THE FUTURE OF THE U. S. NUCLEAR ENERGY INDUSTRY

BY

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APRIL 24, 1975

ENERGY LAB REPORT
MIT-EL 75-006

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ACKNOWLEDGEMENTS

Several people have been involved in the development of the model used for these analyses, and each contributed to the realization of the overall concept. Drew Bottaro, Richard Graves, Dilip Kamat, Fred Zerhoot, and Gregory Daley all deserve much credit for their parts in making this work possible. The authors wish to express sincere gratitude for these efforts.

Mrs. Laurinda Bitran, who typed this manuscript, has spent hours typing, expediting and organizing the many reports of the project. For her perseverance and dedication toward all phases of her activity, we express sincere appreciation.

The financial support for this project was derived from N.S.F.-RANN (Grant # SIA73-07871 A02) and the Ford Foundation. The authors gratefully acknowledge these sources for making this work possible.

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A. INTRODUCTION

Since the end of World War II it has been hoped that nuclear fission would become an economical means of providing energy services for peaceful purposes. Early successes in the use of light water reactors to provide power for submarines led to the development of large scale reactors used to produce steam for the generation of electricity. At the end of 1974 there were 55 commercial reactors licensed to operate to generate electricity and perhaps 150 others in advanced construction stages or on firm orders. Five domestic firms are currently active vendors of nuclear steam supply systems, while many others are involved in mining, fuel processing, and the construction of various individual system components.

As with any new technology, nuclear power has in the past and continues to have associated with it considerable uncertainty. The development of a viable private nuclear energy industry obviously depends critically on the ability of nuclear technology to compete successfully with alternatives. Decisions made by electric utilities during the past ten years regarding nuclear reactors purchased were often made based on expectations which have, more often than not, been very far from being correct. The costs and lead times for constructing nuclear generating facilities have turned out to be far higher and far longer than anyone anticipated in the mid and late 1960's.[1]

[1] In 1968 an A.E.C. report estimated the cost of a 1000 MWe plant at $150 per Kw (1967 dollars). In 1975 the Federal Energy Administration estimated the cost at $450 (1973 dollars). Construction lead times once estimated at 6 years have now risen to 10 years .

At the same time, however, the costs of residual fuel oil have increased far beyond anyone's expectations, the implementation of air pollution restrictions have added considerable costs to the construction of coal and oil burning plants, and once cheap natural gas remains cheap, but generally unavailable[2]. All these things taken together have raised the price of electricity considerably so that expected demand growth has fallen below historical levels[3]. These changing economic circumstances make it worthwhile to examine the future prospects of the nuclear energy industry given the central role of nuclear energy in federal energy policy and R & D efforts.

In this paper we seek to examine the future of the domestic nuclear supply industry under a number of different assumptions about future states of nature. We make use of a regional supply-demand-regulatory model of the U.S. electric utility industry to evaluate the derived demand for commercial nuclear reactors, raw uranium, and uranium enrichment requirements for the period 1975-1995. This period has been chosen to analyze conventional reactor and fuel demands since it is highly unlikely that a commercial breeder technology will be "on line" generating significant quantities of electricity for utilities before 1995[4]. We will be especially concerned here with the effects of government policies regarding clean air standards, the stability of O.P.E.C., reactor licensing procedures, electricity pricing policies, and the cost of capital, on the demand for nuclear generating systems and fuel

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[2] MacAvoy and Pindyck [1].

[3] Electricity consumption increased at a rate of about 7.5% per year between 1968-1972 with $11 oil the F.E.A. predicts a growth rate of 5.6% between now and 1985. See F.E.A. Project Independence Report [19], Appendix, pp. 33.

[4] See A.E.C. [2], Appendix A.

cycle requirements[5].

The paper proceeds in the following way. We first briefly sketch the structure of the domestic nuclear energy industry today. Next, the engineering-econometric supply-demand system used for analysis is described. This model is then used to simulate the derived demand for nuclear and fossil-fueled plants for generating electricity and nuclear fuel cycle requirements for 1985 and 1995 given several possible public policy possibilities. We view these simulations much more as demonstrative of the relative effects of various public policies on the demand for nuclear steam supply systems and fuel than as point predictions of what will actually occur in the future. In addition, this is an attempt to fully integrate engineering and economic modeling of supply and demand interactions, an approach that we believe to be especially useful for analyzing behavior within energy markets.

Among our conclusions are the following: the O.P.E.C. induced rise in fuel prices (if it persists) will do more than anything else to maintain a strong demand for nuclear generating facilities during this period; the maintenance of strict air pollution requirements impacting coal and oil-burning technologies have very large positive effects on the demand for nuclear reactors; peak load pricing increases rather than decreases the demand for nuclear reactors, contrary to the conventional viewpoint of many environmental groups; the combination of continued high oil prices and strict air pollution requirements and higher coal prices will ensure the continued growth of the industry, but at a rate considerably below the published predictions of the

[5]We will ignore, however, capital shortage problems faced by the electric utility industry which might preclude the industry's ability to purchase the desired mix of generating capacity See Joskow and MacAvoy [3] for an analysis of this problem.

Atomic Energy Commission[6]. The reduced growth of the reactor market flows through as reductions in fuel cycle requirements and the expected depletion of natural uranium resources. These outcomes raise a number of questions concerning optimal strategies for breeder reactor development.

[6] The Atomic Energy Commission was broken into two parts in 1975. Regulatory functions are now incorporated in the Nuclear Regulatory Commission and research and development activity has been incorporated into the Energy Research and Development Agency.

B. THE U.S. NUCLEAR SUPPLY INDUSTRY

The nuclear supply industry can conveniently be broken down into two major sectors. The manufacturers of the nuclear steam supply system itself, consisting of the reactor, pressure vessel, steam generator, primary pumps, and various valves, pipes and instruments and the nuclear fuel sector consisting of uranium mining, processing, enrichment, fuel fabrication and processing. As of the end of 1974 U.S. reactor manufacturers had completed, were building, or, had under firm contract 209 reactors, with a total capacity of 203,000 Mwe, for use in generating electricity[7]. These reactors have been or will be manufactured by seven companies, one of which has already left the market (Allis-Chalmers) and one of which has yet to build a reactor (OPS) and whose actual entry into the market is very questionable.

FIRMS	PLANTS	% OF TOTAL	CAPACITY	% OF TOTAL
Allis- Chalmers	1	-	50	-
General Electric	70	34	67,808	33
General Atomic[8]	8	4	6,555	3
Babcok-Wilcox	26	12	25,060	12
Combustion Engineer	29	14	31,492	15
Westinghouse	71	34	67,492	33
O. P. S.	4	2	4,600	2
TOTAL	209	100	203,057	98(2)

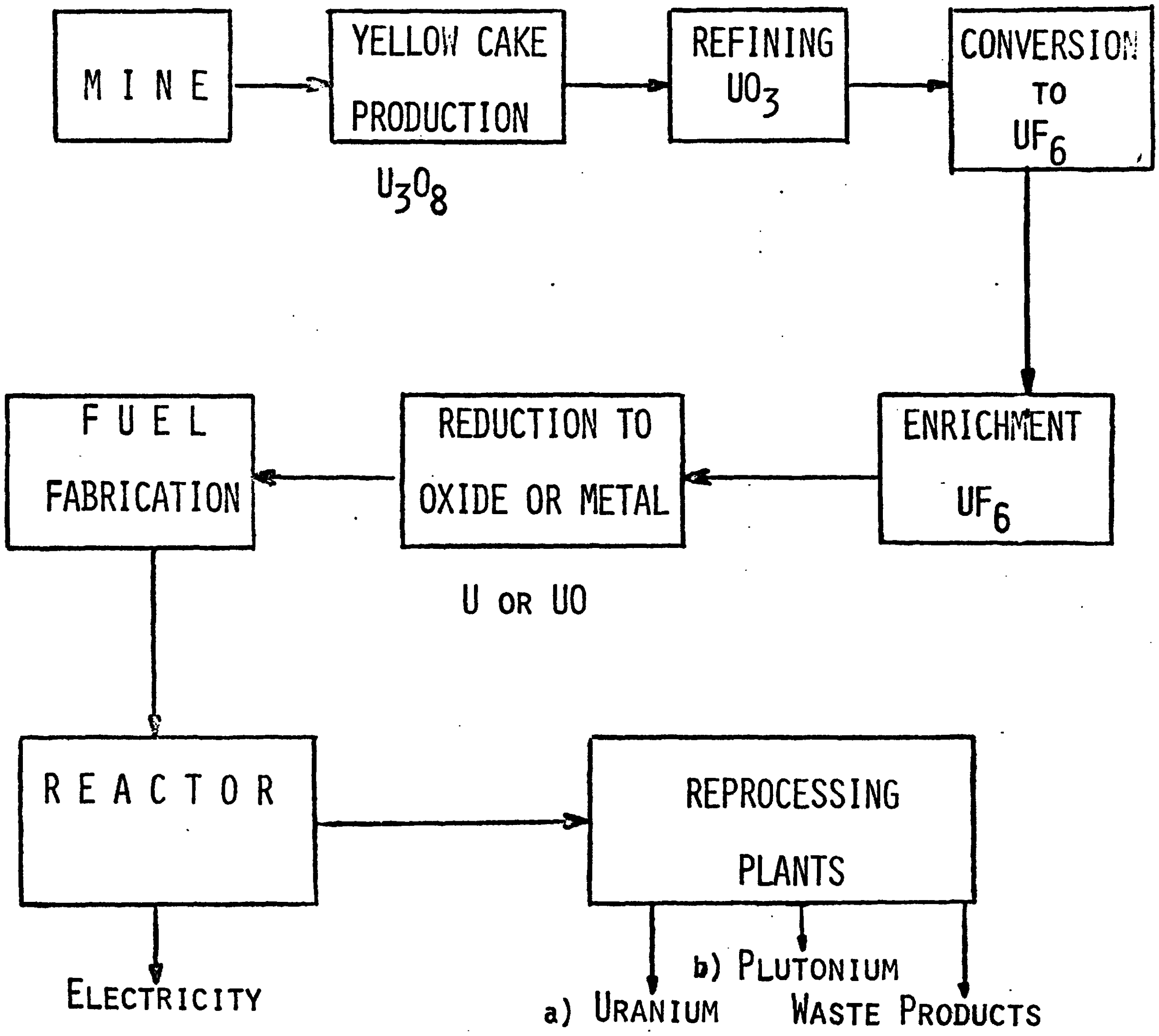
[7] Electrical World, October 15, 1974, p. 41

