ELECTRICITY DEMAND AND UTILITY CAPACITY PLANNING

TESTIMONY BEFORE THE ATOMIC SAFETY
AND LICENSING BOARD,
U.S. ATOMIC ENERGY COMMISSION

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Preface

The testimony that follows this preface was presented by Duane Chapman before a hearing board of the Atomic Energy Commission (AEC). The subject matter discussed in the testimony represents an application of the results of a continuing research project that has been supported by the National Science Foundation, the Oak Ridge National Laboratory, and the Cornell Agricultural Experiment Station for the last three years.

The hearing was conducted to determine whether a license should be granted to the Niagara Mohawk Power Corporation for the construction of a new nuclear power plant (Nine Mile Point, Unit 2) near Oswego, New York. If construction starts in 1974, the plant will not be ready for full operation until 1980. This long delay means that the decision whether or not to build the plant depends to a large extent on predictions of how much electrical power will be needed in 1980. A major conclusion of the testimony is that procedures used by Niagara Mohawk to predict future electricity needs are inadequate. Not only do these procedures lead to unreliable predictions, but more importantly, they are not flexible enough to predict how changes in the economic conditions faced by electric utility companies will affect the quantity of electricity used. The widespread use of such procedures may partially explain the reluctance of utility companies to consider alternatives to their existing management practices such as the replacement of decreasing block rates by flatter or inverted rate schedules.

Many electric utility companies base their predictions of the future need for electric power on the extrapolation of the past growth of the peak load in their service area.1/ The reliability of these extrapolations depends implicitly on the assumption that the future levels of economic factors influencing electricity demand will remain close to their historical trends. While this appears to be a poor assumption in the midst of the current "energy crisis", extrapolation has proved reliable in the past, and in fact, Niagara Mohawk used extrapolation procedures to justify the need for an additional nuclear power plant in a report that was submitted to the AEC hearing board in June, 1972. Consequently, the testimony is concerned with the limitations of the extrapolation procedure presented in this report, and does not consider the implications of more current problems such as the restricted supplies of imported petroleum.

In the testimony, an alternative method of predicting the future demand for electrical power is discussed. Five distinct steps in the analysis can be identified:2/

1/ Peak load may be defined as the largest quantity of electricity generated in any one hour during the year. This peak usually occurs during late December in the Niagara Mohawk service area.

2/ A more detailed account of these procedures is given in two papers submitted as exhibits in the testimony: a) Chapman, L.D., T.J. Tyrrell and T.D. Mount, "Electricity Demand Growth and the Energy Crisis", Science, Vol. 178, Nov.17, 1972, pp. 703-8. b) Mount, T.D., L.D. Chapman and T.J. Tyrrell, "Electricity Demand in the United States: an Econometric Analysis," ORNL-NSF-EP-49, Oak Ridge National Laboratory, Oak Ridge, Tenn., June 1973.

1) Identifying the underlying economic factors that influence the quantity of electricity demanded
2) Specifying a mathematical and statistical model relating these factors to the quantity of electricity
3) Collecting data consistent with the model specification, and estimating the magnitudes of the relationships between the factors and the quantity of electricity
4) Assessing the performance of the estimated model in predicting the quantity of electricity
5) Making predictions of the future need for electricity based on the anticipated levels of the explanatory factors

The fourth step provides a basis for evaluating the performance of alternative methods of prediction. If one method performs poorly, it may be possible to identify the reason by comparing the specific procedures adopted in the first three steps to those used for other methods of prediction that perform better. It should be noted that any prediction method, including the extrapolation of past trends, can be evaluated in this way.

In practice, it is not possible to make an entirely satisfactory evaluation of the performance of a particular model, as the only infallible test is whether predictions of the future quantities of electricity demanded are close to the quantities that are eventually needed. The best practical alternative is to predict the quantities for a suitable set of data that was not used to estimate the model structure. This type of evaluation is illustrated in part B of the testimony, and the model used to make predictions performs remarkably well in this respect.

The usefulness of any analysis should not, however, be judged solely on how well the model fits the available data. Another valuable aspect is the additional insight gained from the analysis about the structure of the relationships that influence electricity demand. For example, one of the conclusions in the testimony is that the price of electricity paid by consumers has an important influence on the quantity of electricity demanded. It is possible to compare the effects of alternative pricing policies on demand, as the magnitude of the relationship between price and quantity is estimated in the analysis. In contrast, the use of extrapolation procedures provides no framework for analyzing such alternatives. As new policies relating to electricity demand will almost certainly be considered in the future, it is essential that electric utility companies adopt more comprehensive methods for predicting future capacity needs. It is only by doing so that satisfactory policy changes can be selected from among the alternatives considered. A third paper submitted as an exhibit[3/] provides an example of how one particular policy, a tax on sulfur emissions in this case, can be appraised before it is actually implemented. An additional advantage is that this type of

3/ Chapman, L.D., "A Sulfur Emission Tax and the Electric Utility Industry," Staff Paper No. 73-17, Department of Agricultural Economics, Cornell University, August, 1973; also in Energy Demand, Conservation, and Institutional Problems, M. Macrakis, ed., MIT Press, January, 1974.

analysis should enable a company to foresee future problems related to generating capacity. Having some time available before a problem manifests itself should make it possible to search for permanent solutions rather than being forced into using short-term contingency plans. Interestingly enough, the rebuttal of Niagara Mohawk to the testimony rested more heavily on the desirability of substituting nuclear power for fossil fuels because of the "energy crisis", rather than upon the extra capacity needs predicted by their extrapolations.

Finally, if an analysis is to be useful to the management of a utility company, it is important that the results are directed to issues that concern management. For example, in a decision about a new generating facility, it is the total generating capacity required in the future that is of interest. Hence, it is necessary to consider the demand for electricity by all classes of consumers, and to relate the total quantity of electricity purchased to the corresponding generating capacity required. This subject forms an important part of the testimony. In contrast, however, many research publications are of little practical value because such considerations are ignored.

CONTENTS

PART A: CAPACITY PLANNING

The empirical tools of economic analysis bear upon the problem of capacity planning. In previous work, we have analyzed electricity demand growth at the national level.[1] We have also used the same methodology to examine the impact of a sulfur emission tax on electricity demand growth in New York State.[2] A current interest is to relate this methodology to particular utility service areas. This should be of value to utilities, government agencies, and citizens' groups throughout the country.

I. POST-WAR DEVELOPMENTS IN ELECTRICITY DEMAND

For most of the United States the post-World War II era has been a period of sustained economic growth. Contributing to this growth has been the development of the electric utility industry whose delivered sales have doubled every 10 years, normally growing at 7%-8% per year. Of course each major category of use has not manifested identical patterns. From 1962 to 1972 total U.S. sales doubled, but industrial use increased by three-fourths while residential and commercial use more than doubled.

The major factors influencing this growth have been declining electricity prices, growing population and income, and a good competitive position, over time, of electricity prices vis-a-vis other fuel prices. The behavior of each of these factors contributed to the strong growth in electricity demand. In a broad sense the utility industry has been commendably efficient. We have used ever increasing amounts at declining prices, and generally have been able to use it instantaneously, on demand, without fear of shortages or rationing.

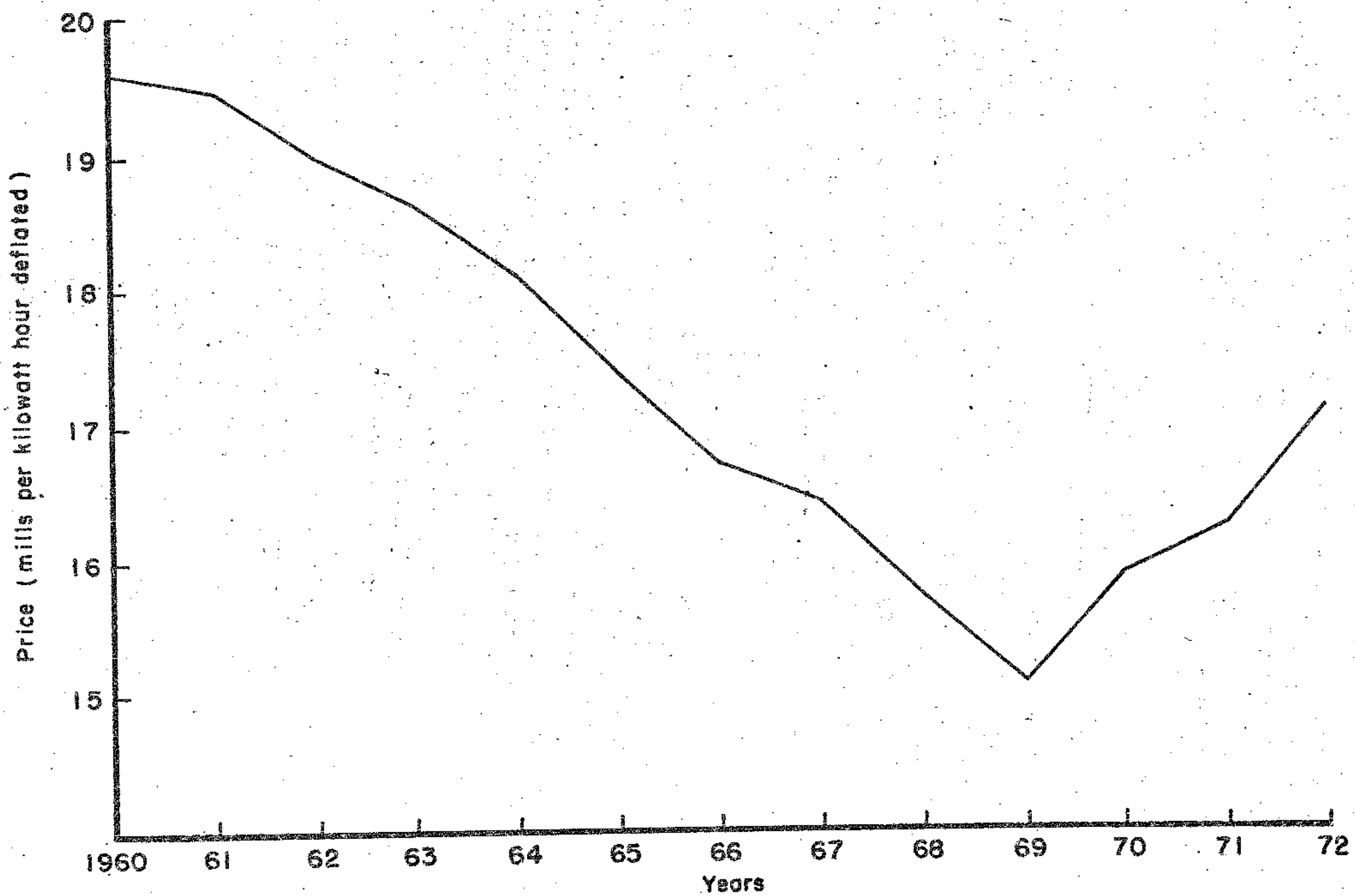
Each of these influencing factors has changed rather smoothly, and hence the growth in sales has been of equal or greater predictability. However, beginning in 1970, the nation experienced abrupt changes in the nature of two of these variables: prices and population growth. In 1971, for the first year since 1946, the deflated average price of electricity rose, and it did again in 1972. This important economic change is evident in the Niagara Mohawk area: see Figure 1. For the foreseeable future the related cost problems of environmental protection and fuel scarcity will cause continued growth in average prices.

