DYNAMIC ENERGY SYSTEM MODELING - INTERFUEL COMPETITION

by

Martin L. Baughman

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ii

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The Massachusetts Institute of Technology has undertaken a program of research on Energy Analysis and Planning. The overall goals of this program are to develop concepts, information, and analytical tools that relate energy supply and demand, the economy and the environment in a manner useful to managers and policy makers in government and the energy industries. The work reported here is the first formal output of this effort.

Further research at refining this model and also developing other models relating to the overall goals of the program is underway.

David C. White
Ford Professor of Engineering

2

A B S T R A C T

This work reports the formulation, development, validation, and applications of a medium to long range dynamic model for interfuel competition in the aggregated U. S. The economic cost structure, investment decisions, and physical constraints are included specifically in the supply models for coal, oil, natural gas, and nuclear fuels, as well as in the consuming sectors residential and commercial, industrial processing, transportation and electricity. The model simulates the development of supply, the fuel selection process in the consuming sectors, the depletion of the resources, and resolves these into fuels consumed cost-price trends in the energy markets of the U. S.

The validation issue is addressed at length through a number of considerations, including comparing the model performance to past reported behavior of the energy system. It is applied to a series of scenarios or case studies to assess the impact of a variety of technologies, policy considerations, and postulated occurrences on the future energy outlook. Here it is seen the model can be a useful tool, forcing a consistent assessment of possible future trends. The model is useful for depicting the effects of policy or hypothesized changes in our energy economy in a complete system framework.

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TABLE OF CONTENTS

Page

Page

LIST OF FIGURES

LIST OF TABLES

CHAPTER 1

INTRODUCTION

Many economic studies have been done on the supply and price of each of the various sources of energy [1, 3, 5, 6, 11]. Studies have been made on the determinants of demand for sources of energy [2, 4, 6]. These studies generally refer to the interdependency of price, supply and demand variables that exist among the competing sources of energy, but apparently no one has undertaken to explore in depth the strengths or implications of these interdependencies. This study is an attempt to investigate these mutual cross-ties between the important competing sources of energy in our economy.

In this work, reference to primary sources of energy generally implies coal, oil, natural gas, and nuclear. A secondary source of energy important in interfuel competition is electricity. This is due to its size as a consumer of primary fuels and enhanced by the high degree of substitutability of these fuels in producing electricity. Energy demand refers to uses of fuels for all purposes. These are commonly broken down into the sub-areas industrial processing, space conditioning (both commercial and residential), transportation, the chemical use of fuel, and electricity (for industrial, commercial, and residential use).

It is true that for many uses in our country the competing sources of energy are highly substitutable. This means that one source of energy can accomplish the user's task as well as another. In 1964, the

Energy Study Group wrote[1]

> "While there are some markets for which only one energy form is now economical, as much as 95 percent of total U.S. energy is consumed for purposes in which several or all of the primary energy sources are potential substitutes (directly or through conversion)."

Later works have reinforced this conclusion.[2] If one considers the effects of technological change over sufficient lengths of time, then 100% of energy utilized is substitutable.

The user under these conditions of substitutability must choose one fuel over another. His choice may be influenced by price, but also such things as convenience in handling, cleanliness, and availability can enter into his decision making process. The high degrees of substitutability characteristic of the sources of energy means that one cannot discuss the supply, demand, and price of a given fuel without also being conscious of the effects of interfuel competition.

This work is an effort to combine the many economic studies of supply and/or demand for the different forms of energy into a medium to long range dynamic model of interfuel competition for the U.S. This means that a model containing the dynamic interactions between supply,

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[1] Energy R + D and National Progress, Energy Study Group headed Ali Bulant Cambel, Lib. Congress Card No. 65-60087, June 5, 1964, pg. XXV.

[2] Gonzalez, Richard J., "Interfuel Competition for Future Energy Markets," Journal of the Institute of Petroleum, Vol. 54, No. 535, July 1968.

demand, and price for competing forms of energy is to be constructed. Given the availability of the fuel resources and the levels of demand for each of the consuming sectors as a function of time, the model will simulate the process by which supply production capacity is constructed and resources are depleted, the processes whereby different fuels are chosen to satisfy the demand, and resolve these processes into prices and market shares for each of the forms of supply.

There is no intent in this study to investigate the effects of seasonal fluctuations of supply and demand on price. For this reason the effects of storage capacity and processed goods inventories are neglected. Rather, the intent is to concentrate on those phenomena which would have their effect on prices for periods of years, two to five to ten or more. Those things which have a substantial effect on the dynamics of supply, demand, and prices over the medium to long term as resource depletion, persistent shortages or excesses in production capacity, or exploration successes and failures are to be studied.

This is a first application of the dynamic modeling concept to the interfuel competition processes, which represents a very complex system. A number of simplifications and approximations were necessary in detail in order to progress on a broad front.

The overall model framework, the model boundaries, the levels of aggregation, and the philosophical approach to modeling this system are discussed in Chapter 2. In Chapter 3 the structure and formulation of the supply models for coal, oil, natural gas, and electricity are discussed. For ease of presentation, some of the diagrams depicting the model structure in Chapter 3 are in Industrial Dynamics symbology.[1] In Chapter 4 a description of the demand models and fuel selection process is given. To the author's knowledge, this is the first application of demand models in this particular form, and certainly much more work must be done concerning the analysis and plausibility of these models. They are used here because they do represent in an aggregated way the dynamics of demand and seem to work well in this particular formulation. Further research is needed to further develop and assess the implications of this structure.

The validation (or model verification) issue is addressed at length in Chapter 5, but in no way represents an exhaustive treatment of the matter. These validation discussions, along with the application of the model to a series of case studies in Chapter 6, however do indicate that the model is credible for a variety of purposes. These same discussions, nevertheless, point to a number of limitations in the present formulation and indicate further refinement is needed.

There are three case studies in Chapter 6. The results are summarized in Table 6.7. In case no. 1, a relatively optimistic outlook in oil and natural gas is input to the model, with the result that cost/price trends for these two fuels remain relatively stable in the long term outlook. This trend in low prices in oil and natural gas encourages their use directly in the residential and commercial and

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[1]For a description of the symbols and their meaning, the reader may wish to consult Industrial Dynamics, by Jay W. Forrester, published by the M.I.T. Press, Cambridge, Mass., 1961, pp. 81-92.

industrial heating markets, and the growth in electricity consumption under these conditions declines to something less than 5% per year, markedly less than historical trends.

In case no. 2, a much more restricted flow of foreign oil into this country is hypothesized. This is in contrast to case 1 where by 1980 over 50% of the oil supply was supplied by foreign sources. This restricted flow could result for either national security or balance of payments reasons. In addition, environmental constraints are entered into the cost parameters and fuel selection process of the electricity supply sector in case no. 2. The import quotas and environmental constraints combine to yield a much more pessimistic outlook in the future fuel supply trends. For the same domestic supply scenario, prices rise much higher for gas, oil, and electricity.

Finally, in case no. 3, cost escalation in the development of oil and natural gas supplies is entered into the model, and the growth trends in consumption are increased by 25% over the previous case studies. The oil import levels for this case are set the same as the National Petroleum Council projection used in case no. 1. Here it can be seen that the increased consumption and escalating costs result in almost as pessimistic an outlook as that for case no. 2 where much less consumption took place.

By no means are these case studies to be considered projections by the author. Rather they represent only an application of the model to a set of hypothesized conditions to assess the impact of various occurrences and usefulness of the model. Within the structural constraints, the model is found to be useful for a number of applications.

The reader, if not particularly interested in the structural formulation of the model, may wish to only peruse Chapters 2, 3, and 4, and read Chapters 5 and 6 in detail. In Chapter 7, some areas of potential further development are identified, and the uses of the model are summarized.

CHAPTER 2

MODEL FRAMEWORK

In the first chapter a general statement of the problem was given --- to develop a dynamic model which characterizes the relationships important in interfuel competition. In this chapter a general discussion of the methodology and the model framework will be given. The intent is to convey what the major assumptions are on which the model is constructed along with the model boundaries.

2.1 Methodology

In order to construct this model, some theory of operation for the interactions between the variables of the model must exist. It is important to realize that behavior resulting from a model is a consequence of the theory on which it is constructed. The model is only as good as the theory, and the theory is only as good as it helps to explain the real world. For example, one might choose the theory of perfect competition and assume it applies to the behavior of interfuel competition in the real world. He could build a model, simulate the interfuel dynamics, and the resulting model behavior could be no more realistic than the validity of the assumptions on which it is built.

Unfortunately, in the study of complex systems, assumptions are necessary to keep the study in manageable proportions. Consequently there usually is not a clear cut answer to the success of the modeling effort. The answer is "in some respects the model is good, in some respects it is bad." This does not present a vacuum as long as an analysis of the good and bad points is included and they are made as explicit as possible.

However, if it is realized that this work is one step in an attempt to understand which theories of operations are important and why they are important in the real system operation, then one can undertake the modeling exercise with no reservations about its applicability.

The first question with which one must cope when trying to model a system is "What is the behavior which I wish to explain?" This is the first step in the definition of the system to be modeled. Based on the answer to this question one can then begin to incorporate or discard relationships and variables relevant to the model structure, keeping those that appear to play a role in behavior to be modeled, discarding those that seem to be of no significance. The greater the body of knowledge about the particular behavior, the easier the modeler's task. The less that is known about the determinants of the behavior to be modeled, the more the modeler must make decisions. In the absence of a clear cut reasonable choice, the only alternative may be to make an assumption and later try to verify or violate that assumption. The final test is whether the model really helps to describe the real system which displays the behavior to be modeled within the limitations of the assumptions made.

For this reason the modus operandi here will be to explicitly state a theory of operation for interfuel competition under explicit assumptions, try to assess the applicability of the model through comparison of the model results to past data from the real system, and evaluate what theories require modification to make the model better conform to the real world process. The development of a model which is a replica of how the real world behaves is then an iterative process of construction, simulation, assessment, modification, construction, simulation, assessment, modification,....etc. With each iteration one gets a better understanding of the important determinants of real world behavior and the shortcomings the model contains. This work describes the results of this process for the dynamics of interfuel competition.

2.2 Model Boundaries

The purpose of this study is to model the mechanisms of behavior important in the dynamics of interfuel competition. Therefore, the model necessarily must contain the interactions between supply and demand within the market clearing process. The market clearing process yields the price and quantity of the different commodities for a given supply-demand configuration; i.e. for the market to clear, supply and demand must be equal. The resulting quantities and prices in turn affect the rates of growth of both supply capacity and levels of demand. This overall model structure is depicted in figure 2.1.

Figure 2.1 depicts the exogenous inputs to the model as the demand by sectors in the upper portion and the resource characterizations in the lower portion. The sector demands are assumed to be in time series form for the major consuming sectors (transportation, space conditioning, industrial processing, etc.). As determined from the rates of

OVERALL MODEL STRUCTURE-INTERFUEL COMPETITION

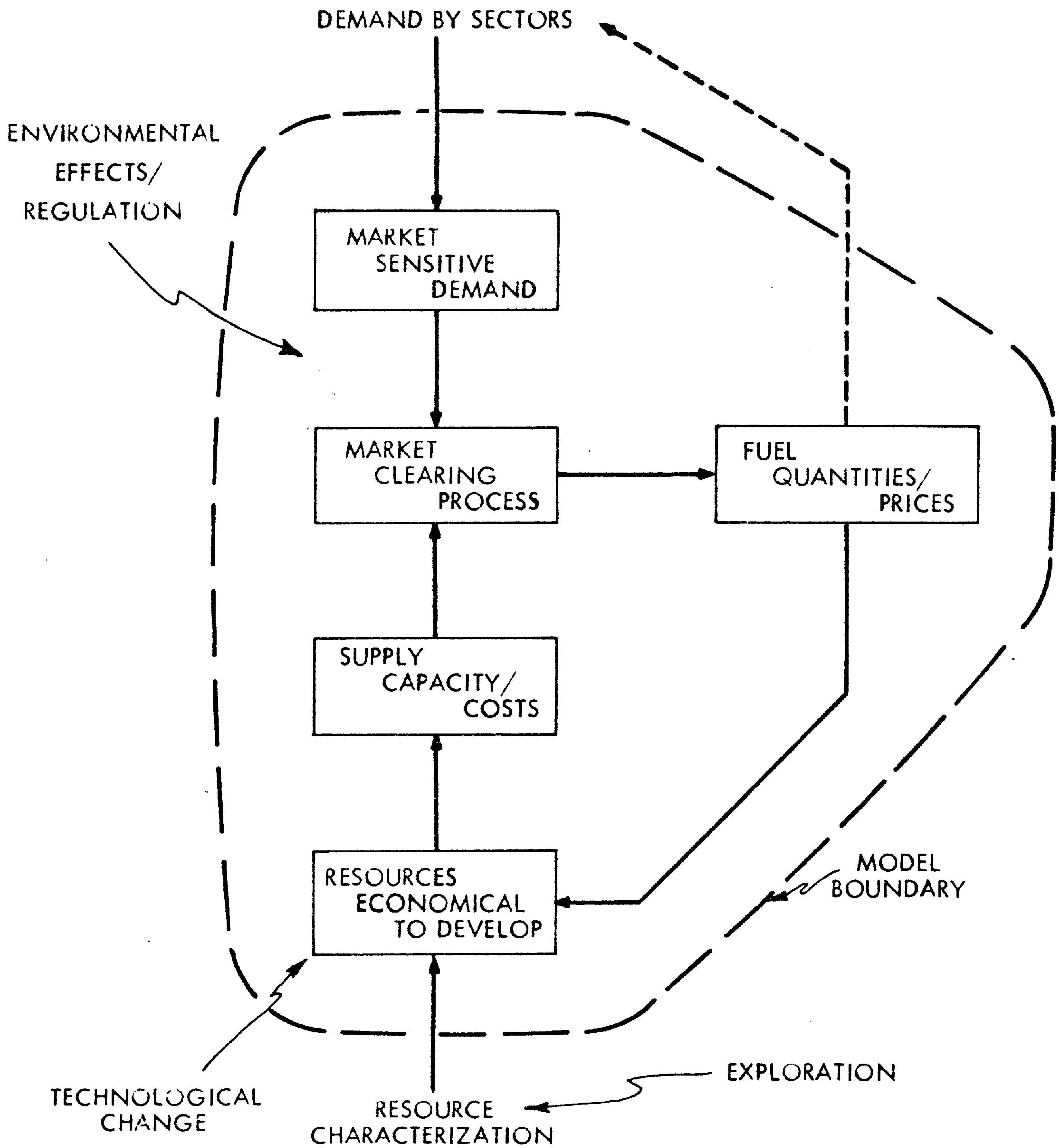

Figure 2.1

growth of demand and also the rates of turnover in the consumers' equipment, some portion of the total demand in the consuming sectors will be going to the market place to buy energy. This portion of the total demand is termed the market sensitive demand in figure 2.1. The aggregate of those consumers who continue utilizing the same fuels from one time period to the next is termed the base demand.

Then from considerations on price, the market clearing process matches up supplies of fuel to meet the market sensitive demand. This is the classical economic supply-demand equilibrium. In order to model this process, one needs the supply schedules for each of the forms of supply, demand schedules for each demand sector, and a theory for the market clearing process. From this the quantities and prices for each of the forms of supply is obtained, which in turn affects the growth in both the supply and demand sectors.

In general, then, the boundary of the system to be modeled is given by the dashed circle in figure 2.1. In order for this to be consistent, it is assumed that none of the variables inside the model boundary affect those outside the boundary. The boundary shown in figure 2.1 therefore has some very important implications.

One of these is indicated by the dashed line from the box "quantities/prices" to the exogenous input "demand by sectors." In reality it is known that the demand schedule for a commodity is usually price dependent; that is, as the price goes down the demand goes up, and vice versa. The greater the sensitivity of the demand change to the price changes, the higher the elasticity of demand.

The measure of elasticity is the ratio of the percent change demand to the percent change in price. Most commodities possess this elasticity because as the price of a given commodity rises, the competing products which will serve the same function become more attractive pricewise. Consequently more of the competing products are bought. If there is no functional substitute, there may be a choice to do without the commodity because of limited resources.

The fact that fuel prices inside the boundary in figure 2.1 does not affect the exogenously determined "demand by sectors" implies that sector demands are assumed to be inelastic in the model. It is true that as the price of one form of supply of energy increases, there is a tendency for the consumers to switch to other cheaper sources of energy. This phenomenon is embodied within the boundaries of the model. The assumption manifested by the dotted line implies that if the price of all sources rose proportionately, the level of total demand would not change. Of course this is not true over the whole range of price changes possible. Yet it is true that in our country today, energy is and has been a very inexpensive commodity in relation to its importance. Expenditures for energy have historically been about 3% of our gross national product. Consequently, it may be possible to increase the price of energy across the board as much as 50 to 100% and it would have little effect except in a few highly energy intensive industries. In other words, it is plausible that the demand for energy in toto <u>is</u> very inelastic in the price ranges that have existed in the past and those foreseen into the future. Regardless, it will be assumed that levels of demand and consumption are dependent upon variables outside the model such as gross national product, population, and other demographic variables and can therefore be considered exogenous.

Another implication of the boundaries chosen in figure 2.1 is that exploration activities and the resulting additions to reserves therefrom are not dependent on variables within the model boundary. It is well known that this is not true. In appendix C there is a discussion of the exploration incentive. It is very dependent on the price one expects to receive for his eventually recovered energy in place. However, the relationship between investment in exploration and the resulting returns is not well-understood. Certainly more work needs to be done in making these relationships more precise. When this is done, the model is constructed in such a way that the fruits of the research could be included in the structure. Until this is done, it will be assumed that the results of exploration (i.e. additions to reserves and the cost of developing those reserves) are inputs to model on the supply side and independent of those variables within the model boundaries.

The basic theory of supply costs and energy prices is derived in this study assuming that the market forces conform to the laws of perfect competition. What this means is that over the long term prices of supply are equal to cost (cost including an acceptable rate of return on invested capital). Over the short term it may be true that the market forces (in the form of uncertainty about costs and deviations from perfect competition) push the price of a fuel above or below cost. When this happens it only means that the resulting profits or losses have the effect of either luring new suppliers onto marketplace or forcing existing suppliers out of the market place until the law of supply and demand forces price again equal to the long run costs. The dynamics of market entry and exit are embodied in this work.

It might appear that the assumption of perfect competition restricts the applicability of this modeling effort to the present day energy system. However, even though many forms of regulation do exist and imperfect competition might exist in the present day energy system, it is likely that over the long term (decades) the forces of interfuel competition from both domestic and foreign energy markets makes the assumption of perfect competition realistic. Further, the theory of perfect competition is a well-understood economic state of affairs, and thus provides a convenient starting place for this modeling effort. Nevertheless, the model is constructed to be adaptable to pricing strategies other than the perfectly competitive case, and this assumption is relaxed after the basic structure is developed.

An area about which nothing has yet been said has to do with the effect of imports and exports on the dynamics of interfuel competition. In reality the import and export levels of this country are highly regulated via quotas and duties. In this study the simplification will be made that imports and exports are exogenous time series input into the model.

Electricity, as a secondary supplier which utilizes the primary fuels and competes on the marketplace with the primary fuels, is not explicitly shown in figure 2.1. This is a limitation only of the diagram. In the work to follow, electricity is dealt with explicitly. At the present time electricity accounts for about 25 percent[1] of our primary fossil fuel consumption, and this share is expected to grow until nuclear energy blossoms into a dominant producer in the future. The leverage that electricity exerts on the primary fuels via the high degree substitutability also warrants the consideration given it in this study. In figure 2.1 think of electricity as simultaneously a supplier and consumer, whose sales to the ultimate consumer are determined in the marketplace, and which simultaneously places a demand on the primary fuels commensurate with those sales. The price of electricity to the consumer is then related to the price that must be paid for primary fuels, along with the other fixed and variable costs pertinent to that industry. More will be said about this later in the section on modeling electricity supply.

Figure 2.1 then portrays the mutual interrelationships between the major components of the interfuel system to be explicitly dealt with in this study. This includes the development of supply capacity on the basis of fuel demands and prices and the identification of the market sensitive demand from the dynamics and growth of demand in the various consuming sectors. Then from supply and demand and a theory for the marketplace, the market is cleared to give fuel quantities sold and the resulting prices. These resulting prices then affect the development of new supply capacity, (depending on the amount of resources which

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[1]Cook, Earl, "The Flow of Energy in an Industrial Society," <u>Scientific American</u>, September 1971, pg. 135.

TABLE OF ASSUMPTIONS AND IMPORTANT CHARACTERISTICS

1. TOTAL DEMAND INELASTIC.
2. TRANSMISSION/DISTRIBUTION CAPACITY NEGLECTED.
3. TRANSMISSION/DISTRIBUTION COSTS INCLUDED AS A CONSTANT MULTIPLIER OF WHOLESALE PRICES.
4. ASSUMED SHORT RUN SUPPLY COST FUNCTIONALS.
5. DYNAMICS OF MARKET ENTRY INCLUDED.
6. EFFECTS OF DEPLETION ON COSTS INCLUDED.
7. ELECTRICITY EXPLICIT.

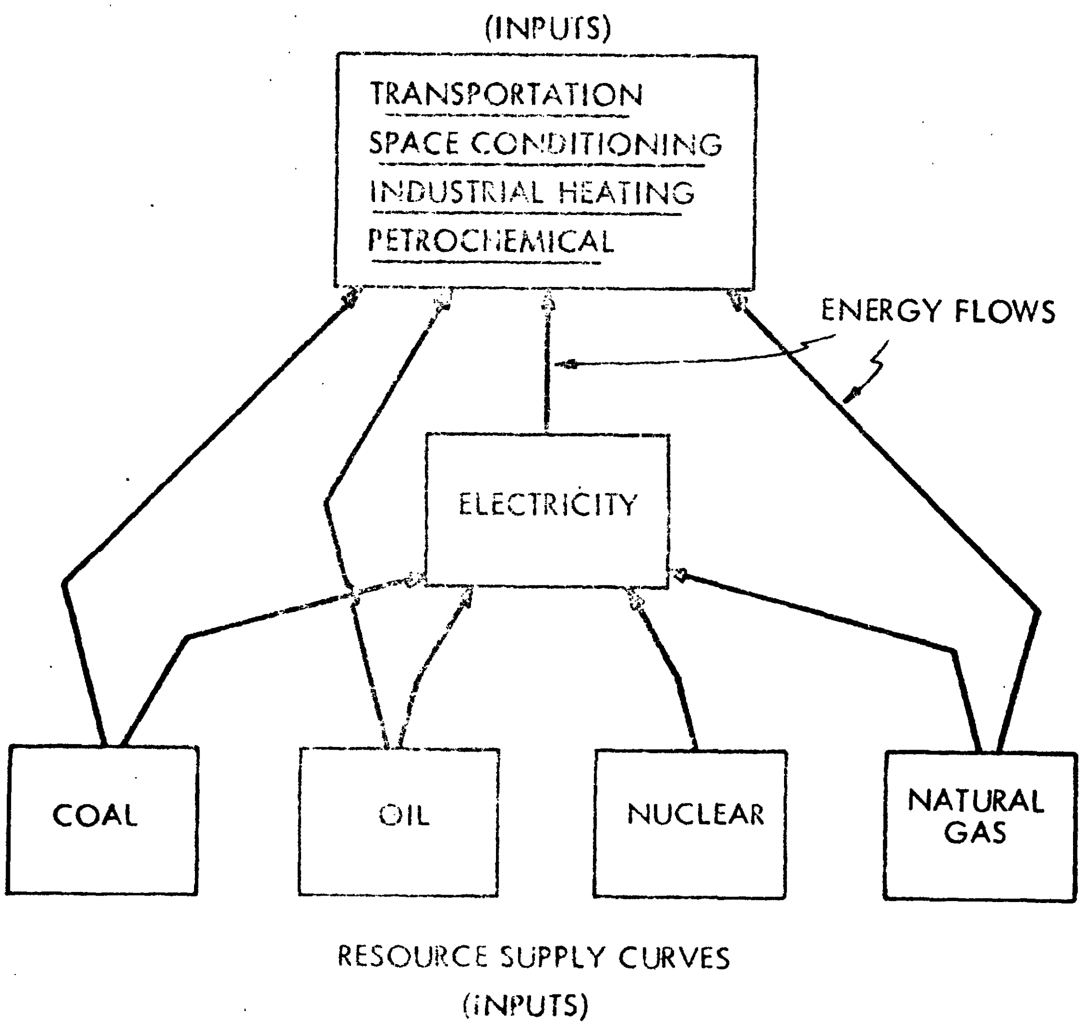

Figure 2.2

are economical to extract at the prevailing prices) and the relative fuel shares in each of the consuming sectors.

Figure 2.2 summarizes the important assumptions and characteristics to be followed in the development of the model. Also included is a broad energy flow diagram to depict the levels of aggregation and interconnections as they exist in this study.

2.3 Levels of Aggregation

It is not clear at the outset what level of aggregation of the variables or what specific interrelationships are important to understand these processes. One can only begin at a reasonable starting place and hope to zero in from there. In this first attempt at modeling the dynamics of interfuel competition there are going to four levels of supply - coal, oil, natural gas, and electricity. There are two reasons for this particular choice. First, this is how much of the national data is supplied.[1] Secondly, it is also a logical extension of previous work. An effort in modeling the complex interactions between the energy, economy, and the environment on a grossly aggregated level has been done. The work is in its very preliminary stages, but it does help to motivate this work and orient one into its realm of applications. See Appendix A for a discussion and references to this work.

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[1]For example, the data from the Bureau of Mines and Edison Electric Institute. See the list of data sources following Appendix B.

Due to the levels of aggregation, the price variables in the model are probably best thought of as price indices. They do not apply specifically to any one product (as gasoline, residual oil, stoker coal, egg coal, or whatever), but to the aggregation of outputs coming from the same raw fuel source (coal, petroleum, etc.). There are a number of ways one might define different indices for this level of aggregation, as for example an average of product prices weighted by output mix. In this work the entire sales for all end products originating from the same raw fuel are lumped together. Consequently, it is useful to think of the price variables in this model as indices of the ratio of total revenues to total sales in physical units (in barrels, kilowatt-hours, tons, or whatever).

There are obvious difficulties in lumping the supply sectors together on this level of aggregation. Often the growth in supply for a particular fuel is predicated on the high profitability of a specific end product, as gasoline from petroleum. Since there are technological limits on the product mix coming from a refinery, in order to supply large quantity of gasoline there is created an oversupply of the by-products, or lesser profitable products. This oversupply would drive down the price until enough demand was generated to clear the market place. The result is that the quantity of raw material consumed is determined by the demand of the highly profitable end product. Consequently, the price of residual oil to the electrical industry is in part related to the demand for gasoline. In addition, changing demand considerations may shift the drive on supply from one output to another output product.

In this work, the problems of primary and by-products are going to be neglected. This assumes that over the time scales of interest here, that either the substitutability of users is great enough to keep all consumption in line with production mixes, or that the production technology exists to shift the output mix to meet the demand configuration.

In the real world there also exist intermediaries between the producers and consumers of energy. Somehow the energy must be transported and distributed to the consumer level, and there are costs involved in this process. In fact for coal the transportation costs make up about 50% of the selling price.[1] In this model the levels of transportation capability are not to be explicitly modeled. This assumes that a transportation network exists on a level commensurate with supply and demand. This has not always been true, as the recent oil tanker shortage indicates.

Geographical considerations are not explicitly included in the model. This places a number of limitations on the uses of the model in its present form. For example, the price regulation on the interstate sales of natural gas has resulted in a redistribution of gas sales from interstate to intrastate markets. On the national level of aggregation used in the model, this behavior is aggregated away. Many of the environmental concerns are regional or sub-regional issues. These too are aggregated away in the model. However, the generic structure

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[1] Moyer, Reed, Competition in the Midwestern Coal Industry, Harvard University Press, Cambridge, Mass., 1964.

is such that it can be disaggregated for regional or statewide applications. If this is done, then the inter-regional links describing the transportation capability must be included. A more complete discussion of the form the model would take with these considerations included is given in chapter 7.

The transportation distribution costs are included in a defacto way in the demand models to be discussed in chapter 4. In essence they are assumed to be a constant multiplier of the wholesale prices. Further discussion of this topic is delayed until the demand models are discussed in chapter 4.

2.4 Relationship to overall study

The study and development of a model for interfuel competition is valuable in itself; but when used in the larger context of the energy systems, it becomes only one gear in a complex machine.[1]

One of the outputs of the interfuel competition model is the market shares and levels of consumption for the primary fuels and electricity. It is well known that the rates of generation of many forms of pollution in our country are closely related to the utilization of energy and more specifically to the form of energy used. The model for interfuel competition is an important segment of the closed loop process of energy utilization and pollution generation, back to environmental policy which affects fuel costs and levels of energy utilization.

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[1]See Appendix A.

There are also indications that low cost energy is a stimulant to economic growth. It is also true that the level of energy consumption is closely correlated to the level of economic output in our country. The interfuel competition model is therefore also an important piece of the closed loop process of economic growth, energy demand, energy costs, and economic growth. In other words, to accurately predict long-term economic growth the role of availability of low cost energy must be included, and the interfuel competition model plays an intricate part in this role. It will be useful to provide data on costs of energy commodities and the level of consumption expenditures for energy given the resource supplies entered into the model.

Similarly, capital investment in energy production facilities is in part influenced by the ease (cost) with which the natural resources can be extracted and processed. The levels of investment activity in each of the primary fuel suppliers is an integral part of the dynamic structure of the interfuel competition model. In addition to affecting costs of energy in each of the supply sectors, this investment places a drain on investment funds available to the rest of the economy. There may be implications for the growth in other sectors of our economy because of this.

The effects of energy costs and utilization upon our environment and the potential of economic growth are discussed in "Dynamics of Energy Systems" as problem areas for which is planned in-depth study. The dynamics of interfuel competition is a part of these long term efforts, and the research in this area must keep in perspective the relationship of this study to the overall research program. The following chapters discuss in detail the structure and operation of the interfuel competition model. Chapter 3 deals with the supply models for both the primary fuels and electricity. Chapter 4 discusses the fuel selection process for the demand sectors modeled. Keep in mind that the link between the dynamics of supply and the dynamics of demand is the fuel prices.

CHAPTER 3

ENERGY SUPPLY MODELING

Introduction

There are basically three subsections of the energy supply models. These are the characterization and dynamics of the marginal development cost curves, the logic and dynamics associated with market entry and sustenance of production capacity, and the cost functional derived from the development and operation of the production capacity. The supply modeling is approached from the level of generality where the equivalent structure in the primary fuel suppliers is utilizied. Electricity requires some modification of this structure to better portray its characteristics. Foreign supplies are considered inputs to the model.

This chapter will discuss the models used in energy supply. First will be a discussion of the primary energy suppliers --- coal, oil, natural gas; nex will be a discussion of the model for the secondary energy supplier --- electricity (with nuclear); and finally a discussion of the way in which foreign sources are entered into the model. In this chapter a general discussion and justification of the models used will be given. In each case it is assumed that the time behavior of each fuel demand is given. The models then give the dynamic behavior of supply capacity and price. In chapter 4 it is assumed that price is given and the models for the fuel selection process for the demand sectors are developed. Finally in chapter 5 the two pieces are merged and the overall model behavior is discussed.

The content of appendix C is drawn upon in modeling the primary supplies. Simplifications were necessary due to the limits of knowledge. The major simplification is that exploration is not modeled, rather the results of exploration are inputs to the model.

3.1 Primary Supply Modeling

Development Cost Functions

A development cost curve relates the amount of capacity economical to install on known deposits to the incremental development costs associated with developing that capacity. A discussion of the formulation of these cost curves follows. For ease of presentation, a discussion of the formulation for the petroleum industry only is given, but with changes in terminology it applies equally well to coal.

The development costs for a given reservoir depend on a number of things. These include the size of the reservoir, the capital costs of capacity construction, and the costs of capital. Given a reservoir developed to an initial capacity q_o, the output of that reservoir (neglecting further development and secondary recovery) would typically appear as the solid line in figure 3.1. If a larger initial capacity q_o^* were installed, the depletion of the reservoir would occur faster as given by the dotted line. The decrease in output over time corresponds to the effects of depressurization of the reservoir due to depletion, or for water displacement techniques the shrinkage of the oil component of the reservoir due to displacement by water. The intensity of the initial level of development is an economic decision.

OUTPUT vs. TIME

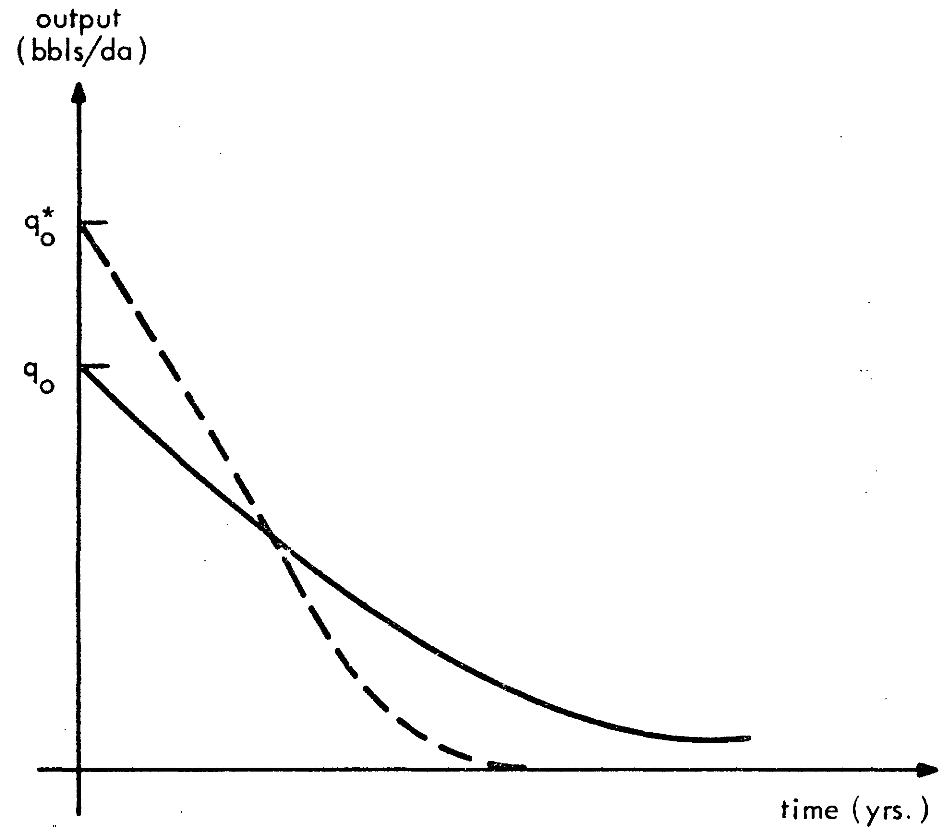

Figure 3.1

The output of a reservoir over time (neglecting secondary recovery) may be approximated by a decaying exponential.[1] If D is the rate of decline of the output as the reservoir is produced, the output vs. time, $q(t)$, may be represented by

$$q(t) = q_o e^{-Dt} \qquad \text{Equation 3.1}$$

where q_o is the initial capacity installed. If R_o is the amount of recoverable resources in the reservoir, assuming that it is fixed gives

$$R_o = \int_o^{\infty} q_o e^{-Dt} dt = q_o/D \qquad \text{Equation 3.2}$$

or

$$D = q_o/R_o \qquad \text{Equation 3.3}$$

That is, the decline rate of output from the initial capacity q_o is the ratio of the initial capacity to the total recoverable resources in place. (Actually this computation slightly underestimates D, for wells do not produce over an infinite length of time.)

From appendix C, it is noted that development is investment in one of two related but distinct options. These include either speedier recovery of a fixed fraction of the total oil in place, or more complete recovery of the oil in place. Both of these options are an investment in present barrel equivalents (PBE's).

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[1]Bradley, Paul G., The Economics of Crude Oil Production, North Holland Publishing Company, Amsterdam, 1962.

If future output is discounted at a rate "r", the present barrel equivalents from a reservoir with initial capacity q_o and recoverable oil R_o is given by

$$PBE = \int_0^{\infty} q(t)\, e^{-rt}\, dt = \frac{q_o}{\frac{q_o}{R_o} + r} \qquad \text{Equation 3.4}$$

From appendix C, if a unit of capacity on this reservoir costs "b" dollars[1], then the marginal development costs (MDC) are given by

$$MDC = \frac{b(q_o + rR_o)^2}{rR_o^{\,2}} \qquad \text{Equation 3.5}$$

The marginal development cost is the incremental cost of the next PBE resulting from investment in more capacity. The marginal development cost function for the reservoir with recoverable oil R_o and cost per unit capacity b is plotted vs. q_o in figure 3.2a.

This relationship was developed for one reservoir. For the U.S. as a rational aggregate, the same analysis applies with a redefinition of terms.[2] For the industry marginal development cost function, the R_o must be defined as the total U.S. reserves, and "b" as the national average cost per increment in capacity. With this redefinition of terms, figure 3.2a also displays the industry marginal development cost function.

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[1]Future operating costs may be discounted and included in the capital cost per unit capacity. See Adelman, The World Petroleum Market, John Hopkins Press for Resources for the Future, forthcoming in 1972, Chapter II and Appendix.

[2]The reader is again referred to Appendix C.

If the industry were operating under the policy of optimal economic choice, then given a price P, the optimum level of supply capacity would be that corresponding to the value where MDC's were equal to price as illustrated in figure 3.2b. Due to the uncertainties involved other factors influence the development decision, and a discussion of how these are modeled is given in the next section.

The marginal development cost curve given in figure 3.2b is a snapshot at one point in time. As reserves get depleted, this decreases the value of R_o and moves the curve counterclockwise about the pivot point "br" (the intersection of the MDC curve with the ordinate axis). Exploration or technological change which increases the level of reserves moves the curve clockwise about the pivot point. Technological change or new finds which reduce the costs per unit capacity move the entire curve down.

To specify the curve at any instant in time, the only variables needed are the cost per unit capacity "b", the discount rate "r", and the recoverable resources "R_o" at that point in time. To specify its dynamics, the effects of exploration, depletion, technological change, and changes in the discount rate must be incorporated. In this work, the additions to reserves (exploration), the cost per unit capacity (technology), and the discount rate are inputs into the model whose values are set to correspond to the particular case of interest. The depletion is modeled endogenously.

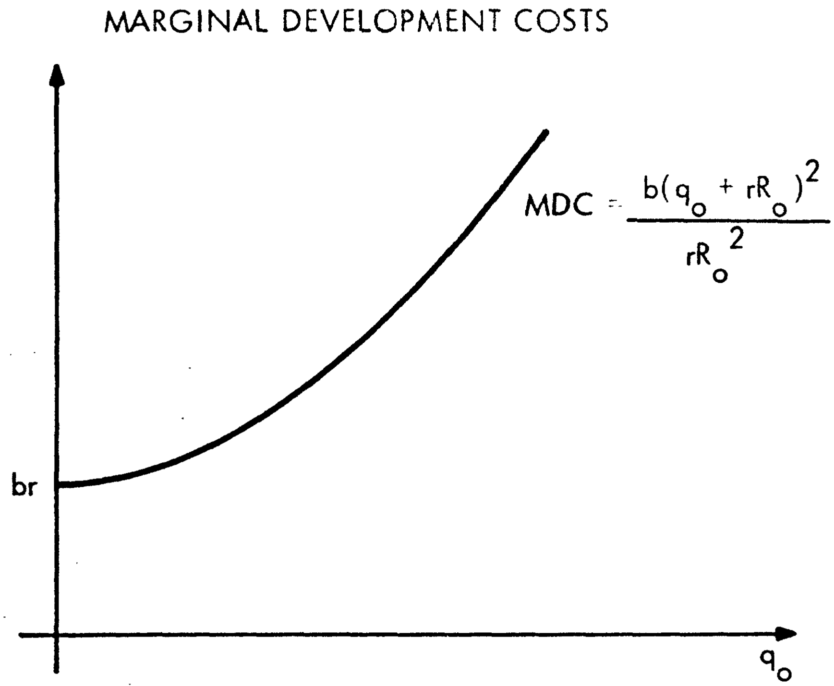

Figure 3.2a

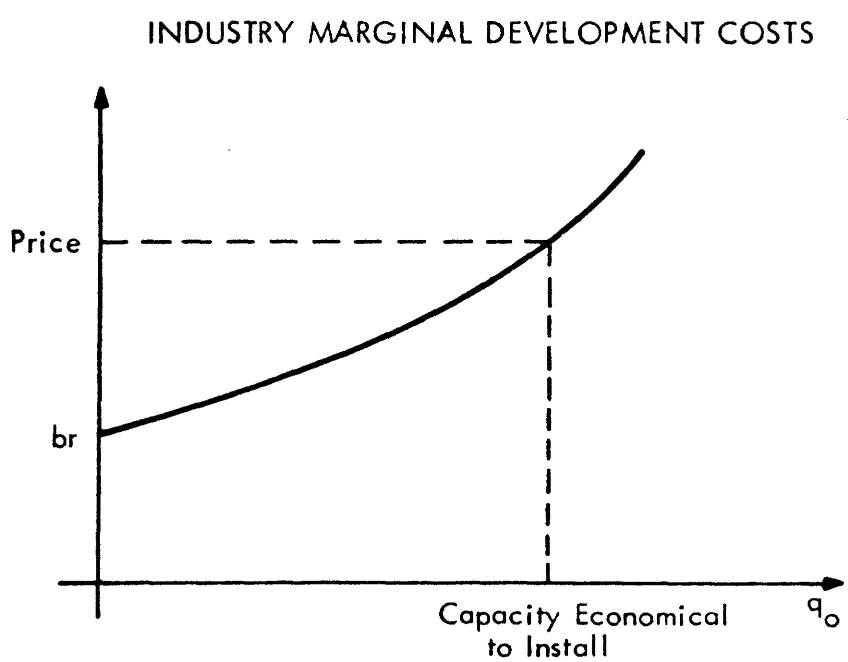

Figure 3.2b

Supply Capacity Dynamics

The industry marginal development cost curve provides the core of the investment decision process in fuel supply. Given price, the desired intensity of development from economic considerations can be determined. In reality there are many other factors influencing the decision processes. Probably most significant is uncertainty --- uncertainty in costs, uncertainty in the general economic milieu, and uncertainty in the future. Also suppliers have goals other than profit maximization, such as maintenance of market share and growth trends. There exists regulation which limits one's options, such as prorationing, price regulation, and environmental standards. All these things as well as the industry structure potentially alter the perfectly competitive decision process. The purpose here is not necessarily to model explicitly these intervening factors, but rather formulate a model structure in which, if desired, these influences could be included.

In this work there are essentially two inputs into the investment decision process. These come from the marketplace in the form of 1) price and 2) the demand or consumption of that fuel. With these and the assessment of the factors influencing costs the development decision is modeled.

The factors determining the marginal development cost function were given in the last section. Suppose for the moment that a reasonable value for price, or more precisely the projected price, is available to the investors in supply. Actually the price used here is derived from the smoothed short run market fluctuations of price in the marketplace, and how it is formulated in the model will be discussed shortly. Given this price the desired capacity from economic considerations is determined as in figure 3.2b. From trends in consumption or sales, the capacity required to serve expected future levels of demand can also be calculated. The capacity development logic of the programmed model then uses these projections on price and consumption and includes an assessment of the productivity of present capacity in simulating the rate of capacity development.

However, this capacity does not become productive immediately. It takes time to allocate the resources (planning, men, machinery) to a particular development, and once construction begins a time delay exists before the development becomes productive. To model these processes, a first order exponential delay followed by a third exponential order construction delay is used. The first order delay models the perception and allocation delays associated with the initiation of construction. The third order delay represents the construction delay from the initiation to completion of development. This process is shown symbolically in the flow chart in figure 3.3.

The period of time over which the projections are made corresponds to the construction delay, or the length of time it takes to get new capacity operable. Also represented in figure 3.3 is the decline in productivity corresponding to the depletion rate. This is to model the exponential decay in output as shown in figure 3.1.

With these basic components the supply capacity dynamics are modeled. To be discussed yet is the relationship between these long run supply dynamics and the short run cost-price dynamics in the marketplace.

CAPACITY DYNAMICS - PRIMARY FUEL SUPPLIERS

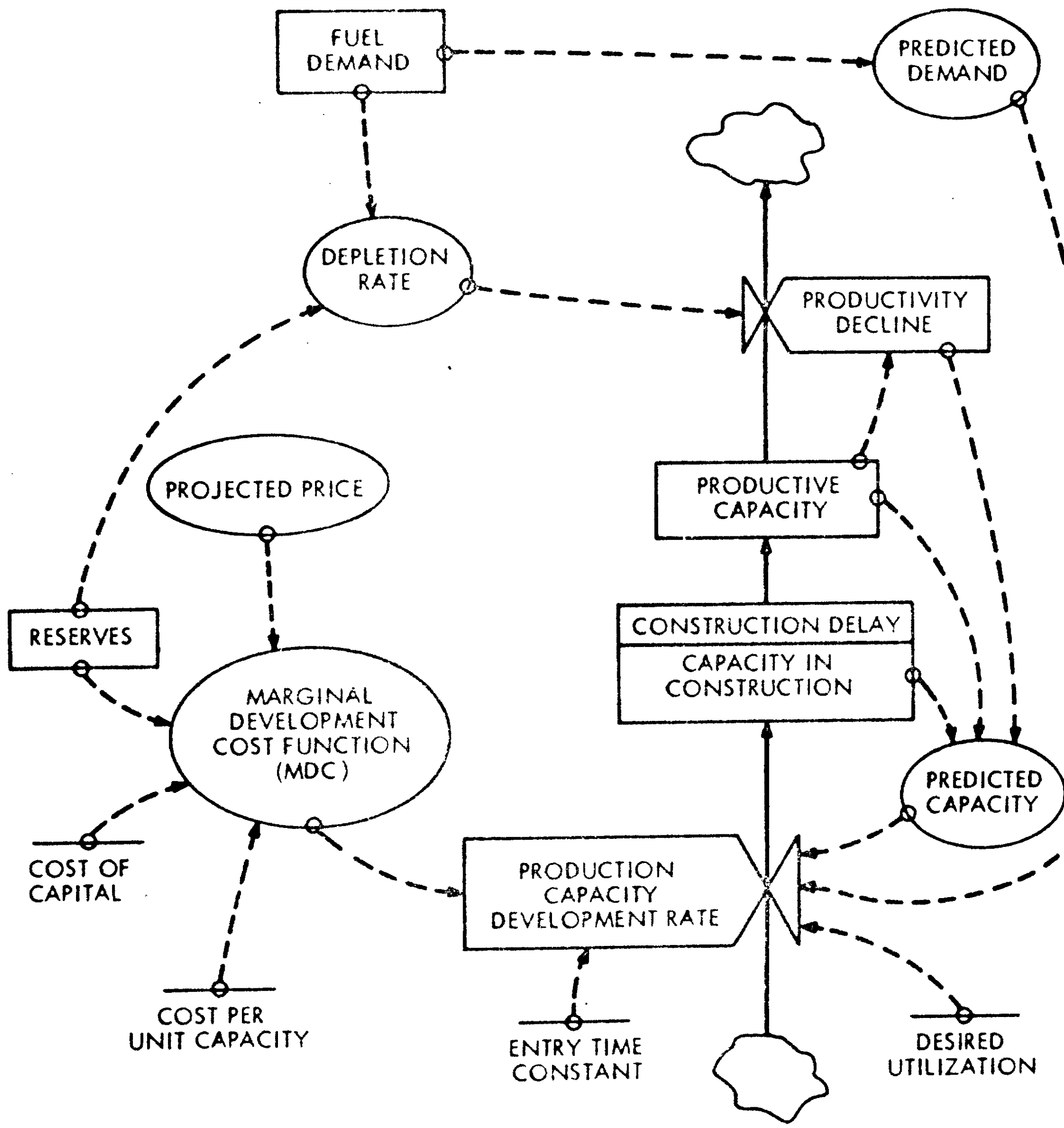

Figure 3.3

Modeling this short term behavior would be unnecessary in this work if only the long run supply-cost relationships were important. However, it can be true that a short run disturbance can sufficiently alter the supply picture that it may take years for the system to recover. In particular the effects of the relatively recent environmental concerns, which have become national issues in just a few years, are perturbing the supply-demand relationships enough to result in severe shortages of environmentally desirable fuels.

The long run price trend for a particular fuel is the collection of the random short run price fluctuations in the marketplace. In a certain world, it would be easy and logical to price output at marginal development cost defined previously. In truth the world is not certain and the industry marginal development costs at any point in time are not easily ascertained. Some random behavior in the dynamics of demand exists, expected development times and acquisition delays may not materialize due to environmental concerns, capital and labor costs may change. All these things affect the supply-demand relationship so that in truth the system may never reach the equilibrium price, but rather it only equilibrates about the equilibrium.

As these disturbances change the supply demand configuration, the price changes over the short term in reaction. The short run supply (capacity fixed) is less elastic than the long run so that small changes in the supply-demand configuration can cause relatively large fluctuations in the short run costs of supply. It is these smoothed short run fluctuations that indicate to the supplier how his particular fuel is faring on market place vis-a-vis the competitive fuels.

The short run costs are made up of the operating and maintenance expenses of sustaining output from that capacity. In this work an assumed functional relationship is used for the short run cost curve. This relationship is constructed in the perfectly competitive case so that if the utilization of existing supply is at the desired level, the short run marginal cost equals the marginal development costs. If the capacity is being under utilized, the short run marginal cost is less than the marginal development cost, and if existing capacity is being utilized over the desired (optimum) utilization level the short run marginal cost is greater than the marginal development cost. In other words the long run equilibrium price is assumed to be the value of the marginal development cost. On the short term, price may fluctuate above or below this equilibrium value. If price goes above the marginal development cost, this encourages further development until costs are again equal to price. If price goes below the marginal development costs further development is discouraged.

This assumed short run marginal cost function can be written as follows:

$$SRMC = (MDC)\left(\frac{a}{1 - \frac{Q_D}{Q_C}}\right) \qquad \text{Equation 3.5}$$

where SRMC is the short run marginal cost

MDC is the marginal development cost

Q_C is the level of production capacity

Q_D is the level of fuel demand

a is the planned surplus capacity.

If the actual utilization is equal to the desired utilization, the SRMC of equation 3.5 is equal to the MDC. If the actual utilization is different than the desired, the short run costs are assumed to behave in accordance with equation 3.5.

The price of a particular fuel does not track exactly the short run marginal costs. In reality these are probably not known at any point in time. Rather these costs are smoothed as data on daily or weekly or monthly operations is gathered and analyzed. A firm then uses this data (along with all the other factors pertinent to its pricing policy) to determine price. So in essence the price of a particular fuel on the marketplace is a function of the smoothed value of the industry aggregate short run marginal costs. It is this price on which consumers make their fuel selection decisions and it is this price and its trends which suppliers use in their investment decisions.

This short run cost-pricing structure is superimposed on the model structure of figure 3.3 and given in figure 3.4. This then completes the generic structure for primary fuel supplies coal, oil and natural gas. The primary inputs to the model are the additions to reserves and the cost per unit capacity. The fuel demand is derived from the demand side of the interfuel competition model discussed in chapter 4. Parameters such as time constants, delays, prediction intervals, etc. must be set to conform to the particular form of supply of interest.

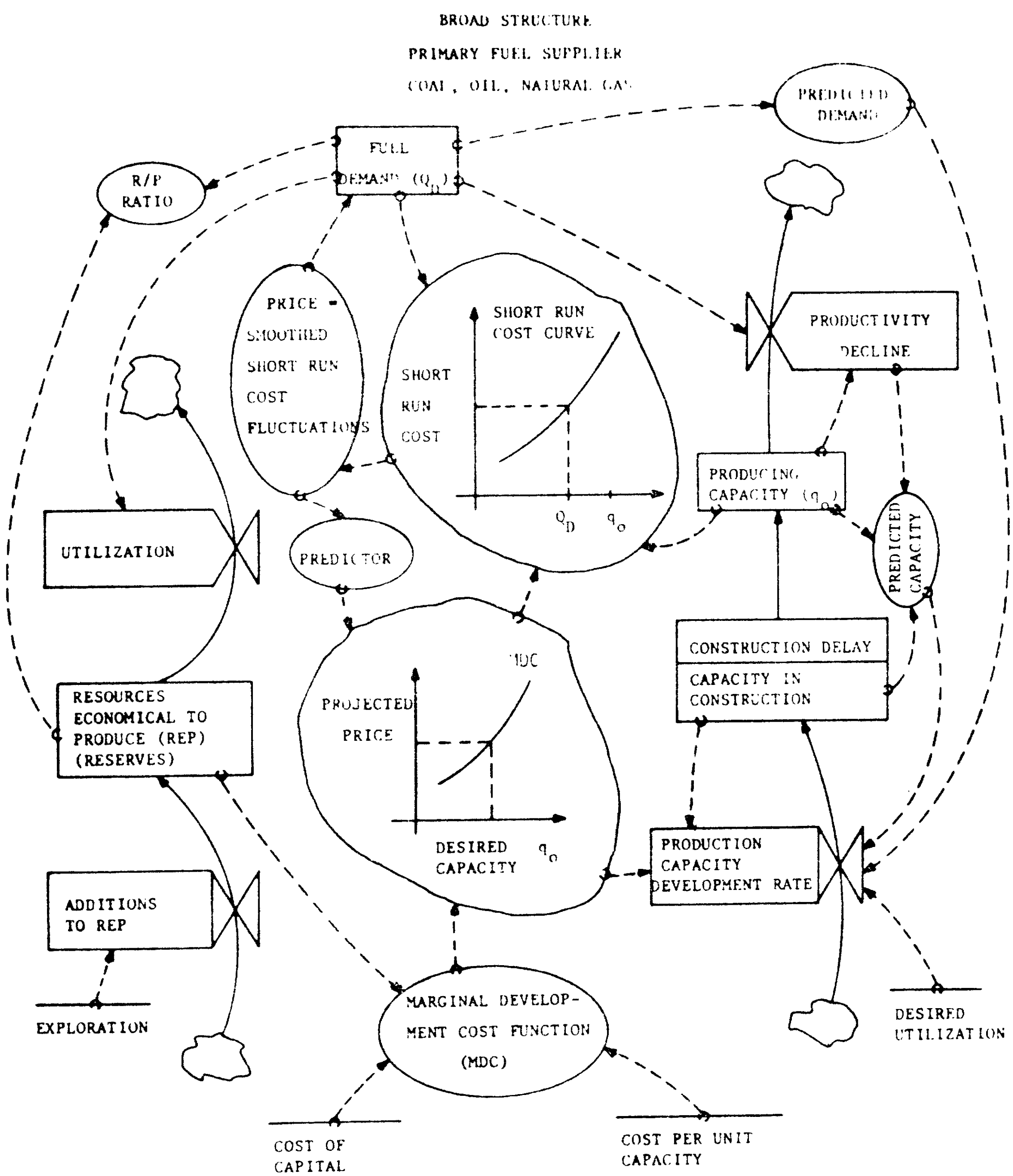
BROAD STRUCTURE
PRIMARY FUEL SUPPLIER
COAL, OIL, NATURAL GAS
PREDICTED DEMAND
FUEL DEMAND (Q_D)
R/P RATIO
PRICE - SMOOTHED SHORT RUN COST FLUCTUATIONS
SHORT RUN COST CURVE
SHORT RUN COST
Q_D
q_o
PRODUCTIVITY DECLINE
PRODUCING CAPACITY (q_o)
PREDICTED CAPACITY
UTILIZATION
PREDICTOR
MDC
PROJECTED PRICE
DESIRED CAPACITY
q_o
CONSTRUCTION DELAY
CAPACITY IN CONSTRUCTION
RESOURCES ECONOMICAL TO PRODUCE (REP) (RESERVES)
PRODUCTION CAPACITY DEVELOPMENT RATE
ADDITIONS TO REP
EXPLORATION
MARGINAL DEVELOPMENT COST FUNCTION (MDC)
DESIRED UTILIZATION
COST OF CAPITAL
COST PER UNIT CAPACITY

Figure 3.4

3.2 Electricity Supply -- with Nuclear

Electricity, as an energy supplier, is unique in that it has no energy storage capability. Because of this, the capacity levels required to maintain a reliable supply are governed by the peak power requirements and not the average output levels. Due to this and the capital intensiveness of the industry, it means that in figure 3.5 the industry can be operating to the left of the minimum on the AC curve, or MC's are less than AC. Further, there exists the option of using nuclear energy in electricity supply, the only place where it is competitive on a large scale in the energy system. Consequently, to more accurately model electricity supply it is necessary to deviate from the primary fuel supply models given in section 3.1.

This deviation is substantial in three aspects. First the role of the nuclear generation option must be defined and included in the model. For ease of presentation, however, let's postpone a discussion of nuclear in electricity supply and assume only fossil fueled generation exists. Once the structure of electricity supply with fossil only is discussed then the role of nuclear will be included.

A second deviation of the electricity supply model from the primary supplier models is that electrical output is priced at average cost rather then the long run marginal cost level. This is in reality what the regulation in electricity rate structures attempts to achieve.

Finally, the decision to build new capacity is the result of trade-offs in economics and reliability. To supply electricity at lowest cost it is desirable to keep reserve capacity (excess capacity over and above peak output requirements) as small as possible so that at a given level of electricity demand (Q_D in figure 3.5) the AC curve is nearer the minimum. Counter to this, to reliably meet peak power requirements, there is a desire to keep excess reserve capacity --- which moves price up the left portion of the AC curve.

The optimum value of reserve capacity is the minimum needed to reliably meet peak power requirements. The cost of the energy delivered is related to the peak to average output, or the capacity utilization factor. The capacity utilization factor (CUF) is defined here as

$$\frac{\text{Energy Delivered (in kwh./yr.)}}{\text{Capacity Installed (in kw.) x hrs./year}} = \text{CUF} .$$

This is nominally in the neighborhood of 0.5 to 0.6 for the U.S.[1] Such things as pumped storage or the overnight battery charging of the electric cars have the potential of increasing this number substantially, and thus reducing average costs.

The decision to build new production capacity is then based simply on projections of peak power requirements. An overcapacity penalizes the supplier with higher than necessary average costs. An undercapacity results in a deficiency in reliability and quality in service to customers (brownouts; etc.). In the model the capacity requirements are based on projections in electric energy consumption divided by the CUF. The projections in consumption are made via a simple quadratic least squares curve fit to the previous 20 years consumption. These projections are made over a length of time corresponding to the siting and

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[1]Calculated from EEI Statistical Yearbook, various issues from annual data on capacity and delivered energy.

