC member by virtue of OPEC's monopoly power would be considered a simple transfer of resources from one inside group to another, and not a true expenditure of resources. Only the "competitive" value of oil would be counted as a cost, for only that part of the money payment represents the value of the oil in its best alternative use.

When the analyst determines the point of view, she is making a value judgment that cannot be declared 'right' or 'wrong.' But those of us who form the audience for the analysis are entitled to know whose point of view was adopted.

2.1.3 Capital Goods

Should the (levelized) cost of existing in-place capital goods be included in the cost of an energy strategy? The answer to this question depends on the purpose of the least-cost analysis.

Suppose, for a moment, that the analysis was motivated by the following question: "How much would we have saved if we had had the foresight to invest in efficient capital equipment rather than in the inefficient equipment we now use?" This is a question of historical interest. It is addressed to what we should have or might have done, not to what we ought to do at the current time. The motivating question implicitly requires that we view the world from the standpoint of the time before current investment decisions were made. Thus, in trying to answer this motivating question, we must put existing capital goods on the same footing as alternative capital goods. Therefore, the cost of both existing and alternative capital goods should be included in our calculations.

Suppose, however, that we are attempting to solve the very practical planning problem: "In what type of equipment should we now invest?" In asking this question, we are looking forwards, not backwards. We must view the installation of existing equipment as an irreversible event. If existing equipment has no use other than to produce energy services, then there are no economic costs (lost opportunities) entailed in using it for that purpose. Therefore, in this case, capital charges for existing equipment should be excluded from our calculations. Capital charges for new equipment, however, should be fully included.

The analyst's decision to include or exclude capital charges on existing equipment is a crucial one. It should be documented and carefully justified.

2.1.4 Implementation of the Energy Strategy

We now turn our discussion to issues that relate to the social organization of energy production. These social issues frequently entail substantial resource expenditures.

Consider an energy-production strategy that requires a well-insulated housing stock. For that strategy to be implemented, homeowners must be informed that insulation is advantageous and induced to install it in their homes. If the economic benefits of insulation do not accrue directly to the homeowners, if the homeowners do not perceive those benefits, or if the homeowners are irrational, then regulation and enforcement may be necessary to implement an insulation program. Providing homeowners with information on insulation and its economic effects may be costly. The regulatory process can also be extremely costly. Vast resource expenditures may be required to enforce regulations. Should these costs be included in the cost of the associated energy strategy?

Or consider the following closely related question. Suppose that a particular strategy calls for a large number of nuclear power plants. These plants are highly unpopular among some segments of the population, and their construction might make those people very unhappy indeed.

Should such "psychological" costs be included in the analyst's cost calculations? Suppose that the construction of nuclear power plants would likely induce widespread social unrest? Should the cost of such unrest be tabulated and included in the cost of the associated strategy?

The appropriate answers to these questions depend on the identity of the policymakers for whom the least-cost analysis is intended. If one wants to convince nuclear opponents that nuclear power is desirable because it is inexpensive, it does not make sense to include the psychological state of those nuclear opponents as a cost of nuclear power. But if the analysis is being conducted on behalf of a politician who is concerned with popular sentiments as well as with dollar and cents, it may make perfect sense to convert sentiments to dollar-costs.

2.1.5 Diminution of Benefits

The least-cost methodology explicitly excludes consideration of the benefits of energy service, a fact I have discussed at some length. In principle, energy services are specified in advance, and all strategies considered provide the same energy service. In fact, however, no two energy strategies provide exactly the same energy services. For example, improvements in the thermal shell of buildings may degrade ventilation to some extent, causing benefits of space heating to be slightly diminished. In order to make different energy strategies comparable, such diminutions of benefits can and should be treated as costs of the strategy with which they are associated. Any increases in benefits should be subtracted from strategy costs.

