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MIT

The electric utility industry consumes over 26% of the primary energy inputs in the United States today. Electricity's share in primary energy consumption has been steadily increasing over time and most energy policy planners expect this trend to continue or even accelerate. The industry is the largest consumer of coal in the United States, the only consumer of uranium and an important consumer of natural gas and fuel oil. As a result, the future of primary fuel consumption in the U.S. depends critically on the growth rate of electricity demand and the choice of fuels to be used to satisfy it.

In this paper we make use of the MIT Regional Electricity Model (REM) to examine the course of future electricity consumption and fuel utilization by the electric utility industry for the United States as a whole as well as for each of nine Census regions in the U.S. The paper proceeds in the following way. First, we briefly sketch out the structure of the MIT Regional Electricity Model that has been used for the analysis. Second, we specify a base case and simulate the model from 1975-1995 to obtain estimates of electricity demands and fuel utilization. Next, we examine the effects of changes in the estimated costs of coal and uranium on electricity demand and fuel utilization. Finally, we compare these projections with other published projections that have been made for 1985. Comparable projections beyond 1985 are not available.

Our major conclusions are the following:

1. Electricity demand is projected to grow at an annual rate of 5.0% per year between 1974 and 1985 and at a rate of 4.6% per year for the entire

simulation period (1974-1995) for the U.S. as a whole based on actual 1974 data and simulation results for the model beyond 1974. These growth rates reflect the very low growth in 1974 and 1975 due to the downturn in economic activity and the rapid rise in electricity prices. There is substantial regional variation in these growth rates. Electricity demand grows in some regions at a rate as low as 3% per year and in other regions at a rate as high as 7.8% per year. Pessimistic projections for the prices of coal and uranium reduces the average annual growth rate in electricity consumption for the U.S. as a whole to as little as 4.0% per year.

2. Nuclear energy is the fastest growing source of electricity. In 1974 nuclear energy provides less than 10% of total electricity generation. This figure rises to 37% in 1985 and to 51% in 1995. In the base case uranium oxide demand increases at a rate of 15% per year over the 1974-1995 period. There is fairly substantial regional variation in nuclear's penetration however. For 1985 one region has only 19% of its electricity generated by nuclear plants while another region has over 63% generated in this way. By 1995 nuclear's share varies from a low of 9% to a high of 76% among the nine regions of the U.S.[1/]

3. Although coal's share in electricity generation falls over the period, actual coal consumption increases over the period. For the U.S. as a whole coal consumption (on a BTU basis) increases at a rate of 2.74% per year for the period 1974-1985, and by 2.8% per year over the entire period. Once again there appears to be substantial regional variation

[1/] This excludes the New England region which will be discussed below.

in these figures. In addition, since lower BTU coal is likely to be exploited in the future, coal consumption measured in tons is likely to increase at a higher rate than is indicated by the BTU consumption figures.

4. Consumption of oil and natural gas, the fossil fuels of greatest policy concern to U.S. energy policy planners falls throughout the period. Increased oil and natural gas prices lead to a reduced utilization of existing plants and few commitments of new plants during the period under examination. For the period 1974-1985 natural gas and oil consumption declines at a rate of 3.5% per year. Over the longer period 1974-1995 oil and natural gas consumption declines at a rate of 3.62% per year.

5. Changes in expected coal and uranium prices have important effects on both total electricity demand and fuel utilization. An increase of 20% in the coal price from the base case assumption reduces total electricity consumption only slightly, but reduces coal utilization by 34% by 1995. A tripling of the uranium price series from the base case assumption (a possibility that now seems to be far from remote) reduces electricity consumption by 8% by 1995 and reduces nuclear energy generation from 50% of the total to 34% of the total. Since current market prices for uranium are above our base case estimates, the rapidly rising price of uranium may well result in a substantial reduction in nuclear energy's penetration.

The MIT Regional Electricity Model (REM)

The model used for the analysis is a regionalized engineering econometric simulation model of U.S. electricity supply and demand.

It integrated within a single simulating framework the following features:

1. A regionalized U.S. descriptive model for capacity expansion and electricity production based upon the normative principles guiding actual industry behavior
2. A set of dynamic demand functions (econometrically estimated) for:
   a. industrial energy consumption and
   b. residential-commercial energy consumption

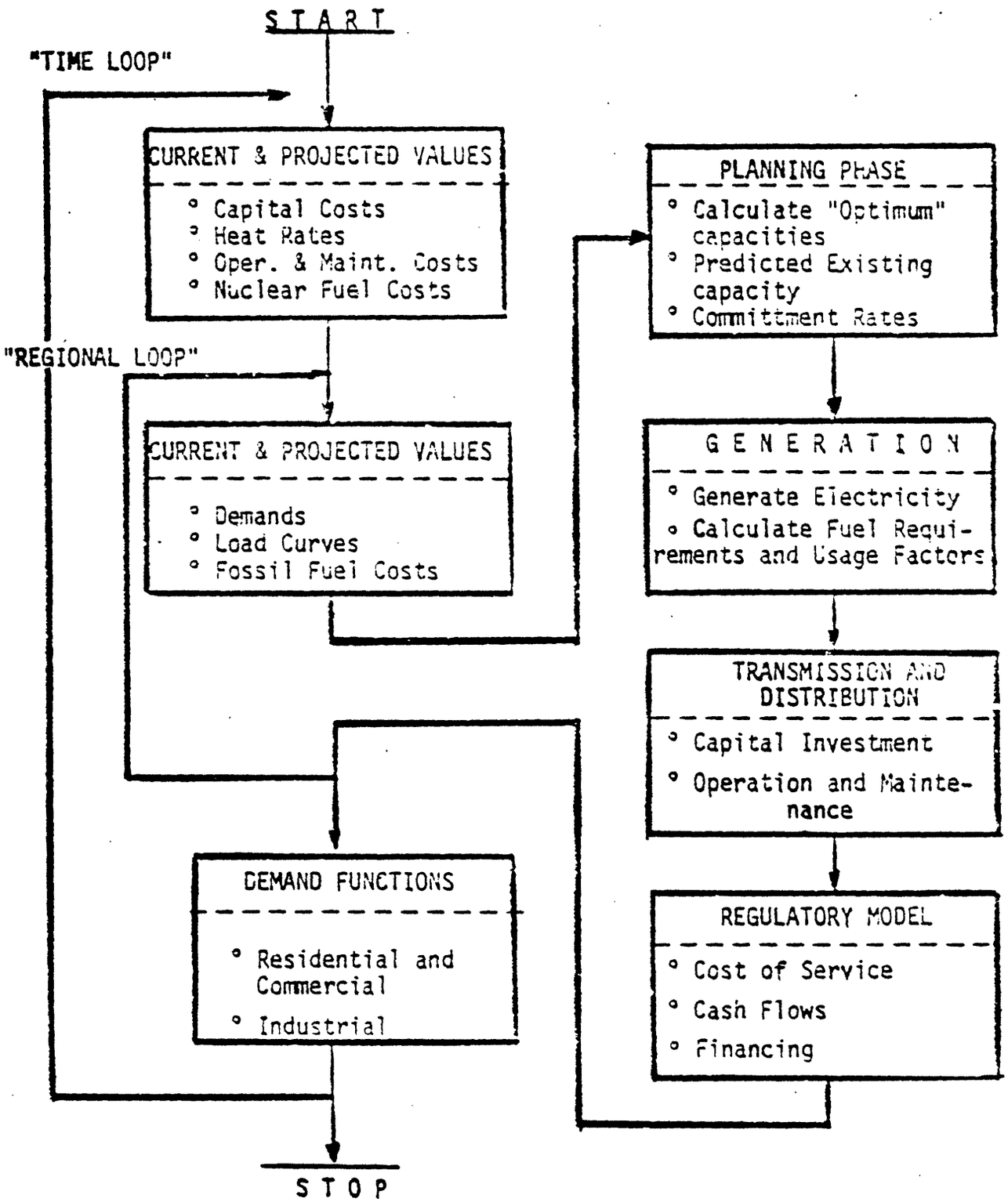
   encompassing simultaneously the substitution between alternative energy sources as well as the more conventional economic growth, income, population, and price effects on total energy consumption
3. A set of econometrically estimated functions relating transmission and distribution physical equipment needs, capital expenditures, and operation and maintenance costs to the configuration of demand and other characteristics of the load area
4. A set of financial accounting relationships that combine the system-derived costs (generation, transmission, and distribution) with the tax, rate-making, and accounting rules for the electric utilities. These relationships provide electricity prices, flows of funds, and financial variables used in other parts of the overall model