ELECTIRCITY SUPPLY COST CURVES

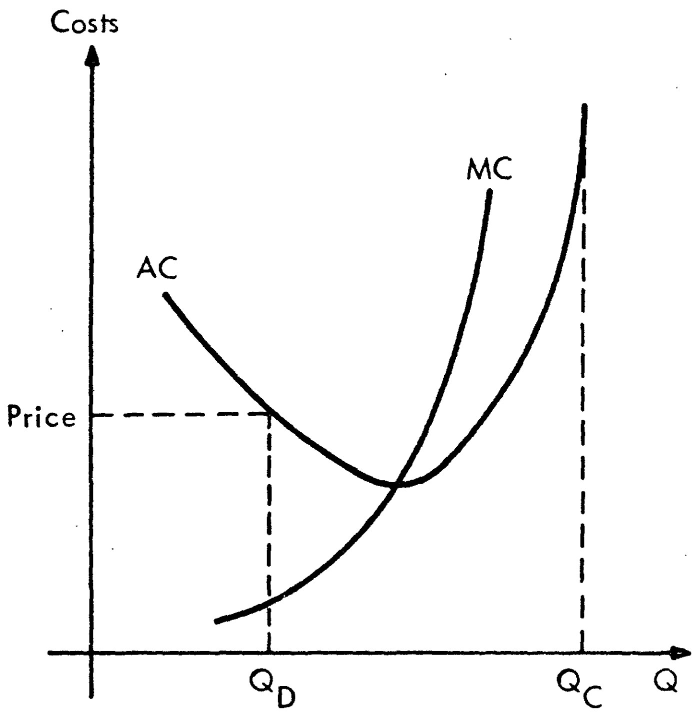

Figure 3.5

construction delay in building a new plant. The CUF is a parameter that must be set to correspond to the particular characteristics of the electrical load being investigated.

The model for electricity supply with fossil only is depicted in figure 3.6. In addition to those things already mentioned, a couple of other details need discussion.

The costs of electricity supply are made up of basically two components. These are the capital costs of plant construction and the variable costs of plant operation. These variable costs are made up of the operating and maintenance costs and the fuel costs incurred in normal plant operation. In this work it is assumed that a constant fraction of the plant investment is written off each year and allocated to the output. This fraction is called the annual capital charge rate. The average fixed costs associated with a unit output in any given year is then the capital write-off for that year divided by the output for that year.[1] The average variable costs are the average operation and maintenance costs and the average fuel cost per unit output. The average fuel price is assumed to be the weighted average of the prices of the competing fossil fuels, weighted by the fraction of electrical output supplied by each fuel. The details of the selection process for fuels in electricity supply are discussed in chapter 4. The amount of primary fuel required to produce a given level of output is determined by the heat rate which also affects the average fuel costs. These

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[1]See 1964 National Power Survey, pp. 282 ff.

ELECTRICITY SUPPLY DYNAMICS
FOSSIL ONLY

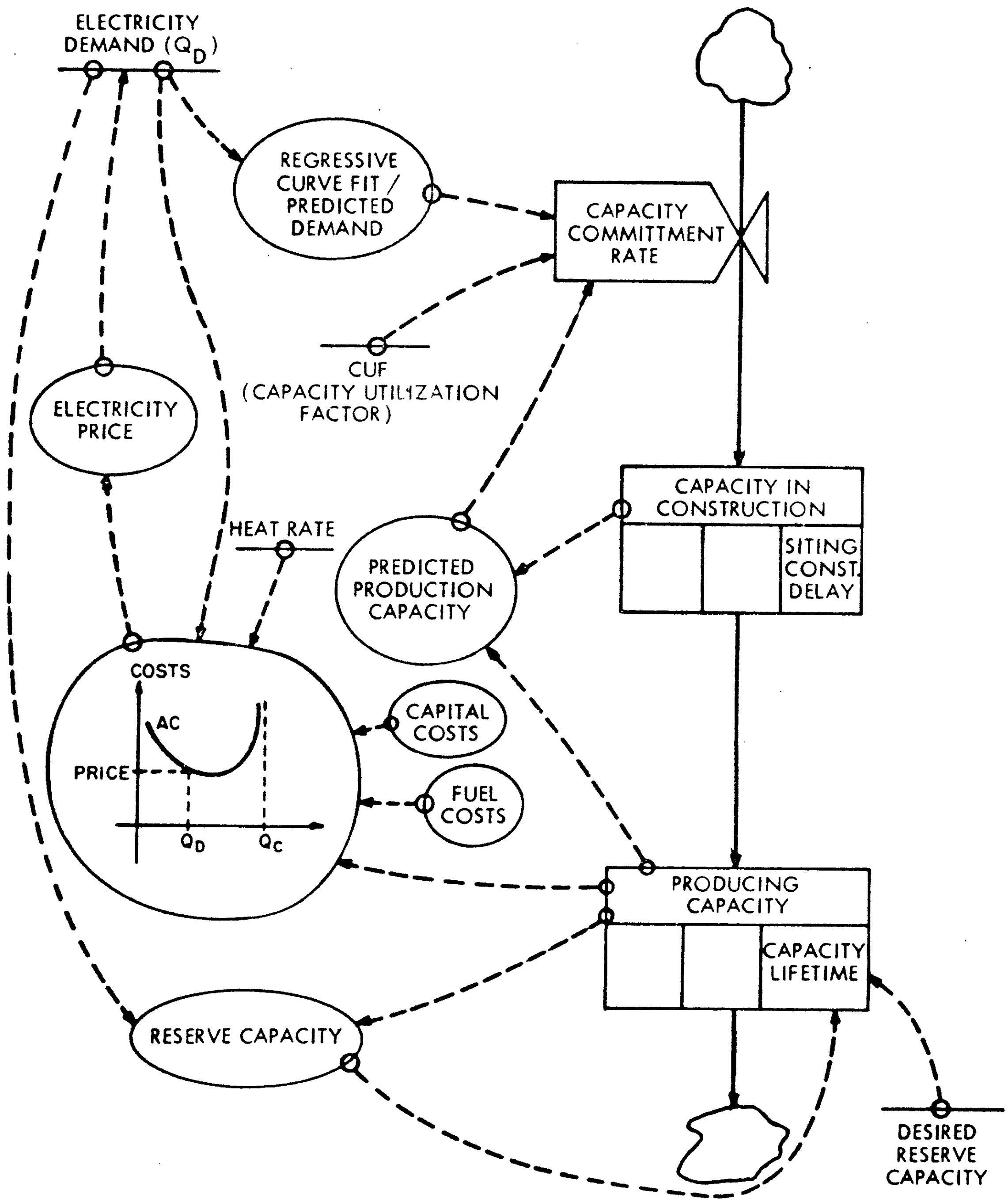

Figure 3.6

dependencies are shown affecting the average costs in figure 3.6.

Also, since there exists the capability in the electrical industry to delay retirement of old capacity when conditions warrant, a dependence between the capacity lifetime and the reserve capacity is depicted. If a shortage in reserve capacity occurs, an extension of the producing lifetime of existing capacity can be used to mitigate the shortage. The mathematical formulation of the costs relationships and the capacity lifetime dependencies are given in Appendix D.

The nuclear generation option does not change the basic structure of the electrical industry as given in figure 3.6, but simply adds to it. In fossil generation, there exists some convertibility of existing plant to utilize alternative fossil fuels. However, once the plant has been constructed, there exists no convertibility between fossil fueling and nuclear fueling. It is fixed for the life of the plant. Further, the choice between a fossil and nuclear fueled plant is made at the time of construction. The factors influencing this choice (among other things) include the relative capital and fuel costs for the two alternative plants. The mix of fossil and nuclear fired plants then affects the fixed and variable costs in the electricity supply cost curves. The characterization and dynamics of depletion of the uranium resources play a part in the analysis of fuel costs for nuclear generation just as fossil fuel costs do for fossil generation. It is the decision process in capacity committment and the effects of the resulting committment on nuclear fuel costs which are to be modeled here.

The first step is to disaggregate electricity supply capacity in figure 3.6 into the fossil and nuclear components as shown in figure 3.7.

ELECTRICITY SUPPLY - FOSSIL VS. NUCLEAR

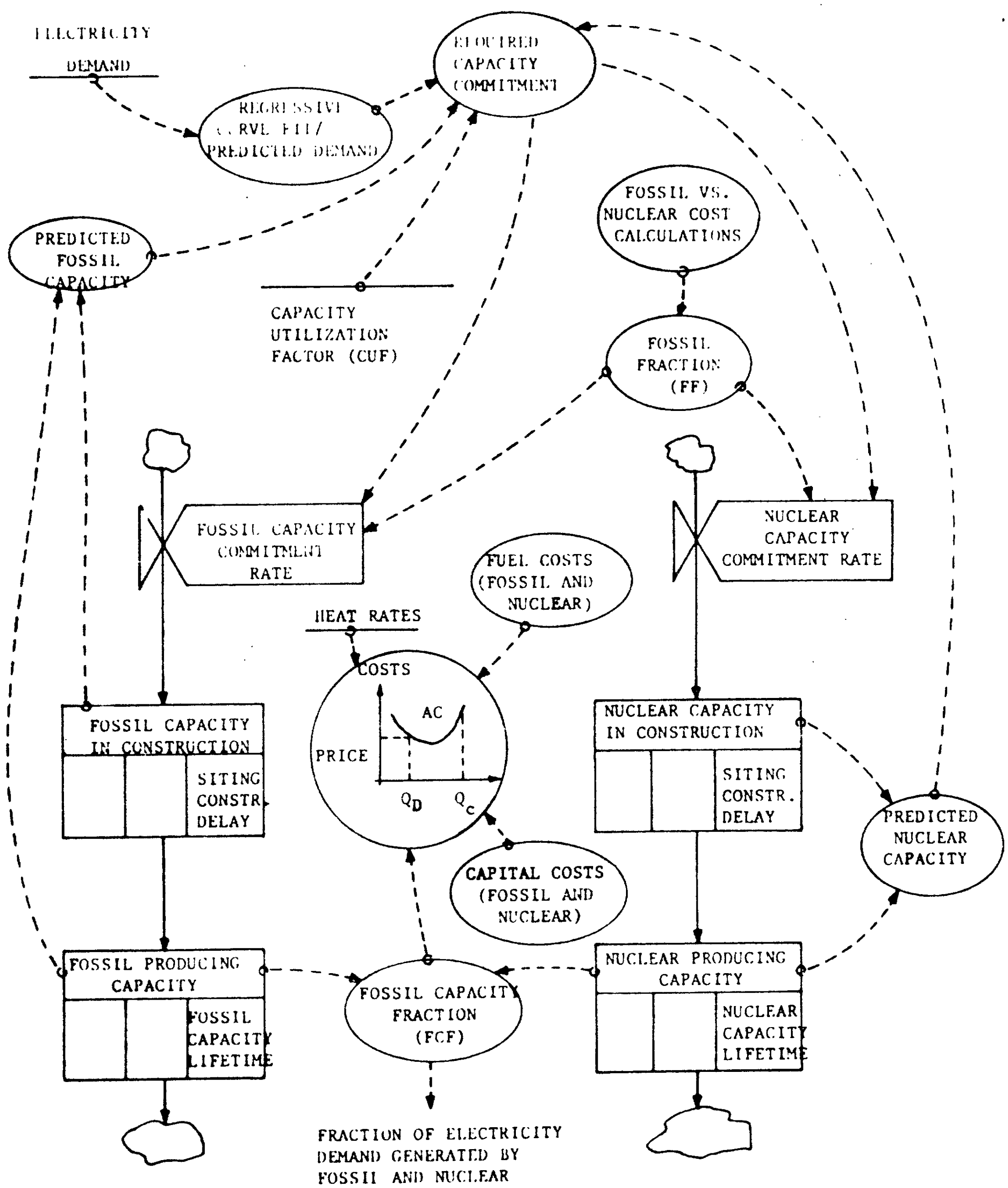

Figure 3.7

Additional factors are needed in the capacity committment logic to give the fraction of total committment made up of fossil capacity and nuclear capacity.

This additional logic is based not only on cost calculations to determine which form of generation is more economical, but also other factors that are not accountable in the normal economic sense affect the final outcome. In this work the decision process will focus explicitly on costs, with the capability of the other factors being entered exogenously into the decision process. The principal components of this committment logic are fossil vs. nuclear cost calculations and the tabulation of the resulting fraction of the capacity committment which is made up of fossil fueled generation. The fossil vs. nuclear cost calculations in the model are fashioned after those of Benedict [8]. A tabulation of the component costs are given in figure 3.8a with typical cost figures inserted for fossil and nuclear respectively.

The ratio of the relative fossil to nuclear costs (in mills/kwh.) is then used to define the fraction of total capacity committment made up of fossil fueled generation. This fossil fraction is designated FF. This relationship might take the form of the table given in figure 3.8b. At low relative fossil to nuclear generation costs, essentially all capacity committment would be fossil (FF = 1.0). As the relative costs of fossil generation increase the fraction of fossil committment would decrease. It is this table which relates to cost the fossil fraction of committment in electricity given all other factors other than cost remain equal.

Figure 3.8a

	COAL		NUCLEAR
Unit Investment Cost $/KW	$202		$255
Annual Capital Charge rate per year		0.13	
Kilowatt-hours generated per year per KW capacity		5256	
Heat rate, million Btu/Kwh	0.009		0.0104
Cost of heat from fuel, cents/million Btu	45		18
Cost of Electricity, mills/Kwh :			
Plant Investment	5.00		6.31
Operation and Maintenance	0.30		0.38
Fuel	4.05		1.87
TOTAL	9.35		8.56

[1] From Benedict, Hanson, "Electric Power from Nuclear Fission", Technology Review, October/November, 1971.

FOSSIL FRACTION TABLE (FF)

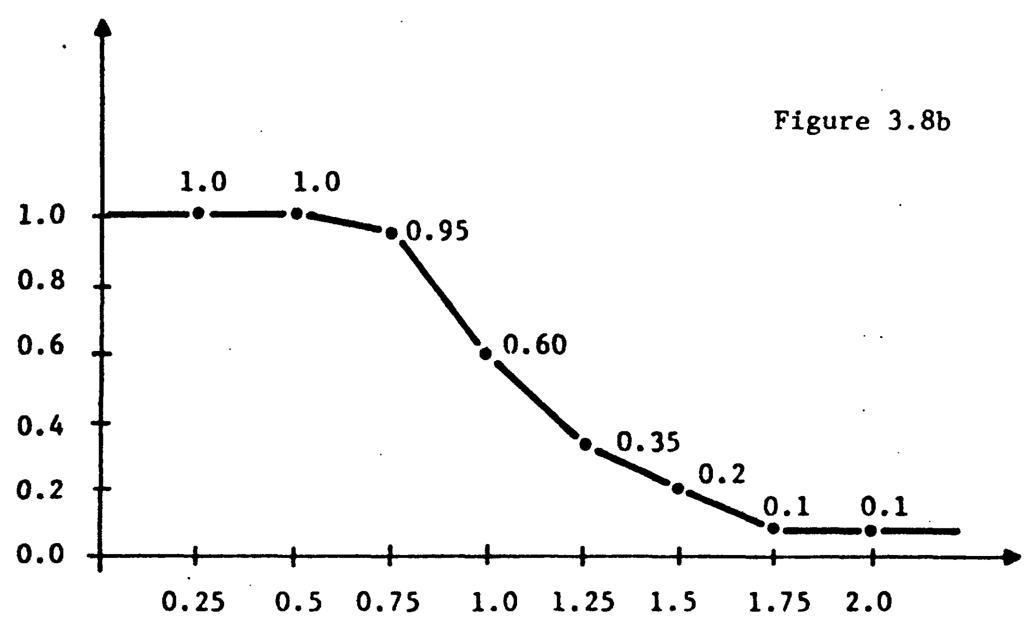

Figure 3.8b

RELATIVE FOSSIL TO NUCLEAR COSTS

If other things change, such as construction delays, then it means that the points in the table move to reflect this condition. For example, increased societal concern over a nuclear plant accident would decrease the attractiveness of nuclear power plants and tend to shift the curve up (increase the fossil fraction) for the same relative costs. Increased lead times in nuclear plant siting, construction and licensing, in addition to increasing interest during construction and unit investment costs, would tend to make nuclear less attractive because of the longer delays in making the plant operable. This would tend to shift up the curve in figure 3.8b for the same relative costs. It is through the fossil fraction table that the intangibles other than cost can be injected in the capacity committment logic.

In figure 3.7, the fraction of producing capacity which is fossil fired is called the fossil capacity fraction (FCF). This quantity, along with the corresponding investment and fuel costs for fossil and nuclear respectively, affects the costs curves of the operating capacity in electricity supply. The level of fixed costs depends on the mix of generating units. The level of variable costs depends on the prices of the corresponding mix of primary fuels. These factors are all weighted into the average cost function in figure 3.7.

The fraction of electricity demand supplied from nuclear generation is assumed to be the same as the fraction of total capacity made up of nuclear capacity. This is a simplification to circumvent the problem of economic dispatch, but over the long term the approximation should be close enough to meet our purposes. With this approximation and with the quantity of fuel required to generate a unit of electrical output, the nuclear fuel utilization rate can be determined. The characterization of the uranium resources is then shown in figure 3.9 as cost (in $/lb.) vs. the quantity of the uranium concentrates available. As the uranium resources are depleted, the costs increase. With the addition of the enrichment and fabrication costs of the uranium fuel, the nuclear fuel costs are obtained. These fuel costs then enter into the capacity committment logic and the calculation of the cost curves in figures 7 and 8a. The conversion factors for the electrical output per unit of uranium concentrates, and the enrichment and fabrication costs must be set to reflect the characteristics of the particular reactor and fuel cycle in consideration. In general, exploration may increase the uranium resources, and this is also shown in figure 3.9. This then completes the model structure for electricity supply and nuclear energy.

The parameters which are required to operate the electricity model are mainly those in figures 3.8a (with the exception of fuel costs which are generated endogenously), in figure 3.8b, and the conversion factors and resource supply curve in figure 3.9. The fossil fuel selection process has not been discussed, but will be in chapter 4. The precise mathematical equations of the model are given in Appendix D.

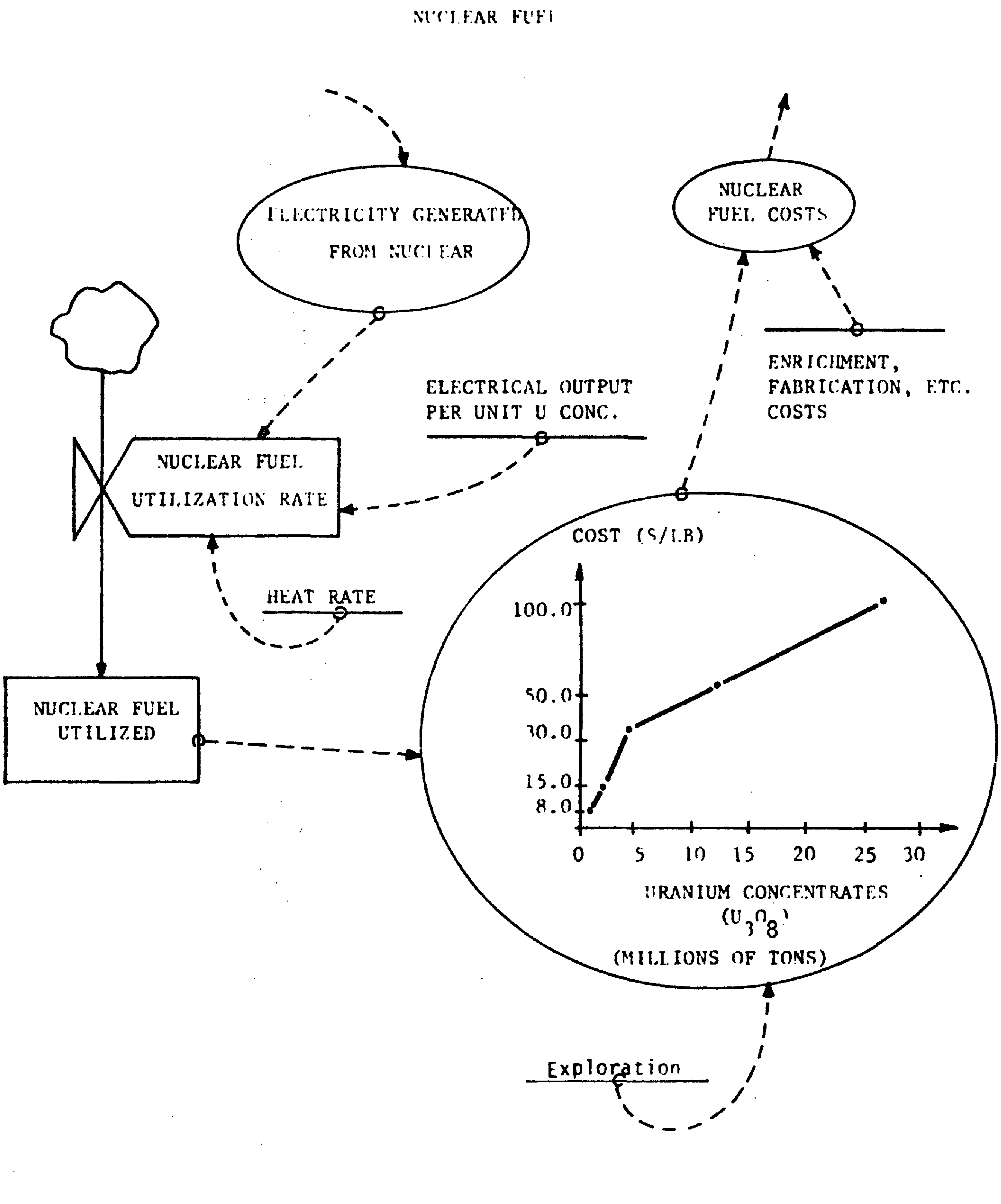
NUCLEAR FUEL
ELECTRICITY GENERATED FROM NUCLEAR
NUCLEAR FUEL COSTS
ENRICHMENT, FABRICATION, ETC. COSTS
ELECTRICAL OUTPUT PER UNIT U CONC.
NUCLEAR FUEL UTILIZATION RATE
HEAT RATE
NUCLEAR FUEL UTILIZED
COST ($/LB)
100.0
50.0
30.0
15.0
8.0
0
5
10
15
20
25
30
URANIUM CONCENTRATES
(U_3O_8)
(MILLIONS OF TONS)
Exploration

Figure 3.9

3.3 Imports and Exports

As mentioned in the introduction to this chapter, the level of imports vs. time are assumed to be inputs into the model. How do they affect the system behavior?

Recall that in the construction of the domestic supply models it was assumed that the level of fuel demand vs. time was given. Exports and imports are simply added to or subtracted from this level of domestic demand as generated within the model. The actual values of demand are derived from the demand dynamics and the fuel selection process as discussed in the next chapter. Once these domestic demands are derived, the quantity to be exported is simply added to it. If imports are available the level of imports is subtracted from the domestic fuel demand as calculated in the next chapter and the net is assumed to be supplied by domestic producers at the price derived as in section 3.1.

Certainly this is a simplified characterization of foreign supply and demand. The concentration in this work, however, is on the domestic supply and demand dynamics and the simplification is considered acceptable for these purposes. It may be desirable in further model development to more completely represent the economic decision processes in import and export behavior --- here it is not done.

In the next chapter the model of the demand dynamics in domestic consumption is discussed. In this chapter it was assumed that fuel demands were known, and the supply models yielded supply vs. price vs. time. Now the loop is to be completed by assuming price is known so that the fuel demands can be derived.

CHAPTER 4

DYNAMICS OF DEMAND

Introduction

The model for the dynamics of demand is basically a capital stock effect model fashioned after that given in Balestra [2]. The model is constructed to identify explicitly that portion of demand in any consuming sector that is sensitive to fuel price and that portion which is not. That portion of demand sensitive to prices over a specified interval of time is termed the market sensitive demand and that portion not sensitive to price is called the base demand. The market sensitive demand is made up of two components --- the replacement demand and the incremental demand. Over an increment of time (say one year), the replacement demand is that portion of past consumers in any given demand sector who (for reasons of technological obsolescence, economic benefits, or convenience) come onto marketplace to "bargain" for a fuel to meet their functional needs. The incremental demand is that portion of total demand in a consuming sector made up of new consumer needs or growth in that sector.

The effective rate of turnover of consumers in the marketplace, or the fraction of consumers not locked into their present fuel consumption patterns is a key factor in how fast the fuel mix in that demand sector reacts to price changes in the marketplace. One would expect that these reaction times to price changes in the various demand sectors to be quite different. That is, in the residential and commercial heating market one would expect the lifetime to be related to the lifetime of furnaces and heating plants in this sector (say on the order of five or more years). In electricity generation, some plants are often designed to burn any of the fossil fuels interchangeably. If the price configuration of the competing fuels is changing significantly under these conditions, one would expect the effective lifetime to be much shorter than the lifetime of capital equipment, i.e. they would react much faster to relative changes in price of the competing fuels. This inertia effect must be set to conform with the particular characteristics of any consuming sector under consideration.

In this work it will be assumed that the demand sector growth rates are inputs to model. This has the implication that those variables endogenous to model, namely prices, do not affect the levels or growth rates of total sector demand in the primary consuming sectors. This assumption can then be interpreted as meaning that in the residential and commercial, industrial, and transportation markets, the growth rates of consumption in these sectors are determined by various economic and demographic conditions outside the scope of model --- an approximation to be sure, but not wholly unreasonable.

How the market sensitive demand (made up of the replacement and incremental demand) reacts to fuel prices and distributes among the fuels is another important ingredient of the demand model. There are a number of factors which influence one's choice of fuel to meet a functional need. One would expect the price of the fuel to be important, but other considerations such as capital costs, availability, cleanliness, ease of maintenance, and convenience certainly affect the user's decision also. Different consumers weight all these considerations differently. How the national aggregate of consumers weights the various decision inputs is difficult to make explicit. It is assumed here that the primary determinant in one's choice of fuel are fuel cost and the other considerations mentioned above are of secondary importance.

This chapter will discuss the model used for dynamics of demand. First the generic model for the dynamics of the fuel distribution for any given consuming sector will be given. Following that a discussion of the model for electricity fuel demands will be given. Finally, a discussion of the model behavior and how the parameters in the demand model were arrived at will be given. For ease of presentation, matrix notation for the equations of the demand dynamics is used.

4.1 Demand Modeling

Define Y_i as the quantity of fuel i supplying the demand in sector Y. The vector $\underline{m}' = [1 \;\; 1 \; \ldots \; 1]$ (primed quantity denotes transpose) so that

$$\underline{m}'\underline{Y}(t) = \sum_i Y_i(t)$$

is the total sector demand in consuming sector Y. Define the quantity G as the growth rate of demand in sector Y, and the matrix $\underline{B}$ as a diagonal matrix whose diagonal terms represent the fraction of consumption locked into its present fuel consuming pattern. The vector $\underline{d}(t)$

is defined as the vector of distribution factors which distributes the market sensitive demand among the fuels. It is this vector which describes how the group of consumers making up the market sensitive demand react to price of alternative fuels in their choice of an energy source to meet their functional needs. This vector shows how the consumers behave on the average, and depicts what fraction of the collective market sensitive demand in a given demand sector chooses each of the competing fuels on the marketplace to meet their needs. The expression relating these distribution factors to fuel prices will be discussed in a moment.

With this definition of terms the dynamic equations of demand can be written for a one year interval as follows. Denote $d_i(t)$ as the fraction of the market sensitive demand that opts for fuel "i" in the time period from t to t + 1. If it is assumed that in this interval of time the growth rate G and distribution factors $\underline{d}$ are constant and equal to G(t) and $\underline{d}(t)$ respectively, the discrete time equation for the amount of fuel "i" (in Btu's) supplying sector Y in time t + 1 can be written as:

$$Y_i(t + 1) = B_i Y_i(t) + d_i(t) \left[\sum_{i=1}^{n} (1 - B_i) Y_i(t) + G(t) \right] \qquad \text{Equation 4.1}$$

for $i = 1,2,\ldots n$ supplying fuels.

This equation says the demand for fuel "i" in consuming sector Y (be it residential and commercial, industrial, or whatever) at time t + 1, is some fraction B_i of the Y demand for fuel "i" at time t, plus some fraction $d_i(t)$ (this fraction depends on the price configuration of the competing fuels) of the market sensitive demand in that consuming sector Y. For this one year interval, G(t) is the incremental demand and

$$\sum_{i=1}^{n} (1 - B_i)\, Y_i(t)$$

is the sum of the replacement demands of all types of fuel consumers in sector Y. The sum of these two (the bracketed term in equation 4.1) is the market sensitive demand and the fraction $d_i(t)$ is supplied by fuel "i" at time t + 1. The quantity

$$B_i\, Y_i(t)$$

is the locked in or base demand for fuel "i" and designates the portion of the demand that existed at time t which is still being supplied by the same fuel "i" at time t + 1. In matrix terminology, dynamic demand equation may be written as

$$\underline{Y}(t + 1) = \underline{B}\ \underline{Y}(t) + \underline{d}(t)\left[m'(\underline{I} - \underline{B})\ Y(t) + G(t)\right] \qquad \text{Equation 4.1a}$$

The assumption that total sector demand is inelastic means that

$$\underline{m}'\underline{d}(t) = \sum_{i=1}^{n} d_i(t) = 1$$

That is, all the market sensitive demand gets supplied by one or another fuel.

The feedback into the demand side of the model from the supply and marketplace sectors is through the fuel prices as obtained from the supply cost curves for each fuel. The effect of fuel prices enters into the demand dynamics through the distribution factors in $\underline{d}(t)$. As the relative prices of the fuels change, the portion of market sensitive demand which is supplied by any particular fuel changes. The form that the relationship between prices and distribution factors should take is an open question. One possible relationship is linear and of the form

$$\underline{d}(t) = \underline{A}\ \underline{p}(t) \qquad \text{Equation 4.2}$$

where $\underline{p}(t)$ is an n + 1 vector with a one in the first row and the value of fuel prices following in consecutive order for fuels 1,2,...,n respectively. $\underline{A}$ is an (n) x (n + 1) matrix to be identified, the first column being the intercept of $\underline{d}(t)$, the other coefficients being the multiplicative coefficients of the prices.

The difficulty with this form is that range constraints must be placed on the prices with a given $\underline{A}$ for the relationship in equation 4.2 to be meaningful. From the definition of the distribution factors in equation 4.1, they are always non-negative with values bounded between zero and one. In addition, simple logical reasoning suggests that as the price of a particular fuel rises relative to the other fuels, the distribution factor for that fuel decreases while those for the other fuels increase. Consequently, those elements of $\underline{A}$ relating the price of a particular fuel (say fuel "i") to the distribution factor for that fuel would carry a negative sign. Conversely, those elements in $\underline{A}$ relating the distribution factors of other fuels to the price of fuel "i" would be positive. Given fixed elements in $\underline{A}$, bounds must be placed on the range of values the prices can take on so that the distribution factors remain between zero and one. When the prices exceed this range, an $\underline{A}$ of different values must be used in equation 4.2 for it to remain meaningful. Since past data is to be used to identify the values of $\underline{A}$, only one $\underline{A}$ for the range of prices occurring in the past is obtainable. What the $\underline{A}$ should be over the time scales of interest in this work (with markedly different price configurations than those occurring historically) is probably an unanswerable question. One thing is certain, if the linear form of equation 4.2 is used, then as prices exceed their permissible range the equation becomes meaningless.

For this reason the relationship of equation 4.2 will not be used, but rather for convenience a log linear relationship will be. This has the form

$$\log_e \underline{d}(t) = \underline{A}\ \underline{p}(t)$$

$$\text{or} \quad d_i(t) = Ai\ e^{a_{i1}p(t)}\ e^{a_{i2}p_2(t)} \ldots e^{a_{in}p_n(t)} \qquad \text{Equation 4.3}$$

$$\text{for } i = 1,2,\ldots n$$

This has the advantage that for all prices the distribution factors are always positive. It has the disadvantage that as prices change the distribution factors don't always sum to one. This problem is alleviated by using the d_i's as weighting factors with their sum normalized to one.

The problem still remains that for markedly different price configurations, the value of $\underline{A}$ in equation 4.3 probably changes. Since it is impossible apriori to ascertain what these changes would be, it will be assumed that the $\underline{A}$ best fitting past data applies for all price configurations. This is a big assumption, but there is really no alternative. Obviously, if the relative prices of the fuels change drastically, one has to place a low level of confidence in the demand dynamics as it depends upon the $\underline{A}$ matrix. This is a restriction of the model structure, and until one can relate the values of $\underline{A}$ to the many intangible factors involved in the fuel selection process, it will remain a difficulty. In this work the $\underline{A}$ matrix will be identified from fits of model behavior to past data. The procedure used in the identification will be discussed in the next section.

Another important assumption implied by equation 4.3 is that only current prices affect current distribution factors. In those consuming sectors where long lead times exist between the initiation and the completion of the energy consuming physical plant, it is probably the fuel prices and trends that existed at the time of initiation which influenced the fuel selection prices. For some uses, electricity in particular, this lead time may be as great as 5 years or more. In equation 4.3 this would suggest that fuel prices for some years previous to the present price should be included as independent variables. However, because of the importance of transportation/distribution costs in fuel prices to the consuming public, the substantive differences in prices occur from region to region of the U.S. rather than from one year to the next in a given region. In other words, the differentials in fuel prices through time because of depletion and technological change (though important in the long term) are not nearly as influential in fuel selection process over the short term (a period of 1 to 5 years) as the differences in fuel prices are that arise from varying region to region costs. For this reason, the fuel price configuration for a region at any point in time is a pretty fair representation of the prices that have existed in that region for a period of a few years. As depletion and technological innovation take place then the fuel price configurations in the regions change and the distribution factors for the regions change as given in equation 4.3.

Since electricity is not a primary source of energy, the electricity demand from the primary consuming sectors (residential and commercial, industrial, and transportation) must be reflected back to the primary sources of energy used for electricity generation. The model used for this is basically the same as that given in equation 4.1. A market sensitive demand made up of the incremental and replacement demands is identified as in the primary supplier models. The relationship between the distribution factors and price takes the same form. The only difference is that to generate a Btu's worth of electricity, more than a Btu is required. In fact, for one Btu out, the plant requires 1/thermal efficiency = heat rate Btu's going in. In the model therefore, the heat rate is a parameter which relates the primary energy requirements of electricity to the electricity demand. Therefore, in equation 4.1 for electricity, the Y_i's are the electrical output produced by the primary fuels, and to get the primary fuel demand they must be multiplied by the heat rate. Historically the heat rate has a trend of decreasing consistently, although recent decrements have been much less than those for the first half of the century. The continual increases in efficiency have contributed significantly to the trend of decreasing prices for electrical energy.

This basically describes the operation of the fuel selection processes for the demand sectors. The consuming sectors corresponding to the $\underline{Y}$ vector in the demand model are given in table 4.1. The fuel suppliers for these sectors accompany them in the table. A summary of the demand model equations is given in figure 4.2. For simulation purposes, the parameters which must be specified are the following, 1) for each demand sector the fraction of consumers over a one year period sensitive to price must be given (the B_i's), 2) in equation 4.3, the matrix $\underline{A}$ which relates the distribution factors to price must be given, 3) and finally the growth rate (G) and the initial conditions of equation 4.1 must be supplied. With this data, the models for the demand sectors residential and commercial, industrial heating, and transportation are made explicit. Each of these have the option of using electricity, and another stage in the fuel selection process is required to completely describe the primary fuel demand.

The total fuel demand is then simply the sum of the consuming sector demands for that fuel. For a given supply capacity, this fuel demand defines a point on the cost curves in the supply models given in chapter 3, which in turn defines a wholesale price. These prices then determine the distribution factors in equation 4.3. With the sector demand growth as an input, this then allows calculation of new fuel demands at a later point in time.

Table 4.1

Consuming Sectors	Fuel Suppliers
1. Residential and Commercial	1. Coal 2. Natural Gas 3. Petroleum 4. Electricity
2. Industrial Heating	1. Coal 2. Natural Gas 3. Petroleum 4. Electricity
3. Transportation	1. Petroleum
4. Electricity	1. Coal 2. Natural Gas 3. Petroleum 4. Nuclear
5. Petrochemical (Not Included)	1. Coal 2. Natural Gas 3. Petroleum

DYNAMIC DEMAND MODEL

$$\begin{bmatrix} Y_1(t+1)\\ Y_2(t+1)\\ \vdots \\ Y_n(t+1)\end{bmatrix} = \underbrace{\begin{bmatrix} B_1 &&&\\ & B_2 &&\\ &&\ddots&\\ &&&B_n\end{bmatrix}\begin{bmatrix}Y_1(t)\\ Y_2(t)\\ \vdots\\ Y_n(t)\end{bmatrix}}_{\text{BASE DEMAND}} + \underbrace{\begin{bmatrix}d_1\\ d_2\\ \vdots\\ d_n\end{bmatrix}}_{\text{DISTRIBUTION MULTIPLIERS}} \underbrace{\left(\underbrace{\sum_{i=1}^{n} \left(1-B_i\right)}_{\text{REPLACEMENT DEMAND}} Y_i(t) + \underbrace{G}_{\text{INCREMENTAL DEMAND}}\right)}_{\text{MARKET SENSITIVE DEMAND}}$$

$$d_i = A_i \quad e^{a_{i1}p_1} e^{a_{i2}p_2} \; . \; . \; . \; e^{a_{in}p_n}$$

$$\text{for } i = 1, 2, \ldots n$$

$$\text{or} \begin{bmatrix} \ln d_1\\ \ln d_2\\ \vdots\\ \ln d_n\end{bmatrix} = \begin{bmatrix} \ln A_1 & a_{11} & a_{12} & \cdots & a_{1n}\\ \ln A_2 & a_{21} & a_{22} & \cdots & a_{2n}\\ \vdots & & & \ddots & \\ \ln A_n & a_{n1} & a_{n2} & & a_{nn}\end{bmatrix} \begin{bmatrix} p_1\\ p_2\\ \vdots\\ p_n\end{bmatrix}$$

B_i IS FRACTION OF CONSUMERS LOCKED INTO FUEL i FOR THE ONE YEAR INTERVAL.

Y_i IS DEMAND IN SECTOR Y FOR FUEL i.

Figure 4.2

4.2 Demand Model Behavior

At first glance the structure of the demand model as described in the last section may seem a rather arbitrary choice. Let us digress for a moment and discuss why this particular structure was chosen and why it seems appropriate. First a discussion of the model's steady state behavior then a look at the concept of price elasticity follows.

In steady state, the growth rate of demand in a particular sector is set to zero. In equation 4.1, it is also true under steady state conditions that $\underline{Y}(t + 1) = \underline{Y}(t)$. Assuming no growth and constant prices, equation 4.1 becomes

$$\underline{Y}_{ss} = \underline{B}\ \underline{Y}_{ss} + \underline{d}_{ss}\ \underline{m}'\ (\underline{I} - \underline{B})\ \underline{Y}_{ss}\ , \qquad \text{Equation 4.4}$$

where $\underline{Y}_{ss}$ is the steady state configuration of fuel demands and $\underline{d}_{ss}$ is the vector of distribution factors corresponding to the constant prices.

If one is only interested in the steady state fuel shares, then $\underline{m}'\ \underline{Y}_{ss} = 1$. Then upon rearranging terms equation 4.4 becomes

$$(\underline{I} - \underline{B} + \underline{d}_{ss}\ \underline{m}'\ \underline{B})\ \underline{Y}_{ss} = \underline{d}_{ss}$$

or $$\underline{Y}_{ss} = (\underline{I} - \underline{B} + \underline{d}_{ss}\ m'\ \underline{B})^{-1}\ \underline{d}_{ss} \qquad \text{Equation 4.5}$$

This shows that the steady state market shares are dependent both on the vector $\underline{d}$ (which depends on prices) and the matrix B (the fraction of demand which is price sensitive from one year to the next). Given a step change in prices (leading to corresponding changes in the components of $\underline{d}_{ss}$), the configuration of the fuel demands in sector $\underline{Y}$ change with time according to equation 4.1 with G equal to zero.[1]

The new steady state fuel shares are again given by equation 4.5. For a two dimensional system, the behavior during a step change in prices (from $\underline{P}$ to $\underline{P}'$) would appear in general as in figure 4.3.

This is the general type of behavior one would expect in the real system for the same conditions. The time constant would depend upon the rate of turnover of consumers on the marketplace (which might be related to the length of long term fuel contracts if they are predominant) as well as the relative magnitude of the step change in prices. Both these dependencies are included in the model of figure 4.2.

Unfortunately the conditions in the real system are never such that this hypothesis can be verified. This is because the relative fuel prices are always in constant change and sustained periods of no growth have not occurred in the real world.

The elasticities and cross-elasticities of the distribution factors are easily determined from equation 4.3. The elasticity is defined as the percent change in a distribution factor divided by the percent in price. In differential form this relationship can be written as

$$e_{ij} = \frac{\partial d_i}{\partial p_j} \frac{p_j}{d_i} = a_{ij}\, p_j \qquad \text{Equation 4.6}$$

where e_{ij} is the elasticity of d_i with respect to price p_j and a_{ij} is

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[1]The system is time varying due to $\underline{d}(t)$.

DEMAND MODEL DYNAMICS

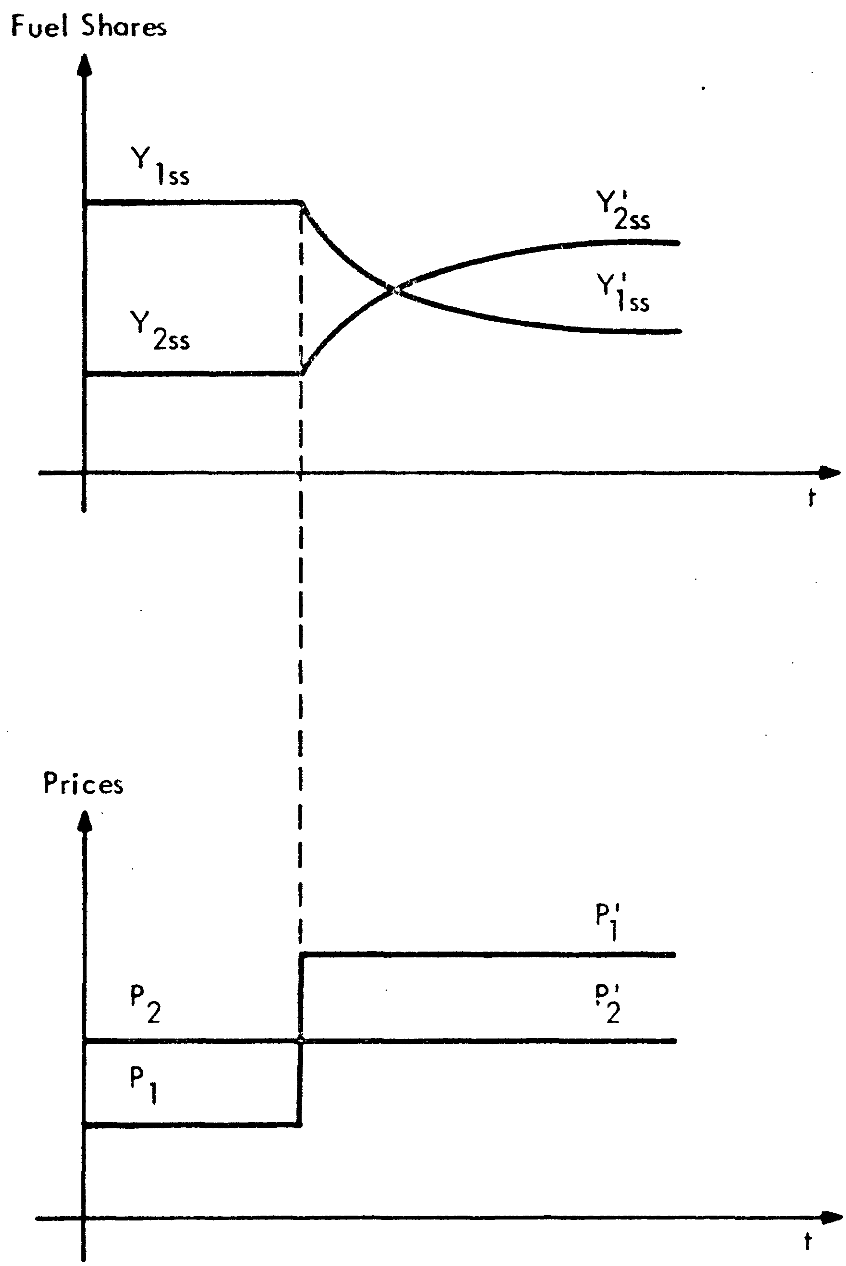

Figure 4.3

the price coefficient in figure 4.2. Note that this isn't the elasticity of consumption, the consumption is Y and the distribution factor is d. However, using equations 4.1 and 4.3 the dynamic elasticity of consumption can be defined.

The elasticity calculated in equation 4.6 is a function of price --- which may at first seem rather strange. However, in the model all prices are in terms of constant dollars. As the price of a particular fuel increases in this constant dollar measure, one would actually expect more sensitivity to it. As the cost of fuels increases relative to other commodities the awareness of energy expenditures would be greater. The increased fuel consciousness should increase the sensitivity of demand to fuel prices. This is exactly what equation 4.6 says. So the elasticity does exhibit reasonable behavior. This relationship is also useful in the definition of what the parameters of the demand models should be. This is discussed in the next section.

4.3 Definition of Parameters

As mentioned in section 4.1, the values of the $\underline{A}$ matrix relating distribution factors to price and the $\underline{B}$ matrix must be specified before the model of figure 4.2 can be used. It would be ideal if these values were invariant with time and location. Unfortunately they most likely are not.

For a small homogeneous region the relationship between the distribution factors and price for a two fuel consuming sector, would probably appear as represented in figure 4.4. When the relative

DISTRIBUTION FACTORS vs. PRICE

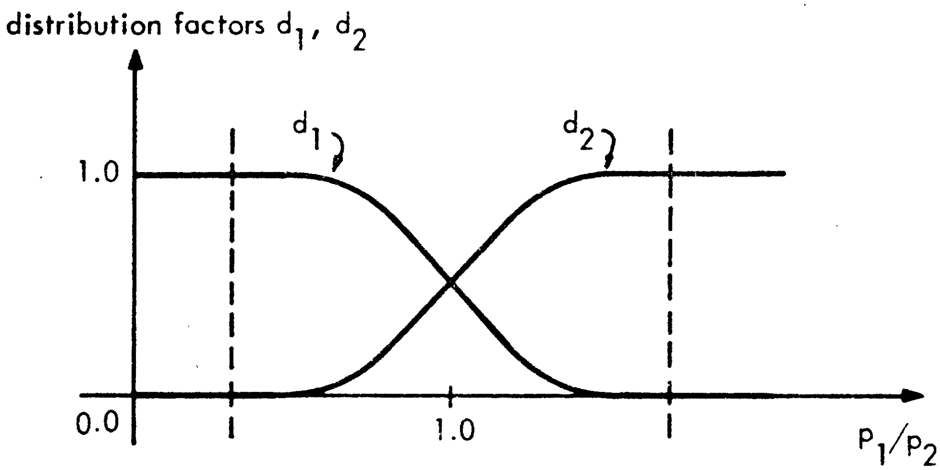

Figure 4.4

prices p_1 and p_2 of both fuels are about equal ($p_1/p_2 = 1$), a change in relative fuel prices would significantly affect the fraction of consumers selecting a particular fuel to meet their functional needs (the distribution factors d_1 and d_2). As the ratio of prices diverges further and further from unity, the effect on the distribution factors would be less and less. Finally, when the relative prices are enough different, either one or the other fuel would be used and there would effectively be no competition between the fuels.

For the U.S. as a whole, the total demand is made up of a series of regional demands. These regions, because of the importance of transportation/distribution costs, have strikingly different fuel price configurations. In fact in some regions prices of selected fuels are far enough from the regional average that they do not effectively compete (as coal in California) and fall outside the region bounded by dotted lines in figure 4.4. In other regions, all the fuels compete effectively for many uses. This suggests that some form of regression analysis on cross-sectional data might be the best way of making explicit the parameters relating price to distribution factors.

Further, remember that the $\underline{B}$ matrix needs to be defined also. In order to identify both the $\underline{B}$'s and $\underline{A}$'s simultaneously in figure 4.2, pooled cross-sectional and time series data would be needed. The time series data would need to be for a length of time as long and preferably longer than the lifetime of the consuming equipment if statistically significant results are to be obtained. In addition, there is no guarantee when the regression is done that the identified parameters have been constant in the past or will remain constant in the future.

These are complicating factors and the purpose here is simply to acknowledge them. The regional dependence of prices makes it questionable whether a national aggregate demand model is meaningful. The possible time varying nature of the parameters casts doubt on the future relevance of regression studies. In the interests of rigor, however, there is no doubt that they should be done.

A prerequisite to this task is the collection of cross-sectional and time series data on fuel consumption and prices by region vs. time for as many regions as necessary to keep homogeneous characteristics within each region. Some data fulfilling these needs has been processed and is reproduced in Appendix B, unfortunately not over a sufficient time period to draw statistically significant results. A major U.S. oil company considered collecting data of this form for their own purposes for the decade of the sixties and estimated it would take two man-years effort.[1]

Therefore, for lack of time, the regression studies were not done in this work. Rather the values for <u>B</u> and <u>A</u> for each consuming sector denoted in table 4.1 were set as follows. First a set of <u>B</u>'s for each consuming sector were preset from physical reasoning and apriori knowledge of the life of the consuming equipment in each consuming sector. The <u>A</u>'s were set apriori to represent reasonable elasticities for each demand sector. Then with comparisons to actual fuel consumption for the years 1947 to 1969 as reported in Appendix B, the values of <u>A</u> and <u>B</u> in each sector were varied to give a reasonably good fit to that

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[1]Private communication, Humble Oil Company.

data. In chapter 5, it will be seen that surprisingly good results were obtained in spite of the sacrifice in rigor. Of course this only means that the candidate set of values obtained are a consistent set and not necessarily correct. A further discussion of the values of the parameters identified and their significance is delayed until chapter 5 when the results of the validation procedure are discussed.

4.4 Transportation/Distribution Costs

In chapter 2 it was mentioned that the transportation/distribution costs in supply were included as a constant multiplier of the wholesale prices derived in chapter 3. In section 4.1 it was pointed out that the prices as derived from the supply models of chapter 3 were used in the dynamics of demand. Where are the transportation/distribution cost multipliers? The answer is that they are hidden in the price coefficients of equation 4.3 (the $\underline{A}$ matrix) and they are not explicit --- though they could be made explicit.

The product of $a_{ij}p_j$ in equation 4.3 portrays the dependence of the distribution factor d_i to the price of fuel "j". If the retail prices were to be used in equation 4.3 in place of the wholesale prices, then those prices shown should be multiplied by the transportation/distribution cost multiplier. The same resulting product $a_{ij}p_j$ results then only if the a_{ij} is divided by this cost multiplier for every coefficient of p_j that occurs in the demand model.

The particular identification scheme used in this work, however, used the wholesale prices generated within the model in the identification procedure described in the last section. Therefore the transportation/distribution cost multipliers are hidden in the values of the parameters identified and no attempt was made to make them explicit.

In chapter 7 a discussion of the issues involved in regional disaggregation of the model is given. For the case of regional or subregional disaggregation the transportation/distribution network must be incorporated into the model, and at that time the transportation/distribution cost components must be made explicit.

This then completes the discussion of the demand models. In appendix D the specific equations for both supply and demand are given. In the next chapter a discussion of the general model behavior and the validation program is given. In chapter 6 the model is applied to a series of case studies and the results are discussed.

CHAPTER 5

MODEL BEHAVIOR - MODEL VALIDATION

Now that the discussion of the components of the overall model have been presented, it is necessary to discuss how they all behave together in a complete system formulation. This chapter will address two issues:

1. How does the overall model behave?
2. Does it properly represent the dynamic structure within the boundaries?

After this discussion, in the next chapter the application of the model to various case studies will be given along with a discussion of the primary determinants of the model behavior.

5.1 Model Behavior

At this point it would be easy to overwhelm one with model simulations and results in an attempt to convey the overall model behavior. In truth it would probably only be confusing. Rather, the approach to be taken here is something like a grand tour of the model interactions for selected hypothetical model conditions. Clearly it will not be an exhaustive discussion of the many model interactions, but it should be useful in helping to understand the modes of operation.

First, let's investigate how a perturbation is transmitted through the system. Suppose for the moment that the system is in a steady state condition. Let's define this steady state as meaning 1) the levels of total consumption in all the primary demand sectors are constant (i.e., no growth) and 2) the market shares of fuels supplying the energy for this consumption are constant. For this to be true all the fuel prices would have to be constant. This would mean that the annual rate of additions to reserves in oil and gas would have to have been constant and equal to consumption of those fuels and technology and depletion were not changing the costs in any of the supply sectors coal, oil, natural gas or electricity.

At time equal to t let's postulate an unexpected and sudden change in the costs of supplying a particular fuel, say oil. Suppose that the cost per unit capacity in oil supply increases for some reason --- possibly a movement toward higher cost oil place due to depletion of the less costly reserves. What does this affect?

First of all it raises the marginal development costs in oil supply (see section 3.1). This would place upward pressure on oil prices in the marketplace and the price would start to rise depending on how long it took to perceive these higher costs and how fast the consumers reacted to these higher prices.

Initially (over a short period of time) the higher prices on the marketplace would have little effect on the levels of consumption until the consumers had time to react and shift their fuel consumption patterns. This reaction time is modeled by identifying only a portion of existing consumption (the market sensitive demand) as being price sensitive over this short period of time. Then depending on the demand elasticities and the fraction of consumption price sensitive in a given interval of time (see section 4.2), the consumption patterns would shift to the lesser expensive sources of supply.

When this happens, an over-utilization of existing supply capacity for coal, natural gas, and electricity exists, and an under utilization of oil supply capacity results. These are registered in the form of higher and lower short run marginal costs to these respective suppliers. As this data gets reported and smoothed, both the changing trends in consumption and the changing prices affect the desired intensity of development and levels of supply for all the sources of energy.

In natural gas and coal, the increased rate of consumption would result in upward pressure on prices until the suppliers reacted and developed the additional capacity necessary to meet the increment in demand. The higher prices of the fossil fuels would raise the fuel costs in electricity, but the higher utilization would lower the levelized capital costs. Depending on the sensitivity of the consumers and suppliers to prices and the time delays involved, new equilibrium prices and fuel consumption patterns would result. The lengths of time involved and the magnitude of the shifts depend on the parameters in the system.

In reality these changing cost-price configurations in supply would change the incentives for exploration.[1] There would be changing incentives for investment in exploration, and depending on the resource endowment the additions to reserves and costs of developing those reserves would change. This exploration process is not modeled in this work, but one must be aware of its implications when using the model

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[1]See Appendix C.

and interpreting the results. One reason the real system is never in a nice well-understood steady state condition is because of the uncertainties and random behavior of the exploration process. This places limitations upon the model uses and the area is discussed as a candidate for further model development in chapter 7.

Further, due to continually changing technology, depletion, the historical trends of ever-present growth in demand, and changing social values, the effects of any given disturbance such as that just described upon the system behavior are often not evident because of the many complex interactions in the time-varying real system. The effects of the same hypothetical disturbance just discussed upon the system behavior when these time varying attributes are present could be significantly different quantitatively or they could even be offset by other trends in the system and not even be discernible. When one is trying to change the real system behavior for some desired purpose it is often not clear where or how much leverage must be applied to accomplish the end. It is for this reason that the model is constructed.

5.2 Model Validation

The model validation problem is a difficult and complex issue, and really the model is never validated in strict sense of the word. Rather, degrees of confidence are established through a series of considerations and each "test" of the model provides a basis for accepting or rejecting the model validity. Certainly the validity issue is also intimately related to the purpose of developing the model. Clearly the model is not valid for investigation of phenomena not expressly contained within the model structure --- rather this is a misapplication of the model. On the other hand, it must properly represent the interrelations of those things expressly contained in the model structure if it <u>is</u> to be valid. Finally, the answer is probably neither that the model is or is not valid, but falls somewhere in the gray area.

The primary issue is then whether the model represents what it set out to do. Let us then reiterate the purpose of the model as given in the introduction of the text.

> "This work is an effort to combine the many economic studies of supply and/or demand for the different forms of energy into a medium to long range dynamic model of interfuel competition for the U.S. This means that a model containing the dynamic interactions between supply, demand, and price for competing forms of energy is to be constructed. Given the availability of the fuel resources and the levels of demand for each of the consuming sectors as a function of time, the model will simulate the process by which supply production capacity is constructed and resources are depleted, the processes whereby different fuels are chosen to satisfy the demand, and resolve these processes into prices and market shares for each of the forms of supply."

Further, the emphasis has been on modeling the decision processes, and more precisely the economic decision processes --- not past behavior. This is an important distinction. Even though the model may behave correctly, if it does not properly represent how decisions are made by the component parts of the system, it is not useful for policy planning. This is because if the decision processes are not present, the model is not useful for investigation and analysis of hypothetical issues that have not occurred in the past (whether policy motivated or random disturbance) even though it may compare to past data very well. For this reason the model is useful only to the extent that it captures and illustrates how the individual components use and react to the inputs which that component senses, regardless of how well it compares to past data. However, comparison to past data is one reasonable validation step and this is to be discussed shortly.

Finally, the emphasis in this work has been on the development of structure, not on the identification of parameters. The identification of parameter values is important when defining what the relative strengths of causal influences may be --- but this is analagous to defining the weightings where the intent in this work has been to define the factors to be weighted. For this reason one may take issue with the precise value of some of the constants and parameters used in the simulation results to be discussed, but the effort has been only to use representative values and reasonable trends over the period of interest.

What, then, has been the validation program for the model reported in this work? Efforts at increasing the confidence in the model structure have been made on several fronts. Certainly other things could be done for further validation, but in the opinion of the author the validation program to be discussed lends much credibility to the model in its present stage of development.

5.2.1 Structural Sensitivity Studies

The first item for discussion regarding the validation procedures is a result of the actual construction, simulation, assessment, modification ... process discussed in section 2.1. The structural components of the supply models went through many iterations before the final forms reported in this work were accepted. Many previous structures were built into the model and preliminary simulation results showed them to be inadequate or incorrect. They either did not properly incorporate and relate the interconnecting influences or did not contain all the necessary components. Through the help of interested and knowledgeable individuals in the energy field the theory of appendix C was developed and the final form of the primary supply model structure was derived therefrom.[1,2]

What information does this convey? In a sense these are sensitivity studies --- not on parameters but on model structure. These sensitivity studies showed that variations in structure from that reported herein produced erratic behavior or inconsistent reasoning and were not valid

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[1] See acknowledgements at the beginning of the text.

[2] Any misinterpretations or misapplications of the theory are the author's.

representations of the supply processes. It would be of little utility to report the structural variations which were failures in development of the model, but the fact that there were failures suggests that some care must be taken in formulating a reasonable representation of the processes. The supply models developed then are a reasonable form built on a consistent theory. Whether they are "correct" it is difficult to say.

