A REGIONALIZED ELECTRICITY MODEL

BY

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INTRODUCTION

The pervasive effects of the Arab oil embargo upon the U.S. economy have not left unscathed the electric utility industry. The industry has been caught in the squeeze of rising fuel costs, increasing capital costs and costs of money, unprecedented delays and legal actions from those seeking pollution abatement measures, and all in the face of extreme uncertainty about future load growth patterns. Many utilities are no longer in the confortable position of merely forecasting load, financing expansion, and operating in a well defined minimum cost mode. Rather, many are fighting for survival amid a set of very constrained options forced upon them by social, environmental, and regulatory forces impacting the managerial and financial decision set. The future evolution of the industry within these constraints requires re-evaluation of the social consequences of the many determinants affecting industry behavior.

With the interactions among the decision variables at any point in time and over time, the numerical tedium of in depth evaluation for alternative actions and consequences can be greatly expedited through the use of mathematical models. The purpose of this paper is to review the theoretical bases for the electrical industry planning and operational decisions and unveil how these have been interconnected into a regionalized U.S. model descriptive of industry behavior, which we have constructed to

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examine the likely effects of alternative public policies.

To this end, in Chapter 1 we review the economic principles of electric utility behavior, both in the operations and planning spheres. In Chapter 2 we discuss how these principles have been combined into the specification and development of an engineering-econometric simulation model for electric utility behavior. Finally, in Chapter 3, the results of some sample simulations done with the model are presented to depict the substitution possibilities inherent in the model structure and exemplify how it can be used. This is a report on work in progress, and therefore the simulations to be discussed are not to be viewed as forecasts, merely examples of model use.

Fortunately much past work has been done in both the theoretical and practical spheres of industry operation and many models for production, maintenance scheduling, and expansion planning decisions are available to draw upon. Unfortunately, however, these models have been developed to be applied by individual planning and operations units within the industry-and, as a consequence, are much too detailed and unwieldy to be scaled up for analysis of the broad scale social (welfare) consequences of national policy and regulatory alternatives. It is for this reason that we have embarked upon the research to be reviewed in this paper.

This document is not intended to be a detailed exposition of all factors affecting the economics of electricity supply. In fact, discussion of many practical details of great import to utilities operational and planning decisions is neglected completely. For this reason our review of the economic principles will not be new information to economists and engineers with a strong background in industry operations. The purpose here is to describe which of the factors have been structured into the regionalized simulation model and how the model relates to the more detailed production costing, generation scheduling, and expansion planning routines widely used within the industry.

Further, it will be seen that the bulk of the discussion to follow concerns itself mainly with thermal systems, either fossil fueled or nuclear. In this country hydro and pumped storage capacity account for about 14% of the total U.S. generation capability, but this fraction is declining since only 7% of new additions fall into these categories[1]. Finally, our discussions are more complete with regard to long term investment planning decisions than the shorter term daily or seasonal operating considerations. The model is a medium to long-term description (approximately one year to thirty years) of industry behavior. We are only concerned with the short term (less than one year) factors as they influence this long term behavior.

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[1] from Electrical World [3].

1. THE THEORY

The planning and operation of an electric power system involves thousands of practical engineering and economic considerations. Obviously, we cannot hope to give a thorough exposition of all the problems in this paper. What are considered here are the broad economic concepts whose interaction affect the costs and planning for electricity supply. These can conveniently be broken into three time spans of interest. The first is the hour by hour operation of the mix of available units to meet the load and its changes over the hours of the day. The second is the scheduling of maintenance and generation capability to be available on a daily, weekly, and seasonal basis for use in meeting the hourly load changes. Finally, there is the long term investment planning horizon where choices between alternative plant construction and retirement programs must be made. The planning horizon for these decisions naturally extends into periods of two to ten or more years simply because of the time it takes to construct and make operational new plants. In the theoretical discussions that follow we break the economic criteria into the above three time intervals.

Minimum Cost Hourly Operation (Economic Load Dispatch)

An electric power system consists of many generating units interconnected with the load via a transmission network. In general, the system consists of numerous vintage plants with many different fuel burning capabilities. The problem of economic dispatch involves how to most economically utilize this mix of generation capability to meet the load within the constraints of the fixed transmission network and its associated losses.

The incremental cost of a unit of electricity from a generating unit depends on the cost of the fuel input and the incremental performance of the boiler-turbine-generator conversion set. In general, this performance is a non-linear function of output, depending on such factors as boiler efficiency, the turbine incremental heat rate, the requirements for auxiliary power in the station, and, can only be assessed from actual operating experience. Given an input-output performance curve for the plant (such as that shown in figure 1), the incremental performance curve is obtained by differentiation (figure 2). The cost of an incremental kwh is obtained by multiplying the incremental fuel rate by the cost of fuel for that unit.

In the absence of transmission losses, to minimize the costs of production for a system of several units, we have the well known results that the incremental costs for all units should be equated[2]. In figure 3 we illustrate graphically the implications of this operating procedure. To obtain the system incremental cost curve, we add together the power outputs for all units at each incremental cost on the ordinate of the plot. For each value of system load (say L_1) there corresponds a system incremental cost (C_1) and a collection of plants whose collective power output equals the system load at that incremental costs ($P_1+P_2+P_3+P_4$). As the load cycles through the swings of the day and seasons of the year, the total system output increases and decreases with a corresponding movement up and down in the system incremental costs[3].

Of course, so far we have neglected many of the everyday issues of great concern to the system operator. In practice there are often many other constraints and considerations that must be factored into the operating decisions, not the least of which is the adjustment of the above simplified operating procedures to account for transmission losses[4].

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[2] See for example Kirchmayer [1] or Turvey [2]. A large body literature exists in relation to this topic.

[3] This movement in incremental costs provides the basis for the British pricing scheme of higher rates during high load periods.

[4] Kirchmayer [1] gives a detailed description of how losses can be factored into the analysis.

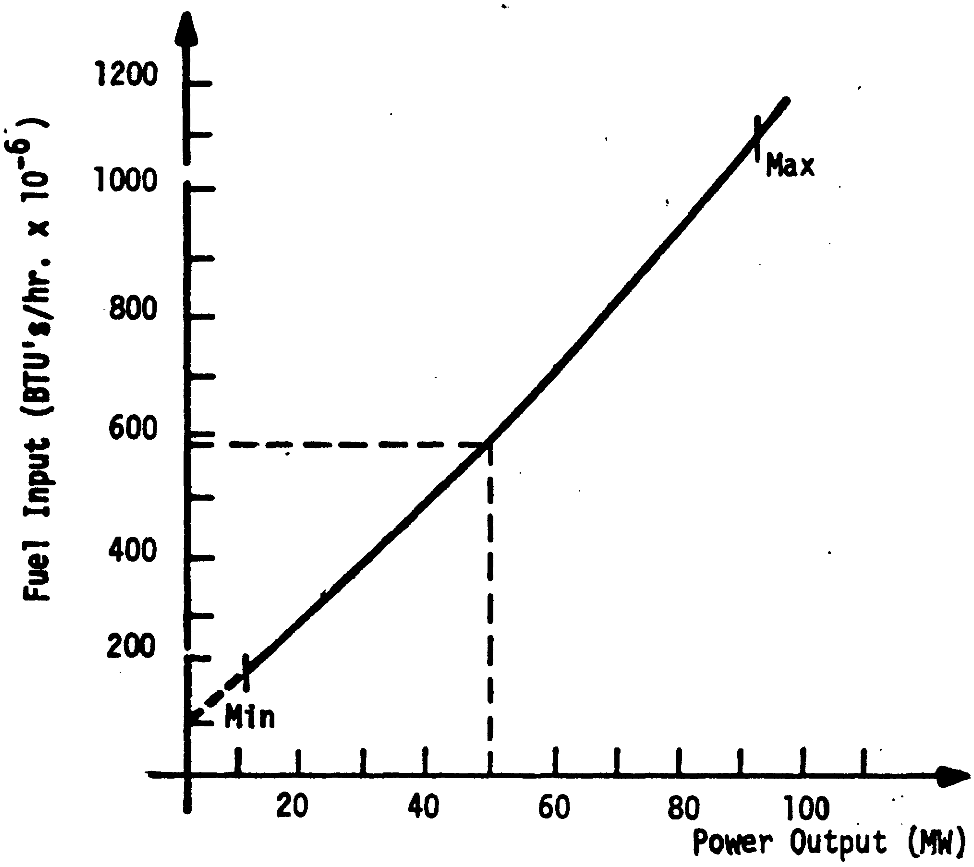


Figure 1: INPUT-OUTPUT CURVE

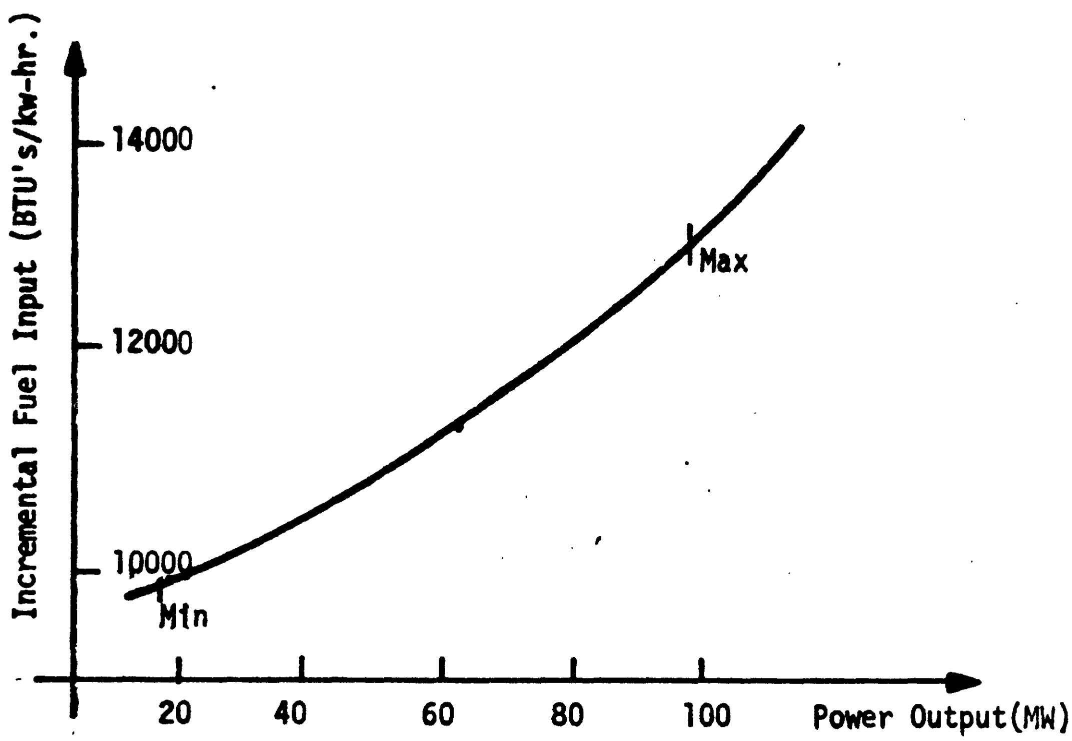
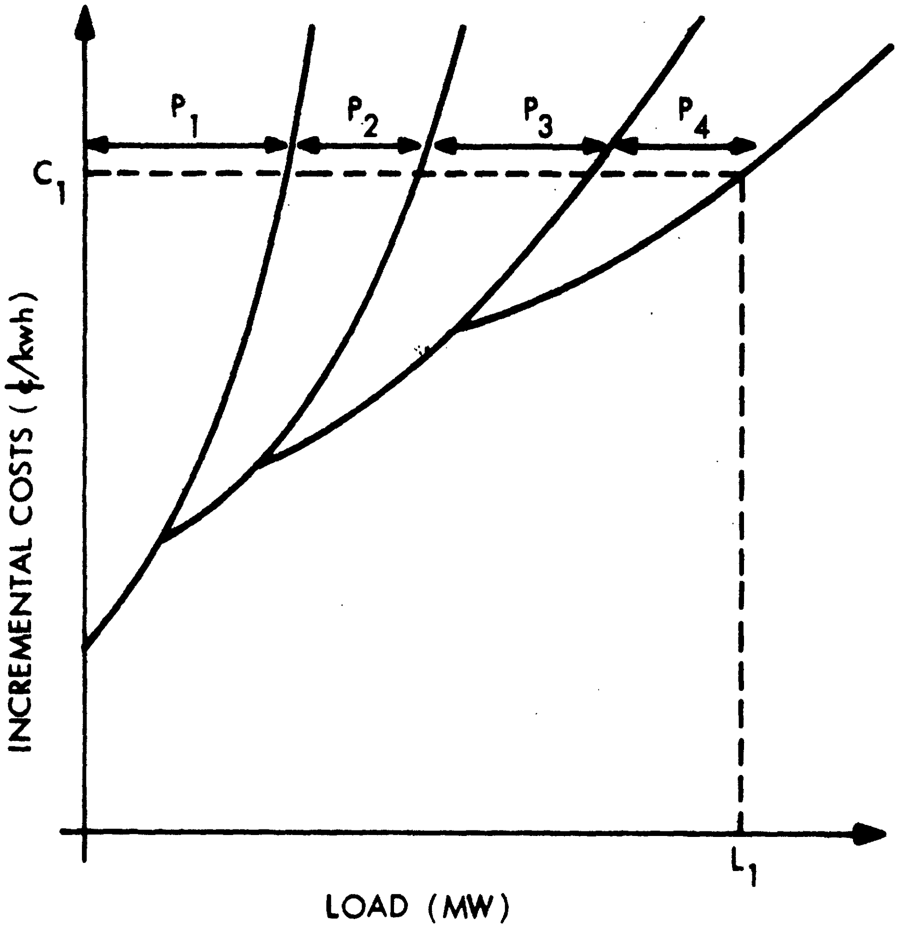