For the last decade the fertility rate (a measure of the number of children born to women of child bearing age) has declined. In 1972 this rate fell below the zero population growth rate, meaning that if continued, U.S. population will begin to level off and stabilize by our grandchildrens' generation. As a consequence the Census Bureau has issued new population projections which forecast substantially lower growth in the rest of this century.

The implication of these momentous changes is clear; it points toward reduced growth in the future.[3]

However, the Niagara Mohawk service area cannot be viewed as a microcosm of the Nation. In both industry and agriculture, it seems likely that the area will not share equally in National income and population growth. While some utilities in the State (especially those in prosperous suburban areas) will experience growth in excess of

FIGURE 1. NIAGARA MOHAWK REAL AVERAGE PRICE OF ELECTRICITY



7% per year, this is unlikely for Niagara Mohawk. In general, heavy industry in New York is not doing well. The index of factory output for New York stood at 84 in 1962, rose to 100 in 1967, peaked at 105 in 1969, and in 1972 was 98, (Figure 2). Simultaneously, industrial sales in the Niagara Mohawk area grew from 9700 MKWH (million kilowatt hours) in 1962 to 12,900 in 1969 (32%) but fell 7% to the 1972 value of 12,000 MKWH. At the same time overall population growth in the area as well as in the State has apparently slowed perceptibly since the late 1960's, (Figure 3).

As a consequence, Niagara Mohawk system sales have grown appreciably less than most other utilities throughout the country. For example, last year (1972) was a year of economic recovery for most of the country, and total U.S. sales grew 7.5% while Niagara Mohawk sales grew 4.4%. This lagging behind has existed for some years, and is due to the economic circumstances discussed here. The question at hand is the determination of anticipated future system growth and its bearing upon the period in which the Nine Mile Nuclear Plant Unit 2 will be needed.

II. PEAK LOAD GROWTH PROJECTION

Peak load growth projections traditionally select a relevant historical period, determine growth over that period, adjust growth for specific anticipated changes, and project growth at some compound rate into the near future. Methods for determining the historical growth include (A) arithmetic definitions and (B) best fit determination. In the arithmetic method, a base year is compared to the latest year of record and a compound growth rate is determined. For the best fit method, the rate of growth and perhaps an intercept value are selected which have the absolute minimum of squared values of errors in the historical period.[4] Both methods are of interest and are examined in this section.

A. The Arithmetic Compound Rate

The arithmetic method has been accurately employed in the past. For example, total U.S. sales grew from .78 trillion KWH in 1962 to 1.11 trillion KWH in 1967, or 7.3% per year. If this rate of growth had been projected to 1972, the prediction would have been 1.58 trillion KWH, a perfect prediction.

The method would have been almost as useful in the Niagara Mohawk area. Applying the 1962-67 growth to a 1972 prediction would have forecast system sales of 27,644 MKWH, an error or 1,200 MKWH. Similarly, 1972 system peak load would have been forecast at 4928 MW, approximately the value predicted by the company's analysts but some 2% above the actual value of 4827: see Figure 4.

The obvious place to begin is to determine the appropriate length of the recent historical experience and apply it to the future. According to our previous discussion, the late 1960's marked an important turning point with respect to industrial production, population growth, and electricity prices. It is clearly inappropriate to include the early 1960's; system peak load grew 37% from 1960 to 1966 but 21% from 1966 to 1972. The growth rates were 3.9% over the seven year period and