The formulation of the demand models was basically an exercise in logic, with extrapolation of the capital stock effect idea to a multi-variable system. Certainly many components in the fuel selection process have been neglected, some were outside the scope of this work and some were considered of secondary significance and therefore not explicitly included in the decision processes. Whether the models are a valid representation the aggregated demand dynamics and fuel selection process is in part dependent upon whether the many simplifying assumptions are justified. Some indication of this is given when the model behavior is compared to past data, but due to the methods used in the quantification and the identification of the many free parameters of the models only weak conclusions can be drawn. Apriori the structural form of the models does seem reasonable. A more rigorous treatment of the fit of the model to past data must be done before stronger statements can be made.[1]

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[1]See section 4.3.

5.2.2 Comparison to Past Data

A second validation step is comparison of the model to past behavior. As mentioned previously, the goal in this work is not specifically to model past behavior, but certainly a good test of the model's validity is whether it displays past behavior when the inputs to the model corresponding to past data are entered. This was done by initializing the model to the 1947 conditions, then simulating a 50 year period with the model and comparing the results to the Bureau of Mines reported data on fuel consumption and price indices for the years 1947 to 1969. The actual model inputs, parameter values, and constants are given in appendix D for this base case simulation. They are summarized in table 5.1. Rather than put into the model the actual values of inputs and time varying parameters as reported from past data (such things as sector demands, additions to reserves, capital costs per unit capacity, imports, etc.), for convenience these values were smoothed and considered in most cases to be simple mathematical functions such as exponentials, ramps, constants, etc. These approximate inputs were derived from the actual data for the 1947 to 1969 time period, and the precise formulation should be clear from the discussions in appendix D.

The simulation results are for a 50 year time period. The actual comparisons to past data are for only the 22 year period from 1947 to 1969. The input growth rates in consumption, the additions to reserves in oil and natural gas, and the trends in factor costs, etc., are set to correspond to this time period. The run is then extrapolated beyond the year 1969 for the remainder of the simulation. This is done merely to display the model behavior over the long term and allow the influences of nuclear generation of electricity and oil imports to be demonstrated. This base case simulation is by no means to be considered a projection by the author. Many things could possibly have significant impact on the results to be shown. The model for the time being is to be thought of as a descriptive tool, not a prescriptive device.

All energy units in the model are expressed in quadrillions of BTU's or for short milliQ's (mQ.)[1]. The price variables are price indices in constant dollars relative to 1947 prices. The prices of the primary supplies coal, oil, and natural gas, and the price of electricity are set nominally to a value of one in 1947. Later values of prices in the simulations are relative to these 1947 prices in constant dollars. The simulation results for this base case run are plotted in figures 5.1 to 5.10. Remember that all energy units are in mQ's, and time zero corresponds to the year 1947.

The actual reported data for the 1947 to 1969 time period for comparison with the model results is reported in appendix B. In table 5.2 are reported these actual values and the model values for selected years.

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[1]One Q corresponds to 10^{18} (one quintillion) BTU's.
A mQ is 10^{15} BTU's.

Table 5.1

Model Characteristics - Base Case

Time Varying Parameters

a) Oil imports

b) Electricity generation from hydro

c) Cost per unit capacity in coal

d) Electricity heat rate (fossil)

e) Unit investment costs (nuclear plants)

f) Unit investment costs (fossil - fired plants)

g) Oil priced above cost 1947-1969

Constants

a) Demand sector growth rates

b) Reserve additions per year in oil and natural gas

c) Cost per unit capacity oil and natural gas

d) Demand sector A's and B's[1]

e) Nuclear heat rate

f) Nuclear fuel vs. price (static curve)

g) Uranium processing, enrichment,..., costs

h) Time constants

i) Time delays

j) Smooth times

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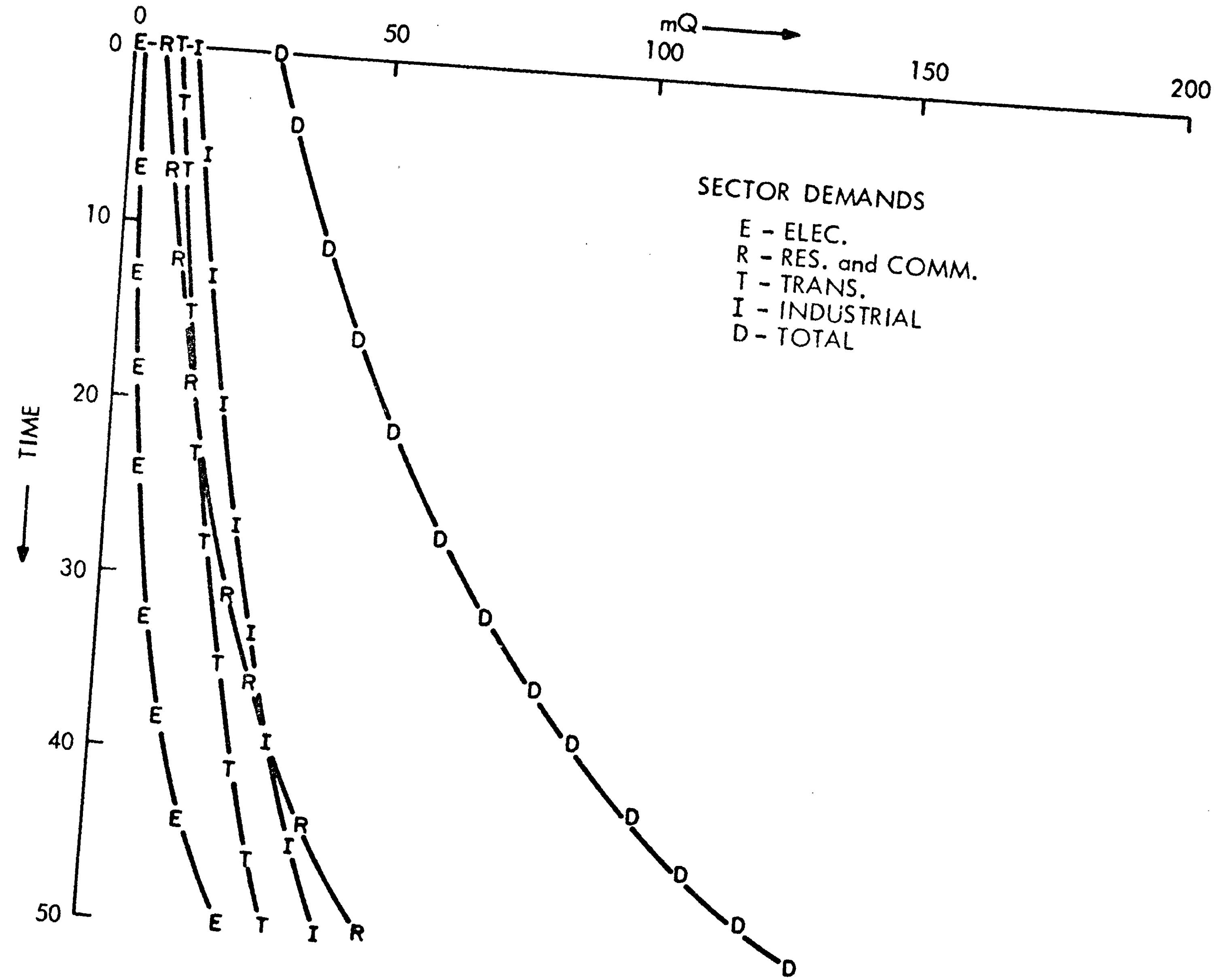
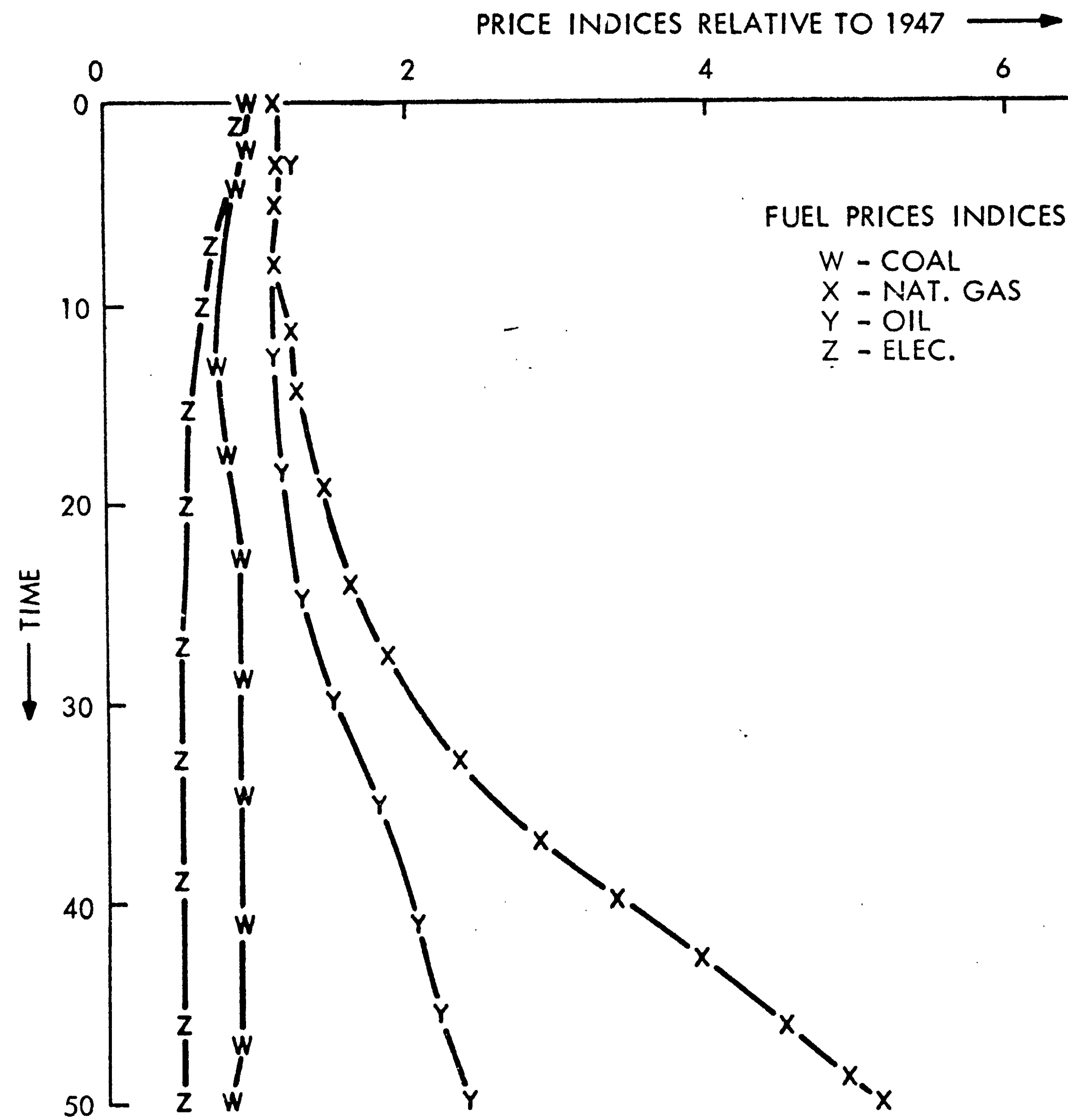
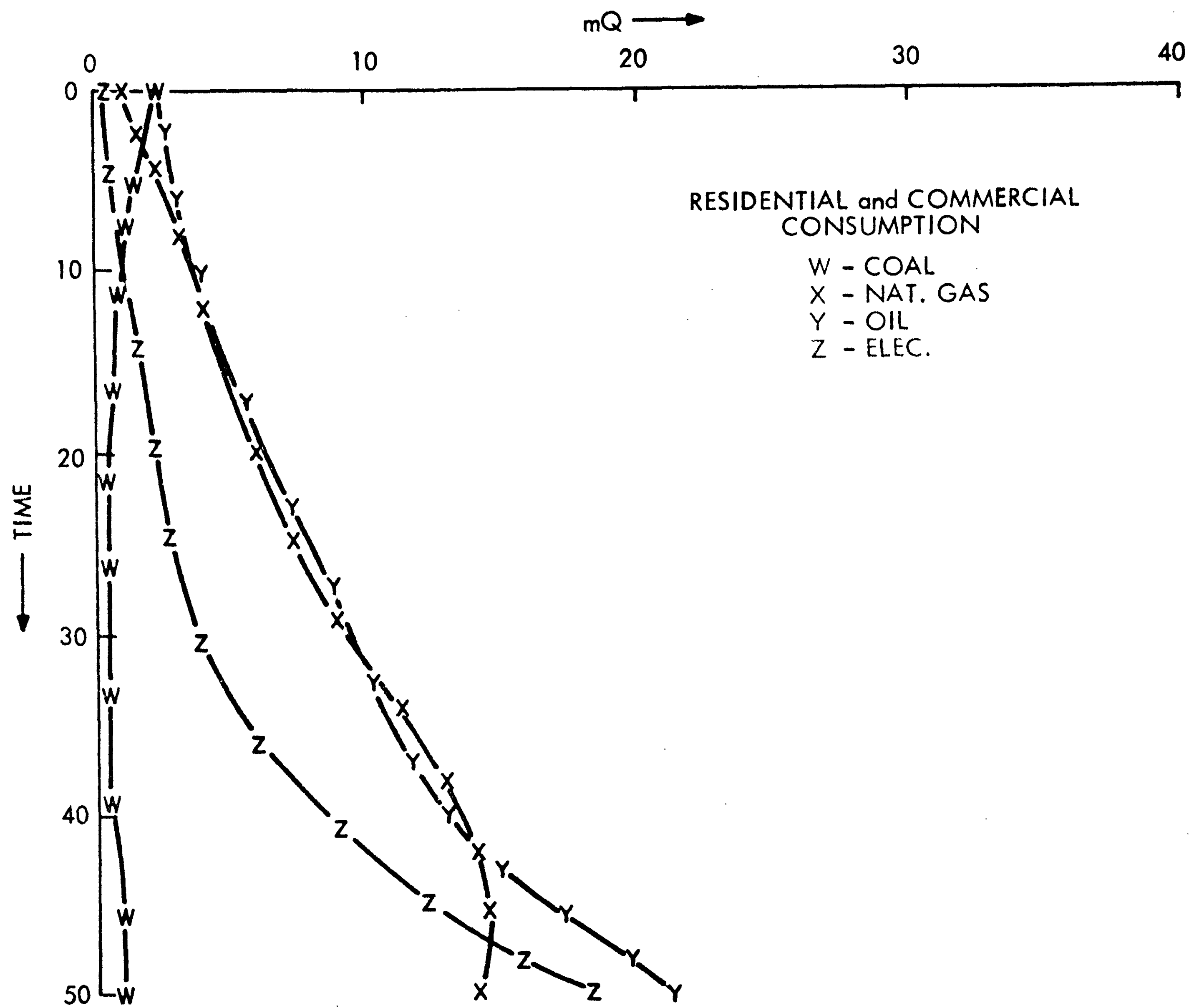
[1]See Figure 4.2.



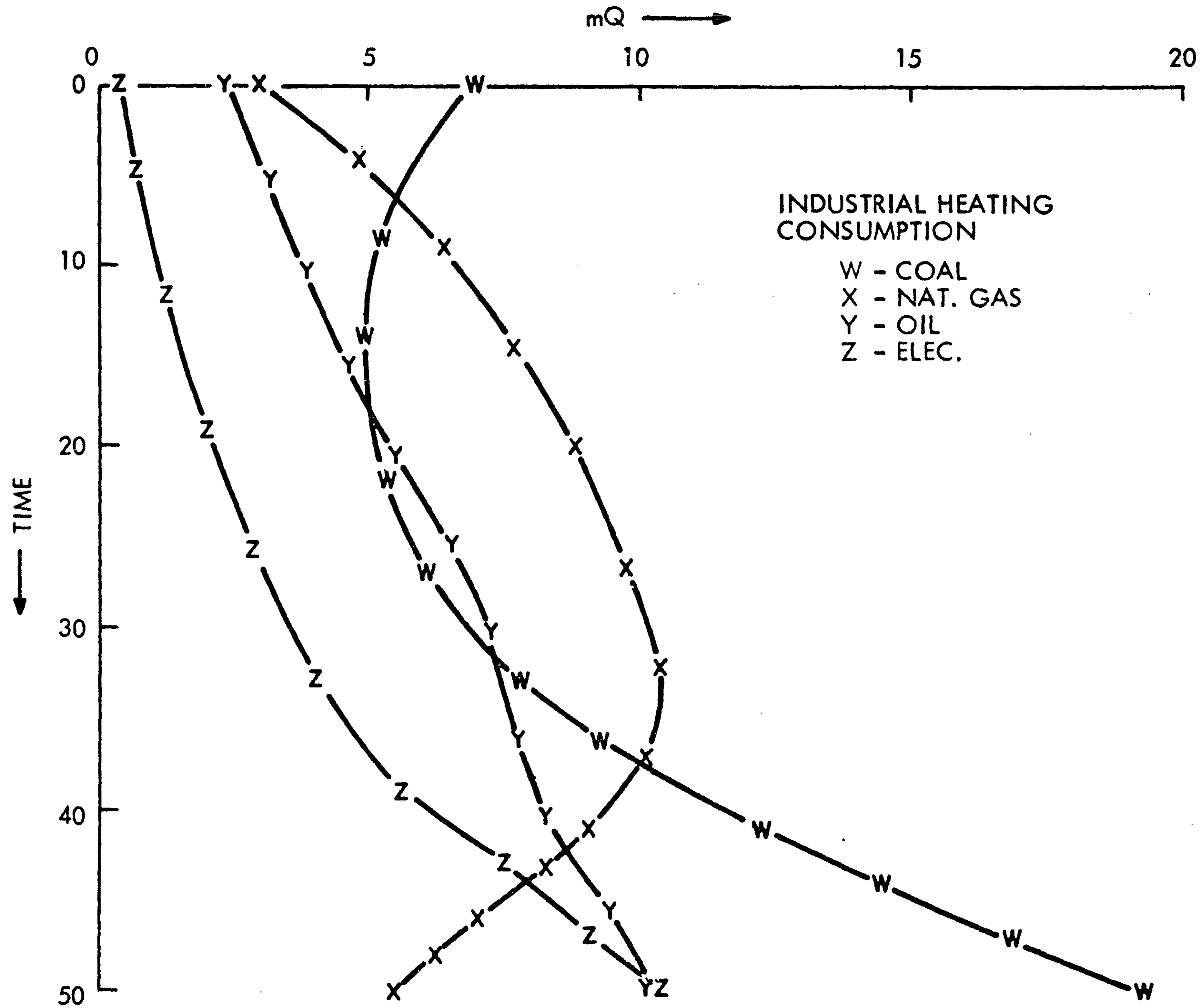
BASE CASE
Figure 5.1



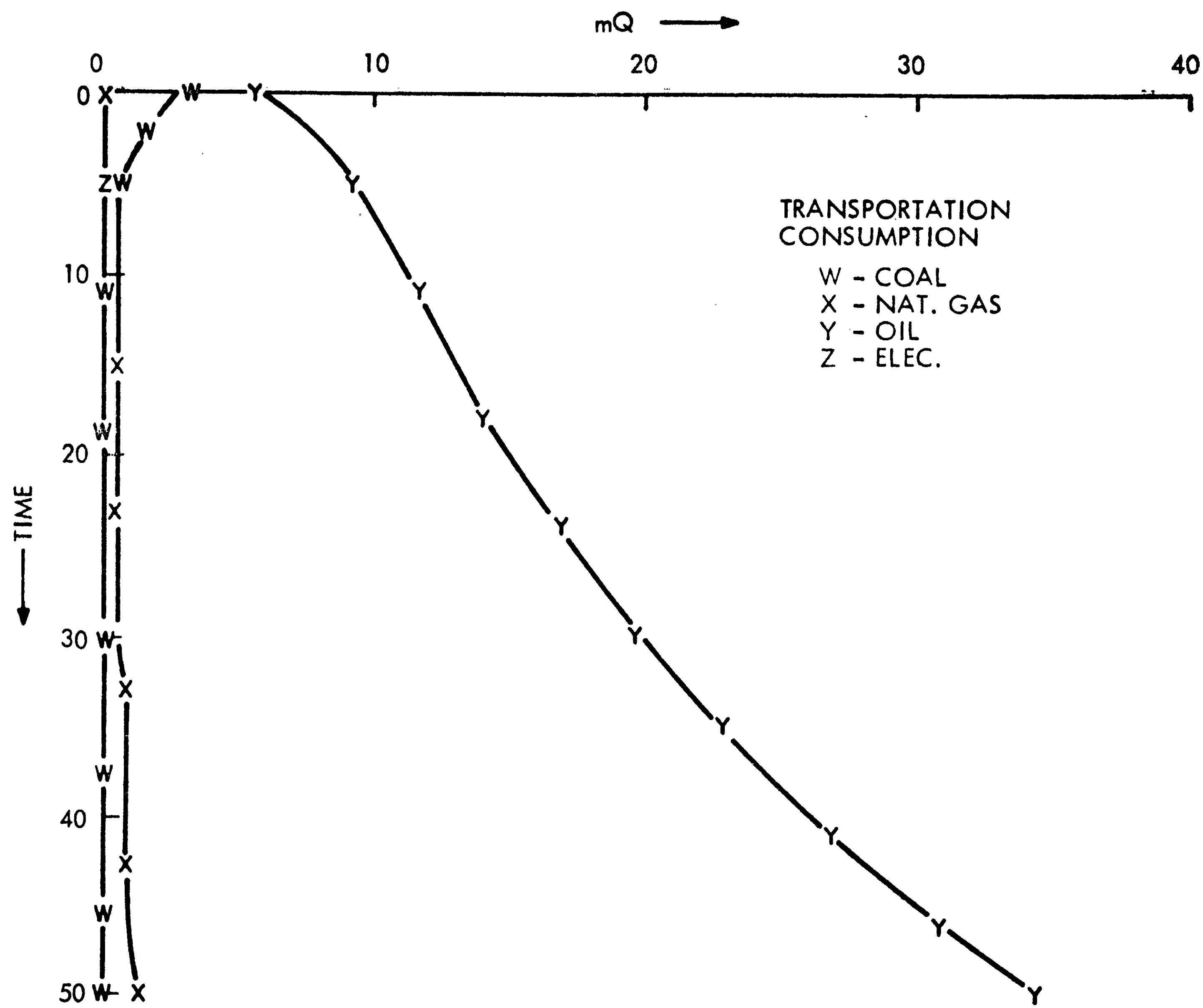
BASE CASE
Figure 5.2



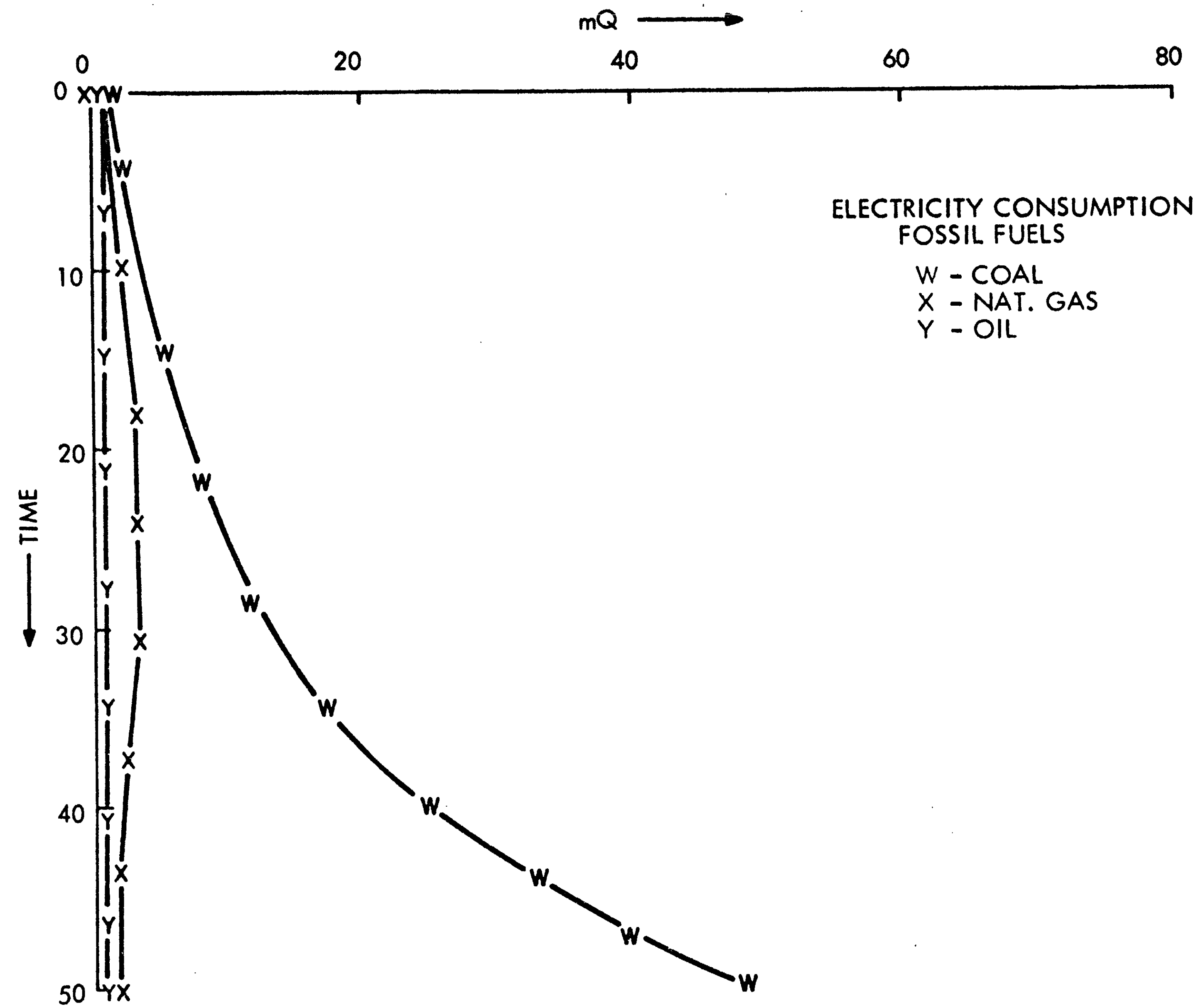
BASE CASE
Figure 5.3



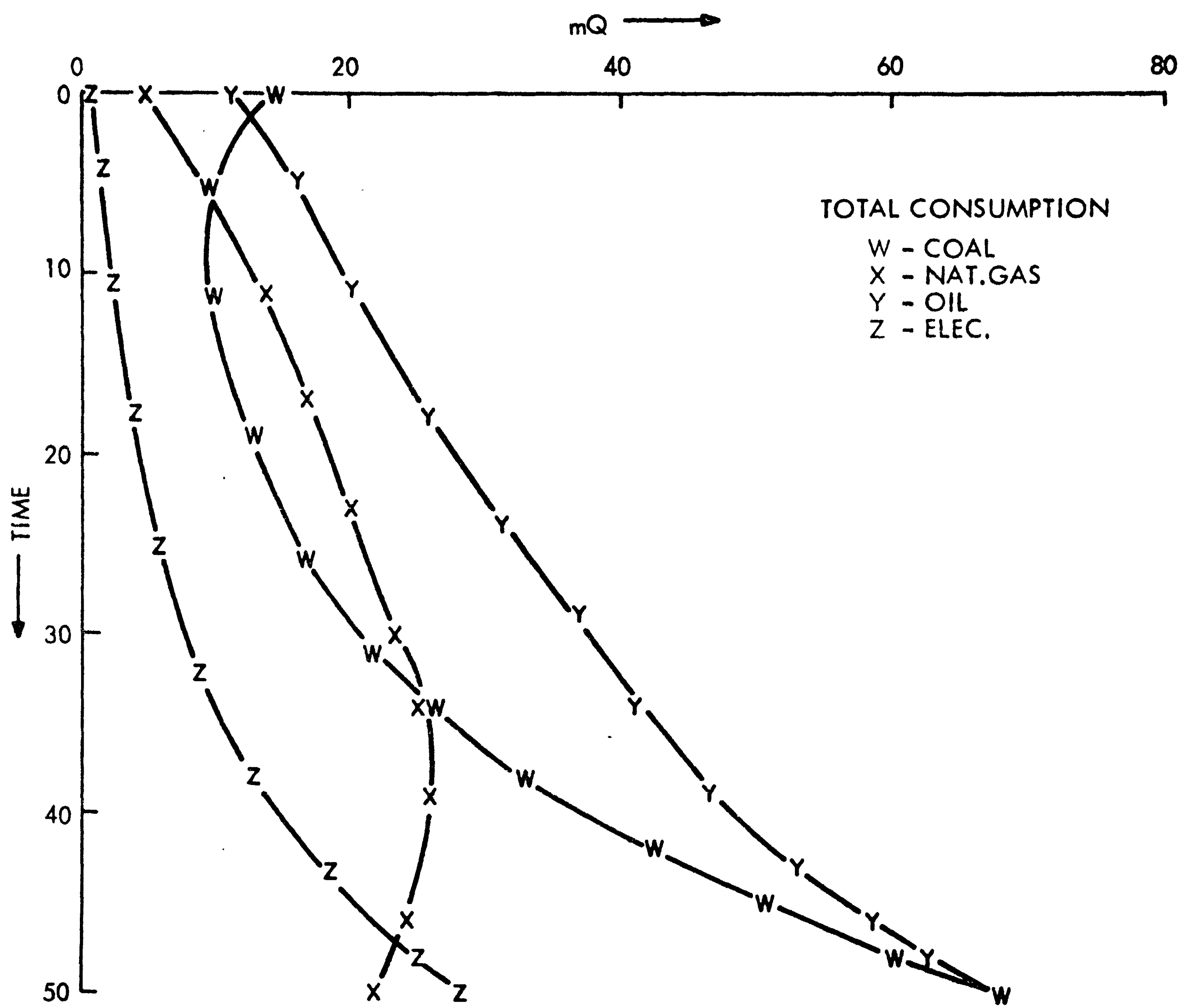
BASE CASE
Figure 5.4



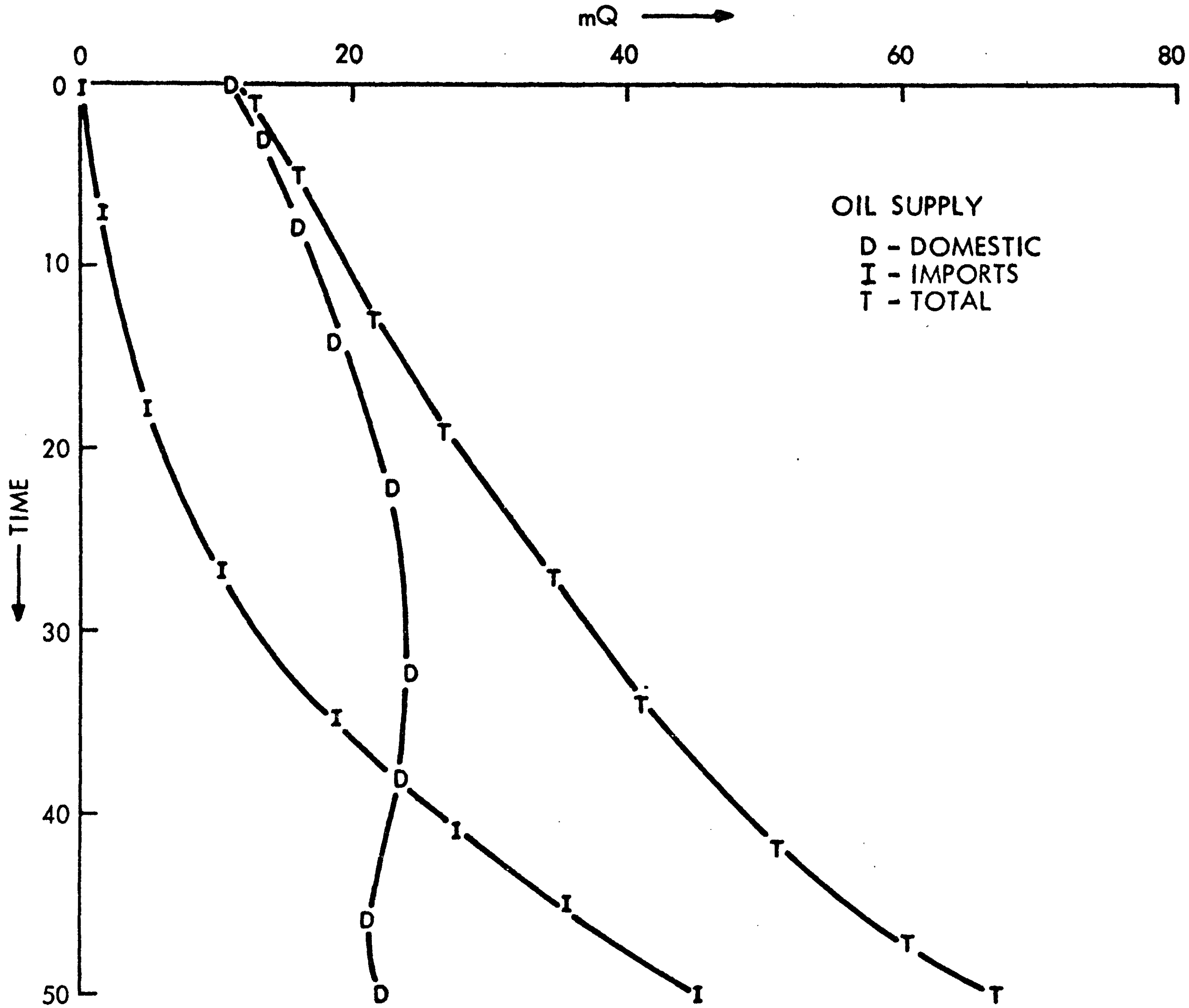
BASE CASE
Figure 5.5



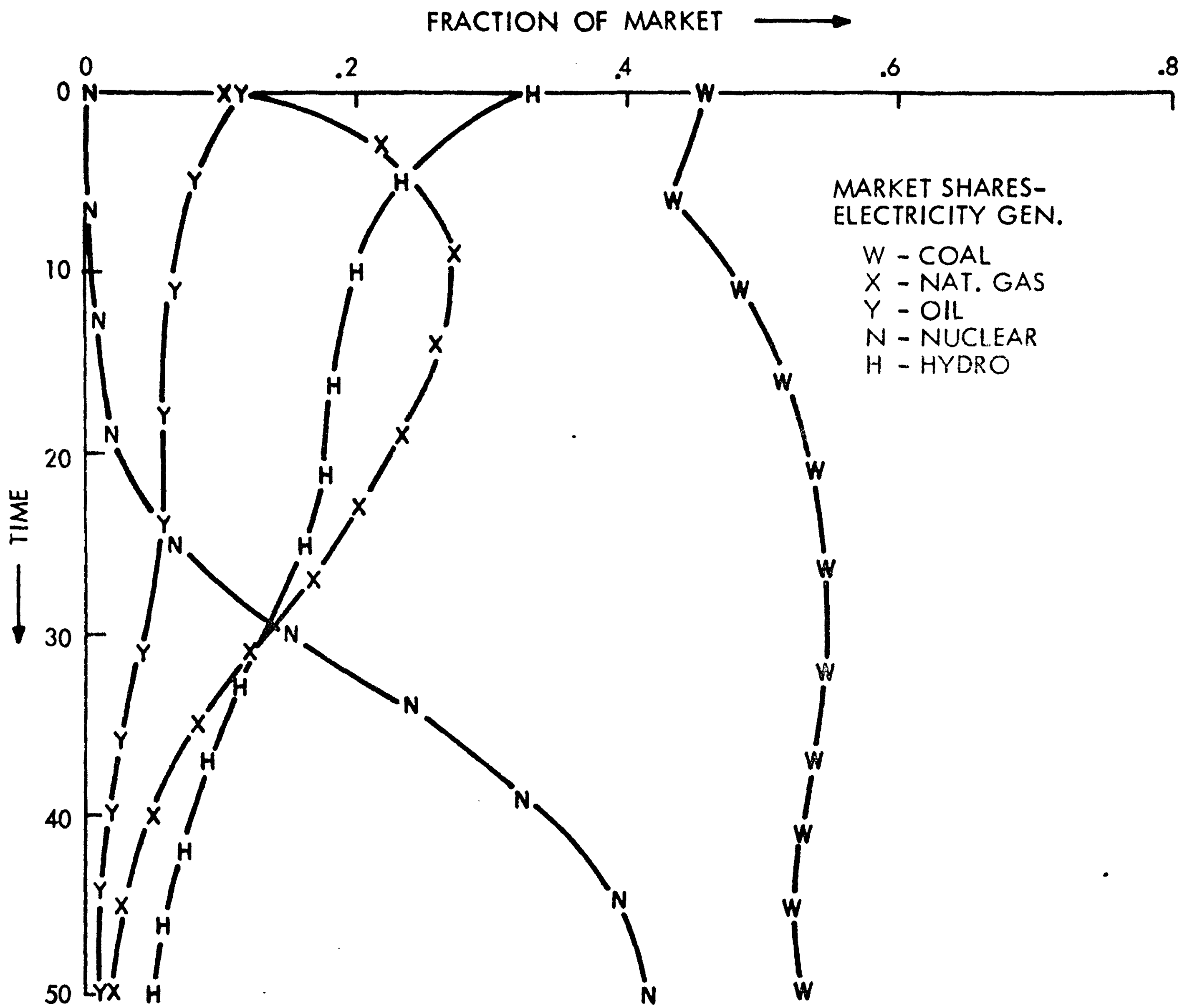
BASE CASE
Figure 5.6



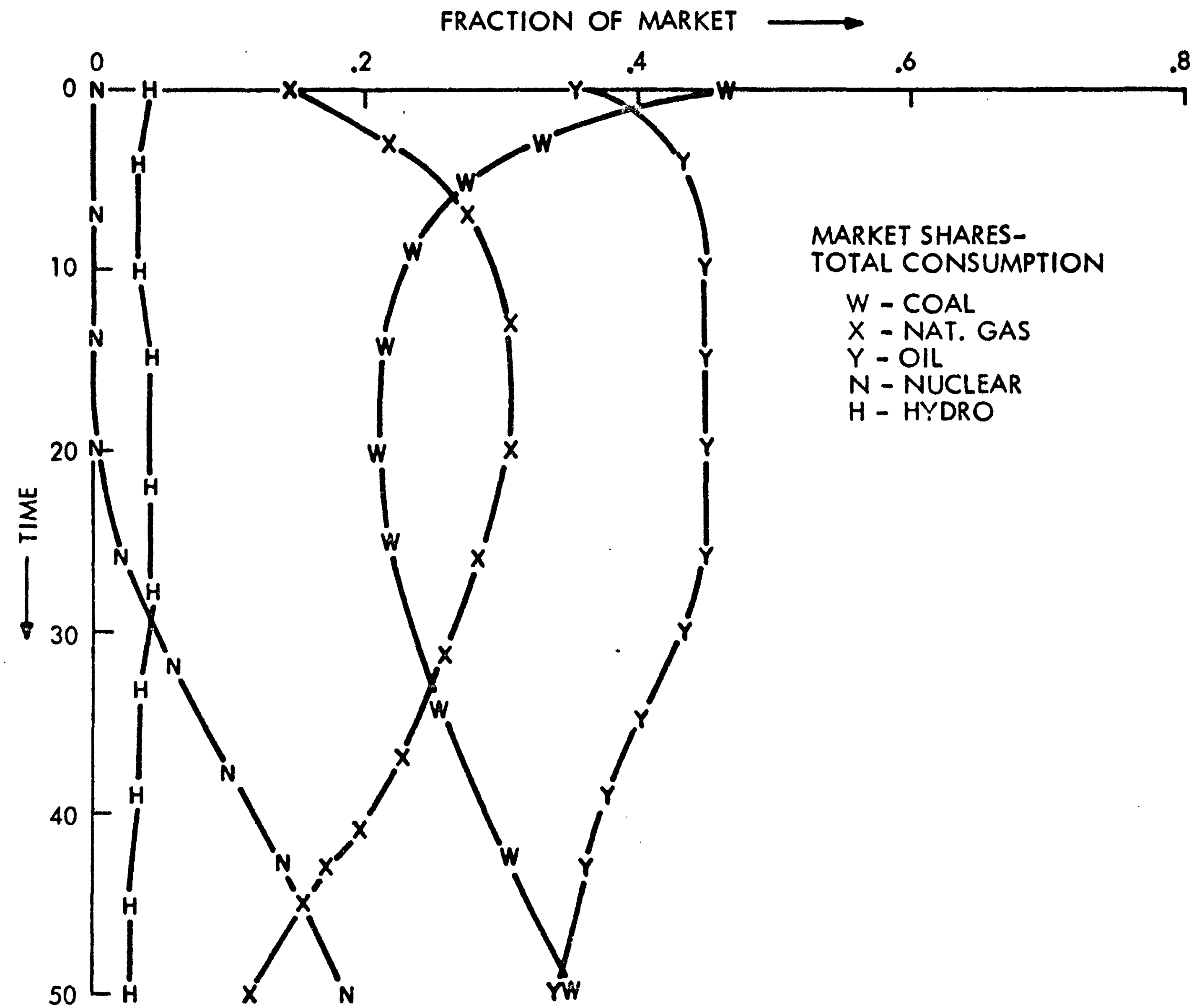
BASE CASE
Figure 5.7



BASE CASE
Figure 5.8



BASE CASE
Figure 5.9



BASE CASE
Figure 5.10

Table 5.2

Base Case - Numerical Results

Year / Variable[5]	1947 Model	1947 Actual[1]	1955 Model	1955 Actual[1]	1961 Model	1961 Actual[1]	1969 Model	1969 Actual[1]
RCD[2]	6.36	6.36	8.96	9.14	11.60	11.70	16.35	16.20
IHD[2]	12.97	12.97	15.80	15.10	18.40	16.20	22.46	22.80
TRD[2]	8.79	8.79	11.00	9.84	13.00	11.00	16.26	15.97
RCDW	2.59	2.58	1.23	1.44	0.76	0.78	0.48	0.38
RCDX	1.13	1.12	3.30	2.85	4.67	4.47	6.61	6.90
RCDY	2.25	2.25	3.47	4.00	4.66	5.03	6.80	6.23
RCDZ	0.39	0.39	0.96	0.85	1.50	1.39	2.45	2.68
IHDW	7.01	7.01	5.15	5.79	4.41	4.69	5.37	5.50
IHDX	3.01	3.01	6.10	4.94	5.59	6.47	9.07	9.89
IHDY	2.49	2.49	3.55	3.33	4.40	3.68	5.77	5.10
IHDZ	0.46	0.46	1.03	1.01	1.50	1.31	2.25	2.22
TRDW	3.00	3.00	0.21	0.46	0.03	0.02	0.01	0.009
TRDX	----	----	0.26	0.25	0.34	0.39	0.44	0.65
TRDY	5.76	5.76	10.50	9.11	12.60	10.58	15.79	15.29
TRDZ	0.03	0.029	0.016	0.019	0.015	0.019	0.018	0.020
ZD	0.88	0.88	2.01	1.88	3.02	2.71	4.72	4.92
WTOZ	1.76	1.99	2.99	3.40	4.86	4.31	8.19	7.40
XTOZ	0.39	0.39	1.74	1.19	2.48	1.89	3.18	3.60
YTOZ	0.44	0.47	0.46	0.51	0.57	0.58	0.81	1.60
NTOZ	----	----	0.015	----	0.045	0.017	0.41	0.14
HTOZ[2]	1.27	1.46	1.38	1.50	1.81	1.63	2.63	2.63
YIMP[2]	----	0.26	2.00	2.01	3.54	3.86	6.58	
XRES[3]	160.0	160.0	238.5	210.0	266.9	262.0	273.1	287.3
YRES[3]	127.0	127.0	175.0	178.0	191.6	190.0	185.0	184.0
WP[4]	1.00	1.00	0.77	0.94	0.78	0.89	0.87	0.86
XP[4]	1.09	1.00	1.13	1.51	1.24	2.04	1.53	2.00
YP[4]	1.00	1.00	1.15	1.25	1.13	1.21	1.19	1.15
ZP[4]	0.97	1.00	0.70	0.74	0.59	0.64	0.55	0.49

All units (except prices) in Quadrillions of BTU's (milliQ's)

[1]Actual values as reported in the Minerals Yearbook, various issues.

[2]Inputs.

[3]Actual values from Reserves of Crude Oil....

[4]Actual prices are price indices relative to the wholesale price index, derived from Bureau of Mines data.

[5]Variable definitions given on next page.

W - Coal X - Natural Gas Y - Oil Z - Electricity

Table 5.2 (continued)

Variable Definition

RCD	-	Residential and Commercial sector consumption
IHD	-	Industrial Heating sector consumption
TRD	-	Transportation sector
RCDW	-	Residential and Commercial consumption coal
RCDX	-	Residential and Commercial consumption natural gas
RCDY	-	Residential and Commercial consumption oil
RCDZ	-	Residential and Commercial consumption electricity
IHDW	-	Industrial Heating consumption coal
IHDX	-	Industrial Heating consumption natural gas
THDY	-	Industrial Heating consumption oil
IHDZ	-	Industrial Heating consumption electricity
TRDW	-	Transportation consumption coal
TRDX	-	Transportation consumption natural gas
TRDY	-	Transportation consumption oil
TRDZ	-	Transportation consumption electricity
ZD	-	Total Electricity production
WTOZ	-	Electricity consumption coal
XTOZ	-	Electricity consumption natural gas
YTOZ	-	Electricity consumption oil
NTOZ	-	Electricity consumption nuclear
HTOZ	-	Electricity consumption hydro
YIMP	-	Oil Imports
XRES	-	Natural gas reserves
YRES	-	Oil reserves
WP	-	coal price index
XP	-	natural gas price index
YP	-	oil price index
ZP	-	electricity price index

What do these results mean? Numerically the model values and the actual values are at first appearance excellent --- so good in fact they are misleading. Why is this? One explanation for this is the number of free parameters and the way the values of many of these parameters were arrived at. Recall in section 4.3 it was stated that the many parameters in the demand models were arrived at by 1) apriori picking reasonable values, and 2) comparing the model outputs with the actual data and adjusting the parameters to increase the quality of the fit. The surprising fact is that relatively few simulations and adjustments were required once the model took its final form. This relatively small number was somewhere in the neighborhood of 10 simulations. This either indicates that a particularly judicious first choice was made, or that the structure of the model in some way compensates for errors in the individual parameter values. In this case it was probably a little bit of both. First, the initial values of the price elasticities of demand were values representative of those reported in the literature for the various relationships on which data could be found. Secondly, because the model is constrained at both the demand and supply ends (by putting in sector demands and resource inventories), the model really only distributes the fuels to the demand sectors in which the total consumption is constrained as a result of the assumption of inelastic total sector demand. On the other hand, the demand for electricity and the consumption of fuels in electricity generation are all modeled completely endogenously with no inputs and this sector also works well compared to past data, so the structural constraints cannot account for everything.

5.2.3 Discussion of Base Case Results

Before going on to discuss further validation procedures, let's digress for a moment and analyze more closely these base case results. This foundation will be useful for further understanding the case studies to be presented in the next chapter.

First of all, what possible strengths and weaknesses of the model are indicated by the results of figures 5.1 - 5.8 and table 5.2? The model compares very well to actual data except in a few isolated incidences. One area where larger deviations in trends occur is in the fuel market shares in electricity generation in the later sixties, the other concerns the price trend of natural gas compared to the actual Bureau of Mines reported data on the average well head price.

In the electricity utilization of fuels, for the 1969 data in table 5.2 it can be seen in particular that the oil used (YTOZ) is low and nuclear generation (NTOZ) is high. Part of the reason for the low value in oil is that the model value of total electricity consumption is slightly low. When reflected back to the generating fuels, this deviation gets multiplied by a factor of three (the ratio of the heat rate and 3412 BTU's per kwh). Therefore, the high nuclear does not completely compensate for the low oil consumption and the errors are magnified by the factor of three. However, there are indications that other things could also be contributing to the poor model behavior.

In other words, what happened in reality but was not reflected in the model that could cause these deviations. First let's take oil. What electric utilities increased their oil consumption in the mid to later sixties? From the cross-sectional data in Appendix B (Table B.12), the consumption of fossil fuels in electricity generation for the years 1960, 1965, and 1969 is given. From there it can be seen that the increased oil consumption took place in regions I, IA, and IB --- in general the east coast. It was in this region of the country in this time period that the import quotas on residual oil were relaxed, which made available to this region low cost residual. It was at this time that many eastern utilities converted from coal to oil fired generation because of the cost advantages. This does not get reflected in the model behavior for two reasons.

First, this imported residual was at a lower price than domestic prices. The model uses the domestic price index calculated endogenously for the fuel selection process in the dynamic demand models. This price index is used for distribution of both domestically produced and imported oil to the consuming sectors. In reality it was not this price index that applied, but something lower. Consequently, in the model less oil was used than actually occurred in reality. This indicates that to better characterize imports, a price should be attached to the quantity imported and averaged into the average price index. In the model only the quantities imported are entered and the endogenously calculated price used.

Secondly, in order to handle this regional phenomenon, a geographical disaggregation of the supply-demand model structure would be necessary. The model in its present stage of development is a nationally aggregated model, and regional phenomenon such as this are averaged away. Further development of this model into a regionally disaggregated model is discussed in chapter 7 as an area for further research.

Another discrepancy in electric generation occurs in the nuclear market share. It is consistently high for the period for which past data is available. One reason for this might be that the cost trends of fossil vs. nuclear plants were not those as given in Appendix D. The perceived nuclear costs as modeled may be a little low. There is also the factor that some utilities were reluctant to move into nuclear generation initially until it had proven itself. This phenomenon is not included in the model, for only the economic decision processes are considered. Finally there is also the influence of lead times in plant siting, construction, and licensing. In the model this lead time is assumed to be the same as for fossil-fired plants, set at seven years. In reality there was a lot of nuclear capacity being constructed in this time period, however it usually took longer than seven years to get it on line. The fact that the assumed lead time in the model is less than what occurred in reality is probably aggravating the discrepancy between the model and actual values.

Yet as the model progresses in time (see figure 5.9) the nuclear market share becomes less than what is expected to occur in reality. At the end of the simulation run at time equal 50 (year 1997), the model gives the nuclear market share at 40%, vs. the AEC projected values of 50% or more. Here again influences not explicitly included in the model may be having their effect. In the model coal maintains a high market share throughout the simulation, declining only in the last ten years when nuclear has the high growth rate. The fossil vs. nuclear committment decision in the model is very sensitive to fossil fuel costs, and coal prices are simulated as being quite low throughout the length of the run. The model continues to use coal generation until late in the run. However, in reality the environmental standards in many regions of the U.S. are forcing utilities to use higher cost lower polluting forms of fuel in plants whose capital costs have increased to meet the environmental standards. Since these standards, or the effects thereof, are not included in the model framework or parameter values base case, the model compares nuclear to low cost coal generation and chooses coal. In reality the comparison is between nuclear and higher cost low sulfur fuels for much of the industrialized east coast. Here nuclear is much more attractive. So again we find regional or sub-regional considerations in which the model fails to compare well with actual data (in this case expected actual data).

Finally there is the trend in natural gas prices from 1947 to 1969 which varies quantitatively from the actual Bureau of Mines reported data. There are several reasons for this.

First of all, the comparisons given in table 5.2 are the marginal development costs of the model vs. the Bureau of Mines reported average wellhead price. The marginal development costs are probably more closely akin to the spot prices in natural gas, not the historical average of contracted sales which make up the average wellhead price.

Secondly the Bureau of Mines price data is that for only interstate sales. The price regulation on interstate sales has resulted in disequilibria in the gas markets, at least in the later sixties, and this makes the Bureau of Mines price series of questionable value.

Consequently the prices being compared in table 5.2 are two different beasts and one would expect them to be different.

Finally, it also appears that the marginal development costs did not rise in the model as they must have in reality, for they don't even rise as fast as the average wellhead price. The reason for this lies in the trends in cost per unit capacity. In the model they were assumed constant. In reality, from the data in Appendix C (table 2), it can be seen that they were rising sharply. These trends are easily entered into the model and simulated, and in the case studies discussed in chapter 6 this is done.

In general though the behavior of the model in this base case simulation --- considering all the simplifications in the model development --- is considered quite acceptable. The analysis of the results reflect in part the limitations of the model in its present aggregated structural form. In part the discrepancies are a result of influences in reality which were not considered explicitly in this base case run, such as environmental factors and regulatory policy. However, these things were intentionally neglected in this stage of the model development. How these disturbances affect the behavior of the model is how it is to be put to use.

5.2.4 Further Validation Discussions

Besides the structural sensitivity studies and the comparison of the base case to past data, other factors can be applied to further increase one's confidence in the model.

There is a lot of feedback structure in the model, is it all necessary? This question could be answered by individually and sequentially disconnecting feedback loops and analyzing the model behavior. This was done in part in model construction stages, when the absence of significant structure was indicated by poor model behavior.

The results in figures 5.1 to 5.10 also indicate the major feedback loops between supply and demand are working. Supplies continue to meet demand, the price trends are reasonable given the input variables, and the demand sectors are reacting to price. Without the changing prices, the demand model is essentially a set of first order differential equations whose behavior would be exponential decay or exponential growth --- but not both. There are several instances where trends in consumption of a particular fuel are reversed due to the price dependence of the demand models. For example, trends in coal and natural gas consumption in the industrial heating sector, natural gas consumption in electricity supply, and natural gas consumption in the residential and commercial sector is reversed. These are due to the elasticities and cross-elasticities of demand to price, and though one may not agree with the precise value of the numbers the trends are certainly reasonable given the assumptions of the run. Some idea of the relative effects of price, in particular the price of natural gas, is given by the difference in the times natural gas consumption peaks in the primary consuming sectors in this simulated run of rising prices. The author does not contend that this is the projected trend in natural gas supply, but if it were, this is the behavior the model would display.[1]

Finally, partial validation can be achieved by exercising the model in a number of ways. That is, one actually uses the model to analyze and interpret real or hypothesized conditions in the real system. Based on the plausibility of the results and the usefulness of the model in these studies, additional confidence in the model formulation and behavior can be obtained. This is done in the next chapter. Various changes in parameters and structure in the model are made (corresponding to a possible or likely event in reality) to assess the impact of these perturbations on the real system.

5.3 Summary of Validation Program

In general, what have all these validation discussions proved? The comparison of the base case with actual data indicates that the model certainly is a viable formulation. The structural sensitivity studies indicate substantive changes in the model structure produce less acceptable behavior. The fact that the electricity sector is behaving acceptably indicates that the behavior of the model is not constrained by the inputs, or conversely that there is some substance to the internal structure. The final test is whether the model is useful in analyzing events in reality and can stand the test of time.

In summary, a reasonable formulation of the dynamic structure and a consistent set of parameters have been found. The application of the

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[1] In reality the future of natural gas may be even bleaker.

model in its present form to a set of case studies is given in the next chapter. There it is seen that the model is a useful analytical tool. The model can be expanded and refined in a number of areas, and these are discussed in the final chapter.

CHAPTER 6

CASE STUDIES

Now that the structure and behavior of the model have been discussed and the validation issue has been addressed, it is time to exercise the model and assess its usefulness. This is done in this chapter by analyzing the effects of a sampling of new technologies, policy issues, and postulated occurrences upon the system behavior. This will serve to provide more insight into the sensitive parameters in the long term behavior of the model and also acquaint the reader as to how the model can be used.

6.1 Case Study No. 1 Results

The reader will recall that in the base case simulation discussed in chapter 5 the values of the parameters and inputs were valid for only the first 22 years of the simulation (1947-1969). In that run the cost/price trends in natural gas and oil were upwards, for natural gas much more so than oil. In reality other sources are expected to mitigate these upward trends. Coal gasification and gas imports are expected to augment the supply of natural gas, and the National Petroleum Council has projected more oil imports will be utilized than have been included in the base case.

The Bureau of Natural Gas (of the Federal Power Commission) has made an assessment of the natural gas supply trends, entitled <u>National</u>

Gas Supply and Demand 1971-1990.[1] They present data on the expected future rate of additions to reserves in natural gas, the level of gas imports expected, and the amount of gas that will be available from coal gasification. In U.S. Energy Outlook, An Initial Appraisal 1971-1985[2], the National Petroleum Council (NPC) has projected the oil imports needed in order to retain current prices in oil supply, assuming past trends in exploration, costs, and rates of reserve additions continue. The next simulation incorporates these projections into the base case study, using the historical growth rates in the component consuming sector consumption trends. As the average cost per unit capacity in natural gas supply has had an upward trend[3], also incorporated into this run is an escalation of 2% per year (probably low) in the natural gas average cost per unit capacity. A summary of the characteristics of this first case study are given in table 6.1 and the simulation results are given in figures 6.1 to 6.12. Remember time zero is 1947 and all energy units are in mQ's.

In figure 6.1 are given the levels of consumption for each of the consuming sectors, essentially the same as for the base case. In figure 6.2 are given the price trends for the set of conditions incorporated into the model behavior. The reader should compare these results to the base case of chapter 5. The NPC is essentially correct

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[1]See list of references.

[2]See list of references.

[3]See Appendix C.

that if past trends in oil continue and the imports they project are available, oil prices remain approximately at the current levels. Note also that the coal gasification and gas imports have stabilized the natural gas price index at about 2.5, or 25% higher than its current level. Of course this behavior is all contingent upon the cost trends, reserve additions, import levels and growth rates in consumption being as hypothesized for this simulation.

The level of total energy consumption as given by the model under these conditions corresponds very closely to that projected in the NPC report for 1985. The NPC numbers were derived using slightly different projected growth rates in the three primary consuming sectors than those used for this simulation so the configuration of consumption is slightly different, but the totals are very nearly the same. In Table 6.2 are summarized the various levels of production of the different forms of energy as given by the model and the reported NPC values.

From Table 6.2, it can be seen that the levels of production of energy from the various sources corresponds quite closely to the NPC values except for electricity. This gets reflected back to nuclear so that nuclear is also low. In the NPC report electricity is projected to grow at an average rate 6.7% per year between now and the year 1985. In the model it only grows at about 4.4%. What is the reason for this?

It is likely that the NPC projected electricity production is inconsistent with the conditions of the scenario that provide for a very optimistic outlook for oil and natural gas. Historically the growth rate of electricity has been at the 6.7% per year level or even higher. Over the period 1947-1969, the price index of oil rose from 1.0 to 1.25 and that for natural gas rose from 1.0 to over 2.0, while at the same time the price index of electricity decreased from 1.0 to about 0.50. In other words the price index of oil compared to electricity more than doubled and the price index of natural gas relative to electricity quadrupled. If over the next 15 years these relative values were to remain constant one would expect the historically growth trends to be significantly altered. In the model they are. The abundant supply of low cost oil and natural gas in the model gets used directly in the primary consuming sectors residential and commercial and industrial heating and the growth in consumption of electricity consumption declines from historical values. Compare figures 6.3 to 6.5 to those in the base case figure 5.3 to 5.5, where the prices of oil and gas increase significantly. The energy consumption patterns have been significantly altered for the different price trends.