5. A set of cost and material balance relationships for the nuclear fuel cycle, encompassing the calculation of raw uranium ore requirements, fuel processing, enrichment, fabrication, and reprocessing needs and costs.

The novelty of the model stems not so much from the way in which any of the individual portions of the model are structured, but rather from scope and breadth of consistency maintainable from the integration of submodels of distinct but interrelated elements of the industry. With the interconnection of these components, we obtain a very robust, yet consistent, analytical device.

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.[1/] Here we attempt only to lay out the basic structure of each part of the model to convey the methodological concepts employed and how the three components of the model interrelate in the overall simulation framework.

[1/] See Refs. [1], [2], [3], [4], [8].



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

a. The Supply Submodel - Investment Decisions

Geographically, the supply model consists of nine regions corresponding to the nine census regions of the U.S.[1/] Each region is treated like a single utility firm. Within each region the model chooses the construction mix of eight plant alternatives with hydro supplied exogenously,[2/] and operates existing plant so as to minimize the cost of production.

Firm 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, and are introduced in order to evaluate the effects of alternative public policies and to perform sensitivity analyses.

Firm expectations about demand are treated differently. While the model incorporates a set of econometric demand equations to generate actual 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

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[1/] The eight plant alternatives are:

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;

[2/] Another regional breakdown sometimes used in electric utility analysis corresponds to the nine regional reliability councils comprising the National Electric Reliability Council. These regions are not coterminus with the census region used here, nor do the regional boundaries, in general, coincide with state boundaries. To facilitate the use of state statistics, on consumption, fuel prices, and demography, and still maintain regionality in the analysis, we chose to use the census regions. The census regions are defined in Table A-2 of the appendix.

the electric utilities employ such a sophisticated analysis of the own-price and cross-price elasticities to project demand. Rather, we specify their projections of demand by exponentially weighted moving averages with a trend adjustment.[1/] As a result of this approach, actual electricity consumption in each period will generally be different from projected 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. 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.

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 model includes a typical load duration curve for each region of the United States. A load duration curve indicates what percentage of the time a given percentage of the region's peak capacity will be utilized. This curve, together with expected total kwh demand, yields a value for expected peak demand. As electricity cannot be readily stored, projected peak demand, plus a margin of reserve in excess of it, identifies the amount of required capacity which, after adjusting for existing capacity, expected additions, and retirements (plants are retired after forty years) determines the amount of new capacity which must be built.

[1/] 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 [16].

The model incorporates different lead times for different types of plant. Nuclear plants require a lead time of ten years, fossil fueled plants a lead time of five years, and gas turbines and internal combustion units a lead time of 2.5 years. Hydroelectric plants have a lead time of six years. The amount of hydroelectric capacity which is constructed in each period does not result from the investment decision but rather is an exogenous input.

The model moves through time in half-year increments from 1947 to 1997. During each time period the investment decision must be carried out on these three future time horizons. Because the actual demands which are observed will, in general, differ from the demands which were expected, expectations concerning future loads will change, so that a given plant type may be built either because it is the optimal economic choice among all the plants, or else because it is the optimal choice among those plants available given the constraints on lead times.

To be specific, consider the problem of choosing an optimal new plant mix among, say, three available alternatives. The expected levelized average cost of a plant can be written as:

$$AC = FC/U + VC$$

AC = levelized average costs, in cents per kwh,
FC = fixed costs such as capital charges and fixed operation and maintenance expenditures, in cents per year,
VC = variable costs such as fuel costs and variable operation and maintenance expenditures, in cents per kwh,
U = utilization factor, in hours per year.

The average cost curves of the three plants are graphed in Figure 1, where it is supposed that variable costs vary inversely with fixed costs. An optimal program for plant expansion requires that the new plant be

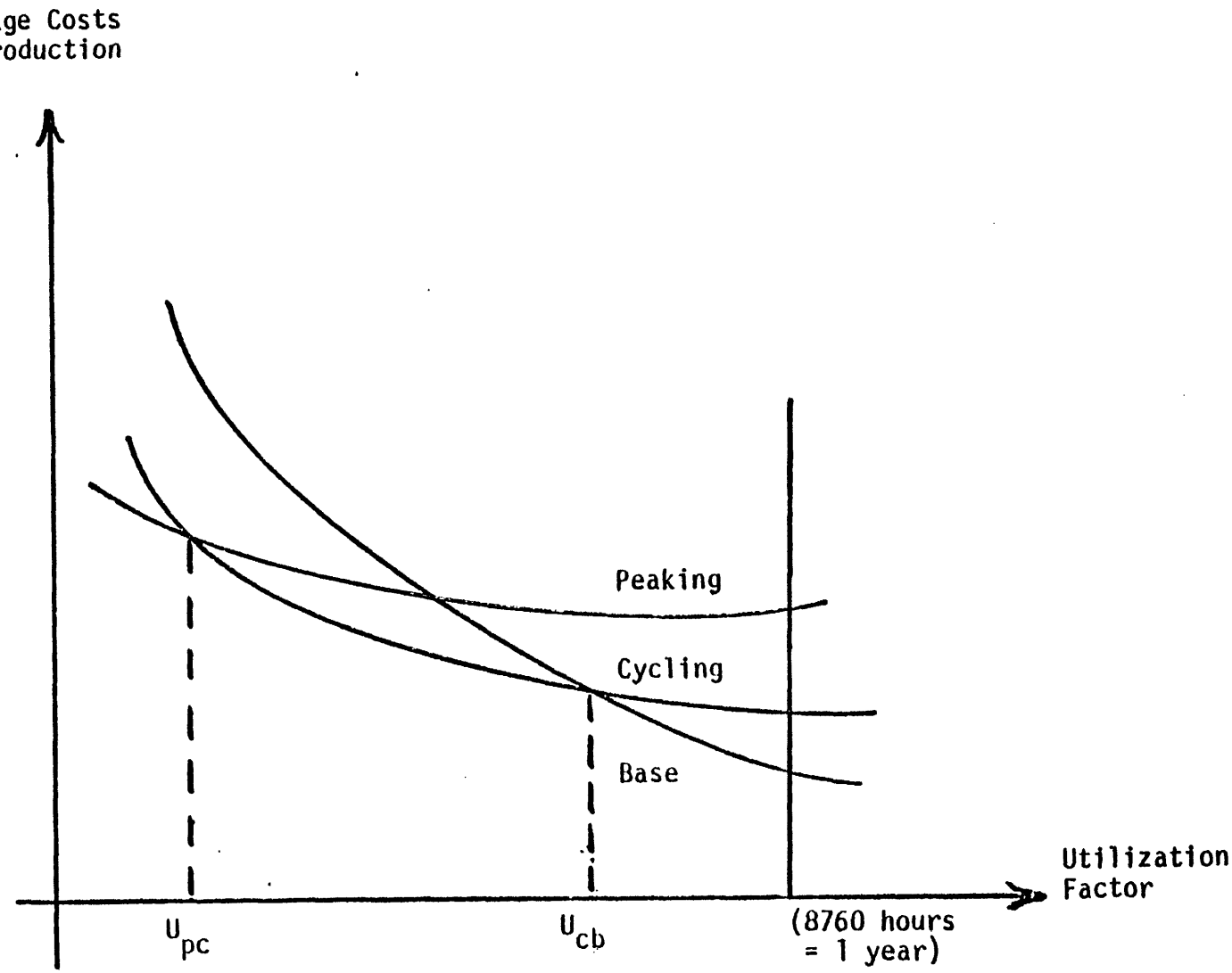
Average Costs
of Production
Peaking
Cycling
Base
Utilization
Factor
U_{pc}
U_{cb}
(8760 hours
= 1 year)