Figure 2: INCREMENTAL PERFORMANCE CURVE

Source: Kirchmayer [1], pp 8-9



SYSTEM INCREMENTAL COSTS

FIGURE 3

Other factors such as transmission capacity constraints at certain generation or load centers or dynamic response constraints (the need to be able to change generation quickly to match possible load changes) may force alteration of the economic dispatch procedures. In general, however, these are second order corrections to the basic philosophy of equating incremental operating costs for the units on-line.

The scheduling of units to be on-line on a daily, weekly, and seasonal basis moves us into the second time span of interest.

Generation Maintenance Scheduling

The problem of generation and maintenance scheduling is to match the daily and seasonal generation requirements of the utility with the needs for routine maintenance and repair of the interconnected set of generating units which comprise the system. On the short term daily or weekly horizon, the scheduler's task is to select the mix and amount of capacity required to most economically meet the swinging load requirements within the constraints of the longer run maintenance schedule. On an annual basis, the problem is to schedule the required maintenance outages in such a way as not to subject the system to excess security degradation, again within the objective of minimizing overall costs.

In 1973, the maintenance costs for generating plant accounted for about 50% of total utility maintenance expenditures[5], and total maintenance expenditures in turn comprise about 10% of total operating expenses[6]. However, until recently, the major portion of the literature on the topic of maintenance scheduling has not concerned itself with

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[5] Reference [3].

[6] Reference [4].

costs but rather with reliability considerations. The maintenance scheduling algorithms discussed in the literature normally persue the objective of levelizing certain system reliability measures (such as reserves or loss of load probability) over the course of the year[7].

The actual implementation of these techniques involves forming a priority list, which gives the order in which generators are to be selected for scheduling, then filling in the valleys of the seasonal load patterns subject to the criterion being used (see figure 4). The priority lists are formed in various ways, the most common including an ordering of generators on the basis of capacity, largest first, or alternatively on the basis of "capacity times duration", which recognizes that the duration of the scheduled ontage affects the scheduling difficulty. Recently, however, more sophisticated techniques have become available which automatically utilize dollar costs, environmental measures and maintenance crew availability, in addition to the historical security criteria[8].

The daily commitment routines are often mechanized. Many sophisticated mathematical programming computer codes are available that schedule available units on a daily basis to meet forecasted load and system interchange agreements according to their merit order of operation. The model to be discussed in chapter 2 of this paper does not explicitly incorporate a maintenance scheduling and unit commitment logic. Rather, in our model we recognize that units are not available for operation throughout the entire year by imposing duty cycle (maximum allowable hours per year of operation) limitations on equipment availability.

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[7] A good survey is given in Gruhl [5].

[8] A recent example is Gruhl [5].

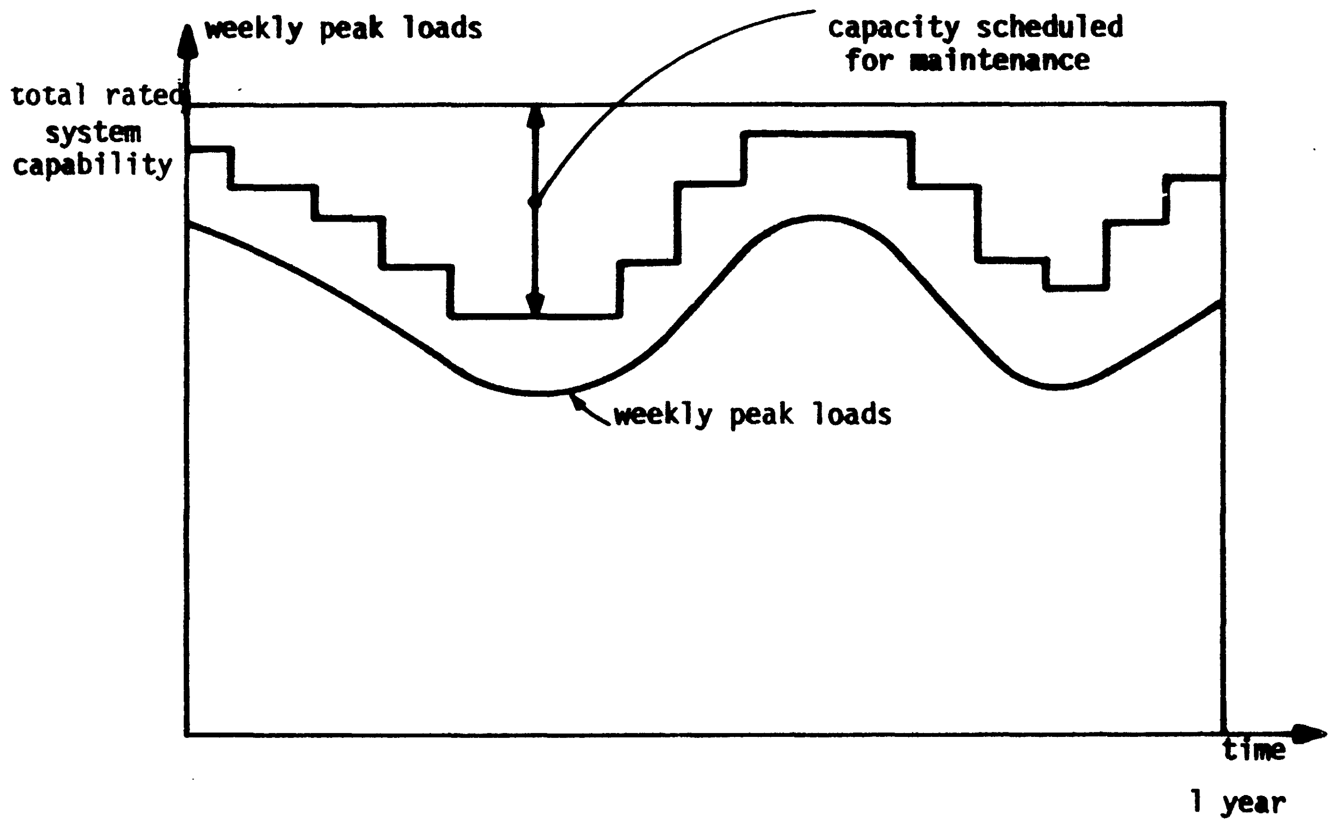
weekly peak loads
capacity scheduled
for maintenance
total rated
system
capability
weekly peak loads
time
1 year

FIGURE 4

OPTIMAL EXPANSION PLANNING

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. Further, the different plant alternatives have complementary functions in a modern interconnected power system so that the optimum balance between the plants depends on both the inherited as well as the expected structure of the system.

The decision to build new capacity in a power system 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 power requirements) as small as possible, so that for a given level of electricity demand the average costs are at a minimum. Counter to this, to meet peak power requirements with a high degree of confidence there is a desire to keep excess reserve capacity -- which increases the average costs of energy produced.

The investment decision in electricity supply is basically governed by the projected load, or more precisely the projected load duration curve, and the economic parameters of the plant alternatives. The load duration curve characterizes the fraction of time that the electrical load is equal to or greater than various output levels. In figure 5 is shown a typical curve for New England for the year 1971[9]. For example, the point at 50% on the abscissa indicates that the load for New England was 7683 MW or higher for 50% of that year. The minimum load is indicated at 4322 MW and the maximum is 12,000 MW.

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[9] Obtained through private correspondence with the New England Electric System, Westboro, Massachusetts.

