NUREG/CR-1147
ORNL/NUREG/TM-359

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Econometric Model for the Disaggregation of State-Level Electricity Demand Forecasts to the Service Area

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P-016

120555031837 2 ANRE
US NRC
SECY PUBLIC DOCUMENT ROOM
BRANCH CHIEF
HST LOBBY
WASHINGTON DC 20555

Prepared for the
U.S. Nuclear Regulatory Commission
Office of Nuclear Regulatory Research
Under Interagency Agreement DOE 40-550-75

OPERATED BY
UNION CARBIDE CORPORATION
FOR THE UNITED STATES
DEPARTMENT OF ENERGY

8003100183

Printed in the United States of America. Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road, Springfield, Virginia 22161

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NUREG/CR-1147
ORNL/NUREG/TM-359
Dist. Category RE

Contract No. W-7405-eng-26

Energy Division

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Manuscript Completed — August 1978
Date Published — February 1980

Prepared for the

U.S. Nuclear Regulatory Commission
Office of Nuclear Regulatory Research
Washington, D.C. 20555
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NRC FIN No. B-0190-8

Prepared by the
OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37830
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UNION CARBIDE CORPORATION
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DEPARTMENT OF ENERGY

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ABSTRACT

In this paper an econometric model for the disaggregation of state-level electricity demand forecasts to the service area developed by Oak Ridge National Laboratory (ORNL) for the Nuclear Regulatory Commission (NRC) is presented. Based on demand models for the service area and the remainder of the state in which it is located, a model which explains the service area's share of the state's demand is developed and estimated for six service areas using econometric techniques. The share is then forecasted and combined with the forecasts for state demand presented in *Regional Econometric Model for Forecasting Electricity Demand by Sector and by State* to obtain service area forecasts to 1990.

The results from the paper indicate that some service areas differ dramatically from the state and the region of which they are a part. The historic difference in the growth rate of electricity demand is reflected in the forecasted future growth rates generated by the model. This implies that the application of regional or state growth rates to some particular service areas may be inappropriate. The major causes of the difference between the areas seem to be differences in the responsiveness and growth of prices, income, population and industrial activity.

I. INTRODUCTION

Electric utilities and their public regulatory bodies have in recent years become highly in need of reliable demand forecasts for capacity expansion decisions. Inaccurate forecasts can impose substantial costs on the utilities and their consumers. A forecast which overstates demand may cause the utility to invest in capacity which would remain idle for a substantial part of its life. When a forecast understates demand, inefficient generation methods would have to be used – such as peaking units running longer than optimal – or power interuptions and their associated costs endured.

The Nuclear Regulatory Commission (NRC) is charged with the responsibility of licensing nuclear power plants. In this process consideration is given to the effects of whether or not the particular plant is built, especially the economic impacts. Therefore, an accurate method of forecasting demand is needed by the NRC. This study is directed to help answer this need.

As lead times for capacity expansion decisions become longer, the level of error possible in the forecasts increase. Unfortunately, in the last decade the lead times, especially for base loaded plants, have increased substantially. In the past, the longest lead times for new plants were from three to five years. Now, however, for nuclear and coal fired plants, lead times are estimated to be 12 and 10 years respectively. Therefore, the accuracy of demand forecasts must be high.

When capacity decisions are made at the utility level, accurate forecasts must be made at this level. Often it is not sufficient to apply a growth rate in demand from a larger region of which the utility is a part. A utility service area can be substantially different from the region. For example, from 1969-1978 the annual growth rate in total demand for Consolidated Edison Company of New York, Inc. was approximately -1.0 percent while the state as a whole was experiencing a growth rate of approximately 2.5 percent. If capacity planning were at the utility level in this case, substantial differences would have resulted if the state's rather than the utility's growth rate were accurately forecasted and used.

This study develops a theoretical basis for a model which will forecast electricity demand and price at the service area level and discusses the results of such a model applied to various geographically separated service areas. The service area to which the model is applied are: Consolidated Edison Company of New York, Inc.; Central Hudson Gas and Electric Corporation; Commonwealth Edison Company; San Diego Gas and Electric Company; Carolina Power and Light Company; Detroit Edison Company. Data limitations at the service area level, specifically the time duration of the data, require the model to have a simple form.