Figure 1

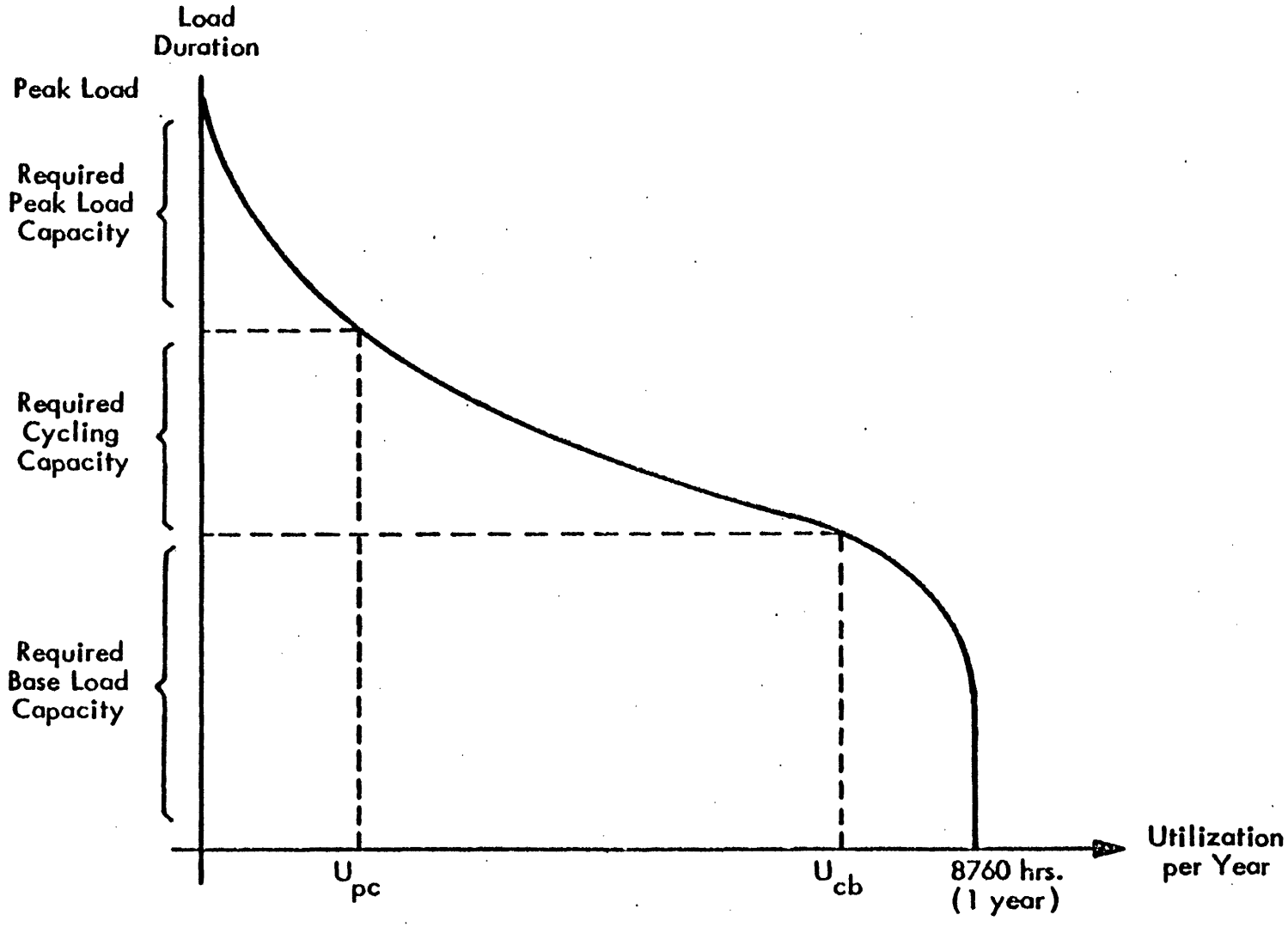
Load
Duration
Peak Load
Required
Peak Load
Capacity
Required
Cycling
Capacity
Required
Base Load
Capacity
U_{pc}
U_{cb}
8760 hrs.
(1 year)
Utilization
per Year

FIGURE 2

built so as to minimize the levelized annual cost per kwh. Equating the expressions for average costs of the three plants yields the points of intersection U_{pc} and U_{cb}. These are projected onto the load curve to obtain the optimal amounts of each type of plant in the final plant mix (Figure 2). These optimal amounts, less projected existing capacity, determine the amount of each plant which should be built. Note that if the average cost curve for one plant lies entirely above those of the other plants, there will only be two points of intersection, and only two types of plant will be built.

b. The Supply Submodel - Production Decisions

In any particular year a given amount and mix of plants exist and decisions must be made regarding how best to generate electricity. The production decisions are made so as to minimize variable cost; that is: considering only the fuel costs and variable operation and maintenance expenses associated with each plant. Capital charges and other fixed expenses are sunk costs and so are disregarded. The plant alternative which is least expensive in this respect is placed at the top of the "merit order," with the other alternatives following according to their variable costs. The total kwh demand is met by moving down the merit order, generating the maximum possible amount of electricity from any particular plant alternative before moving on to lower ranked alternatives. The available output of each plant is equal to capacity in kilowatts, times 8760 hours per year, times the duty cycle. The duty cycle is a factor between zero and one which is meant to take into account expected and unexpected outages due to maintenance operation.

c. The Supply Submodel - Transmission and Distribution Investments

The transmission and distribution requirements to deliver the generated output to the final consumer are broken into six components and costed separately. The six equipment needs are separated into: 1) structure miles of transmission capability; 2) pole miles of primary distribution capability; 3) KVA substation capacity at the transmission level; 4) KVA substation capacity at the distribution level; 5) the KVA capacity of line transformers; and 6) the number of meters. Each of these physical quantities is statistically 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.) through the use of regression techniques.

Operation and maintenance costs of the transmission and distribution system depend upon the amount and configuration of the installed equipment. 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 load characteristics of a service area. In the model regression techniques are used to estimate the latter set of interdependencies to determine and allocate these costs.[1/]

[1/] The estimated functions for both equipment requirements and O & M expenses, based on time-series cross section data (1965-1971), are reported in Baughman and Bottaro [1].

d. 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 is utilized 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 is utilized to divide total energy consumption into oil, natural gas, and electricity consumption.[1/]

For the industrial sector a similar formulation is utilized. Total industrial 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, estimated using cross-sectional data, is used to determine total energy consumption in each of the states. Finally, a set of fuel split equations is utilized to allocate the total energy

[1/] Marginal electricity prices are used in order to minimize distortions arising from the declining block structure of electricity rates.