LOAD DURATION DATA FOR 1971 - NEW ENGLAND POWER EXCHANGE

MAXIMUM MW = 12005.0 MINIMUM MW = 3576.0 TOTAL MW = 64946367.0

LOAD FACTOR = 61.76

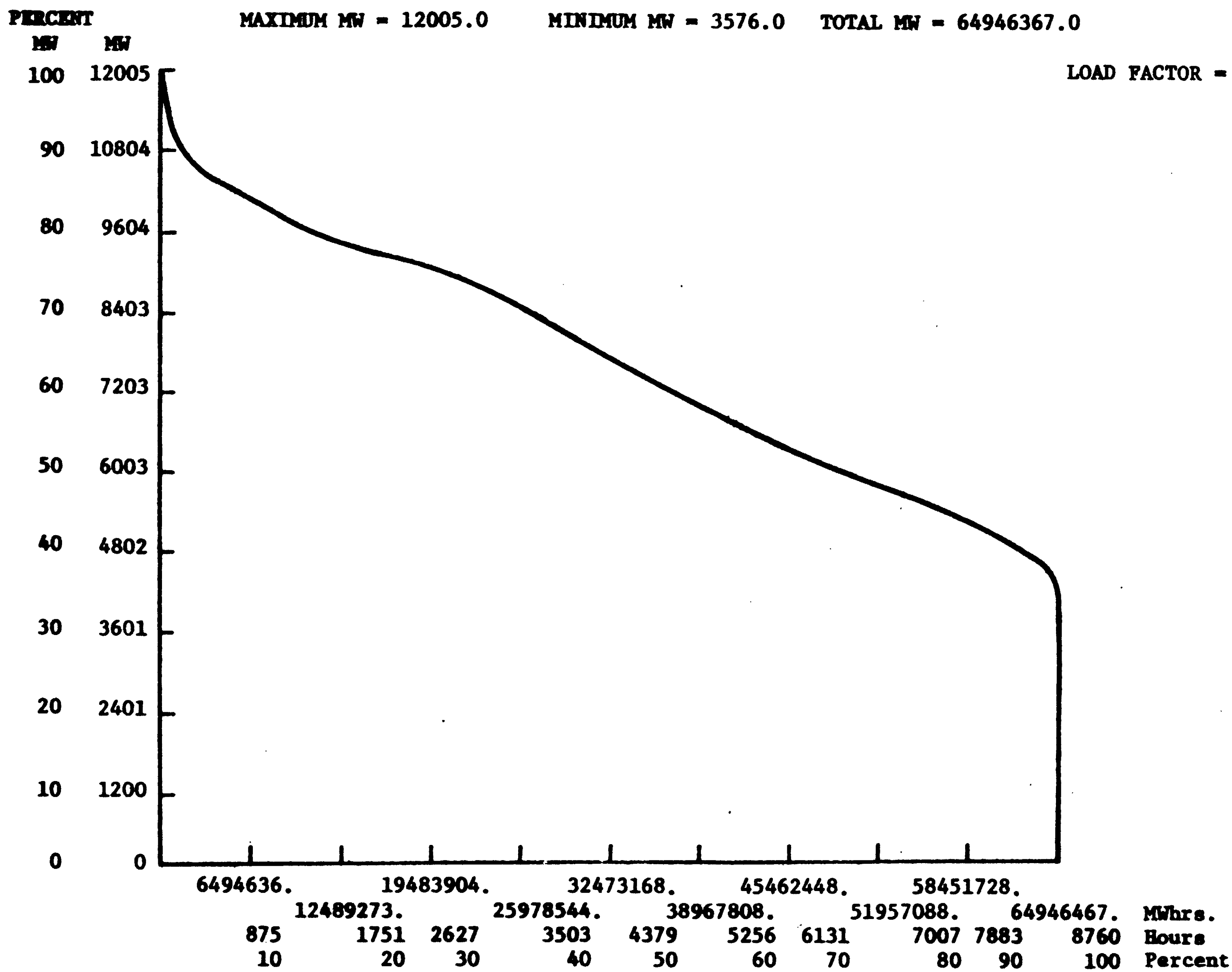

FIGURE 5

Since the load varies in such extremes, and also because utilities are expected to supply the load at all times, the economics of capacity expansion must interrelate the investment decision variables with the load dynamics. The principal economic parameters of electrical generating units are the capital costs, operation and maintenance costs, fuel costs, and heat rates (or conversion efficiencies). The higher the capital cost per kw. capacity, in general the more efficient is the unit that can be purchased and the lower the operating costs that are incurred. The levelized average cost (in cents per kwh.) of the output from a generating unit can be written as:

$$(1) \quad AC = \frac{100\, k_1 a + 100\, F}{U} + \frac{k_2\, H_r}{10^6} + O_c$$

where

- AC = average costs in cents per kwh.
- k_1 = capital cost (dollars/kw.)
- a = annual write-off rate[10] (1/year).
- F = fixed operation and maintenance costs ($/year).
- k_2 = fuel cost (cents/MMBtu's).
- H_r = heat rate (Btu's/kwh.).
- U = utilization factor (hours per year).
- O_c = variable operation and maintenance costs (cents/kwh.)

For illustration let's assume we have three units varying inversely in a capital costs and operating costs. The average cost per kwh produced as a function of utilization of these plants is shown graphically in figure 6. The bottom profile (or envelope) of these curves represents a minimum cost production profile.

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[10] This includes depreciation, insurance costs, return on investment, and other associated fixed capital charges. See reference [6], pp. 282ff.

If we assume that plant capacity is measured by its mean availability[11] the design of the most economical generation mix to meet a load curve such as that of figure 5 has been well established. Turvey[12] has shown that the conditions for optimality are that the marginal costs (the change in levelized annual system costs including fuel costs due to an additional increment in capacity) be the same for all the plant alternatives. If they are not the same, a change in the composition of the plant program would reduce the present worth of the system costs. An optimal mix derived in this way yields a minimum present worth generating cost within the constraints of meeting the projected load.

Equivalently, since demand is exogenous to these calculations, the optimal plant program can be stated as that plant composition which minimizes the levelized annual cost per kilowatt hour. For new plant with characteristics corresponding to the three plant alternatives of figure 6, the optimal mix is derived in the following way. The intersections of the cost curves shown on figure 6 correspond to:

$$U_{cb} = \frac{100\,[k_1{}^b a + F^b - k_1{}^c a - F^c]}{\dfrac{k_2{}^c\, H_r{}^c - k_2{}^b\, H_r{}^b}{10^6} + O_c{}^c - O_c{}^b}$$

and

$$U_{pc} = \frac{100\,[k_1{}^c a + F^c - k_1{}^p a - F^p]}{\dfrac{k_2{}^p\, H_r{}^p - k_2{}^c\, H_r{}^c}{10^6} + O_c{}^p - O_c{}^c}$$

where the superscripts b,c, p denote parameter values for the base load, cycling, and peaking units respectively. For that portion of the load corresponding to utilization factors greater than U_{cb} the minimum cost

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[11] i.e., correcting for forced outage rates. Available capacity = rated capacity x (1 - forced outage rate).

[12] Reference [2], pp. 16 ff.

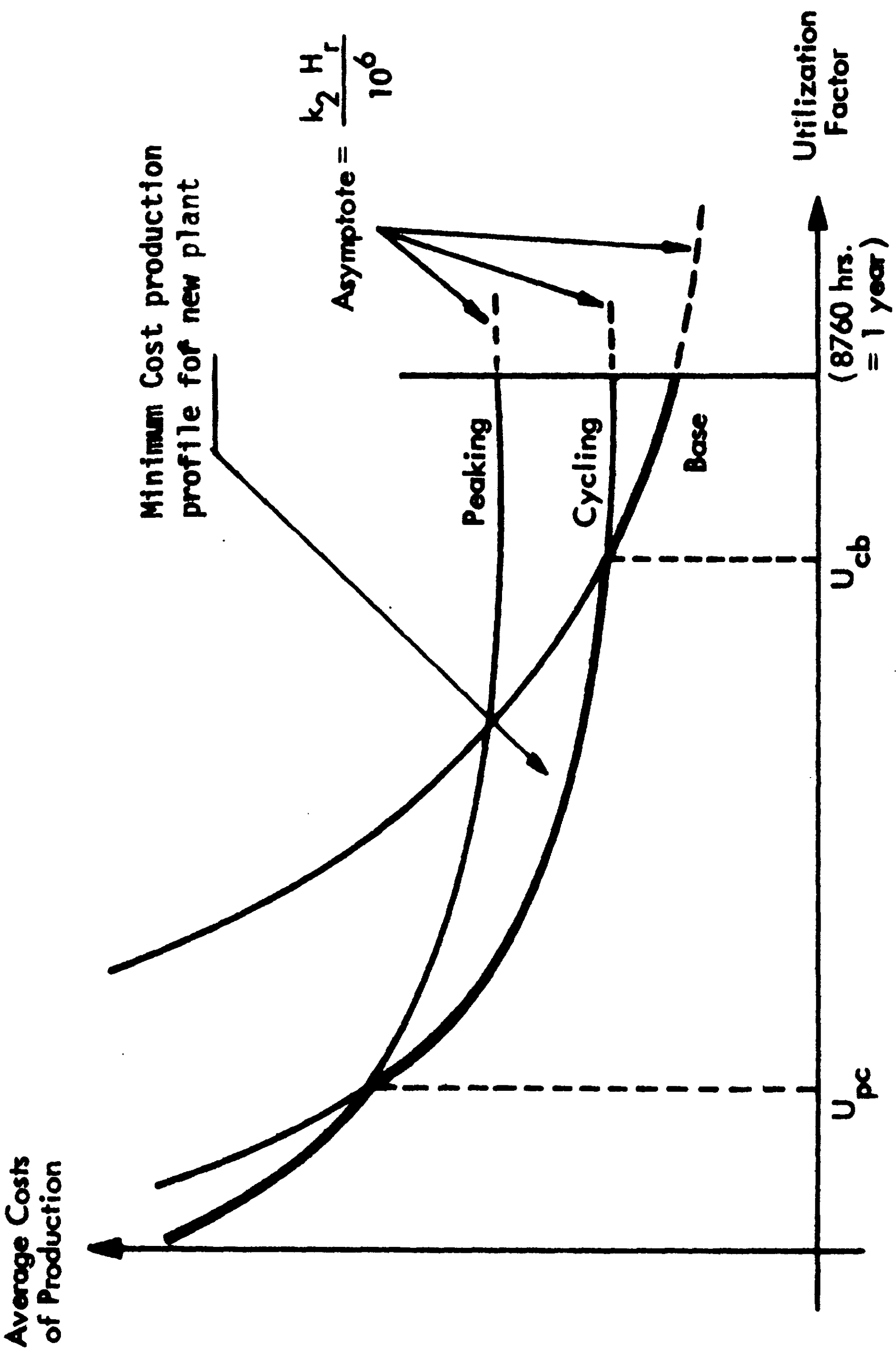
Minimum Cost production profile for new plant
Asymptote = $\frac{k_2 H_r}{10^6}$
Utilization Factor
Peaking
Cycling
Base
(8760 hrs. = 1 year)
U_{cb}
U_{pc}
Average Costs of Production

FIGURE 6

plant is of the base load category because the fuel efficiency offsets the high capital costs. For $U_{cb} \leq U \leq U_{pc}$ the minimum cost plant is a cycling plant, and so on for other utilization factors[13].

If one had no existing plant the optimum mix of capacity would be that shown on Figure 7, at least for this simplified three plant example. In practice, one only constructs increments corresponding to the difference between desired capacity and existing plant after correction for retirements.

The retirement conditions for existing plant can be illustrated with the help of equation (1). For existing plant the initial investment costs are sunken costs. The levelized costs of generation per kilowatt hour therefore become

$$(2) \qquad AC = \frac{100F}{U} + \frac{k_2 H_r}{10^6} + 0_c$$

If for any existing plant this cost function, when plotted on Figure 6, falls completely above the minimum cost production profile for new plants, then a net savings accrues if new plant is constructed to replace the old. If the cost function falls below the minimum cost profile anywhere along the profile, then it is more economical to use this existing plant at those utilization levels than to replace it with additional investment in new plant.

Depending upon the configuration of prospective sites and the load centers of the system, adjustments to account for the transmission system losses are necessary. The procedure for optimization of the transmission system is best handled by including into the present worth analysis of expansion alternatives the transmission increments required

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[13] The conditions for optimality are identical to those given by Turvey [2], except we also consider variable operation and maintenance costs.