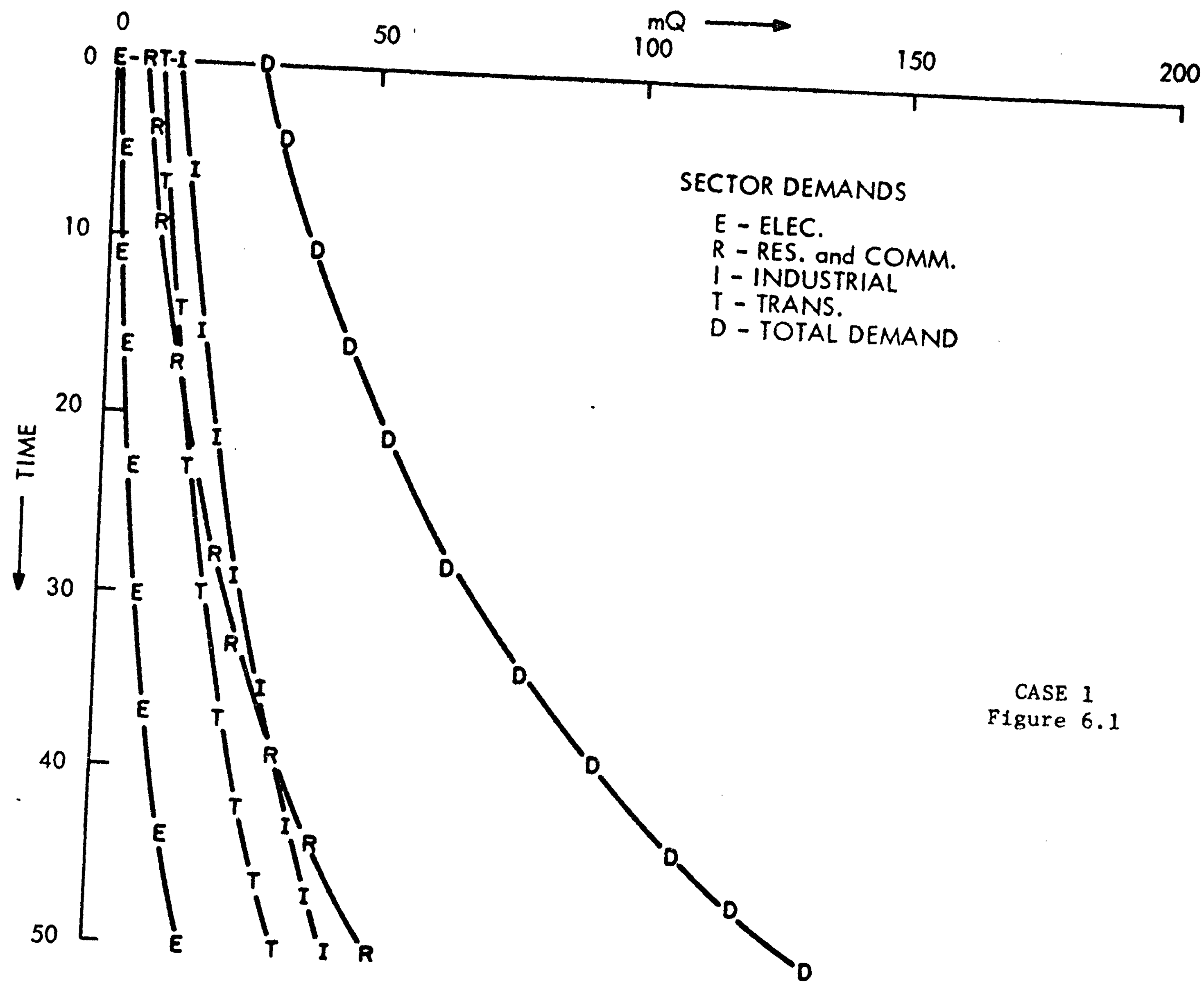
Still other things besides the low electricity growth rate are manifesting themselves in the model behavior. In figures 6.8 and 6.9 are summarized the sources of supply of natural gas and oil, and in 6.10 the market shares in electricity generation. There it is seen that coal maintains a high market share throughout the length of the run, with nuclear growing to only a little less than 40% of the market by time equal fifty (year 1997). By most standards this is low. In reality other factors are expected to influence the behavior of the system and they have not yet been included in the model. So for the second case study let's devise and incorporate a different scenario into the model to investigate the impact on the system behavior.

Table 6.1

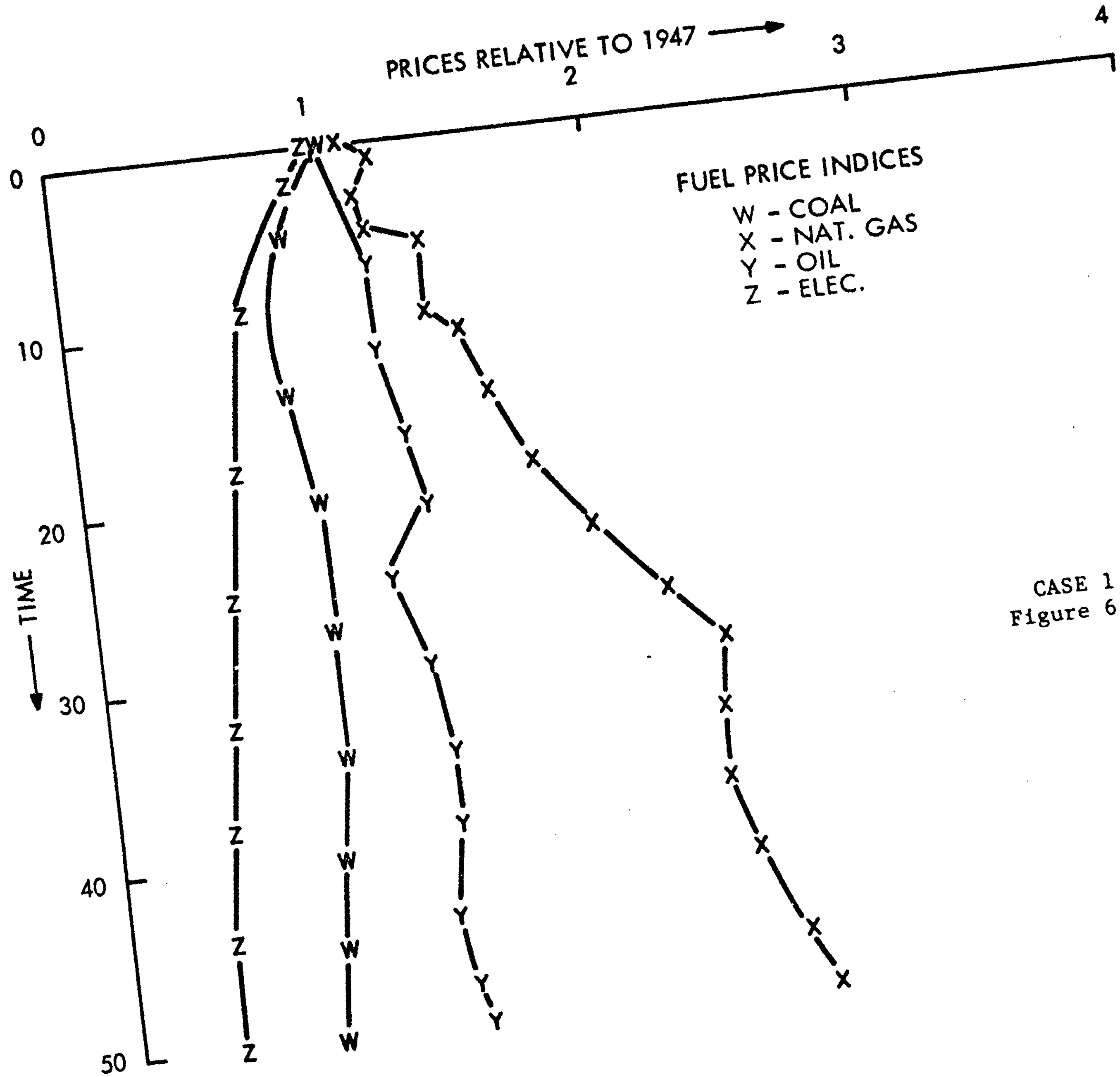
Case Study No. 1

Characteristics

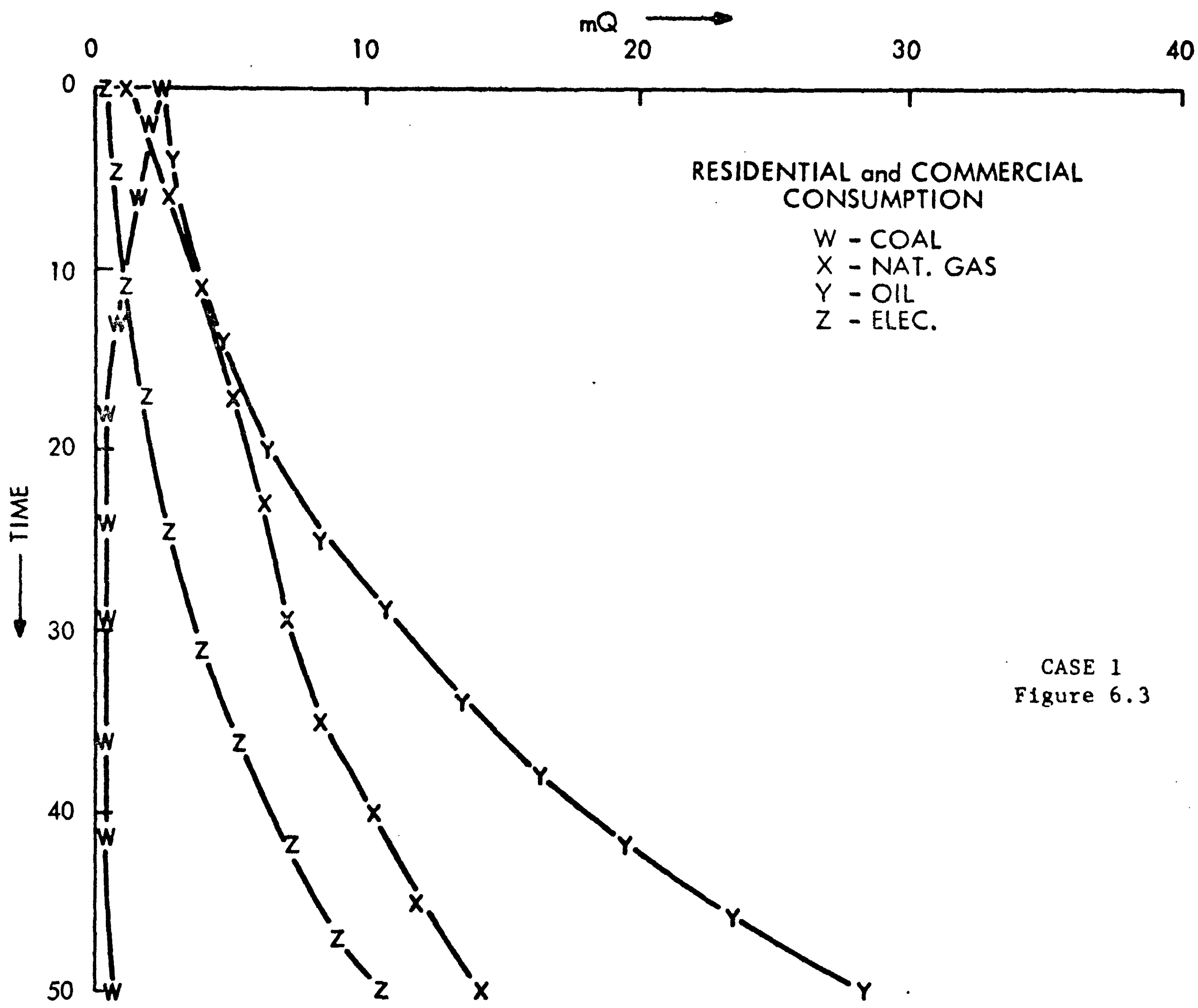
1. Gas imports at levels given by Bureau of Natural Gas (BNG) of the FPC.
2. Gas reserve additions at levels given by BNG.
3. Coal Gasification at levels given by BNG
4. Oil imports at NPC levels
5. Cost per unit capacity in natural gas escalating at 2% per year starting at time zero (1947).
6. Everything else as in base case.



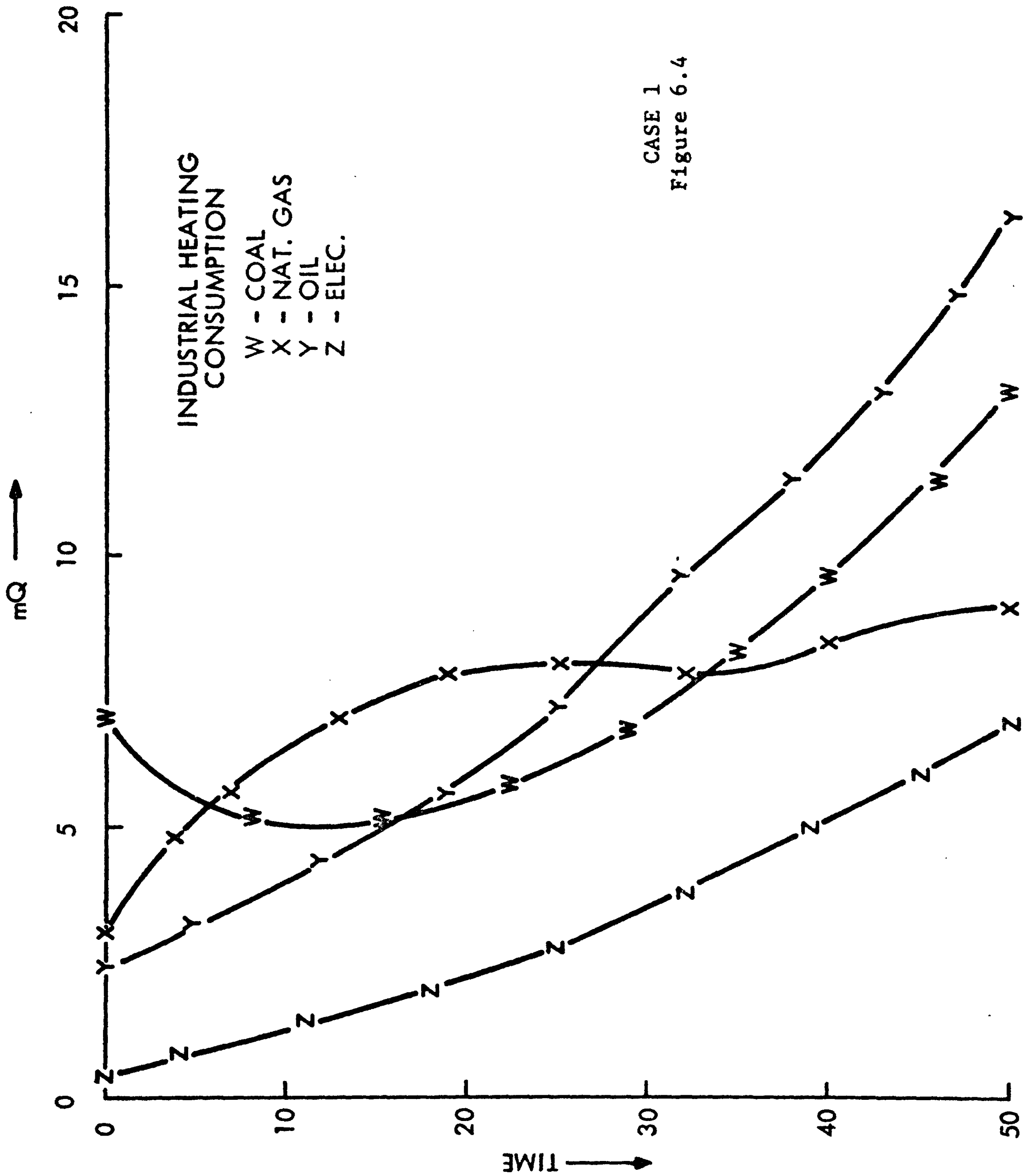
CASE 1
Figure 6.1



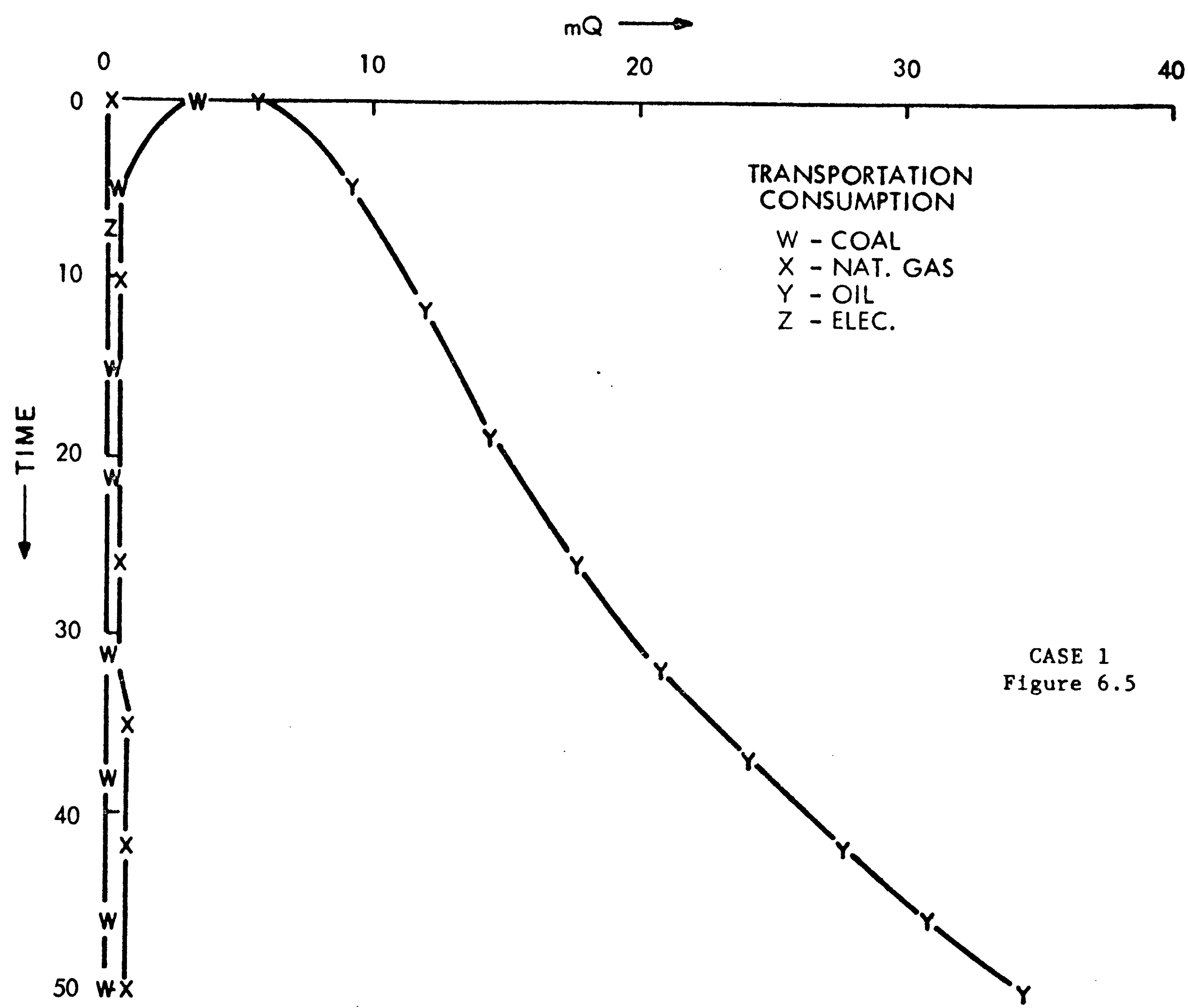
CASE 1
Figure 6.2



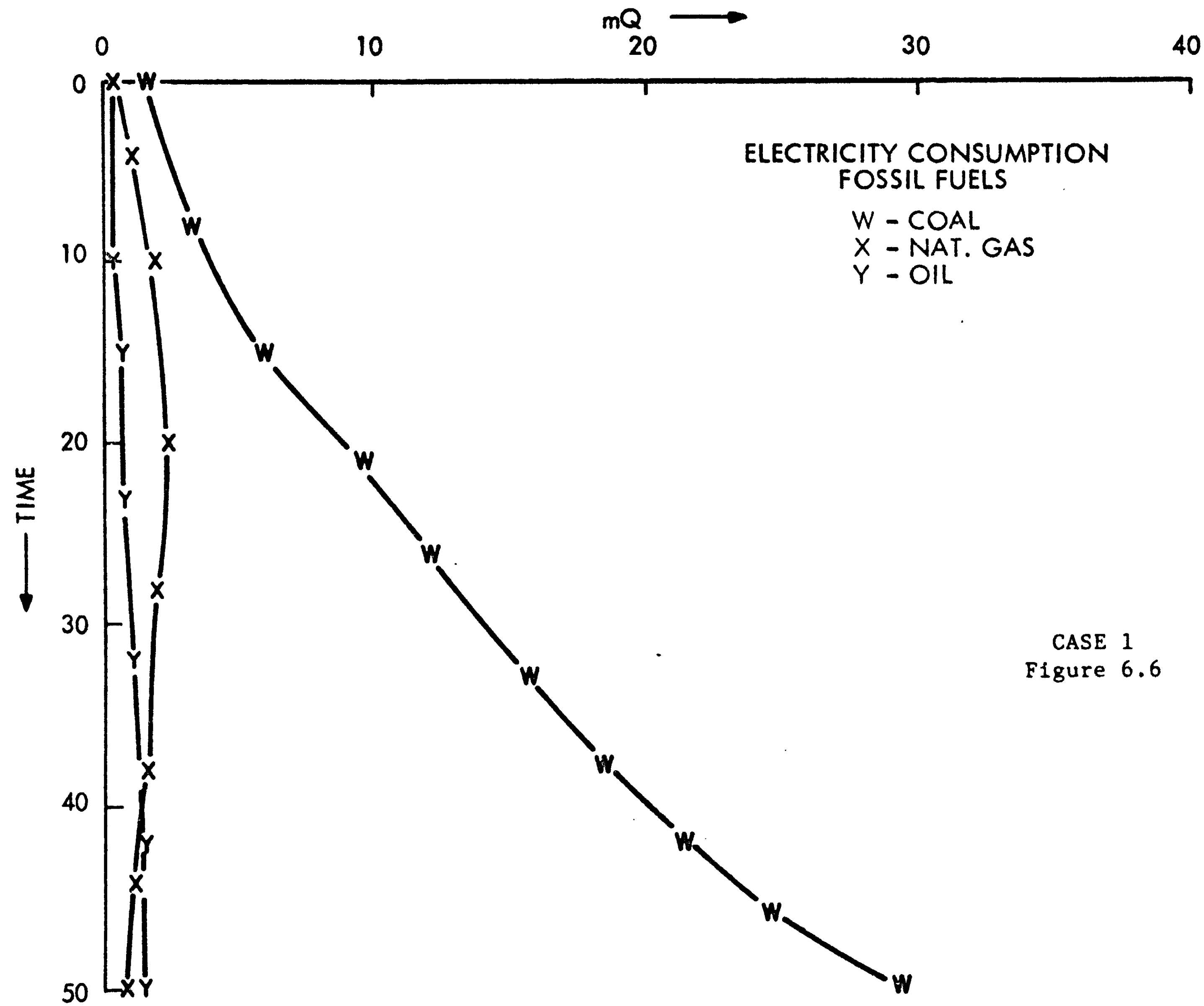
CASE 1
Figure 6.3



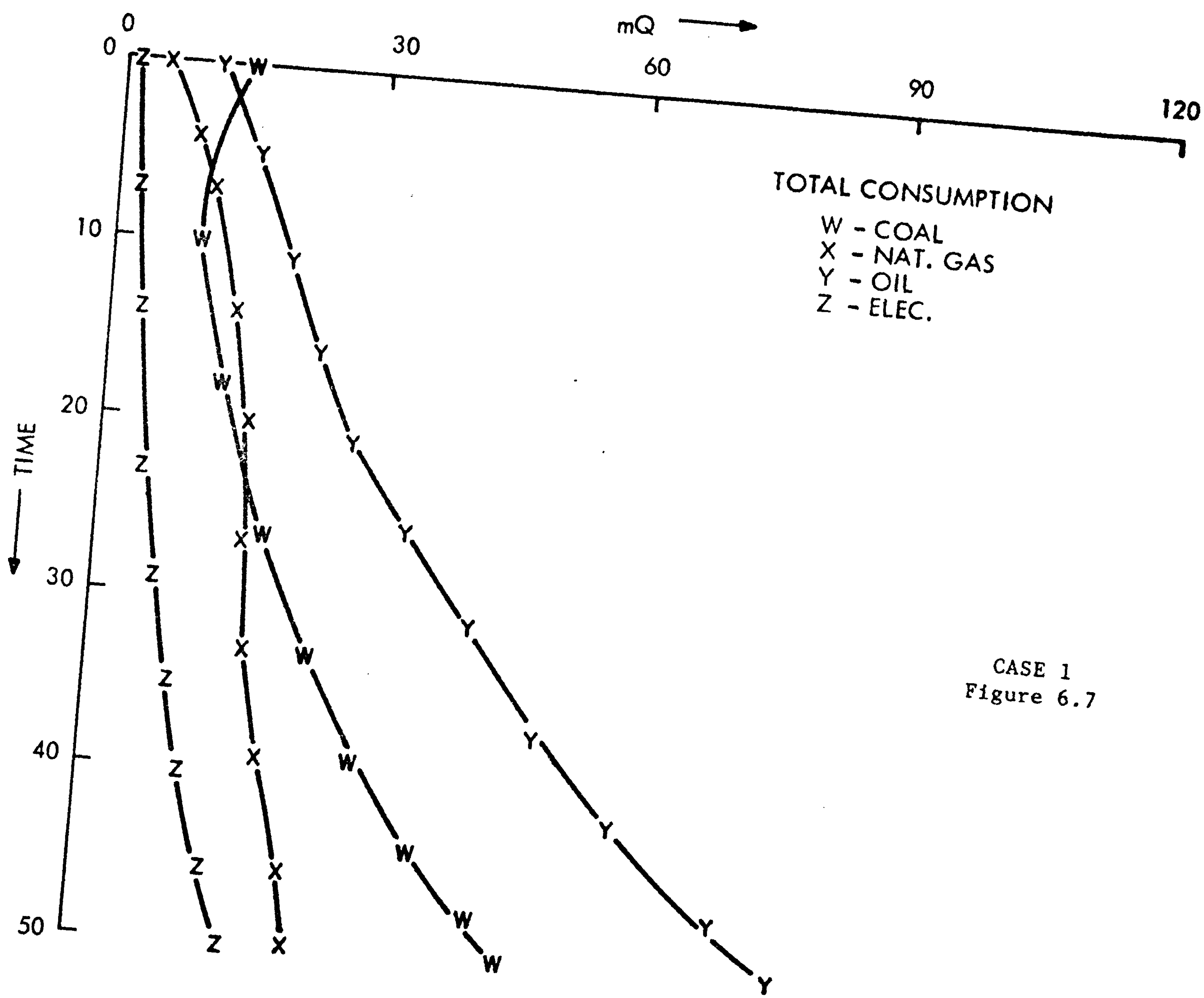
CASE 1
Figure 6.4



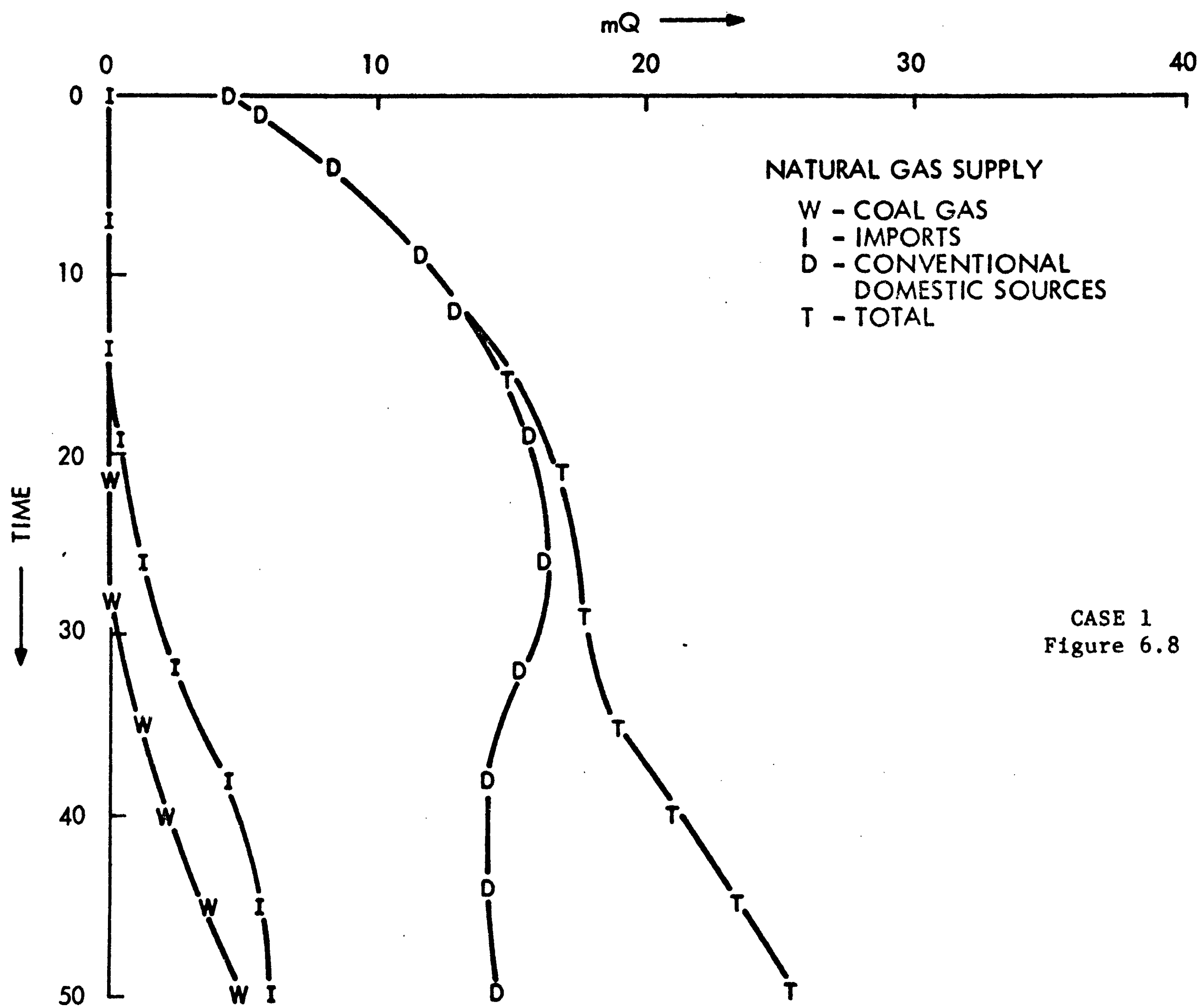
CASE 1
Figure 6.5



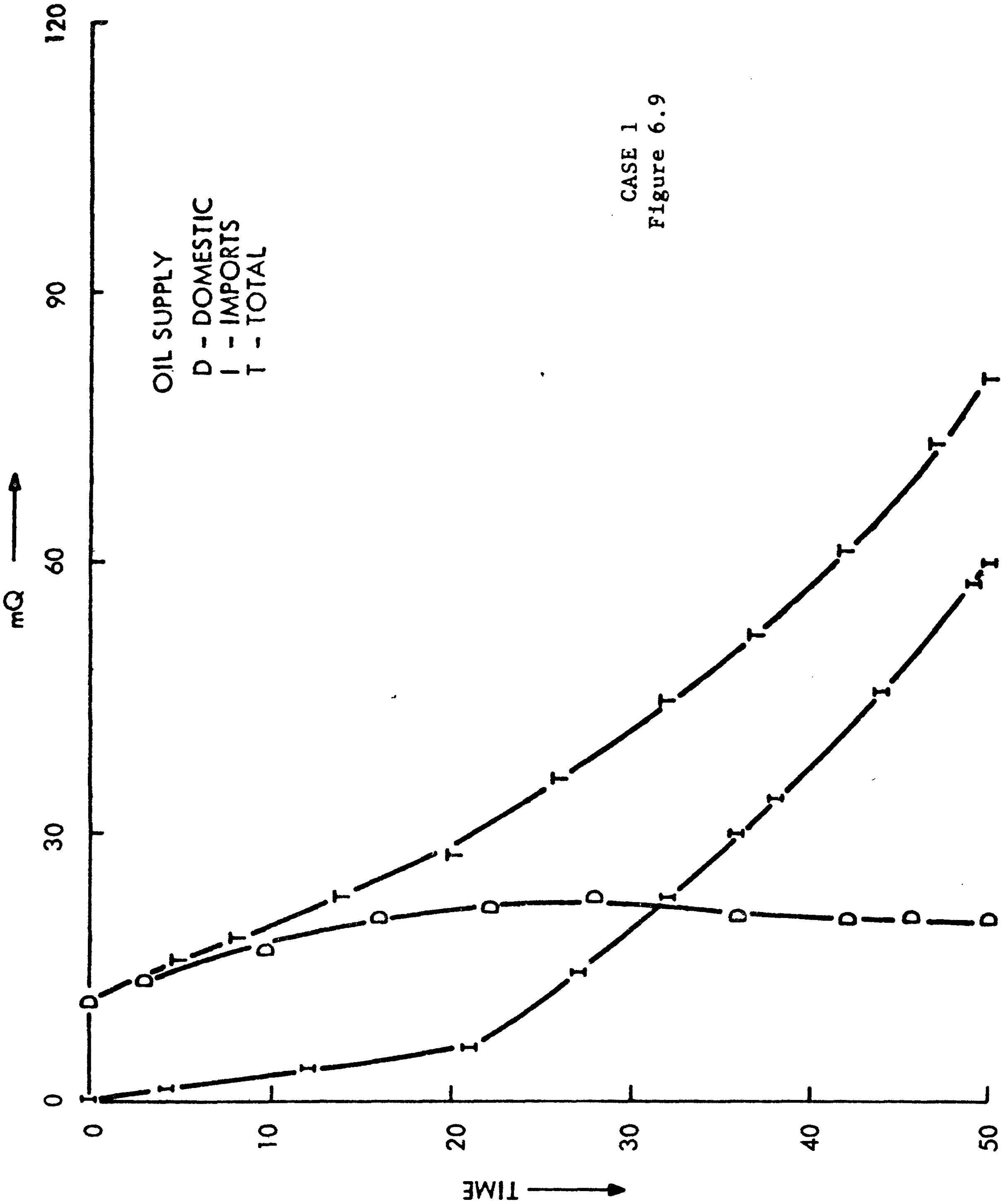
CASE 1
Figure 6.6



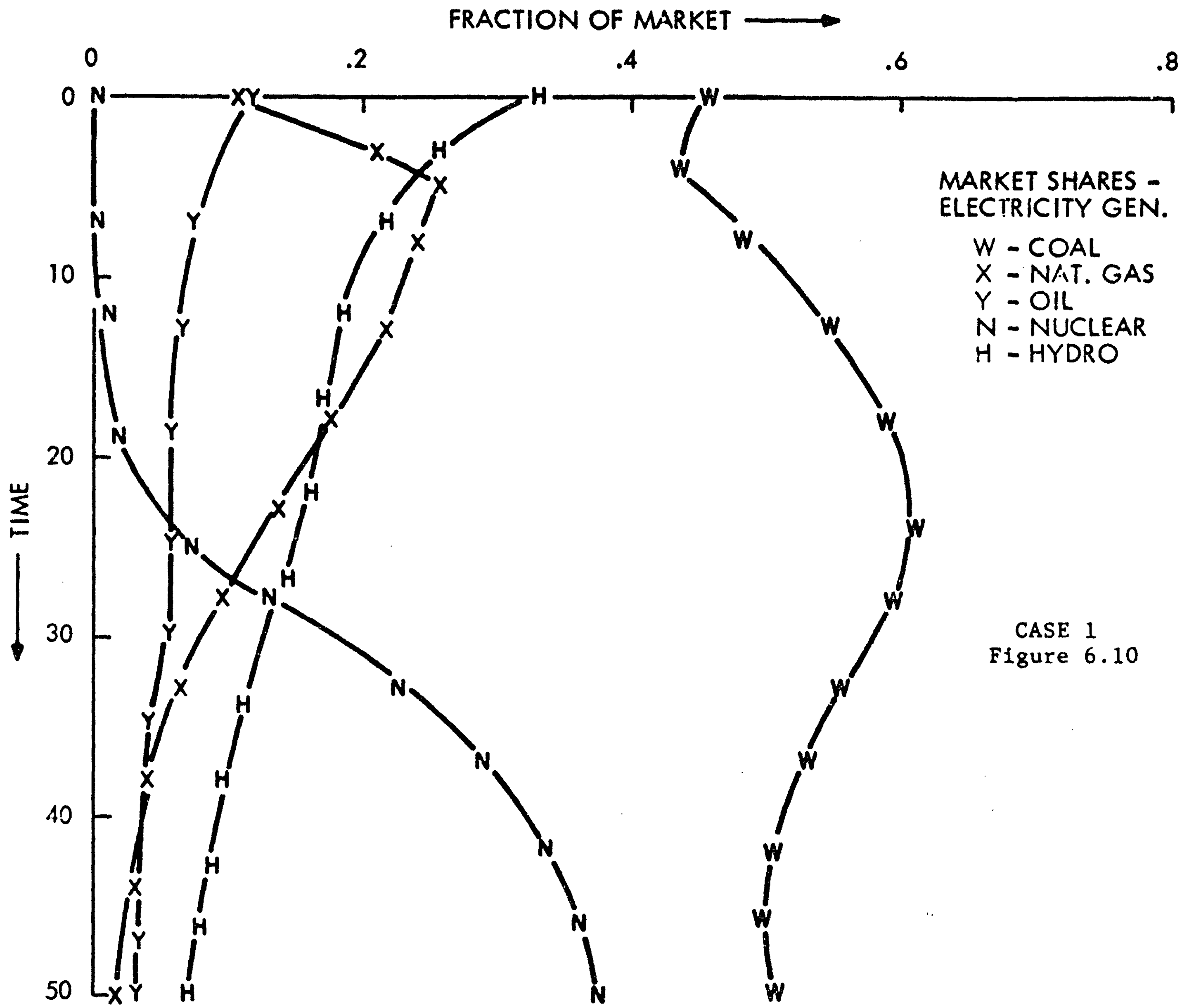
CASE 1
Figure 6.7



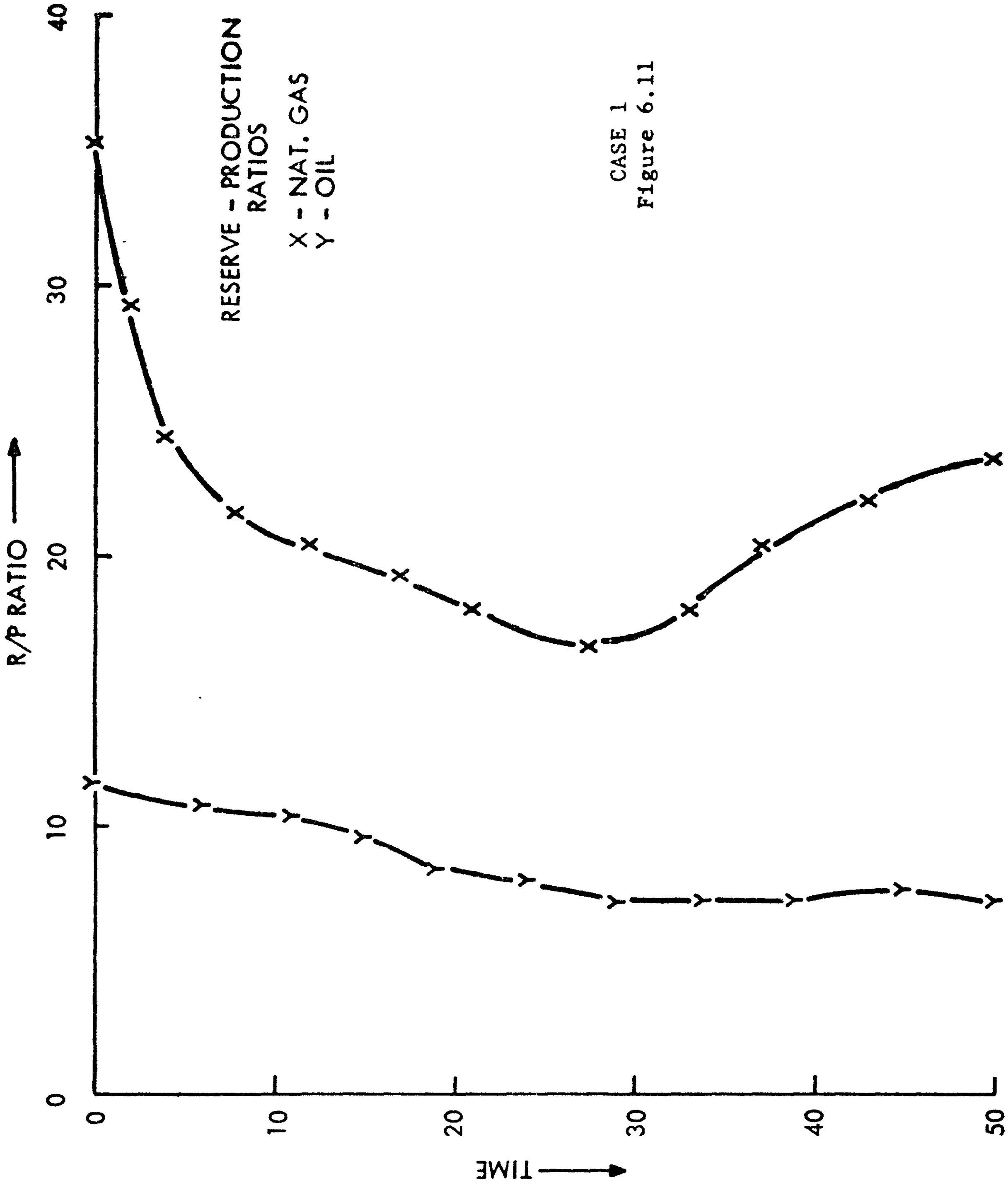
CASE 1
Figure 6.8



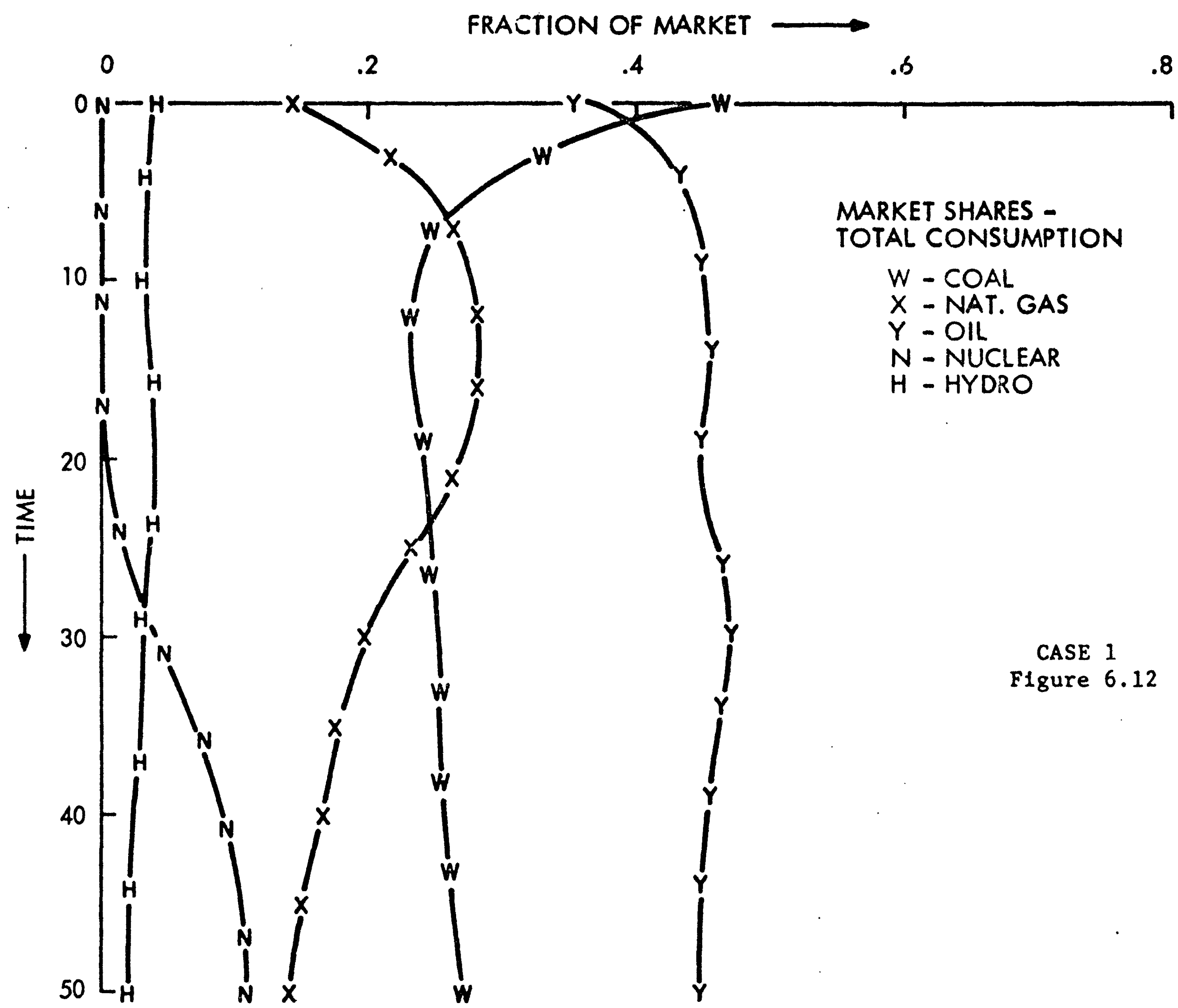
CASE 1
Figure 6.9



CASE 1
Figure 6.10



CASE 1
Figure 6.11



CASE 1
Figure 6.12

Table 6.2

Supply Summary Case Study No. 1

Variable	Model Value (in mQ's)	NPC Value
Total energy consumption	117.0	125.0
Domestic oil production	20.7	22.0
Oil imports (input to model)	33.1	31.0
Domestic natural gas production	13.4	14.5
Natural gas imports (input to model)	4.5	6.1
Gas from coal gasification (input)	1.6	0.9
Domestic coal consumption	30.1	28.0
Electricity production	11.0	16.4
Nuclear used in electricity production	10.0	19.0

1985 Values

6.2 Case Study No. 2

One thing that has been neglected in case study No. 1 is the concern for the environment and the emissions standards that must be met by the major energy using installations. These in reality have affected both the large industrial users and the electric utilities, but most significantly electricity supply. In case study No. 2, the effects of the environmental concern are incorporated into the electricity sector in two ways.

First it is assumed that limitations are placed on the coal burning capability of electric utilities. It is assumed that for the same price configuration of the fossil fuels, only half as many electrical suppliers are permitted to use coal as would use it in case 1, and the remaining half are distributed equally to oil and natural gas consumption. This could occur if coal burning technology was non-existent or so costly that coal could not meet the emissions standards in parts of the country. Secondly, it is assumed that the environmental concerns increase the average capital costs of fossil fired plants by 25% over those in case study No. 1. This might come about due to the need of sulfur dioxide removal, precipitators, etc. on the fossil fired plants which were not required to shift to cleaner fuels. If one thinks these impacts to be too severe, then think of them as a worst case.

Case study No. 1 also contains a very optimistic outlook for oil. It is conceivable that the rate of reserve additions in oil supply could be as high as their historical average, but much of this additional supply is expected to some from higher cost locations. Therefore it is likely that the average cost per unit capacity in oil supply will escalate as more and more future supply comes from these less accessible locations. So included in case study No. 2 is a cost escalation factor of 2% per year on the average costs per unit capacity starting in 1970.

Finally, in case study No. 1, a very strong dependence on foreign sources of oil is indicated in figure 6.9. In fact by time equal to thirty (1977), almost half the oil supply is derived from foreign sources. Some oilmen express pessimism that this much foreign dependence in oil supply will be allowed, and certainly it has grave implications for national security. So in case study No. 2 a much weaker dependence on foreign oil supplies is assumed, with projected imports increasing at only half the rate as that used in case study No. 1.

The conditions of this second case study are summarized in Table 6.3. The simulation results are given in figures 6.13 to 6.24. In figure 6.14 it can be seen that the price trends for oil and natural gas are significantly upward from those in case 1. This is for four reasons: 1) oil imports have been decreased; consequently more domestic consumption for the same rate of additions to reserves, 2) escalating costs per unit capacity were included in oil supply, 3) increased consumption of oil and natural gas is induced because of the environmental standards in electricity, and 4) increased consumption of natural gas (for the same supply format as used in case No. 1 is induced due to the higher oil prices. The supply and consumption configuration for this case is significantly changed from that of case No. 1.

The changes in the consumption patterns can easily be seen by comparing figures 6.15 to 6.17 to those for case No. 1, figures 6.3 to 6.6. In the residential and commercial market, the demand for oil is switched to electricity and natural gas, and when natural gas prices rise sufficiently, almost exclusively electricity. In the industrial markets coal and electricity take the place of the higher cost oil and natural gas. In the electricity consumption of fossil fuels, a significant increase in oil and gas consumption results due to the environmental standards imposed on this case.

A summary of the supply configuration for case No. 2 is given in table 6.4. Total energy consumption is slightly higher than for case No. 1 due to the increased share of electricity production. It can be seen the shortfall in oil imports is made up by the three alternative sources: natural gas, coal, and nuclear. The higher prices of oil and natural gas have increased the growth rate of electricity over that of case No. 1, in fact increased it to around the 6.7 to 7.0% that many sources project.

From figure 6.2? it can be seen that the environmental impacts in electricity have changed the fuel consumption configuration in electricity supply drastically. The higher capital costs of fossil fired plants have made nuclear more attractive, and in addition the limitations on burning low cost coal vs. the higher cost natural gas and oil have made nuclear even more attractive. In this case study by 1985 nuclear captures almost 50% of the electricity market and reaches about 70% by the year 1997, where it starts to level out. Also, though not given in the plots, the model gives the price of uranium concentrates has risen to about $16 per pound by the end of the run compared to $8 per pound presently. In reality the breeder reactor is expected to be a bona fide competitor by this time and its dynamics are not included in the program, therefore one must be careful in the interpretation of these results in the latter part of the run.

There are other caveats of which the reader and eventual user must be aware. If the price trends were to be those as displayed in figure 6.14, one would expect that many of the constrained inputs into the model might be quite different. The significantly higher prices would encourage much more exploration in both oil and natural gas and one would expect that higher rates of additions to reserves would result. The price dependence of the exploration process is not modeled. These higher prices might also encourage further supply from unconventional sources (synthetic gas and synthetic oil) and the price dependence of these forms of supply is not included in the model. Finally, the dependence of the primary consuming sector growth rates and levels of total consumption upon fuel prices and energy costs are not included in the model. These limitations apply to all the case studies given in this chapter and the topic is discussed further in the next section and chapter 7.

As the model stands, the results demonstrated may be inconsistent with expectations. One can only say that if the primary consuming sector growth rates, the rate of reserve additions, imports, and levels of supply from unconventional sources are consistent with the cost/

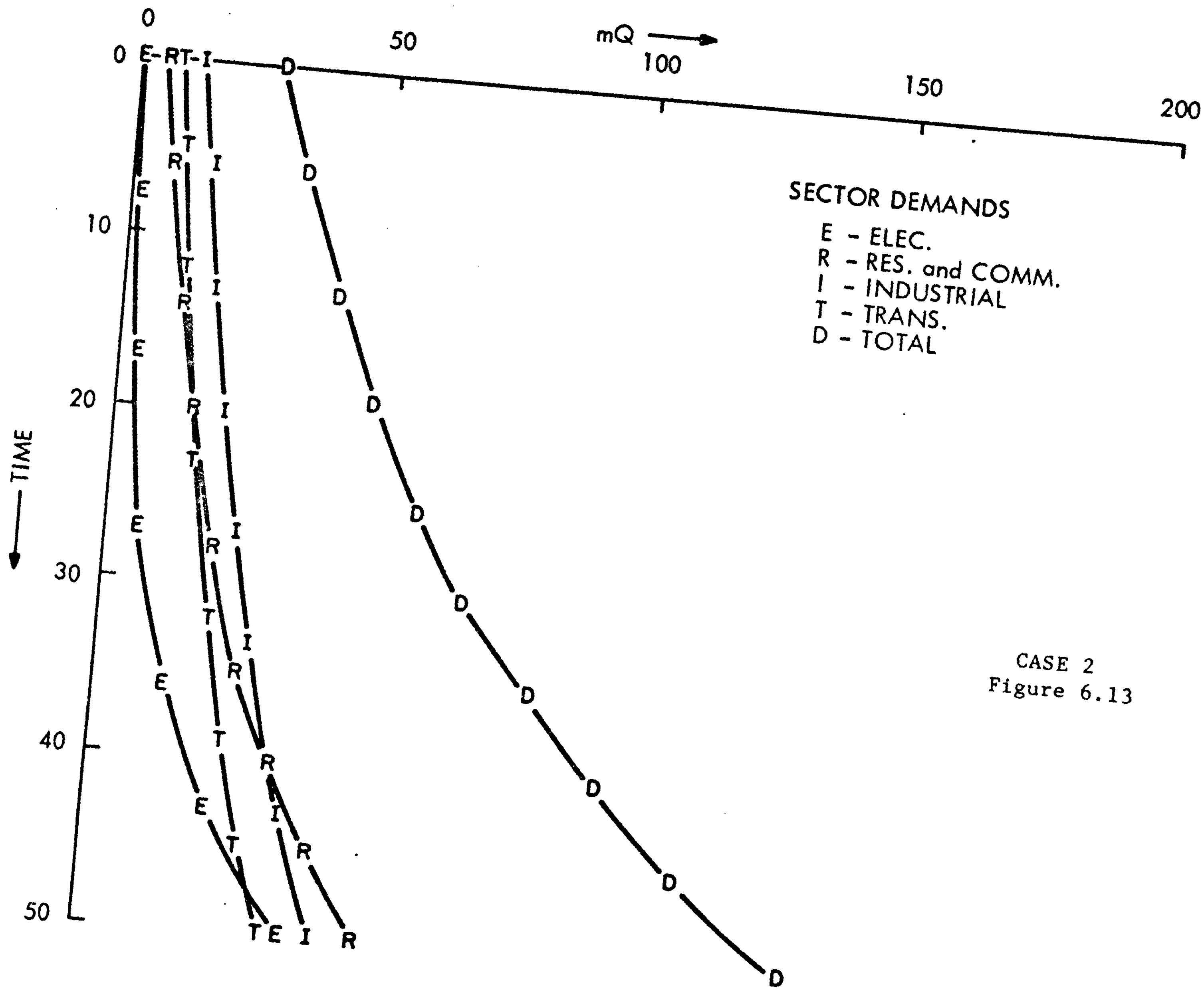
price trends indicated, then these are the price, supply, and consumption configurations that result. If the inputs are considered inconsistent, the user would probably want to adjust these inputs to be consistent with the price trends shown and rerun the model.