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 to allow us to disentangle total energy price effects from locational effects.[1/]

In Table 1 we report the average 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 sample values of the variables in each equation.

[1/] 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, this results because 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 of -0.20. In a national context, it obviously would be a serious error to confuse the two effects.

e. Determining the Price of Electricity with the Regulatory Financial Submodel[1/]

The price of electricity used in the demand model is the endogenously computed price of electricity, lagged one period. This price is computed in the regulatory-financial submodel, which sets that price which will yield a predetermined rate of return on the utilities rate base. Included in the rate base are capital expenditures for generation, transmission, and distribution equipment.

The allowed rate of return on the rate base is a weighted average of the cost of capital to the utilities. In the model, capital expenditures can be financed in any of four ways which are, ranked according to desirability: debt, preferred stock, common stock, and the State Power Authority - a lender of last resort. The amount of financing which can be provided by each of the first three alternatives is constrained by rules of prudent money management. The inputed costs of each of the alternatives are given in Table A-9, along with the constraints. These determine the cost of capital to the utilities which, together with capital expenditures adjusted for depreciation and taxes, yields the regional average price for electricity. From this, two prices for electricity are computed in each region, one of which is the price to the industrial sector, the other of which is the price to the residential and commercial sector. The ratio of the two prices depends on the difference of the costs in supplying the two sectors, this difference being due to expenditures on transmission and distribution equipment.

[1/] See references 8 and 9 for a detailed discussion of the regulatory financial submodel.

f. Forecasts 1975-1995: A Base Case

The model makes separate forecasts of major variables for each of the nine census regions, so that most data must be in regional format. The prices of fossil fuels play a major role in both the investment and production decisions, and are crucial to the demand model.

Fossil fuels are assumed to be available in any amount at a single price, which varies from period to period and across regions. Prior to 1975, approximations to historical prices are used. Subsequently, the assumptions of the Base Case are as follows:

In the case of coal, the model reads a national average minemouth price and then for each region adds to it an amount representing the cost of transportation to that region. In 1975, the price of medium BTU content coal is taken to be $14.50 per short ton. As the model assumes the immediate introduction of stack gas desulfurization, this should be regarded as a price for high sulfur coal. Withdrawal of this assumption without the removal of air quality restrictions would lead to a markedly higher price for coal. This price is escalated at an average rate of 6.7% per year to obtain future prices for coal. Inflation is assumed to be 5.5% per year throughout the model, so that this amounts to an increase of a little more than 1% per year in real terms, due to increased labor costs, mine depletion, etc. Regional differences reflect historical trends, adjusted according to current expectations.

The case of oil is similar. The national average price of oil at the wellhead is taken to be $8.18 per barrel in 1975. This was obtained by averaging a marginal price of $11.00 per barrel with the controlled

price of less than six dollars per barrel. The schedule of future prices has the average price approaching the marginal price until 1985, after which time it is equal to it. The marginal price stays constant in real terms throughout the period from 1975 to 1995. Regional prices are derived by adding the estimated costs of transportation and refining to the national price.

Natural gas is treated somewhat differently. The price of gas in 1975 is 155 cents per mcf, which corresponds to the average contract price for new intrastate sales. The great uncertainty surrounding the natural gas industry precludes any strong forecast about the future. The model adopts a neutral position, using a price series which insures that total gas consumption does not change appreciably over time. Note that, while this price is used to determine the ranking of existing gas plants in the merit order, it does not enter into the investment decision, for the model does not allow any new base load or intermediated load gas plants to be built. Tables A-3 through A-5, which give the regional prices for all fossil fuels for 1975, 1985, and 1995, offer a more precise statement of the regional spreads.

The costs of uranium oxide and separative work used in the Base are given in Table A-6. We view these figures as representing a floor on future uranium and enrichment costs. The flow rates of fuel and fuel cycle costs for each of the three reactor types treated in the model were derived from information obtained from ERDA.

Projected capital costs for each of the various plants are necessary to the investment decision. The costs used in the model were obtained by surveying a large number of utilities throughout the United States.

Costs for coal and oil burning plants include scrubbers. It is assumed that these will be available in the near future at a cost of about $50.00/kw, which falls in the middle of the range of current estimates. Unit capital costs for New England are given in Table A-7, and the multipliers used to derive prices for the other regions from these are given in Table A-8 (15).

Values for a number of macroeconomic variables such as GNP, personal income, value added in manufacturing, population, and the rate of inflation are used in the demand model. The rate of growth of real GNP is taken to be 3.8%, that of value added to be 4%. The long-run rate of inflation is 5.5%. State growth rates for personal income were estimated from data, while those for population were derived from projections made by the Survey of Current Business (11).

g. Simulation Results

Model simulation results are presented in Tables 3 through 6 and 16-20. The amounts consumed of various fuels in each region and for the U.S. as a whole are given for 1980, 1985, 1990, and 1995, measured in BTU's. Coal consumption is expressed in tons using the conversion factors indicated. Uranium oxide consumption is determined within the model based on a set of technical coefficients on fuel consumption and enrichment. Oil and natural gas consumption are expressed in terms of barrels of oil. Table 2 gives actual figures for 1974 and Tables 7, 8, 9 present regional growth rates for 1974-1985 and 1974-1995. Tables 16-20 present the associated kwh generation by region and by fuel type.

In the simulation, the average annual rate of growth of demand for electricity was 5.0% from 1974 to 1985, and 4.5% from 1974 to 1995. Over the twenty year period, the mix of fuels used for generation purposes underwent considerable change. The dominant factor is the shift to nuclear plants. Nuclear generation accounts for only 6.1% of total BTU consumption in 1974, but by 1995 this fraction has risen to 51.1%. These results of course do not reflect the effects of a possible moratorium on nuclear power. For further discussion of this possibility see reference (7).[1/]

[1/] Light water reactors may be run on either a uranium or a plutonium fuel cycle. Plutonium is produced by reprocessing the spent fuel output from reactors run on either cycle. We assume that the only reprocessing capacity which will be available is that which is currently planned, amounting to 2250 metric tons in 1982 and 3750 tons in 1987 and afterwards. The amount of available reprocessing capacity and the amount of spent fuel available for reprocessing together determine the supply of plutonium. This supply is then allocated first to existing light water reactor capacity and then to new capacity. Although we do not include consumption of plutonium in the results presented, 13% of the light water reactor capacity installed in 1995 is run on a plutonium fuel cycle.

The rise in the use of nuclear fuels is largely at the expense of coal. The percentage of BTU consumption attributed to coal falls from 45.0% in 1974 to 32% in 1995. In the same year our industrial coal demand model indicates that upwards of 75 million tons are required to supply other industrial demands. Current production of eastern coal is about 550 million tons per year but, allowing for mine depletion, base production from this region in 1985 may be expected to be substantially lower than this, perhaps as little as 375 million tons (see ref. (10)). After including exports, this leaves a sizable difference to be made up with western coal. The difference in tons is probably even larger than that predicted here since the average BTU content of western coal is lower than that for eastern coal. The required supply of western coal may, however, be subject to a number of constraints in the short run, including possible shortages of transport facilities, mining machinery, and manpower.