On the other hand, data at the state level exists for lengthy time periods, is fairly accurate, and has a large number of variables. Thus, the accuracy of the service area forecast may be increased if it incorporates state-level information. State level information is supplied by the State-Level Electricity Demand (SLED) model.[1] The information used is state-level estimates or forecasts of demand and price by customer class. The model has been estimated and forecasts made for 48 states. Results have shown that the model has an accurate forecasting record.

This paper will first discuss the hypothesized major determinants of demand for the three most important customer classes: residential, commercial, and industrial. Next, the results of the estimation of the relationship with demand of the major determinants will be discussed. Finally, the results will be presented using the model for forecasting within the sample period and to 1990.

II. MODEL DEVELOPMENT

A. Residential Demand

The demand model as proposed specifies long run equilibrium electricity demand to be dependent on electricity price, income, the number of customers and weather measured by heating and cooling degree days. $Q_R^* = f(P_R, I, C_R, W)$. The subscript "R" refers to the residential sector. If electricity is a normal good, we would expect that $\partial Q_R^*/\partial P_R < 0$, $\partial Q_R^*/\partial I > 0$. In addition, we would expect that $\partial Q_R^*/\partial C_R > 0$

since additional customers would at least use some additional electricity. Also, if electricity is used for spare conditioning an increase in the weather variable would raise demand, therefore $\partial Q_R^*/\partial W > 0$. As an approximation to the function f, we will assume that the demand relationship has the following form:

$$Q_R^* = \alpha_1 P_R^{\beta_1} I^{\beta_2} C_R^{\beta_3} W^{\beta_4} \varepsilon_1 \tag{1}$$

Since the capital stock of customers is fairly fixed in the short run, customers probably cannot adjust immediately to a different equilibrium level of demand.[2] It will be assumed to follow a Nerlove[3] adjustment process, that is,

$$\frac{Q_{R,t}}{Q_{R,t-1}} = \left(\frac{Q_{R,t}^*}{Q_{R,t-1}}\right)^{\gamma}$$

where $0 < \gamma \leq 1$. Performing a Koyck[4] transformation on the long run equilibrium demand equation yields:

$$Q_R = \alpha_1 P_R^{\beta_1} I^{\beta_2} C_R^{\beta_3} W^{\beta_4} L^{\beta_5} \varepsilon_1$$

where L is Q lagged one period and $\beta_5 = \gamma$. Using the subscripts "SA" to refer to variables of the service area and "0" to refer to variables of the remainder or the other part of the state, as will be used in the remainder of this study, other residential, and service area residential demand can be represented by the following two equations:

$$Q_{R0} = \alpha_{10} P_{R0}^{\beta_{10}} I_0^{\beta_{20}} C_{R0}^{\beta_{30}} W_0^{\beta_{40}} L_0^{\beta_{50}} \varepsilon_{10} \tag{2}$$

$$Q_{RSA} = \alpha_{1SA} P_{RSA}^{\beta_{1SA}} I_{SA}^{\beta_{2SA}} C_{RSA}^{\beta_{3SA}} W_{SA}^{\beta_{4SA}} L_{SA}^{\beta_{5SA}} \varepsilon_{1SA} \tag{3}$$

Dividing Eq. (3) by Eq. (2), and taking the natural logarithm of both sides of the resultant equation yields the linear estimatable form:

$$\ell n\frac{Q_{RSA}}{Q_{RO}} = \alpha_1' + \beta_{1SA}\ell nP_{RSA} - \beta_{10}\ell nP_{RO} + \beta_{2SA}\ell nI_{SA}$$

$$- \beta_{20}\ell nI_0 + \beta_{3SA}\ell nC_{RSA} - \beta_{30}\ell nC_{RO} + \beta_{4SA}\ell nW_{SA}$$

$$- \beta_{40}\ell nW_0 + \beta_{5SA}\ell nL_{SA} - \beta_{50}\ell nL_0 + \varepsilon_1' \qquad (4)$$

where $\alpha_1' = \ell n(\alpha_{1SA}/\alpha_{1S})$ and $\varepsilon_1' = \ell n(\varepsilon_{1SA}/\varepsilon_{1S})$. Equation (4) states that the split of state demand between the service area and the remainder of the state is a function of the variables which are responsible for the causation of the demand in the two regions.