Table 6.3

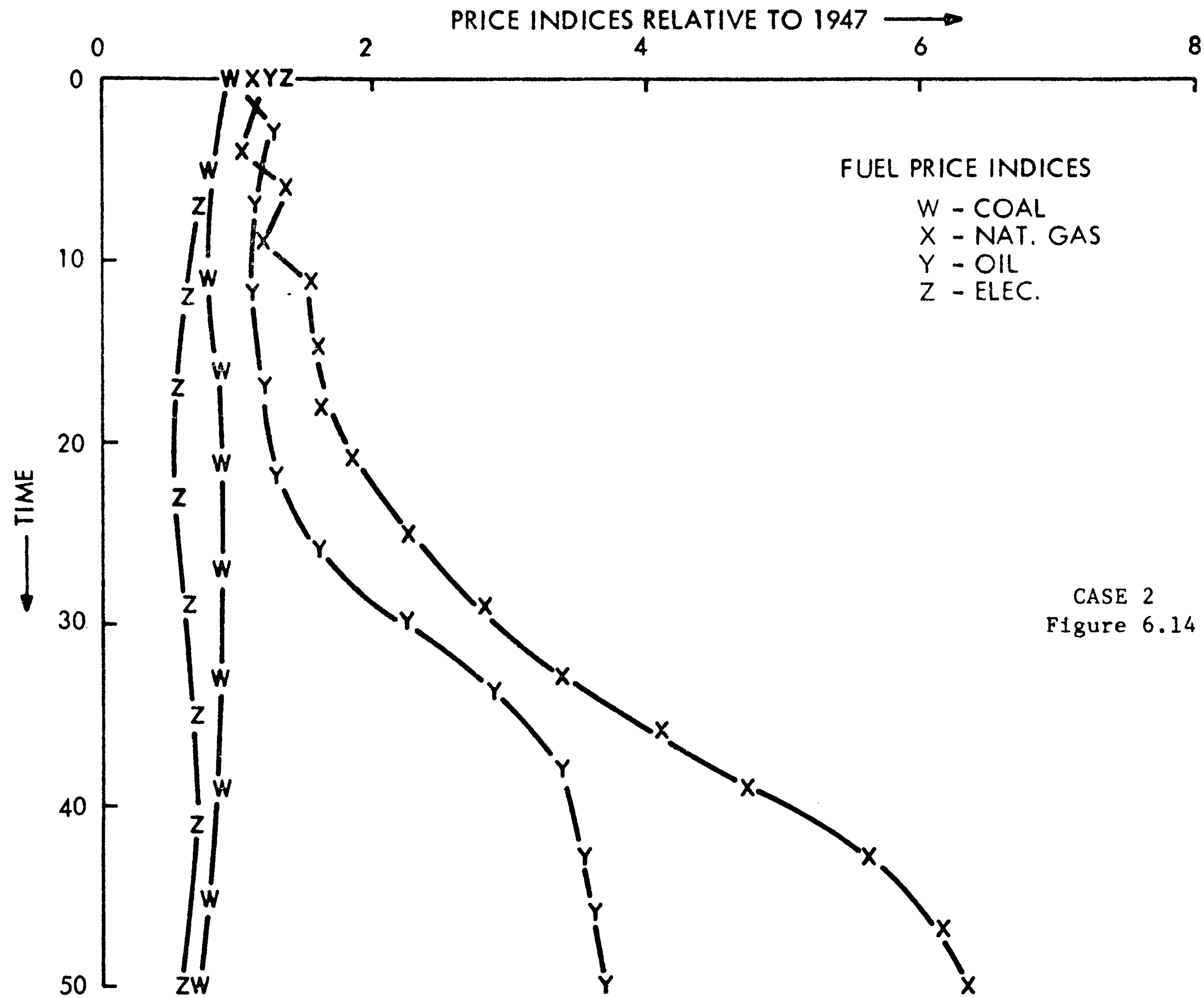
Case Study No. 2

Characteristics

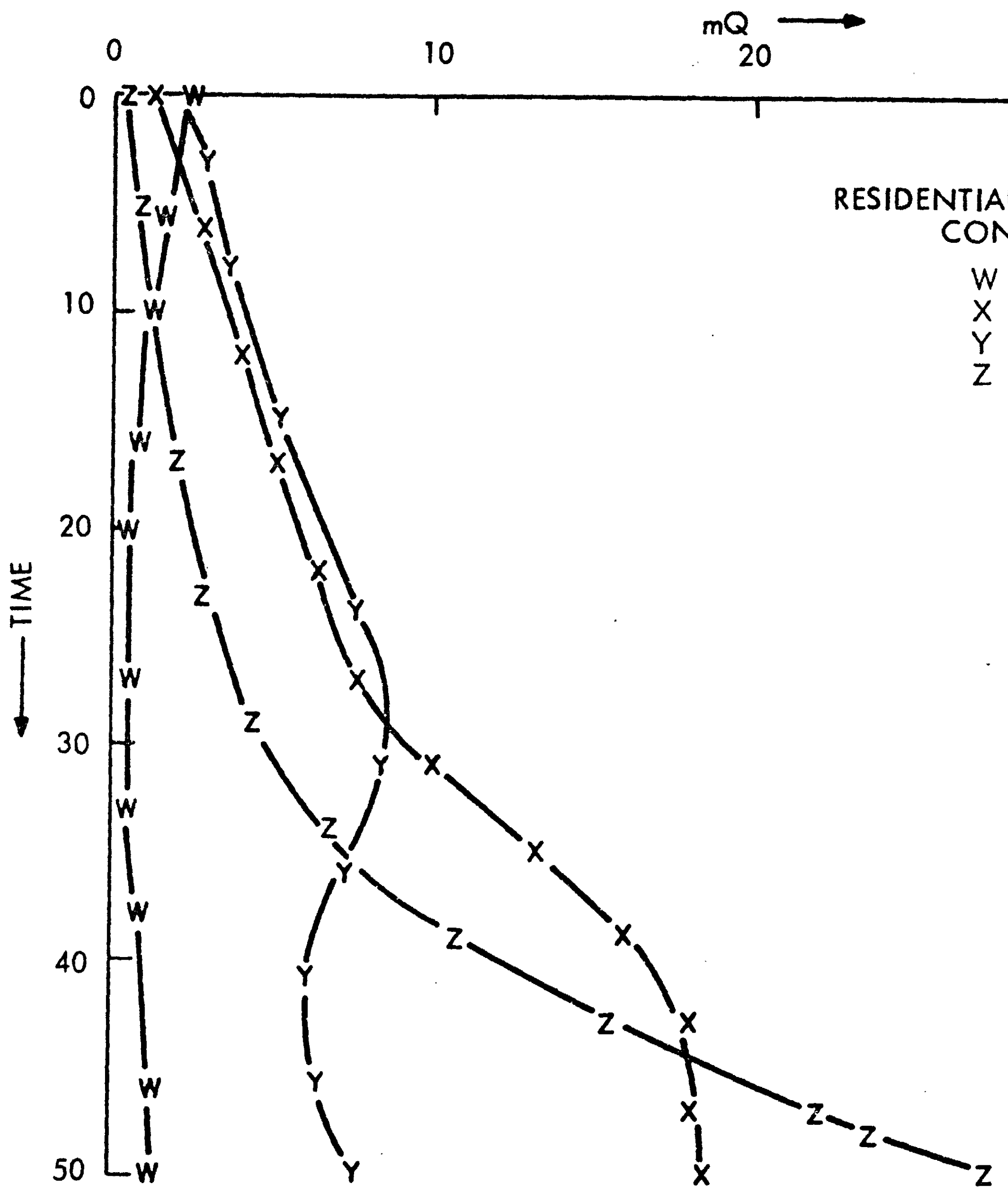
1. Increases in rate of consumption of coal in electric utilities cut to half the value of case No. 1 from 1970 on (distribution factor of coal multiplied by 0.5).
2. Remaining fossil fuel consumption distributed equally between oil and gas.
3. Fossil plant capital costs in electricity supply increased by 25% over case No. 1 from 1970 on.
4. Cost escalation in oil supply of 2% per year from 1970 on.
5. Oil imports increase at half the rate of case No. 1 from 1970 on.
6. Everything else as in case study No. 1.



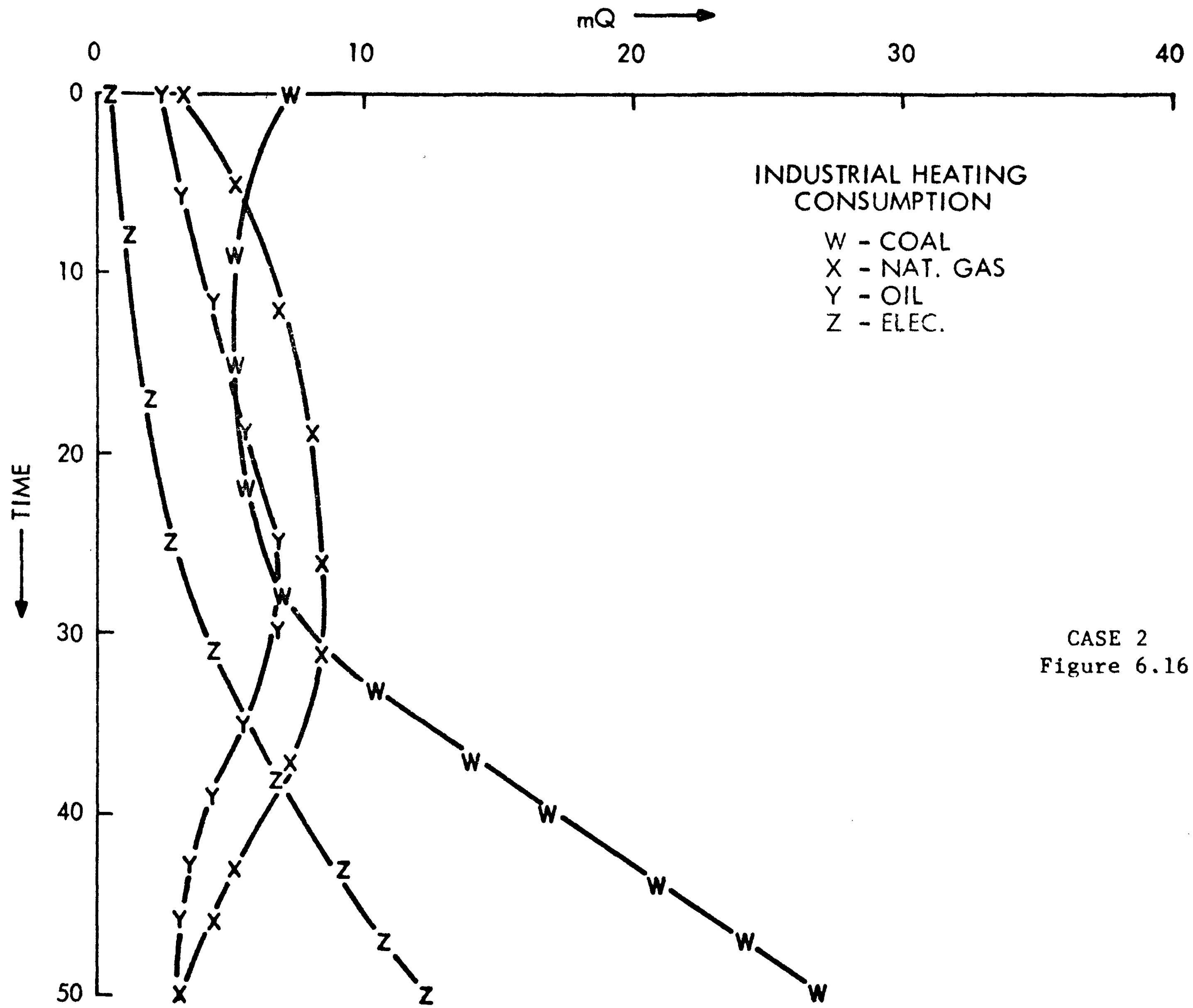
CASE 2
Figure 6.13



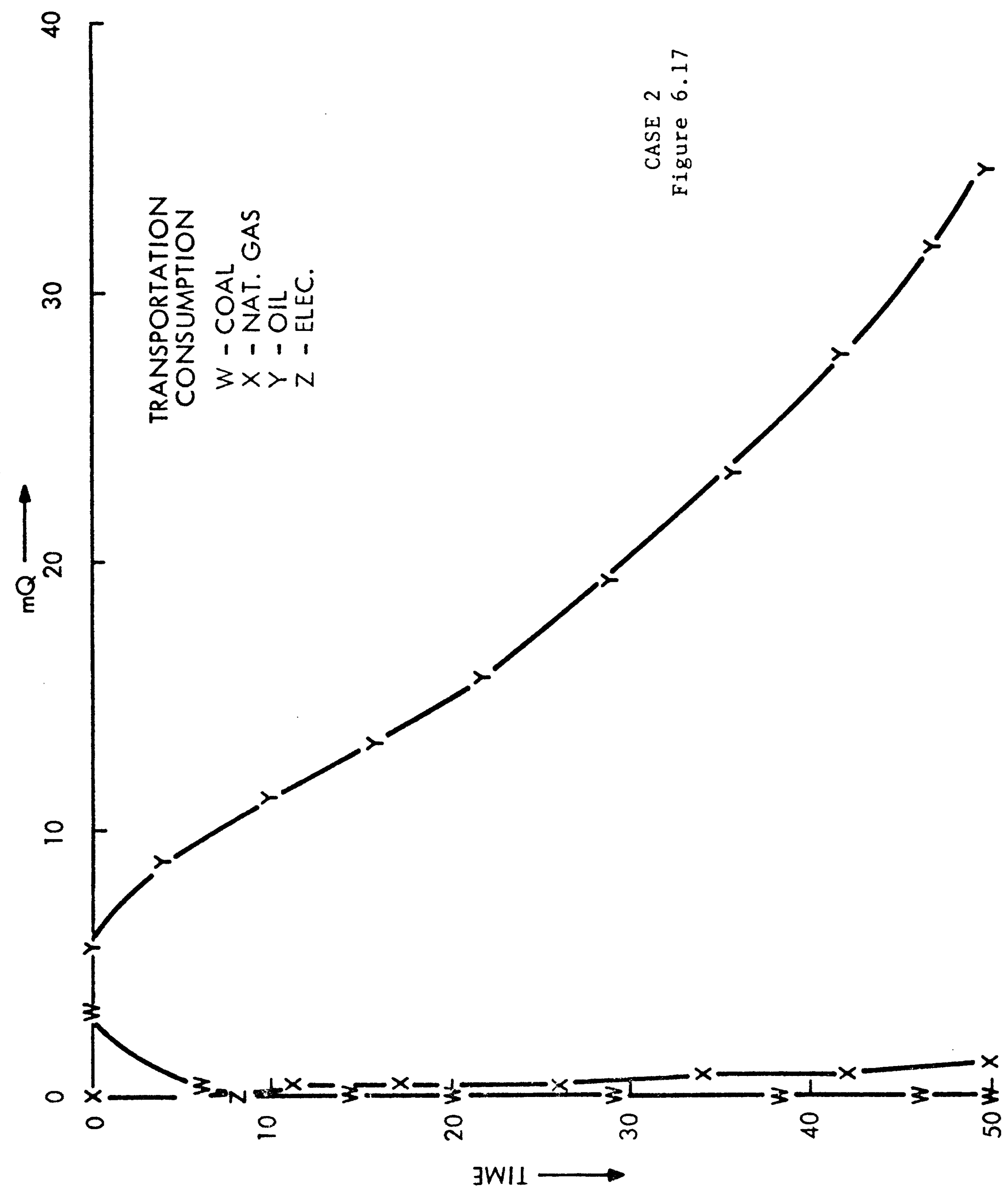
CASE 2
Figure 6.14



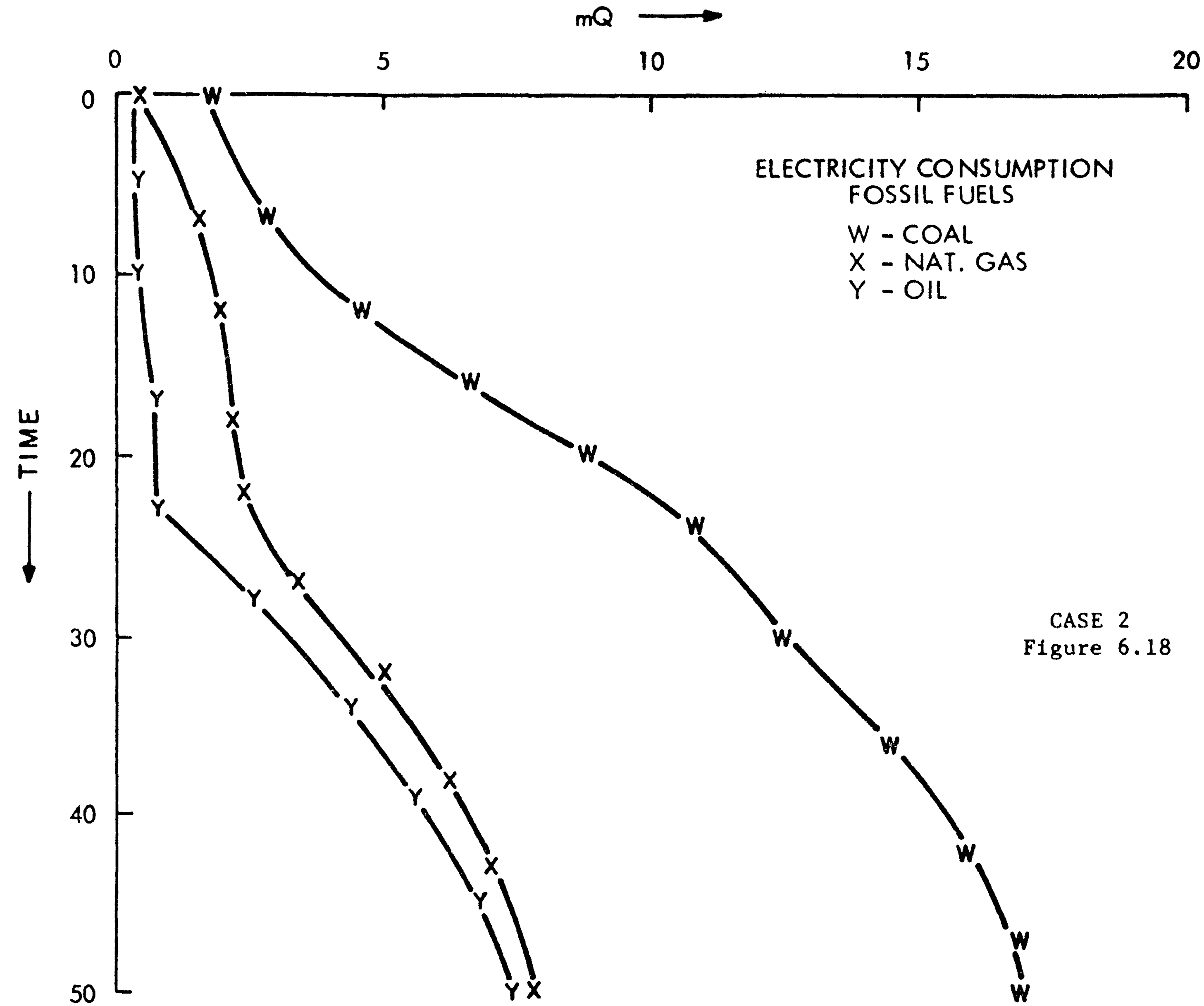
CASE 2
Figure 6.15



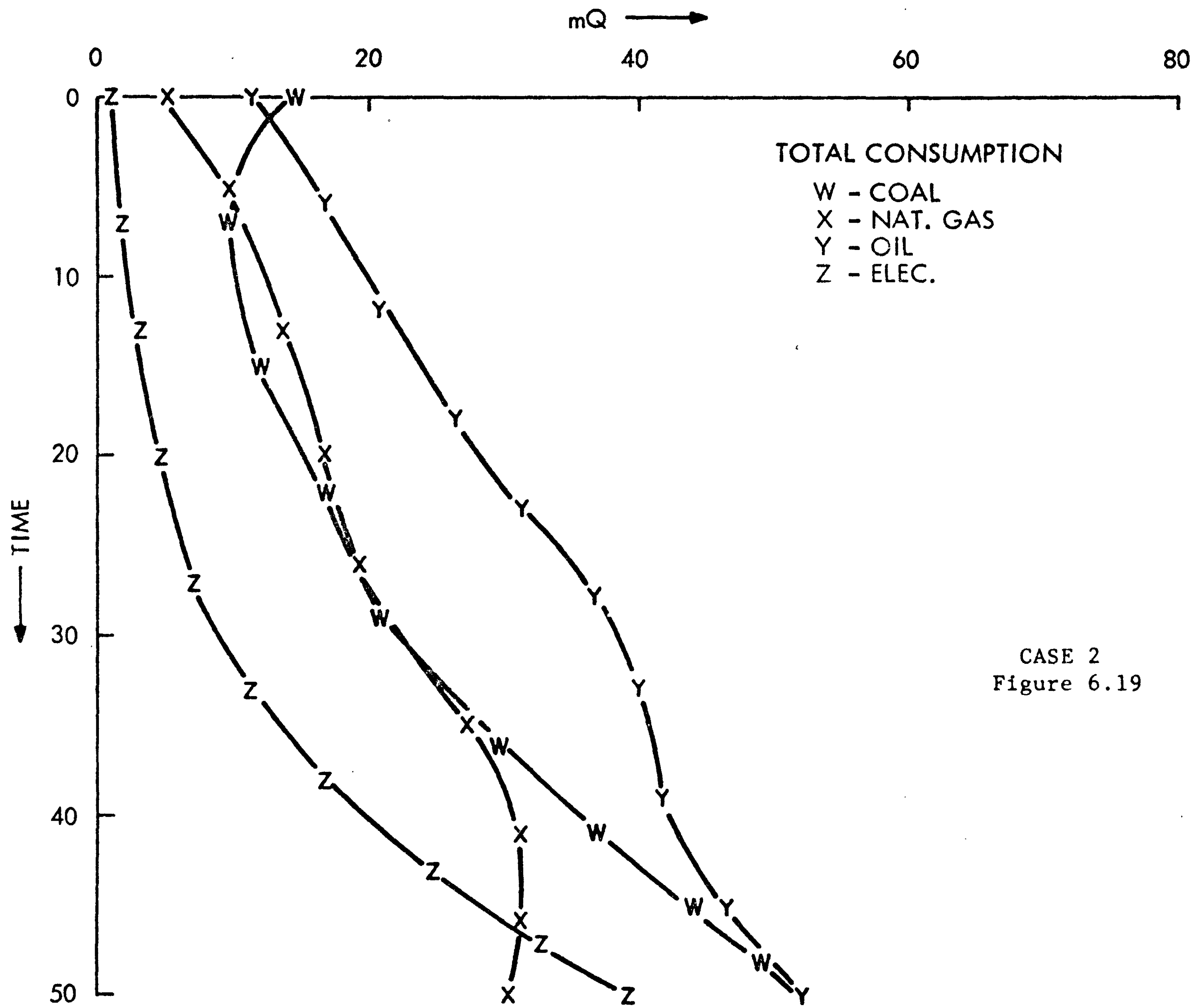
CASE 2
Figure 6.16



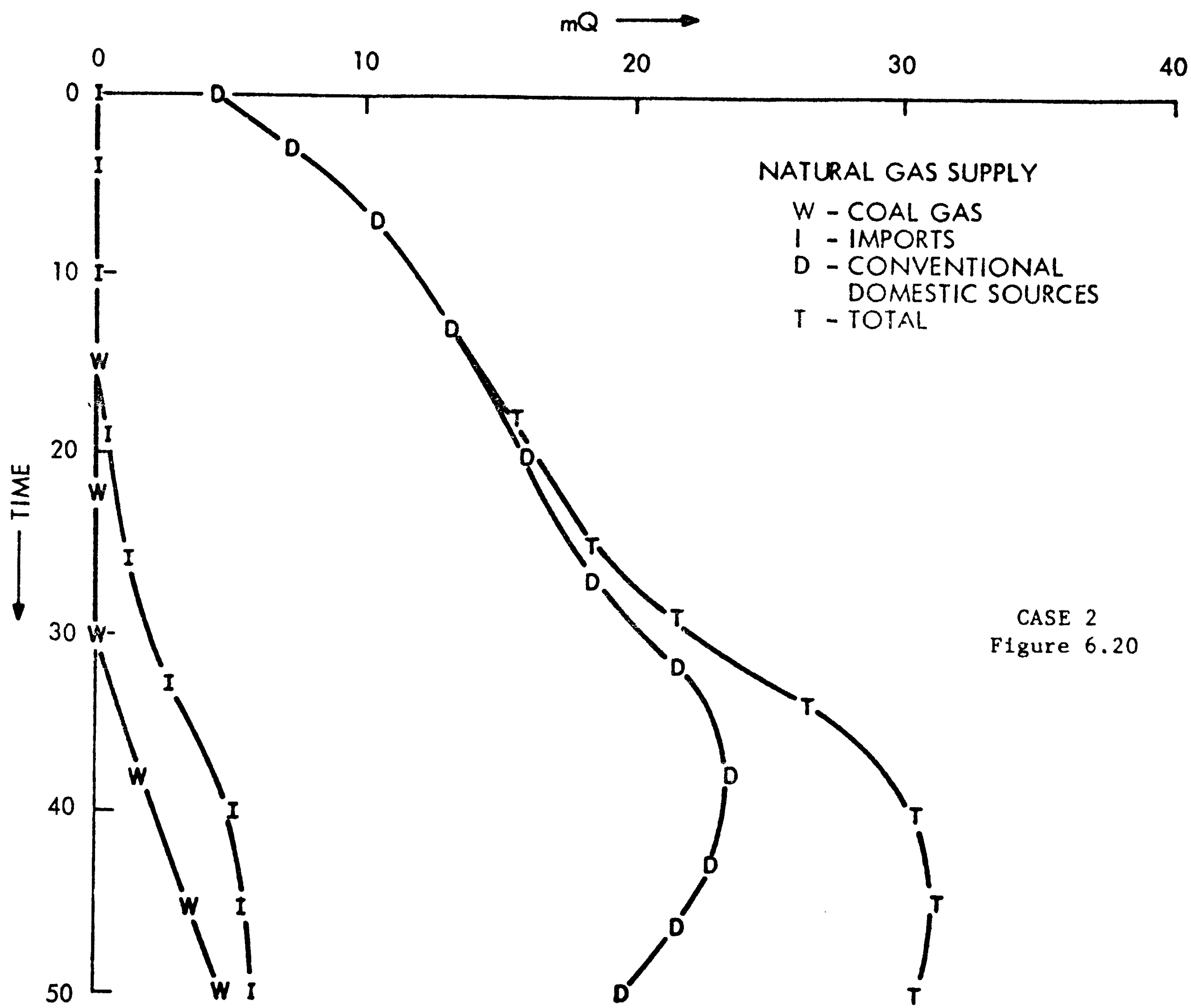
CASE 2
Figure 6.17



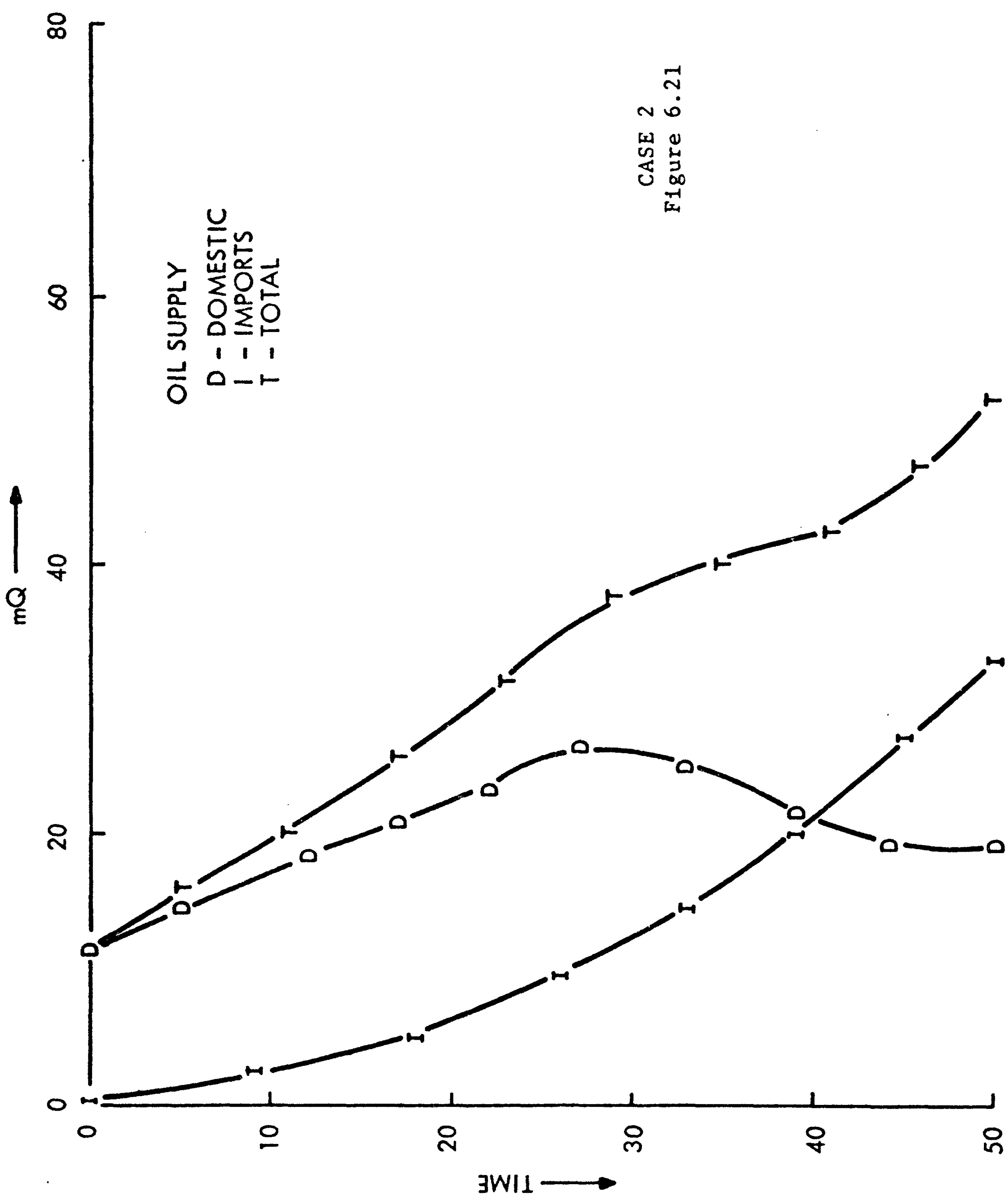
CASE 2
Figure 6.18



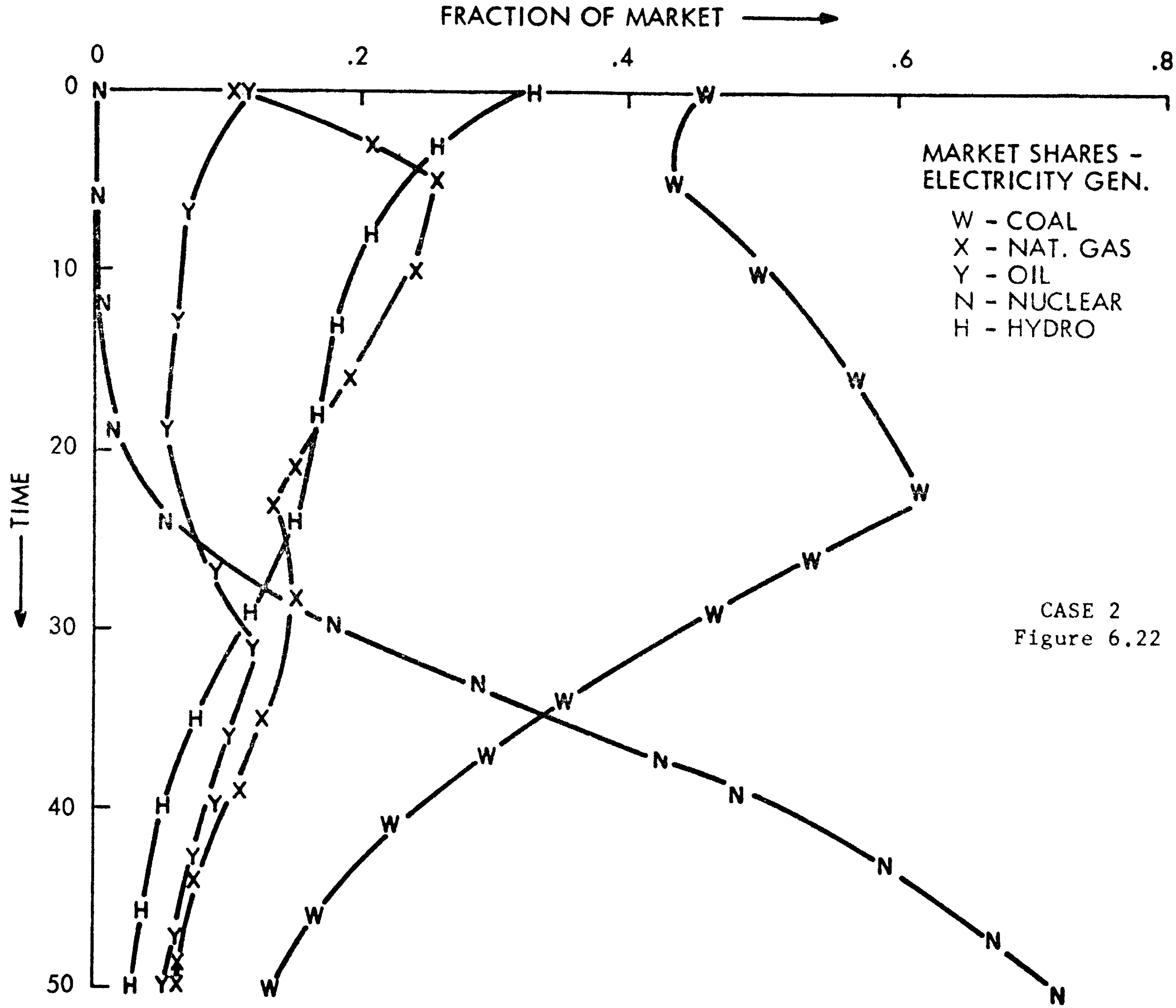
CASE 2
Figure 6.19



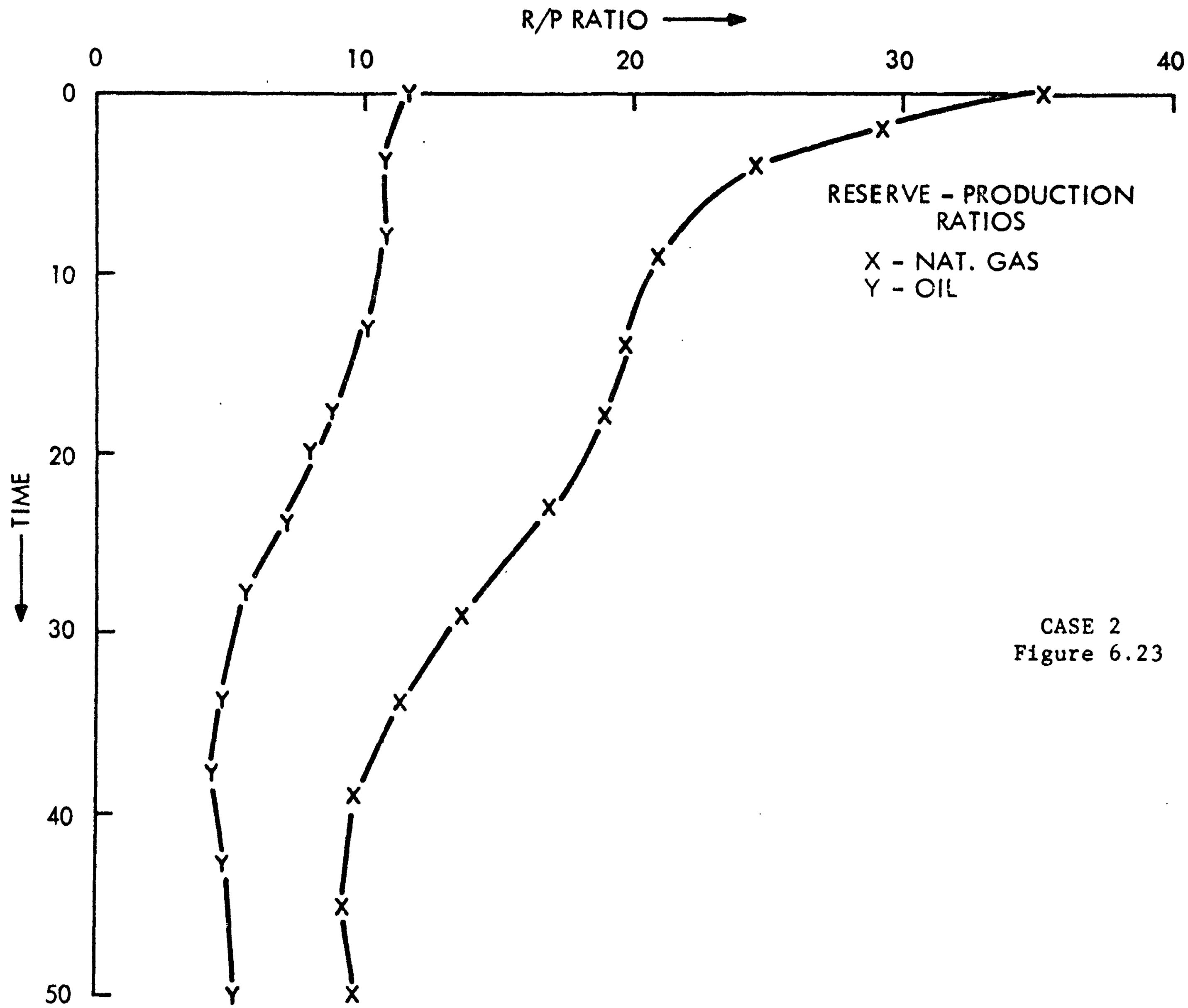
CASE 2
Figure 6.20



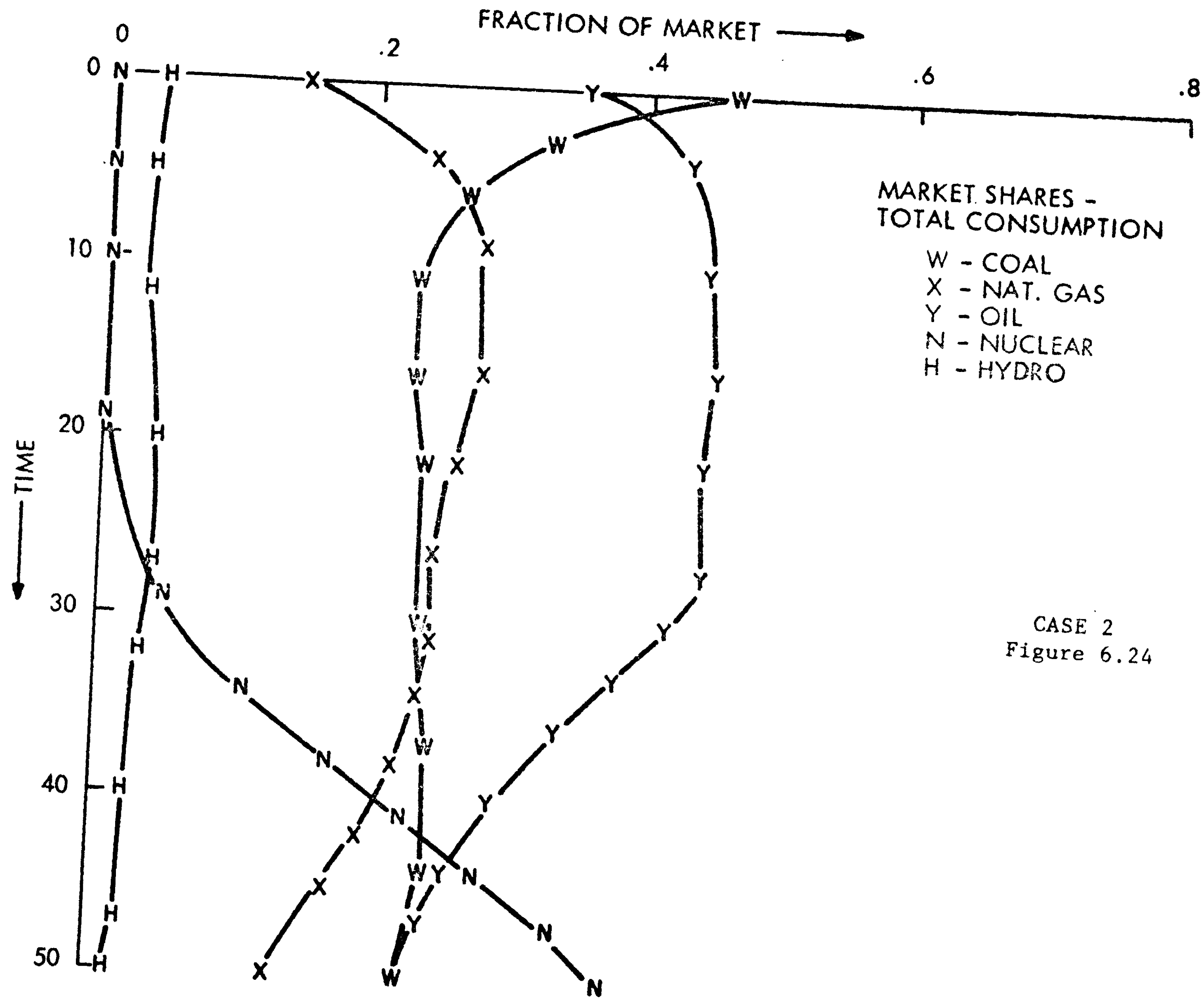
CASE 2
Figure 6.21



CASE 2
Figure 6.22



CASE 2
Figure 6.23



CASE 2
Figure 6.24

Table 6.4

Supply Summary Case No. 2

Variable	Model Value (in mQ's)	NPC Value
Total energy consumption	129.8	125.0
Domestic oil production	22.0	22.0
Oil imports (input to model)	19.2	31.0
Domestic natural gas production	23.4	14.5
Natural gas imports (input to model)	4.5	6.1
Gas from coal gasification (input)	1.6	0.9
Domestic coal consumption	32.4	28.0
Electricity production	16.8	16.4
Nuclear used in electricity production	23.1	19.0

1985 Values

6.3 Case Study No. 3

The final case study is to investigate the impact of higher growth rate of consumption upon the supply-demand balance and cost trends for another supply scenario. This scenario draws heavily upon the previous cases with some minor alterations in the supply variables and a substantive changes in the component sector consumption growth rates. As mentioned earlier, the trends in domestic oil and gas supply are to higher cost sources, both offshore and less accessible onshore locations. The cost escalation factors used previously reflecting these trends may have been optimistically low in light of these trends. In the next case study the escalation factors are assumed to be 5% per year for both oil and gas. This high rate may be pessimistic, but it certainly is not inconsistent with past trends and future expectations.

Kept in the next run is the 25% increase in capital costs of fossil fired plants, but dropped is the fuel burning limitation in electricity supply of case study No. 2. In other words it is assumed in this case that at the expense of these higher capital costs, all fossil fuels are viable competitors in electricity generation and can meet the environmental standards.

Finally, the trends of oil imports, gas imports, and coal gasification are the same as those used in case study No. 1, derived from the NPC and Bureau of Natural Gas sources.

These characteristics are pretty much the same as for the previous runs, the difference is that in the case study No. 3, the growth rates in total consumption by the primary consuming sectors are increased by

25% in 1970 (time = 23.0) over those used in the previous case studies.

These characteristics of case study No. 3 are listed in table 6.5. The simulation results are given in figures 6.25 to 6.36. Remember that this case corresponds very closely to case No. 1 exdept for the conditions listed in table 6.5.

As would be expected, the additional growth in consumption has significant impacts on the future energy outlook. The total energy consumed in 1985 is 142 mQ vs. the 125 for previous runs --- up about 10%. A 25% error in growth is large, but on the other hand the growth in consumption in some sectors has changed as much as 25% from one decade to the next, so 25% error is not unreasonable. In fact this 25% higher growth rate to 1985 is what the Chase Manhattan Bank is projecting.[1]

In figure 6.26 the price trends of oil and natural gas are significantly up, though not quite as high as in case No. 2. Of course by the end of the run there is about twice as much imported oil available in this case as in case No. 2. This increased foreign oil availability serves to mitigate the consequences of the higher growth rates in consumption and even compensates for the escalating costs. The apparent conclusion is that oil import policies have great impact on the future energy outlook.

Further, it can be seen that coal, both directly and through electricity, as well as nuclear in electricity take up the slack for these

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[1] Outlook for Energy in the United States to 1985, The Chase Manhattan Bank, June 1972.

higher consumption levels. This is as one would expect if the imports, addition to reserves, and synthetic fuels were constrained as they are in the model. Here again the caveats outlined for case study No. 2 apply, and if the reader feels inconsistencies are demonstrated in the model results due to the price dependence of factor inputs, these inputs need to be adjusted and the model rerun.

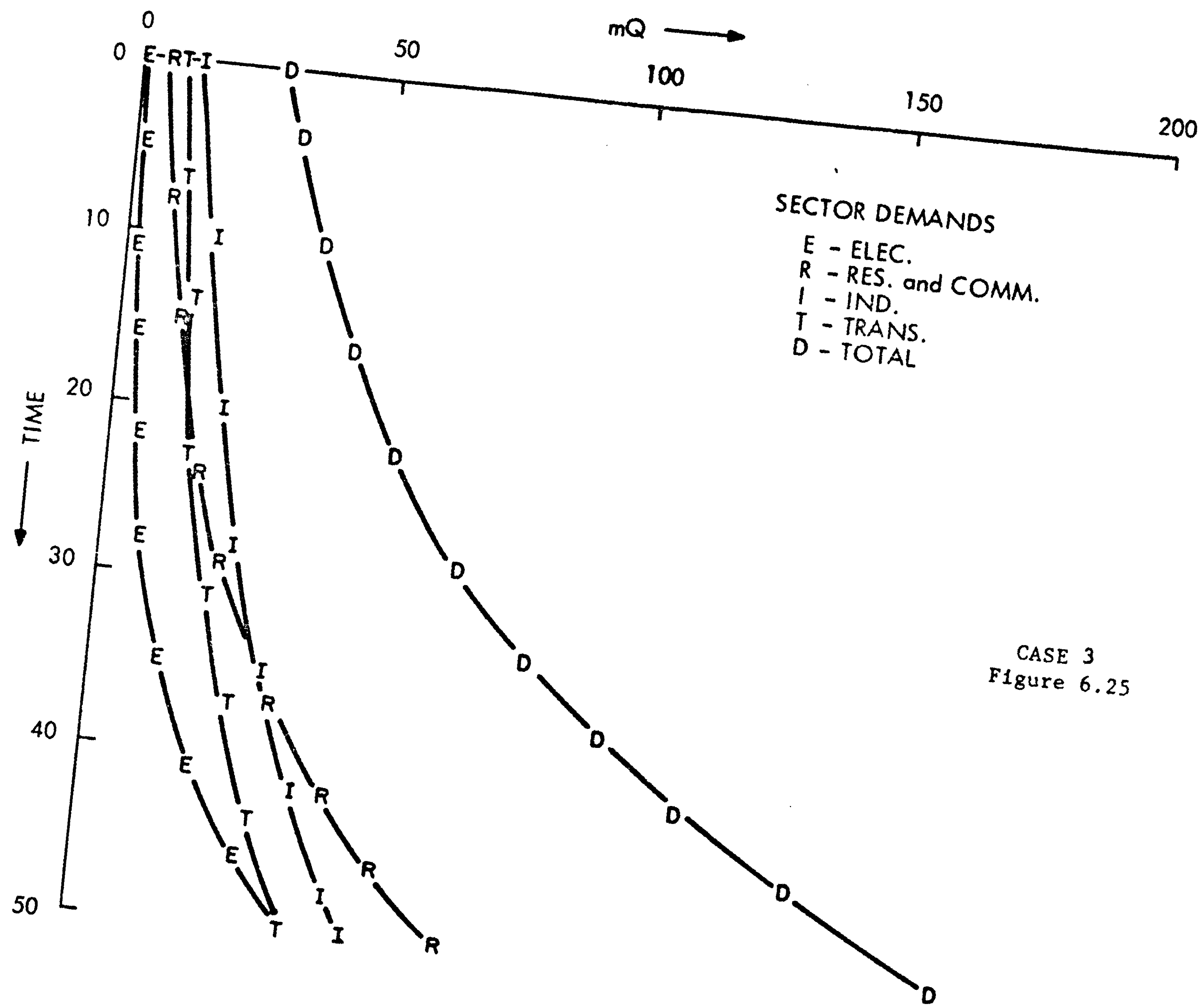
Another interesting phenomenon demonstrated in this case are the trends in supply for both oil and natural gas supply from domestic sources as displayed in figures 6.33 and 6.34. The increased prices are apparently more affected by the escalating costs rather than the declining reserve production ratios (compare to case No. 2). These increasing costs discourage as intensive development as took place in case no. 2, and domestic production starts declining in both oil and natural gas about midway through the run (1975 to 1980), while increasing reserve production ratios are encountered. This is the result of the normal economic decision processes as these suppliers react to the factors input into the model and could be expected to occur in reality under the same set of conditions. The domestic production peaks for gas at about 25% lower production than in case 2, and oil production peaks at about 15% less than that in case 2. In addition these peaks occur earlier in time due to the rapidly escalating costs.

Table 6.5

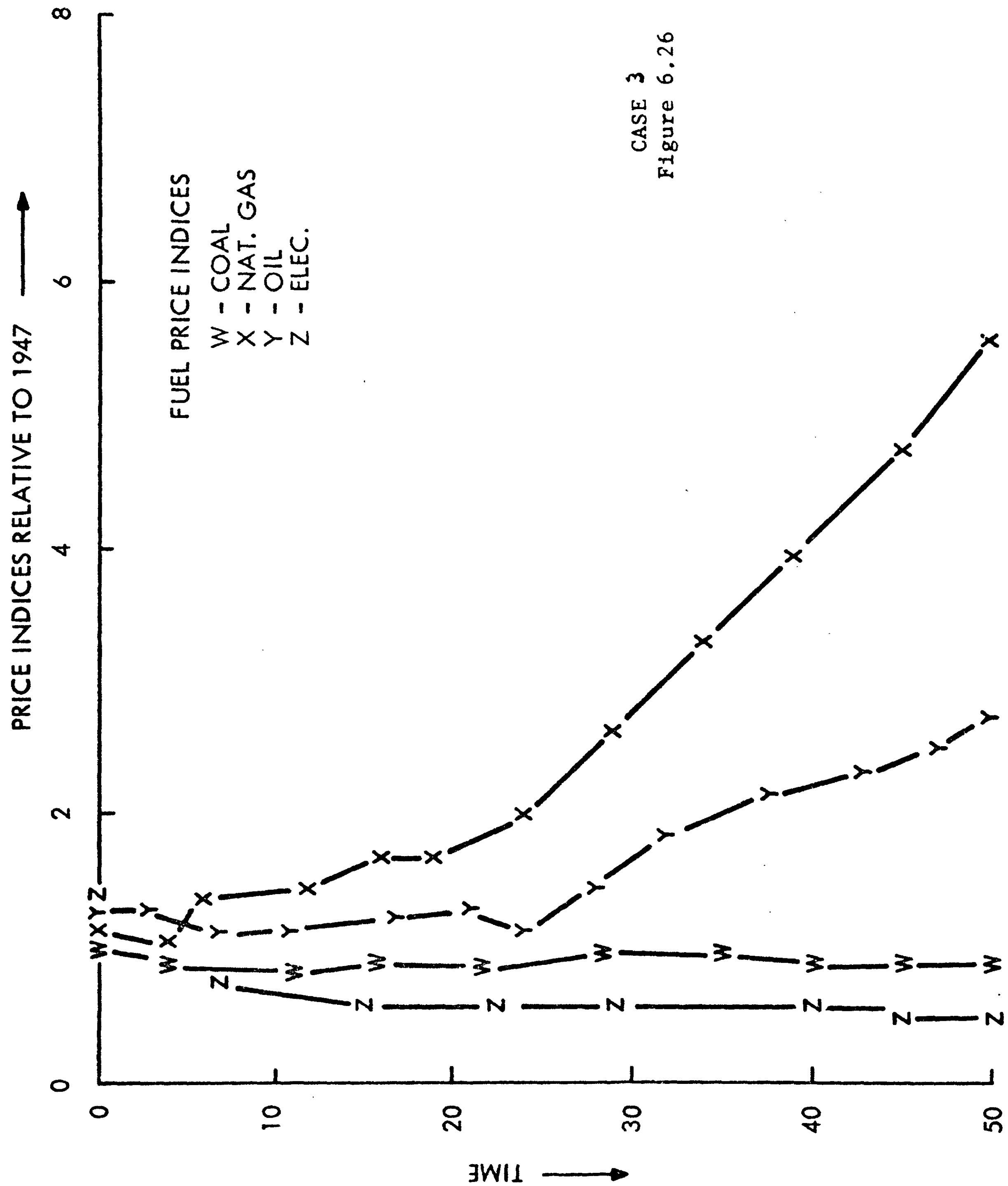
Case Study No. 3

Characteristics

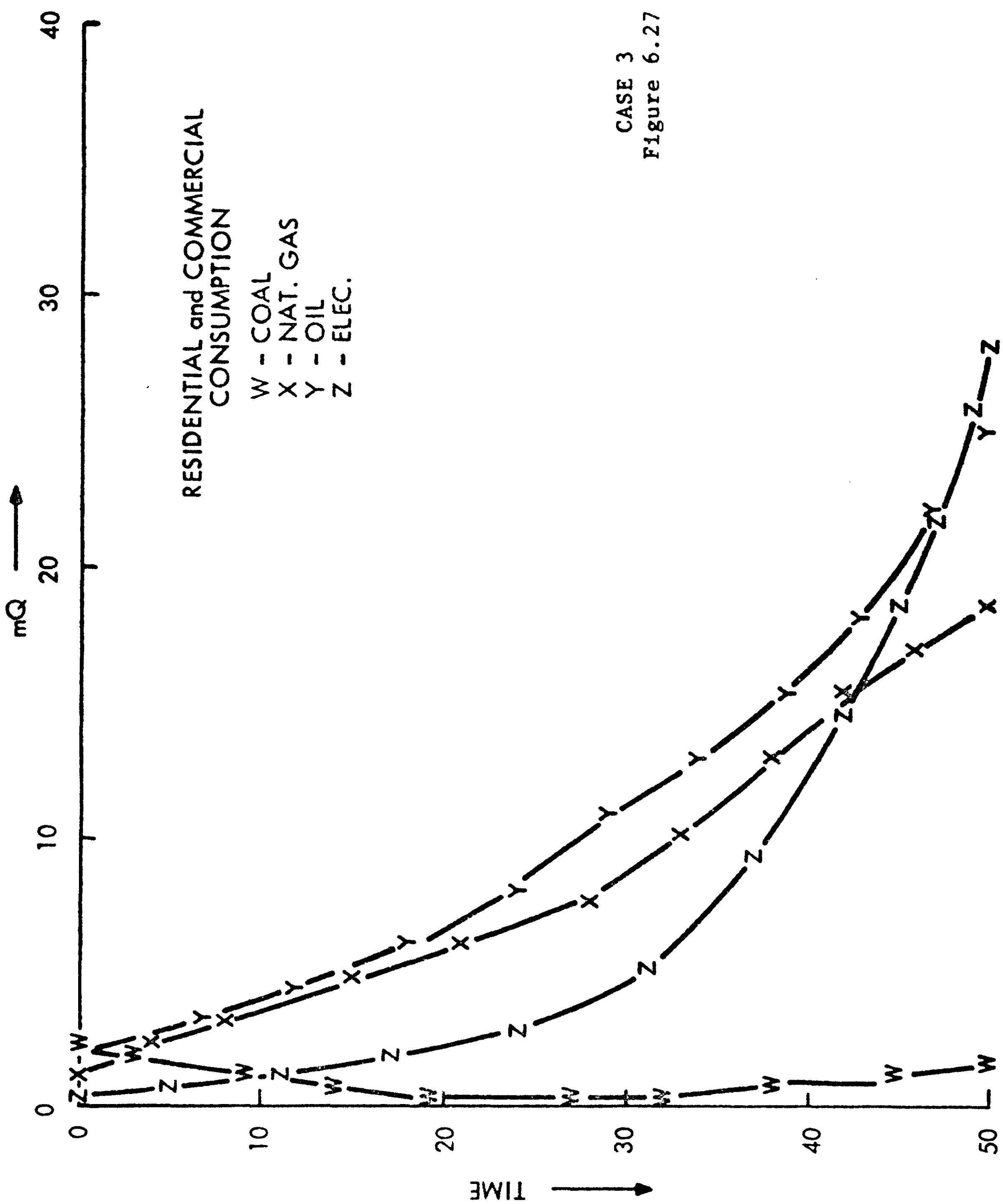
1. Cost escalation in oil and natural gas supply of 5% per year from 1970 on.
2. Fossil plant capital costs in electricity supply increased by 25% over case No. 1 from 1970 on.
3. Growth in consumption of primary consuming sectors increased by 25% over case No. 1 from 1970 on.
4. Everything else as in case study No. 1.