The attendant difficulty in forecasting the price and availability of coal suggests that some sensitivity analysis is in order. Variations in the price of coal influence the demand for electricity, as the two energy forms compete to supply industrial demand as well as the choice of fuel for generating electricity and the price of electricity, so that two effects must be measured. In Tables 10 and 11 the effects of variations in coal prices are presented. The long-run effect of variations in coal prices on the demand for electricity appears to be slight, whereas the long-run effect on the amount of coal consumed by utilities is marked. A 20% increase in the expected price of coal reduces coal consumption in 1995 by 34%.

Recent increases in the price of uranium and continuing uncertainties about future uranium prices call for analysis of the effects of increased uranium prices on electricity demands, generation from nuclear facilities, and consumption of uranium oxide. In Tables 12, 13, and 14 we report the effects of a doubling and a tripling of the price of uranium oxide. Tables 12 and 14 indicate that there is a substantial substitution of coal for nuclear that arises from increases in the price of uranium of such magnitudes. In 1995 a doubling of the price of uranium reduces the nuclear share of generation from 50% to 41% and a tripling of the price reduces this share further to 35%. Increasing costs of other parts of the nuclear fuel cycle such as enrichment and reprocessing may reduce nuclear's share even further.

Table 13 indicates that increases in the price of uranium oxide of these orders of magnitude also effects the demand for electricity. For 1985 a tripling of the price of uranium reduces electricity demand by 4% and in 1995 by 8%.

The short-run effects of a sudden and dramatic change in uranium prices and uranium price expectations is also of interest. Examining Table 12 we see that in 1985 uranium consumption is reduced below the base case for increases of two and three times in the price of uranium. The reduction is modest reflecting the fact that most of the plants on line in 1985 were either operating or under construction when the price expectations change in 1975. Coal consumption in 1985 actually declines slightly reflecting the fact that part of the reduction in electricity demand in the short run must be accommodated by a reduction in commitments and utilization of coal burning plants due to differences in construction lead times among the plant alternatives.

Regional Results

While the national trend away from oil and natural gas and toward nuclear energy is generally reflected in the individual regions, differences in electricity prices, fossil fuel costs and expected changes in population and aggregate economic activity yield considerable differences among regions. For the 1974-1995 period regional electricity demand growth (Table 7) varies from a low of under 3% per year to a high of 7.4%. In 1985 (Table 18) nuclear's share of total generation ranges from a high of 63% to a low of 19%. In 1995 the range is from over 90% to less than 10%. We will examine three regions exhibiting different combinations of growth in electricity consumption and nuclear penetration and discuss the determinants of the behavior in the individual regions. The regions are the New England Region, which has a moderate growth in electricity consumption and high nuclear penetration; the Middle Atlantic Region, which has low growth and high nuclear penetration; and the Mountain Region, which has high growth and relatively low nuclear penetration.

REGION I--NEW ENGLAND

	75	85	95
Price of coal ($/short run)	27.65	58.72	101.98
Price of gas (¢/mcf)	174.85	229.85	379.85
Price of oil ($/bbl)	9.92	25.59	42.15
Price of electricity (mills/kwh)	32.88	48.10	63.86

Capital Cost Multiplier, fossil fueled plants: 1.0

Capital Cost Multiplier, nuclear plants: 1.0

Growth of demand for electricity, 74-85: 5.96 per year

74-95: 6.06 per year

Growth of population, 75-95: .89%/yr

Growth of per capita personal income (real dollars), 75-95: 2.67%/yr

The rate of growth in demand for electricity in New England is one of the highest in the nation, despite the fact that the region ranks fifth in terms of population growth and seventh in terms of growth in personal income. The prices of fossil fuels are very high relative to other regions, as the region faces the highest coal prices and second highest gas prices in the U.S. These circumstances combine to make electricity a relatively attractive energy source, and explain the high rate of growth in electricity consumption.

The high capital cost multiplier for fossil fueled plants makes nuclear plants the favored choice for supplying this demand. Generation by gas and oil burning plants, which account for almost 50% of total generation in 1974, declines substantially and by 1995 accounts for less than 3% of the total. By 1995 reliance on nuclear power has become almost complete, with nuclear plants producing more than 90% of generation requirements.

A more detailed examination of the simulation results indicates that the nuclear share is probably overestimated. The supply model tends to underestimate the generation requirements for the region in the mid 1990's. As a result, to meet actual demand, we have let nuclear plants run well beyond their rated load factors of 70%. In reality, supply shortages would probably be made up by purchases of power from adjacent regions of the country. Over the longer term more intermediate load oil or coal plants would be built to handle the additional loads. The 1990 figures for New England, where nuclear has 70% of the total, are probably more realistic.

REGION II--MIDDLE ATLANTIC

	75	85	95
Price of coal ($/short ton)	22.07	44.68	78.59
Price of gas (¢/mcf)	176.51	231.51	381.51
Price of oil ($/bbl)	9.92	25.59	42.15
Price of electricity (mills/kwh)	29.59	47.19	86.88

Capital Cost Multiplier, fossil fueled plants: 1.0126

Capital Cost Multiplier, nuclear plants: 1.0

Growth of demand for electricity, 75-85: 3.50% per year

75-95: 2.86% per year

Growth of population, 75-95: .76%/yr

Growth of per capita personal income (real dollars): 2.45%/yr

The Middle Atlantic Region is one of the slowest growing regions in the U.S., having the second lowest rate of growth of population and the lowest rate of growth of per capita personal income. The rate of growth of demand for electricity is the second lowest. As was the case with Region I, fossil fuel prices are relatively high, with the region facing the highest gas prices and second highest coal prices in the country. The price of electricity, however, is substantially higher than that of any other region, reflecting extraordinarily high transmission and distribution investment costs, so that electricity does not compare as favorably to alternative energy forms as it does in the New England region. The capital cost multiplier for fossil fueled plants is the nation's highest. All endogenously determined additions to capacity subsequent to 1975 take the form of nuclear reactors which, meeting only 8.5% of generation requirements in 1974, rise to a position of dominance, by 1995 accounting for 77% of the total.

REGION VIII--MOUNTAIN

	75	85	95
Price of coal ($/short ton)	11.63	27.97	54.48
Price of gas (¢/mcf)	153.24	198.97	348.97
Price of oil ($/bbl)	9.57	25.01	41.57
Price of electricity (mills/kwh)	23.15	43.18	64.72

Capital Cost Multiplier, fossil fueled plants: .9097

Capital Cost Multiplier, nuclear plants: .9081

Growth of demand for electricity, 75-85: 7.78%

75-95: 7.44%

Growth of population, 75-95: 1.26%/yr

Growth of per capita personal income (real dollars): 3.79%/yr
1975-95

The rate of growth of demand for electricity in the Mountain states is the highest in the country. The growth rates of population and per capita personal income rank second highest. Hydroelectric and coal burning capacity for generation remain relatively attractive alternatives in this region. Nuclear accounts for less than 10% of the electricity generated in the region in 1995. This represents by far the smallest share of generation requirements met by nuclear power in any region for that year.

The high rate of growth of coal burning capacity reflects the very low price of coal to the region, and also the failure of the expectation equations used in the model to pick up the high rate of growth of demand and introduce enough nuclear capacity into the pipeline. The projections of future demand are consistently short of actual demand. The projection

of demand for 1985 made in 1980 falls 22% short of the actual demand, so that heavy use is made of peaking units. This accounts for the prodigious consumption of gas and oil during 1985.

Comparisons with other Studies

Finally, we present some comparisons with other studies of the electric utility industry. We make the comparisons only for 1985 since those are the only ones that are generally available. In Table 15 we present the generation by fuel type for the U.S. as a whole as predicted by WASH-1139(74), the FEA Project Independence Report, and NERA(1972) along with those projected by the MIT Regional Electricity Model.