FIGURE 2. NEW YORK STATE INDEX OF FACTORY OUTPUT

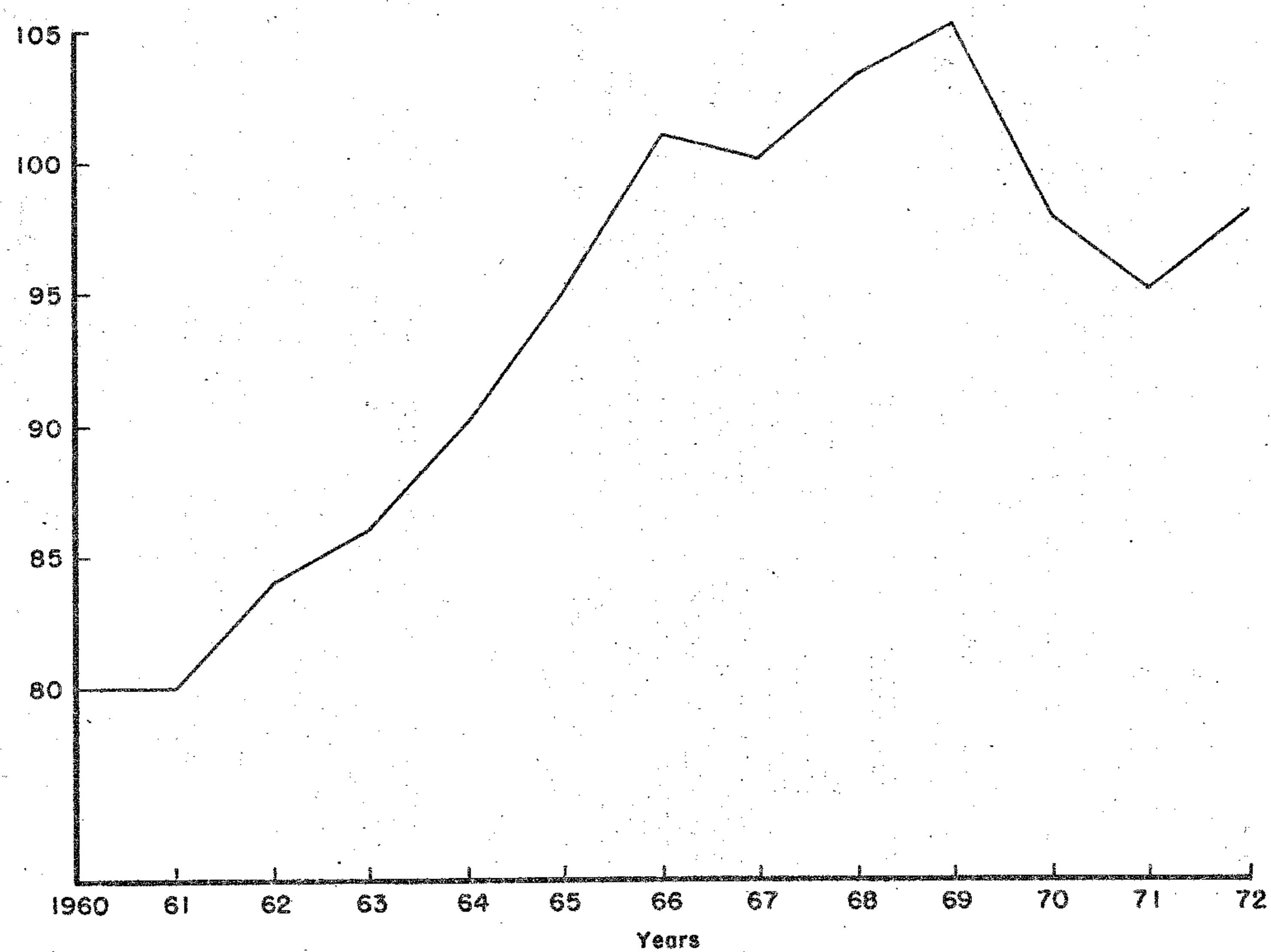


FIGURE 3. POPULATION, NEW YORK STATE AND NIAGARA MOHAWK SERVICE AREA

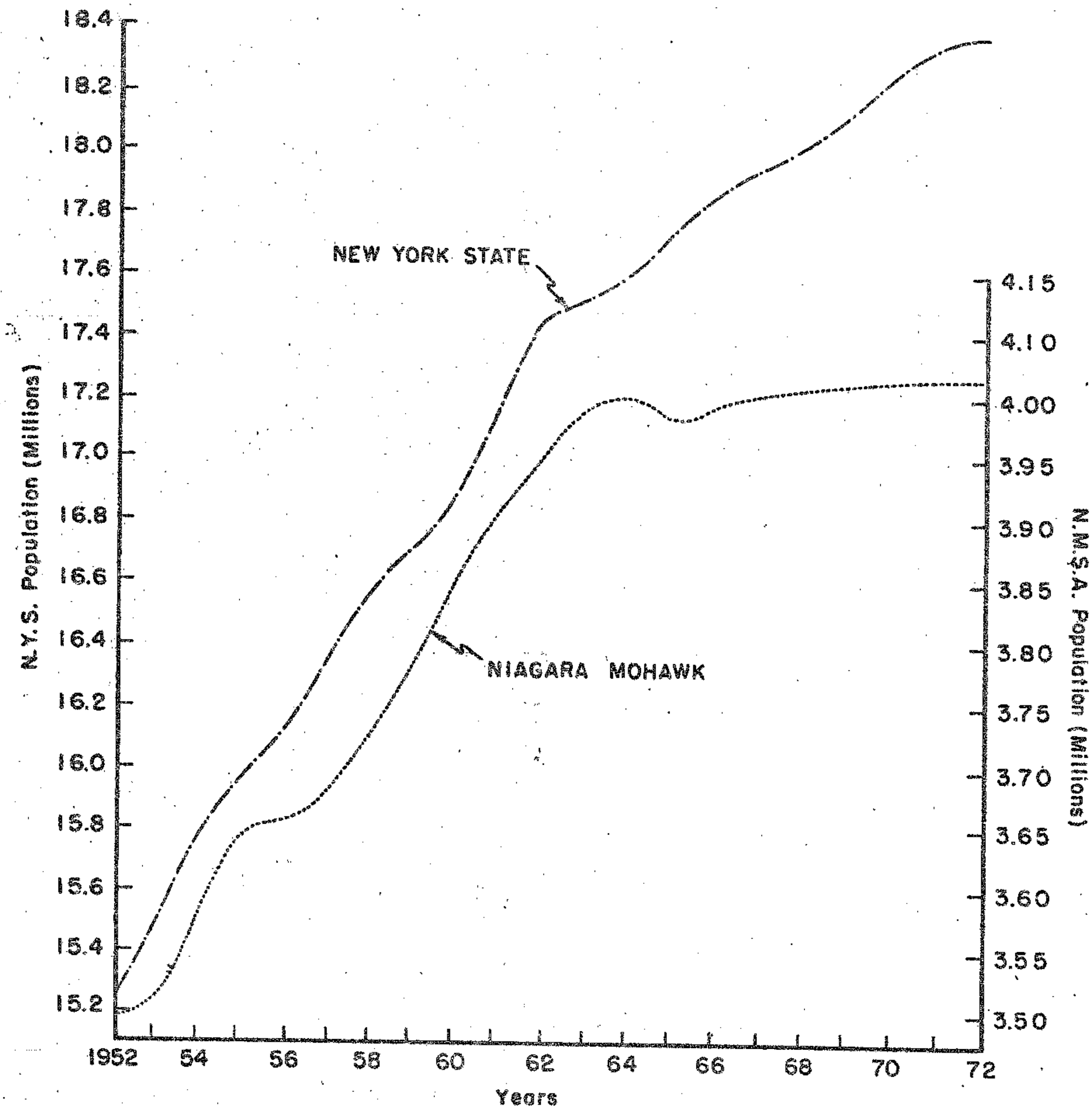
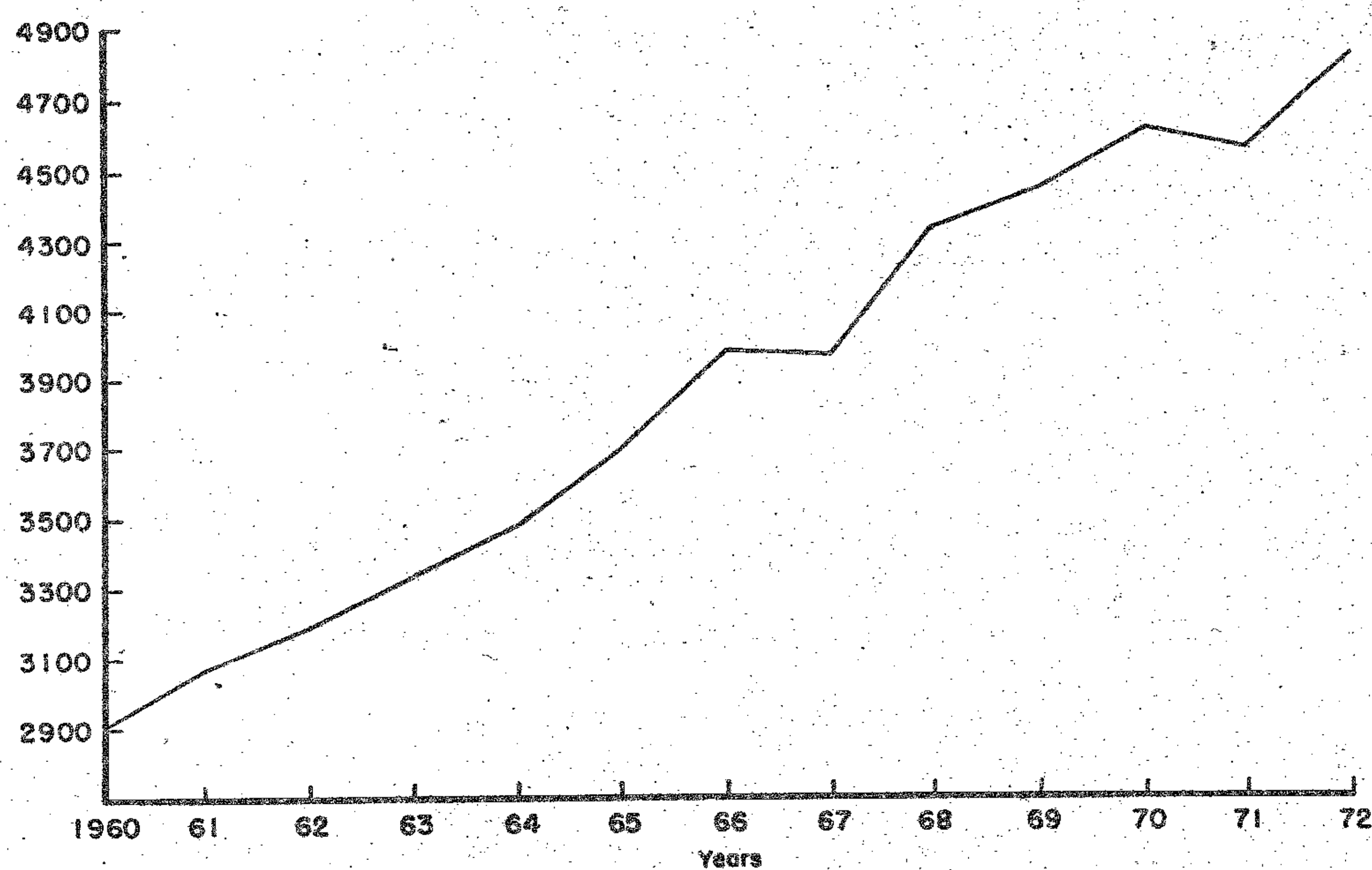


FIGURE 4. NIAGARA MOHAWK WINTER PEAK LOAD, MEGAWATTS



4.0% over the five year period. Therefore 4% would seem to be the correct arithmetic compound growth figure to use in future projections. In this and subsequent discussion it is assumed that peak load continues to occur in December of each year.

The result appears in column 1 of Table 1, showing extrapolated net system peak load growth through 1995.[5] The 18% reserve margin defines the preferred capacity in column 2. Deducting anticipated system capacity in column 3 defines additional requirements in equivalent units of 1100 MW capacity.

The year the plant is needed can be determined in at least three ways. First, all the excess capacity in the 1974-80 period might be sold to other utilities. The plant would then be brought into use by December 1981, the first year necessary to meet the 18% reserve goal. Second, the plant may be viewed as necessary in the year in which one-half of its capacity is needed. This definition suggests 1983 as the year of need. Third, the 6925 MW of excess capacity in the 1947-80 period might be sold to other utilities, who in turn would provide 5500 MW in 1981-86, thus defining the first year of need as 1987.

But the arithmetic growth rate is determined only by the first and last years in a period. Any information contained in the experience of the other years in a period is ignored. The desirability of considering all years in a period leads to the best fit method discussed in the next section, and the desirability of understanding the causes of variation in growth leads to the demand analysis in Section III.

B. The Best Fit Compound Rate

Figure 5 compares the above arithmetic growth rate with the best fit growth for 1965-72. Note that the arithmetic rate is determined by the 1965 and 1972 values only, while the best fit line more closely approximates the eight years in the period. Thus the arithmetic rate has an average error of +59 MW, a total absolute error of 724 MW, and a total squared error of 93,500 MW. The best fit relation has an average error of +1 MW, total absolute error of 701 MW, and total squared error of 69,000 MW.

This best fit relationship is:

$$Q_t = 3652.2 * (1.0363)^k.$$

Q represents net system peak load in megawatts, t is the year, and k is years since 1964 (i.e., k = t - 1964).[6] Table 2 shows the application of this relationship. Employing the same criterion for defining year of need as above, if excess capacity in the 1974-81 period is sold then the plant is needed in 1982. The year in which one-half of the plant is needed in 1984. If excess capacity in 1974-81 of 7640 MW is traded for 7670 MW in 1982-88, the plant is needed in 1989.

The best fit relationship for the 1967-72 period[7] is:

$$Q_t = 4235.5 * (1.0242)^k.$$

k is now years since 1966. The structure of Table 3 is that of the preceding tables, and this 5 year best fit extrapolation defines years of need according to the three criteria as 1987, 1990, and 1999.

Table 1. Extrapolated Compound Growth, Arithmetic Definition

(Megawatts)

Year	Net System Peak Load (1)	Required Capacity (2)	Anticipated System Capacity (3)	New Requirements (4)	New Requirements 1100 MW Units (5)
1972	4827.0000	5695.8590	5944.0000	-248.1406	-0.2256
1973	5020.0780	5923.6910	6674.0000	-750.3086	-0.6821
1974	5220.8780	6160.6360	7494.0000	-1333.3630	-1.2121
1975	5429.7140	6407.0620	7463.0000	-1055.9370	-0.9599
1976	5646.9020	6663.3430	8283.0000	-1619.6560	-1.4724
1977	5972.7770	6929.8780	8132.0000	-1202.1210	-1.0928
1978	6107.6870	7207.0700	8101.0000	-893.9297	-0.8127
1979	6352.0000	7495.3590	8070.0000	-574.6406	-0.5224
1980	6606.0780	7795.1710	8040.0000	-244.8281	-0.2226
1981	6870.3200	8106.9760	8040.0000	66.9766	0.0609
1982	7145.1320	8431.2570	8040.0000	391.2578	0.3557
1983	7430.9330	8768.5030	8040.0000	728.5039	0.6623
1984	7728.1750	9119.2460	8040.0000	1079.2460	0.9811
1985	8037.3000	9484.0150	8040.0000	1444.0150	1.3127
1986	8358.7920	9863.3750	8040.0000	1823.3750	1.6576
1987	8693.1480	10257.9100	8040.0000	2217.9140	2.0163
1988	9040.8750	10668.2300	8040.0000	2628.2340	2.3893
1989	9402.5070	11094.9600	8040.0000	3054.9600	2.7772
1990	9778.6050	11538.7500	8040.0000	3498.7530	3.1807
1991	10169.7400	12000.3000	8040.0000	3960.3000	3.6003
1992	10576.5300	12480.3100	8040.0000	4440.3160	4.0367
1993	10999.6000	12979.5300	8040.0000	4939.5310	4.4905
1994	11439.5800	13498.7000	8040.0000	5458.7070	4.9625
1995	11897.1600	14038.6600	8040.0000	5998.6600	5.4533