Assuming that the service area has a relatively small influence on the other parts of the state and the converse, the signs of the coefficients β_{10}, β_{1SA}, β_{20}, β_{2SA}, β_{30}, β_{3SA}, β_{40}, and β_{4SA} must be consistent with the signs, given above, of the partial derivatives with respect to the variable the coefficient is associated with. β_{50} and β_{5SA} must be >0 and ≤ 1 or demand would be unstable. Of course, the coefficients are the elasticities of demand with respect to their associated variables.

Since price is not independent of demand, due to declining or increasing block rates, the supply response of the utility and regulation imposed on the utility, unbiased estimation of the demand equation requires that this relationship be explained. The determinants of price are assumed to be demand, the number of customers, and the average total cost of the utility, or in functional notation:

$$P_R = g(Q_R, C_R, ATOC) \ . \qquad (5)$$

The sign of $\partial P_R/\partial Q_R$ is indeterminant due to the pricing structure utilities usually use declining or increasing back pricing. There should be a positive relationship between price and average total cost,

since as average total cost rises one would expect that a utility will demand, and a regulatory commission will grant, an increase in the price the utility is allowed to charge. Therefore, the sign of $\partial P_R/\partial ATOC$ should be positive. Similar to the relationship between price and quantity, the relationship between price and customers is indeterminant due to the pricing structure. Given that average total cost and residential demand stays constant, an increase in the number of customers may increase or decrease price due to the non-uniform pricing structure.

The functional form of the relationship between price and its explanatory variables will be assumed to be:

$$P_R = \alpha_2 Q_R^{\beta_6} C_R^{\beta_7} ATOC^{\beta_8} \varepsilon_2 \ . \tag{6}$$

Taking the natural logarithm of both sides of this equation, applying it to the service area and the other part of the state, and subtracting yields the following linear estimatable equations:

$$\ell n\left(\frac{P_{RSA}}{P_{RO}}\right) = \alpha_2' + \beta_{6SA}\ell n Q_{RSA} + \beta_{7SA}\ell n C_{RSA} + \beta_{8SA}\ell n ATOC_{SA}$$

$$- \beta_{60}\ell n Q_{RO} - \beta_{70}\ell n C_{RO} - \beta_{80}\ell n ATOC_0 + \varepsilon_2' \tag{7}$$

where $\alpha_{2SA}' = \ell n(\alpha_{2SA}/\alpha_{20})$, $\varepsilon_2' = \ell n(\varepsilon_{2SA}/\varepsilon_{20}')$.

Equations (4) and (7) constitute a linear in logs system of two equations. If the assumption is made that the variables besides the demands and prices are exogenous to the system, then there are four endogenous variables $\ell n Q_{RSA}$, $\ell n Q_{RO}$, $\ell n P_{RSA}$, and $\ell n P_{RO}$.

Many of the variables in the model move together fairly closely, therefore, presenting problems of multicollinearity. In addition, the number of observations is fairly small due to short historical data series. In estimating the equations then, the number of degrees of freedom is small; therefore, the variance of the estimators would be large.

In order to solve this problem two simplifying assumptions may be used. When two variables move together fairly closely, such as service area income and the income of the rest of the state, one will be assumed to be related approximately by the form:

$I_0 = \gamma I_{SA}^{\beta 20SA} \omega$. If ω is small, tne variance of the estimators may be decreased. Substituting this into equation (4) yields:

$$\ell n \frac{Q_{RSA}}{Q_{RO}} = \alpha_1'' + \beta_{1SA} \ell n P_{RSA} - \beta_{10} \ell n P_{RO} + \beta_{2SA}' \ell n I_{SA}$$

$$+ \beta_{3SA} \ell n C_{RSA} - \beta_{30} \ell n C_{RO} + \beta_{4SA} \ell n W_{SA}$$

$$- \beta_{40} \ell n W_0 + \beta_{5SA} \ell n L_{SA} - \beta_{50} \ell n L_0 + \varepsilon_1''$$

where $\alpha_1'' = (\alpha_1' - \beta_{20} \ell n \gamma)$, $\varepsilon_1'' = (\varepsilon_1' - \beta_{20} \ell n \omega)$ and $\beta_{2SA}' = \beta_{2SA} - \beta_{20} \cdot \beta_{20SA}$. Using this assumption eliminates the income in the rest of the state from the equation. Of course, the same assumption could be used for the remainder of the variables in the equation.