[8] General Atomic is the only company that does not manufacture light water reactors. General Atomic uses a High Temperature Gas Cooled technology which uses both a different cooling and heat transfer technology and a different fuel cycle than the light water reactors manufactured by the other vendors. One of Gulf Atomic's reactors has been completed and is now operating.

A number of additional companies manufacture important components of the nuclear steam supply system such as the pressure vessel, primary pumps, pressurizers and instrumentation and control systems. One or more of the major reactor manufacturers also supply each of the various basic components for the nuclear supply system. A complete nuclear generating facility with a capacity of $1000 MW_e$ costs about $450 million to build (in 1974 dollars). Roughly 30% of this cost is associated with the cost of the nuclear steam supply system, the initial nuclear fuel core and the containment while the remainder can be attributed to the turbine-generator set and the rest of the engineering and construction work on the plant.

The Nuclear Fuel Sector is depicted in Figure 1. Over 300 companies are engaged in uranium mining and exploration. Fifteen companies operate uranium milling plants which process raw uranium ore to produce uranium oxide. Capacity in 1973 was approximately 20,000 tons of uranium oxide annually (U_3O_8) and the four firm concentration ratio (based on capacity) was 52%. The conversion of uranium oxide to UF_6 used as input to the enrichment plants is provided by two companies. In addition, two firms are building plants to convert slightly enriched uranium into UF_6 and an additional firm has the capability to convert highly enriched recovered uranium to UF_6. At the present time enrichment capacity is provided entirely by government facilities owned by the Atomic Energy Commission. Current capacity is 17.1 million separative work units per year (SWU) which is in the process of being expanded to 27 million SWU per year. Future private enrichment capacity is desired by the A.E.C., but great uncertainty remains regarding who will provide it and when it will be needed (this is discussed further below). Fuel fabrication for reactor core loadings is provided almost entirely by the four major light water reactor manufacturers. At the end of 1974 there were no private reprocessing facilities in operation to reprocess spent uranium fuel. However, one plant that had been in operation is being rebuilt and expanded and is expected to be in operation by the end of

THE NUCLEAR FUEL CYCLE FOR LIGHT WATER REACTOR FUELS



a) Uranium derived from reprocessing may be recycled through the enrichment and fuel fabrication process.

b) Plutonium which is currently stored may be recycled as fuel in light water reactors or breeder reactors.

FIGURE 1

1976. Additional capacity is under construction by General Electric and Allied Gulf.

The further evolution of the nuclear fuel sector depends critically on the rate at which demand for nuclear fuels grows. Investment requirements for both diffusion plants and reprocessing facilities are very high since economies of scale require substantial lumps of capacity to be added if minimum efficient scale is to be achieved[9].

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[9]See The Nuclear Age [18], p. 52. Alternative enrichment technologies that are less capital intensive and have much smaller minimum efficient sizes are also being developed, primarily outside the United States.

C. THE ELECTRICITY MODEL

The model used for the analysis is a regionalized engineering-econometric simulation model of U.S. electricity supply and demand. The model consists of three basic parts. The heart of the model is a regional supply model which simulates the decision-making processes involved in operating and expanding an electricity supply system. This part of the model is a behavioral model in that is specifies the expected cost minimizing "rules of thumb" used by electric utility companies to make supply decisions. While each of these rules of thumb is generally consistent with cost minimizing behavior as perceived within the decision making structure, the model itself uses these specific decision rules to generate short run and long run behavior, and is not cast in the linear programming framework that has been employed elsewhere[10].

The second major component of the electricity model is a set of demand equations. The demand system simultaneously estimates the demands for electricity, natural gas, coal, and oil consumed in the residential and commercial, and industrial sectors. The demand system employed is dynamic and nonlinear and the relevant elasticities have been estimated using econometric techniques applied to a time series of cross-sections for 49 states.[11]

The final component of the model is the regulatory model which links supply decisions to demand decisions by setting prices for electric services. The regulatory model is a simple set of equations which attempts to represent the kinds of regulatory rules used to

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[10] See for example the important work by Haefle and Manne [4] analyzing the Breeder Reactor. In addition, since the electric utility industry is regulated, pure cost minimizing behavior may not be observed. See Averch and Johnson [16] and the interesting study by Roberts [5]. Griffen [6] uses a purely econometric approach that subsumes the investment and operating decision rules into fitted supply functions.

[11] We use "marginal" electricity prices to minimize distortions arising from the declining block nature of electricity rate structures.

establish prices within the state regulatory system currently prevailing in the United States.

A broad flow diagram of the overall model is shown in Figure 2 and depicts the major features of the model. A complete description of each of the submodels used here would be impossible given the space limitations of a single paper. Each part of the model has been described in great detail elsewhere[12]. Here we attempt only to lay out the basic structure of each model to convey the methodological concepts employed and how the three components of the model interrelate in the overall simulation framework. The two major loops of the model, the "time loop" and the "regional loop", serve to move the model through time and span nine census 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; to meet <u>expected</u> load.
3. the generation of electricity via usage of existing plant to meet <u>actual</u> load.
4. transmission and distribution requirements and costs.
5. the "cost of service" and utility cash flows.
6. electricity demands for the alternative customer classes given the endogenous set of electricity prices.

a. <u>The Supply Model</u>

Geographically, the supply model consists of nine regions corresponding to the nine census regions of the U.S. Within each region the model optimizes the construction mix of eight plant alternatives with the ninth supplied exogenously. The plant alternatives cor- correspond to:

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[12] See Refs. [7], [8], [9], [10], [11].