FIGURE 5. NIAGARA MOHAWK ACTUAL PEAK LOAD, ARITHMETIC COMPOUND GROWTH, AND BEST FIT COMPOUND GROWTH, MEGAWATTS

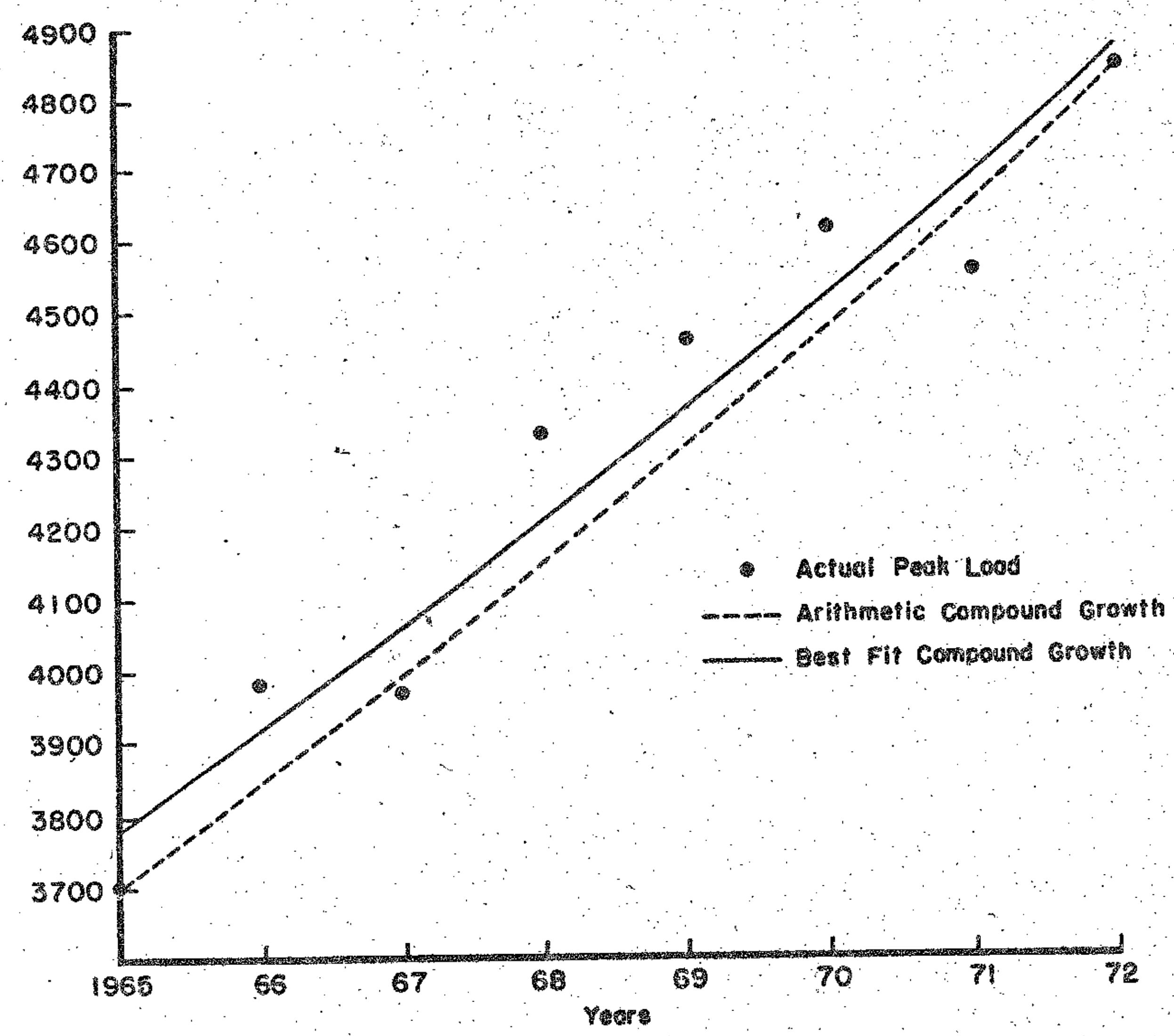


Table 2. Extrapolated Compound Growth, Seven Year Best Fit

(Megawatts)

Year	Net System Peak Load (1)	Required Capacity (2)	Anticipated System Capacity (3)	New Requirements (4)	New Requirements 1100 MW Units (5)
1972	4858.1710	5732.6400	5944.0000	-211.3594	-0.1921
1973	5034.5230	5940.7380	6674.0000	-733.2617	-0.6666
1974	5217.2730	6156.3820	7494.0000	-1337.6170	-1.2160
1975	5406.6600	6379.8530	7463.0000	-1083.1400	-0.9847
1976	5602.9210	6611.4490	8283.0000	-1671.5500	-1.5196
1977	5806.3040	6851.4370	8132.0000	-1280.5620	-1.1641
1978	6017.0700	7100.1440	8101.0000	-1000.8550	-0.9099
1979	6235.4920	7357.8780	8070.0000	-712.1211	-0.6474
1980	6461.8350	7634.9640	8040.0000	-415.0352	-0.3773
1981	6696.3980	7901.7500	8040.0000	-138.2500	-0.1257
1982	6939.4760	8188.5820	8040.0000	148.5820	0.1351
1983	7191.3750	8485.8240	8040.0000	445.8242	0.4053
1984	7452.4210	8793.8590	8040.0000	753.8594	0.6835
1985	7722.9450	9113.0740	8040.0000	1073.0740	0.9755
1986	8003.2850	9443.8780	8040.0000	1403.8780	1.2763
1987	8293.8000	9786.6830	8040.0000	1745.6830	1.5879
1988	8594.8670	10141.9400	8040.0000	2101.9450	1.9109
1989	8906.8550	10510.0800	8040.0000	2470.0890	2.2455
1990	9230.1710	10891.6000	8040.0000	2851.6050	2.5924
1991	9565.2260	11286.9600	8040.0000	3246.9680	2.9518
1992	9912.4410	11696.6800	8040.0000	3656.6830	3.3243
1993	10272.2500	12121.2600	8040.0000	4081.2650	3.7102
1994	10645.1300	12561.2600	8040.0000	4521.2610	4.1102
1995	11031.5500	13017.2300	8040.0000	4977.2340	4.5248

Table 3. Extrapolated Compound Growth, Five Year Best Fit (Megawatts)

Year	Net System Peak Load (1)	Required Capacity (2)	Anticipated System Capacity (3)	New Requirements (4)	New Requirements 1100 MW Units (5)
1972	4773.4140	5632.6280	5944.0000	-311.3711	-0.2831
1973	4888.9330	5768.9410	6674.0000	-905.0586	-0.8228
1974	5007.2500	5908.5440	7494.0000	-1585.4450	-1.4413
1975	5128.4250	6051.5420	7463.0000	-1411.4570	-1.2831
1976	5252.5350	6197.9920	8283.0000	-2085.0070	-1.8955
1977	5379.6520	6347.9880	8132.0000	-1784.0110	-1.6218
1978	5509.8390	6501.6090	8101.0000	-1599.3900	-1.4540
1979	5643.1750	6658.9450	8070.0000	-1411.0540	-1.2828
1980	5779.7460	6820.1010	8040.0000	-1219.8980	-1.1090
1981	5919.6170	6985.1480	8040.0000	-1054.8510	-0.9590
1982	6062.8750	7154.1910	8040.0000	-885.8086	-0.8053
1983	6209.6010	7327.3280	8040.0000	-712.6719	-0.6479
1984	6359.8750	7504.6520	8040.0000	-535.3477	-0.4867
1985	6513.7890	7686.2690	8040.0000	-353.7305	-0.3216
1986	6671.4250	7872.2810	8040.0000	-167.7188	-0.1525
1987	6832.8780	8062.7960	8040.0000	22.7969	0.0207
1988	6998.2380	8257.9210	8040.0000	217.9219	0.1981
1989	7167.5970	8457.7650	8040.0000	417.7656	0.3798
1990	7341.0540	8662.4450	8040.0000	622.4453	0.5659
1991	7518.7100	8872.0780	8040.0000	832.0781	0.7564
1992	7700.6670	9086.7890	8040.0000	1046.7890	0.9516
1993	7887.0270	9306.6910	8040.0000	1266.6910	1.1515
1994	8077.8980	9531.9210	8040.0000	1491.9210	1.3563
1995	8273.3860	9762.5970	8040.0000	1722.5970	1.5660

There is no clear reason to prefer either of the best fit extrapolations. However, it is clear that extrapolation values should not be derived from data for the early 1960's which manifest the previous conditions of falling prices and regular and strong growth in factory output and population. As discussed above, each of the extrapolation techniques deals with the influence of prices, population, and income by assuming that demand growth in a convenient historical period can be extrapolated into the future. Again, as noted previously, this assumption was valid for most of the post-WWII period until the late 1960's, but is no longer so. For demand growth planning we need a method which explicitly links independent forecasts of important factors and explicit empirical estimates of their influence with sales growth, peak load growth, and the timing of necessary new facilities.

III. DEMAND ANALYSIS CAPACITY PLANNING

Previous investigations of demand growth in residential, commercial, and industrial sectors bear upon the problem of forecasting capacity requirements.[8]

First, the results of these analyses are generally successful in delineating the interaction of prices, population, and income with electricity demand. The estimates of individual parameters are logical in sign and statistically significant. On a national basis, the models typically explain more than 99% of the variance in demand over time (1947-70) and between states for each class. Finally, the long run elasticity estimates are essentially unaffected by the choice of function or estimating technique.

The overall success of the research leads us to expect that the ~~methodology~~ may be fruitfully applied to individual service areas. However, we must emphasize two limitations before introducing this methodology. The primary limitation derives from our previous discussion of changing economic circumstances in the Niagara Mohawk service area and throughout the country. We cannot be certain that future responses will follow existing patterns, nor may we subject this problem to statistical analysis. Three illustrations will suffice. National gas shortage may impart a further impetus to electricity growth, but concern for petroleum and gas availability may result in policies which substitute gas for electricity. (More on this in the next section.) Petroleum shortages may lead some consumers to install electric heating, but in the Northeast where much electricity is generated in oil-fired plants, such actions would reduce total energy availability. Rising gasoline prices may reduce the weight of cars and gasoline consumption per mile, thereby reducing industrial electricity requirements in automobile manufacturing and gasoline refining. But pollution control requirements may cause electric cars to be widely used, thereby accelerating electricity demand. In summary, projections made into the distant future are always subject to their assumptions and no form of projections can guarantee long term accuracy.