The other assumption that may be used is that the responsiveness may be the same for the service area as for the rest of the state. For example, in equation (4) assume $\beta_{50} = \beta_{5SA}$. Equation (4) can then be written as:

$$\ell n \frac{Q_{RSA}}{Q_{RO}} = \alpha_1' + \beta_{1SA} \ell n P_{RSA} - \beta_{10} \ell n P_{RO} + \beta_{2SA} \ell n I_{SA}$$

$$- \beta_{20} \ell n I_0 + \beta_{3SA} \ell n C_{RSA} - \beta_{30} \ell n C_{RO} + \beta_{4SA} \ell n W_{SA}$$

$$- \beta_{40} \ell n W_0 + \beta_{5SA}' \ell n \left(\frac{L_{RSA}}{L_{RO}} \right) + \varepsilon_1' .$$

As before, this assumption can be applied to the other variables in the equation.

When both the assumptions are made on a particular equation the effect on the ratio of demands will be captured by the constant term. Assume that weather in the service area remains fairly proportionate to the weather in the rest of the state. Also, assume that the long run equilibrium demand responsiveness of the two areas are similar. This implies $W_0 = \gamma W_{SA}$ ω and $\beta_{40} = \beta_{4SA}$. Equation (4) can be written as

$$\ell n \frac{Q_{RSA}}{Q_{RO}} = \alpha_1'' + \beta_{1SA} \ell n P_{RSA} - \beta_{10} \ell n P_{RO} + \beta_{2SA} \ell n I_{SA}$$

$$- \beta_{20} \ell n I_0 + \beta_{3SA} \ell n C_{RSA} - \beta_{30} \ell n C_{RO} + \beta_{5SA} \ell n L_{SA}$$

where $\alpha_1'' = (\alpha_1' - \beta_{4SA} \gamma)$ and $\varepsilon_1'' = (\varepsilon_1' - \beta_{40} \ell n \omega)$.

B. Commercial Demand

The commercial sector will be modeled in a similar manner to the residential sector. Long run equilibrium demand for electricity in the commercial sector will be assumed to be dependent on price, income, population, and weather, or in functional notation $Q_C^* = f(P_C, I, POP, W)$, with the subscript "C" referring to the commercial sector. The relationship between demand and price or $\partial Q_C^* / \partial P_C$ is hypothesized to be negative, with income, $\partial Q_C^* / \partial I$, positive with population, $\partial Q_C^* / \partial POP$, positive and with weather, $\partial Q_C^* / \partial W$, positive. An increase in electricity price, other factors remaining constant, would cause a substitution away from electricity in the commercial sector. An increase in income or population, other factors remaining constant, would cause an increase in services in the commercial sector thereby increasing the demand for electricity in this sector since it is one of the inputs to this sector. A change in weather, W, would change the amount of electricity used for space conditioning. Assuming the same functional form for commercial demand as residential demand and the same adjustment process to long-run equilibrium demand, dividing the service area demand function by the state demand function and taking natural logarithms of both sides of the resultant equation yields the linear estimatable form:

$$\ell n \frac{Q_{CSA}}{Q_{CO}} = \alpha_1' + \beta_{1SA} \ell n P_{CSA} - \beta_{10} \ell n P_{CO} + \beta_{2SA} \ell n I_{SA}$$

$$- \beta_{20} \ell n I_0 + \beta_{3SA} \ell n POP_{SA} - \beta_{30} \ell n POP_0 + \beta_{4SA} W_{SA}$$

$$- \beta_{40} W_0 + \beta_{5SA} L_{CSA} - \quad {}_0 L_{CO} + \varepsilon_1' \ . \tag{8}$$

The price equations will be assumed to have the same form as the price equations in the residential sector. Taking the natural logarithm of both sides of the equations produces:

$$\ell n \left(\frac{P_{CSA}}{P_{CO}} \right) = \alpha_2' + \beta_{6SA} \ell n Q_{CSA} + \beta_{7SA} \ell n C_{CSA} + \beta_{8SA} \ell n ATOC_{SA}$$

$$- \beta_{60} \ell n Q_{CO} - \beta_{70} \ell n C_{CO} - \beta_{80} \ell n ATOC_0 + \varepsilon_2' \ . \tag{9}$$