Very often, energy-efficient equipment is less convenient than energy inefficient equipment. Efficient automobiles are often characterized by cramped interiors, sluggish acceleration, high noise levels and manual transmissions. Such inconveniences should be charged off as added costs of efficiency if the analysis is to avoid a pro-efficiency bias.

Of course, translation of inconveniences to costs requires numerous value judgments. Often, these judgments can be facilitated by data descriptive of consumer willingness to pay for added conveniences.

2.1.6 Conclusion

There are no simple answers to the question: "Which resource expenditures should be counted as costs?" Many decisions in this area require value judgments by the analyst. Many decisions depend on the point of view of the analysis. It is essential, therefore, that these decisions be well-documented and explained.

2.2 At What Prices Should Expended Resources Be Evaluated?

The evaluation of expended resources is a difficult process requiring good judgment and forecasting ability. When a resource is bought and sold in a competitive market, the actual price tends to reflect true economic scarcity. Therefore, competitive prices are normally a good index of current resource value. Unfortunately, competitive prices are often unavailable to the analyst. This may be because a resource is not traded in a competitive market, or it may be because the analyst cannot secure the relevant market data. Often, the analyst needs to know the future value of a resource, and it may be difficult to forecast such values even when current values are known. There is no single "right" way to evaluate resources, but there are many wrong ways to do it. I will discuss a number of them.

2.2.1 Resources Traded in Competitive Markets

When a resource is traded in a competitive market, the competitive price forms a good starting point for resource evaluation. But even in this simplest case, difficulties can arise. As an example, consider the case of coal. Coal is one of the few basic energy sources whose supply is competitive. But coal is not homogeneous; nor is the railroad system that transports the coal. Since coal supplies differ by quality and by location, there are a very large number of competitive prices available, one for each type of coal and for each location in which it is traded.

Furthermore, although the national market for coal tends to be competitive, some firms may exercise local monopoly power. More importantly, the market for coal miners is unionized. Consequently, the wage bill in the coal-mining sector may overstate the true economic costs of that labor. This would be reflected in the market price for coal, so that a downward price adjustment might be desirable.

There are other non-competitive factors in coal supply. Some states, and the federal government have imposed taxes and royalty charges on coal production. These fees may affect a sufficiently large proportion of coal to drive up its market price in some regions.

We can see then, that even competitive prices should be examined to determine how well they reflect underlying economic scarcity. They may deviate from scarcity values for a variety of reasons: non-competitive elements in resource supply and transportation, externalities in resource production, or because of buyers and sellers who are poorly informed about market conditions or who have incorrect expectations about the future. When substantial deviations exist, price adjustments in the computation of costs may be desirable.

2.2.2 Regulated Markets

Prices in regulated markets rarely have the virtue of reflecting true economic scarcity. Therefore, it is important to try to estimate the economic cost of delivering marginal units of the resource involved. This is an extremely difficult task. For natural resources, like gas, both production and depletion costs must be considered. And depletion costs, the value of the resource in its next best alternative use (possibly in the future), cannot be calculated with conventional accounting procedures. Some economists have proposed complicated dynamic optimization techniques to find them, but at this time the state of the art has not been advanced far.

Both natural gas and electricity fall into the category of resources whose production and sale are regulated, and there is reason to believe that their regulated prices underestimate their economic value. The analyst must do his/her best to make appropriate price adjustments. The difficulty of the problem is not a good reason to cost out these resources at the regulated price.