We see that REM predicts less electricity consumption in 1985 than the other three projections available. The differences between the FEA projection and the REM projections fall primarily as differences in generation attributable to fossil fuels. The NERA projections were made in 1972 prior to the rapid rise in fossil fuel costs and the costs of building nuclear generating stations, and reflect the optimistic projections of that period for electricity demand, and oil and nuclear generation. The reduced fossil fuel requirements predicted by REM should make the achievement of the objectives of Project Independence somewhat easier, at least in terms of the electric utility industry's contribution, than had been thought previously.

Conclusions

We have used the MIT Regional Electricity Model to examine the likely future course of electricity consumption and fuel utilization by the electric utility industry for the United States as a whole and for each of nine census regions. We predict that electricity consumption will grow at a rate substantially below historical trends for the United States as a whole but with considerable variation among census regions. As long as oil and natural gas prices remain at or near current real levels, these fuels are no longer an economic alternative for generating electricity. Generation from oil and natural gas burning plants and the utilization of these fuels declines as coal and nuclear plants are built to meet additional demand and to replace existing facilities.

Given estimates of construction costs, the critical variables for predicting fuel utilization by the electric utility industry are the price of enriched uranium fuel used in light water reactors and the price of coal. Increases in uranium prices above historical predictions, as now seems likely, indicates that coal will play a very important role in the generation mix. However, if coal prices increase more quickly than we have estimated in the base case due to either increased production costs or to restrictions on the use of western coal, nuclear energy's share may remain at the projected levels or even increase in some regions even if nuclear fuel prices increase dramatically.

Given the critical importance of coal and uranium prices to the electric utility sector and the plethora of good data on reserves and the price formation process for both resources, but especially uranium, we

believe that further efforts directed towards obtaining additional information about the supply functions of each of these fuels is critical for our ability to make sensible energy policy plans for the rest of this century.

TABLE 1

SUMMARY ELASTICITIES

RESIDENTIAL AND COMMERCIAL

		Price Gas	Price Oil	Price Electricity	Income
Gas Consumption	SR	-.15	.01	.01	SR = +0.08
	LR	-1.01	.05	.17	LR = +0.52
Oil Consumption	SR	.04	-.18	.01	
	LR	.19	-1.12	.16	
Electricity Consumption	SR	.05	.01	-.19	
	LR	.17	.05	-1.00	

INDUSTRIAL

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

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

TABLE 2

1974 (actual)*

REGION	COAL (10^{15} btus/10^6 tons)	GAS & OIL (10^{15} btus/10^6 bbls)	HYDRO (10^{15} btus)	NUCLEAR (10^{15} btus/10^3 tons U_3O_8)
New England	.0518818/1.9802214	.4276642/68.0452188	.0479102	.1775655/--
Middle Atlantic	1.0132416/38.6733435	.8606707/136.9404455	.2998296	.209412/--
East North Central	2.8138219/107.3977824	.3002227/47.7681305	.0334354	.296772/--
West North Central	.6631834/25.3123435	.3319243/52.8121400	.1309594	.097545/--
South Atlantic	1.8607579/71.0212939	1.1011896/175.2091647	.1750997	.261765/--
East South Central	1.3549637/51.7161718	.0961229/15.2940175	.2571307	.0660345/--
West South Central	.0692294/2.6423435	2.1194410/337.2221161	.09559872	.0037905/--
Mountain	.4924080/18.7941985	.2470710/39.3112172	.3250296	0.0/--
Pacific	.0422160/1.6112977	.6922238/110.1390294	1.6600550	.0708855/--
TOTAL U. S.	8.3617027/319.1489588	6.1765301/982.7414638	3.0250483	1.1837700/--

Source: Edison Electric Institute. Statistical Year Book of the Electric Utility Industry. New York, New York. 1974.

Conversion Factors: Coal: 26.2×10^6 BTU/Ton
Gas & Oil: 6.285×10^6 BTU/Ton

TABLE 3

1980

REGION	COAL (10^{15} btus/10^6 tons)	GAS & OIL (10^{15} btus/10^6 bbls)	HYDRO (10^{15} btus)	NUCLEAR (10^{15} btus/10^3 tons U_3O_8)
New England	.0303312/1.1577406	.4730562/75.2632	.0515617	.4394776/1.2572305
Middle Atlantic	.8999063/34.3494110	.6997499/111.3302	.3093444	1.0856133/3.1056293
East North Central	3.7382402/142.688614	.1963370/31.2372	.0442917	.5166365/1.4779639
West North Central	.7891349/30.1212616	.6295752/100.1654	.1954150	.2161577/.6183738
South Atlantic	2.2423220/85.5894165	.3716865/59.1353	.2744249	.9400676/2.6892797
East South Central	1.4555511/55.5583801	.3494877/55.6035	.3114865	.4795889/1.3719741
West South Central	.2981386/11.3799496	2.1833162/347.3656	.0761420	.4616231/1.3205669
Mountain	.8107842/30.9476166	.2030183/32.3002	.4400156	.0239799/.0686001
Pacific	.0075385/.2877433	1.1930351/189.8118	1.9405308	.6573154/1.8804103
TOTAL U. S.	10.271947/392.080078	6.2992621/1002.2124	3.6432126	4.82046/13.79

TABLE 4

1985

REGION	COAL (10^{15} btus/10^6 tons)	GAS & OIL (10^{15} btus/10^6 bbls)	HYDRO (10^{15} btus)	NUCLEAR (10^{15} btus/10^3 tons U_3O_8)
New England	0.0/0.0	.4310923/68.5868	.0525807	.8264650/2.1221031
Middle Atlantic	.8970106/34.2388916	.6213998/98.8647	.3219194	1.6011457/4.1112762
East North Central	3.5991163/137.378250	.0546971/8.7023	.0447860	1.3457079/3.4553823
West North Central	1.3473587/51.4286652	.1223562/19.4669	.2145376	.9404498/2.4147954
South Atlantic	2.0892258/79.7457428	.3242916/51.5948	.2952172	2.1507921/5.5225879
East South Central	1.7175798/65.5600128	.0144327/2.2962	.3348585	1.1704426/3.0053412
West South Central	.2781658/10.6175861	1.8252268/290.3935	.0795563	1.4509106/3.7255046
Mountain	1.0513487/40.1299744	.3651326/58.0926	.5564648	.4522801/1.1613203
Pacific	.1918980/7.3247480	.8811392/140.1892	2.1898031	1.5662537/4.0216634
TOTAL U. S.	11.1717014/426.423584	4.6397683/738.187	4.0897236	11.5044475/29.54

TABLE 5

1990

REGION	COAL (10^{15} btus/10^6 tons)	GAS & OIL (10^{15} btus/10^6 bbls)	HYDRO (10^{15} btus)	NUCLEAR (10^{15} btus/10^3 tons U_3O_8)
New England	.0687767/2.6252050	.3918310/62.3403	.0535997	1.1932926/3.3381112
Middle Atlantic	.2135540/8.1513567	.0195852/3.1160	.3277038	3.3481808/9.3662036
East North Central	2.2304077/85.1346436	.0189305/3.0118	.0452803	3.3101330/9.2597624
West North Central	1.9557753/74.6519318	.0257155/4.0913	.2352995	1.0544043/2.9496081
South Atlantic	1.5819864/60.3844147	.0818879/13.0284	.3217459	4.2786751/11.9691576
East South Central	.9548767/36.4476318	.0115604/1.8393	.3595057	2.4745293/6.9222538
West South Central	.2842278/10.8489733	1.6757593/266.6132	.0824544	2.3328600/6.5259459
Mountain	2.1359968/81.5309906	.0168993/2.6887	.7168609	.4420896/1.2367032
Pacific	.2381807/9.0913563	.5735756/91.2558	2.3753672	2.6883001/7.5202543
TOTAL U. S.	9.6637802/368.866455	2.8157447/447.9848	4.5178184	21.1224648/59.088