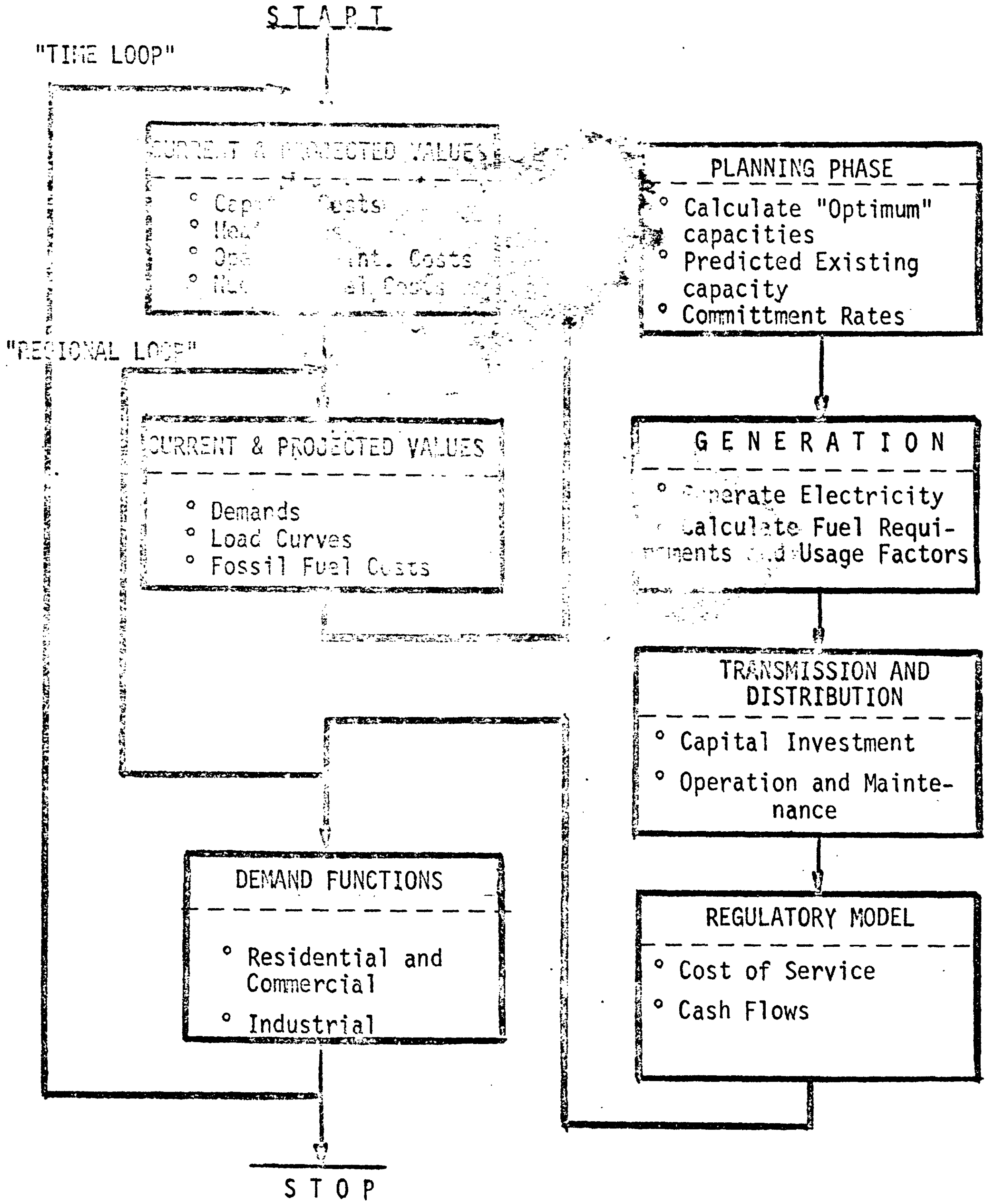

FIGURE 2: FLOW DIAGRAM OF THE ELECTRICITY MODEL INTERCONNECTION WITH REGULATORY MODEL AND DEMAND SUB-MODELS

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;
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).

Expectations regarding fuel costs, plant construction costs and plant operating characteristics are exogenous inputs into the model. We have obtained estimates for these variables by surveying a number of electric utilities in the United States. Changes in these expectations due to changing public policies and changing domestic and international resource conditions are obviously of great importance. For example, the collapse of O.P.E.C. would lead to drastically reduced prices for oil, while more stringent air pollution requirements will increase the costs of use of coal and oil fired plants significantly. We examine the effects of thse types of changes in the expected cost characteristics in the analysis presented in the next section of the paper.

Expectations about demand are treated differently. While the model incorporates a set of econometric demand equations to generate <u>actual</u> demand given a vector of prices of all basic energy inputs (coal, oil, natural gas, and the endogenous electricity price) we do not assume that the electric utilities employ such a sophisticated analysis of the own-price and cross-price elasticities to project demand. Rather we believe that electric utilities are considerably more naive. We specify their projections of demand by exponentially weighted moving averages with a trend adjustment[13]. As a result of this approach, actual electricity consumption in each period will generally be different from projected energy consumption. The electricity supply decisions can of course be adjusted as the utility adjusts its expectations given more information about actual consumption. However, the supply decision can only be reoptimized given lead-time constraints on different kinds of equipment[14]. At any point in time the utility will generally have a different amount of capacity and different mix of plants than would have been chosen if the future had been known with certainty. We believe that this more realistically represents the actual decision making process than does the traditional programming approach which assumes that the firm knows the future with certainty.

The investment decision in the model 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 3 is shown a typical curve for New England for the year 1971. 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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[13] 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 tecnique 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 [12].

[14] The model operates so as to make expectations over three different planning horizons. These correspond to a ten year lead time for the construction of nuclear plants, five years for fossil fired thermal plants, and two and one-half years for gas turbines and internal combustion units.

LOAD DURATION DATA FOR 1971 - NEW ENGLAND POWER EXCHANGE

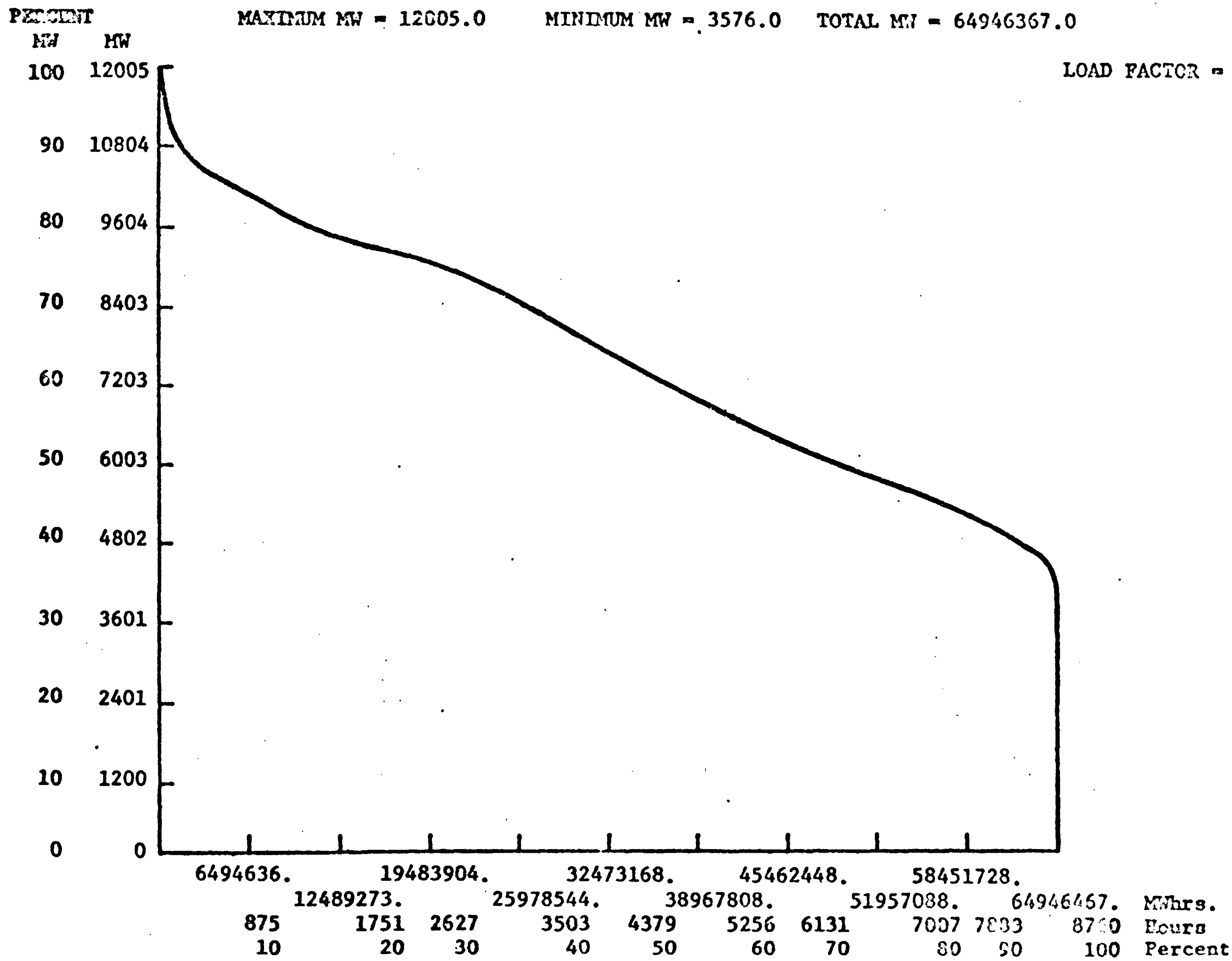

FIGURE 3

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 optimal plant program can be stated as that plant composition which minimizes the levelized annual cost per kilowatt-hour[15], where the levelized average cost (in cents per kwh.) of the output from a generating unit can be written as:

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

with

AC = average costs in cents per kwh.
k_1 = capital cost (dollars/kw.)
a = annual write-off rate[16] (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 4. The bottom profile (or envelope) of these curves represents a minimum cost production profile.