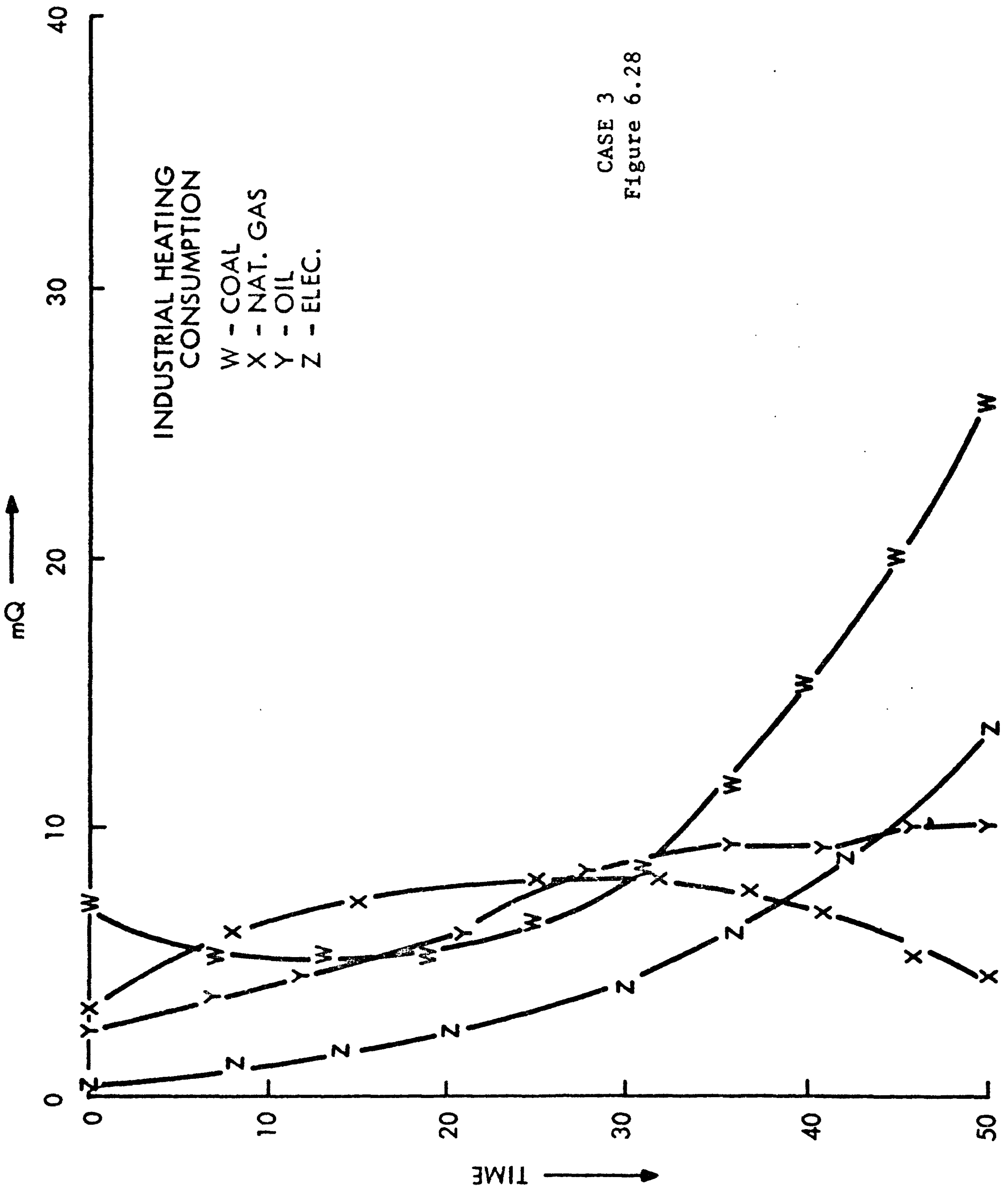
CASE 3
Figure 6.25



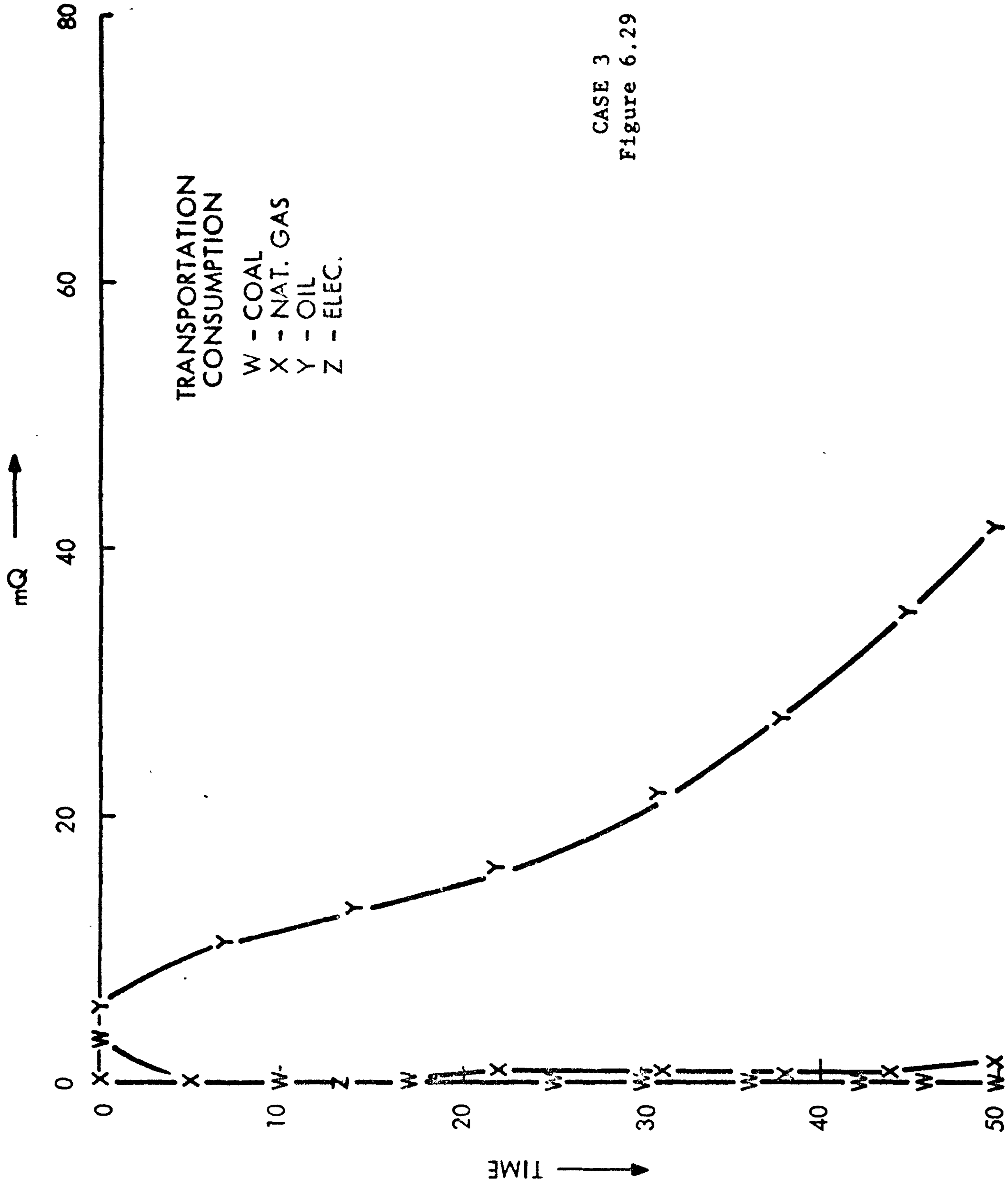
CASE 3
Figure 6.26



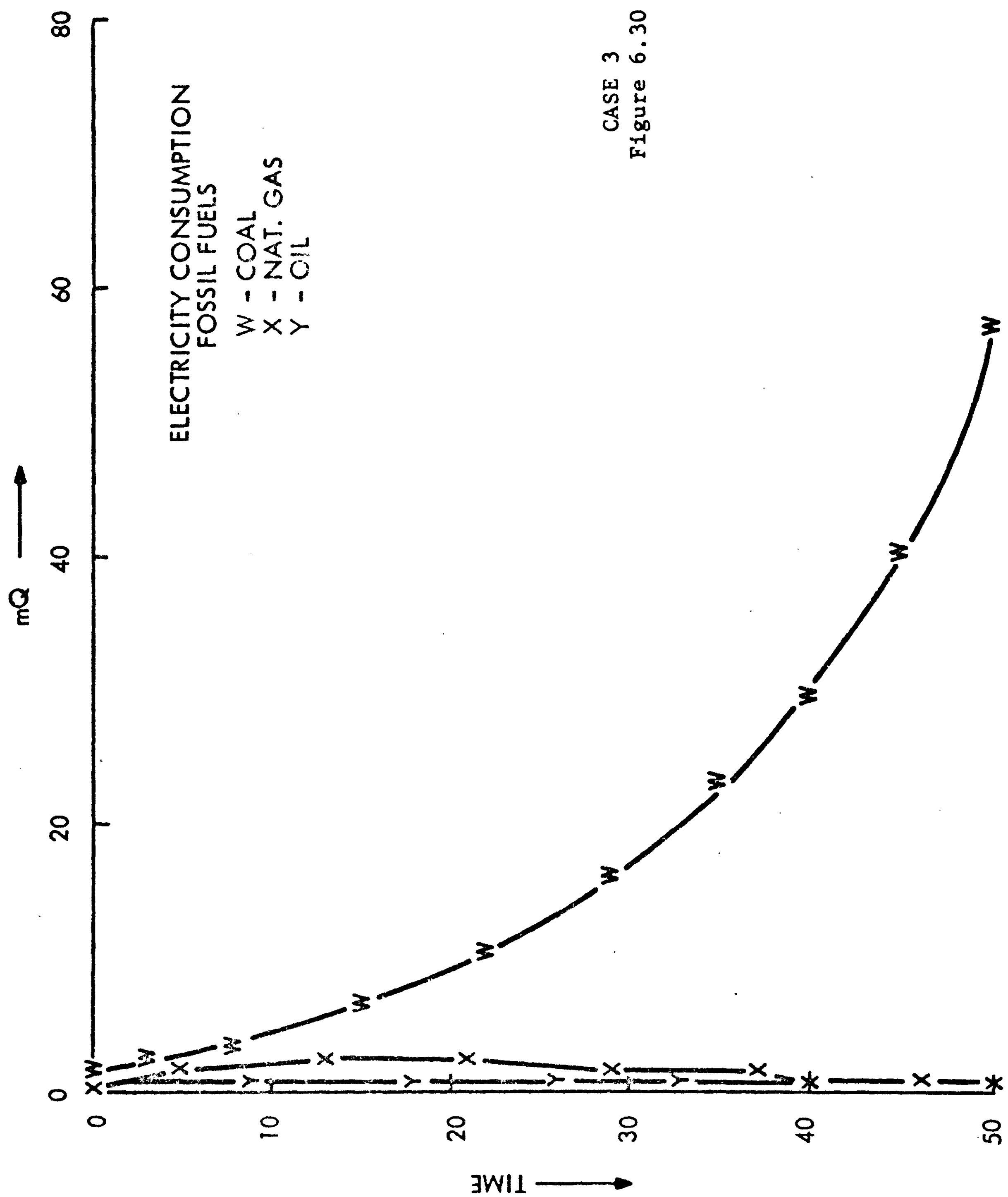
CASE 3
Figure 6.27



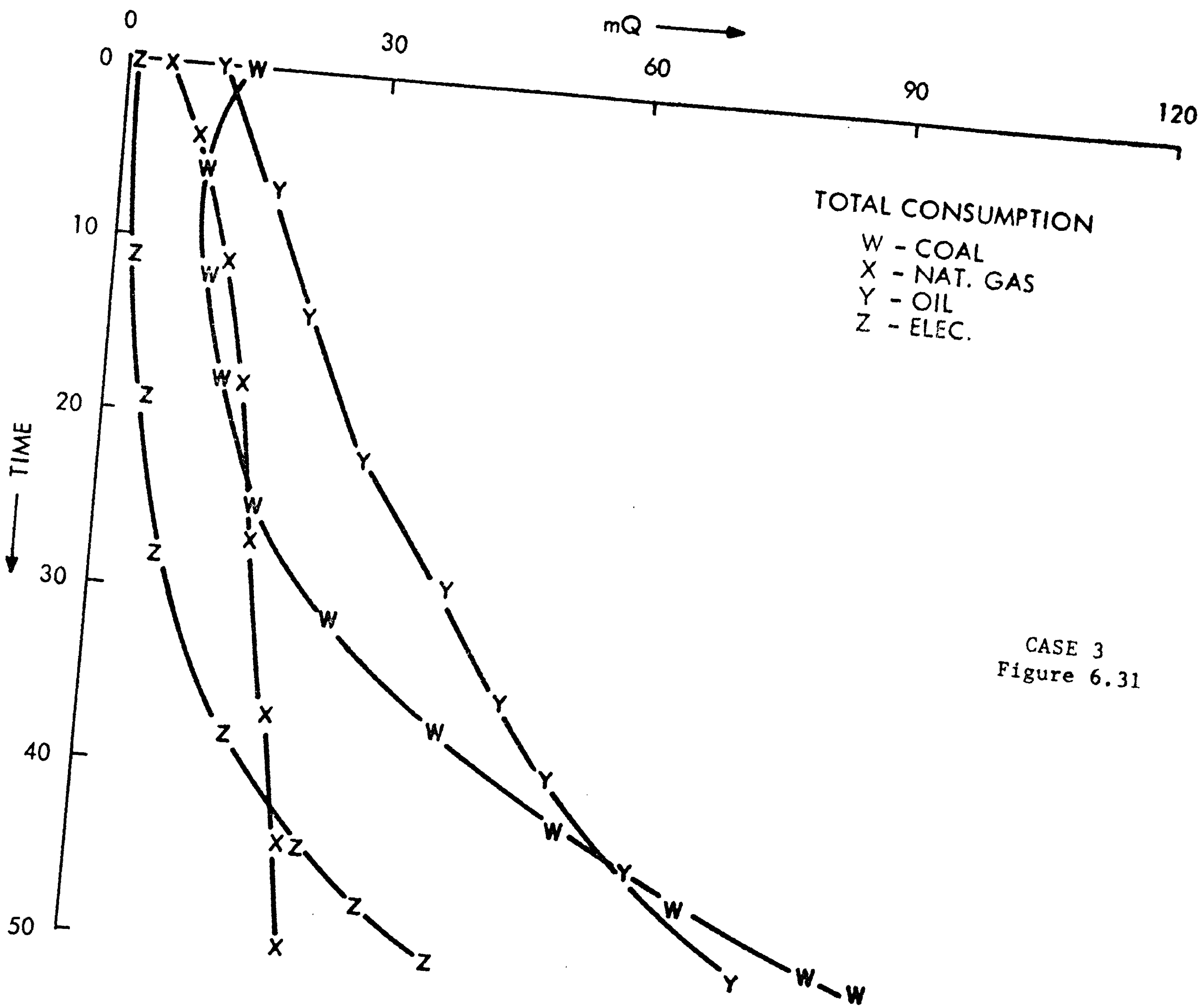
CASE 3
Figure 6.28



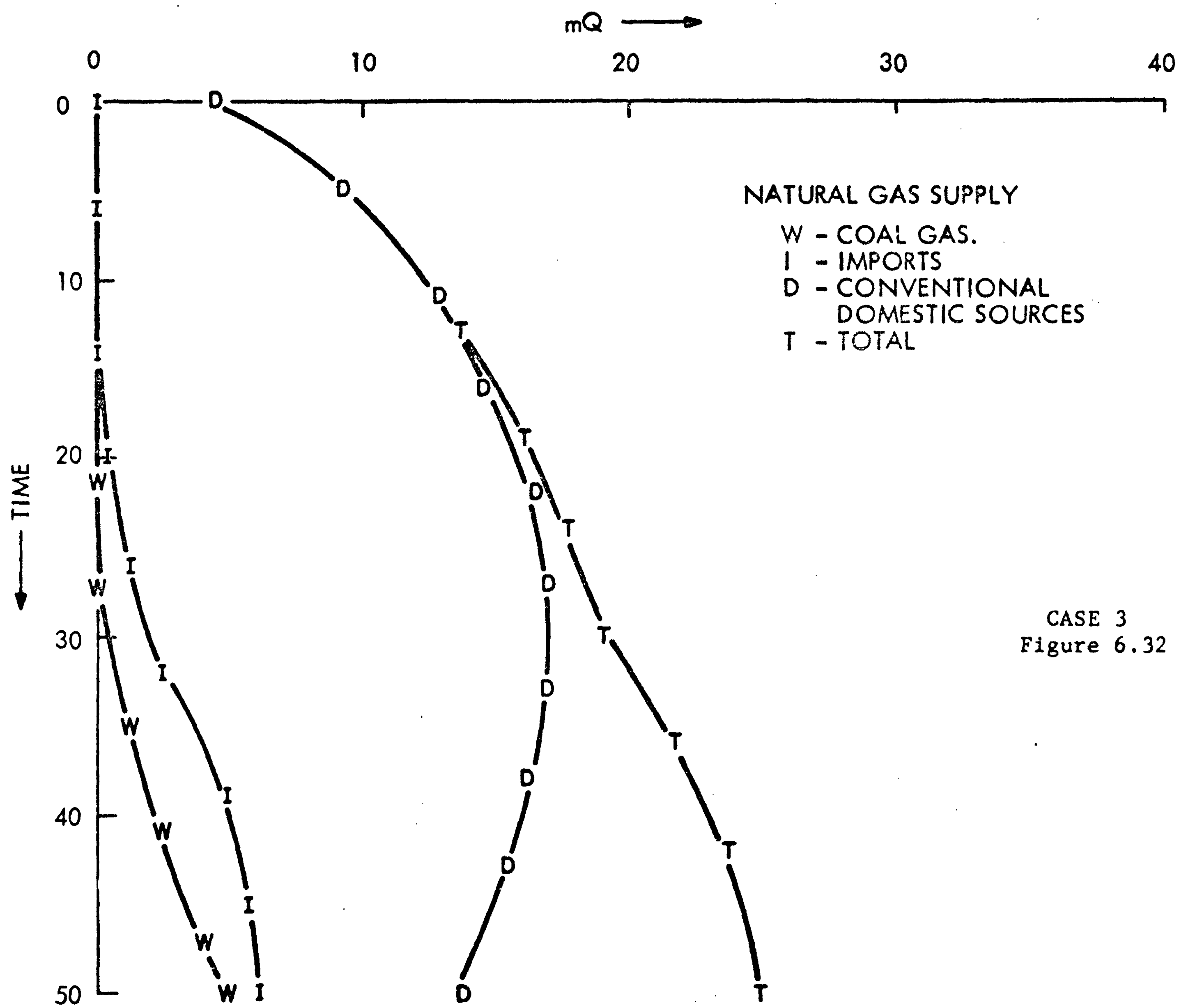
CASE 3
Figure 6.29



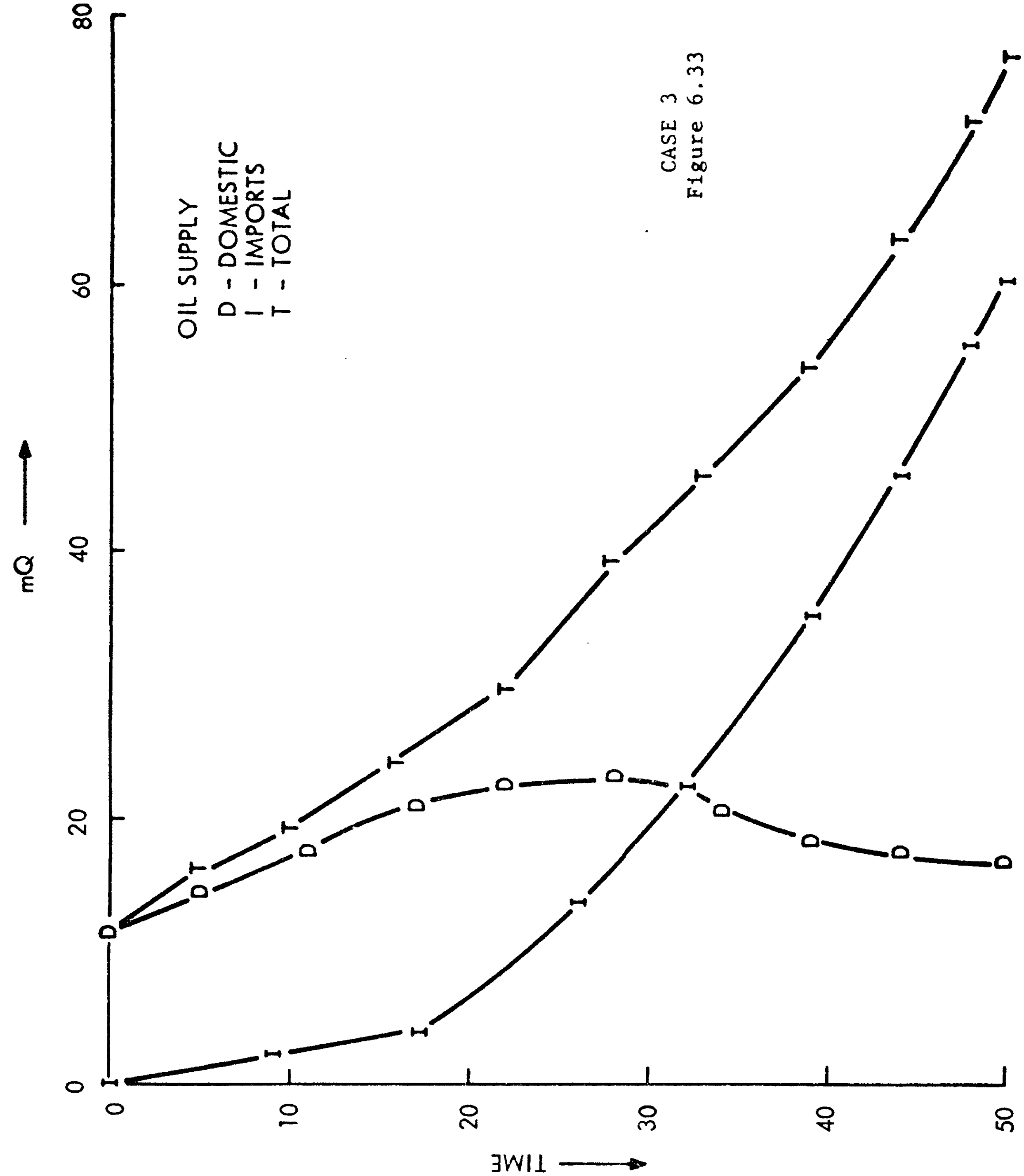
CASE 3
Figure 6.30



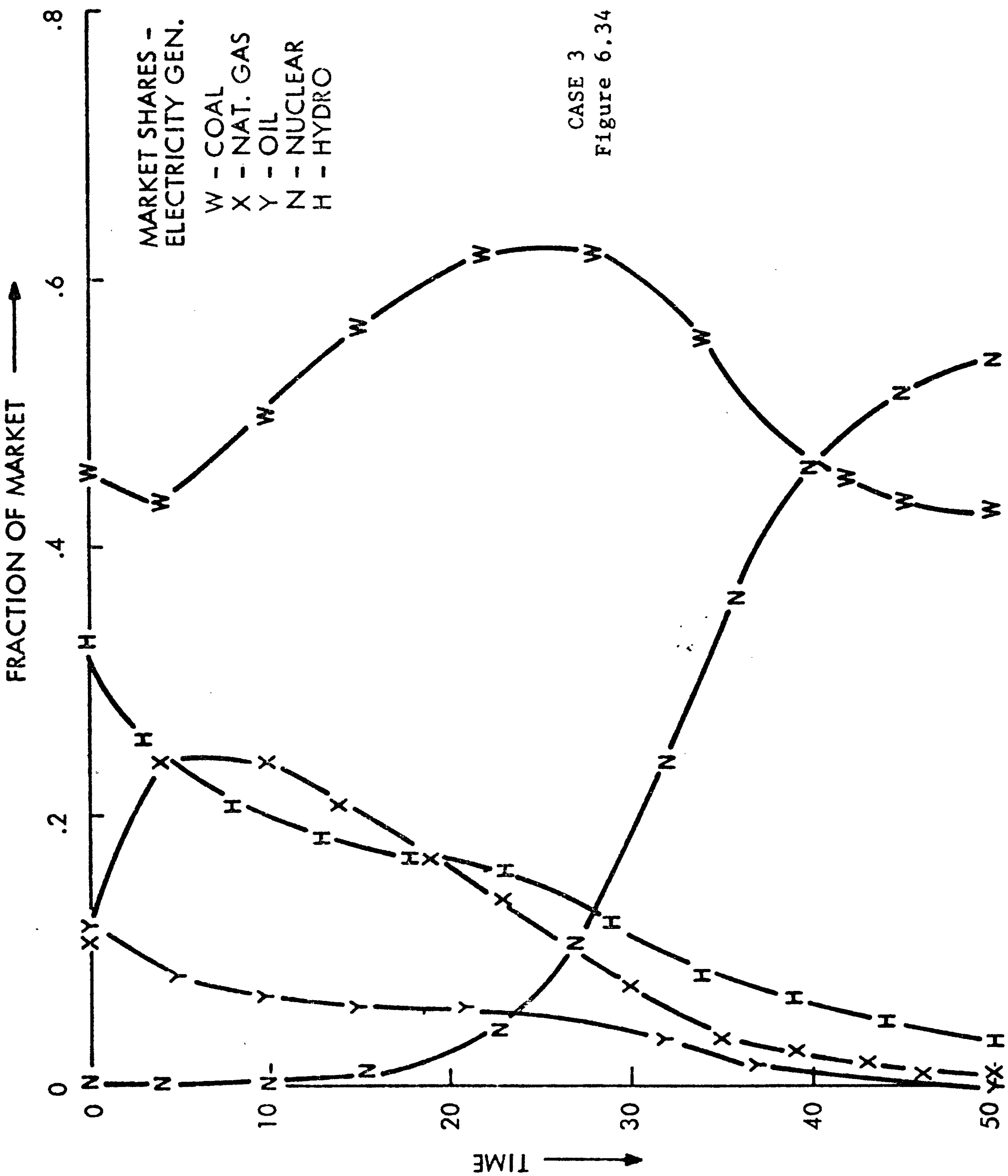
CASE 3
Figure 6.31



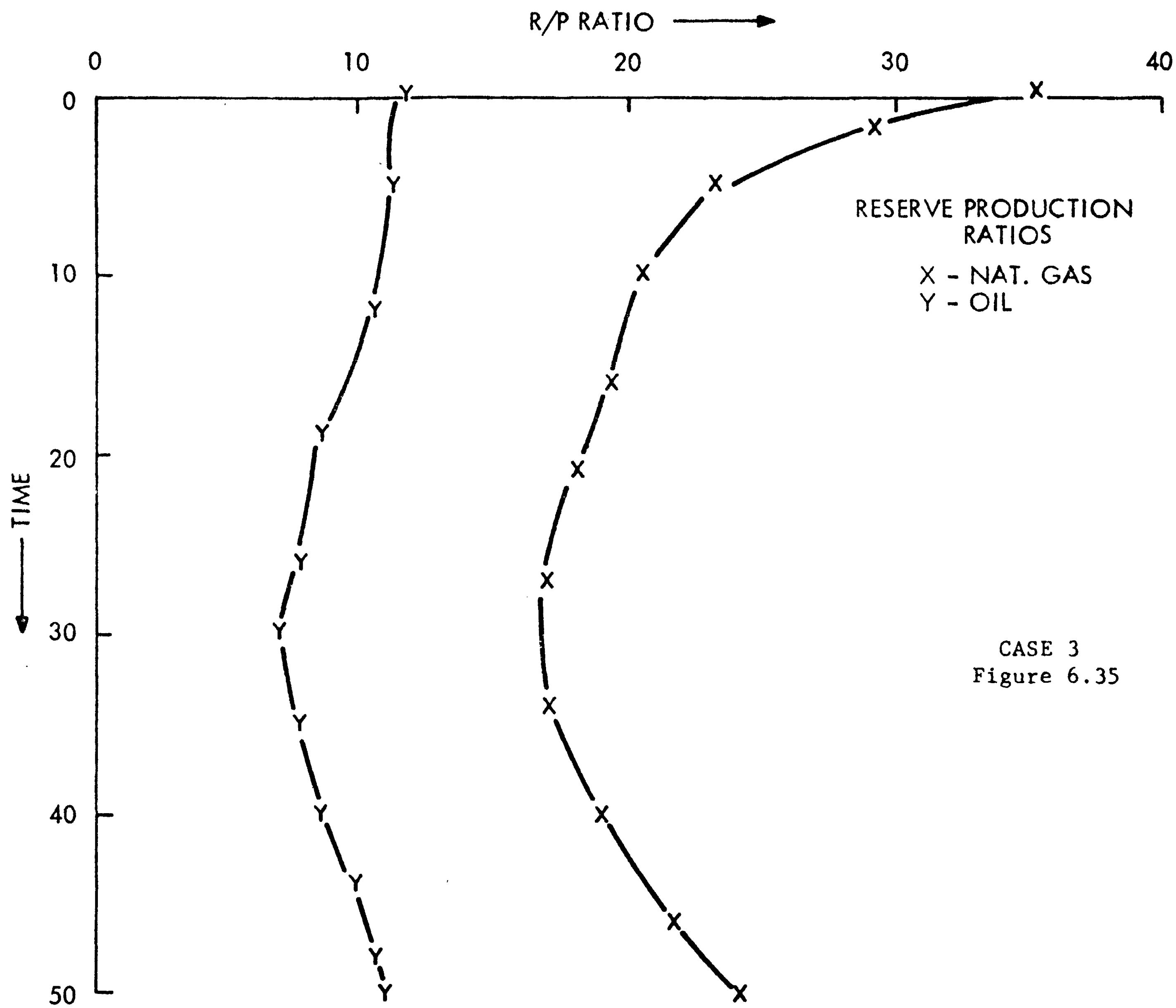
CASE 3
Figure 6.32



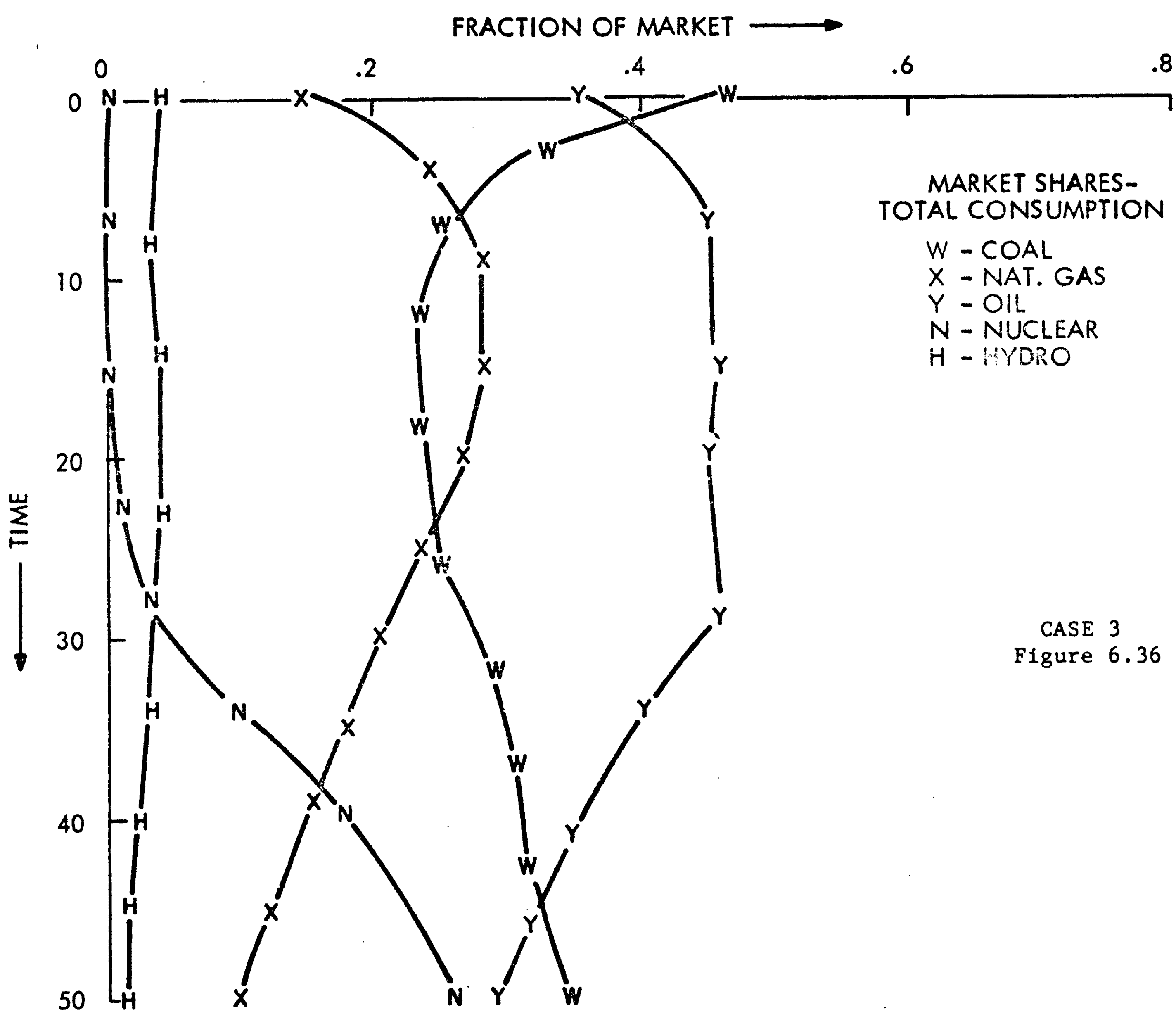
CASE 3
Figure 6.33



CASE 3
Figure 6.34



CASE 3
Figure 6.35



CASE 3
Figure 6.36

Table 6.6

Supply Summary Case No. 3

Variable	Model Value	NPC Value
	(in mQ's)	
Total energy consumption	142.1	125.0
Domestic oil production	19.0	22.0
Oil imports (input to model)	33.1	31.0
Domestic natural gas production	16.2	14.5
Natural gas imports (input to model)	4.5	6.1
Gas from coal gasification (input)	1.6	0.9
Domestic coal consumption	42.9	28.0
Electricity production	17.0	16.4
Nuclear used in electricity production	21.3	19.0

1985 Values

6.4 Summary --- Case Studies

The rather optimistic outlook of case no. 1 is changed drastically in both cases no. 2 and no. 3, and for different reasons. Neither the scenario for case no. 2 or case no. 3 are outside the realm of possibilities. An even more pessimistic outlook is obtainable if the decreased oil imports of case no. 2 were used in case no. 3. A summary of the results of these studies is given in table 6.7.

In case study no. 1, a rather optimistic outlook for oil and natural gas was entered into the model. As would be expected under these conditions, the oil and gas are used directly in the primary consuming sectors and the historical electricity growth rate declines markedly.

In case study no. 2, cost escalation in oil was included, much more stringent oil import quotas were hypothesized, and environmental constraints were included in electricity supply. This provided for a much more pessimistic outlook in energy supply, in that prices of oil, natural gas and electricity rose significantly. The oil shortfall was taken up by coal and gas directly, and coal and nuclear through electricity.

In comparing case no. 1 with case no. 2, an interesting conflict of policy is detected. The environmental factors encouraged the use of cleaner fuels in electricity supply, but the import policies made these cleaner fuels less available. Rather than decreasing coal consumption from case no. 1 to case 2 as the environmental constraints favored, the higher prices of oil and gas and the higher electricity production

Table 6.7

Case Study Summary

Case	Characteristics	Supply Summary 1985 (in mQ's)		Fuel Price Indices 1985 (1947 = 1.00)	
Base Case	1. See Table 5.1	1. Total consumption	119.0	Coal	0.89
		2. Domestic oil production	22.9	Nat. Gas	3.01
		3. Oil imports	22.5	Oil	1.90
		4. Domestic gas production	25.7	Elec.	0.51
		5. Gas imports	0.0		
		6. Domestic coal production	32.5		
		7. Electricity production	12.6		
		8. Nuclear used in elec.	11.9		
Case no. 1	1. Gas imports at BNG levels	1. Total consumption	117.0	Coal	0.83
	2. Coal gas at BNG levels	2. Domestic oil production	20.7	Gas	2.26
	3. Gas reserves adds at BNG levels	3. Oil imports	33.1	Oil	1.27
	4. Oil imports at NPC levels	4. Domestic gas Production	13.4	Elec.	0.44
	5. Gas costs escalating 2%/yr.	5. Gas imports	4.5		
	6. Everything else as in base case	6. Domestic coal consumption	30.1		
		7. Electricity production	11.0		
		8. Nuclear used in elec.	10.0		
Case no. 2	1. Coal burning limitations in electricity	1. Total consumption	129.8	Coal	0.87
	2. Fossil plant costs increased by 25%	2. Domestic Oil production	22.0	Gas	4.49
	3. Oil costs escalating 2%/yr.	3. Oil imports	19.2	Oil	3.36
	4. Oil imports increase at half NPC rate	4. Domestic gas production	23.4	Elec.	0.69
	5. Everything else as in case 1	5. Gas imports	4.5		
		6. Domestic coal consumption	32.4		
		7. Electricity production	16.8		
		8. Nuclear used in elec.	23.1		
Case no. 3	1. Oil <u>and</u> gas costs escalating at 5% per yr.	1. Total consumption	142.1	Coal	0.92
	2. Fossil plant costs increased by 25%	2. Domestic oil production	19.0	Gas	3.75
	3. Consumption growth rates increased by 25%	3. Oil imports	33.1	Oil	2.16
	4. Everything else as in case 1	4. Domestic gas production	16.2	Elec.	0.56
		5. Gas imports	4.5		
		6. Domestic coal consumption	43.0		
		7. Electricity production	17.0		
		8. Nuclear used in elec.	21.3		

Table 6.7 (Continued)

Consumption Summary 1985

	Case I	Case II	Case III
R + C consumption	32.5	32.5	38.1
Ind. heating consumption	33.5	33.5	36.8
Transportation consumption	25.4	25.4	28.2
R + C consumption coal	0.47	0.60	0.62
" " gas	9.59	15.50	12.89
" " oil	16.32	6.63	14.70
" " elec.	6.09	9.73	9.91
Ind. heating consumption coal	9.09	14.81	13.31
" " " gas	8.19	7.11	7.24
" " " oil	11.38	4.60	9.19
" " " elec.	4.84	6.98	7.02
Trans. consumption coal	0.017	0.019	0.020
" " gas	0.69	0.78	0.81
" " oil	24.69	24.61	27.38
" " elec.	0.027	0.030	0.032
Electricity consumption	10.69	16.75	16.97
Elec. consumption of coal	18.42	14.84	26.84
" " " gas	1.51	6.15	1.31
" " " oil	1.38	5.42	0.79
" " " nuclear	10.05	23.12	21.35
" " " hydro	3.50	3.50	3.50
Oil reserves	150.8	100.7	153.3
Nat. gas reserves	286.2	234.6	290.4

All units in mQ's.

increased total coal consumption slightly. For other than national security purposes, case no. 2 looks less desirable than case no. 1, but it may be where present policy is leading and may be worth the costs for national security purposes. This is a policy question which is not to be decided here, rather the purpose here is only to demonstrate the utility of the model in analyzing these issues.

In case no. 3, even higher cost escalation was assumed in oil and gas but the projected imports of case no. 1 were available; it was assumed coal burning technology was sufficient to meet environmental standards in electricity supply, and growth in overall consumption was 25% higher than historical trends. Again the effects were severe compared to case no. 1, but price-wise slightly less so than those of case no. 2 mainly because of the increased foreign oil availability.

In this case it can also be seen that the rapidly escalating costs discourage intensive production in oil and gas, and the production levels for these commodities peak and tail off at considerably lower values than in case no. 2. The same thing would have happened in case no. 2 if it were not for the increased electricity demand of oil and gas derived from the fuel burning limitations imposed in that case. This indicates that the environmental constraints entered in case no. 2 were even more severe than the results of that single run show. Further, it is coal consumption that increases to meet the added demand in case no. 3. For environmental purposes, advanced conversion technology of coal to liquid and gaseous fuels is obviously needed.

Clearly, for a complete analysis of any issue many simulations for many different scenarios would be needed. The purpose here is only to show how the model can be adopted to analyze a complex entanglement of issues in a rational manner. The results given here are not to be considered projections by the author, but rather only an assessment of the hypothesized conditions.

In fact, these three case studies are only a small sampling of what is needed to analyze hypothesized or expected occurrences in the interfuel competition model. The results presented are derived by varying basically only the oil imports, cost per unit capacity in oil and natural gas supply, the primary consuming sector growth rates, and possible environmental constraints in electricity supply. Other variables, such as the rate of reserve additions in oil and natural gas, the breeder reactor, sources of synthetic crude oil, changing consumer preferences, the electric car, and others can be incorporated into the model behavior. The model is useful to both assess their likely impact on the future energy supply demand balance and also to ascertain under what conditions new technologies or augmented supplies are needed.

The results of these case studies are also enlightening for other reasons. First of all the plausibility of the behavior within the constraints of the model boundaries increases one's confidence in the formulation. In case study no. 1, where the assumptions and inputs derived from the NPC and BMG reports were entered into the model --- their results were obtained. The NPC's projection of oil imports that would stabilize prices under their optimistic conditions stabilized prices in the model. But also, the stable prices indicated that their projected growth rate in electricity supply was too high if prices really were stable. The model forces consistent thinking about this hypothesized set of conditions. These results indicate that the model is performing well both qualitatively and quantitatively compared to past data and expected future trends in the energy system, and confidence can be placed in the model results.

Secondly, the case studies brought to light some of the major limitations of the model in its present formulation. The economic cost structure is explicitly contained in the model for only conventional production of coal, oil, natural gas, and electricity (including nuclear). Other unconventional sources, the results of exploration, and imports are entered as exogenous inputs into the model without the cost structure included. Because of this, inconsistencies in the resulting price trends and the levels of production from unconventional sources, or levels of imports, or rate of reserve additions may result. In these cases the model must be used as an interactive tool, with the exogenous inputs adjusted to be consistent with the resulting price trends. This limitation is not severe as long as the eventual user is aware and compensates for it.

Finally, energy prices and costs of supplying this energy in reality impinge upon the economic growth processes and levels of consumption. This relationship is also neglected in the model structure, and here also the interaction between energy prices and consumption growth trends must be included by the user as he sees fit. All these limitations are identified and discussed in the next chapter as areas for further study.

CHAPTER 7

FURTHER RESEARCH, CONCLUSIONS

7.1 Further Research

In many areas potential further development and refinement of the model could be done, depending upon the particular problems to be addressed. These could be to adapt the model to more specific policy issues, or also to internalize some of the feedback structure which was neglected in this study but exists in reality.

Since the model is working so well on this aggregated level, it might be desirable to adapt it to regional or sub-regional problems. The generic structures for the supply and consuming sectors are described in this work. To disaggregate regionally, one could use these same structures for as many regions as one desires. However, to do this one would have to define all the parameters and constants used in the model for each region of interest, and this may be difficult. Much more data exists on a national level than exists regional or statewide levels, and the task of parameter definition for these smaller units may be difficult.[1] It is when undertaking this regional disaggregation that one would also include the inter-regional transportation links and the relevant costs. Conceivably, the demand and supply models as given in this work could be completely disconnected, with the transportation problem modeled as a linear program in between. This concept

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[1]However, the same data needs to be assembled to identify in a rigorous fashion what some of the parameters for the aggregated model should be (see section 4.3).

has been applied in oil supply and apparently worked quite well.[1] It might be useful to adopt that methodology here.

One might also want to disaggregate by fuel products and fuel quality. Oil in this model is not disaggregated into the many oil products, some of which compete against each other. A more refined oil model would probably need this detail. Certainly disaggregation for fuel quality (low-sulfur vs. high sulfur) could be a desired refinement if environmental issues were to be addressed in more detail.

Another area where further model development would be desirable is the incorporation of the exploration process into the feedback structure of the existing model. This is a complex and difficult process to model. First of all the factors that influence the decision to invest in exploration are required. Secondly, some sort of characterization of the natural resource endowment is needed. And finally, a description of the efficiency of the exploration and the actual finding of these resources must be developed. It is likely here that some sort of probabilistic structure is needed as uncertainties abound in the process.

A long term objective is to include the interfuel competition model into the overall energy system structure discussed in appendix A. The model described in this work is compatible with that overall modeling effort, and certainly it allows one to be much more explicit in the definition of relationships discussed in that work (see section

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[1] Debanne, J. G., A Continental Oil Supply and Distribution Model, paper presented at 44th Annual Fall Meeting of the Society of Petroleum Engineers of AIME, Denver, Colorado, Sept. 28 - Oct. 1, 1969.

2.3). It is when this is done that the effects of energy on economic growth and growth in consumption can be made more explicit.

Finally, it may be desirable to include endogenously the cost structure and dynamic behavior of some of the sources of energy supply which were considered inputs to the model in this work. For example, the cost and dynamics of breeder reactors and/or coal gasification might be included explicitly, so that instead of inputting what one thinks the actual supply from these sources would be, he only inputs the relevant cost trends. The model then simulates the construction and growth from these sources depending upon price trends and its competitive position.

7.2 Conclusions

This research has been on the development, structural formulation, validity and limitations of a dynamic interfuel competition model. The emphasis has been on the development of a tool useful for analysis of trends and influences impinging upon the dynamic energy supply demand balances. The assessment of the validity and usefulness of this tool are issues addressed at length in chapters 5 and 6, while the theory and structural formulation are discussed in chapters 2, 3, and 4. Many assumptions were made, and the quality of the results tends to substantiate those assumptions. Many simplifications were made in considering, at least in the initial formulation, many inputs to the model as exogenous and independent of variables endogenously contained within the model framework. When using the model, the user must be aware of these simplifications and be prepared to compensate for them.

The model is a useful tool in that it contains the economic cost structure and the physical dynamics of the interfuel competition processes on the aggregated level modeled. The analyst must provide only the relevant inputs in the supply and consuming sectors. The model contains the supply expansion dynamics and fuel selection process, and can quickly simulate future U. S. energy balances for a variety of scenarios for both supply (domestic and foreign) and consumption trends. Environmental constraints, as they impinge upon the economic decision processes or limit available options can be included. The impacts and need of new technologies can be assessed. The effects of broad scale policy (such as import policies) can be simulated and analyzed. Still, the model is an interactive tool, and only as useful as the eventual user can tax its capabilities.

Clearly, there are also many issues that cannot adequately be treated with an aggregated model. Many regulatory constraints and environmental problems occur on a regional or sub-regional level. Some problems have to do with transportation/distribution constraints on energy, and these problems are completely neglected in this work. However, as a tool for industry planning and a vehicle for analysis of governmental policy on a broadly aggregated level, the model does apply and can be a valuable source of information.

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APPENDIX A

PRELIMINARY STUDIES[1]

Preliminary investigations of certain aspects of the energy system dynamic structure and behavior have been done at MIT. This work focused on the state variables that are important in the energy system dynamics and on their interrelations in the total system behavior. Models have been constructed and simulated on the computer in DYNAMO language. A summary of the structural formulation is given here.

The model discussed here is the result of using a completely postulative approach to model development. It is still in its beginning stages of development, is built on incomplete information about the energy system, and has not met the model verification requirements as set forth in this work. The model is a highly aggregated model for the total U. S. energy system, which focuses on some of important relationships between energy, the economy, and the environment.

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[1]For a more complete discussion of these modeling efforts, the reader should consult Technology Review, Oct./Nov. 1971, in "Energy, the Economy, and the Environment", by David C. White, or "Dynamics of Energy Systems", A Program of Research by M.I.T., April 28, 1971.

Model Structure

This model considers energy supply and demand in the total, with no disaggregation for the fuels. A model of this sort does not permit one to investigate the effects of interfuel competition or the depletion of resources of any given fuel. Yet, it does provide a framework to study the macroeconomic problems of investment demand, the effects of cost of energy as a whole on demand and its growth, and the effects of environmental concern on the dynamics of energy supply. The effort to this point has been in trying to identify the structure of the interrelationships in the energy system. Little or no effort has been expended in quantifying the relationships, other than trying to determine relative strengths of parallel relationships for simulation purposes.

The basic structure is given in Figures A.1 and A.2. The model is proposed to cover a period of 5 to 50 years. The node labeled graphs depict the basic state variables in the model and the basic interrelationships. The following discusses the relationships given in the figure, but in no way gives a complete description of the implications of the relationships. Many assumptions were made in the initial formulation, and all these imply further study needs to be made in that portion of the model.

The aggregate demand is modeled as follows. Energy demand per capita is assumed to be correlated with real gross national product (GNP) per capita. This has in fact been approximately true in the U. S.

for the last 30 years.[1] It also is true for a collection of world nations.[2] Population is assumed to grow exponentially at a constant rate. The model for economic growth is basically a Harrod-Domar model. Part of the GNP is made up of consumption (government and personal) and part goes to investment which results in further growth of the GNP.

For aggregated energy supply, the decision to build new capacity (electric power plants, oil refineries, etc.) is assumed to be based on the trends in growth in the energy demand, the reserve capacity necessary to achieve a reliable supply, and the desired capacity margin for economical operation. The decision to build is designated by the committment rate in Figure A.1. However, in reality even after the decision to build new capacity there exists an acquisition delay before this capacity is productive. This is made up of siting and construction times to physically construct this capacity. The energy demand then determines the capacity utilization, and the reserve capacity which closes the loop. This is the basic supply and demand model.

However, there exist many complex ties between supply and demand outside of the basic supply and demand parameters. These are superimposed on Figure A.1 in Figure A.2. It has been assumed that energy is required for growth in GNP. A measure of the energy available is the reserve capacity, and it is assumed that this affects the rate of new capital investment and GNP growth. For example, a shortage in

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[1]White, David C., "Energy, the Economy, and the Environment", Technology Review, Vol. 74, No. 1, October/November, 1971, pg. 19.

[2]Ibid., pg. 23.

ENERGY SYSTEM SUPPLY AND DEMAND

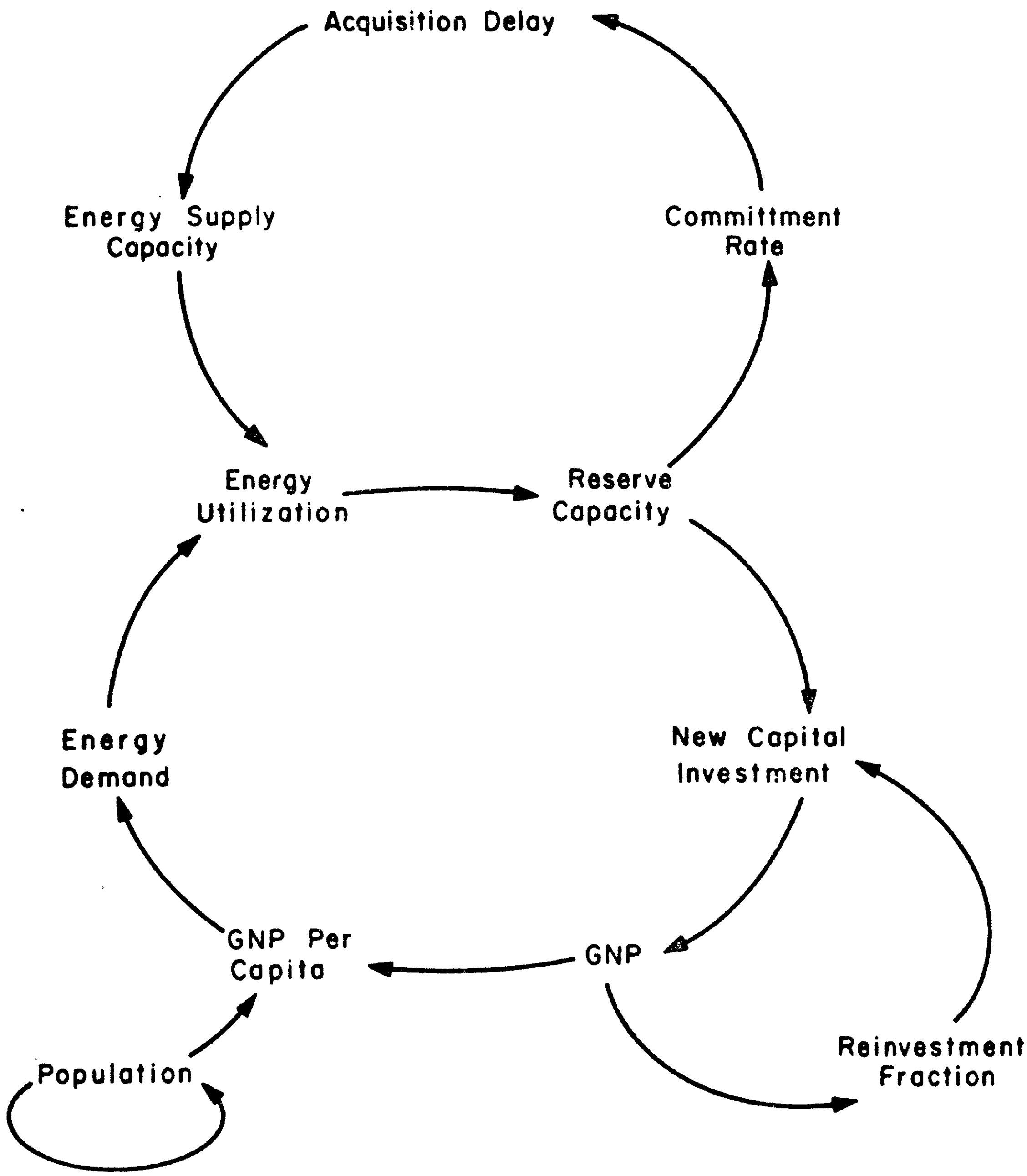

Figure A.1

PRELIMINARY ENERGY SYSTEM STRUCTURE

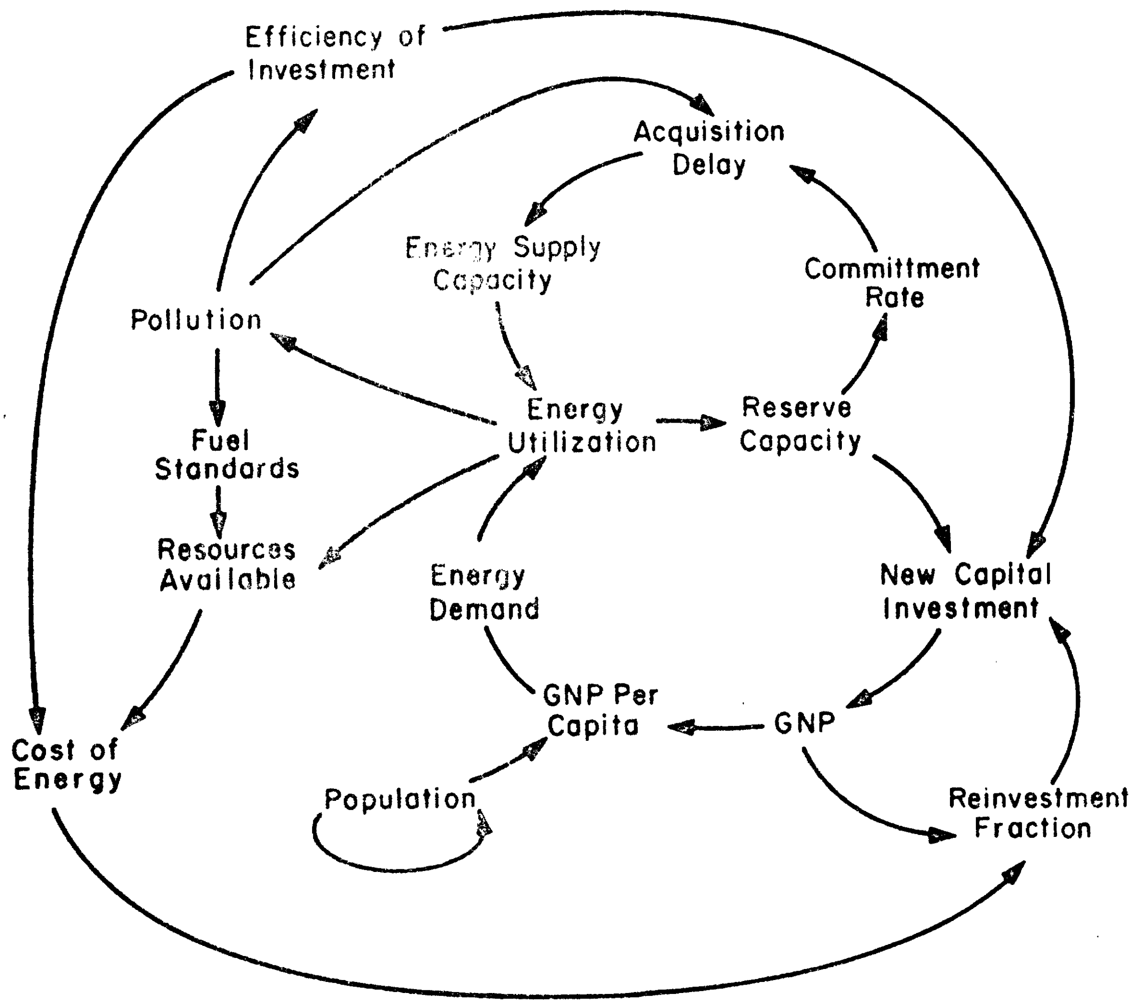

Figure A.2

reserve (in energy supply) would decrease the rate of new capital investment. Pollution and environmental concern affect siting and acquisition delays as evidenced by the delays in acquiring new power plants.

There also exist economic ties from the supply sector back to the demand sector, via the cost of energy and the investment demand for energy. Changes in these two quantities can be brought about by pollution, resource availability, and technology. Pollution has been assumed to be related to the rate at which energy is utilized. Pollution levels affect the desire to combat pollution and the efficiency of investment in the supply sector. That is, pollution abatement equipment raises the capital outlay per unit capacity for the supply sector. This in turn lowers the pollution generation rate. If these capital outlays are large enough, they could effect the capital available for investment in the rest of the economy. At present, about 20% of the investment in new plant and equipment in the U.S. goes to energy.[1] In Figure A.2 energy investment is subtracted from new capital investment in the rest of the economy.

Figure A.2 also depicts that, as energy is used, this depletes the energy resources available at a given price. Pollution affects the fuel standards, which in turn affects the resources available and exploitable at a given price. The ease with which these resources may be exploited and the efficiency of investment affect the cost of energy,

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[1] U. S. Energy Policies, An Agenda for Research, by Resources for the Future, Inc., Distributed by The John Hopkins Press, Baltimore, Maryland, 1968, pg. 23.

which feeds back to reinvestment. Here, it has been assumed that the demand for energy is very inelastic. That is, people will continue to consume energy in one form or another barring drastic price changes. This suggests that as the cost of energy fluctuates, the consumption fraction of GNP for energy fluctuates accordingly, and vice versa for the reinvestment fraction, which affects economic growth.

In addition to the many variables displayed in the figures, there are a number of auxiliary variables and parameters in the energy system that have been introduced into the model that have not been discussed here. The purpose here is not to discuss the relative merits of the structure or formulation of this model, but rather only to convey the overall energy system structure so that the interfuel competition model can be placed in perspective. For a more detailed discussion of this model the reader should consult the references given at the beginning of this appendix.

APPENDIX B

DATA

B.1 National Aggregated Data

The following tables contain the data used for model validation and analysis of the model behavior. The first eight tables (B1 - B9) contain nationally aggregated data on fuel prices and fuel consumption. Following these eight tables is the regional data that is more useful for a rigorous identification of the demand model parameters. Unfortunately there is just not enough available for statistically significant results.

See the list of data sources following the appendix for a summary list of sources.

Fuel Prices

Year	Bituminous Coal[1] ($/ton at merchant coal ovens)	Petroleum[1] (¢/gal. of #2 fuel oil at Phil. refinery)	Natural Gas[1] (¢/MCF at point of consumption)	Electricity[2] (¢/KWH to Residential)
1947	7.43	7.02	23.2	3.09
1948	8.74	9.71	24.1	3.01
1949	9.33	8.17	25.2	2.95
1950	9.27	8.35	26.6	2.88
1951	9.51	9.30	29.8	2.81
1952	9.85	9.60	33.2	2.77
1953	10.01	10.10	35.5	2.74
1954	9.57	9.70	38.1	2.69
1955	9.16	9.90	40.0	2.64
1956	9.85	10.40	41.5	2.60
1957	10.76	11.06	43.1	2.56
1958	10.74	9.59	46.2	2.53
1959	10.49	9.86	47.7	2.50
1960	10.54	9.29	50.1	2.47
1961	9.83	9.85	51.0	2.45
1962	9.71	10.13	51.4	2.41
1963	9.40	9.80	51.2	2.37
1964	9.84	9.24	51.6	2.31
1965	9.65	9.53	51.4	2.25
1966	9.81	10.02	52.3	2.20
1967	10.33	10.57	51.9	2.17
1968	10.58	10.90	50.4	2.12
1969	10.75	10.90	51.5	2.09

Table B-1

[1] Source, Minerals Yearbook, various issues.

[2] Source, EEI Statistical Yearbook, various issues, and Historical Statistics.

Fuel Prices - Wholesale

Year	Bituminous Coal[1] ($/ton)	Crude Petroleum[1] ($/bbl)	Natural Gas[1] (¢/MCF)	Natural Gas Liquids[1] (¢/gal)	Wholesale Price Index[2] (1947=100)
1947	4.16	1.93	6.0	5.3	100.0
1948	4.99	2.60	6.5	7.4	108.2
1949	4.88	2.54	6.3	6.1	102.8
1950	4.84	2.51	6.5	5.5	106.8
1951	4.92	2.53	7.3	5.9	119.0
1952	4.90	2.53	7.8	5.7	115.8
1953	4.92	2.68	9.2	6.0	114.0
1954	4.52	2.78	10.1	5.5	114.2
1955	4.50	2.77	10.4	5.2	114.8
1956	4.82	2.78	10.8	5.7	118.5
1957	5.08	3.09	11.3	5.5	122.0
1958	4.86	3.01	11.9	5.6	123.8
1959	4.77	2.90	12.9	5.6	123.9
1960	4.69	2.88	14.0	5.7	124.0
1961	4.58	2.89	15.1	5.1	123.7
1962	4.48	2.90	15.5	5.1	123.9
1963	4.39	2.89	15.9	4.7	123.7
1964	4.45	2.88	15.4	4.7	123.8
1965	4.44	2.86	15.6	4.9	126.2
1966	4.54	2.88	15.7	5.3	130.3
1967	4.62	2.92	16.0	5.5	130.9
1968	4.67	2.94	16.4	4.9	134.0
1969	4.99	3.09	16.7	4.7	139.2

Table B-2

[1] Source, Minerals Yearbook, various issues.

[2] Source, Wholesale Prices and Price Indices, U. S. Dept. of Labor, Bureau of Labor Statistics, various issues.