TABLE 6

1995

REGION	COAL (10^{15} btus/10^6 tons)	GAS & OIL (10^{15} btus/10^6 bbls)	HYDRO (10^{15} btus)	NUCLEAR (10^{15} btus/10^3 tons U_3O_8)
New England	.0100654/.3841966	.0702400/11.1752	.0546188	2.2458172/6.3474886
Middle Atlantic	.5327911/20.3366241	.1068050/16.9927	.3289614	3.2675753/9.2353469
East North Central	2.2912989/87.4588623	.0392802/6.2495	.0457747	3.8169241/10.7879778
West North Central	2.6378469/100.686600	.0557037/8.8625	.2571539	.9934970/2.8079855
South Atlantic	2.2718248/86.7155457	.2122864/33.7748	.3520994	5.3534250/15.1307033
East South Central	1.7317619/66.1013489	.0370058/5.8876	.3850025	2.3646069/6.6832316
West South Central	.5135816/19.6033936	1.6920967/269.2125	.0850085	2.2252417/6.2893222
Mountain	3.1885729/121.707809	.1159132/18.4418	.9065567	.4176956/1.1805692
Pacific	1.0557280/40.2971191	.4123861/65.6106	2.5184641	2.9279442/8.2754031
TOTAL U. S.	14.2334709/543.291504	2.7417171/436.2072	4.9336400	23.612727/66.738

TABLE 7

DEMAND FOR ELECTRICITY
AVERAGE ANNUAL PERCENTAGE RATES OF GROWTH

REGION	1974-1985	1974-1995
New England	5.96	6.06
Middle Atlantic	3.50	2.86
East North Central	3.63	2.97
West North Central	7.28	5.93
South Atlantic	3.40	4.39
East South Central	5.71	4.68
West South Central	5.10	4.41
Mountain	7.78	7.44
Pacific	6.29	5.07
Total U. S.	4.97	4.54

TABLE 8

FUEL CONSUMPTION 1974--1985
AVERAGE ANNUAL PERCENTAGE RATES OF GROWTH

REGION	COAL	GAS & OIL	U_3O_8	HYDRO
New England	--	.14	15.01	.92
Middle Atlantic	-1.03	-2.86	20.31	.72
East North Central	2.34	-14.49	14.73	2.77
West North Central	6.73	-8.70	22.88	4.67
South Atlantic	1.13	-10.50	21.10	4.94
East South Central	2.25	-16.32	29.87	2.50
West South Central	13.56	-1.32	71.72	-1.58
Mountain	7.22	3.26	--	5.09
Pacific	14.84	2.29	32.50	2.62
U. S.	2.74	-3.50	22.97	2.85

TABLE 9

FUEL CONSUMPTION 1974--1995
AVERAGE ANNUAL PERCENTAGE RATES OF GROWTH

REGION	COAL	GAS & OIL	U_3O_8	HYDRO
New England	-7.30	-8.05	12.84	.66
Middle Atlantic	-2.79	-9.27	13.98	.48
East North Central	-.74	-9.11	12.93	1.55
West North Central	7.04	-8.01	11.69	3.31
South Atlantic	1.19	-7.38	15.46	3.42
East South Central	1.41	-4.32	18.58	1.98
West South Central	10.31	-.89	35.47	-.52
Mountain	9.56	-3.37	--	5.05
Pacific	16.84	-2.22	19.39	2.04
U. S.	2.80	-3.62	15.32	2.40

TABLE 10

EFFECT OF COAL PRICES ON TOTAL U.S. DEMAND FOR ELECTRICITY

COAL PRICES (as % of base case prices)	DEMAND (mmwh)	
	1985	1995
.80	3201.721	4768.082
.90	3185.213	4737.027
1.00	3167.212	4722.961
1.10	3146.732	4732.074
1.20	3120.534	4739.609

TABLE 11

EFFECT OF COAL PRICES ON CONSUMPTION OF COAL BY ELECTRIC UTILITIES

COAL PRICES (as % of base case prices)	COAL CONSUMPTION (10^6 tons)	
	1985	1995
.80	449.44	723.77
.90	438.32	635.64
1.00	426.42	543.29
1.10	411.63	464.12
1.20	402.43	360.42

TABLE 12

EFFECT OF URANIUM PRICES ON CONSUMPTION OF U_3O_8 AND COAL

URANIUM PRICES (as multiple of base case prices)	CONSUMPTION OF U_3O_8 (10^3 tons)		CONSUMPTION OF COAL (10^6 tons)	
	1985	1995	1985	1995
1.0	29.54	66.74	426.42	543.29
2.0	25.59	44.77	422.95	609.76
3.0	24.63	27.73	408.78	676.46

TABLE 13

EFFECT OF URANIUM PRICES ON THE DEMAND FOR ELECTRICITY

URANIUM PRICES (as multiple of base case prices)	DEMAND FOR ELECTRICITY(mmwh)	
	1985	1995
1.0	3167.212	4722.961
2.0	3093.726	4446.297
3.0	3042.458	4349.922

TABLE 14

EFFECT OF URANIUM PRICES ON THE PERCENTAGE OF GENERATION REQUIREMENTS MET BY NUCLEAR REACTORS

URANIUM PRICES (as multiple of base case prices)	PERCENTAGE OF TOTAL GENERATION	
	1985	1995
1.0	36.32	50.00
2.0	35.87	40.97
3.0	37.39	34.00

TABLE 15

GENERATION BY FUEL TYPE IN THE UNITED STATES--1985
(10^9 kwh)

	COAL	OIL & GAS	HYDRO	NUCLEAR	TOTAL
WASH 1139	960-1510	910-1090	360	1320-1570	3550-4530
FEA--PIB	1642	546	480	1251	3919
NERA	1060	812	460	1925	4256
REM	1117	461	409	1150	3137

TABLE 16

ELECTRICAL GENERATION 1974(actual)*
(by plant type, mmwh)

REGION	COAL	GAS & OIL	LWRU	IC & GT	HYDRO	TOTAL
New England	5.147	42.137	16.911	.290	4.753	69.237
Middle Atlantic	100.520	85.086	19.944	.298	29.745	235.594
East North Central	279.149	28.439	28.264	1.309	3.317	340.517
West North Central	65.792	30.835	9.290	2.094	12.992	121.042
South Atlantic	184.599	108.708	24.930	.537	17.371	336.145
East South Central	134.421	9.536	6.289	0.0	25.509	175.756
West South Central	6.868	209.375	.361	.887	9.484	227.070
Mountain	48.850	24.263	0.0	.248	32.245	105.622
Pacific	4.188	68.563	6.751	.11	164.688	246.819
Total U. S.	829.543	607.077	112.740	5.674	300.104	1864.961

*Source: Edison Electric Institute. Statistical Year Book of the Electric Utility Industry for 1974. New York, New York. 1974.