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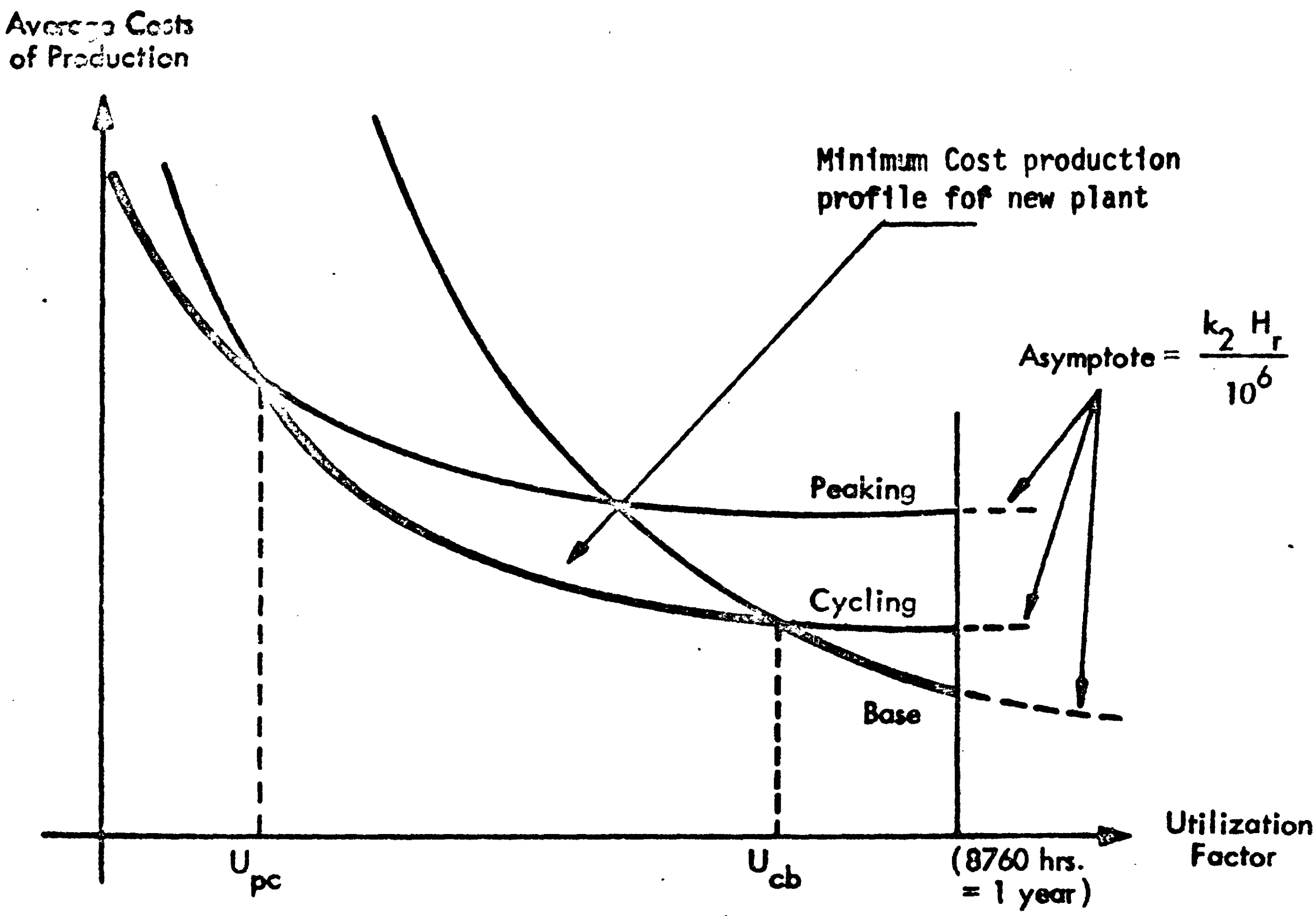
[15] See Turvey [13], pp.

[16] This includes depreciation, insurance costs, return on investment, taxes and other associated fixed capital charges.



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

F I G U R E 4

If we assume that plant capacity is measured by its mean availability[17] the design of the most economical generation mix to meet a load curve such as that of figure 3 has been well established. Turvey[18] 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 4, the optimal mix is derived in the following way. The intersections of the cost curves shown on figure 4 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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17 i.e., correcting for forced outage rates. Available capacity = rated capacity x (1 - forced outage rate).

18 Reference [13], pp. 16 ff.

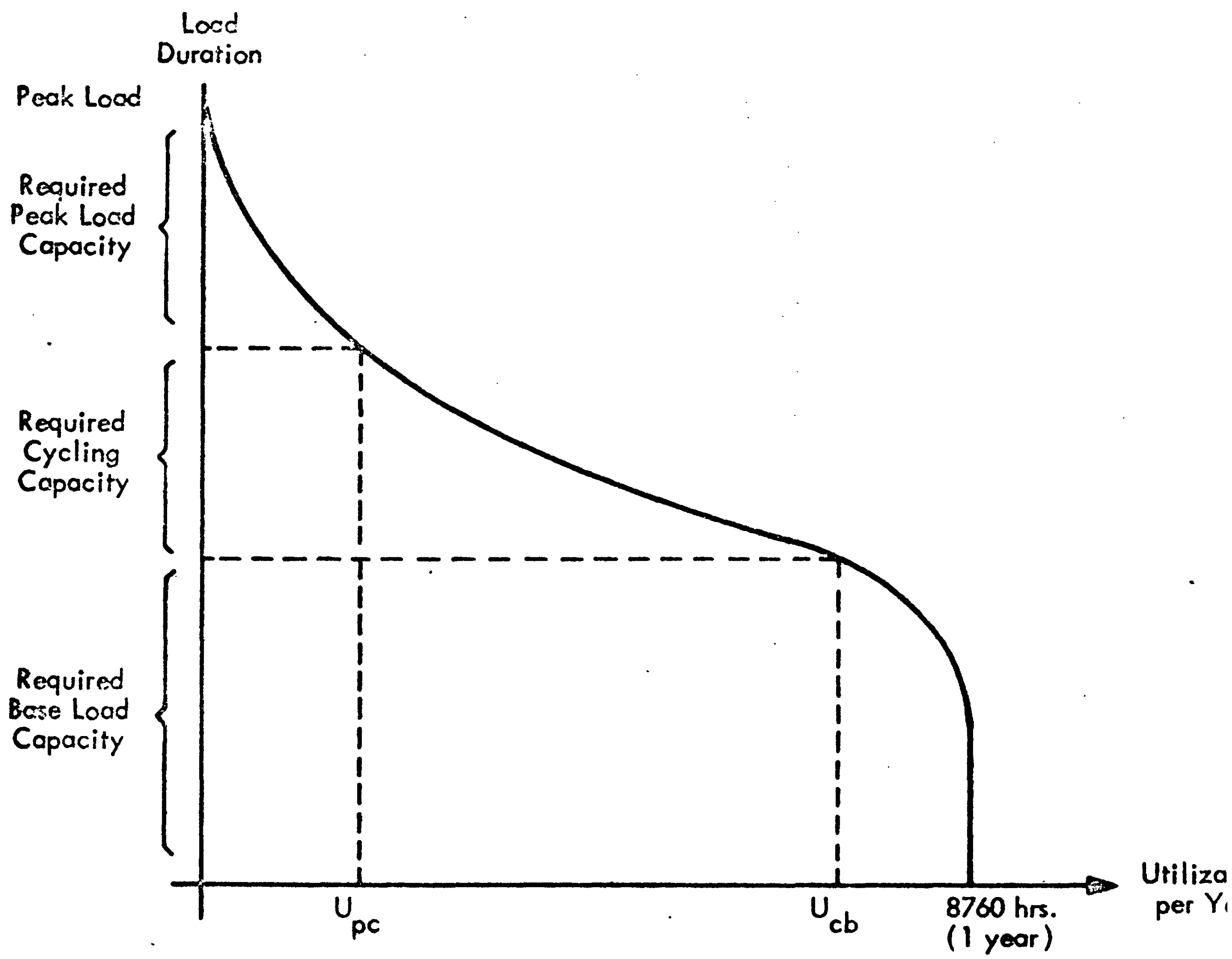
Load
Duration
Peak Load
Required
Peak Load
Capacity
Required
Cycling
Capacity
Required
Base Load
Capacity
U_{pc}
U_{cb}
8760 hrs.
(1 year)
Utiliza
per Y

FIGURE 5

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[19].

If one had no existing plant the optimum mix of capacity would be that shown on Figure 5, 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 sunk costs. The levelized costs of generation per kilowatt hour therefore become

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

If for any existing plant this cost function, when plotted on Figure4 , 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.

The model is constructed to formulate expectations and make capacity committments according to these cost minimizing rules 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 so as to

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

minimize expected costs[20,21].

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. 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 6 with the aid of an integrated

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

21

The material balance and cost relationships for the nuclear fuel cycles of alternative reactors are derived from recent work by Gregory Daley [14] 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.