Fuel Price Indices Relative to the WPI

(1947=100)

Year	Coal	Natural Gas	Oil	Electricity
1947	100.0	100.0	100.0	100.0
1948	110.8	100.0	124.4	90.0
1949	114.0	102.0	127.9	93.0
1950	108.7	101.2	121.6	87.0
1951	99.3	102.2	110.1	76.0
1952	101.7	112.3	113.2	77.0
1953	103.6	134.2	121.6	78.0
1954	95.0	147.1	125.9	76.0
1955	94.3	151.0	125.0	74.0
1956	97.8	152.0	121.5	71.0
1957	100.0	154.3	131.0	68.0
1958	94.4	160.1	126.2	66.0
1959	92.4	173.8	121.5	65.0
1960	91.0	188.0	120.5	64.0
1961	89.1	204.0	121.1	64.0
1962	87.2	209.0	121.5	63.0
1963	85.4	214.0	121.0	62.0
1964	86.5	207.5	120.8	60.0
1965	84.5	206.0	117.2	58.0
1966	83.7	200.5	114.3	54.0
1967	84.8	204.0	115.8	54.0
1968	83.6	204.0	113.8	51.0
1969	86.2	200.0	114.9	49.0

Source: Calculated from table B.2 and electricity price of table B.1.

TABLE B-3

Gasoline Prices[1]

Year	at refineries in Oklahoma	Tank wagon prices to dealers at 55 cities	station prices with tax
1969	12.18	17.11	34.84
1968	11.73	16.51	33.71
1967	12.38	16.31	33.16
1966	12.25	15.83	32.08
1965[2]	12.21	15.38	31.15
1964[3]	11.59	14.82	30.35
1963	12.15	15.22	30.42
1962	12.56	15.45	30.64
1961	12.80	15.80	30.76
1960	12.47	16.08	31.13
1959[4]	12.32	16.09	30.49
1958	12.43	16.22	30.38
1957	12.31	16.69	30.96
1956[5]	11.62	16.34	29.93
1955[6]	11.05	16.18	29.07
1954[7]	10.96	16.19	29.04
1953	11.02	15.95	28.69
1952	10.60	15.27	27.56
1951	10.56	15.33	25.56
1950	10.32	15.10	25.26
1949[8]	10.15	15.05	25.29
1948[9]	11.19	14.55	24.38
1947	8.42	12.33	21.61

[1] All prices are in cents/gallon and are the average prices for that year.
[2] 92 octane since '65 [3] 91 octane [4] 89 octane before July 1, 1959
[5] 88 octane [6] 82 octane [7] 82 octane
[8] Grade 1 before June 1, 1949 [9] 73-75 octane

Source, Minerals Yearbook, various issues.

Table B-4

Residual Fuel Oil Prices[1]

Year	#6 at refineries in Oklahoma	at Gulf Coast	Bunker "C" at New York
1969	1.71	2.22	2.28
1968	1.67	2.22	2.28
1967	2.15	2.23	2.29
1966	2.15	2.19	2.25
1965	2.08	2.19	2.26
1964	1.96	2.19	2.30
1963	1.90	2.19	2.30
1962	1.90	2.30	2.47
1961	1.88	2.30	2.52
1960	1.89	2.19	2.45
1959	1.97	2.10	2.38
1958	1.73	2.31	2.60
1957	2.25	2.72	3.12
1956	2.14	2.23	2.76
1955	1.74	2.11	2.48
1954	1.31	1.95	2.24
1953	1.15	1.80	2.16
1952	1.26	1.75	2.31
1951	1.80	1.85	2.32
1950	1.64	1.78	2.09
1949	1.08	1.57	1.90
1948	2.44	2.82	3.00
1947	2.01	2.04	2.29

[1] All prices are in dollars/barrel and are the average price for the year.

Source, Minerals Yearbook, various issues

Table B-5

Consumption of Energy Resources in Household and Commercial Sector[1]

Year	Anthracite	Bituminous Coal and Lignite	Natural Gas Dry	Petroleum	Total Direct Resources Inputs	Utility Electricity	Total Sector Energy Inputs
1947	813	2586	1125	2251	6774	391	7165
1948	920	2318	1262	2539	7039	442	7481
1949	667	2358	1387	2472	6884	488	7373
1950	660	2253	1642	3038	7593	546	8139
1951	652	1995	2007	3202	7857	615	8471
1952	619	1797	2213	3350	7978	666	8644
1953	457	1615	2294	3391	7757	733	8490
1954	346	1406	2566	3650	7968	797	8765
1955	331	1444	2850	4001	8625	854	9479
1956	331	1333	3151	4183	8997	935	9933
1957	271	981	3391	4069	8712	1019	9730
1958	238	988	3712	4568	9505	1095	10601
1959	192	815	4024	4719	9750	1203	10952
1960	172	851	4268	4923	10214	1262	11476
1961	129	783	4477	5028	10417	1385	11802
1962	121	797	4849	5227	10996	1490	12486
1963	103	671	5027	5258	11059	1645	12704
1964	85	560	5343	5190	11178	1792	12970
1965	168	546	5518	5635	11867	1948	13815
1966	143	575	5945	5766	12429	2101	14530
1967	128	497	6223	6206	13054	2257	15311
1968	122	447	6451	6129	13148	2467	15615
1969	118	376	6897	6237	13628	2681	16309

[1]All figures are in trillions of BTU's.

Source, 1947 to 1965 from Morrison and Readling, 1966 to 1969 from *Minerals Yearbook*, various issues.

Table B-6

Consumption of Energy Resources
in Industrial Sector[1]

Year	Anthracite	Bituminous Coal and Lignite	Natural Gas Dry	Petroleum	Total Direct Resources Inputs	Utility Electricity Purchased	Total Sector Energy Inputs
1947	285	7014	3007	2490	12795	459	13254
1948	104	6412	3276	2530	12322	500	12822
1949	65	5506	3332	2466	11369	485	11854
1950	127	5830	3728	2642	12326	559	12885
1951	60	6343	4251	3044	13698	656	14354
1952	60	5613	4392	3034	13098	682	13780
1953	48	6057	4554	3092	13751	765	14515
1954	44	4815	4537	3119	12515	802	13317
1955	53	5796	4935	3329	14113	1008	15121
1956	61	5901	5094	3688	14744	1113	15857
1957	66	5792	5331	3478	14667	1133	15801
1958	54	4812	5540	3292	13698	1102	14799
1959	55	4692	5921	3458	14126	1215	15341
1960	54	4844	6287	3682	14867	1306	16173
1961	46	4694	6471	3682	14893	1306	16200
1962	49	4762	6841	3880	15532	1403	16934
1963	57	5015	7160	3994	16226	1464	17690
1964	46	5362	7451	4184	17043	1544	18587
1965	101	5640	7671	4138	17550	1634	19184
1966	88	5806	8203	4352	18449	1788	20237
1967	90	5553	8599	4298	18540	1868	20408
1968	81	5537	9274	4820	19712	2044	21756
1969	72	5505	9894	5099	20570	2219	22789

[1] All figures are in trillions of BTU's.

Source, 1947 to 1965 from Morrison and Readling, 1966 to 1969 from *Minerals Yearbook*, various issues.

Table B-7

Consumption of Energy Resources in Electric Utility Sector[1]

Year	Anthracite	Bituminous Coal and Lignite	Natural Gas Dry	Petroleum	Hydro-power	Nuclear Power	Total Gross Energy Inputs	Utility Elec. Pur-chased
1947	90	1994	386	468	1459	-	4397	879
1948	101	2291	495	444	1507	-	4837	970
1949	85	1936	569	577	1565	-	4733	999
1950	92	2136	651	662	1601	-	5142	1129
1951	98	2439	791	499	1592	-	5419	1294
1952	96	2492	942	492	1614	-	5635	1370
1953	91	2714	1070	577	1550	-	6003	1517
1954	80	2786	1206	480	1479	-	6031	1617
1955	82	3402	1194	512	1497	-	6686	1880
1956	84	3729	1283	497	1598	-	7190	2065
1957	85	3796	1385	512	1568	1	7348	2167
1958	71	3678	1421	515	1740	2	7427	2212
1959	67	3989	1684	546	1695	2	7984	2435
1960	70	4187	1785	564	1775	5	8387	2586
1961	64	4311	1889	577	1628	17	8486	2710
1962	58	4580	2034	579	1780	23	9055	2910
1963	55	5017	2218	600	1740	33	9663	3128
1964	57	5353	2403	636	1873	34	10356	3359
1965	55	5825	2392	744	2049	39	11104	3600
1966	56	6341	2692	905	2073	58	12125	3905
1967	55	6523	2834	1013	2341	81	12847	4142
1968	56	7074	3245	1181	2355	132	14043	4529
1969	53	7403	3598	1603	2635	141	15433	4920

[1] All figures are in trillions of BTU's.

Source 1947 to 1965, Morrison and Readling, 1966 to 1969 from Minerals Yearbook, various issues.

Table B-8

Consumption of Energy Resources in Transportation Sector[1]

Year	Anthracite	Bituminous Coal and Lignite	Natural Gas Dry	Petroleum	Total Direct Resources Inputs	Utility Electricity Purchased	Total Sector Energy Inputs
1947	24	3006	Neg.	5761	8791	29	8820
1948	23	2601	Neg.	6157	8780	27	8808
1949	19	1873	Not Available	6183	8075	25	8100
1950	20	1681	130	6785	8616	24	8640
1951	17	1508	199	7482	9207	23	9230
1952	16	1070	214	7868	9168	22	9190
1953	13	796	238	8158	9205	20	9225
1954	11	505	239	8358	9114	18	9131
1955	12	462	254	9109	9837	19	9856
1956	10	377	306	9448	10142	17	10159
1957	9	268	310	9649	10236	15	10251
1958	9	130	323	9818	10280	16	10296
1959	7	100	362	9923	10392	17	10409
1960	6	85	359	10372	10822	18	10840
1961	Neg.	22	391	10575	10988	19	11007
1962	Neg.	20	396	11001	11416	18	11434
1963	Neg.	19	439	11506	11964	19	11983
1964	Neg.	20	451	11791	12262	20	12282
1965	Neg.	19	517	12179	12715	18	12733
1966	Neg.	18	553	12777	13348	16	13364
1967	Neg.	14	594	13542	14150	17	14167
1968	Neg.	11	610	14681	15302	18	15320
1969	Neg.	9	651	15290	15950	20	15970

[1] All figures are in trillions of BTU's.

Source, 1947 to 1965 from Morrison and Readling, 1966 to 1969 from Minerals Yearbook, various issues.

Table B-9

B.2 Regional Data

The following five tables (B-10 - B-14) contain regional classifications and regional data.

Regional Classifications

Region	
I	Maine
	N. H.
	VT.
	MASS.
	R. I.
	CONN.
I-A	N. Y.
	N. J.
	PA.
	DEL.
	MD.
	D. C.
I-B	VA.
	W. V.
	N. C.
	S. C.
	GA.
	FLA.
	KY.
	TENN.
	ALA.
	MISS.
	OHIO
I-C	IND.
	ILL.
	MICH.
	WISC.
II-A	MINN.
	IOWA
	MO.
	N. D.
	S. D.
	NEB.
II-B	ARK.
	LA.
	OKLA.
	TEX.
	N. M.
	KANS.
III-A	MONT.
	IDAHO
	WYO.
	UTAH
	COLO.
	WASH.
	OREG.
III-B	ARIZ.
	NEV.
	CAL.
ALAS.	Not included
HI.	

Table B-10

Consumption Residential and Commercial Sector
(in Trillions of Btu's)

Region	Year	Coal	Nat. Gas	Oil	Elec.
I	1960	16.2	88.1	743.4	51.4
IA	"	52.4	757.5	1369.9	200.4
IB	"	221.9	456.8	521.3	300.5
IC	"	375.6	702.4	776.4	209.3
IIA	"	129.7	408.6	324.5	75.1
IIB	"	8.3	614.6	154.3	141.9
IIIA	"	44.2	191.9	213.1	121.6
IIIB	"	.8	547.6	74.1	139.7
I	1965	8.9	128.4	836.9	79.3
IA	"	38.8	957.6	1722.9	319.9
IB	"	159.9	1114.2	589.9	467.8
IC	"	247.9	1124.4	764.6	294.3
IIA	"	51.1	521.1	337.1	115.0
IIB	"	3.2	688.7	180.0	239.4
IIIA	"	32.7	267.1	234.7	161.6
IIIB	"	2.6	728.3	57.3	223.0

Source, Zaffarano, Supply and Demand for Energy---

Table B-11

Consumption Industrial Sector
(in Trillions of Btu's)

Region	Year	Coal	Nat. Gas	Oil	Elec.
I	1960	63.7	26.3	174.9	45.1
IA	"	1324.2	377.5	514.2	216.1
IB	"	1522.5	886.3	376.8	488.6
IC	"	1387.7	483.4	308.6	186.3
IIA	"	232.6	242.8	67.0	47.4
IIB	"	53.3	3450.7	388.0	115.2
IIIA	"	145.2	288.6	95.6	112.6
IIIB	"	38.4	531.0	132.1	114.7
I	1965	28.0	44.8	163.6	55.4
IA	"	1482.7	546.4	470.8	267.2
IB	"	1882.3	1207.5	383.6	573.0
IC	"	1693.0	747.7	272.0	245.3
IIA	"	279.4	368.2	67.2	62.9
IIB	"	52.4	3712.7	491.8	170.5
IIIA	"	160.9	404.5	88.6	161.5
IIIB	"	70.7	650.8	161.4	134.5

Source, Zaffarano, Supply and Demand for Energy---

Table B-12

Fossil Fuel Consumption Electricity Sector
(in Trillions of Btu's)

Region	Year	Coal	Nat. Gas	Oil
I	1960	159.5	13.4	106.7
IA	"	910.5	96.3	165.1
IB	"	1744.3	206.8	86.8
IC	"	1106.2	60.4	7.0
IIA	"	203.3	168.6	7.2
IIB	"	11.0	799.7	4.1
IIIA	"	52.4	43.9	15.8
IIIB	"	0.0	396.0	148.2
I	1965	238.2	10.9	144.3
IA	"	1259.1	101.0	257.0
IB	"	2328.8	191.6	180.6
IC	"	1508.0	64.8	5.5
IIA	"	295.0	170.0	6.5
IIB	"	66.8	1214.6	3.3
IIIA	"	90.6	33.6	10.6
IIIB	"	10.6	611.7	103.8

Source: 1960 and 1965 from Zaffarano, Supply and Demand for Energy---,
1969 from EEI Statistical Yearbook, 1970.

Table B-13 (cont. next pg.)

<u>Consumption Electricity Sector</u>

Region	Year	Coal	Nat. Gas	Oil
I	1969	131.0	5.32	350.0
IA	"	1320.0	154.0	585.0
IB	"	3400.0	381.0	308.0
IC	"	1920.0	136.0	15.3
IIA	"	430.0	209.0	9.4
IIB	"	56.3	1820.0	5.0
IIIA	"	126.0	43.6	10.9
IIIB	"	26.0	742.0	125.0

<u>Table B-13</u> (cont.)

Prices 1962 ¢/MMBTUs

Region	Coal[1]	Nat. Gas[1]	Oil[1]	Elec.[2]
I	35.6	34.6	34.2	2.16
IA	30.7	33.8	35.4	1.53
IB	24.0	25.3	41.4	1.33
IC	25.0	29.8	72.7	1.42
IIA	27.0	24.8	65.2	2.00
IIB	28.3	21.4	42.4	1.84
IIIA	18.4	28.1	44.4	0.87
IIIB	22.8	35.9	49.0	1.73
National Averages	25.6	26.3	34.5	1.68

[1] Source, EEI Statistical Yearbook, 1963

[2] Source, 1964 Federal Power Survey, pg. 281

Table B-14

B.3 Data Sources

1. Zaffarano, R. F., et. al., Supply and Demand for Energy in the United States by States and Regions, 1960 and 1965, U. S. Dept. of Interior, Bureau of Mines Information Circular 8434, 1970.

2. Edison Electric Institute, Historical Statistics of the Electric Utility Industry, 1963.

3. Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, various yrs.

4. Morrison, Warren E., and Readling, Charles I., An Energy Model for the United States, Featuring Energy Balances for the Years 1947 to 1965 and Projections and Forecasts to the Years 1980 and 2000, Washington, D. C., U. S. Dept. of Interior, Bureau of Mines Information Circular 8384, 1968.

5. National Power Survey, Federal Power Commission, U. S. Government Printing Office, Washington, 1964.

6. Minerals Yearbook, U. S. Dept. of Interior, Bureau of Mines, Washington, D. C., U. S. Government Printing Office, various issues.

7. U. S. Department of Labor, Bureau of Labor Statistics, Wholesale Prices and Price Indices, various issues.

APPENDIX C

INVESTMENT AND PRICING IN ENERGY SUPPLY[1]

In modeling the investment process in primary fuel supply, it is necessary to delineate the investment alternatives and the considerations affecting the levels of investment in each of these alternatives. The purpose of this appendix is to discuss the theory of this investment process. For ease of presentation the theory will be applied to only the petroleum industry; however it applies equally well to coal.

At any point in time an investor in oil supply has four alternatives. He can:

1. Invest in capacity on existing reservoirs to speed recovery of the oil in place in those reservoirs.
2. Invest in more complete recovery of the oil in place in those reservoirs.
3. Invest in exploration to find new sources of oil in place in hopes that the successful finding and development of those sources leads to his required return on this investment expenditure.
4. Do nothing.

It is also true that the list of four alternative investments above are not necessarily independent. At any point in time the investor is limited by the state of technology and nature as to what he can get for

[1]The assistance of Prof. Morris Adelman and Mr. Mike Telson is gratefully acknowledged.

his investment. The decision among the alternatives is related to the price an investor expects to receive for his eventually recovered oil and what it costs him for each of his alternatives. The do nothing alternative is the result if none of the other three alternatives are acceptable.

Under the assumption of perfect competition, each individual supplier is faced with a price he expects to receive for his product and must make his decisions based on this input. The aggregate of these perfectly competitive suppliers define a supply curve (the quantity these suppliers are willing to supply vs. the market price), which when given the demand curve determines the equilibrium price and quantity transacted in the marketplace. Let us for the moment assume price as a given and see how this affects the decision processes of a small individual supplier. Later the attempt will be made to relate this to the aggregate behavior.

C.1 Development Investment in Oil Supply

First let us look at the first investment alternative --- investment in capacity --- neglecting the other alternatives for the moment. Assume that we have a reservoir with recoverable oil at present prices equal to R_o. Assume that this R_o is fixed and independent of the level of producing capacity placed upon the reservoir. With an initial capacity q_o placed on the reservoir, the output of this capacity vs. time may be approximated by an exponential decline, where the total integrated output equals R_o.[1] If "a" is the decline rate of output, then over a sufficiently long time

$$R_o = \int_0^{\infty} q_o \, e^{-at} \, dt \ .$$

This means that

$$R_o = q_o \,/\, a \quad \text{or} \quad a = q_o \,/\, R_o \ .$$

Since a well does not really produce over an infinite length of time, the "a" calculated this way is a bit low, but for simplification it will be used as a surrogate. If future output is discounted at a rate "r", then the discounted accumulated output (termed the present barrel equivalents or PBE's) assuming continuous discounting is

$$PBE = \int_0^{\infty} q_o \, e^{-rt} \, e^{-at} \, dt$$

$$= \frac{q_o}{a+r} = \frac{q_o}{(q_o \,/\, R_o) + r} \qquad \text{Equation C.1}$$

Suppose that to install the initial capacity q_o an investment I is required.[2] An investor would be willing to invest in capacity on this reservoir only until the cost of the next PBE is just equal to the price he expects to receive for the PBE. In other words, the supplier will continue investing in capacity on this reservoir with the same

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[1]See Bradley, The Economics of Crude Oil Production, listed in references to Appendix C.

[2]The operating costs may be included in I. See Adelman, The World Petroleum Market, listed in references.

eventual output R_o until marginal cost of development just equals the price he expects to receive for the PBE's in the reservoir. If his investment is I then the marginal development cost (MDC) function is

$$MDC = \frac{\partial I}{\partial PBE} = \frac{\partial I}{\partial q_o} \cdot \frac{\partial q_o}{\partial PBE} \quad , \qquad \text{Equation C.2}$$

Both I and PBE are functions of q_o, the initial capacity installed. To find the level of initial capacity it is economical to install, all that is needed is I as a function of q_o. The MDC function is then only a function of q_o, and setting it equal to price we find the level of q_o economical to install. Suppose that a unit capacity cost b dollars, then

$$I = bq_o \quad , \quad \frac{\partial I}{\partial q_o} = b$$

$$\text{and} \quad \frac{\partial PBE}{\partial q_o} = \frac{rR_o^2}{(q_o + rR_o)^2} \quad .$$

Therefore the MDC function is

$$MDC = b\,\frac{(q_o + rR_o)^2}{rR_o^2} \quad . \qquad \text{Equation C.3}$$

For this same cost per unit capacity (b) the average cost per present barrel equivalent is[1]

$$AC = b(q_o / R_o + r) \quad . \qquad \text{Equation C.4}$$

---

[1]See Adelman, "Long Run Cost Trends".

These MDC and AC functions are shown graphically in figure C.1. In fact the MDC and AC functions are slightly different than those above because of the initial investment required in such things as access roads and gathering terminals. Therefore in reality the curves would look more like those in figure C.2. However for more intense levels of development, the curves of figure C.2 approach those of C.1.

If we set the MDC of equation C.4 equal to price (P), we get

$$q_o^* = R_o\left(\sqrt{\frac{Pr}{b}} - r\right) \quad . \qquad \text{Equation C.6}$$

This means that it is economical to install this capacity (q_o^*) on the reservoir, or at this level of capacity the marginal cost per PBE is just equal to price. At levels of investment below q_o^*, the cost per additional PBE is less than price so we should expand production. At levels of investment above q_o^*, it costs more to produce an additional PBE than we will receive, an undesirable investment.

This would complete the discussion if R_o were indeed fixed, either by nature or technology. In the past this may have been more or less true in the oil industry. However, with the advent of gas and water injection, secondary recovery techniques, and increasing technology in reservoir engineering, it is becoming more and more an economic decision as to what fraction of the oil in place to recover. In the previous discussion we have been assuming that R_o is fixed, and the only way to increase the present barrel equivalents is through additional investment in capacity.[1] However, from Equation C.1, it is

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[1]See Equation C.1 for $q_o = 0$, PBE = 0. As q_o increases the PBE's increase. In the limit $\lim_{q_o \to \infty} PBE = R_o$.

COST CURVES

Figure C.1

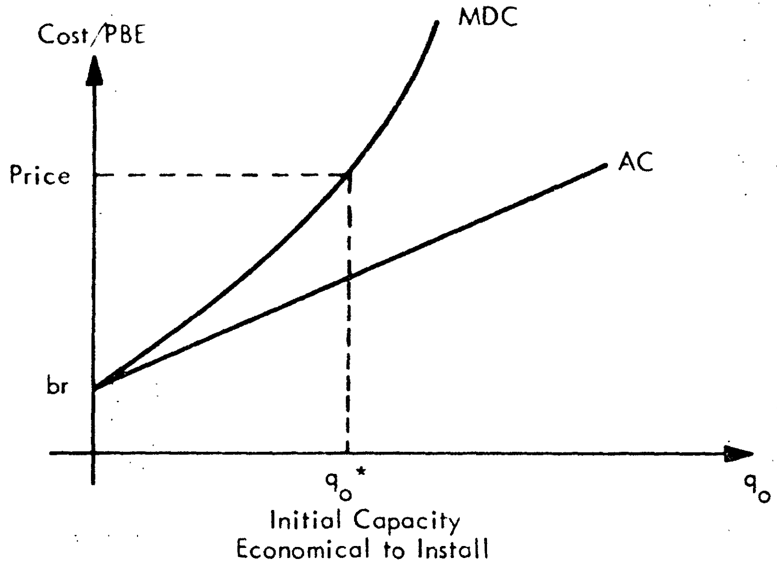
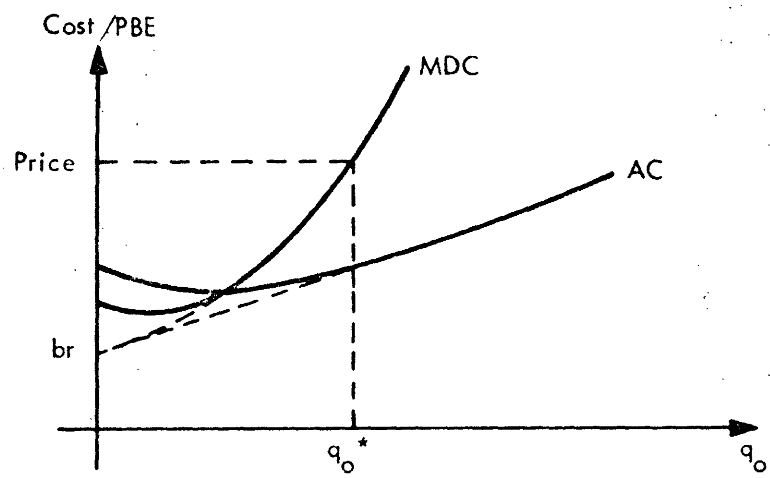
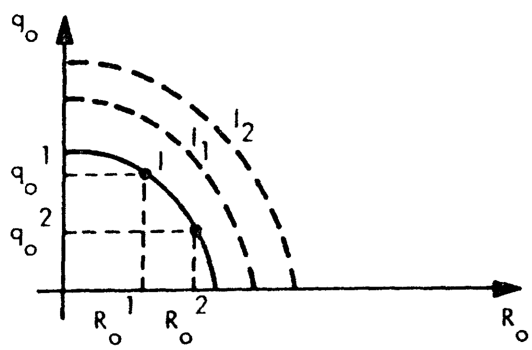


Figure C.2



PRODUCTION - POSSIBILITY CURVES

Figure C.3



also clear that if we can increase the recoverable oil in place (R_o), this also increases the PPF's. This brings in the second investment alternative listed at the beginning of the discussion --- investment in more complete recovery of existing oil in place.

Assume for the moment that these two investment alternatives are independent. We can either invest in q_o or invest in R_o. For a given level of total investment, we have a range of alternatives in the resulting levels of q_o and R_o. Suppose this range of alternatives is as depicted in figure C.3. For the investment I we could get initial capacity q_o^1 and recoverable oil R_o^1. If however, for this same level of investment we were to install fluid injection apparatus, we could get more complete recovery, say R_o^2, but have less to spend on capacity. Consequently the resulting q_o^2 would be less than q_o^1 for the same level of investment. The exact shape and placement of the curve in figure C.3 is dependent upon technology at any point in time and the characteristics of the reservoir in question. However, in theory such a relationship exists for a given reservoir. In fact a family of such curves exist, one for each different level of total investment. For investment I_1 greater than I, with the recovery of the same ultimate output fixed, a higher initial capacity can be installed. For the same initial capacity, say q_o^1, a higher recovery than R_o^1 could be attained if I_1 is greater than I, and so on for the whole family of curves.

Now, not only must we decide what level of investment to undertake, but also how it should be distributed among q_o and R_o. In practice it may be difficult to explicitly define the investment alternatives in figure C.3. If, however, we have the production possibility curves, i.e. investment as a function of q_o and R_o, then in theory we allocate investment funds so that

$$\left.\frac{\partial I}{\partial PBE}\right|_{R_o = R_o^*} = \left.\frac{\partial I}{\partial PBE}\right|_{q_o = q_o^*}$$

$$\text{where} \quad I = f(q_o \, , R_o) \; .$$

This says that we invest in q_o and R_o so that at the optimum $(q_o^* \, , R_o^*)$, the marginal cost of a PBE from additional investment in q_o is equal to the marginal cost of a PBE resulting from an investment in R_o. In other words,

$$\left.\frac{\partial I}{\partial q_o} \cdot \frac{\partial q_o}{\partial PBE}\right|_{q_o^* \, , R_o^*} = \left.\frac{\partial I}{\partial R_o} \; \frac{\partial R_o}{\partial PBE}\right|_{q_o^* \, , R_o^*} \qquad \text{Equation C.7}$$

Both sides of this equation are functions of q_o and R_o, and this equation yields what the relationship between q_o^* and R_o^* should be for optimal investment allocation. The optimum level of investment is found by setting each side of equation C.7 also equal to the price. This gives two equations and two unknowns to be solved for q_o^* and R_o^*.

In practice our ability to solve this optimal investment problem is limited by our ability to explicitly define the production possibility curves. Even having them, it may be difficult to analytically solve equation C.7, and one may have to resort to numerical methods. In theory, however, the aforementioned method would be the correct way of utilizing that information.

In reality, one probably does not have the knowledge of the reservoir to make a comprehensive analysis of the investment strategies just described. Usually the decision on investment in more complete recovery comes in the later stages of the primary recovery operation or even following it. It is not until then that a realistic assessment of secondary or tertiary recovery potential can be made, and then only with uncertainty. However, if it is realized that this investment option is only an investment in more present barrel equivalents (PBE's), the conclusion is still the same. Invest in more recovery until the cost per PBE is equal to price.

Let us summarize before turning to the issue of exploration. When building capacity on a fixed amount of recoverable oil from a reservoir (R_o), we build capacity until the marginal cost of the next PBE equals price. Since we are investing in more and more capacity to get a maximum amount of PBE's (maximum PBE = R_o), the marginal cost is an increasing function of installed capacity. This means decreasing returns for each dollar invested result. If we allow investment in recovery to also be an option, then R_o is no longer fixed. The investment should then be allocated so that the marginal cost of the next PBE resulting from investment in more recovery is equal to the marginal cost of the next PBE resulting from investment in more capacity. The level of total investment is determined again by price. Here also decreasing returns for investment in recovery are unavoidable because there is only a known finite amount of oil in place. Now let us turn to investment in exploration.

C.2 Investment in Exploration

In the preceding section we saw that development expenditures could be made for two reasons, either for increasing capacity or increasing recoverability. Both of these investment alternatives result in an increase in present barrel equivalents (PBE's). A third investment alternative is for exploration. Exploration itself does not result in more PBE's, for a reservoir must be developed with some capacity q_o before any of the oil in place in that reservoir can be considered a PBE.[1] In truth this is not strictly correct, because a successful exploratory well can be the first producer on a reservoir. However, the significant returns for the exploration effort do not accrue until the reservoir is fully developed or the knowledge and rights to are sold. At that point the rewards for finding the reservoir materialize.

What are these rewards? Let's go back to our simple example in the previous section. Suppose for some exploration expenditure (I_E) we find a reservoir with a fixed amount of recoverable oil "R_o" (investment in recoverability is not an option) and cost per capacity of "b" dollars. Then under optimal development[2], we develop until marginal development cost equals the price. This is depicted in figure C.4. Also note that the price received for the output of this reservoir is above the average costs. The difference between the marginal costs (MC)

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[1]See Equation C.1.

[2]See previous section.

and the average costs (AC) represents the profit per PBE when undertaking this investment. By taking the difference of the marginal costs and average costs of equations C.4 and C.5 respectively, and multiplying by the number of PBE's from Equation C.1, we get the present value of the profit from this development. This is

$$PBE(MDC - AC) = \frac{b}{rR_o} (q_o^*)^2 \qquad \text{Equation C.8}$$

Substituting for q_o^* from equation C.6 we get the rewards for exploration (R_E) are

$$R_E = PBE(MDC - AC) = R_o \left(\sqrt{P} - \sqrt{br}\right)^2 \qquad \text{Equation C.9}$$

In other words, for this simplified investment I_E, neglecting the time delays involved in finding and developing the reservoir, the present value of the returns is R_E. This is directly proportional to amount of recoverable oil found, which in turn gets multiplied by the square of the term containing price (P), cost per unit capacity (b), and development discount rate (r). After the fact the success of this investment can be evaluated by examining how much I_E was expended to get R_E and what the desired return was.

The point is this. The success of exploration investment depends on what is found in terms of R_o and b. The incentive to invest depends on what one expects to find in terms of R_o and b, and what he expects the price of the resulting output to be. We see, therefore, that when undertaking an exploration effort, we are not looking for only recoverable oil (R_o), but rather an amount of recoverable oil at a cost per unit capacity (b) such that R_E gives the desired return on I_E. So to

RETURNS TO EXPLORATION (R_E)

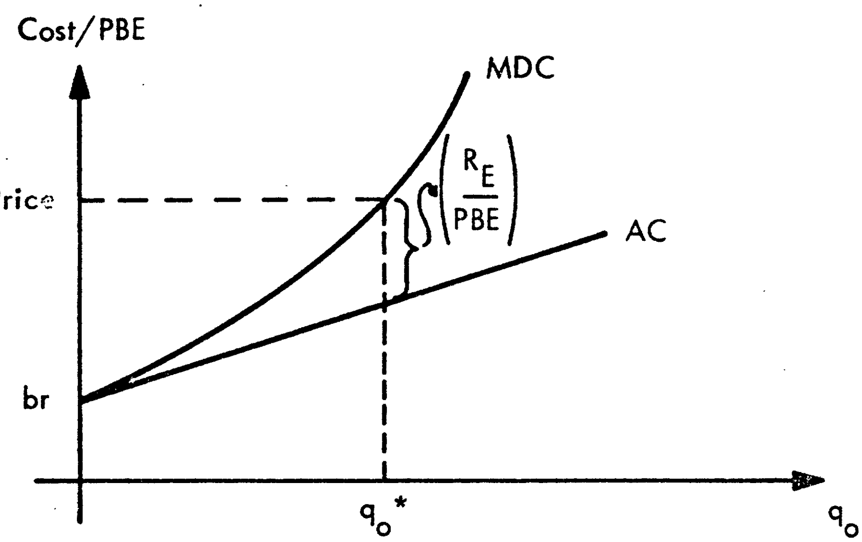

Figure C.4

INDUSTRY COST CURVES

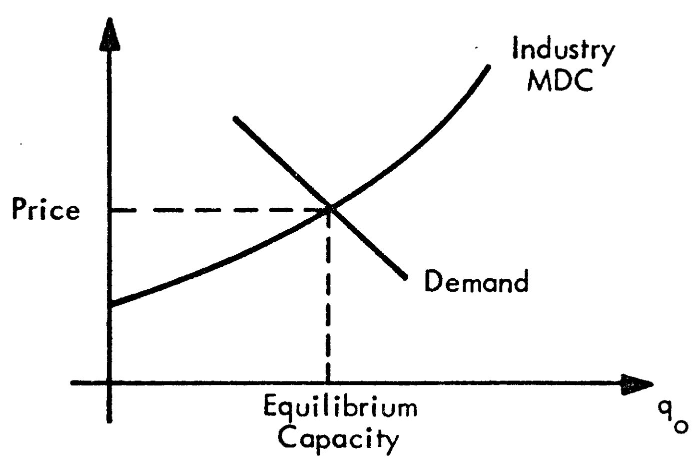

Figure C.5

properly analyze the results of past exploration activity not only do we need the R_o found but also the information about the cost per unit capacity to develop that recoverable oil. This cost is related obviously to the location and depth of R_o as well as the state of development technology.

The level of exploration expenditures an investor should undertake in any interval of time is difficult to ascertain. It depends on what he perceives as the probability of success at the likely exploratory sites and what he expects to find (R_o and b). He then undertakes those investments where the expected return meets his desired return (assuming no budgeting constraints). There are a lot of judgmental decisions involved.

C.3 Industry Performance

Now that the theory for the behavior of the small competitive supplier has been discussed, let us turn to the aggregate behavior and what the theory means for the industry as a whole.

First of all it was assumed that price was a given to the individual suppliers. In the marketplace the equilibrium price would be determined by the intersection of the industry supply curve and the aggregate demand curve. Under the assumption of perfect competition, this means price would be equal to the industry marginal development costs. In principle this industry supply curve is simply the sum of the individual supply curves.

From equation C.4 the industry marginal development costs can be calculated if we have observations on the average industry cost per unit capacity, the industry depletion rate, and a representative development discount rate. Equation C.4 may be rewritten in terms of the depletion rate by dividing both the numerator and denominator of the right side by R_o^2. If we designate the depletion rate (q_o / R_o) by the variable "a" equation C.4 becomes

$$MDC = b \frac{(a + r)^2}{r} \qquad \text{Equation C.10}$$

Using the same notation, the average costs from equation C.5 can be written as

$$AC = b(a + r) \qquad \text{Equation C.11}$$

In table 1 are tabulated the costs for the oil industry for the last decade. The decade is grouped into two four year periods and a three year period. This is done in the source to average possibly anomolous years.

In using equation C.10, we have assumed that all development expenditures went to the construction of new capacity. As mentioned in the section on development investment, some could have gone for expanding recovery. In a certain world, the cost per PBE for these two expenditures should be equal at the margin. However, if some of the development expenditures were for increasing recovery, then the marginal development costs as calculated in Table 1 would be high.

The data in the table suggest that in the earlier part of the decade, output was priced above marginal cost. Then in the period 1968-1970 the MDC's jumped by about 65¢ due both to the higher costs

Table 1

Oil Industry Cost Calculations

Time Period	(1) Development Expenditures per unit capacity (b) ($/DB) undeflated	(2) Depletion Rate (a) (1/year)	(3) MDC r = .10 ($/bbl.)	(4) AC r = .10 ($/bbl.)	(5) Price ($/bbl.)
1960-1963	2280	.089	2.23	1.18	2.89
1964-1967	2075	.0984	2.23	1.12	2.88
1968-1970	2790	.119	3.66	1.67	3.00

Sources: Columns (1) and (2) from Adelman; columns (3) and (4) calculated from equations C.10 and C.11. Column (5) from Bureau of Mines, various issues.

per unit capacity and the higher depletion rate. In fact the MDC's jumped to a value 20% higher than the reported Bureau of Mines price in that time period. It is likely here that investment in recoverability has biased our calculations. Nevertheless, the trend also reflects a possible movement to higher cost oil in place (higher "b" and/or lower "R_o") in the latter part of the decade.

Let's examine what the effect of these cost-price configurations could have on industry operations. First let's take the case where prices are above marginal development costs. Recall in the last section that the rewards for exploration were related to the difference between the MDC's and AC's if output were priced at the MDC. If output is priced above the MDC's, the AC's remain the same but the rewards for exploration are now related to the difference in price and the average costs of development. Consequently, in this cost-price configuration, the rewards are great for finding new sources of oil with characteristics (R_o and b) something akin to the industry average. We would expect then that exploration activity would be at a higher level than it would have been had the price been lower.

Further, there exists the incentive for individual industry suppliers to further expand output from existing sites, in fact expand it until MDC equals price. So in the early to middle sixties, we would expect a lot of exploration activity if there were reasonable expectations of finding new sources as well as an expansion of capacity on existing reservoirs. If the exploration were successful one would expect a downward pressure on prices due to the advent of this new oil on the market. In addition, if capacity expansion took place to where MDC's equal price, this further supply from existing reserves would put more downward pressure on price. From the published data on additions to reserves, it appears that exploration had not been that successful, and the trend in the depletion rate suggests that more intensive development was the contributing factor to the growth in supply. However, the reward structure for exploration was such as to encourage continuing exploration in this time period, but the poor success must have lowered expectations.

In the later sixties when costs go above price, there would be upward pressure on prices. In order to encourage the development of more supply prices would have to increase. Further, the rewards for exploration have dropped. Given the apparently poor results of exploration in the early sixties one would expect the exploration activity to dwindle, unless the expectation was for higher prices. The number of exploratory wells drilled in the period 1960-1970 dropped from 16.7 thousand to 7.7 thousand.[1] Apparently the expectation of higher prices was not there (most likely because of foreign competition).

In summary then, the oil industry has found itself in a period of rising costs and an increasingly pessimistic outlook for finding new sources of supply. On the domestic scene it appears that further supply in the future will be dominated by increasing recovery of the known oil in place, rather than the development of new sources. The costs and capability for doing this depend in large part on the growth

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[1] Source, Adelman, "Long Run Cost Trends".

in technology for increasing recovery. To meet the growth in demand, imports will have to be utilized. Barring significant gains in exploration capability, advances in recovery technology offer the only hope to a continuing supply of domestic oil, with Alaska possibly providing a cushion of time to make these gains.

Now let us turn our attention to natural gas. Table 2 displays the MDC's and AC's of natural gas corresponding to the same format as Table 1. Here we see the trend is also toward increasing costs, in fact a much sharper increase than that for oil. In the earlier part of the decade there is also evidence that output was priced above marginal cost. This would result in the same incentives for behavior as those discussed for oil. However, in the period 1968-1970, it appears even that MDC's exceeded price.

The reason for this is the price data used. The Bureau of Mines price is the average wellhead price of interstate sales of natural gas. This price is calculated from contracted agreements on interstate sales, some of these contracts made many years previous. The marginal development cost is the price at which one would expect new contracts to be let at, which could be significantly different from the average wellhead price. The Bureau of Mines price therefore only reflects the regulated price ceiling on interstate sales. Yet for the 1968-1970 time period, the MDC's exceeded even this regulated ceiling. There is really no incentive at all to develop more capacity if the MDC's are above price. Clearly there must have been intrastate markets where this gas could be sold at prices above the price ceiling and those

Table 2

Natural Gas Industry Cost Calculations

(Non-Associated Natural Gas and Non-Associated Natural Gas Liquids)

Time Period	(1) Development Expenditures per unit capacity (b) ($/MCF / da.) (Undeflated)	(2) Depletion Rate (a) (1/yr.)	(3) MDC r = .1 (¢/MCF)	(4) AC r = .1 (¢/MCF)	(5) Price (¢/MCF)
1960-1963	92.1	.0588	6.4	4.0	15.0
1964-1967	125.4	.0670	9.6	5.7	15.5
1968-1970	307.0	.0855	28.9	15.6	16.0

Sources: Columns (1) and (2) from Adelman; columns (3) and (4) calculated from equations C.10 and C.11. Column (5) from the Bureau of Mines, various issues.

reported in the Bureau of Mines. The increasing ratio of intrastate to interstate gas sales for the industry in this time period should confirm this. The effect of this is to make natural gas available to consumers only in those states where it is abundantly produced and at a price higher than the price ceiling. It also means that suppliers would not be willing to produce this natural gas for interstate markets at the ceiling prices, consequently the regulation induced shortage of natural gas. This condition will persist as long as the regulation in its present form is continued.

For both the oil and gas industries we see a trend of costs rising faster than prices. Much of the reason for this is the fact that output was priced above cost at the beginning of the decade.[1] Apparently, though, costs approached and even surpassed price in some markets by the end of the decade. The cushion of excess profits provided a mechanism for stable prices, but apparently that cushion is now getting very thin or even non-existent. This suggests that one could expect much more dynamic behavior of prices and supply of energy in the future than has been evident in the past. It should provide for interesting observation.

C.4 The Theory as Applied to the Dynamic Model

Now that the theory and performance of the oil and natural gas industries has been discussed, the next question is how can it be used

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[1]There are indications that this may have been true for some time previous also.

in a dynamic model. It is here that we quickly become faced with our finite knowledge, not only of what has been, but what might be.

In trying to model past behavior of marginal development costs, knowledge of the past collection of reservoirs (their recoverable oil and cost per unit capacity) is needed as well as when they were found. To model the exploration process, the investment in exploration as well as the success of the exploration effort must be made explicit. We know what past reported behavior has been, but how can this knowledge be extrapolated into the future.

In trying to formulate a useful dynamic model therefore, one is faced with modeling what he can, accepting its limitations, and providing the capability of entering the different possible alternatives for those things that can't be explicitly related. One area in which we are forced to do this is exploration. One is treading on very shaky ground in setting down any explicit relationship between exploration expenditures and the resulting discoveries therefrom. Even though returns in past decade for exploration expenditures for the most part have been meager, there has been one big exception --- Alaska. Further, there are numerous geological formations which in the past were not prime candidates for exploration activity, but which could very well turn up significant amounts of oil. There are also many offshore locations which have not been fully explored.

It would be ideal if we had knowledge of the total collection of potential sources of oil and gas in this country, or even those that past exploration has yielded. This knowledge would be most useful when delineated as to size of reservoir and the cost of putting a unit capacity on it. It is entirely conceivable though maybe not true, that at slightly higher prices there is a vast collection of untapped oil in place with characteristic R_o and b which would be economical to develop at those higher prices. The reserve concept tells us nothing about this potentiality, nor is there information available for which the potential could be assessed. The concept of reserves (meaning the future accumulated output expected from existing capacity) and reserve/production ratios we have seen are a consequence of the normal decision making process. At any point in time the trend in the reserve/production ratio (R/P), although offering information about the results of past exploration effort, does not tell us what this information along with increased technology in exploration or development, could offer.

The question then is what can be modeled. For this work the following is done.

In the dynamic model it will be assumed that inputs are what is normally called reserves (the inventory of oil available from existing developments) and the cost per unit capacity. Both of these can and will be affected by changes in technology and exploration. The additions to reserves due to exploration are of a very uncertain nature, maybe being significant and maybe not. Advancing technology in the past has been of a slow but steady nature, which might suggest that its effects are more predictable than exploration. The model formulated in this form places the uncertainty involved with exploration and technology in the user's rather than the modeler's responsibility. It simply must be accepted as a limitation of the model until more information about the exploration activity and oil in place is known.

The previous discussion on industry performance does tell us something about the assumption of perfect competition. In the past it apparently has not been true. However the trends indicate that costs approached price in the decade of the sixties. For oil the foreign competition was probably the reason. For natural gas the price ceiling held prices down. It appears that at present output from these industries is priced much closer to their marginal development costs than may have been true in the last twenty years. So the model based on the assumption of perfect competition in supply will probably be more appropriate in the future policy studies than it will be for simulation of past policy performance.

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APPENDIX D

MODEL EQUATIONS AND BASE CASE PARAMETERS

Introduction

In this appendix the aim is to combine the discussions of chapters three and four into a consistent program for simulation of the interfuel dynamics. There are basically three generic structures which need to be discussed. These are the demand sector dynamics for the primary demand sectors residential and commercial, industrial heating, and transportation. Next there is the generic structure for the primary fuel supplies: coal, oil, and natural gas. Finally, the structure of electricity demand and supply, where the electricity demand is derived from the primary consuming sectors and the supply is produced by the primary fuels. It is when discussing electricity supply that nuclear is discussed also.

In chapter 5 a discussion of the model validation issue is given. The results of a base case run for comparison with historical data are discussed there as part of the validation procedure. This base case consists of a 50 year simulation with the initialization of the programmed model at the 1947 actual conditions. The output from the model is compared to data on actual fuel consumption and market shares for the period 1947 to 1969. For ease of presentation then the initialized values, constants, parameters, and inputs are those that were identified and used in this base case simulation. Rather than put into the model the actual values of the inputs as reported from past data (such things as sector demands, additions to reserves, capital costs per unit capacity, imports, etc.), these inputs were smoothed and considered in most cases to be simple mathematical functions such as exponentials, ramps, constants, etc. These approximate inputs were derived from the actual data for the 1947 to 1969 time period, and the precise formulation should be clear from the discussions following in this chapter.

All energy units are converted to a common base of quadrillions of BTU's, or for short milliQ's (mQ.).[1] The equations are expressed in Dynamo language.[2] The forms of supply coal, natural gas, oil, and electricity are attached the code letters W, X, Y, and Z respectively; the demand sectors residential and commercial, industrial heating, and transportation are attached the code letters RC or R, IH or I, and TR or T respectively. This helps to make clearer the particular sector and fuel about which one is speaking and their use should be obvious shortly. A complete program listing follows the text and the reader will probably find it useful to refer back and forth between the text and the listing.

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[1] One Q corresponds to 10^{18} Btu's, a milliQ is 10^{15} Btu's.

[2] See the Dynamo II User's Manual. Due to the restrictions in equation writing in Dynamo, some redundancies occur in the programmed model. Also, the author does not claim to be an expert or efficient programmer.

D.1 Primary Demand Models --- RC, IN, and TR

The residential and commercial demand (RC) is modeled as an exponential growth process. The total level of demand is given by

L RCD.K = RCD.J + (DT) (RCDGR.JK)

N RCD = 6.36

A RCDG.K = 0.043*RCD.K

R RCDGR.KL = RCDG.K

where RCD = level of residential and commercial demand (or consumption)

RCDGR = rate of growth of RCD, modeled at 4.3% per year in the base case

RCD is initialized at 6.36 mQ's per year in 1947

RCDG is the incremental demand in the RC sector.

The level of consumption of fuels i in the residential and commercial sector is given by

L RCDi.K = RCDi.J + (DT)(-RCDiDR.JK + RCDDi.J*RCMSD.JK)

for i = W, X, Y, Z (coal, natural gas, oil, and electricity respectively)

where RCDi = the residential and commercial consumption of fuel i

RCDiDR is the rate of decline of consumption of fuel i if none of the market sensitive demand is supplied by fuel i

RCMSD is the RC market sensitive demand to be defined shortly

and RCDDi is the RCD distribution factor multiplying the market sensitive demand (see figure 4.2) for each fuel.

The initial level of consumption for each of these fuels is

N RCDW = 2.59 , 1947 demand for coal (mQ's)

N RCDX = 1.13 , natural gas

N RCDY = 2.25 , oil

N RCDZ = 0.30 , electricity.

The replacement demands are given by

A $RC\underline{i}RD.K = RCD\underline{i}.K * RC\underline{i}B$

for i = W, X, Y, Z respectively

where $RC\underline{i}RD$ is the RC replacement demand for fuel $\underline{i}$

and $RC\underline{i}B$ is the $1.-B_i$ factor (see figure 4.2) for each of the supplying fuels in the RC sector.

The RC market sensitive demand is the sum of the incremental demand and replacement demands, it can be written as

R $$RCMSD.KL = RCDG.K + \sum_{i=W,X,Y,Z} RC\underline{i}RD.K$$

where RCMSD is the RC market sensitive demand.

The distribution factors (d_i in figure 4.2) are calculated in a two step procedure. First the unnormalized values (see equation 4.3) are computed, then they are normalized so their sum is equal to unity. This is in line with the assumption that total consumption in each consuming sector is inelastic. First the unnormalized values are given by

A $$RCDD\underline{i}1.K = R\underline{i} * \prod_{j=W,X,Y,Z} EXP(R\underline{i}\underline{j} * P\underline{i}.K)$$

for i = W,X,Y,Z

where RCDD$\underline{i}$1 is the unnormalized distribution factor for fuel i

R$\underline{i}$ corresponds to A_i's in figure 4.2 for the RC sector

R$\underline{ij}$ corresponds to the a_{ij}'s for the RC sector in figure 4.2

P$\underline{j}$ is the price of fuel $\underline{j}$

and EXP(·) denotes the exponent of the argument.

The sum of these unnormalized factors is given by

$$\text{A} \quad \text{RTOTAL.K} = \sum_{i=W,X,Y,Z} \text{RCDD}\underline{i}\text{1.K}$$

and the normalized distribution factors are given by

$$\text{A} \quad \text{RCDD}\underline{i}\text{.K} = \text{RCDD}\underline{i}\text{1.K/RTOTAL.K}$$

for i = W,X,Y,Z

where RCDD$\underline{i}$ is the normalized distribution factor d_i in the RC sector for fuel i.

The values of the constants corresponding to the $\underline{A}$ and $\underline{B}$ matrix of figure 4.2 for the RC sector are given in the program listing for the base case. These are listed as

RC$\underline{iB}$, R$\underline{i}$, $\underline{i}$ = W,X,Y,Z

and R$\underline{ij}$, $\underline{i}$ = W,X,Y,Z, and $\underline{j}$ = W,X,Y,Z

where RC$\underline{i}$B corresponds to B_i in figure 4.2

R$\underline{i}$ corresponds to A_i in figure 4.2

R$\underline{ij}$ corresponds to the a_{ij}'s in figure 4.2

These are the basic equations for residential and commercial demand sector dynamics.

For the industrial heating and transportation sectors, the model equations are structurally the same. The only difference for these sectors is that where RC or R occurs for the residential and commercial sector an IH or I is used in the industrial heating sector, and TR or T is used in the transportation sector. The equations, initial conditions, and constants for these sectors are given in the program listing following the text.

The total consumption by these primary consuming sectors for each fuel is given by

A $\underline{i}$O.K = RCD$\underline{i}$.K + IHD$\underline{i}$.K + TRD$\underline{i}$.K

for i = W,X,Y,Z

where WO, XO, YO, ZO is the demand for each of the forms of supply W, X, Y, and Z by the primary consuming sectors.

This is not the total demand for primary fuels; the fuels consumed to generate the electrical output ZO have not been added in yet. The sum of these energy demands is called the total energy demand (TED).

D.2 Electricity Demand for Fuels

The electricity demand model structure is quite similar in structure to that just described for the primary consuming sectors. The difference is that the role of nuclear and hydro generation must be taken into account. This is accounted for in the identification of the market sensitive demand in the fossil fuel market. Just like in the last section the market sensitive demand in fossil fuel generation is the sum of the replacement demands and incremental demand. However, since nuclear and hydro forms of generation are capacity fixed, the fraction of total electrical output coming from these two sources must be identified.

The incremental electricity demand consists of the growth in electrical consumption as derived from the primary consuming sectors. This can be written as

$$\text{A} \quad \text{ZDG1.K} = \sum \begin{array}{l}\text{increments in electrical consumption} \\ \text{from each primary consuming sector.}\end{array}$$

where ZDG1 is the incremental electricity demand.

The fossil fuel replacement demands are given by

$$\text{A} \quad \text{ZF}\underline{\text{i}}\text{RD.K} = \text{ZF}\underline{\text{i}}\text{.K} * \text{ZF}\underline{\text{i}}\text{B}$$

for i = W, X, Y

where ZF<u>i</u>RD is the replacement demand in electricity for fossil fuel <u>i</u>

ZF<u>i</u> is the fraction of total electrical output supplied by fuel <u>i</u>

and ZF<u>i</u>B is the fraction of demand for fuel <u>i</u> in electricity generation that becomes market sensitive over a one year interval.

The fraction of electrical output supplied by nuclear is assumed to be the same as the fraction of total capacity made up of nuclear, therefore

$$\text{A} \quad \text{ZFN.K} = (1.0\text{-FCF.K}) * \text{ZO.K}$$

where ZFN is the electrical output produced from nuclear generation (in mQ/yr.)

FCF is the fraction of capacity made up of fossil fired (and hydro) plants

and ZO.K is the total electrical output.

The electrical output produced from hydro generation is an input to the model, assumed for the base case to be given by

A ZFH.K = CLIP(ZFH1.K, ZFH2.K, 23.0, TIME.K)

A ZFH1.K = 0.29 * EXP (0.047 * TIME.K)

A ZFH2.K = 0.29 * EXP (0.047 * TIME.K) * EXP(0.016 *(TIME.K - 23.0))

where ZFH is the electrical output produced by hydro generation (in mQ/yr.)

CLIP is a dynamo switch function

EXP(·) is the exponential function.

The variable ZFH is initialized at 0.29 in 1947 and grows thereafter at 4.7% per year for 23 years until 1970, from 1970 on it grows at 1.6% per year. The fossil incremental demand is then derived by subtracting the increments in nuclear and hydro output from the total growth in electrical output. This is written as

A ZFFG.K = ZDG1.K - DELZFN.K/DT - DELZFH.K/DT

where ZFFG is the growth in electrical output to be supplied by fossil fuels (fossil incremental demand)

ZDG1 is the total growth in electrical output

DEIZFN/DT is the growth in output supplied by nuclear generation

and DEIZFH/DT is the growth in output supply by hydro generation.

The fossil market sensitive demand is then the sum of the fossil incremental demand and the fossil replacement demands, or

$$\text{R} \quad \text{ZFSD.K} = \text{ZFFG K} + \sum_{\underline{i}=W,X,Y} \text{ZF}\underline{i}\text{RD.K}$$

where ZFSD is the fossil market sensitive demand

ZFFG is the fossil incremental demand

and ZF$\underline{i}$RD is the replacement demand of fuel $\underline{i}$.

The dynamics of the fossil fuel demands in electricity are now given by the same equations as those for the primary consuming sectors, except that Z denotes the demand sector now rather than the RC, IH, or TR used in the last section.

The consumption of the primary fuels (in mQ's) in electricity generation is easily obtained from the equations

$$\text{A} \quad \underline{i}\text{TOZ.K} = \text{ZF}\underline{i}\text{.K} * \text{HRF.K}/3.412\text{E-}3 \qquad i = W,X,Y$$

where $\underline{i}$TOZ is the consumption of fuel $\underline{i}$ in the electricity sector

ZF$\underline{i}$ is the output of electricity produced by fuel $\underline{i}$

HRF is the fossil heat rate in millions of Btu's per kwh.

and 3.412E-3 is the lossless conversion rate in millions of Btu's per kwh.

For comparison to Bureau of Mines statistics the nuclear and hydro

(NTOZ and HTOZ) are calculated using the same formula.

Now the total demand for all forms of energy can be calculated by adding in that required for secondary suppliers. An option for the coal gasification is included in the base case structure though it is not used in the base case simulation. The natural gas produced from coal is designated XFW and the amount produced this way is entered exogenously via a table function. The coal used in coal gasification is designated WTOX, and WXCE is the demand for coal in mQ's per unit of synthetic gas produced. The total demands for each form of fuel can now be written as

A WD.K = WO.K + WTOZ.K + WTOX.K

A XD.K = XO.K + XTOZ.K

A YD.K = YO.K + YTOZ.K

A ZD.K = ZO.K

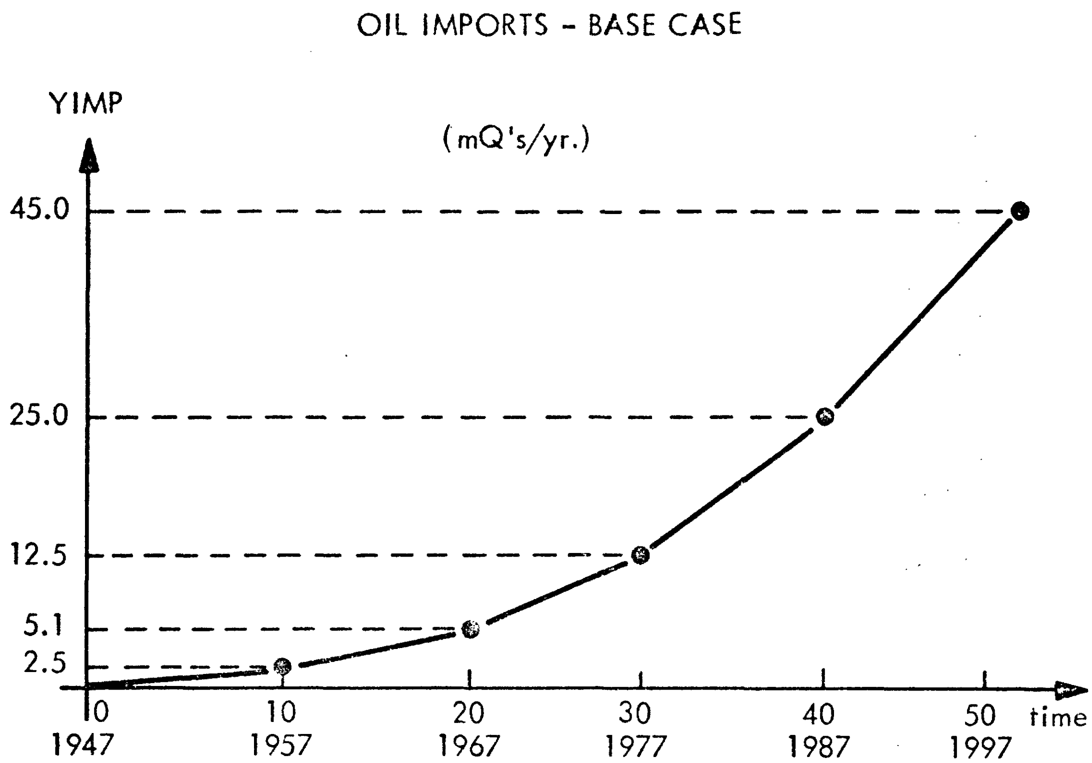
where <u>i</u>D is the total demand for fuel <u>i</u>, <u>i</u> = W, X, Y, Z

<u>i</u>O is the consumption by the primary consuming sectors of fuel <u>i</u>

<u>i</u>TOZ is the consumption of fuel <u>i</u> in electricity supply

and WTOX is the coal consumed in the coal gasification process.