TABLE 17

ELECTRICAL GENERATION 1980
(by plant type, mmwh)

REGION	COAL	GAS & OIL	LWRU	IC & GT	HYDRO	TOTAL
New England	3.033	46.904	43.948	.298	5.156	99.338
Middle Atlantic	89.991	68.763	108.561	.897	30.934	299.147
East North Central	373.824	17.590	51.664	1.514	4.429	449.021
West North Central	78.913	61.177	21.616	1.319	19.542	182.567
South Atlantic	224.232	35.531	94.007	1.214	27.442	382.425
East South Central	145.555	32.268	47.959	1.986	31.149	258.916
West South Central	29.814	217.057	46.162	.944	7.614	301.591
Mountain	81.078	19.390	2.398	.675	44.002	147.544
Pacific	.754	117.749	65.732	1.151	194.053	379.439
Total U. S.	1027.194	616.429	482.046	9.998	364.321	2499.987

TABLE 18

ELECTRICAL GENERATION 1985
(by plant type, mmwh)

REGION	COAL	GAS & OIL	LWRU	IC & GT	HYDRO	TOTAL
New England	0.0	42.634	82.646	.432	5.258	130.971
Middle Atlantic	89.701	60.942	160.115	1.089	32.192	344.039
East North Central	359.912	3.762	134.571	1.552	4.479	504.275
West North Central	134.736	10.786	94.045	1.318	21.454	262.338
South Atlantic	208.923	30.408	215.079	1.838	29.522	485.769
East South Central	171.758	.352	117.044	.992	33.486	323.632
West South Central	27.817	173.619	145.091	8.094	7.956	362.576
Mountain	105.135	18.731	45.228	16.166	55.646	240.906
Pacific	19.190	86.478	156.625	1.487	218.980	482.760
Total U. S.	1117.170	427.711	1150.445	32.968	408.972	3137.266

TABLE 19

ELECTRICAL GENERATION 1990
(by plant type, mmwh)

REGION	COAL	GAS & OIL	LWRU	IC & GT	HYDRO	TOTAL
New England	6.982	39.057	119.329	.712	5.360	171.441
Middle Atlantic	21.681	.797	334.818	1.174	32.770	391.239
East North Central	226.437	.204	331.013	1.692	4.528	563.875
West North Central	198.556	1.163	105.441	1.426	23.530	330.115
South Atlantic	160.608	5.947	427.867	2.331	32.175	628.927
East South Central	96.942	.012	247.453	1.145	35.951	381.501
West South Central	28.856	150.244	233.286	19.586	8.245	440.217
Mountain	216.853	.169	44.209	1.523	71.686	334.440
Pacific	24.181	56.334	268.830	1.868	237.537	588.750
Total U. S.	981.094	253.927	2112.246	31.457	451.782	3830.505

TABLE 20

ELECTRICAL GENERATION 1995
(by plant type, mmwh)

REGION	COAL	GAS & OIL	LWRU	IC & GT	HYDRO	TOTAL
New England	1.048	6.508	224.582	.776	5.462	238.376
Middle Atlantic	55.499	9.691	326.758	1.377	32.896	426.220
East North Central	238.677	1.900	381.692	2.104	4.577	628.951
West North Central	274.776	3.392	99.350	2.315	25.715	405.547
South Atlantic	236.649	15.800	535.343	6.061	35.210	829.061
East South Central	180.392	1.604	236.461	2.161	38.500	459.117
West South Central	53.948	126.967	222.524	47.322	8.501	458.812
Mountain	332.143	8.512	41.770	3.420	90.656	476.500
Pacific	109.972	40.417	292.794	2.438	251.846	697.468
Total U. S.	1482.654	214.790	2361.273	67.973	493.364	4620.051

APPENDIX A:

TABLE A-1

PLANT ALTERNATIVES

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. Plutorium Recycle Reactors
8. Liquid Metal Fast Breeder Reactors
9. Hydroelectric

TABLE A-2

DEFINITION OF REGIONS

REGION I (NEW ENGLAND)	-- Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut
REGION II (MIDDLE ATLANTIC)	-- New York, Pennsylvania, New Jersey
REGION III (EAST NORTH CENTRAL)	-- Michigan, Wisconsin, Indiana, Illinois, Ohio
REGION IV (WEST NORTH CENTRAL)	-- North Dakota, South Dakota, Kansas, Iowa Nebraska, Missouri, Minnesota
REGION V (SOUTH ATLANTIC)	-- Delaware, Maryland, D.C., Virginia, West Virginia, North Carolina, South Carolina, Georgia, Florida
REGION VI (EAST SOUTH CENTRAL)	-- Alabama, Kentucky, Tennessee, Mississippi
REGION VII (WEST SOUTH CENTRAL)	-- Oklahoma, Texas, Arkansas, Louisiana
REGION VIII (MOUNTAIN)	-- Nevada, Utah, Arizona, New Mexico, Idaho, Montana, Colorado, Wyoming
REGION IX (PACIFIC)	-- California, Oregon, Washington

TABLE A-3

FOSSIL FUEL PRICES -- GAS (CENTS/MCF)

(Current Dollars)

REGION	1975	1985	1995
I	174.854	229.854	379.854
II	176.508	231.508	381.508
III	168.346	223.346	373.346
IV	152.265	198.970	348.970
V	173.199	228.199	378.199
VI	163.934	218.934	368.934
VII	143.749	187.940	337.940
VIII	153.235	198.970	348.970
IX	172.096	227.096	377.096
U. S. (average wellhead price)	155.	210.	360.

TABLE A-4

FOSSIL FUEL PRICES -- COAL (DOLLARS/SHORT TON)

(Current Dollars)

REGION	1975	1985	1995
I	27.654	58.718	101.980
II	22.069	44.676	78.594
III	17.653	37.943	67.371
IV	15.032	30.478	54.478
V	21.683	46.921	80.630
VI	15.904	34.080	60.220
VII	18.154	31.000	55.000
VIII	11.629	27.972	54.478
IX	19.720	39.195	69.198
U.S. (average minemouth price)	14.50	31.00	55.00

TABLE A-5

FOSSIL FUEL PRICES -- OIL (DOLLARS/BARREL)

(Current Dollars)

REGION	1975	1985	1995
I	9.920	25.590	42.150
II	9.920	25.590	42.150
III	11.080	26.750	43.310
IV	9.946	25.590	42.150
V	9.746	25.300	41.860
VI	9.630	24.720	41.280
VII	9.398	24.720	41.280
VIII	9.572	25.010	41.570
IX	9.920	25.590	42.150
U. S. (average wellhead price)	8.18	22.69	39.25

TABLE A-6

	COSTS OF U_3O_8 ($/pound) (Current Dollars)	COSTS OF SEPARATIVE WORK ($/SWU) (Current Dollars)
1975	10.03	44.38
1980	22.88	62.91
1985	53.28	91.25
1990	86.01	133.20
1995	127.42	193.12

TABLE A-7

UNIT CAPITAL COSTS ($/kilowatt)

(for New England 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

TABLE A-8

CAPITAL COST MULTIPLIERS BY REGION

	FOSSIL CAPITAL COST MULTIPLIER	NUCLEAR CAPITAL COST MULTIPLIER
New England	1.000	1.000
Middle Atlantic	1.0126	1.000
East North Central	.9860	1.000
West North Central	.9531	.9359
South Atlantic	.9527	.9515
East South Central	.8760	.8510
West South Central	.8718	.8449
Mountain	.9097	.9081
Pacific	.9601	.9416

TABLE A-9

FINANCIAL PARAMETERS

1975-1995

Regulated Return on Equity	=	14%
Cost of Debt	=	9%
Cost of Preferred Stock	=	9%
Debt Limit	=	60%
Minimum Interest Coverage Ratio	=	1.75
Preferred Stock Fraction	=	10%

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