A second limitation is the reliability of the relationship between system sales and peak load requirements. Table 4 shows such information for 1968-72. The net system peak load factor averaged .62

Table 4. Net System Sales and Peak Load

Year	Net System Sales (MKWH)	Net System peak load (MW)	System peak load factor
1968	23,381	4335	.61
1969	24,699	4442	.63
1970	24,949	4614	.62
1971	25,319	4551	.64
1972	26,440	4827	.62

NOTE: The system peak load factor is the ratio of net system sales to the product of the net system peak load and the hours in the year. Sources are the annual reports sales data in Niagara Mohawk Annual Report 1972 and the peak load data in U.S. Atomic Energy Commission Docket 50-410, Exhibit E, Nine Mile Point Nuclear Station Unit 2, Applicant's Environmental Report, Construction Permit Stage, Supplement 2.

and was relatively stable in the .61-.64 range. The .62 value is employed here. However, improvements in load factor would imply equivalent reductions in desired capacity.

With these limitations in mind, we may proceed with the application of the method to the capacity planning problem. There are two broad steps to consider: (A) Determination of an accurate set of parameters, and (B) Selection of independent projections of values of the causal factors.

Part B explains the analysis through which predictive accuracy for the Niagara Mohawk service area over the 1948-71 period is examined. It should be repeated here that the explanatory accuracy of the demand functions is quite high, and each parameter is statistically significant.

It might now be useful to note certain characteristics of the demand equations used. First, they involve a substantial time lag in the response of demand to changed circumstances. In the residential and commercial sectors, about one-eighth of a long run response is evident in the first year, and it takes 5 years for one-half of a long run response to be incurred. In the industrial demand equation apparent response is faster, exceeding 50% of the long run response in the first year.

Second, these demand functions show different responses to changes in the same factors. Table 5 expresses long run elasticities for the three demand equations.[2] The industrial demand equation indicates industrial use of electricity has not been significantly affected by service area populations and income. Industry in the service area manufactures products for use throughout the Nation and world, and as a consequence factory output and electricity price are more important than service area population and personal income. As a consequence, we have calculated parameter values for the industrial sector particular to the Niagara Mohawk area and according to information relating industrial demand to the index of factory output, electricity price, and lagged electricity demand.

The assumptions regarding population, income and prices in the future are derived from independent analyses by the Census Bureau, the Department of Commerce, and the Federal Power Commission.

We may illustrate the methodology by use of the case in which factory output is assumed to follow the growth in total personal income from manufacturing in New York. Costs and rates increase at the .9% per year rate forecast in the 1970 National Power Survey. In this case, the predicted values of population, income, deflated electricity and gas prices, and index of factory output are shown as columns 1-8 in Table 6. Residential, commercial and industrial demand predictions follow in columns 9-11. Municipal sales are assumed to be one-eleventh of total sales (column 12). The net system peak load factor determines winter peak load as discussed above, and is shown in column 13. Desired capacity, anticipated system capacity without plant, and new plant requirements (columns 14-17) are determined in the same manner as in the preceding section.

The results according to the same criteria discussed above define the first year the plant is needed as 1992, 1998, and sometime in the next century.

Table 5. Long Run Elasticities in Demand Functions

	Consumer Class		
Factor	Residential	Commercial	Industrial
Electricity Price	-1.21	-1.60	-.62
Population	.94	.98	---
Per Capita Income	.30	.80	---
Gas Price	.21	.05	---
N.Y. Factory Output	---	---	.58

Table 6. Demand Projections and Capacity Requirements for the Niagara Mohawk Utility Region, 1971-1995, High Factory Output Growth.[a]

Year	Population (thousands) (1)	Income ($1000) (2)	Residential Price of Electricity (mills/kw-hr.) (3)	Commercial Price of Electricity (mills/kw-hr.) (4)	Industrial Price of Electricity (mills/kw-hr.) (5)	Residential Price of Gas[b] ($/1000 therms) (6)
1971	4109.4	3.3210	19.7	16.8	7.36	114.8
1972	4144.3	3.4266	19.9	16.9	7.42	115.5
1973	4179.3	3.5322	20.0	17.1	7.49	116.3
1974	4214.2	3.6378	20.2	17.2	7.55	117.0
1975	4249.1	3.7434	20.4	17.4	7.61	117.8
1976	4286.1	3.8490	20.5	17.5	7.68	118.5
1977	4323.0	3.9546	20.7	17.7	7.74	119.3
1978	4360.0	4.0603	20.9	17.8	7.80	120.0
1979	4397.0	4.1659	21.1	18.0	7.87	120.8
1980	4433.9	4.2767	21.2	18.1	7.93	121.5
1981	4473.0	4.3875	21.4	18.2	7.99	122.3
1982	4512.0	4.4983	21.6	18.4	8.06	123.0
1983	4551.0	4.6091	21.7	18.5	8.12	123.8
1984	4590.0	4.7199	21.9	18.7	8.18	124.5
1985	4629.0	4.8307	22.1	18.8	8.25	125.2
1986	4664.7	4.9415	22.2	19.0	8.31	126.0
1987	4700.3	5.0524	22.4	19.1	8.37	126.7
1988	4736.0	5.1632	22.6	19.3	8.44	127.5
1989	4771.6	5.2740	22.7	19.4	8.50	128.2
1990	4807.3	5.3848	22.9	19.5	8.56	129.0
1991	4842.9	5.4956	23.1	19.7	8.63	129.7
1992	4878.5	5.6064	23.3	19.8	8.69	130.5
1993	4914.2	5.7172	23.4	20.0	8.75	131.2
1994	4949.8	5.8280	23.6	20.1	8.82	132.0
1995	4985.5	5.9388	23.8	20.3	8.88	132.7

a/ In this case electricity price is assumed to grow at 0.86% per year; Index of Factory Output grows at the same rate as personal income from manufacturing for New York State. See Appendix II.

b/ Recall that for demand in year t, the price of gas is that of the preceding year, t-1.

Table 6 (cont'd.)

Year	Commercial Price of Gas ($/1000 therms) (7)	Index of Factory Output (1967=100) (8)	Residential Demand for Electricity c/ (million kw-hrs.) (9)	Commercial Demand for Electricity c/ (million kw-hrs.) (10)	Industrial Demand for Electricity c/ (million kw-hrs.) (11)
1971	97.2	95.0	6449.8	4716.1	12106.9
1972	97.8	98.5	6699.2	4972.1	12156.8
1973	98.5	102.[illegible]	6934.6	5219.7	12294.3
1974	99.1	105.5	7156.4	5458.9	12458.8
1975	99.7	109.1	7365.1	5689.6	12629.3
1976	100.4	112.6	7561.9	5912.5	12798.9
1977	101.[illegible]	116.1	7747.3	6127.6	12965.2
1978	101.6	119.6	7921.9	6335.3	13127.5
1979	102.3	123.1	8086.6	6535.9	13285.6
1980	102.9	126.6	8242.2	6730.4	13439.8
1981	103.5	130.9	8389.8	6919.6	13621.2
1982	104.1	135.2	8529.9	7103.7	13808.7
1983	104.8	139.6	8663.1	7283.0	13995.[illegible]
1984	105.4	143.9	8789.9	7457.7	14177.8
1985	106.0	148.2	8910.7	7627.9	14356.3
1986	106.7	152.5	9025.2	7793.4	14530.4
1987	107.3	156.8	9134.1	7954.2	14700.3
1988	107.9	161.1	9237.7	8110.8	14866.0
1989	108.6	165.4	9336.3	8263.2	15027.7
1990	109.2	169.7	9430.5	8411.9	15185.5
1991	109.8	174.0	9520.5	8557.0	15339.7
1992	110.5	178.3	9606.7	8698.7	15490.4
1993	111.1	182.6	9689.4	8837.1	15637.6
1994	111.7	187.0	9768.9	8972.6	15781.5
1995	112.4	191.2	9845.3	9105.2	15922.3

b/ Recall that for demand in year t, the price of gas is that of the preceding year, t-1.

c/ For 1971, electricity demand and sales are predicted values and all other data are actual values. For 1972 and thereafter, all explanatory variables (columns 1-8) are forecast values and all other variables are predicted values.

Table 6 (cont'd.)

Year	Total Sales of Electricity[c] (million kw-hrs.) (12)	Peakload (megawatts) (13)	Desired Capacity (megawatts) (14)	System Capacity (megawatts) (15)	New Requirements (megawatts) (16)	Number of New Plants Required (17)
1971	25490.3	4650.0	5487.0	5669.0	-182.0	-0.17
1972	26210.8	4822.7	5690.8	5944.0	-253.2	-0.23
1973	26893.4	4948.3	5839.0	6674.0	-835.0	-0.76
1974	27581.4	5074.9	5988.3	7497.0	-1505.7	-1.37
1975	28252.5	5198.3	6134.0	7463.0	-1329.0	-1.21
1976	28900.6	5317.6	6274.7	8283.0	-2008.3	-1.83
1977	29524.1	5432.3	6410.1	8132.0	-1721.9	-1.57
1978	30123.2	5542.5	6540.2	8101.0	-1560.8	-1.42
1979	30698.9	5648.4	6665.2	8070.0	-1404.8	-1.28
1980	31253.6	5750.5	6785.6	8040.0	-1254.4	-1.14
1981	31823.7	5855.4	6909.4	8040.0	-1130.6	-1.03
1982	32386.6	5959.0	7031.6	8040.0	-1008.4	-0.92
1983	32935.2	6059.9	7150.7	8040.0	-889.3	-0.81
1984	33467.9	6157.9	7266.4	8040.0	-773.6	-0.70
1985	33984.4	6253.0	7378.5	8040.0	-661.5	-0.60
1986	34483.9	6344.9	7487.0	8040.0	-553.0	-0.50
1987	34967.4	6433.8	7591.9	8040.0	-448.1	-0.41
1988	35435.8	6520.0	7693.6	8040.0	-346.4	-0.31
1989	35890.0	6603.6	7792.2	8040.0	-247.8	-0.23
1990	36330.8	6684.7	7887.9	8040.0	-152.1	-0.14
1991	36759.0	6763.5	7980.9	8040.0	-59.1	-0.05
1992	37175.3	6840.1	8071.3	8040.0	31.3	0.03
1993	37580.5	6914.6	8159.3	8040.0	119.3	0.11
1994	37975.2	6987.3	8245.0	8040.0	205.0	0.19
1995	38360.0	7058.1	8328.5	8040.0	288.5	0.26

c/ For 1971 electricity demand and sales are predicted values and all other data are actual values. For 1972 and thereafter all explanatory variables (columns 1-8) are forecast values and all other variables are predicted values.