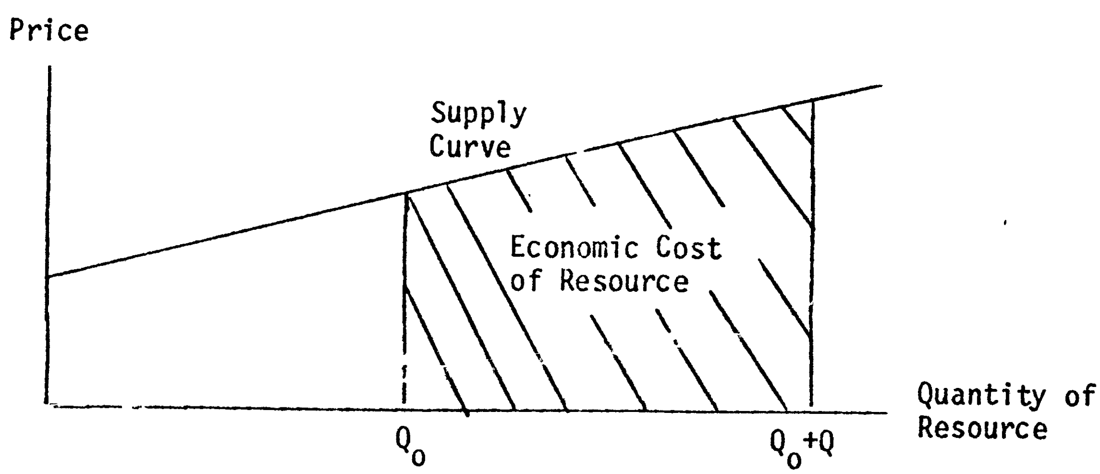
2.2.3 Resources with Strategy-Dependent Prices

When the production of energy services consumes a large portion of the available quantity of a resource, the price of that resource may well depend on the energy strategy implemented. In such cases, estimating the economic cost of the resource used up by a given strategy, requires knowledge not only of the price that would prevail given the implementation of that strategy, but of the entire supply curve for that resource. This is because of the fact that the a competitive market price reflects the economic cost of the marginal (last) unit of the resource delivered; previous units are less costly. If a strategy uses only a small portion of the supply of a resource, then the value of the last unit is a good approximation for the value of all units used by that strategy. Otherwise, each succeeding unit of the resource must be valued differently. The conventional technique for evaluating the cost of such a resource is to calculate the area under the supply curve, bound by the quantity of the resource usage external to the strategy, on the one side, and total resource usage, including that of the strategy, on the other side.

A supply curve for a resource is illustrated in Figure 1. Suppose the non-energy sector of the economy uses quantity Q_0 of the resource, while the energy-service sector specified by a given energy strategy uses quantity Q of that resource. Then the shaded area corresponds to the economic cost of the resource used up in the given strategy.

As an example, consider an energy strategy specifying extensive retrofitting of heating systems. Suppose that the retrofitting work would use a substantial portion of the available labor time of plumbers over a period of several years. To calculate the economic cost of the plumbers' labor, one would determine the supply curve for plumbers, and calculate the area designated in Figure 1. Notice that the last plumber used costs quite a bit more than the first plumber used. Because more and more plumbers are used, each succeeding plumber is withdrawn from important alternative work.

Figure 1



2.2.4 Future Costs

Calculating the cost of an energy strategy projected into the future requires some form of economic forecasting ability. Good forecasting techniques can range from educated "guestimation" to sophisticated econometric forecasting models. In order to obtain some sort of confidence interval for cost estimates, it is important to conduct sensitivity studies with respect to all forecasted parameters and data. Usually, it is useful to present results for several variants of the key parameters.

If important parameters are highly uncertain, the strategy that is optimal for the most likely (or expected) outcome of the parameters generally will not be the optimal strategy. This is because of the need to "hedge one's bets" in an uncertain world. If key parameters are unknown, it is often best to postpone irreversible commitments.

Consider, as an example, the problem of developing a strategy for long-term investments in electricity generating equipment. If it is certain that in the future coal-fired boilers will be less expensive to operate than gas-fired boilers, then coal-fired boilers should be installed. If the opposite is certain, then gas-fired boilers should be installed. But it does not follow that a combination of gas-fired and coal-fired boilers is a good strategy when relative costs are uncertain. It may be much better to hedge with stop-gap investments in small gas turbines until more information emerges about future costs.