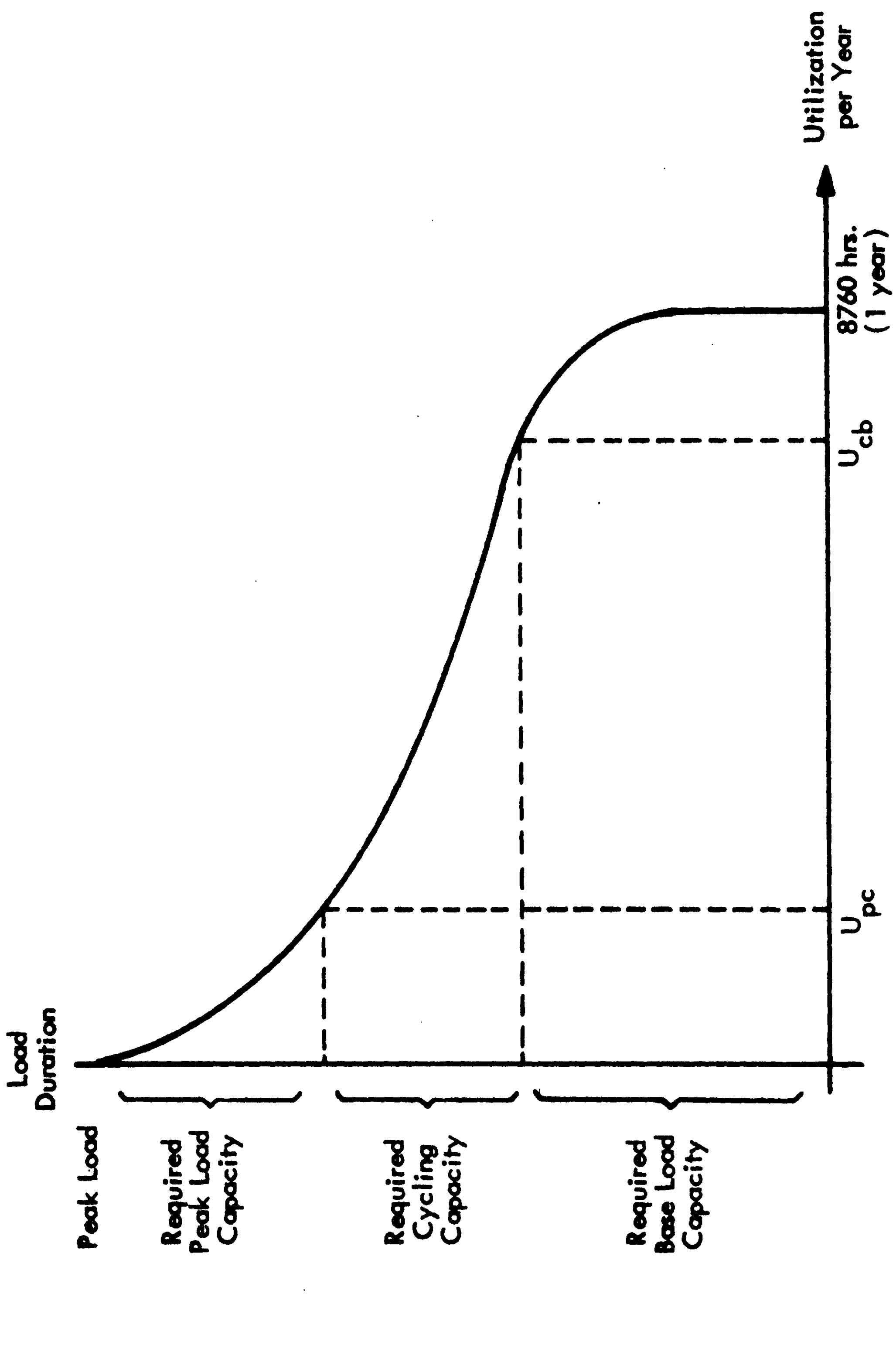
Utilization per Year
8760 hrs. (1 year)
U_{cb}
U_{pc}
Load Duration
Peak Load
Required Peak Load Capacity
Required Cycling Capacity
Required Base Load Capacity

FIGURE 7

for each plant. The marginal condition for optimality is that the capital cost of a unit increment of transmission capacity should just equal the present worth of the savings in operating costs that can be obtained with the transmission increment. These savings can come in two direct forms -- a reduction in transmission losses or the substitution of a lower running cost plant for a higher cost plant in the system. Indirectly, a saving of reserve requirements may also be possible.

In the model to be described in the following sections, the configuration of the transmission system is not specifically included. However, aggregate transmission and distribution requirements (in physical quantities) are empirically related to the load and generation characteristics of the system. This allows us to obtain aggregate capital expenditures which are used in the pricing logic of the model.

Electricity Pricing

The price of delivered electrical energy is regulated by the Federal Power Commission and various state regulatory commissions. The revenue allowed utility is based upon the historical "cost of service" formula. The utility is allowed to recover its fuel costs, operation and maintenance costs, administrative overhead, depreciation, taxes and a fair rate of return on the rate base. The application of this formula to the accounting data for a utility over the relevant time period defines the total revenue restrictions placed upon the firm.

Within this historical cost of service concept the rates to various consumer groups depend upon the allocation of the fixed and variable costs incurred[14]. These costs are normally classified in three cate-

[14] A more complete discussion of the pricing question can be found in Joskow [7].

gories: customer charges, energy charges, and demand charges. Customer charges are those costs which vary with the number and type of customers, such as meters, costs of meter reading, line transformers, etc. Energy charges are those costs which vary most closely with the level of kilowatt generation and delivery, the best example being fuel cost. Demand charges are those costs associated with supply and transmission capability (not utilization). The investment cost of generation and transmission facilities provides the best example in this category. Rate schedules are designed to reflect the allocation of these costs to different customer classes at varying levels of energy demand. Due to economies of scale and the decline in average fixed costs per kilowatt hour with increasing kilowatt hour demand the rate schedules have generally taken the form of declining block rates.

In the past few years, and especially with the impetus of recent capital limitations in the utility sector, both the historical "cost of service" concept as well as the cost allocation schemes have come under increasing scrutiny. Implementation of the historical cost of service formula requires knowledge of future demand to establish the required price per kilowatt hour and future demand grows increasingly more uncertain. The definition and application of a "fair" rate of return is most difficult to implement in a period of volatile capital markets. And finally, whether existing rate structures adequately reflect the differential in costs of supply to various rate classes and users of electricity is being closely examined. In chapter 3 we briefly examine some of the implications of "cost of service" pricing with our model. We expect that as the model gets more fully developed further analysis of the pricing question will be forthcoming. At present, pricing in the model is based solely upon the historical cost of service concept.

2. THE MODEL

The engineering-econometric simulation model is designed to provide a quantitative understanding of the effect of a wide range of variables on electricity supply decisions and the cost of electricity. The variables that we concentrate on are electricity demand; the capital and operating costs of different types of generating plant; fuel prices; and, finally, the shape of load curves. A change in any one of these items may well affect most features of the future evolution of fuels consumption and costs within the industry. Other issues we hope to address by making future modifications to the initial model are the effects of sulfur restrictions, nuclear growth constraints, peak load pricing, capital constraints, and breeder reactor availability.

The model we have constructed is basically a descriptive formulation. Nevertheless, central to the model operation are the optimization concepts discussed in the previous chapter for generation expansion and merit order operation of the system. These concepts are standard to the industry and therefore must be a part of a model descriptive of industry behavior.

Geographically, the model consists of nine regions corresponding to the nine census regions of the U.S. (see figure 8). Within each region the model optimizes the construction mix of eight plant alternatives with the ninth supplied exogenously. The plant alternatives correspond to:

1. gas turbines and internal combustion units;
2. coal fired thermal;
3. natural gas fired thermal;
4. oil fired thermal;
5. light water uranium reactors;

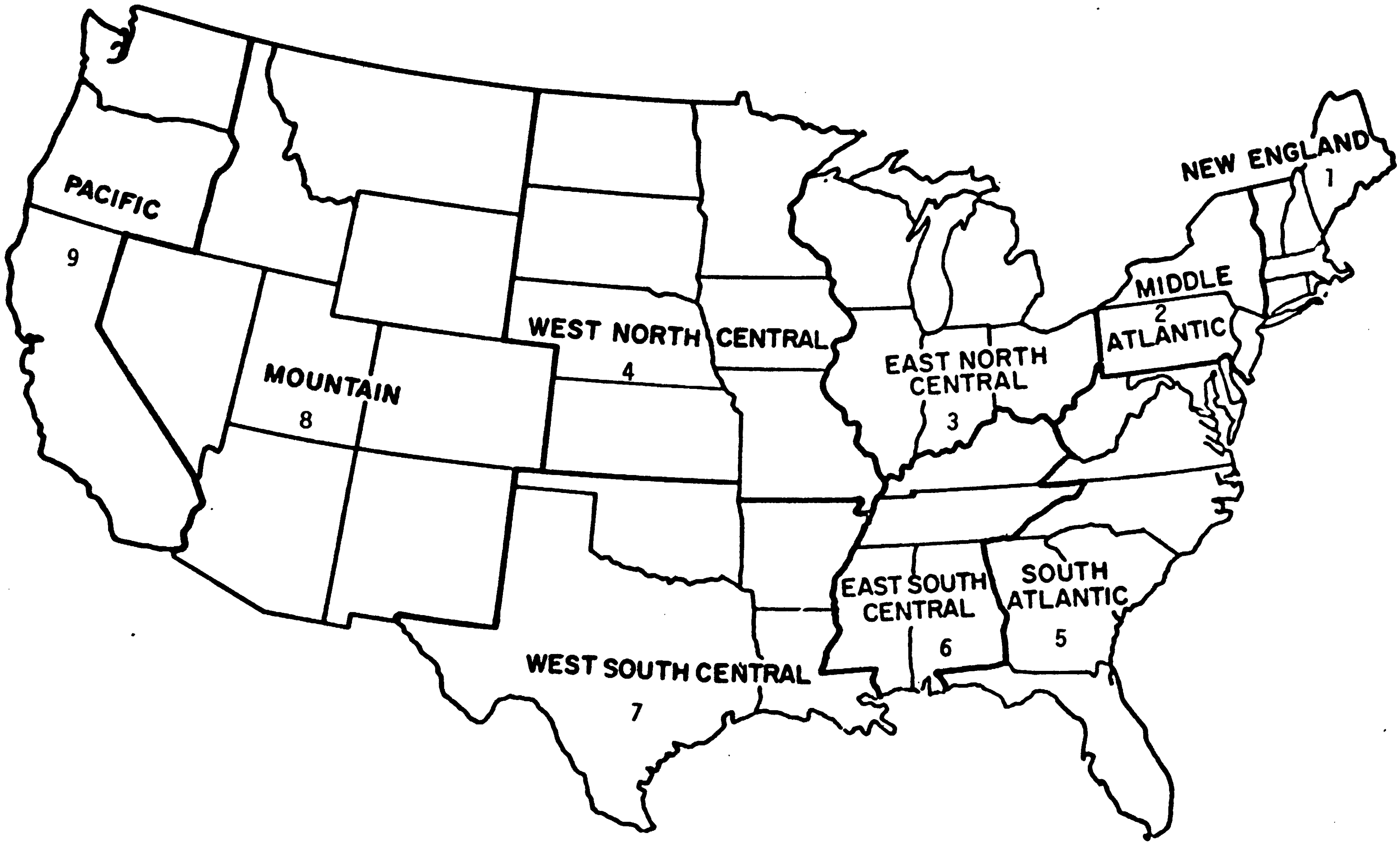

FIGURE 8: REGIONAL MAP OF THE UNITED STATES

6. high temperature gas reactors;
7. plutonium recycle reactors;
8. liquid metal fast breeder reactors;

and

9. hydro generation capacity (input as exogenous time series by region).

There is no provision for wholesale interchange between regions other than by altering the demand variables to explicitly incorporate inter-regional transactions[15].

A broad flow diagram of the overall model shown in figure 9 depicts the major features of the model. The two major loops of the model, the "time loop" and the "regional loop", serve to move the model through time and span the nine regions successively. The primary building blocks are the calculation of:

1. expectations of the major decision variables, nationally and regionally;
2. the system expansion plans and new plant construction;
3. the generation of electricity via usage of existing plant;
4. transmission and distribution requirements and costs;

and finally,

5. the "cost of service".

The variables that are supplied exogenously to the model for these calculations are listed on Table 1. The following sections outline the specification of the model for each of the above listed building blocks.

[15] In 1970, interstate electricity wholesale transactions made up no more than 7.3 percent of all power company dollar transactions(Ref. [8], pg. 11). Based on net interregional energy deliveries, the percentage would even be lower.