Alternatively, factory output might be assumed to follow the predicted growth in real per capita personal income in New York. In this case the first criteria defines the year of need as 1994, and the second and third criteria would indicate need after 2000. Finally, it can be assumed that factory output grows at the same rate as per capita personal income in manufacturing in the state. In this case the first criteria selects 2000, and the others again select years in the next century.

IV. GUIDING PEAK LOAD GROWTH

In the preceding discussion we have noted the difficulty in projecting future growth raised by changing economic policies and circumstances. In this section, we note the possibilities of specific policies to influence load growth.

It is well known that a typical home in New York may waste one-third to one-half of its heating BTU's because of inadequate insulation.[10] In response to this situation, utilities in Michigan and the Michigan Public Service Commission are undertaking a program to finance the insulation of old homes. It is logical to expect companies in New York to either (1) initiate similar programs, or (2) undertake comprehensive customer education programs of financial savings to customers which result from proper insulation.

Such a program can be introduced into the capacity planning procedure. Necessary for this would be estimates of the (1) economically efficient level of insulation in old and new homes, (2) current average insulation levels in old and new homes, (3) average heat and air cooling savings from proper insulation, (4) average customer financial savings, (5) number of old and new homes affected by a comprehensive program, and (6) reduction in future capacity required for electric heating resulting from proper insulation.

A second policy the company should consider is the allocation of natural gas from industrial customers to residential and commercial customers. Since the country as well as this area is in a period of insufficient oil and natural gas for the foreseeable future, it is imperative that utilities address the question of use efficiency. It is well known that use of electricity requires approximately twice the system BTU's as gas for heating and cooling. Each BTU delivered in the home by electricity requires 3 BTU's in coal or oil or nuclear fission for generation. But, if the company encourages the transfer of natural gas to residential and commercial use, the industrial customer may generally replace this fuel directly with oil or coal. Obviously such a company policy not only effects electricity peak load growth, but also saves the overall service area substantial BTU's in fossil fuel use -- and with an overall reduction in costs. This kind of natural gas management program sets the same priorities which the Federal Power Commission requires gas transmission companies to follow in forced gas curtailments. It can be anticipated that utilities which undertake gas management will have a higher priority claim for scare gas than utilities which do not have such programs.

V. SUMMARY: THE YEAR OF NEED

In the preceding comments we have examined future capacity requirements through both extrapolation and demand analysis. The year of apparent need was determined according to three criteria. Thus, according to the particular method of analysis and criteria of need, we considered 18 cases, as summarized in Table 7. The earliest year of need is 1981, determined by the arithmetic extrapolation method of peak load growth and the criteria of sale of all excess capacity. The latest year of need cannot be selected, falling sometime in the next century. The median year of those falling in this century is 1987. It should be emphasized that none of the cases forecast declining peak load: all anticipate growth. Rather, the forecasted requirements are compared to anticipated growth without the Nine Mile Unit 2 facility.

We note further that the company may consider guiding peak load growth through insulation and natural gas management programs.

We do not wish to suggest that any single case considered here should be considered to be correct. Rather, the application of conventional economic and engineering concepts to the problem indicates a span of years in which capacity beyond the 8040 MW level may be necessary. This does not suggest that the company should cease its efforts in site acquisition or in exploration of additional nuclear generation potential. Nor should the economic circumstances in the service area be construed as representative of conditions throughout the country, nor are the specific conclusions which follow from this analysis directly transferable to other utilities in the state and nation.

The appropriate conclusions are narrow in scope and simply stated. First, methods of economic analysis can be applied to the problem of capacity planning. Second, the facility in question is not likely to be required for system use in 1979 or 1980 as expected by the Niagara Mohawk Power Corp. and the Atomic Energy Commission Staff. The most likely period of need appears at present to be in the mid 1980's.

PART B: DEMAND ANALYSIS

VI. DEMAND FOR ELECTRICITY IN THE SERVICE AREA

The procedures used to estimate the demand for electricity within the Niagara Mohawk utility region are determined according to consumer classes. For the residential and commercial sectors, the Mount-Chapman-Tyrrell Constant Elasticity Model, Ordinary Least Squares (CEM-OLS) was used.[11] This model was derived from an analysis of the demand for electricity for the entire United States.

The assumption that electricity demand is determined by four explanatory variables[12] - population, income, price of electricity, and price of alternative fuel sources - is believed to be true for the Niagara Mohawk region's residential and commercial sectors, as well as for the United States. Employing the model for the industrial sector was believed not to be as appropriate here because the area is divided into two distinct economic categories. One region is the north and central area of New York State, including the Adirondacks. It is largely rural and much of this area is sparsely populated. The second

Table 7. Year of Need

	Criteria of need		
	All excess capacity is sold	One-half of capacity is required	Excess capacity in near future is traded for capacity in subsequent years
Extrapolation			
A. 4% (1965-72 growth)	1981	1983	1987
B. Best fit, 1965-72	1982	1984	1989
C. Best fit 1967-72	1987	1990	1999
Demand analysis, factory output growth assumptions [1/]			
A. Total personal income from manufacturing	1992	1998	2000+
B. Per capita personal income, all sources	1994	2000+	2000+
C. Per capita personal income, manufacturing	2000	2000+	2000+

1/ The index of factory output for New York is assumed to follow the growth rate of the appropriate factor as indicated. See Appendix II.

type is characterized by dense population and by being highly industrialized. Buffalo, Syracuse, and Albany-Schenectady-Troy constitute the areas in this category.

Since the markets of industrial products from the region are unlikely to be contained within the region itself, but rather in other areas of the State or in other states, it seemed unlikely that the population and per capita income of the Niagara Mohawk region should have a very great effect on the industrial demand for electricity. This assumption was tested in a preliminary analysis of the industrial demand for electricity within the region and the population and income coefficients were found to be insignificant. As a result, a separate model was developed for the industrial sector using the State Index of Factory Output and the price of electricity as the determining variables.

A. Estimation: Residential, Commercial, and Industrial Sectors

Adapting the general demand model to the Niagara Mohawk region required the following procedures. First, the model was used to predict the demand for electricity with data for the region over the past 24 years (1948-1971). Second, the predicted values were compared to the actual values and the size and source of the inequality were identified (see subsection VI-B below). Third, the inequality was adjusted by re-estimating the constant term and the newly adjusted model was tested in the same manner described above. The results of these tests indicated that the model predicted residential and commercial demand over the past 24 years with exceptional accuracy. Lastly, the new model was used to forecast demand in the future.

The general models used for the residential and commercial sectors are:

$$\log Q_t = \log A + V\log Q_{t-1} + B_1\log Pop_t + B_2\log Inc_t + B_3\log PRE_t + B_4\log PRG_{t-1}$$

Residential Sector

where Q_t = quantity of electricity demanded by the residential sector in the current year

Q_{t-1} = quantity of electricity demanded by the residential sector in the previous year, i.e., lagged demand

Pop_t = population in the current year

Inc_t = per capita income in the current year

PRE_t = the residential price of electricity in the current year

PRG_{t-1} = the residential price of gas in the preceding year

A, V, B_1, B_2, B_3, B_4 are the parameter values for the residential sector associated with the constant term, and the coefficients of lagged demand, population, income, price of electricity and price of gas, respectively.

Commercial Sector

where Q_t = quantity of electricity demanded by the commercial sector in the current year

Q_{t-1} = quantity of electricity demanded by the commercial sector in the preceding year

Pop_t = population in the current year

Inc_t = per capita income in the current year

PRE_t = the commercial price of electricity in the current year

PRG_{t-1} = the commercial price of gas in the preceding year

A, V, B_1, B_2, B_3, B_4 are the parameter values for the commercial sector associated with the constant term, the coefficients of lagged demand, population, income, price of electricity and price of gas respectively.

Industrial Section (Niagara Mohawk)

The model developed specifically for the industrial sector of the Niagara Mohawk region is:

$$\log Q_t = \log A + V \log Q_{t-1} + B_1 \log IFO_t + B_2 \log PRE_t$$

where Q_t = quantity of electricity demanded by the industrial sector in the current year

Q_{t-1} = quantity of electricity demanded by the industrial sector in the preceding year, i.e., lagged demand

IFO_t = the index of factory output for New York State in the current year

PRE_t = the industrial price of electricity in the current year

A, V, B_1, B_2 are the parameter values associated with the constant term, and the coefficients of lagged demand, index of factory output and price of electricity, respectively.

The results of this model are as follows:

Table 8. Parameter Estimates for the Industrial Sector

Explanatory Factor	Units of Measure	Parameter	Estimated Value
Lagged Demand	million kw-hrs	V	0.3443
Price of Electricity	cents/100 kw-hrs	B_1	-0.4046
Index of Factory Output	1967 = 100	B_2	0.3785
Constant Term		A	6.1742

Standard Error of Regression Coefficients: V = 0.1517
B_1 = 0.2404
B_2 = 0.1642
A = 1.9165

R-SQUARED, unadjusted = 0.8540378
Number of Observations = 24

The short-run elasticities of price and the index of factory output are B_1 and B_2, respectively. The coefficent of lagged demand determines elasticity*: the long run elasticity of price is $B_1/(1-V)$. The importance of V is that it determines how rapidly demand will adjust to a change in one of the explanatory variables. Specifically, V indicates

*Elasticity is defined as the per cent change in quantity demanded associated with a one per cent change in a particular explanatory variable.

what proportion of electricity demand consumed in any given year will be a function of the amount consumed in the previous year; 1-V is the proportion that demand will change in one year as the result of a change in one of the explanatory variables. The value of V must lie between one and zero. If V is very small, this indicates that demand will adjust rapidly; if V is large, demand will adjust slowly. Since the V coefficient (0.3443) is much closer to zero than to one, one should expect the industrial sector of Niagara Mohawk to adjust rapidly to a change in either price or in the level of factory output.

B. Theil Method of Error Analysis

H. Theil's inequality coefficient[13] was used to test the accuracy with which the CEM-OLS model can forecast residential demand within the Niagara Mohawk region. This coefficient (U) is:

$$U = \frac{\sqrt{1/n \sum (P_i - A_i)^2}}{\sqrt{1/n \sum P_i^2} + \sqrt{1/n \sum A_i^2}}$$

where $P_i, \ldots, P_n$ is the predicted demand for year $i, \ldots, n$, and $A_i, \ldots, A_n$ is the actual demand for the same year.