In short, the kinds of strategies appropriate to a highly uncertain world are qualitatively different from those suited to a certain world, whatever the description of that certain world may be. The best strategy for the best guess about future prices may be a poor strategy indeed. To find the least-cost strategy in the face of uncertainty, the analyst may be best advised to use stochastic optimization techniques. Needless to say, the application of such complicated techniques to large systems of variables is highly problematical. In any event, an appreciation of the implications of uncertainty is useful.

2.3 What Variables are Endogenous to the Cost-Minimization Process?

The analyst's answer to this question will determine the scope of the policy model. The analyst must find a natural boundary for the problem. All variables outside that boundary are to be specified as parameters in advance of the analysis or omitted from consideration entirely; the values of the variables within that boundary will be determined by the analysis itself. In the design of a policy model for selecting a minimum-cost energy strategy, there are a number of broad classes of candidates for endogenous variables. These include important macroeconomic variables, capital stock by technology type, energy supplies by source, utilization rates of energy-using capital, innovation of energy-related technologies, energy prices, and prices of non-energy resources.

Selecting the endogenous variables for a policy model is an analytical task requiring substantial creativity. Nevertheless, a few general common-sense rules may be formulated. Variables that <u>define</u> the strategy being sought must be endogenous. With respect to the selection of a least-cost energy strategy, the capital stock by technology type is at the heart of any strategy description, and so must be endogenous. Variables whose values are sensitive to the strategy chosen should also be endogenous. If a group of variables is highly interdependent, then either all should be endogenous or else enough of them should be exogenously specified to determine the rest uniquely. For example, it would not be logical to make the supply of coal endogenous and the supply of natural gas exogenous.

If one variable causally determines the value of another, it would not make sense to have the former endogenous and the latter exogenous. More generally, causality may run from exogenous variable to endogenous, from endogenous to endogenous, but not from endogenous to exogenous.

These rules are a rough guide to logical consistency in policy model design. But the overall blueprint of the model, the decision about what variables will be at its focus, should depend on the ultimate purpose of the analysis. Almost every variable explicitly represented in a model adds to its conceptual difficulty, its cost and its completion time. It is important to keep this fact in mind during the crucial task of choosing the level of aggregation for the model. Variables should be omitted entirely unless they are to the point of the analysis. It probably would not be a good idea to have a variable representing academic salaries in a model of energy strategies. Academic salaries are extraordinarily important, but, in the opinion of most authorities on the subject, they are not closely related to the energy question. Every variable included in the analysis should be relevant from a conceptual point of view.

I will now proceed to consider some specific classes of variables. Then I will discuss the limitations of the least-cost methodolgy in this connection.

2.3.1 Capital Stock by Technology Type

The capital stock of energy-service producing equipment is at the heart of any energy-strategy model, and must be represented as a decision variable. The difficult question in this connection is the appropriate level of detail. In general, it is usually suggested that highly aggregated representations are preferable until the structure of the model is well understood and under control.

2.3.2 Capacity-Utilization Rates of Energy Consuming Equipment

As I have explained in a previous section, capacity utilization rate variables are extremely important aspects of an energy strategy. Along with fuel prices, they determine the appropriate rate of substitution between capital costs and energy efficiency. With the cost of obtaining efficiency given, the higher the energy price and the higher the utilization rate, the more efficiency is justified.

2.3.3 Efficiency of Energy-Consuming Equipment

The efficiency variable is at the foundation of any energy strategy. It may be represented either as a continuous variable, where each level of efficiency has an associated capital cost, or as a discrete variable, associated with the technology type of the equipment and the cost of that equipment.

2.3.4 Energy Supplies and Prices by Source

If the energy strategies under study are U.S. national strategies, then energy prices and associated supply variables that depend on those strategies should be endogenous. The domestic supplies and prices of coal and natural gas are examples. If prices are modelled as exogenous parameters, there is an implicit assumption that supply is perfectly elastic at its parametrically given price. This is unrealistic for coal and gas. If quantities are modelled as exogenous parameters, then there is an implicit assumption that supply is perfectly inelastic or, equivalently, that the amount of the resource that can be obtained is independent of extraction or production costs.