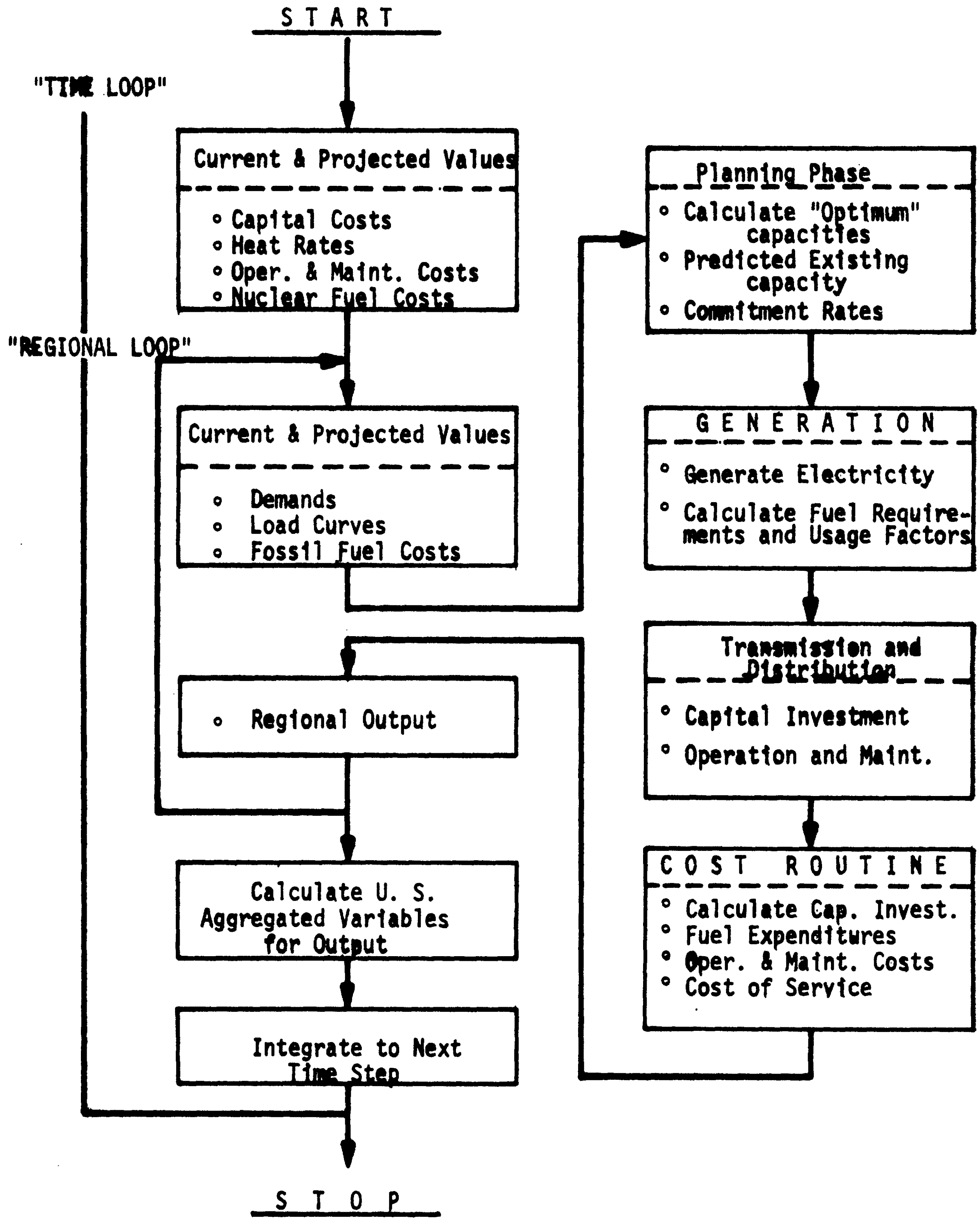

Figure 9: BROAD FLOW DIAGRAM OF THE ELECTRICITY SUPPLY MODEL

E X O G E N O U S   I N P U T S

REGIONAL INPUTS

Demand by region[16]

Normalized Load Duration Curves

Expected Fossil Fuel Prices

INPUTS FOR EQUIPMENT ALTERNATIVES

Expected Unit Capital Equipment Costs

Expected Unit Operation and Maintenance Costs

Expected Unit Forced Outage Rates

Expected Unit Duty Cycles

Expected Unit Heat Rates

NATIONAL INPUTS

Uranium Concentrates Supply Function

Expected Nuclear Fuel Processing Costs

Lead Times for Construction of:

- Peaking units
- Fossil thermal units
- Nuclear units

Lifetime of Plants

T A B L E 1

[16] Eventually, the regional demands (in kwhs.) will be derived endogenously through use of demand functions we have estimated. See references [9] and [10].

EXPECTATION EQUATIONS

To build into the model the plant and fuel choice decision making process it is necessary to specify functions for expectations of the main decision variables. This must be done with functions that smooth random variations and take account of long term trend effects, while at the same time, from a modeling point of view, are simple, easy to use, and require little computer storage.

The reason for incorporating such expectation structures into the model is to better represent dynamic behavior and reactions to uncertainty. As an example, take the case where the electricity demand growth rate changes abruptly from an historical value of 8% per annum to a new value of 4% in steady state. When expectations are formed endogenously, planning and capacity expansion are geared to the 8% growth rate until the time a 4% rate of growth is apparent -- then adjustments are made. If, on the other hand, we tell the model some years prior to the change in growth rate that it is going to change to 4% per year, the planning process can adjust in anticipation and overcapacity would not be planned. These two alternatives provide for grossly different dynamic behavior. To make the model descriptive in the pure sense, models for expectations must be part of the overall formulation.

There are several variables that must be forecasted endogenous to the descriptive formulation. These include fuel prices (by region and fuel), capital costs and heat rates of the plant alternatives (9 plants), total demand and capacity requirements (by region), as well as the expectation for retirements of existing plant over the various planning horizons. The model operates on three different planning horizons. These correspond to a ten year lead time for construction of nuclear plants, five years for fossil-fired thermal plants, and two and one-half years for gas turbines and internal combustion units. Expectations for the appropriate decision variables must be formed over this entire range of planning horizons.

The technique used to derive these expectations is by exponentially weighted moving averages with a trend adjustment[17]. If one wants to forecast the variable D_t (demand at time t) to "n" years in the future, the equations are:

$$(1) \quad \bar{F}_t = \alpha D_t + (1 - \alpha)\, \bar{F}_{t-1}$$

$$(2) \quad \bar{T}_t = \alpha(\bar{F}_t - \bar{F}_{t-1}) + (1 - \alpha)\, \bar{T}_{t-1}$$

$$(3) \quad E(D_t) = F_t + \left(\frac{1 - \alpha}{\alpha}\right) \bar{T}_t$$

$$(4) \quad D^{*}_{t+n} = E(D_t) + n\, \bar{T}_t$$

where

$\bar{F}_t$ = smoothed value of demand at time t.

$\bar{T}_t$ = the smoothed value of the trend at time t.

$E(D_t)$ = estimated demand at time t incorporating trend adjustment.

D^{*}_{t+n} = forecasted value of demand at time t + n.

α = exponential smoothing time constant ($0 < \alpha < 1$)

The value of α specifies the weight to be attached to current and historical information. For $\alpha = 1$, all historical information is discounted and forecasts are derived from current values. As α approaches zero, more and more weight is given to smoothed historical information in relation to current values.

[17] There are numerous ways in which one can formulate expectation models, all the way from simply assuming current values will continue forever to very complex adaptive algorithms. The exponential smoothing technique is a compromise and borders on the naive. We have used it here because of its simplicity and ease of use. A further discussion of alternative techniques can be found in Buffa [11].

CAPACITY EXPANSION

The model is constructed to formulate expectations and make capacity commitments for three different lead times; 10 years for nuclear plant; 5 years for conventional steam plant, and $2\frac{1}{2}$ years for peaking capacity. Over the different planning horizons the model calculates how much and what mix of plant investments should be undertaken. This is done by forecasting the decision variables and simulating the start of construction of capacity in the amounts and mix as described in Chapter 1.

For example, a ten year forecast of demand[18] and the relevant plant characteristics is made and the "optimal" amount and mix of nuclear plants is calculated. Then, after account is taken of capacity in construction that will be available at the end of the ten year horizon, the proper increment in capacity requirements is introduced into the construction pipeline. The model then recursively moves this capacity increment through the ten year lag as the model simulates through time. After ten years it exits from the pipeline and moves into operating plant inventory[19].

For the five year horizon, essentially the same procedure is undertaken for fossil fired plants, but with additional adjustments to better match the supply system to the projected demand. The nuclear plant to be available in five years is already in the construction stages (started at least five years ago). The demand trend may have changed since that time, and even if not we now have a five year demand forecast that is more reliable than the ten year forecast made five years previously. Because of this, adjustments may need to be made for the over or under commitment of nuclear plant made previously. These adjustments are made in the fossil construction program in the model to compensate. This is done by adjusting the fossil plant commitment so the sum of fossil plus nuclear is at the level needed to match the five year demand forecast.

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[18] For these calculations the shape of the load duration is supplied exogenously. This is one of the variables we plan to change and investigate the effects of in our future work.

[19] There is also the provision in the model to change the required lead times for construction in the alternative plant categories.

For the peaking unit commitment ($2\frac{1}{2}$ year lead time) the same calculations are repeated. Again there exists the opportunity to correct the supply capability to better match the more reliable demand forecast.

The retirement condition built into the model is simply a 30 year lifetime for each of the plant alternatives (except for hydro, for which the capacity vs. time is exogenous). The retirements in any given year correspond to the capacity completed thirty years previously[20]. Further, it is assumed that plants can be constructed in any increment, i.e. discrete unit sizes are not accounted for in the model.

The material balance and cost relationships for the nuclear fuel cycles of alternative reactors are derived from recent work by Gregory Daley[21] which we have incorporated. Costs per kilogram of nuclear fuel for twelve different nuclear fuel processes are used as a function of time. These processes are:

1. LWR-U fuel fabrication costs
2. LWR-PU fuel fabrication costs
3. HTGR fuel fabrication costs
4. LMFBR - Blanket - fuel fabrication costs
5. LMFBR - Core-fuel fabrication costs
6. Reprocessing Costs
7. UF_6 to UO_3 preparation costs
8. UO_3 to $PU(NO_3)$ to mixed oxide preparation
9. Natural U_3O_8 to UO_3 preparation costs
10. UO_3 to UO_2 for greater than 2% enrichment preparation costs.
11. Th $(NO_3)_4$ + UNH + UF_6 to oxide preparation costs for HTGR microspheres.
12. UNH to UF_6 conversion costs.

Data used in the model are based on the WASH-1099 projections[22].

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[20] Adjustments to the amount of new capacity to be constructed are made to account for these retirements.

[21] Reference [12].

[22] Reference [13].

GENERATION

The generation portion of the model simulates the utilization of plant inventories for production of electrical output. At the time production decisions are made all installation (initial investment) costs are sunk costs and only operating costs (fuel plus variable operation and maintenance costs) are used for selection of which plant is to generate at what utilization factor. Each of the nine plant alternatives is ranked according to its merit of operation (corresponding to the level of fuel and operating costs). The available energy output from each plant is the capacity times 8760 hours per year times the duty cycle[23]. The total kilowatt hour demand is then generated by consecutively adding the available energy output from each plant type according to its rank in the merit order until the total demand is generated.

The guiding principle is to use the least operating cost plant as much as possible, and, conversely, the highest operating cost plant as little as possible. This is represented graphically on figure 10 with the aid of an integrated load duration curve[24]. The energy from 0.0 to N_1 corresponds to the available energy from nuclear plant, and, since it is lowest in operating cost in this example, it is first in the merit order. Next, come the hydro plants with energy output equal to $H_1 - N_1$, and so on. As a final refinement, since it is possible to get no generation from internal combustion units with this scheme,

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[23] The term available capacity is used here to mean rated capacity x (1.0 - forced outage rate). It takes into account the unexpected and unplanned outages. The duty cycle is a number between 0.0 and 1.0 that reduces plant availability in the time domain. This is how the model incorporates energy constraints arising from planned maintenance outages, refueling outages for nuclear plants, or water limitations for hydro plants.