To get the total demand on domestic supplies from conventional sources the levels of exports or imports must be added or subtracted respectively to <u>i</u>D above. In the base case oil imports only are included, and they are input via a table function. The amount of imported oil vs. time is denoted YIMP, and the table of values is given in figure D.1.



OIL IMPORTS - BASE CASE
YIMP
(mQ's/yr.)
45.0
25.0
12.5
5.1
2.5
0
1947
10
1957
20
1967
30
1977
40
1987
50
1997
time

Figure D.1

In addition the gas produced from coal must be subtracted from XD. The amount of imported oil and gas is denoted YIMP and XIMP respectively, therefore

A XE.K = XD.K - XIMP.K - XFW.K

A YE.K = YD.K - YIMP.K

where XE is the demand for domestically produced gas from conventional sources

and YE is the demand for domestic oil.

D.3 Primary Supply Models --- W, X, and Y

The primary fuel supply models for coal (W), natural gas (X), and oil (Y) are very similar. For ease of presentation, the equations for natural gas will be given first, then the simplifications and complications for coal and oil will be discussed.

D.3.1 Natural Gas Supply (X)

The level of proven reserves at any point in time is given by

I XRES.K = XRES.J + (DT) (XARR.JK - XPRDR.JK)

N XRES = 160.0

where XRES is the level of natural gas reserves, initialized in 194[illegible] to 160 mQ's.

XARR is the rate at which new reserves are added in natural gas supply (X addition to reserve rate)

and XPRDR is the X proven reserve depletion rate, or rate of consumption of natural gas.

For the base case it is assumed that additions to reserves are constant through time with 18 mQ[1] of reserves added each year. Therefore

R XARR.KL = 18.0

and R XPRDR.KL = XE.K

where XE.K is the rate of consumptio, or X demand as determined from the demand models.

The rate of development depends on two things in the model; these are the predicted demand and the predicted price. The value of price in the market place is the smoothed value of the short run marginal costs.

A XP.K = XSP.K

A XSP.K = SMOOTH (XSRMC.K, XPST)

C XPST = 4.0

where

XP is the price used in the marketplace in the fuel selection process

XSP is the smoothed short run marginal costs

XSRMC is the short run marginal cost, defined as in chapter 3.

XPST is the price smoothing time constant

and

SMOOTH is a dynamo macro for exponential smoothing.

To get the predicted price, a least squares quadratic curve fit is made to the last four years'prices and extrapolated ahead the length of the capacity development time.

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1 See Reserves of Crude Oil, ... as of December 31, 1970. The additions to reserves were not constant, but for convenience their mean value over the 22 year period 1947 to 1969 was used. See Bibliography for reference data.

```
A    XSP1.K = DELAY3(XSP.K,XPDT)
A    XSP2.K = DELAY3(XSP1.K,XPDT)
A    XSP3.K = DELAY3(XSP2.K,XPDT)
C    XPDT = 1.0
A    XPP.K = PRED(XSP.K, XSP1.K, XSP2.K, XSP3.K, XPT, XPDT)
C    XPT = XCDT + 3.0 * XPDT
C    XCDT = 1.0
```

where XSP1 is the smoothed price delayed one year

XSP2 is the " " " two years

XSP3 is the " " " three years

XPDT is the interval between price sample data points (1 yr.)

XPP is the predicted price

XPT is the length of the prediction (XCDT)

XCDT is the capacity development time

DELAY3 is a dynamo third order delay macro

and PRED is a user supplied macro to fit a least squares quadratic to four data points and extrapolate the curve from the first data point ahead to XPT.

From the marginal development cost curve the capacity potentially economical to develop is given by[1]

```
A    XCEED.K = XRES.K * (SQRT(XPP.K * R.K/XCPUC.K) - R.K)
```

where XCEED is the capacity economical to develop as calculated from marginal development cost function

---

[1]See Appendix C.

R is the development discount rate, assumed to be 10% for both oil and gas

and XCPUC is the cost per unit capacity, normalized by the base price of the fuel in 1947.

In the base case simulation the cost per unit capacity for natural gas was assumed to be a constant

A XCPUC.K = 4.00

This number is calculated from the 1947 cost per unit capacity in dollars per mQ per year, and normalized by the price of the fuel in 1947 in dollars per mQ. It is assumed to be constant through the duration of the base case run.

The predicted demand for natural gas (XPD) is calculated in a fashion identical to the predicted price. The desired capacity in natural gas at the time in the future equal to construction delay (XCDT) is then assumed to be the average of that calculated from the marginal development cost function and the ratio of the predicted demand to the desired capacity utilization, i.e.

A XDC.K = (XCPED.K + XPD.K/0.8)/2.0

where it is assumed the desired utilization is 80%. The capacity economical to develop is then this desired capacity less what already exists, what is already in the development stages, plus that which will become unproductive over the development construction time.

A XCED.K = XDC.K - XPC.K - XCBD.K + XDPR.K * XPC.K * XCDT

R XCDR.KL - (MAX (XCED.K, 0.0))/XEDT

where XCDR is the rate at which new capacity is developed

XEDT is the entry time constant of figure 3.3

XDPR is the depletion rate

XCBD is the capacity in the development stages

and XPC is the existing production capacity

The depletion rate is given by

A XDPR.K = XE.K/XRES.K

where XDPR is the depletion rate of natural gas, and the reserve production ratio is the inverse of this

A XRPRO.K = XRES.K/XE.K

where XRPRO is the reserve production ratio.

The rate at which the capacity being developed becomes productive is the development rate delayed by the capacity development time.

R XCCR.KL = DEL3IA (XCDR.JK, XCDT, XINZ)

N XINZ = (XDPR + .10) * XPC

where XCCR is the capacity completion rate

XINZ is the initiatization of this rate of completion in a trend of 10% growth per year.

and DEL3IA is a user supplied macro for a third order delay macro whose value is initialized at XINZ.

The capacity being developed is therefore

L XCBD.K = XCBD.J + (DT) (XCDR.JK - XCCR.JK)

where XCBD is the capacity being developed.

The level of production capacity is given by

L XPC.K = XPC.J + (DT) (XCCR.JK - XPDR JK)

N XPC = 5.2

where XPC is the level of production capacity, initialized at 5.2 mQ/yr. in 1947

and XPDR is the productivity decline rate.

The productivity decline rate (XPDR) can be written as

R XPDR.KL = XDPR.K * XPC.K

Now, the marginal development costs are given by[1]

A XMDC.K = XCPUC.K*(XPC.K + R.K*XRES.K)^2/(R.K*XRES.K^2).

The short run marginal costs are given by[2]

A XSRMC.K = XMDC.K * XALPH.K * XPC.K/(XPC.K - XE.K)

A XALPH.K = 0.2

where XALPH is one minus the desired utilization.

To complete all the loops then, the price is the smoothed value of these short run marginal costs. Also calculated is the actual capacity utilization factor (XCUF)

XCUF.K = XE.K/XPC.K.

This completes the discussion of the natural gas supply model.

---

[1]See Appendix C.

[2]See Equation 3.5.

D.3.2 Coal Supply (W)

For coal supply, the same basic structure is used. However, it is assumed that there are large amounts of coal reserves available, so that essentially the marginal development cost function calculated in Appendix C is a constant value at any point in time. In this case the capacity development decision is made only from demand trends, and not from the marginal development cost function.

The cost per unit capacity in coal is assumed to decline at 1% per year due to technological change and the gradual shift to lower cost strip mining operations. Finally, the capacity utilization factor in coal is assumed to be lower, at 60%, so that

A WALPH.K = 0.4

and A WDC.K = WPD.K/0.6

D.3.3 Oil Supply (Y)

In the oil supply model, the structure is identical to natural gas except in the pricing logic. Here the smoothed short run marginal costs (YSP) are multiplied by a factor YPM. This factor is to account for the historical price of oil being above the marginal cost levels. It is entered in the form of a table function, and its reason for existence is given in appendix C. The value of this price multiplier vs. time is given in figure D.2.

Finally, the level of consumption of domestic oil is denoted by YF rather than YD. As mentioned in section D.1, YD is the total demand for oil and YF is the difference between YD and the level of imports.

OIL PRICE MULTIPLIER

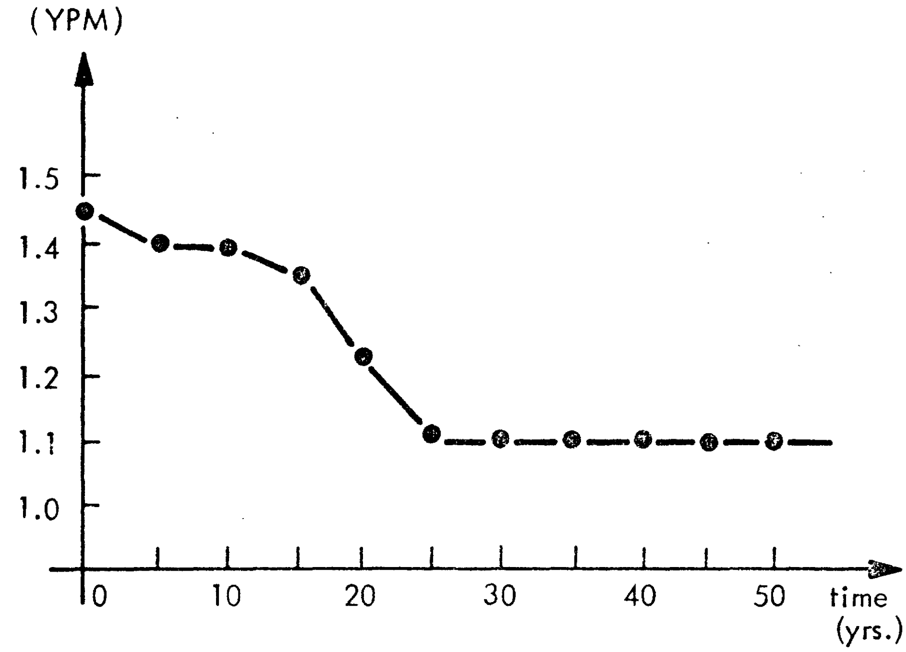

Figure D.2

D.4 Electricity Supply (Z)

The equations for electricity supply are different from those for the primary fuel suppliers for two reasons. First there are two kinds of generating capacity which must be kept separate and distinct (fossil and nuclear --- hydro is assumed to be included in the fossil); secondly, output is priced at average cost rather than the marginal cost. First the supply capacity and cost dynamics will be discussed, then the fossil vs. nuclear capacity committment logic will be presented.

The decision to build new capacity in electricity supply is assumed to be based on trends in demand. First the predicted demand for the interval corresponding to the capacity construction time is calculated.

```
A    ZD1.K = DEL3IA (ZD.K, DELZ, .646)
A    ZD2.K = DEL3IA (ZD1.K, DELZ, .413)
A    ZD3.K = DEL3IA (ZD2.K, DELZ, .265)
C    DELZ = 5.0
C    ZCCT = 7.0
A    ZPTIME.K = ZCCT. + 3.0 * DELZ
A    ZPD.K = PRED (ZD.K, ZD1.K, ZD2.K, ZD3.K, ZPTIME.K, DELZ)
```

where ZD1 is the value of demand delayed by DELZ = 5.0 yrs., initialized at 0.646 --- the electricity demand in 1942.

ZD2 is the value of demand delayed by 10 yrs., initialized at .413 in 1937.

ZD3 is the value of demand delayed by 15 yrs., initialized at .265 in 1932.

ZCCT is the capacity construction time in electricity

ZPTIME is the time over which the quadratic curve fit is extrapolated

PRED is a user supplied macro for a least squares quadratic curve fit to four points and extrapolation to ZPTIME.

and ZPD is the value of the predicted demand.

The predicted capacity that will be available from existing committments is given by

A ZPPC.K = ZPC.K (1.0 - ZCCT/ZPLT.K) + ZCIC.K

where ZPPC is the predicted capacity

ZPC is the existing capacity

ZPLT is the production capacity lifetime

ZCCT/ZPLT is the fraction of existing producing capacity which will become obsolete in ZCCT years,

and ZCIC is the capacity in construction.

The committment rate is given by

A ZCR1.K = (ZPD.K) (ZDR.K) - ZPPC.K

A ZCCR.KL = MAX (ZCR1.K, 0.0)

A ZDR.K = 2.0

where ZCCR is the capacity committment rate

ZDR is the desired reserve (=2.0), or the capacity utilization factor is 0.5

ZPPC is the predicted production capacity from existing committments, and ZPD is the predicted demand.

The fraction of committment made up of fossil generation is designated the fossil fraction (FF).[1] Therefore

R ZFCCR.KL = FF.K * ZCCR.K

R ZNCCR.KL = (1.0 - FF.K) * ZCCR.K

where ZFCCR is the fossil capacity committment rate

ZNCCR is the nuclear capacity committment rate.

In substance the dynamics of fossil capacity and nuclear capacity are identical. As the capacity is initiated, after the construction delay, this capacity becomes productive and finally becomes obsolete. For fossil this is written as

R ZFROC.KL = DELAY3 (ZFCCR.JK, ZCCT, ZROCI)

N ZFROCI = 0.11 * ZFPC

R ZFCOR.KL = DEL3IA (ZFROC.JK, ZPCLT.K, ZFCORI)

N ZFCORI = 0.03 * ZFPC

where ZFROC is the rate of completion of the committments made for fossil fired plants ZCCT years earlier, initialized at 8% growth (ZFROCI)

ZFCOR is the capacity obsolescence rate

ZPCLT is the production capacity lifetime

and ZCCT is the capacity construction time.

The values of ZPCLT and ZCCT are assumed to be the same for both fossil and nuclear. In the base case run ZCCT is set equal to seven years.

---

[1]See Section 4.2.

ZPCIT will be discussed in a moment.

The levels of capacity in construction and actual producing capacity are given by

L ZFCIC.K = ZFCIC.J + (DT)(ZFCCR.JK - ZFROC.JK)

N ZFCIC = ZFROCI * ZCCT * 0.75

L ZFPC.K = ZFPC.J + (DT)(ZFROC.JK - ZFCOR.JK)

N ZFPC = 1.76

where ZFCIC is the fossil capacity in construction, initialized at 75% of initial rate of completion,

and ZFPC is the fossil fired production capacity, initialized at 1.76 mQ/yr. in 1947.

For nuclear the capacity dynamics equations are the same only initialized at zero in 1947.

As mentioned in section 4.2, the lifetime of producing capacity may be extended if the desired reserve conditions are not being met. Therefore the production capacity lifetime is modeled as

A ZPCIT.K = ZNPCIT + ZEIT.K

C ZNPCIT = 40.0

A ZEIT.K - (ZDR.K - 1.0 - ZRES.K) * 200.0

where ZNPCIT is the nominal lifetime of 40 years

and ZFIT is the extension of the lifetime as a function of reserve.

The production capacity lifetime as a function of reserve is displayed in figure D.3. This looks like a very strong dependence, but it only affects about 3% of the total capacity when the system doubles in size

ELECTRICITY PRODUCTION CAPACITY LIFETIME

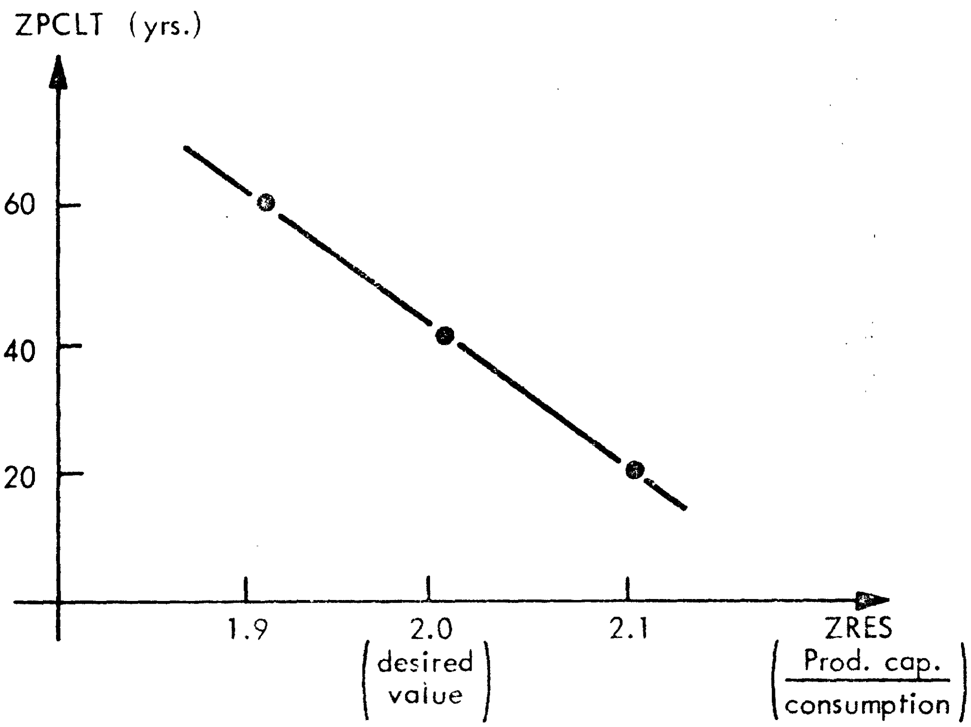

Figure D.3

every 10 years as it has been doing historically.

The fossil capacity fraction (FCF), the total producing capacity, and the total capacity in construction can now be written as

A FCF.K = ZFPC.K/(ZFPC.K + ZNPC.K)

A ZPC.K = ZFPC.K + ZNPC.K

A ZCIC.K = ZFCIC.K + ZNCIC.K

The average cost, or the price of electricity can be calculated from the relative factor costs for fossil and nuclear respectively. The average fixed costs are derived from the ratio of the annual capital write-off to the delivered energy, or

A ZAFC.K = ACCR * ZINV.K/ZDA.K

where ZAFC are the average fixed costs, in cents per kwh.

ZINV is the level of invested capital in electricity (in cents)

ACCR is the annual capital charge-off rate, assumed to be 12.5% per year in the base case

and ZDA is the energy delivered, in kwh.

The capacity committment rate in units of kwh/yr./yr. is given by

A ZCCR1.K = ZCCR.K/2.99E-8 kwh/yr./yr.

where ZCCR is the capacity committment rate in mQ's per year per year

and 2.99E-8 is the conversion factor from mQ's/yr. to kwh/yr.

The investment rate is given by

R ZINVR.KL = ZCCR1.K * FF.K * UIF.K

+ ZCCR1.K * (1.0 - FF.K) * UIN.K

where ZINVR is the rate of investment in new capacity

UIF is the capital cost per kw of a fossil plant in cents per kw.

and UIN is the capital cost in cents per kw. for a nuclear plant.

The level of invested capital in electricity supply is therefore given by

L ZINV.K = ZINV.J + (DT)(ZINVR.JK - ZDPRR.JK)

N ZINV = 18.E11

R ZDPRR.KL = ACCR * ZINV.K

where ZINV is the level of invested capital

ZDPRR is the rate of write-off, or the depreciation rate of this capital

and ZINVR is the investment rate.

The average variable costs for a nuclear plant are given by

A ZAVCN.K = OAMCN + NFC.K * HRN

where ZAVCN are the average variable costs for a nuclear plant

OAMCN are the operating and maintenance costs, assumed to be a constant

NFC is the nuclear fuel cost in cents per million Btu's

and HRN is the nuclear heat rate in millions of Btu's per kwh, also assumed to be a constant.

For fossil, the average variable costs are

A ZAVCF.K = OAMCF + FFCC * ZFM.K * HRF.K

where ZAVCF are the average variable costs for a fossil plant

OAMCF are the operating and maintenance costs

FFCC is a fossil fuel cost base price of 30 cents per million Btu's

HRF is the fossil heat rate in millions of Btu's per kwh

and ZFM is a multiplier to account for the changing prices of the fossil fuels.

It is given by

$$\text{A} \quad \text{ZFM.K} = \frac{\sum_{\underline{i}=W,X,Y} (\underline{i}\text{P} * \underline{i}\text{TOZ})}{\sum_{\underline{i}=W,X,Y} \underline{i}\text{TOZ}}$$

where $\underline{i}$P is the fuel price index relative to 1947

and $\underline{i}$TOZ is the consumption of fuel $\underline{i}$ in electricity generation.

With these variables then

A ZAC.K = ZAFC.K + ZAVC.K

A ZP.K = ZAC.K/ZBASE

C ZBASE = 1.40

where ZAC is the average cost of electricity in cents per kwh.

ZBASE is the average cost of electricity generation in 1947 in the cents/kwh.

and ZP.K is the price of electricity relative to this base price.

The final section of the program then gives the cost calculations for fossil vs. nuclear committment decisions. The variable UIF is the unit investment cost in cents per kw. for fossil plants. This is assumed to start at $300/kw. in 1947 and decay exponentially to $200/kw. The nuclear capital costs are entered by a table function. The variables NPI and FPI are the average fixed costs at the assumed capacity utilization factor of 5256 hrs./yr. The fossil heat rate (HRF) is assumed to start at 15,000 Btu's per kwh in 1947 and decline to 11,000 Btu's per kwh. The nuclear heat rate (HRN) is assumed to remain constant at 10,400 Btu's/kwh. The sum of the average fixed and variable costs for the alternative investments are then given by FIC and NIC for fossil and nuclear respectively. The relative fossil to nuclear costs (RFTONC) then define what fraction of the total capacity committment is fossil (and hydro) generation. This is given by the fossil fraction table (FF), and for the base case is the same as that given in figure 3.10b. The only variable to be defined yet is then the nuclear fuel costs.

The nuclear fuel utilization rate is given by

R NFUR.KL = ZFN/175.0

where NFUR is the nuclear fuel utilization rate in millions of tons

ZFN is the electrical output produced by nuclear

and 175.0 is the conversion factor from millions of tons U_3O_8 to mw.[1]

---

[1]Derived from Benedict, Energy Technology to the Year 2000, for plutonium recycle mode of operation.

The cost of the uranium concentrates in dollars per pound is given by NFC1 as a function of the nuclear fuel utilized (NFU.). This functional dependence is approximately the same as that demonstrated in figure 3.11. The nuclear fuel utilized is given by

```
L    NFU.K = NFU.J + (DT) (NFUR.JK)
N    NFU = 0
```

Finally, the nuclear fuel costs in cents per million Btu's is given by

```
A    NFC.K = (5.0 * NFC1.K/8.0) + 13.0
```

where NFC are the nuclear fuel costs in cents per million Btu's

and NFC1 is the cost of uranium concentrates in dollars/pound.

This is derived thusly[1]. At $8/lb. the cost of the uranium concentrates make up about 5 cents of the total fuel costs, and this portion varies with cost of uranium concentrates. The 13.0¢ is considered fixed and corresponds to the conversion, enrichment, fabrication, shipping, reprocessing, and waste management costs, with the plutonium credit and carrying charges figured in.

The remaining program statements in the listing are the calculation of supplementary variables including fuel market shares in each of the consuming sectors and the Dynamo specification cards.

---

[1] M.I.T. course 22.34, Economics of Nuclear Power class notes, by Manson Benedict.

References

Pugh, Alexander L. III, Dynamo II User's Manual, The M.I.T. Press, Cambridge, Mass. and London, England, 1970.

Benedict, Manson, "Electric Power from Nuclear Fission," Special Symposium in Technology Review, "Energy Technology to the Year 2000," Oct./Nov., 1971.

```
* DYNAMIC ENERGY SYSTEM MODELING-- INTERFUEL COMPETITION
MACRO DEL3IA(IN,DEL,INZ)
A DEL3IA.K=$LV3.K/$DL.K
L $LV3.K=$LV3.J+DT*($RT2.JK-DEL3IA.J)
N $LV3=$DL*INZ
R $RT2.KL=$LV2.K/$DL.K
L $LV2.K=$LV2.J+DT*($RT1.JK-$RT2.JK)
N $LV2=$LV3
R $RT1.KL=$LV1.K/$DL.K
L $LV1.K=$LV1.J+DT*(IN.JK-$RT1.JK)
N $LV1=$LV3
A $DL.K=DEL/3.
MEND
MACRO DEL3IO(IN,DEL)
A DEL3IO.K=$LV3.K/$DL.K
L $LV3.K=$LV3.J+DT*($RT2.JK-DEL3IO.J)
N $LV3=0.
R $RT2.KL=$LV2.K/$DL.K
L $LV2.K=$LV2.J+DT*($RT1.JK-$RT2.JK)
N $LV2=$LV3
R $RT1.KL=$LV1.K/$DL.K
L $LV1.K=$LV1.J+DT*(IN.JK-$RT1.JK)
N $LV1=$LV3
A $DL.K=DEL/3.
MEND
MACRO PREC(D,D1,D2,D3,PTIME,DEL1)
A $A.K=(D.K+D1.K+D2.K+D3.K)/4.0
A $B.K=(D3.K+((D2.K-D1.K)/3.0)-D.K)*9.0/20.0
A $C.K=(D3.K-D2.K-D1.K+D.K)/4.0
A $PT.K=PTIME.K
A $P31.K=1.0-(2.0*$PT.K)/(3.0*DEL1)
A $P32.K=1.0-((3.0*$PT.K)/DEL1)+(($PT.K*$PT.K)/(DEL1*DEL1))
A PREC.K=$A.K+$B.K*$P31.K+$C.K*$P32.K
MEND
NOTE     TOTAL PRIMARY ENERGY CONSUMPTION
A TPEC.K=WD.K+XD.K+YD.K+NTOZ.K+HTOZ.K
```

```
NOTE    TOTAL ENERGY DEMAND BY PRIMARY CONSUMING SECTORS
A TED.K=WC.K+XC.K+YC.K+ZC.K
NOTE
NOTE
NOTE    RESIDENTIAL AND COMMERCIAL MODELLING
NOTE
L RCD.K=RCD.J+(DT)(RCDGR.JK)
N RCD=6.36
A RCDG.K=.043*RCD.K
R RCDGR.KL=RCDG.K
NOTE   REPLACEMENT DEMANDS
A RCWRD.K=RCDW.K*RCWB
A RCXRD.K=RCDX.K*RCXB
A RCYRD.K=RCDY.K*RCYB
A RCZRD.K=RCDZ.K*RCZB
NOTE   MARKET SENSITIVE DEMAND
A RCMSD1.K=RCDG.K+RCWRD.K+RCXRD.K+RCYRD.K+RCZRD.K
R RCMSD.KL=RCMSD1.K
NOTE  DECAY RATES
R RCDWDR.KL=RCWRD.K
R RCDXDR.KL=RCXRD.K
R RCDYDR.KL=RCYRD.K
R RCDZDR.KL=RCZRD.K
NOTE  LEVELS OF FUEL CONSUMPTION
L RCDW.K=RCDW.J+(DT)(-RCDWDR.JK+RCDDW.J*RCMSD.JK)
N RCDW=2.59
L RCDX.K=RCDX.J+(DT)(-RCDXDR.JK+RCDDX.J*RCMSD.JK)
N RCDX=1.13
L RCDY.K=RCDY.J+(DT)(-RCDYDR.JK+RCDDY.J*RCMSD.JK)
N RCDY=2.25
L RCDZ.K=RCDZ.J+(DT)(-RCDZDR.JK+RCDDZ.J*RCMSD.JK)
N RCDZ=.39
NOTE  DISTRIBUTION MULTIPLIERS
A RCDDW1.K=RW*EXP(RWW*PW.K)*EXP(RWX*PX.K)*EXP(RWY*PY.K)*EXP(RWZ*PZ.K)
A RCDDX1.K=RX*EXP(RXW*PW.K)*EXP(RXX*PX.K)*EXP(RXY*PY.K)*EXP(RXZ*PZ.K)
A RCDDY1.K=RY*EXP(RYW*PW.K)*EXP(RYX*PX.K)*EXP(RYY*PY.K)*EXP(RYZ*PZ.K)
```

```
A RCDDZ1.K=RZ*EXP(RZW*PW.K)*EXP(RZX*PX.K)*EXP(RZY*PY.K)*EXP(RZZ*PZ.K)
A RTOTAL.K=RCDDW1.K+RCDDX1.K+RCDDY1.K+RCDDZ1.K
A RCDDW.K=RCDDW1.K/RTOTAL.K
A RCDDX.K=RCDDX1.K/RTOTAL.K
A RCDDY.K=RCDDY1.K/RTOTAL.K
A RCDDZ.K=RCDDZ1.K/RTOTAL.K
NOTE  CONSTANTS
C RCWB=0.10
C RCXB=0.10
C RCYB=0.10
C RCZB=0.10
C RW=.02
C RX=.23
C RY=.65
C RZ=.10
C PWW=-0.9
C RXW=0.27
C RYW=0.35
C RZW=0.27
C RWX=.05
C RXX=-.5
C RYX=.35
C RZX=.1
C RWY=0.15
C RXY=0.75
C RYY=-1.2
C RZY=0.3
C RWZ=0.
C RXZ=.25
C RYZ=.25
C RZZ=-.5
NOTE
NOTE
NOTE
NOTE
NOTE   INDUSTRIAL PROCESSING DEMAND MODELLING
```

```
NOTE
NOTE
NOTE
L  IHD.K=IHD.J+(DT)(IHDGR.JK)
N  IHD=12.97
A  IHDG.K=.025*IHD.K
R  IHDGR.KL=IHDG.K
NOTE    REPLACEMENT DEMANDS
A  IHWRD.K=IHDW.K*IHWR
A  IHXRD.K=IHDX.K*IHXR
A  IHYRD.K=IHDY.K*IHYR
A  IHZRD.K=IHDZ.K*IHZR
NOTE    MARKET SENSITIVE DEMAND
A  IHMSD1.K=IHDG.K+IHWRD.K+IHXRD.K+IHYRD.K+IHZRD.K
R  IHMSD.KL=IHMSD1.K
NOTE   DECAY RATES
R  IHDWDR.KL=IHWRD.K
R  IHDXDR.KL=IHXRD.K
R  IHDYDR.KL=IHYRD.K
R  IHDZDR.KL=IHZRD.K
NOTE   LEVELS OF FUE   CONSUMPTION
L  IHDW.K=IHDW.J+(DT)(-IHDWDR.JK+IHDDW.J*IHMSD.JK)
N  IHDW=7.01
L  IHDX.K=IHDX.J+(DT)(-IHDXDR.JK+IHDDX.J*IHMSD.JK)
N  IHDX=3.01
L  IHDY.K=IHDY.J+(DT)(-IHDYDR.JK+IHDDY.J*IHMSD.JK)
N  IHDY=2.49
L  IHDZ.K=IHDZ.J+(DT)(-IHDZDR.JK+IHDDZ.J*IHMSD.JK)
N  IHDZ=0.45
NOTE   DISTRIBUTION MULTIPLIERS
A  IHDDW1.K=IW*EXP(IWW*PW.K)*EXP(IWX*PX.K)*EXP(IWY*PY.K)*EXP(IWZ*PZ.K)
A  IHDDX1.K=IX*EXP(IXW*PW.K)*EXP(IXX*PX.K)*EXP(IXY*PY.K)*EXP(IXZ*PZ.K)
A  IHDDY1.K=IY*EXP(IYW*PW.K)*EXP(IYX*PX.K)*EXP(IYY*PY.K)*EXP(IYZ*PZ.K)
A  IHDDZ1.K=IZ*EXP(IZW*PW.K)*EXP(IZX*PX.K)*EXP(IZY*PY.K)*EXP(IZZ*PZ.K)
A  ITOTAL.K=IHDDW1.K+IHDDX1.K+IHDDY1.K+IHDDZ1.K
A  IHDDW.K=IHDDW1.K/ITOTAL.K
```

```
A IHDDX.K=IHDDX1.K/ITOTAL.K
A IHDDY.K=IHDDY1.K/ITOTAL.K
A IHDDZ.K=IHDDZ1.K/ITOTAL.K
NOTE  CONSTANTS
C IHWB=0.10
C IHXB=0.10
C IHYB=0.10
C IHZB=0.10
C IW=0.14
C IX=0.40
C IY=0.40
C IZ=0.06
C IWW=-.54
C IXW=0.19
C IYW=0.19
C IZW=0.19
C IWX=.2
C IXX=-.8
C IYX=.4
C IZX=.2
C IWY=0.3
C IXY=0.6
C IYY=-1.2
C IZY=0.3
C IWZ=.2
C IXZ=.2
C IYZ=.2
C IZZ=-.6
NOTE
NOTE
NOTE
NOTE
NOTE      TRANSPORTATION DEMAND MODELLING
NOTE
NOTE
NOTE
```

```
L TRD.K=TRD.J+(DT)(TRDGR.JK)
N TRD=9.79
A TRDG.K=.029*TRD.K
R TRDGR.KL=TRDG.K
NOTE    REPLACEMENT DEMANDS
A TRWRD.K=TRDW.K*TRWB
A TRXRD.K=TRDX.K*TRXB
A TRYRD.K=TRDY.K*TRYB
A TRZRD.K=TRDZ.K*TRZB
NOTE    MARKET SENSITIVE DEMAND
A TRMSD1.K=TRDG.K+TRWRD.K+TRXRD.K+TRYRD.K+TRZRD.K
R TRMSD.KL=TRMSD1.K
NOTE    DECAY RATES
R TRDWDR.KL=TRWRD.K
R TRDXDR.KL=TRXRD.K
R TRDYDR.KL=TRYRD.K
R TRDZDR.KL=TRZRD.K
NOTE   LEVELS OF FUEL CONSUMPTION
L TRDW.K=TRDW.J+(DT)(-TRDWDR.JK+TRDDW.J*TRMSD.JK)
N TRDW=3.00
L TRDX.K=TRDX.J+(DT)(-TRDXDR.JK+TRDDX.J*TRMSD.JK)
N TRDX=0.00
L TRDY.K=TRDY.J+(DT)(-TRDYDR.JK+TRDDY.J*TRMSD.JK)
N TRDY=5.75
L TRDZ.K=TRDZ.J+(DT)(-TRDZDR.JK+TRDDZ.J*TRMSD.JK)
N TRDZ=0.03
NOTE   DISTRIBUTION MULTIPLIERS
A TRDDW1.K=TW*EXP(TWW*PW.K)*EXP(TWX*PX.K)*EXP(TWY*PY.K)*EXP(TWZ*PZ.K)
A TRDDX1.K=TX*EXP(TXW*PW.K)*EXP(TXX*PX.K)*EXP(TXY*PY.K)*EXP(TXZ*PZ.K)
A TRDDY1.K=TY*EXP(TYW*PW.K)*EXP(TYX*PX.K)*EXP(TYY*PY.K)*EXP(TYZ*PZ.K)
A TRDDZ1.K=TZ*EXP(TZW*PW.K)*EXP(TZX*PX.K)*EXP(TZY*PY.K)*EXP(TZZ*PZ.K)
A TTOTAL.K=TRDDW1.K+TRDDX1.K+TRDDY1.K+TRDDZ1.K
A TRDDW.K=TRDDW1.K/TTOTAL.K
A TRDDX.K=TRDDX1.K/TTOTAL.K
A TRDDY.K=TRDDY1.K/TTOTAL.K
A TRDDZ.K=TRDDZ1.K/TTOTAL.K
```

```
NOTE   CONSTANTS
C  TRWB=0.333
C  TRXB=0.20
C  TRYB=0.20
C  TRZB=0.20
C  TW=.001
C  TX=.025
C  TY=.97
C  TZ=0.001
C  TWW=-.002
C  TXW=.001
C  TYW=.001
C  TZW=0.
C  TWX=0.
C  TXX=-.002
C  TYX=.001
C  TZX=.001
C  TWY=.01
C  TXY=.025
C  TYY=-.05
C  TZY=.015
C  TWZ=.001
C  TXZ=.002
C  TYZ=.002
C  TZZ=-.005
NOTE
NOTE
NOTE      ENERGY CONSUMPTION BY PRIMARY CONSUMING SECTORS
NOTE
A  WO.K=PCDW.K+IHDW.K+TRDW.K
A  XO.K=RCDX.K+IHCX.K+TRDX.K
A  YO.K=RCDY.K+IHCY.K+TRDY.K
A  ZO.K=RCDZ.K+IHCZ.K+TRDZ.K
NOTE
NOTE    ELECTRICITY DEMAND
NOTE       INCREMENTAL DEMAND
```

```
A ZDG2.K=(RCDDZ.K*RCMSD1.K)-RCZRD.K+(TRDDZ.K*TRMSD1.K)-TRZRD.K
A ZDG1.K=ZDG2.K+(IHDDZ.K*IHMSD1.K)-IHZRD.K
NOTE    REPLACEMENT DEMANDS
A ZFWRD.K=ZFW.K*ZFWB
A ZFXRD.K=ZFX.K*ZFXB
A ZFYRD.K=ZFY.K*ZFYB
NOTE   MARKET SENSITIVE DEMAND
NOTE    NUCLEAR MARKET SHARE
A ZFN.K=(1.0-FCF.K)(ZD.K)
A ZFH.K=CLIP(ZFH1.K,ZFH2.K,23.0,TIME.K)
A ZFH1.K=0.29*EXP(0.047*TIME.K)
A ZFH2.K=0.29*EXP(0.047*23.0)*EXP(0.016*(TIME.K-23.0))
NOTE   FOSSIL MARKET SENSITIVE DEMAND
L ZFND.K=ZFN.J
N ZFND=0.0
L ZFHD.K=ZFH.J
N ZFHD=0.29
A DELZFN.K=ZFN.K-ZFND.K
A DELZFH.K=ZFH.K-ZFHD.K
A ZFFG.K=ZDG1.K-(DELZFN.K/DT)-(DELZFH.K/DT)
R ZFSD.KL=ZFFG.K+ZFWRD.K+ZFXRD.K+ZFYRD.K
NOTE    FUEL DECAY RATES
R ZFWDR.KL=ZFWRD.K
R ZFXDR.KL=ZFXRD.K
R ZFYDR.KL=ZFYRD.K
NOTE     ELECTRICITY OUTPUT PRODUCED FROM W,X, AND Y
L ZFW.K=ZFW.J+(DT)(-ZFWDR.JK+ZDDW.J*ZFSD.JK)
N ZFW=0.40
L ZFX.K=ZFX.J+(DT)(-ZFXDR.JK+ZDDX.J*ZFSD.JK)
N ZFX=0.09
L ZFY.K=ZFY.J+(DT)(-ZFYDR.JK+ZDDY.J*ZFSD.JK)
N ZFY=0.10
NOTE
A WTOZ.K=ZFW.K*HRF.K/3.412E-3
A XTOZ.K=ZFX.K*HRF.K/3.412E-3
A YTOZ.K=ZFY.K*HRF.K/3.412E-3
```

```
A NTOZ.K=ZFN.K*HRN/3.412E-3
A HTOZ.K=ZFH.K*HRF.K/3.412E-3
NOTE    DISTRIBUTION FACTORS
A ZDDW1.K=ZW*EXP(ZWW*PW.K)*EXP(ZWX*PX.K)*EXP(ZWY*PY.K)
A ZDDX1.K=ZX*EXP(ZXW*PW.K)*EXP(ZXX*PX.K)*EXP(ZXY*PY.K)
A ZDDY1.K=ZY*EXP(ZYW*PW.K)*EXP(ZYX*PX.K)*EXP(ZYY*PY.K)
A ZTOTAL.K=ZDDW1.K+ZDDX1.K+ZDDY1.K
A ZDDW.K=(ZDDW1.K/ZTOTAL.K)
A ZDDX.K=(ZDDX1.K/ZTOTAL.K)
A ZDDY.K=(ZDDY1.K/ZTOTAL.K)
NOTE    CONSTANTS
C ZFWR=0.05
C ZFXR=C.C5
C ZFYR=0.05
C ZW=0.20
C ZX=C.45
C ZY=0.35
C ZWW=-1.9
C ZXW=0.9
C ZYW=0.9
C ZWX=1.C
C ZXX=-2.0
C ZYX=1.0
C ZWY=1.5
C ZXY=1.5
C ZYY=-3.0
NOTE
NOTE
NOTE
NOTE     FUEL CONSUMPTION
A WD.K=WC.K+WTOZ.K+WTOX.K
A XD.K=XC.K+XTOZ.K
A YD.K=YC.K+YTOZ.K
A ZD.K=ZC.K
A YIMF.K=TABLE(YTAB,TIME.K,0.0,50.0,10.0)
T YTAB=C.C/2.5/5.1/12.5/25.0/45.0
```

```
A  YE.K=YC.K-YIMP.K
A  XIMP.K=TABLE(XTAB,TIME.K,0.0,50.0,10.0)
T  XTAB=0.0,0.0,0.0,0.0,0.0,0.0
A  XE.K=XD.K-XIMP.K-XFW.K
A  XFW.K=TABLE(XFWTAB,TIME.K,0.0,50.0,10.0)
T  XFWTAB=0.0,0.0,0.0,0.0,0.0,0.0
C  WXCE=1.3
A  WTOX.K=WXCE*XFW.K
NOTE
NOTE
NOTE   DISCOUNT RATE
A  R.K=0.1
NOTE
NOTE
NOTE          COAL  SUPPLY
NOTE
C  WCDT=2.0
C  WDPR=0.03
A  WD1.K=DELAY3(WD.K,WPDT)
A  WD2.K=DELAY3(WD1.K,WPDT)
A  WD3.K=DELAY3(WD2.K,WPDT)
A  WPD.K=PRED(WD.K,WD1.K,WD2.K,WD3.K,WFT,WPDT)
A  WDC.K=WPD.K/0.6
C  WEDT=2.0
N  WPDT=WEDT
N  WPT=3.0*WPDT+WCDT
A  WCPED.K=WDC.K-WPC.K-WCBD.K+WCDT*WDPR*WPC.K
A  WCED.K=MAX(WCPED.K,0.0)
R  WCDR.KL=WCED.K/WEDT
L  WCBD.K=WCBD.J+(DT)(WCDR.JK-WCCR.JK)
N  WCBD=0.0
N  WINZ=WDPR*WPC
R  WCCR.KL=DEL3IA(WCDR.JK,WCDT,WINZ)
R  WPDR.KL=WDPR*WPC.K
L  WPC.K=WPC.J+(DT)(WCCR.JK-WPDR.JK)
N  WPC=24.0
```

```
A  WMDC.K=WCPUC.K*R.K
A  WCPUC.K=10.0*EXP(-0.01*TIME.K)
A  WALPH.K=0.4
A  WSRMC.K=WMDC.K*WALPH.K*WPC.K/(WPC.K-WD.K)
A  WSP.K=SMOOTH(WSRMC.K,WPST)
A  WP.K=WSP.K
C  WPST=4.0
A  WCUF.K=WD.K/WPC.K
NOTE
NOTE
NOTE          NATURAL GAS SUPPLY
NOTE
C  XCDT=1.0
L  XRES.K=XRES.J+(DT)(XARR.JK-XPRDR.JK)
N  XRES=160.
R  XARR.KL=18.0
R  XPRDR.KL=XE.K
A  XCPED.K=XRES.K*(SQRT(XPP.K*R.K/XCPLC.K)-R.K)
A  XE1.K=DELAY3(XE.K,XPDT)
A  XE2.K=DELAY3(XE1.K,XPDT)
A  XE3.K=DELAY3(XE2.K,XPDT)
A  XPD.K=PRED(XE.K,XE1.K,XE2.K,XE3.K,XPT,XPDT)
A  XDC.K=(XCPED.K+XPD.K/0.8)/2.0
A  XCED.K=XDC.K-XPC.K-XCBD.K+XDPR.K*XPC.K*XCDT
A  XCPLC.K=4.0
A  XDPR.K=XE.K/XRES.K
A  XRPRO.K=XRES.K/XE.K
R  XCDR.KL=(MAX(XCED.K,0.0))/XEDT
C  XEDT=1.C
L  XCBD.K=XCBD.J+(DT)(XCDR.JK-XCCR.JK)
N  XCBD=XINZ*XCDT
N  XINZ=(XDPR+.10)*XPC
R  XCCR.KL=DEL3IA(XCDR.JK,XCDT,XINZ)
R  XPDR.KL=XDPR.K*XPC.K
L  XPC.K=XPC.J+(DT)(XCCR.JK-XPDR.JK)
N  XPC=5.2
```

```
A XMDC.K=XCPUC.K*(XPC.K+R.K*XRES.K)*(XPC.K+R.K*XRES.K)/(R.K*XRES.K*XRES.
X K)
A XSRMC.K=XMDC.K*XALPH.K*XPC.K/(XPC.K-XE.K)
A XALPH.K=0.2
A XP.K=XSP.K
A XSP.K=SMOOTH(XSRMC.K,XPST)
A XSP1.K=DELAY3(XSP.K,XPDT)
A XSP2.K=DELAY3(XSP1.K,XPDT)
A XSP3.K=DELAY3(XSP2.K,XPDT)
C XPDT=1.0
A XPP.K=PRED(XSP.K,XSP1.K,XSP2.K,XSP3.K,XPT,XPDT)
N XPT=XCDT+3.0*XPDT
C XPST=4.0
A XCUF.K=XE.K/XPC.K
NOTE
NOTE
NOTE        OIL SUPPLY
NOTE
C YCDT=1.0
L YRES.K=YRES.J+(DT)(YARR.JK-YPRDR.JK)
N YRES=127.0
R YARR.KL=20.0
R YPRDR.KL=YE.K
A YCPED.K=YRES.K*(SQRT(YPP.K*R.K/YCPLC.K)-R.K)
A YE1.K=DELAY3(YE.K,YPDT)
A YE2.K=DELAY3(YE1.K,YPDT)
A YE3.K=DELAY3(YE2.K,YPDT)
A YPC.K=PRED(YE.K,YE1.K,YE2.K,YE3.K,YPT,YPDT)
A YDC.K=(YCPED.K+YPD.K/0.8)/2.0
A YCED.K=YDC.K-YPC.K-YCBD.K+YDPR.K*YPC.K*YCDT
A YCPLC.K=1.46
A YDPR.K=YE.K/YRES.K
A YRPRO.K=YRES.K/YE.K
R YCDR.KL=(MAX(YCED.K,0.0))/YEDT
C YEDT=1.0
L YCBD.K=YCBD.J+(DT)(YCDR.JK-YCCR.JK)
```

```
A YCBC=YINZ*YCDT
N YINZ=(YCPR+.06)*YPC
R YCCR.KL=DEL3IA(YCDR.JK,YCDT,YINZ)
R YPDR.KL=YDPR.K*YPC.K
L YPC.K=YPC.J+(DT)(YCCR.JK-YPDR.JK)
N YPC=13.3
A YMDC.K=YCPUC.K*(YPC.K+R.K*YRES.K)*(YPC.K+R.K*YRES.K)/(R.K*YRES.K*YRES.
X K)
A YSRMC.K=YMDC.K*YALPH.K*YPC.K/(YPC.K-YE.K)
A YALPH.K=0.2
A YP.K=YSP.K*YPM.K
A YPM.K=TABLE(YPTAB,TIME.K,0.0,50.0,5.0)
T YPTAB=1.45,1.40,1.40,1.35,1.20,1.00,1.00,1.00,1.00,1.00,1.00
A YSP.K=SMOOTH(YSRMC.K,YPST)
A YSP1.K=DELAY3(YSP.K,YPDT)
A YSP2.K=DELAY3(YSP1.K,YPDT)
A YSP3.K=DELAY3(YSP2.K,YPDT)
C YPDT=1.0
A YPP.K=PRED(YSP.K,YSP1.K,YSP2.K,YSP3.K,YPT,YPDT)
N YPT=YCDT+3.0*YPDT
C YPST=4.0
A YCUF.K=YE.K/YPC.K
NOTE
NOTE
NOTE
NOTE          ELECTRICITY SUPPLY
NOTE
NOTE
A ZD1.K=DEL3IA(ZC.K,DELZ,.646)
A ZD2.K=DEL3IA(ZD1.K,DELZ,.413)
A ZD3.K=DEL3IA(ZD2.K,DELZ,.265)
C DELZ=5.0
NOTE
NOTE
C ZCCT=7.0
A ZPTIME.K=ZCCT+3.0*DELZ
```

```
A ZPC.K=PRED(ZD.K,ZD1.K,ZD2.K,ZD3.K,ZPTIME.K,DELZ)
A ZPPC.K=(ZPC.K)(1.0-ZCCT/ZPCLT.K)+ZCIC.K
A ZCR.K=(ZPD.K)(ZCR.K)-ZPPC.K
A ZCR1.K=MAX(0.0,ZCR.K)
NOTE   COMMITTMENT RATE
A ZCCR.K=ZCR1.K
R ZFCCR.KL=ZCCR.K*FF.K
R ZNCCR.KL=ZCCR.K*(1.0-FF.K)
A ZDR.K=2.0
NOTE   FOSSIL CAPACITY
N ZFROCI=0.11*ZFPC
R ZFROC.KL=DEL3IA(ZFCCR.JK,ZCCT,ZFROCI)
N ZFCCRI=0.03*ZFPC
R ZFCOR.KL=DEL3IA(ZFROC.JK,ZPCLT.K,ZFCORI)
L ZFCIC.K=ZFCIC.J+(DT)(ZFCCR.JK-ZFROC.JK)
N ZFCIC=ZFROCI*ZCCT*0.75
L ZFPC.K=ZFPC.J+(DT)(ZFROC.JK-ZFCCR.JK)
N ZFPC=1.76
NOTE NUCLEAR CAPACITY
R ZNROC.KL=DEL3IC(ZNCCR.JK,ZCCT)
R ZNCCR.KL=DEL3IO(ZNROC.JK,ZPCLT.K)
L ZNCIC.K=ZNCIC.J+(DT)(ZNCCR.JK-ZNROC.JK)
N ZNCIC=0.0
L ZNPC.K=ZNPC.J+(DT)(ZNROC.JK-ZNCCR.JK)
N ZNPC=0.0
NOTE
NOTE     TOTAL ELECTRICITY PRODUCTION CAPACITY
NOTE
A FCF.K=ZFPC.K/(ZFPC.K+ZNPC.K)
A ZPC.K=ZFPC.K+ZNPC.K
A ZCIC.K=ZFCIC.K+ZNCIC.K
A ZPCLT.K=ZNPCLT+ZELT.K
A ZELT.K=(ZDR.K-1.0-ZRES.K)*200.0
C ZNPCLT=40.0
A ZRES.K=(ZPC.K-ZD.K)/ZD.K
A ZCUF.K=ZD.K/ZPC.K
```

```
NOTE
NOTE
A ZFM.K=(XP.K*XTOZ.K+YP.K*YTOZ.K+WP.K*WTOZ.K)/(WTOZ.K+XTOZ.K+YTOZ.K)
A ZCCR1.K=ZCCR.K/2.29E-8      KWH/YR/YR
A ZDA.K=ZD.K/3.412E-12        KWH/YR
L ZINV.K=ZINV.J+(DT)(ZINVR.JK-ZDPRR.JK)            CENTS
N ZINV=18.0E11
R ZINVR.KL=ZCCR1.K*FF.K*UIF.K+ZCCR1.K*(1.-FF.K)*UIN.K     CENTS/YR
R ZDPRR.KL=ACCR*ZINV.K
A ZAFC.K=(ACCR*ZINV.K)/ZDA.K
A ZAVC.K=ZAVCF.K*FCF.K+ZAVCN.K*(1.-FCF.K)
A ZAVCF.K=CAMCF+FFCC*ZFM.K*HRF.K
A ZAVCN.K=CAMCN+NFC.K*HRN
A ZAC.K=ZAFC.K+ZAVC.K          CENTS/KWH
A ZP.K=ZAC.K/ZBASE
C ZBASE=1.40
NOTE
NOTE   NUCLEAR PLANT SELECTION PROCESS
NOTE
NOTE   UIF AND UIN IN CENTS PER KW
A UIF.K=(200.+100.*EXP(-.08*TIME.K))*100.
C ACCR=0.125
C CUF=5256.
A FPI.K=UIF.K*ACCR/CUF
A UIN.K=100.0*UIM.K
A UIM.K=TABLE(NCCTB,TIME.K,0.0,50.0,5.0)
T NCCTB=800.,700.,590.,400.,300.,220.,250.,250.,250.,250.,250.
A NPI.K=UIN.K*ACCR/CUF
NOTE    FUEL COSTS
A FFC.K=FFCC*ZFM.K
C FFCC=30.0
NOTE NUCLEAR FUEL COSTS IN CENTS/MBTUS
A NFC.K=(5.0*NFC1.K/8.0)+13.0
A ZNM.K=NFC.K/18.0
A HRF.K=0.011+.004*EXP(-.4*TIME.K)
C HRN=0.0104
```

```
C OAMCF=0.03
C OAMCN=0.033
NOTE  PROJECTED FOSSIL VS NUCLEAR COSTS IN CENTS/KWH
A FIC.K=FPI.K+OAMCF+FFC.K*HRF.K
A NIC.K=NPI.K+OAMCN+NFC.K*HRN
A RFTONC.K=FIC.K/NIC.K
A FF.K=TABLE(FFTAB,RFTONC.K,0.0,4.0,0.25)
T FFTAB=1.0/1.0/1.0/0.95/0.6/0.35/0.2/0.1/0.1/0.1/0.1/0.1/0.1/0.1/0.1/
X 0.1/0.1
NOTE    175 MILLIC PER MTONS U308
R NFUR.KL=ZFN.K/175.0
NOTE NFU IN MTONS
L NFU.K=NFU.J+(DT)(NFUR.JK)
N NFU=0.0
NOTE COST OF URANIUM CONCENTRATES IN $/LB
A NFC1.K=9.0+6.0*NFU.K-NFCA.K
A NFCA.K=CLIP(NFCB.K,0.0,NFU.K,1.50)
A NFCB.K=-3.0+2.0*NFU.K
NOTE
NOTE
NOTE     PRICES
A PW.K=WP.K
A PX.K=XP.K
A PY.K=YP.K
A PZ.K=ZP.K
NOTE
NOTE     CALCULATION OF FUEL MARKET SHARES
NOTE
S RWMS.K=RCDW.K/RCD.K
S RXMS.K=RCDX.K/RCD.K
S RYMS.K=RCDY.K/RCD.K
S RZMS.K=RCDZ.K/RCD.K
S IWMS.K=IHDW.K/IHD.K
S IXMS.K=IHDX.K/IHD.K
S IYMS.K=IHDY.K/IHD.K
S IZMS.K=IHDZ.K/IHD.K
```

```
S  TWMS.K=TRDW.K/TRD.K
S  TXMS.K=TRDX.K/TRD.K
S  TYMS.K=TRDY.K/TRD.K
S  TZMS.K=TRDZ.K/TRD.K
S  EWMS.K=ZEW.K/ZD.K
S  EXMS.K=ZEX.K/ZD.K
S  EYMS.K=ZEY.K/ZD.K
S  ENMS.K=ZEN.K/ZD.K
S  EHMS.K=ZEH.K/ZD.K
S  WMS.K=WD.K/TPEC.K
S  XMS.K=XD.K/TPEC.K
S  YMS.K=YD.K/TPEC.K
S  NMS.K=NTOZ.K/TPEC.K
S  HMS.K=HTOZ.K/TPEC.K
NOTE
NOTE
NOTE
PRINT  TPEC,RCC,IHC,TRD,ZD,WD,XD,YD,WC,XC,YC,ZP,WP,XP,YP
PRINT  WPC,XPC,YPC,ZPC,RCDW,RCDX,RCDY,RCDZ
PRINT  IHDW,IHDX,IHDY,IHDZ,TRDW,TRDX,TRDY,TRDZ
PRINT  FF,FCF,RFTCNC,NFC1,NFC,ZNPC,WTCZ,XTCZ,YTCZ,NTOZ,HTOZ
PRINT  XRES,YRES,XCUF,YCUF,WCUF,ZCUF,YRPRC,XRPRO,YIMP,YE,XFW
PRINT  XIMP,XE,YSP
PLOT  RCD=R,IHD=I,TRD=T,ZD=E,TED=D
PLOT  WD=W,XD=X,YD=Y,ZD=Z
PLOT  WP=W,XP=X,YP=Y,ZP=Z
PLOT  RCDW=W,RCDX=X,RCDY=Y,RCDZ=Z
PLOT  IHDW=W,IHDX=X,IHDY=Y,IHDZ=Z
PLOT  TRDW=W,TRDX=X,TRDY=Y,TRDZ=Z
PLOT  WTCZ=W,XTCZ=X,YTCZ=Y
PLOT  WD=W,YD=Y,XD=X,ZD=Z
PLOT  XE=D,XIMP=I,XD=T,XFW=W
PLOT  YE=C,YIMP=I,YD=T
PLOT  EWMS=W,EXMS=X,EYMS=Y,ENMS=N,EHMS=H
PLOT  WMS=W,XMS=X,YMS=Y,NMS=N,HMS=H
PLOT  XRPRC=X,YRPRC=Y
```

```
PLOT WCUF=W,ZCUF=Z,XCUF=X,YCUF=Y(0.0,1.0)
SPEC DT=0.10/LENGTH=50.0/PRTPER=2.0/PLTPER=1.0
RUN
```

BIOGRAPHICAL NOTE

Martin Lynn Baughman was born February 18, 1946 in Paulding, Ohio. He graduated from Paulding High School in June, 1964 and in September of that year entered Ohio Northern University at Ada, Ohio. He graduated in 1968 with high distinction in electrical engineering. He then entered the Massachusetts Institute of Technology in the fall of 1968 with a National Science Foundation Traineeship. He received the S.M.E.E. in 1970 and the E.E. degree in 1971. His Master's thesis was in the field of electric power systems entitled "Load Shed Scheme Utilizing Frequency and its Derivatives".

From 1969 to 1970 he was a part time employee of the New England Electric System located at Westboro, Mass. A publication with Prof. F. C. Schweppe entitled "Contingency Evaluation: Real Power Flows from a Linear Model" resulted from this work, and was presented at the 1970 I.E.E.E. Summer Power Meeting.

For the 1969-1970 school year he was a teaching assistant in a basic electronics laboratory at M.I.T. and from 1970 to 1972 he was a Fannie and John Hertz Foundation Fellow. He is a member of Phi Kappa Phi, Phi Eta Sigma, and Sigma Xi.