2.3.5 Innovation

In the long run the amount of innovation that occurs in the area of energy production and consumption will depend partly on the price of energy inputs and services. Therefore least-cost energy analysis with long time horizons should make energy innovation an endogenous variable.

Of course, it is very difficult to make accurate predictions about the quantity and effect of innovations. The analyst may choose to seek expert opinion.

2.3.6 Limitations of the Least-Cost Methodology

As I have noted above, least-cost methodology requires that benefits be exogenous and specified in advance. Therefore, there are several categories of variables that cannot be endogenous to a least-cost model. These include demands for energy services and macroeconomic variables.

The prices of energy services will be highly sensitive to the energy strategy selected. Therefore, if the demand for a particular energy service is price-elastic, then the quantity of that service demanded should be, but cannot be, endogenous to the least-cost model. To specify demand exogenously is to assume that either the price of energy services will not depend on the energy strategy, or that service demand is price inelastic. This is unrealistic for most energy services.

Energy is so fundamental to our economy that our overall economic performance is likely to depend on the energy strategy selected. Therefore, it would be desirable to endogenize a number of key macroeconomic variables. But this is incompatible with the least cost methodology.

The inability of the least-coast methodology to represent the causal connection between energy strategy, on the one hand, and demand and macroeconomic performance, on the other, is a serious limitation of that methodology.

2.4 What constraints are used in conjunction with the least-cost objective function?

The least-cost methodology is a methodology of constrained minimization. The very concept of least-cost has no meaning until sufficient constraints are specified to define the feasible set of energy strategies. The audience for a least-cost study will be unable to interpret its results without clear knowledge of the model constraints.

2.4.1 Simulation of Base-Year Data

At some time during the process of model development, it is important to have the model constrained sufficiently to simulate actual production of energy services during the base year for which data is available. Forcing a model to simulate known data has two benefits. First, the model is partially validated. A model that cannot correctly simulate something that has actually happened probably cannot simulate future events of a similar nature. Second, the set of constraints needed to simulate the base-year case provides a point of comparison with different sets of constraints yielding different least-cost strategies. When we see a strategy with a lower cost than that associated with existing behavior, it is useful to be able to answer the question, "What constraints were dropped?"

2.4.2 The Economic and Technological Environment

Constraints must be used to describe various features of the economic and technological environment including energy sources, energy conversion technologies and industrial production technologies. Furthermore, upper and lower bounds on stocks of certain capital goods must be present in order to force model conformance with real-world base-year capital stocks. It would not make much sense to allow the model to make drastic changes in the stock of structures over a short period, for example. Constraints must often be added to the model in order to force a measure of realism on areas of the model that are loosely specified. In models that do not endogenize innovation and technical change, it may be desirable to have constraints on rates of technical change and market penetration of new technologies.

3. Conclusions

The most serious limitation of the least-cost methodology is that it focuses on costs and cannot take benefits into account. But both costs and benefits depend on the national energy strategy selected. To specify a level of benefits or energy services that prevailed during a period of low energy prices biases the energy strategy that is chosen towards increased efficiency in energy consumption.

The least-cost methodology does have the advantage, however, of avoiding all of the problems attendant to benefits computation. This is one argument that can be made in favor of its use. In the context of selecting a national energy strategy, however, I do not find the argument convincing. As I have pointed out above, the concept of cost has critical subjective elements, as does the concept of benefits. The decisions of the analyst regarding the evaluation of expended resources can have a critical impact on cost figures.

The subjective elements in least-cost analysis impose a number of obligations on the analyst. The analyst must be consistent in approach. Decisions must be appropriate for the purpose of the analysis. But most important of all, the analyst must meticulously document any subjective input and assumptions. Lack of such documentation prevents other parties interpretion of the results of the analysis in a meaningful way and can cause those results to be confusing or misleading.

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