[24] The use of the integrated load duration curve (integrated load function) was first introduced by Jacoby [14]. It is a plot of energy demand (integral of the load duration curve) against power demand. In Jacoby's context it was used to identify the position in the merit order that should be occupied by hydro generation capability (the scheduling problem).

PLANT UTILIZATION vs. INTEGRATED LOAD FUNCTION

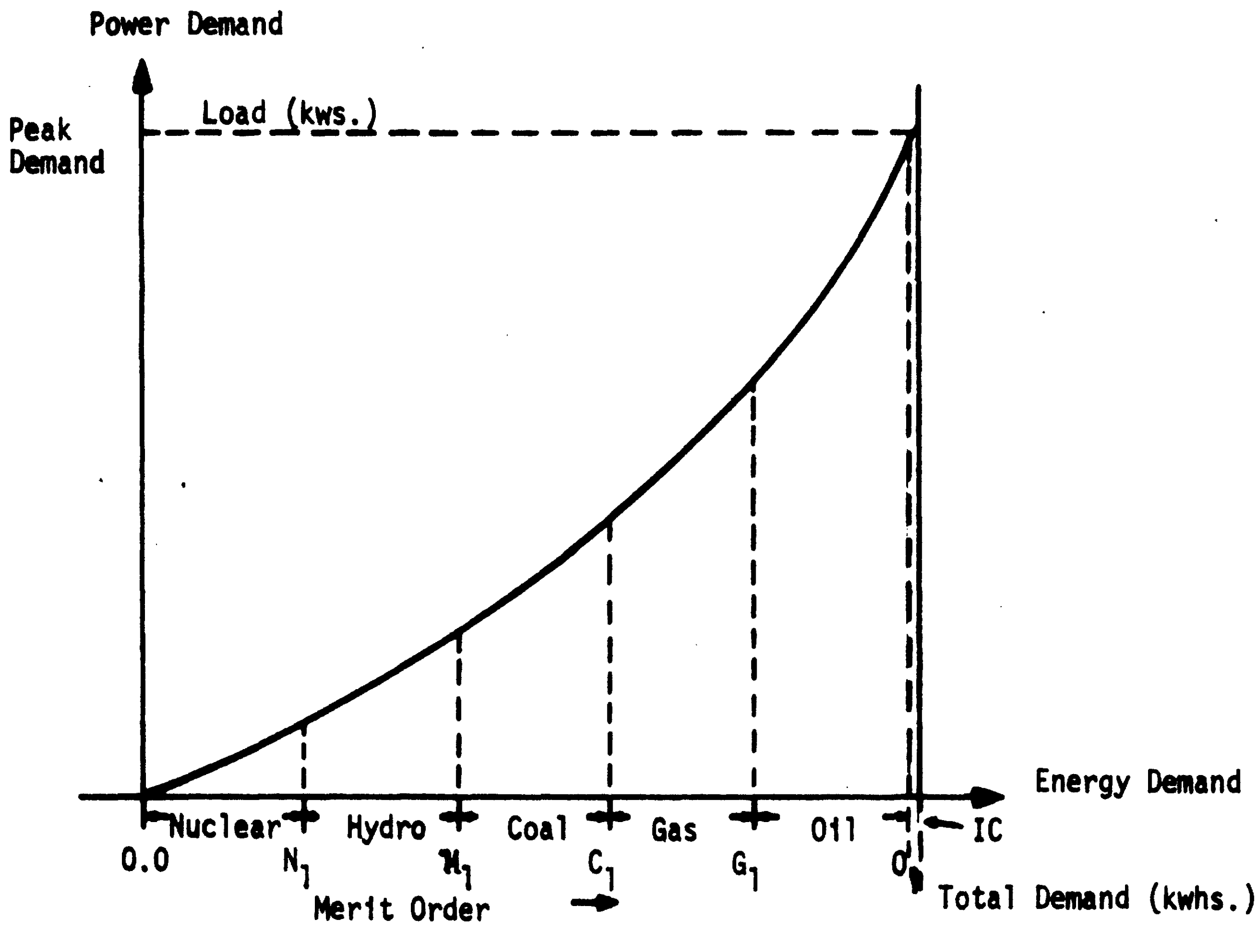

FIGURE 10

the generation from internal combustion units is assumed to meet at least 0.3% of the total generation requirements.

TRANSMISSION AND DISTRIBUTION

Transmission and distribution is much less capable of analytical treatment than is generation. The total of new generating capacity and the plant mix are related to total load growth and to the characteristics of the generating system. Investment in transmission and distribution, on the other hand, is nothing more than the sum of individual schemes determined either by the relation between prospective load growth in particular load enters and the generation configuration or by the need to replace obsolete equipment. For this reason, we have utilized empirical methods to obtain investment and maintenance in transmission and distribution rather than a structured analytical treatment similar to that used for generation planning.

The transmission and distribution requirements to deliver the generated output to the final consumer are broken into five components and costed separately. The five equipment needs are separated into: 1) structure miles of transmission capability; 2) KVA substation capacity at the transmission level; 3) KVA substation capacity at the distribution level; 4) the KVA capacity of line transformers; and 5) the number of meters. Each of these physical quantities is empirically related to the characteristics of the service area (such as land area) the number and nature of the connected customers (large light and power, residential, etc.) and the demand configuration in each region of the country (total kwh. sales, load density, etc.). The data used to derive the estimates are a time series of cross-section for privately owned utilities in each of the states of the continental U.S. The source of data was the Federal Power Commission series on Statistics of Privately-Owned Electric Utilities in the United States for the years 1965 through 1971.

The results of the estimation process are summarized in Table 2[25]. It was found that the configuration of consumers (residential and commercial vs. large light and power) is not nearly as important for transmission as it is for distribution. For example, Table 2 shows that for each million kilowatt-hours of sales to the residential and commercial sector 718.4 KVA of transmission substation capacity, 485.7 KVA of distribution substation capacity, and 568.2 KVA of line transformer capacity is needed. For equivalent sales to large light and power customers, however, only 529.9 KVA, essentially 0.0, and 102.6 KVA of capacity of each of the respective components is needed. For structure miles of transmission, furthermore, a differentiation between customer classes is not significant, though load density is. And finally, large light and power consumers require on the average about 14 meters per customer compared to 1.03 per residential and commercial customer. This difference in equipment requirements is one of the reasons that the rates for large light and power customers differ significantly from the residential and commercial rates.

"COST OF SERVICE" CALCULATIONS

Symbolically, the cost of a unit electricity output can be written as[26]:

$$c_t = \frac{F_{ct} + O_{ct} + d_t + r_t\,(1 + T_t)\,[\sum_{1}^{t}(k_t - d_t)]}{S_t}$$

where

c_t = average cost per kilowatt hour in period t

F_{ct} = fuel costs in period

[25] A more complete discussion of these results is forthcoming in Bottaro[15].

[26] This model is quite naive and neglects many elements of the financing and tax structure of electric utilities. We are developing a more complete financial-cost of service model which will eventually replace this over-simplified specification.

TRANSMISSION AND DISTRIBUTION EQUIPMENT NEEDS*

(Numbers in parentheses are t - statistics)

TRANSMISSION

(1) $SMT = \underset{(3.08)}{1019.6} + \underset{(24.1)}{0.192}\ EST - \underset{(-4.81)}{965.5}\ LD + \underset{(7.96)}{0.0318}\ AREA \qquad R^2 = .76$

(2) $SKVAT = \underset{(2.65)}{8.5 \times 10^5} + \underset{(19.98)}{718.4}\ ESRC + \underset{(12.42)}{529.9}\ ESLLP - \underset{(-1.79)}{4.42 \times 10^5}\ LD \qquad R^2 = .91$

DISTRIBUTION

(3) $SKVAD = \underset{(0.76)}{1.95 \times 10^5} + \underset{(20.64)}{485.7}\ ESRC - \underset{(-0.18)}{5.04}\ ESLLP + \underset{(2.47)}{7.92}\ AREA \qquad R^2 = .83$

(4) $LTKVAD = \underset{(32.6)}{568.2}\ ESRC + \underset{(5.09)}{102.6}\ ESLLP + \underset{(2.82)}{5.14}\ AREA \qquad R^2 = .94$

(5) $NMD = \underset{(14.0)}{1.03}\ NRCC + \underset{(9.4)}{14.4}\ NLLPC \qquad R^2 = .99$

SMT = transmission requirements (structure miles)
SKVAT = substation requirements at the transmission level (KVA)
SKVAD = substation requirements at distribution level (KVA)
LTKVAD = line transformer requirements (KVA)
NMD = meter requirements (number)

EST = total energy sales (kwhrs. in millions, MMKwhs.)
LD = load density (millions of Kwhrs. per square mile)
AREA = geographic area (square miles)
ESRC = energy sales to residential and commercial customers (MMKwhs.)
ESLLP = energy sales to large light and power customers (MMKwhs.)
NRCC = number of residential and commercial customers
NLLPC = number of large light and power customers

* From Bottaro [15]

TABLE 2

0_{ct} = other operation and maintenance costs in period

d_t = depreciation in period

r_t = return on rate base in period

T_t = tax rate in period

k_t = capital investment contribution to rate base in period

S_t = total kilowatt sales in period

The independent variables used for calculations of the cost of service are derived from various variables endogenous to the model and the exogenous cost inputs as follows.

Additions to the rate base are the sum of capital expenditures for generation, transmission, and distribution equipment. The capacity commitments for each category are obtained in the model by the methods described in the previous sections. The unit cost parameters for capacity increments are exogenous engineering inputs. Depreciation is taken as 3.0% of the utility plant existing at the start of each year[27].

The fuel costs are derived regionally from the endogenously calculated plant utilization patterns and exogenous fuel prices. Generation maintenance expenditures are derived from the product of the unit operating cost parameters and the same endogenous plant usage variables. Maintenance costs for the transmission and distribution system are related to the equipment needs derived as we described in the previous section.

The only other remaining elements of the cost of service calculation are "r", the rate return on the rate base, and "T", the tax rate. We have

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[27] From calculations of the depreciation as a percent of net utility plant, an average for the years 1965-1972 was 3.01% (calculated from the combined income statements and balance sheets for investor-owned utilities as reported in the Edison Electric Institute Statistical Yearbook, various issues).

combined these into one number, the product of $r \times (1 + T)$. Historical data on the return on assets for investor-owned utilities yields a value for this quantity of approximately 11.0%.[28].

In the next section we show how the model behaves numerically by presenting the results of a historical simulation (backcast). Then, in the final chapter we use the model to investigate the effects on future supply of increased fuel prices, increased rates of return, and alternative future demand growth rate projections.

MODEL BEHAVIOR

To illustrate how the model relationships described in the previous sections behave when simulated with real historical data, we have prepared a "back cast" simulation[29]. The results of the simulation yield information about the numerical quality (validity) of the model operation as well as insight into the behavior of the real system. This simulation was done over the twenty-five year period from 1947 to 1972.

A single simulation yields a time history for a very large number of variables, by region, plant, and fuel. It is not possible to include the numerical tedium of comparisons of all actual and model dependent variables in this text. We do, however, summarize the behavior of some of the most significant variables.

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28 Calculations from combined income statements and balance sheets for investor-owned utilities for the years 1960-1972 yield values of 9.65% to 11.58%, with an average of 11.04% (same sources as foonote 27).

29 This was done by using actual historical values of electricity consumption and estimates of the various cost parameters the model needs for its operation (i.e. actual values of the <u>independent</u> variables), then simulating over a historical period. The model outputs are then compared to actual values of the <u>dependent</u> variables.

In tables 3 and 4 we summarize the actual vs. the model values for aggregated U.S. data on capacity and generation (by type of plant and fuel) for the years 1967 and 1972, twenty years and twenty five years into the simulation, respectively.