When U = 0, the predicted demand equals the actual demand in all observations, and the model forecasts perfectly. When U = 1, the opposite is true and the model is ineffectual. Thus, the closer U is to zero, the better the forecast; the closer it is to one, the poorer the forecast.

The numerator of the inequality coefficient U can be rewritten as follows:

$$1/n \sum (P_i - A_i)^2 = (\bar{P} - \bar{A})^2 + (SDP - SDA)^2 + 2(1 - r)(SDP)(SDA)$$

where $\bar{P}$, $\bar{A}$, SDP, SDA are the means and standard deviations of the predicted and actual values, respectively, and r is the correlation coefficient.

The denominator (D) of U is such that the value of U will always be between zero and one. Substituting D into the above equation for U we have:

$$U_m = \frac{\bar{P} - \bar{A}}{D}$$

$$U_s = \frac{SDP - SDA}{D}$$

$$U_c = \frac{\sqrt{2(1 - r)(SDP)(SDA)}}{D}$$

where $U_m^2 + U_s^2 + U_c^2 = U^2$. U_m^2 is the partial coefficient of inequality representing the difference between the predicted and actual values caused by an unequal tendency (the mean). U_s^2 is the partial coefficient representing the difference caused by unequal variation. U_c^2 is the partial coefficient representing the difference caused by imperfect covariance. Moreover,

$$UM = \frac{U_m^2}{U^2} ; \quad US = \frac{U_s^2}{U^2} ; \quad UC = \frac{U_c^2}{U^2} ; \quad \text{and } UM + US + UC = 1$$

Thus, UM, US, and UC are the proportions of inequality caused by the mean, variance and covariance, in that order, and are reported in percentages rather than proportions.

The CEM-OLS model was used to calculate demand for the residential and commercial sectors for the past 24 years. Using the computational formulas outlined above, the inequality coefficients were calculated in real rather than logarithmic units.

The results for the residential sector are as follows:

$U = .0269471$	$U_m^2 = .00065521$	UM = 90.2%
$U^2 = .00072614$		US = 6.3%
	$U_s^2 = .00004544$	UC = 3.5%
	$U_c^2 = .00002592$	

and for the commercial sector:

$U = .0407781$	$U_m^2 = .00143492$	UM = 86.3%
$U^2 = .0016628$		US = 11.4%
	$U_s^2 = .00018965$	UC = 2.3%
	$U_c^2 = .00003843$	

These calculations are evidence that for the residential sector 90.2% of the inequality between the predicted demand and the actual demand is caused by a shift in the mean, 6.3% is a result of unequal variation, and 3.5% is due to imperfect covariation. In the commercial sector, 86.3% of the inequality between predicted and actual values is due to a shift in the mean, 11.4% due to unequal variation, and 2.3% due to imperfect covariation.

The CEM-OLS model was applied to the industrial sector and tested in a similar manner. The results of this test were that 26.1% of the inequality between predicted and actual values was due to a shift in the mean, 10.4% due to unequal variation and 63.5% due to imperfect covariation.

Errors of unequal means or variances are systematic errors and the model can be adjusted for these. Errors from imperfect covariation are unsystematic and cannot be adjusted. Since the mean was such a large proportion of the inequality in the residential sector and commercial sector, the constant term (A) is adjusted. In the industrial model, the greatest proportion of the inequality was due to imperfect covariation. This supported the contention that the CEM-OLS model would not be appropriate for the Niagara Mohawk region.

The constant term for the residential and commercial sectors was adjusted by subtracting the log of the actual value from the log of the predicted value for each observation. This difference was totalled for all 24 years and then divided by 24 to obtain an average in logs. The average difference was then subtracted from the constant term.

The average difference for the residential sector was .0591 and for the commercial sector .0842. The new constant term for the residential sector became:

$$.4612 - .0591 = .4021$$

and for the commercial sector:

$$.5897 - .0842 = .5055$$

Using the new constant terms the CEM-OLS model was used to predict demand within the Niagara Mohawk region over the past 24 years. Again, the U inequality coefficients were computed to estimate the accuracy with which the new model forecasts demand. The results of these calculations were:

Residential Sector:

$U_2 = .0071613$
$U^2 = .00005128$

$U_m^2 = .00000252$

$U_s^2 = .00002326$

$U_c^2 = .00002568$

UM = 5%
US = 45%
UC = 50%

Commercial Sector:

$U = .006832$
$U^2 = .00004668$

$U_m^2 = .00000065$

$U2_s = .00000768$

$U_c^2 = .00003836$

UM = 1.4%
US = 16.4%
UC = 82.2%

As we explained earlier, U = 0 indicates perfect forecasting. If $U \neq 0$, then it is desirable to have U as near to zero in value as possible. Moreover, if $U \neq 0$, the most desirable value for UM and US is zero, and the most desirable value for UC is one. When UM and US equal zero, this means that systematically repeating errors have been eliminated and that the error remaining (UC) is unsystematic and cannot be adjusted.

The inequality caused by the mean was reduced from 90.2% to 5% in the residential sector; and from 86.3% to 1.4% in the commercial sector. Moreover, the inequality coefficients for the adjusted model are extremely close to zero in both sectors: .0072 for the residential and .0068 for the commercial. The importance of these coefficients cannot be over estimated. They indicate that the CEM-OLS model predicted demand for the residential and commercial sectors of the Niagara Mohawk region with remarkable accuracy.

The accuracy of the industrial model derived specifically from Niagara Mohawk data was tested in the same manner discussed above. The inequality coefficients resulting from these calculations were:

$U = .0284397$
$U^2 = .0008088$

$U_m^2 = .000001314$

$U_s^2 = .000009122$

$U_c^2 = .000798458$

UM = 0.2%
US = 1.1%
UC = 98.7%

The U term for the CEM-OLS industrial sector was .046, while the U term for the Niagara Mohawk model was .028. A comparison indicates that the Niagara Mohawk model predicted demand with greater accuracy than the CEM-OLS model since the U coefficient is closer to zero. Because UC = 98.7% for the Niagara Mohawk model, the inequality remaining is due to unsystematic errors for which the model cannot be adjusted.

While the industrial model is not quite as accurate for predicting demand for electricity as the residential and commercial models, the industrial model is nevertheless reliable because the U term is small. It can be anticipated that the industrial sector is more unpredictable than the residential and commercial sectors as industrial demand for electricity within any given utility region is subject to sudden changes. Consider, for example, the impact of a firm's decision to move in or out of an area within the region. Nevertheless, the inequality coefficient is evidence that this model predicted industrial demand within the Niagara Mohawk region with considerable accuracy.

C. Predicting Future Demand

Once the model which best predicted demand for the Niagara Mohawk region was obtained, predicting future demand became a matter of calculating how the determining variables - population, income, price of electricity and price of gas and index of factory output - were likely to change in the future, and then applying the coefficients to each of the predicted variables.

The source of each variable as well as the source of each variable's predicted growth rate is described in detail in Part B.

APPENDIX I

This information was calculated during the course of the Niagara Mohawk hearing and was presented as part of the oral testimony. While the preceding analysis of Theil coefficients using the full 24 years of historical data is important, it is useful to calculate the Theil coefficients for the most recent 10 year period, using the predicted lagged demand variable rather than the actual demand variable for the preceding year.

This final test is more significant for utilities for two reasons: (1) utilities typically use a recent short-term period from which to project future demand, and (2) using the predicted lagged demand variable more nearly approximates forecasting demand into the future.

For example, if the model has a tendency to make errors in prediction of increasing magnitude from year to year, this will create a small error in the first year of prediction, and a much larger error in the tenth year since each year's error in prediction will be compounded. Thus, the test using the predicted lag is a final check that the model is working properly.

Consider the time period from 1962 to 1971. In order to predict demand for electricity in 1962, the actual values of all the independent variables are used. To predict demand for 1963, the process is the same except that instead of using the actual demand in 1962 as the lagged demand variable, the predicted demand for 1962 will become lagged demand in 1963, and so on for the subsequent years.

In addition to calculating the Theil coefficients (as outlined previously), one should also check the percentage errors in prediction for each year. Even if the Theil coefficients are relatively close to zero, it may be that the model is making errors in prediction of increasing magnitude when the predicted lagged demand is used. Thus, one should check that the model is performing well.

The Theil coefficients, using the predicted lagged demand variable for the period 1962-1971 are as follows:

Residential:
$U = .021206$
$U^2 = .0004497$

$U_m^2 = .0001127$ UM = 25.1%
$U_s^2 = .003167$ US = 70.4%
$U_c^2 = .0000203$ UC = 4.5%

Commercial:
$U = .011386$
$U^2 = .0001296$

$U_m^2 = .0000432$ UM = 33.4%
$U_s^2 = .0000748$ US = 57.7%
$U_c^2 = .0000116$ UC = 8.9%

Industrial:
$U = .01174$
$U^2 = .0001378$

$U_m^2 = .0000067$ UM = 4.9%
$U_s^2 = .0000070$ US = 5.0%
$U_c^2 = .0001243$ UC = 90.1%

The percentage errors for each year were calculated as follows:

$$\frac{\text{Predicted Demand} - \text{Actual Demand}}{\text{Actual Demand}}$$

and are reported in the following table, by sector:

Percentage Errors in Prediction, 1962-1971

Year	Residential	Commercial	Industrial
1962	1.19	1.84	0.34
1963	1.33	1.12	0.73
1964	2.51	0.83	0.28
1965	1.25	0.10	-3.13
1966	0.26	-1.40	-3.48
1967	-1.74	-2.72	0.29
1968	-3.20	-2.33	1.36
1969	-4.86	-2.30	1.83
1970	-5.83	-1.76	2.94
1971	-6.57	-3.45	3.90

APPENDIX II

A. Data Sources

(1) The following variables were obtained from Niagara Mohawk's 1972 Annual Report:

(1) Residential Sales, 1971 and 1970
(2) Commercial Sales, 1971 and 1970
(3) Industrial Sales, 1971 and 1970
(4) Other Sales, 1971
(5) Total Generation, 1971
(6) Existing Capability, 1971
(7) Purchased Power, 1971

(2) System Capacity in megawatts is Niagara Mohawk's predicted total capacity without Nine Mile Point 2.
Source: U.S. Atomic Energy Commission, Final Environmental Statement Related to Construction of Nine Mile Point Nuclear Station, Unit 2. Niagara Mohawk Power Corporation, Docket No. 50-410, Washington, D.C., June 1973, pp. 8-9, 8-11.