PLANT UTILIZATION vs. INTEGRATED LOAD FUNCTION

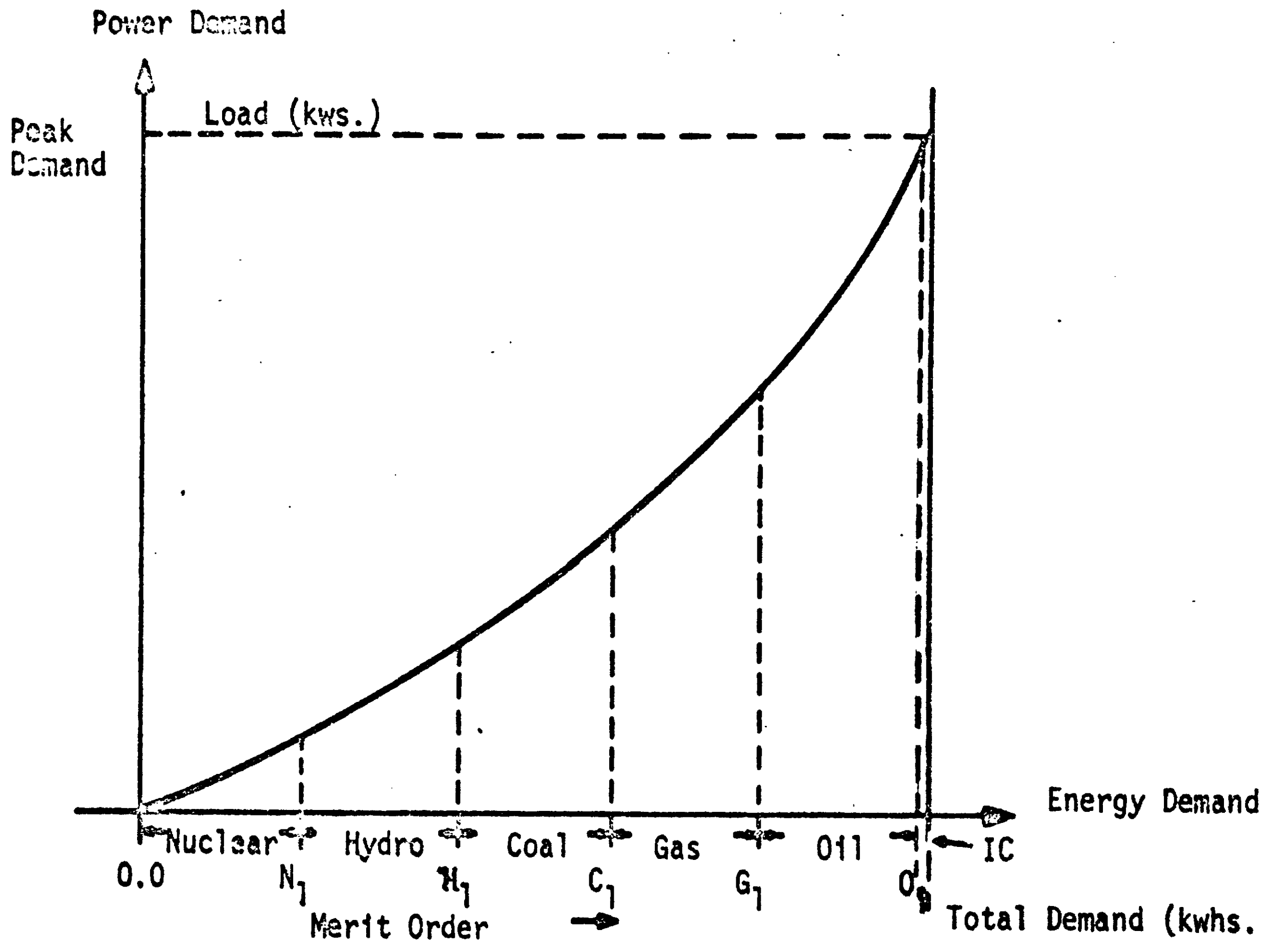

FIGURE 6

load duration curve[22]. 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. Finally, the internal combustion (peaking) units are brought into operation.

In the model 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 available 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.

b. 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 can be 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

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22 The use of the integrated load duration curve (integrated load function) was first introduced by Jacoby [15]. 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).

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.

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 estimate equipment and maintenance requirements for transmission and distribution rather than a structured analytical [illegible] similar to that used for generation planning and electricity production.

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.).

Operation and maintenance costs of the transmission and distribution system depend upon the amount and configuration of the installed equipment. In addition, however, since the equipment requirements are so closely interrelated to the configuration of consumers and their consumption, it is also possible to relate these costs directly to the demand characteristics of a service area. In this paper we have estimated and used the latter set of interdependencies to determine and allocate these costs.

The estimated functions for both equipment requirements and O & M expenses, based on time-series - cross section data (1965-1971), are reported in Appendix A.

c. THE DEMAND MODEL

The demand model consists of a set of demand equations for electricity, oil, natural gas, and coal for the residential and commercial and the industrial sectors (coal only in the industrial sector). These equations have been estimated using cross-sectional data for 49 states for the period 1968-1972. By specifying completely the energy demand sector we can make estimates of actual electricity consumption based on a set of fuel prices that are completely consistent with the fuel prices used for making decisions regarding electricity supply.

For the residential and commercial sector the demand model consists of an equation which estimates total energy consumption per capita as a function of a weighted energy price index (weighted by both consumption and the end-use efficiency of the various fuels) and incomes. A lagged adjustment formulation is utilized to isolate short run and long run effects. In addition a set of "fuel split" equations are estimated which divide total energy consumption into oil, natural gas, and electricity consumption. The equations estimated and the relevant statistics are reported in Appendix B.

For the industrial sector a similar formulation is utilized. Total energy consumption for the sector is estimated as a function of an energy price index and value added in manufacturing. National aggregated time series data for the period 1950-1972 is utilized here. Next a locational equation is estimated using cross-sectional data to determine total energy consumption in each of the states. Finally, a set of fuel split equations is estimated which allows us to allocate the total energy consumption in each state among the four basic fuels, electricity, oil, natural gas and coal. The additional locational equation is utilized along with a total demand equation estimated with national time series data to allow us to disentangle total energy price effects from locational effects[24]. The estimated relationships are reported in Appendix B. More detailed discussion of both sectors can be found in refs. [8], [9].

In Table 1 we report the own price and cross-price elasticities for the residential-commercial and industrial sectors for both the short run (one year) and the long run. Since the elasticities are non-linear and vary from one state to the next, we present here only the calculated elasticities for the mean values of consumption of the various fuels.

d. THE REGULATED PRICE MODEL

The price of electricity is not set in competitive markets, but rather is determined by state and federal regulatory authorities using fairly well established administrative procedures. The type of regulation used for setting electricity prices is generally known as rate of return or rate base regulation. In this procedure regulatory commissions attempt to set prices that will yield a predetermined "fair rate of return" on an original cost rate base after deductions for operation and maintenance costs, depreciation and taxes have been made. Our regulatory model seeks to simulate this procedure using the relevant outputs from the supply model as inputs into the regulatory model.

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24 If one utilizes cross-sectional data to estimate the total energy demand relationship for the industrial sector, a seemingly very high price elasticity results. In fact, however, this merely coincides with the fact that industry tends to locate where energy prices are low. This locational effect is very large, estimated to have a long-run elasticity of -2.0 (with twenty-five years adjustment). After netting this out we find that the price of elasticity of total demand is significantly less, on the order -0.20. In a national context, it obviously would be a serious error to confuse the two effects.

TABLE 1

SUMMARY ELASTICITIES

RESIDENTIAL AND COMMERCIAL

		P_g	P_o	P_e	INCOME
Gas	SR	-.06	.01	.04	SR = +0.08
	LR	-.62	.14	.35	LR = +0.52
Oil	SR	.02	-.08	.04	
	LR	.19	-.81	.35	
Electricity	SR	.02	.01	-.13	
	LR	.18	.14	-1.31	

INDUSTRIAL

		P_g	P_o	P_e	P_c
Gas	SR	-.07	.01	.03	.01
	LR	-.81	.14	.34	.15
Oil	SR	.06	-.11	.03	.01
	LR	.75	-1.32	.34	.14
Electricity	SR	.06	.01	-.11	.01
	LR	.73	.13	-1.28	.14
Coal	SR	.06	.01	.03	-.10
	LR	.75	.14	.33	-1.14

SR = short run (one year) elasticity
LR = long run elasticity

THE RATE BASE

The rate base is equal to the sum of capital expenditures for generation, distribution, and transmission equipment (at original cost) less accumulated depreciation plus an allowance for working capital. The expenditure components are obtained from the electricity supply model as is depreciation which is assumed to be 3.0% of the utility plant at the start of each year[25]. The F.P.C. Working Capital Formula is used to obtain an allowance for working capital of approximately 1/8 of gross revenue.

OPERATING COSTS

The major components of operating costs are fuel costs, maintenance costs, taxes, and depreciation. All but taxes are outputs from the electricity supply model. Utility taxes are extremely complicated and a detailed tax model has not been included here (although one is being constructed). Rather, for reasons of simplicity we use the average tax rate for the period 1950-1972 (the effective tax rate) in conjunction with the allowed rate of return (net) to construct a before tax rate of return used for ratemaking purposes.

Using these data we then construct an average electricity price for each region in the model according to the following equation:

$$P_t = \frac{F_t + O_t + d_t + r_t(1 + t_y) \cdot RB_t}{KWH_t}$$

where

[25] 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).

P_t = average price of electricity

F_t = fuel costs in period t

O_t = other operating and maintenance costs in period t

d_t = depreciation in period t

r_t = allowed rate of return on rate base in period t (inputted exogenously).

t_y = effective income tax rate.

RB_t= Rate Base in period t.

KWH_t=total KWH consumed in period t

This average price is then used as an index to determine future price movements in the residential-commercial and industrial sales categories. The prices at the point of end use computed in this way then become inputs into the demand equations along with all fossil fuel prices (consistent with those used in the supply model) to generate residential and commercial, and industrial electricity demands.

D. ANALYSIS OF THE NUCLEAR ENERGY INDUSTRY (1975-1995)

The Electricity Model is used to generate derived demands for nuclear reactors and nuclear fuel cycle requirements under a number of different states of the world for the period 1975 to 1995 represented by the seven cases discussed below.

CASE 1 - BASE CASE :

We assume that expected oil prices remain at their current real level ($11 per barrel) and that air pollution requirements can be met at costs in the center of the range of recent cost projections. Natural gas for the electric utility sector is assumed to be unavailable except at high intrastate prices. Coal prices reflect current expectations for long term contracts. All fuel prices include transport costs to the various regions of the country specified in the model (a detailed list of the Base Case inputs appears in Appendix C).