In 1967, the total U.S. generation capacity predicted by the model is 270 million kilowatts, compared to an actual of 267 million kilowatts. The configuration of capacity by plant type varies slightly from the actual, the most significant disparity occurring in the mix of conventional steam plants vs. internal combustion units. The model shows more internal combustion and gas turbine units than existed in reality, both for 1967 and 1972. The probable reason for this is that the historical values of capital costs used (especially those in the 1950's, which are the most difficult to find data on) don't really reflect the costs of using that technology. Even so, the generation numbers compare closely enough that it is not a big issue. Another disparity is the comparison of nuclear capability which in 1967 is too low in the model, while in 1972 is slightly too high. In reality, if one reviews the expectations expressed in the early literature of nuclear power, one would expect an enormous trend toward nuclear installations in the 60's. If nuclear growth in the model were unconstrained it would reveal the same trends. The cautious view of a radical new technology and lack of manufacturing capacity nevertheless restrained the growth to something considerably more modest than naive cost minimization alone would dictate. In hindsight, the true costs were much higher than expected and the social reaction much more restraining than anticipated. The model results displayed in Tables 3 and 4 are similarly constrained by simply forcing the new nuclear capacity commitments for the fifties and early sixties to be consistent with actual historical trends. (In the simulations into the future to be presented in section 3 these constraints on nuclear growth are removed after 1974).

The simulated historical generation shown in the tables have two rather large disparities in 1972. First, the model predicts generation from nuclear plants over twice what actually occurred. In practice, equipment deratings and the lack of operating experience resulted low actual load factors for nuclear plants during the year of about 30-35%. The model assumes a plant load factors of about 70% for nuclear. The second disparity, which has been corrected for and doesn't reveal itself in the tables, has to do with generation from natural gas. If one uses actual data for fuel prices to produce the back cast simulation (i.e. that data reported by Edison Electric Institute), the model shows almost twice the generation from natural gas that actually occurred in 1972[30]. What the historical data on fuel prices does not incorporate is that natural gas was supply limited due to the price regulation in that sector. The only way in which the model behavior can be made to conform to actual generation trends is to set the natural gas price equal to the shadow price of natural gas associated with the prevailing excess demand situation. This was done to obtain the results shown in Table 4. The increment over and above the true gas prices necessary to get results consistent with historical generation trends suggests the true shadow price of gas for the utility sector was more like 30-40¢ per M.C.F. at the wellhead rather than the 18-22¢ actually reported.

To help show the model's quantitative behavior for each of the nine regions, Table 5 gives the actual vs. fitted data for generation. The same trends apparent in the national statistics exist in the regional data, only now they can be viewed in more regional detail.

The final variables to be compared are the "cost of service" derived from the model and the actual cost of service. Since direct

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[30] See Joskow and Mishkin [16] for an econometric study which yields a similar phenomenon.

RESULTS OF THE BACK CAST SIMULATION - 1967

(Aggregate U.S. Statistics)

CAPABILITY (Thousands of Kilowatts)		
PLANT TYPE	MODEL	ACTUAL*
Hydro	48,035	47,350
Steam Conventional	171,432	210,210
Nuclear	1,137	2,437
Internal Combustion and Gas Turbine	49,137	7,078
TOTAL	269,740	267,075

GENERATION (Millions of Kilowatt-Hours)		
PLANT TYPE	MODEL	ACTUAL*
Hydro	221,616	220,043
Steam Conventional	978,634	979,636
Coal	564,821	629,979
Oil	46,690	89,289
Natural Gas	367,123	264,656
Nuclear	7,280	7,147
Internal Combustion and Gas Turbine	4,221	4,923
TOTAL	1,211,749	1,211,749

*Actual values are from the 1967 Edison Electric Institute Statistical Yearbook

TABLE 3

RESULTS OF BACK CAST SIMULATION - 1972

(Aggregate U.S. - Statistics)

CAPABILITY (Thousands of kilowatts)		
PLANT TYPE	MODEL	ACTUAL*
Hydro	60,655	56,566
Steam Conventional	249,548	295,026
Nuclear	19,364	15,300
Internal Combustion and Gas Turbine	69,665	32,714
TOTAL	399,232	399,606

GENERATION (Millions of kilowatt-hours)		
PLANT TYPE	MODEL	ACTUAL*
Hydro	279,573	272,734
Steam Conventional	1,337,752	1,413,882
Coal	835,157	770,617
Oil	159,757	272,482
Natural Gas	342,838	375,682
Nuclear	123,999	54,031
Internal Combustion and Gas Turbine	6,001	6,676
TOTAL	1,747,323	1,747,323

*Actual values are from the 1972 Edison Electric Institute Statistical Yearbook

TABLE 4

observation on the actual cost of service is not possible, the average revenue per kilowatt hour sold is used as a surrogate. Figure 11 displays a plot of the actual vs. fitted for the years 1957-1971. Even though our cost of service model is quite naive, the root mean square error is still only .082¢/Kwhr.

In the sum, these results are quite encouraging. In the next section we present some analyses done to illustrate how the model can be used.

RESULTS OF BACK CAST SIMULATION - 1972

REGIONAL GENERATION STATISTICS

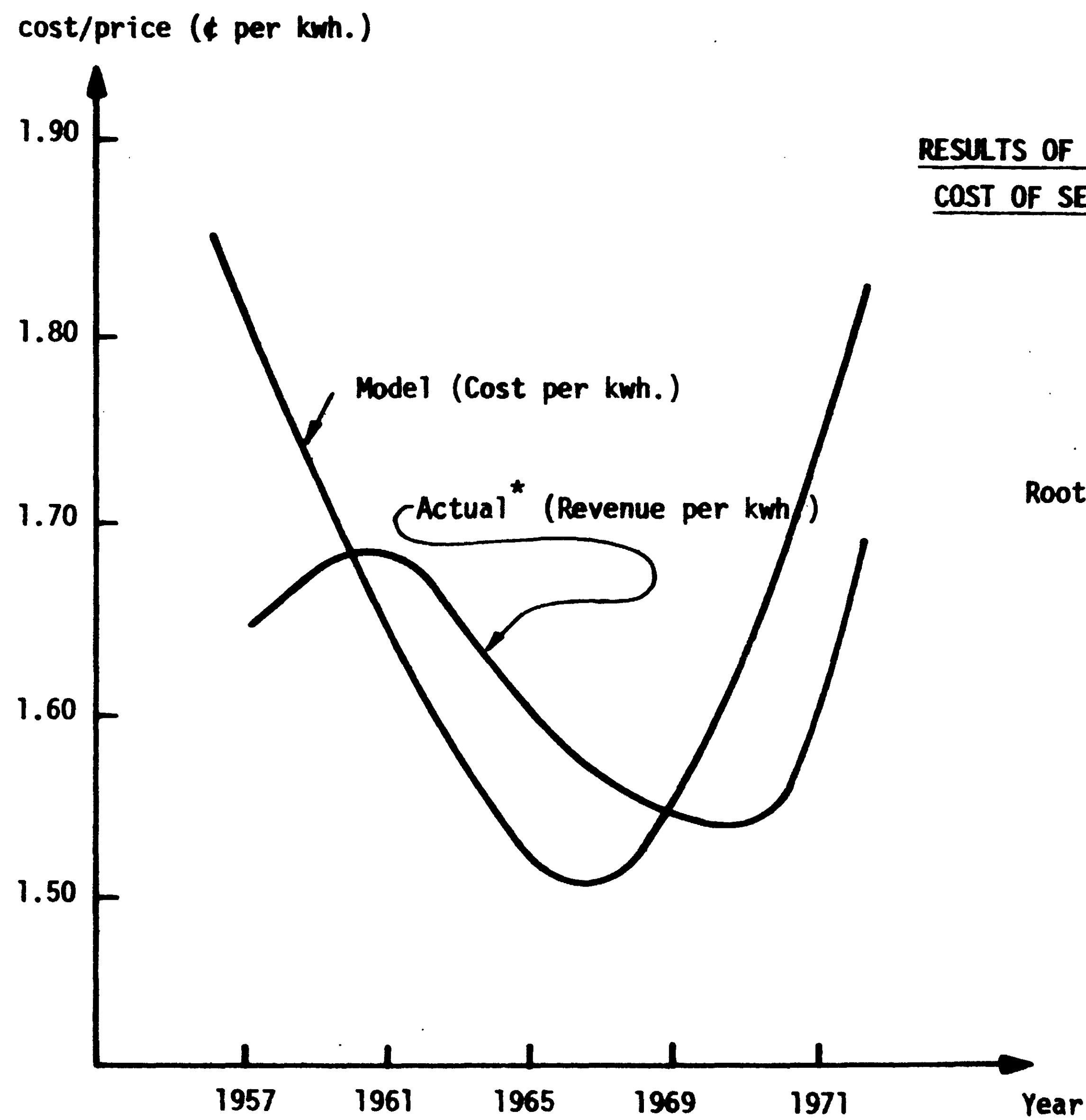
(All units are millions of kilowatt-hours)

	HYDRO		CONVENTIONAL STEAM		NUCLEAR		INTERNAL COMBUSTION	
	Model	Actual*	Model	Actual*	Model	Actual*	Model	Actual*
REGION 1 (New England)	5,067	5,087	40,979	53,090	14,468	9,500	243	409
REGION 2 (Middle Atlantic)	28,520	28,851	165,690	194,189	30,410	11,110	676	305
REGION 3 (East North Central)	4,367	4,279	302,742	297,537	20,509	18,486	986	1,508
REGION 4 (West North Central)	14,843	14,325	81,883	90,632	4,981	3,558	337	2,395
REGION 5 (South Atlantic)	21,141	17,480	231,037	275,249	21,100	5,343	822	569
REGION 6 (East South Central)	25,263	25,160	145,520	142,263	17,584	--	1,112	9
REGION 7 (West South Central)	5,979	3,921	180,789	203,382	5,276	--	789	988
REGION 8 (Mountain)	29,868	29,276	44,966	61,309	879	--	234	252
REGION 9 (Pacific))	144,255	143,987	113,316	90,420	8,792	6,043	802	15

* Actual values from 1972 Edison Electric Institute Statistical Yearbook

TABLE 5

RESULTS OF BACK CAST SIMULATION
COST OF SERVICE FOR TOTAL U.S.



Root Mean Square error = .082¢/kwh

F I G U R E 11

* Actual from the Edison Electric Institute Statistical Yearbook, various issues.

3. ANALYSIS WITH THE MODEL (Simulations to 1985)

Recent events in the energy sector have precipitated large uncertainties in three critical decision variables in the utility sector. First, the Arab oil embargo triggered a complete reordering of the prices of fossil fuels used in the utility sector. Secondly, the increase in fossil fuel costs have been accompanied by unprecedented inflation rates and high costs of capital. Finally, the desire for energy independence and the overall conservation ethic have combined, at least so far, to substantially decrease the rate of growth in demand. All three events have important implications for the future evolution of electricity supply system. In this section we use the model that has been described above to illustrate how it can be used to analyze the effects on future electricity supply of the U.S. through the year 1985 for two scenarios that incorporate recent changes in the expectations of these variables. These simulations are not to be viewed as forecasts. The results are presented here only to depict the substitution possibilities inherent in the model structure and exemplify how it can be used.

The Cases

Specifically, the results of two simulations are reported. The only difference between the two cases is the expected rate of growth of electricity demand. In the first case we use a value that is near the high end of historical experience, an average rate of growth of 7.5% per year between 1973 and 1985. In the second case we use a value which we feel is more probable, an average growth rate of about 4.4% per year[31]. Other inputs to the model are set to be consistent with post embargo future trends.