(3) Net System Peak Load Factor in megawatts determines winter peak load.
Source: Final Environmental Statement, p. 8-11, and Supplement 2 to Applicant's Environmental Report, Construction Permit Stage.

(4) Population for Niagara Mohawk Utility Region
The counties within the region were identified by the map of Utility Regions within New York State published by the New York Power Pool, Schenectady, New York, April 1972. Those counties having less than half of their areas within Niagara Mohawk's boundaries were omitted so as not to bias the actual population within the region. Those counties having half or more of their total areas within the region were included. The list of the 29 counties follows:

Albany	Franklin	Livingston	Oswego
Cattaraugus	Fulton	Madison	Rensselaer
Chautauqua	Genessee	Montgomery	St. Lawrence
Columbia	Hamilton	Niagara	Saratoga
Cortland	Herkimer	Oneida	Schenectady
Erie	Jefferson	Onondaga	Schoharie
Essex	Lewis	Orleans	Warren
			Washington

Population of the total region was computed by checking census data published in the New York State Statistical Yearbook for 1973, obtaining the population for each county and then adding them together.
Source: New York State Division of the Budget, Office of Statistical Coordinator, New York State Statistical Yearbook, 1973, Albany, New York, July 1973.

(5) Personal Income, Per Capita, Niagara Mohawk Utility Region
Per capita income for the region was obtained by taking personal income per county, summing the total and dividing that figure by total population for the region. This method was used since merely averaging

the per capita income for each county would not take account of the different populations and would weight the average in favor of less populated regions.

The dollar terms were then deflated by the Consumer Price Index (1967 = 100) in order to discount the effects of inflation and were reported in thousands of dollars per person.

Source: New York State Statistical Yearbook, 1973.

(6) Price of Gas, Niagara Mohawk Utility Region

The sales and revenues of gas within the region for 1970 were obtained from Niagara Mohawk's Annual Report for 1972. The conversion factor necessary to convert cubic feet to therms was obtained by Richard Goldsmith from the Niagara Mohawk Corporation. This factor was 1025 BTU's per cubic foot of gas (100,000 BTU's = 1 therm). Although Niagara Mohawk's gas utility region is smaller than its electric utility region, its price of gas was considered more representative of the whole region than the average price of gas for the State since New York City biases the State figures. Price was computed by consumer class as follows:

$$\text{Price} = \frac{\text{Total Revenues}}{\text{Total Sales(cubic feet)}(1025\ \text{BTU's}/\text{ft}^3)/100{,}000\ \text{Therms/BTU}}$$

The prices were reported in dollars per 1000 therms and deflated by the Consumer Price Index.

Source: Niagara Mohawk Annual Report, 1972.

(7) Price of Electricity, Niagara Mohawk

The annual revenues and sales for 1971 by consumer class within the region were obtained from Niagara Mohawk's Annual Report, 1972. The price of electricity for each class was computed as follows:

$$\text{Price} = \frac{\text{Total Revenues}}{\text{Total Sales}}$$

The residential and commercial prices of electricity were reported in mills per kilowatt hour; the industrial price was reported in cents per 100 kilowatt hours. All were deflated by the Consumer Price Index.

Source: Niagara Mohawk Annual Report, 1972.

(8) Index of Factory Output, New York State

The index of factory output for the State was used as an indicator of industrial demand within the Niagara Mohawk region because 45-50 per cent of total industrial sales of electricity for the State have been within the region during the past ten years. In addition, Niagara Mohawk sells, on the average, as much electricity to its industrial customers as it does to residential and commercial customers combined.

The index of factory output is a measure of the amount of real goods produced within the state; 1967 is the base year (1967 = 100) and every year before or after 1967 is evaluated according to how it compares to 1967. For example, if factory output in 1960 was 75% of factory output in 1967, its index would be 75.

These figures were computed by the New York State Department of Commerce.

Source: New York State Statistical Yearbook, 1973, p. 114.

B. Forecasts of Population, Income, and Prices

(1) Population

The projected increase in population was Series E-1, computed by the U.S. Bureau of the Census for New York State. The "E" refers to a fertility assumption (that fertility rates will stay at 2.11 children per woman) and the "1" refers to a migration assumption (that migration trends will continue in the pattern established in the period 1960-1970).

The projected increases are:

1970-1975 - 0.85%/year 1980-1985 - 0.88%/year
1975-1980 - 0.87%/year 1985-2000 - 0.77%/year

Source: U.S. Department of Commerce, Bureau of the Census, "Population Estimates and Projections," Current Population Reports, Series P-25, No. 477, March 1972.

(2) Personal Income per Capita

The projected increase in per capita income for the Niagara Mohawk Region was the percentage increase projected for the State of New York by the U.S. Department of Commerce.

The projected increases are: 1969-1980 - 3.18%/year
1980-2000 - 2.66%/year

Source: Robert E. Graham, Jr., Henry L. DeGraff, and Edward A. Trott, Jr., "State Projections of Income, Employment and Population," Survey of Current Business, Vol. 52, No. 4, Washington, D. C., April 1972, p. 35.

(3) Price of Gas

The projected increase in gas prices is 13% from 1970 to 1990, based on an estimate made by the Federal Power Commission.

Projected increase: 1970-2000 - 0.65%/year

Source: Duane Chapman, Timothy Tyrrell and Timothy Mount, "Electricity Demand Growth and the Energy Crisis," Science, Vol. 178, November 17, 1972, p. 706.

(4) Price of Electricity

Two different assumptions were made about the projected increase in the price of electricity. The first one was based on a conservative estimate made by the Federal Power Commission which predicts a 19% increase in electricity prices from 1968-1990.

Model I - Projected increase: 1970-2000 - 0.86%/year

Source: Federal Power Commission, The 1970 National Power Survey, Part I, U.S. Government Printing Office, Washington, D. C., December 1971, p. I-1-34.

Model II - Projected increase: 1970-2000 - 3.3%/year

(5) Index of Factory Output

The index of factory output was projected to increase at three different rates of growth based on figures computed by the U.S. Department of Commerce.

In Model I, the index of factory output was assumed to increase at the same rate as personal income from manufacturing projected.

Model I - Projected increase: 1969-1980 - 3.7%/year
1980-2000 - 3.4%/year

In Model II, the index was projected at the same rate of increase predicted for personal income per capita in New York State.

Model II - Projected increase: 1969-1980 - 3.18%/year
1980-2000 - 2.66%/year

In Model III, the rate of increase was obtained in the following manner. First, personal income from manufacturing was divided by the predicted population in order to obtain personal income from manufacturing, per capita. Then the percentage increase per year for manufacturing income was computed. This figure was the third rate of increase used in this analysis for the index of factory output.

Model III - Projected Increase: 1969-1980 - 2.0%/year
1980-2000 - 1.72%/year

Source: Robert E. Graham, Jr., Henry L. DeGraff, and Edward A. Trott, Jr., "State Projections of Income, Employment and Population," Survey of Current Business, Vol. 52, No. 4, Washington, D.C., April 1972.

FOOTNOTES

1. See Chapman, D., T. Tyrrell, and T. Mount, "Electricity Demand Growth and the Energy Crisis", Science 178 (4062) 703-8, November 17, 1972; and Mount, T., D. Chapman, and T. Tyrrell, Electricity Demand in the United States: An Econometric Analysis, ORNL-NSF-EP-49, June 1973.
2. See Chapman, D., "A Sulfur Emission Tax and the Electric Utility Industry", Cornell Agricultural Economics Staff Paper No. 73-17, August 1973.
3. For a discussion on the significance of these changes for national demand forecasting, see Chapman, D., T. Tyrrell, and T. Mount, op. cit.
4. From the original compound growth assumption $Q_i = A(1 + r)^i$, the arithmetic rate is defined by:

$$r = 10^{**}[\log 10\ (Q_L/Q_B)/(L - B)] - 1$$

Q_L is peak load in the latest year of record, Q_B is the same in the base year, and L and B are respectively the latest year and the base year. r is the compound growth rate, and the base year is $Q_B = A$. The best fit method defines

$$r = \sum_{i=B}^{L} (X_i - \overline{X})(Q_i - \overline{Q}) / \sum_{i=B}^{L} (X_i - \overline{X})^2$$

Here i is each year from the base year to the latest year and X_i is the series of numbers 1, 2, 3,..., B-1. $\overline{X}$ and $\overline{Q}$ are average values. The intercept value is $A = \overline{Q} - (1 + r)\overline{X}$. All terms are logarithmic. This method of course has the characteristic that squared error

$$\sum_{i=B}^{L} (Q_i - A - (1 + r)X_i) \text{ is minimized.}$$

5. The historical data for net system peak load are taken from Supplement 2 of the Final Environment Statement. These data are generally about 95MW less than the series in the company's annual reports. This difference may be attributable to the treatment of Canadian sales, or some other reason unknown to us. The Supplement is also the source of anticipated system capacity. The 1980 value is carried through to 1995 for illustrative purposes only.
6. The t statistics for the intercept and growth rate in logarithmic form are 420.9 and 9.2, respectively, above the .005 significance levels. Explained variance (R^2) is 93%.
7. The t statistics for the logarithms of the constant term and the growth rate are 4.4 and 463.9, above the .975 and .955 significance levels. Explained variance is 87%.
8. A familiarity with Chapman, D., T. Tyrrell and T. Mount, op. cit. and Mount, T., D. Chapman, and T. Tyrrell, op. cit.; and an examination of Part B will provide background for this discussion.
9. See also, Mount, T., D. Chapman, and T. Tyrrell, op. cit., p. 9.

10. Of particular interest are "Individual Action for Energy Conservation," prepared by the Subcommittee on Energy of the House Committee on Science and Astronautics, June 1973; John Moyers, The Value of Thermal Insulation in Residential Construction, Oak Ridge National Laboratory Report ORNL-NSF-EP-9, Oak Ridge, Tennessee, December 1971; and Eric Hirst and John Moyers, "Efficiency of Energy Use in the United States," March 30, 1973, Science.
11. Mount, T., D. Chapman, and T. Tyrrell, op. cit.
12. Although the price of complimentary products (household appliances) is a significant factor, the relative price is assumed to remain at present levels.
13. The explanation of the inequality coefficient has been summarized from: H. Theil, Economic Forecasts and Policy, North-Holland Publishing Company, Amsterdam, 1965, pp. 31-7.