CASE 2 - NO O.P.E.C. :

In this case we assume that O.P.E.C. never existed. The real prices of fuels do not exhibit the sharp increases that occurred in 1974, rather they are escalated at 2% per year in real terms from 1973 - 1995. Everything else is as in the Base Case.

CASE 3 - HIGH AIR POLLUTION RESTRICTIONS :

Implementation of strict air pollution requirements raises the costs of coal and oil-fired plants by 10.0 percent and 8.0 percent respectively over the Base Case. In addition, the operation and maintenance costs of coal-fired plants are increased by about 2.8 mills/kwh. to reflect the higher operating cost of sulfur and particulate removal systems. Everything else is as in the Base Case.

CASE 4(a) - PEAK LOAD PRICING

Peak load pricing is assumed to be instituted in 1975 with a gradual improvement of system load factors by 10% by 1985. Everything else is as in the Base Case.

CASE 4(b) - PEAK LOAD PRICING

Peak load pricing is assumed to be instituted with the effect of improving system load factors by 20% in each region over the period 1975-1985. All else is as in the Base Case.

CASE 5 - DECREASED NUCLEAR LEAD TIMES:

Streamlined siting and licensing procedures are assumed to be implemented by the end of 1975 that reduce the required lead time for constructing nuclear plants from 10 years (the value used in all other cases) to 7 years. Everything else is as in the Base Case.

CASE 6: HIGH COSTS OF CAPITAL

It is assumed that increased costs of debt and equity increase by 3% the annual capital charge rate used by utilities from a base case value of 15% to a value for this run of 18%. Everything else is as in the Base Case.

CASE 7: HIGH COSTS OF URANIUM ORE AND ENRICHMENT

It is assumed that future costs of uranium ore rise significantly above the current values of \$8 to \$10 per pound and the cost of separative work rises at the rate of inflation over the next twenty years. The costs of U_3O_8 rise gradually in this case to 2.5 times the base case values by 1985 while the costs of separative work rise from current values of \$48 per SWU to \$80 per SWU in nominal dollars by 1985. By 1995, in nominal terms, the cost of U_3O_8 reaches \$72/pound and separative work reaches a cost of \$138 per SWU (corresponding to \$22 per lb U_3O_8 and \$43 per SWU in in 1974 dollars[26]).

The results are reported in the following tables. In Table 2 we report the total generating capacity for the country and the associated nuclear generating capacity for 1980, 1985, and 1995 for each case. We also report A.E.C. projections for the same periods, one made in 1972 before the drastic rise in oil prices and one made in early 1974 after that rise. In Table 3 we report the cumulative utilization of uranium and the annual enrichment requirements in separative work units. In Table 4 we report the nominal average price of electricity for each case and the accumulated rate base in nominal terms for each of these years. In Table 5 we report the resulting demands for electricity for each of the years.

In the simulations reported here we assume that plutonium recycle in light water reactors does not occur during the time period and that the breeder reactor is not commercially available until 1995. However in allowing credits for recovered plutonium we are implicitly assuming that plutonium will be valuable as a reactor fuel and reflect this in the light water reactor fuel cycle costs. We chose this procedure to concentrate on the tradeoffs between nuclear and conventional technologies rather than on inter-reactor substitutions. Given the current pace of the U.S. Breeder Program[27] we believe that it is in fact unlikely that a substantial number of commercial breeder reactors will be operating before 1995[28].

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[26] This may even be conservative. Enrichment already sells at $100 per SWU in Europe where prices reflect the long run marginal cost of enrichment. See Nucleonics Week, March 13, 1975, pg.1.

[27] See "The Fast Flux Test Facility", Report of the General Accounting Office, January 1975.

[28] In other research we are analyzing inter-reactor substitution possibilities and the "value" of plutonium under alternative estimates of uranium supply functions, fuel cycle costs, and reactor construction costs.

Perhaps one of the most striking results of the analysis occurs in the comparisons between our projected levels of nuclear capacity and those projected by the Atomic Energy Commission. In almost every case the projected nuclear capacity falls below the range of A.E.C. projections. For the Base Case (1) in the year 1995 (which is the most interesting since, because of the ten year lead times, much of the nuclear capacity through 1984 is already in the pipeline) we project nuclear capacity additions of only 80% of the A.E.C.'s low estimate and 52% of the A.E.C.'s high estimate (Table 2). Two important factors heavily influence this result. First, our projections of the costs of building nuclear plants are higher than those used by the A.E.C. both absolutely and relative to the fossil fuel alternatives. In addition, since electricity prices and demand are endogenous to the model, higher electricity prices reduce expected demand growth below the range of A.E.C. forecasts (Table 5).

An examination of the results for Case 2 indicates that these divergences are not the result of the O.P.E.C. induced rise in oil prices; in fact quite the opposite seems to be the case. In Case 2 we assume that the rapid jump in fuel prices did not occur in 1974, but rather that the real price of fossil fuels increase smoothly by 2% per year from 1973-1995. The effect of this low price scenario is to dramatically reduce new reactor installations over the next twenty years[29]. In the "NO O.P.E.C" world reactor installations are predicted to be only 48% of the low 1974 A.E.C. estimate and 31% of the high estimate. In fact the projected nuclear capacity for 1995 lies in the center of the A.E.C. 1972 (pre-O.P.E.C.) projections for 1985. Continued low oil prices combined with the dramatic increases in construction costs of nuclear facilities would have put the nuclear technology at a much less advantageous competitive position with oil fired capacity. The

[29] The projected value of demand growth in this case is 4.9%, essentially equal to the Base case and significantly less than historically growth trends. This occurs for three reasons: first, population growth is projected to be 1.02% per year in the future, where the historical value was 1.50% for the period 1947-1973. Secondly, in the no O.P.E.C. case we still incorporate the real increases in capital costs of generating plant that have occurred or are expected over the simulation period. Finally, with lower costs of the fossil fuels, less substitution to electricity at the point of end-use occurs. All three occurrances depress future demand growth below historical values.

nuclear energy industry appears to have gained substantial advantages from the higher oil prices that have helped to maintain the economic competitiveness of nuclear reactors. Without these increases, the future of the industry with five or six profitable firms would have to be seriously questioned.

We have not done an independent analysis of the minimum efficient scale for producing nuclear steam supply systems. However, our discussions with existing reactor vendors indicated that 5 reactors sales per year was required to get close to the "flat" portion of the average cost function. With the A.E.C. projections it appears that five or six firms could have been easily accommodated in the industry. Our Base Case projections indicate that probably only two could be operated profitably if competitive prices are charged for the reactor systems. Given the commanding positions of General Electric and Westinghouse the long term viability of the other reactor vendors must be brought into question. In addition, the evolution of a two firm industry may have serious repercussions for the competitiveness of the prices of nuclear steam supply systems. Possible incentives for electric utilities to be less than aggressive cost minimizers may aggravate the problem.

The other cases enumerated in the tables illustrate further the sensitivities of the future nuclear industry to other possible public policy actions. For example, the effect of stringent air quality requirements placed on coal and oil-fired facilities is to increase by 25%, or 124,000 megawatts over the base case, the installed nuclear capacity in 1995. These are commitments that would be made over the 1975-1985 time period, and this amount corresponds to an additional 12 plants of 1000 megawatts each ordered per year over the next ten years. Obviously, this is a big stimulus to the nuclear industry and given the discussion above would make another two reactor vendors viable competitors.

Cases (4a) and (4b), which incorporate increasing load factors, also result in increased reactor installations compared to the base case. This is because with flatter load curves more base load exists, and nuclear is the least cost alternative for base-load generation in most regions of the country. Consequently, increased load factors -- a likely result of peak-load pricing -- increase new reactor installations by about 2000 megawatts per year for each 10% increase in load factor obtainable over the period.

For Case No. 5, we've assumed that streamlined siting and licensing procedures reduced the length of the lead time required for nuclear reactor installation by 3 years (from 10 years to 7 years). This is an important policy instrument that has received much recent publicity, especially in the context of "one-stop" licensing where a utility could receive all necessary siting and construction permits from a single authority, in one set of proceedings. The effect of this change on the future rate of nuclear reactor installations is very interesting. From table 1 it can be seen that by 1985 there is over 25% more nuclear capacity installed compared to the Base Case. By 1995, however, the total installed nuclear capacity is essentially the same as the base case (only a 3% difference). The implication is that the reduction in lead time results in what is really a transient effect. Initially, much more nuclear capacity is installed (assuming the reactors would be available from the suppliers), but in the long run, given the average shape of today's load curve, a maximum of 40-45% of total capacity is all that can be economically proportioned as nuclear. Clearly, with flatter load curves, nuclear can economically comprise a larger share of total capacity. Cases (4a) and (4b) illustrate this. For the load shapes assumed for the Base Case and Case N° 5, 40-45% is the saturation level. Therefore, a reduction in lead times is a short-run stimulus to the industry bringing the system to long run equilibrium more quickly.