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[31] As will be seen, the other conditions of the scenario reflect price increases for the fossil fuels of about 100% for gas, 100% for oil, 50% for coal, and resulting from the simulations, an increase of 50% in the real price of electricity for the low growth case. From demand analyses performed by the authors, [9] and [10], these conditions yield a demand growth for electricity of between 4% and 5%.

Average national prices for crude oil are assumed to follow a trend from the current average of around $10.00 per barrel to $11.50 per barrel in 1985, and average national coal prices are escalated from a 1973 value of $9.00 per ton to $25 per ton in 1985. For natural gas prices, to reflect that the current price regulation in that sector has resulted in serious supply shortages, we have used a price consistent with the equivalent BTU cost of oil. This time series starts in 1974 at $1.50 per MCF and escalates to $2.10/MCF by 1985. Regional prices are obtained by adding the historical differential between the delivered regional cost of fuel and the average national price. It has further been assumed that regional fuel prices so calculated reflect availability of the fuel resource.

The capital costs of alternative plants have been assigned the nominal values shows in Table 6. These are escalated after 1980 at the annual rates shown in the right hand column. The capital costs of coal-fired plant are set substantially higher than gas or oil to reflect the costs of stack gas desulfurization. Correspondingly, it has been assumed in the simulation that all available coal supplies can be used regardless of sulfur content.

The final change in input data made to make the conditions for the simulations more closely reflect recent trends is an increase in the regulated rate of return (used in the cost of service calculations) over historical values. This parameter was increased in 1972 by 50% over the historical value reported in chapter 2. In all cases the system load factors are constant at approximately 61%[32].

In the next section the results of the simulations are presented.

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[32] The system load factor is the ratio of the area under the load curve to the product of the peak load times 8760 hours per year. A 61% system load factor corresponds quite closely to the recent Edison Electric Institute forecast[17]

CAPITAL COSTS OF PLANT ALTERNATIVES

USED IN CASE STUDIES

P L A N T	1 9 7 2 $/Kw.	1 9 8 0 $/Kw.	Escalation Rate After 1980
Conventional Steam			
Coal	245	548	4.5%
Gas	185	345	5.6%
Oil	185	345	5.6%
Light Water Reactors	250	662	5.6%
Internal Combustion and Gas Turbine	150	225	4.6%
Hydro	163	230	4.6%

TABLE 6

Simulation Results

Tables 7, 8, and 9 summarize the simulation results for the aggregated U.S. in 1970 and 1985 for the two cases, 7.5% growth and 4.4% growth in demand per annum, respectively.

Table 7 displays the demand and capacity statistics for the two cases. The results indicate that the reduction in demand growth has far greater impact on the long term conventional steam plant requirements than any other category. For the 4.4% growth case, the capacity of conventional steam plant is only about half the simulated 1985 requirements for the 7.5% growth case. Nuclear capacity installations, on the other hand, are essentially the same for the two cases. This is because this capacity is already in the construction pipeline.

Under the conditions used in the simulations, it is nuclear plant that shows the most significant increase in generation over the period (Table 8). The generation from the oil and gas fired plants declines significantly in both cases between now and 1985. The large increase in the prices of these fuels is no doubt the motivating influence, but the thing that allows it to happen is the large increase in nuclear generation. This nuclear capacity is used as base load, which allows current base load oil and gas fired plants to be used on a cycling basis. Consequently, the usage factors and fuel requirements for these plants decrease with time. Note also that no new gas-fired plants are constructed. This is a direct result of supply limitations reflected in the model with the high opportunity cost of gas.

Table 9 displays the trend in cost of service and investment patterns for the simulations. The 50% increase in required rate of return in combination with increased fuel prices yields an immediate increase of about 60% in the cost of service. After that, the cost of service increases by another 80% in the high growth case, and rises another 60% in the low growth case.

Initially, between 1975 and 1979, there is overcapacity in the low growth case because of the abrupt change from historical growth patterns. This overcapacity results in costs which, when spread over the smaller number of kilowatt hours demanded, are greater than for the high growth case. But as the reserve margins decline with increasing demand to normal values around 1980, the cost of service for the low growth case is surpassed by the higher growth case. For the high growth case a large amount of high cost new equipment is adopted into the system which, when added to that in 1974, yields a much higher rate base per unit output. For the low growth case, on the other hand, this proportion of inflated cost equipment is much lower, so that when reserve levels return to normal, the cost of service for this case is also lower.

Regionally, the trends in supply are also quite enlightening. The principal gas consuming region in the 1980's consistent with these forecasts is West South-Central, the main supply region. The principal oil consuming regions are the New England, Middle Atlantic, South Atlantic, and Pacific areas, mainly because they have the majority of existing oil capacity. The model also results in all regions consuming at least some coal, with the balance of generation supplied by hydro and nuclear.

The percentage of total capacity made up by nuclear for each region is shown in Table 10 for the year 1982. As might be expected, the regions with the highest fossil fuel costs correspond to those with the highest nuclear fraction. (The higher fractions for the 4.4% growth case reflect a decreased installation of fossil fuel plant in the low growth scenario).

RESULTS OF SIMULATIONS

DEMAND AND CAPABILITY

U. S. AGGREGATE STATISTICS

ELECTRICITY DEMAND (Kilowatt-hours x 10^9)

Y E A R	1 9 7 3	1 9 7 9	1 9 8 5
7.5% Growth	1696.7*	2621.8	4111.8
4.4% Growth	1696.7*	2245.4	2923.1

CAPABILITY (Millions of Kilowatts)

PLANT/YEAR	1973	1 9 7 9		1 9 8 5	
		7.5%	4.4%	7.5%	4.4%
Hydro	61.2*	77.2	77.2	89.0	89.0
Conventional Steam	318.4*	379.0	379.0	548.0	371.7
(Coal)	N.A.	(186.8)	(186.8)	(362.7)	(202.1)
(Natural Gas)	N.A.	(81.6)	(81.6)	(64.4)	(64.4)
(Oil)	N.A.	(110.5)	(110.5)	(121.6)	(105.2)
Nuclear	21.1*	69.1	69.1	203.0	202.3
Int. Combustion and Gas Turbine	37.7*	138.9	103.4	213.5	113.5
TOTAL	438.4*	664.2	628.8	1053.5	776.4

*Actual values from Ref. [3]

These results are sample simulations, not forecasts.

T A B L E 7

RESULTS OF SIMULATIONS

GENERATION AND PLANT LOAD FACTORS

U. S. AGGREGATE STATISTICS

GENERATION (Kilowatt-hours x 10^9)	1973	1979		1985	
PLANT TYPE/YEAR		7.5%	4.4%	7.5%	4.4%
Hydro	271.1*	447.3	447.3	513.1	513.1
Conventional Steam	1495.8*	1984.2	1572.9	2694.0	1397.7
(Coal)	(843.6)*	(1349.1)	(1184.4)	(2465.8)	(1190.6)
(Natural Gas)	(337.5)*	(233.2)	(186.5)	(85.4)	(72.6)
(Oil)	(314.7)*	(401.9)	(202.0)	(142.8)	(134.6)
Nuclear	83.3*	442.2	442.2	1300.0	1295.2
Int. Combustion and Gas Turbine	6.2*	10.3	7.5	15.8	10.0
TOTAL	1856.4*	2884.0	2469.9	4523.0	3216.1
PLANT USAGE FACTORS**	1973	1979		1985	
		7.5%	4.4%	7.5%	4.4%
Hydro	.506	.660	.661	.658	.658
Conventional Steam	.540	.596	.473	.561	.429
(Coal)	(N.A.)	(.824)	(.724)	(.776)	(.673)
(Natural Gas)	(N.A.)	(.326)	(.261)	(.151)	(.182)
(Oil)	(N.A.)	(.415)	(.209)	(.135)	(.113)
Nuclear	.45	.731	.731	.731	.731
Int. Combustion and Gas Turbine	.02	.009	.008	.008	.010

* Actual values from Ref. [3]

** 1973 values computed from capability and generation statistics

These results are sample simulations, not forecasts.

TABLE 8

RESULTS OF SIMULATIONS

COST OF SERVICE AND GENERATION INVESTMENT

U.S. AGGREGATE STATISTICS

COST OF SERVICE (¢/kwh.)		
YEAR/CASE	7.5% Growth	4.4% Growth
1973	1.85*	1.85*
1975	2.90	2.93
1977	3.16	3.26
1979	3.51	3.67
1981	4.00	3.82
1983	4.53	4.17
1985	5.11	4.74
TOTAL INVESTMENT BASE (Billions of Dollars)		
YEAR/CASE	7.5% Growth	4.4% Growth
1973	113.8*	113.8*
1975	126.6	126.6
1977	160.8	159.1
1979	220.1	201.9
1981	294.6	230.6
1983	402.3	284.8
1985	548.2	377.1

*Actual Values from Ref. [3]

These results are sample simulations, not forecasts

TABLE 9

RESULTS OF SIMULATIONS

NUCLEAR GENERATION AS A PERCENTAGE OF TOTAL OUTPUT

1 9 8 2

REGION/CASE	7.5% Growth	4.4% Growth
New England	30.4	38.9
Middle Atlantic	27.0	34.7
East North Central	13.8	17.8
West North Central	27.1	34.8
South Atlantic	27.0	34.7
East South Central	18.6	23.8
West South Central	15.2	19.5
Mountain	1.7	2.2
Pacific	17.5	22.4

T A B L E 10

These results are sample simulations, not forecasts.

It is interesting to note that when making simulations without the 50% increase in the cost of capital and associated regulated rate of return two effects are apparent. First, the cost of service is less than in the results presented in Table 10 by about 25%. The increase in rate of return is therefore responsible for about 25% of the increases in cost of service displayed in Table 9 between 1973 and 1985. The rest is made up by increased fuel costs and escalating costs of equipment. The second change that results with a lower cost of capital is an increase in the proportion of total supply made up by the capital intensive plant alternatives and a decrease in the internal combustion and gas turbine plant. The higher the cost of capital, the more one should substitute fuel and operation expenditures for capital expenditures, ceteris paribus, for minimum cost operation. The 50% increase in costs or capital results in about 6% more peaking capacity being adopted into the system by 1985 and less nuclear and conventional steam plant than would occur if costs of capital had remained the same. Furthermore, at the low cost of capital, nuclear capacity commitments average about 40,000 MW per year in the later 1970's. For the high cost of capital, these commitments are reduced to 12,000 MW per year.

Finally, there are many other uncertainties that could impact upon the system, including tax policies, the design of rate structures, environmental pressures, fuel shortages, load shapes, and other trends in costs. The results presented here are for two very restricted scenarios. It has been assumed that the 50% increase in average rate of return is enough to remove the capital restrictions the industry faces at present, and the assumptions about the availability of coal supplies may be overly optimistic. If these assumptions are valid, however, the trends for future development of the industry indicated by the model do seem quite plausible. Without the increase in rates of return, and with the present depressed conditions of the capital markets, it is quite possible that the industry may not have the resources to evolve as indicated in these simulations. The reason for development of the model is to have a tool that can be used to evaluate the sensitivities and substitution possibilities in response to such uncertainties. The cases presented revolve around changes in only the expected future demand. Other cases with changed assumptions about fuel costs, equipment costs, load shapes, the cost of capital and the rates of return are possible and will be examined in a forthcoming paper. It is in this context that the model becomes a most useful tool.

4.0 CONCLUSIONS

This document is a report on research in progress. The purpose is to relate the directions being taken to develop a regionalized behavioral model of the U.S. electric utility industry. The model is to be further developed in the financial - cost of service subsection, electricity demand functions are to be included into the formulation, and many of the model cost inputs will be reviewed and updated. Initial analyses indicate the model exhibits many of the behavioral phenomena that are necessary for assessing the effects of changing national energy policy upon the industry. It is for this purpose that the model is being developed. Future reports on further developments will be forthcoming.

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