Case N° 6 illustrates the sensitivity of the system configuration to changing costs of capital. For this case the annual capital charge rate is increased from 15% to 18% in 1975 for the duration of the run, reflecting a higher cost of the debt and equity to the utility[30]. Obviously, if the cost of capital increases, then, ceteris paribus, for minimum cost operation, one should substitute more fuel costs for capital costs in the plant mix. This gets reflected in the results as a reduction in installed nuclear capacity in 1995. Part of the reduction comes about because with the higher costs of capital the average cost of electricity is higher and demand is reduced (the price in 1995 is 11% higher and demand is 10% less). Part of the response is also the result of substitution of lower capital cost but higher fuel cost fossil-fired plants for the nuclear reactors. Of the total 122Gw. reduction in nuclear capacity, 108 Gw. is accounted for by the reduction in demand, and an additional 14 Gw. is replaced with fossil-fired generation.

A final illustration of the implicit sensitivity of the future outlook is given in Case N°. 7. In this case, we increase significantly the costs of U_3O_8 (from \$8 to \$22/lb in real terms) and assume that the costs of separative work increase at the rate of inflation in nominal terms (instead of assuming declining real costs as was done in the other cases). The effect on light water reactors installation is disastrous. Total installed capacity in 1995 is only 203 gigawatts compared to almost 500 gigawatts in the Base Case. Clearly, however, under these conditions the alternative reactor concepts such as breeder reactor look much more attractive.

Finally, we examine the results for two important components of the fuel cycle -- uranium oxide demand and enrichment requirements. Once again, in all cases uranium utilization falls below the range of forecasts presented by the A.E.C. The lower demand for uranium ore

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[30] This could also reflect changes in depreciation practices for tax purposes, changes in the investment tax credit, and the use of flow-through rather than normalized accounting procedures for regulatory purposes.

predicted may have profound implications for the economics of the fast breeder reactor which can only become viable as uranium prices rise in response to depletion of uranium reserves. Since, in our analysis uranium reserves are depleted more slowly than in the A.E.C. analysis, we have the industry moving up the uranium supply function more slowly and at any point in time the associated uranium prices predicted here are below those predicted by the A.E.C. These supply functions are those on which the A.E.C. has based its cost-benefit analysis of the breeder program[31].

Separative work requirements for uranium enrichment generally fall below or in the bottom half of the range of A.E.C. (which assume plutonium recycle in LWR's) forecasts. Given the current uprating programs of existing diffusion plants there appears to be sufficient domestic capacity to meet domestic enrichment demand well beyond 1985 (except in Case N°. 5 where capacity is fully utilized in 1985). This appears to give either government or industry sufficient time to carefully evaluate alternative enrichment technologies (other than gaseous diffusion) on which research and development is going forward around the world, before making major financial committments for building additional increments of enriched capacity.

[31] See Thomas Cochran [17] for an interesting critique of the Cost-Benefit Analysis for the Fast Breeder program. In the context of this model we are pursuing an analysis of the breeder reactor alternative. We ask a somewhat different set of questions than have other analyses of this technology: Given a set of costs and technical characteristics for conventional reactors, breeder reactors and fossil fuel generators, what mix of plants would electric utilities choose and what is the implied "value" of plutonium given these demands?

TABLE 2

GENERATION CAPACITY (millions of kilowatts)

TOTAL CAPACITY	BASE CASE	CASE # 2	CASE # 3	CASE # 4a	CASE # 4b	CASE # 5	CASE # 6	CASE # 7	A.E.C. 1972	A.E.C. 1974
1980	696	686	679	684	684	695	661	696	630	655-770
1985	820	786	809	780	774	857	739	811	859	800-112
1995	1158	1207	1154	1063	1004	1194	1050	1214	1528	1280-1530
NUCLEAR CAPACITY										
1980	80	80	87	80	80	80	80	80	127-144	85-112
1985	193	176	212	201	201	252	177	147	256-332	231-275
1995	497	297	621	513	525	480	375	203	602-972	620-960

1974 ACTUAL

TOTAL CAPACITY = 474

NUCLEAR CAPACITY = 30

TABLE 3

CUMULATIVE UTILIZATION OF URANIUM (millions of tons U_3O_8)

and

SEPARATIVE WORK DEMAND (separative work units in millions)

URANIUM UTILIZATION	BASE CASE	CASE # 2	CASE # 3	CASE # 4(a)	CASE # 4(b)	CASE # 5	CASE # 6	CASE # 7	A.E.C. 1972	A.E.C. 1974
1980	.071	.071	.072	.071	.071	.070	.070	.068	N.A.	.092-.115
1985	.179	.178	.191	.182	.182	.196	.176	.157	N.A.	.251-.307
1995	.788	.572	.872	.794	.887	.836	.649	.482	N.A.	.869-1.248
SEPARATIVE WORK DEMAND										
1980	8.52	8.52	9.31	8.52	8.52	8.52	8.52	7.45	14.7-17.4	11.3-14.2
1985	20.6	18.8	22.6	21.4	21.4	26.9	18.8	15.7	25.6-35.8	23.0-28.5
1995	53.0	31.7	66.2	54.7	60.0	51.2	33.9	21.6	50.3-81.1	49.4-79.6

T A B L E 4

PRICES AND RATE BASE

(¢/kilowatt-hour and billions of dollars respectively, both in nominal terms)

PRICE OF ELECTRICITY	BASE CASE	CASE # 2	CASE # 3	CASE # 4 a	CASE # 4b	CASE # 5	CASE # 6	CASE # 7	A.E.C. 1972	A.E.C. 1974
1 9 8 0	3.75	3.33	4.07	3.73	3.72	3.75	4.16	3.80	N.A.	N.A.
1 9 8 5	4.50	4.13	4.80	4.38	4.35	4.80	4.89	4.58	N.A.	N.A.
1 9 9 5	6.60	5.83	7.53	6.52	6.50	6.68	7.61	7.10	N.A.	N.A.
CAPITAL STOCK										
1 9 8 0	238	229	232	232	232	237	220	237	N.A.	N.A.
1 9 8 5	386	344	391	368	365	442	330	366	N.A.	N.A.
1 9 9 5	956	870	1053	915	901	945	823	887	N.A.	N.A.

1 9 7 4 A C T U A L

PRICE OF ELECTRICITY = 2.30¢/Kwh.
CAPITAL STOCK = $127.4 billion

TABLE 5

ELECTRICITY DEMAND (including losses)
(Millions of kilowatt-hours)

ELECTRICITY DEMAND	BASE CASE	CASE # 2	CASE # 3	CASE # 4a	CASE # 4b	CASE # 5	CASE # 6	CASE # 7	A.E.C. 1972	A.E.C. 1974
1980	2656	2559	2597	2656	2656	2656	2427	2636	2810	2820-3320
1985	3225	3067	3095	3225	3225	3174	2883	3183	3960	3520-5000
1995	4948	4953	4580	4948	4948	5041	4452	5001	7060	5700-8390

1974 ACTUAL (Estimated from Actual Sales Assuming 10% Losses)

ELECTRICITY DEMAND = 1862

E. CONCLUSIONS

In this paper we have presented an engineering-econometric simulation model of electricity supply, demand and price regulation. This model has been utilized to analyze the derived demands for nuclear reactors and nuclear fuel cycle requirements, the two major components of the U.S. nuclear energy industry, as they are affected by alternative public policies and alternative expectations of fuel and construction costs.

The main conclusions of these analyses are:

1. The derived demand for nuclear reactors in the utility industry is likely to be considerably below recent A.E.C. forecasts.

The main reason for this is that future demand growth will likely be considerably less than historical growth trends -- averaging somewhere between 4.5% and 5.5% per year between now and 1995. Even without the recent sharp increases in fuel costs demand growth would be below historical levels, but were it not for these same increases the long-run economic viability of nuclear reactors as a competitive generating alternative would indeed be questionable. In the "No O.P.E.C." scenario it is unlikely that the industry could sustain more than two reactor vendors in the long run.

2. Due to the reduction in expected nuclear growth, the uranium ore and separative work required to fuel these reactors will be below or near the low end of the A.E.C.'s recent projections.

Our results indicate that, unless policies are adopted that reduce the required lead time for nuclear generation facility installation, the planned government capacity for separative work of 27 million SWU's per year would be sufficient to meet the nation's needs for the period up to and slightly beyond the mid-1980's. With lead times reduced to 7 years, we could be taxing these facilities for domestic enrichment

ment requirements by 1985.

3. The effect of stringent air quality regulations applied to coal and oil-fired generation facilities is to increase the competiveness and derived demand for nuclear reactors.

The effect could be as great as a 25% increase in capacity installed nuclear by 1995. Conversely, greatly reduced air quality regulations are a depressant to nuclear growth.

4. Peak load pricing policies, if effective in reducing growth in peak loads relative to total kilowatt-hour requirements, are favorable to the nuclear industry.

A 10% increase in system load factor could mean as much as 2000 megawatts per year additional nuclear installation.

5. Rapidly increasing costs of uranium fuel and separative work on top of the recent increases in nuclear plant capital costs could have large unfavorable effects on the economic outlook of nuclear reactors.

Under these conditions the advanced reactor concepts must be considered; however, even when considering these alternatives, we would not expect nuclear to become a greater proportion than 40-45% of installed capacity unless action is taken to reduce the peak to average load requirements.

All things considered, it appears that purely on economic grounds and ignoring capital shortage problems resulting from state regulation of electricity rates, the future of the U.S. nuclear energy industry is less bright than the most recent government forecasts indicate. The evolution of the industry will be slower and fuel cycle requirements less than federal energy policy planners have indicated. Among other things this buys additional time for careful consideration of alternative technologies and institutional structures for bringing on additional increments of diffusion capacity and the introduction of commercial breeder reactors.

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APPENDIX A:

ESTIMATED RELATIONSHIPS FOR 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) $$SKVAT = \underset{(2.20)}{6.75 \times 10^5} + \underset{(19.8)}{712.5}\ ESRC + \underset{(12.4)}{523.2}\ ESLLP \qquad R^2 = .91$$

DISTRIBUTION

(3) $$SKVAD = \underset{(40.2)}{485.4}\ ESRC + \underset{(2.47)}{9.46}\ AREA \qquad R^2 = .83$$

(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) $$NMD = \underset{(77.3)}{1.006}\ NRCC + \underset{(9.1)}{14.0}\ NLLPC + \underset{(2.57)}{7.28}\ NPUBC \qquad R^2 = .99$$

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
NPUBC = number of public authorities customers.

TABLE A-1

ESTIMATED RELATIONSHIPS FOR TRANSMISSION AND DISTRIBUTION OPERATION AND MAINTENANCE COSTS

(t-statistics in parentheses)

$$OMT = \underset{(6.53)}{1.75\ NRCC} + \underset{(6.33)}{199.1\ ESRC} + \underset{(4.78)}{92.11\ ESLLP} \qquad R^2 = .90$$

$$OMD = \underset{(89.2)}{18.80\ NRCC} + \underset{(3.65)}{159.8\ NLLPC} \qquad R^2 = .97$$

$$OMG = \underset{(66.9)}{26.05\ NRCC} + \underset{(11.2)}{908.3\ NLLPC} \qquad R^2 = .96$$

OMT = Operation and maintenance expenditures for transmission (in 1967 dollars)

OMD = Operation and maintenance expenditures for distribution (in 1967 dollars)

OMG = General and administrative overhead expenses (in 1967 dollars)

TABLE A-2

APPENDIX B:

RESIDENTIAL-COMMERCIAL AND INDUSTRIAL DEMAND RELATIONSHIPS

Tables B-1 and B-2 give the estimated equations for the residential-commercial sector total energy demand and fuel choice relationships.

Tables B-3 to B-5 give the corresponding equation system for the industrial sector, including the location "state-split" equation.

$$\mathrm{LOG}\left(\frac{\text{energy}}{\text{population}}\right) = A + B * \left(\frac{\text{personal income}}{\text{population}}\right) + C * (\text{minimum temperature})$$

$$+ D * \left(\frac{\text{population}}{\text{area}}\right) + E * (\text{average price}) + F * \mathrm{Log}\left(\frac{\text{energy }(-1)}{\text{population }(-1)}\right)$$

RANGE = 1968 - 1972 R^2 = .927 F(5/239) = 622

COEF	VALUE	T-STAT
A	2.91	5.21
B	2.89e-5	1.77
C	-.0012	-2.00
D	9.73e-6	2.34
E	-4.88e4	-3.83
F	.839	26.4

RESIDENTIAL-COMMERCIAL

TOTAL DEMAND

TABLE B-1

$$\mathrm{LOG}\left(\frac{gas}{electricity}\right) = A + C * \mathrm{Log}\left(\frac{gas\ price}{electricity\ price}\right) + D * (maximum\ temperature) + F * (minimum\ temperature) + H * \mathrm{Log}\left(\frac{gas\ (-1)}{electricity\ (-1)}\right)$$

$$\mathrm{LOG}\left(\frac{oil}{electricity}\right) = B + C * \mathrm{Log}\left(\frac{oil\ price}{electricity\ price}\right) + E * (maximum\ temperature) + G * (minimum\ temperature) + H * \mathrm{Log}\left(\frac{oil\ (-1)}{electricity\ (-1)}\right)$$

RANGE = 1968 - 1972 R^2 = .954 F(7/482) = 1462

COEF	VALUE	T-STAT
A	.07	.56
B	.208	1.65
C	-.137	-3.29
D	-.0015	-1.04
E	-.0022	-1.58
F	-.0022	-1.74
G	-.0063	-3.19
H	.897	66.0

RESIDENTIAL-COMMERCIAL

FUEL-SPLIT

TABLE B-2

LOG (ENERGY) = A + B * LOG (AVERAGE PRICE) + C * LOG (VALUE ADDED) + D * LOG (PRICE OF CAPITAL SERVICES)

RANGE = 1950 - 1972 R^2 = .961 F(3/19) = 182 DW = 1.86

COEF	VALUE	T-STAT
A	14.0	4.11
B	-.239	-1.33
C	.742	15.08
D	-.270	-1.89

First Order Auto Correlation Coefficient = .337

INDUSTRIAL

TOTAL - DEMAND

TABLE B-3

$$\mathrm{LOG}\left(\frac{\text{ENERGY IN STATE } i}{\text{ENERGY IN CALIF}}\right) = A * \mathrm{LOG}\left(\frac{\text{AVERAGE PRICE IN } i}{\text{AVERAGE PRICE IN CALIF}}\right)$$

$$+ B * \mathrm{LOG}\left(\frac{\text{POPULATION IN } i}{\text{POPULATION IN CALIF}}\right)$$

$$+ C * \mathrm{LOG}\left(\frac{\text{ENERGY } (-1) \text{ IN } i}{\text{ENERGY } (-1) \text{ in CALIF}}\right)$$

RANGE = 1968 - 1972 $R^2 = .984$ F(2/237) = 7506

COEF	VALUE	T-STAT
A	-.156	-4.92
B	-.047	3.24
C	.927	54.1

INDUSTRIAL

STATE - ALLOCATION

TABLE B-4

$$\mathrm{LOG}\left(\frac{gas}{electricity}\right) = A + D * \mathrm{LOG}\left(\frac{gas\ price}{electricity\ price}\right) + E * \mathrm{LOG}\left(\frac{gas\ (-1)}{electricity\ (-1)}\right)$$

$$\mathrm{LOG}\left(\frac{oil}{electricity}\right) = B + D * \mathrm{LOG}\left(\frac{oil\ price}{electricity\ price}\right) + E * \mathrm{LOG}\left(\frac{oil\ (-1)}{electricity\ (-1)}\right)$$

$$\mathrm{LOG}\left(\frac{coal}{electricity}\right) = C + D * \mathrm{LOG}\left(\frac{coal\ price}{electricity\ price}\right) + E * \mathrm{LOG}\left(\frac{coal\ (-1)}{electricity\ (-1)}\right)$$

RANGE = 1968 - 1972 R^2 = .945 $F(4/730)$ = 3130

COEF	VALUE	T-STAT
A	-.231	-4.31
B	-.354	-6.80
C	-.540	-8.23
D	-.301	-7.13
E	-.856	58.9

INDUSTRIAL

FUEL - SPLIT

TABLE B-5

APPENDIX C: INPUT DATA FOR BASE CASE SIMULATION

FUEL PRICES*
CURRENT DOLLARS

	Coal ($/ton)	Nat. Gas** (¢/MCF)	Oil ($/Bbl)
1975	11.00	155	8.18
1980	16.00	180	16.44
1985	21.00	210	22.69
1990	28.50	274	30.03
1995	36.00	360	39.25

ECONOMIC GROWTH

Real G.N.P. Growth
Real Value-added in Manufacturing
Real Personal Income

=

-2.1%	1974
0.0%	1975
3.8%	1976-1995

INFLATION RATE

Non-Farm Wholesale Price Index

12.5%	1974
8.5%	1975
5.5%	1976-1995

POPULATION GROWTH

1.02% per year 1974-1995

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*Values in table are Average National prices: natural gas and oil at the wellhead, coal at the minemouth. Transportation markups are added on for each region in the model. It is assumed that the average wellhead price for natural gas is 40¢/MCF less than new contract prices shown in Table.

**The natural gas price shown corresponds to the average contract price for new intrastate sales. This price is used in the model to determine the merit order of existing natural gas plants for generation purposes. The model is constrained to build no new natural gas plants in the simulation.

UNIT CAPITAL COSTS ($/kilowatt)

(in current dollars)

	Coal	Oil	Natural Gas	Nuclear	Gas Turbines
1975	338	264	248	428	134
1980	472	384	342	662	179
1985	643	556	483	883	229
1990	881	781	694	1172	288
1995	1144	1025	916	1560	362

	COSTS OF U_3O_8 ($/pound) (Current Dollars)*	COSTS OF SEPARATIVE WORK ($ SWU) (Current Dollars)*
1975	8.83	40.71
1980	11.12	43.99
1985	14.54	48.54
1990	19.00	53.69
1995	24.83	59.24

ANNUAL CAPITAL CHARGE RATE

15% 1974 - 1995

*These values, when deflated, are commensurate with those reported in refs. [20], [21].

LOAD FACTORS BY REGION

New England	.634
Middle Atlantic	.638
East North Central	.661
West North Central	.519
South Atlantic	.624
East South Central	.753
West South Central	.535
Mountain	.540
Pacific	.657