C. Industrial Demand

In the industrial sector, since electricity is an input into the production process, the long run equilibrium demand for electricity will be assumed to be dependent on the activity in the sector and the substitution between other inputs in the production process. The activity in the sector will be characterized by value added. Substitution will be assumed to depend largely on the price of electricity. In functional notation this can be written as $Q_I^* = f(P_I, VA)$. As value added increases, one would expect that electricity demand would increase since electricity is an input into the production process. If electricity is a normal input one would expect that as the price of electricity increases, substitution would be away from electricity. Of course the above assumes other effects stay constant. Assuming the same functional form as in the previous sectors and the same adjustment process to long-run equilibrium demand, dividing the service area demand equation by the state demand equation, and taking natural logarithms of both sides of the resultant equations produces a demand ratio equation of the form:

$$\ell n \frac{Q_{ISA}}{Q_{IO}} = \alpha_1' + \beta_{1SA} \ell n P_{ISA} - \beta_{IO} \ell n P_{IO} + \beta_{2SA} \ell n VA_{SA}$$

$$- \beta_{20} \ell n VA_0 + \beta_{3SA} L_{ISA} - \beta_{30} L_{10} + \varepsilon_1' \qquad (10)$$

The subscript "I" refers to the industrial sector.

As in the residential and commercial sector, the price equations will take the same form in the industrial sector. Taking natural logarithms of both sides of the equations yield:

$$\ell n \left(\frac{P_{ISA}}{P_{IO}} \right) = \alpha_2' + \beta_{4SA} \ell n Q_{ISA} + \beta_{5SA} \ell n C_{ISA} + \beta_{6SA} \ell n ATOC_{SA}$$

$$- \beta_{40} \ell n Q_{IO} - \beta_{50} \ell n C_{IO} - \beta_{60} \ell n ATOC_0 + \varepsilon_2' \qquad (11)$$

Each customer class, therefore, has two equations. The first explains the difference in the demand in the service area relative to the demand in the remainder of the state. The second explains the relationship between the price charged a particular customer class in the service area and the price charged the class in the remainder of the state. The relationship between these two sets of variables is explained by a set of variables which are derived from the demand or price equations for a single area. Due to data limitations or multicollinearity between variables, simplifying assumptions may be necessary before estimation to obtain accurate parameter, demand and price estimates. These assumptions are that one variable can be approximated by a function of another variable, the response to one variable in an area is the same as the response to the same variable in the other area, or both. The next section describes the estimation technique and the results obtained.

III. ESTIMATION

Since in the equations to be estimated, (4), (7), (8), (9), (10), and (11), explanatory variables are endogenous to the demand system,

ordinary least squares estimation of the relationships expressed by the equations would lead to biased estimators. The problem arises due to the simultaneous nature of the demand and price equations. In the demand equation, the demand ratio is explained by price; while in the price equation, the price ratio is explained by demand. Both equations together determine price and demand. Ordinary least squares would not disassociate this two-way relationship.

There are a variety of methods which can be used to obtain asympototically unbiased estimates in a simultaneous-equation system. The method used in this analysis was two-stage least squares. Since, however, the degrees of freedom are so small, the asymptotic unbiasness property does not hold and the distortions may, in fact, be greater than ordinary least squares. One cannot determine, though, the degrees of freedom necessary for two-stage least squares to be a better, or worse, estimating process than ordinary least squares. At least, with two stage least squares, we know that the bias is approaching zero with larger samples, which is not true with ordinary least squares.

Estimation was performed for each class separately. A method which estimated all classes jointly may have produced estimates which were asymptotically more efficient, but an insufficient number of data observations prevented using these alternative methods. The variables used in the model are specifically described and their sources referenced in Appendix A and E. Appendix B reports the results of the estimation process. The numbers under the coefficient estimates, in parenthesis, are the t-statistics. Since the statistics only have a t distribution asymptotically and in this analysis the degrees of freedom are low, the usefulness of the statistics are questionable. In two-stage least squares estimation, the normal R^2 statistic usually is not meaningful. The R^2 value reported then is the R^2 value of the transformed equation. This statistic gives information on how well this equation behaved. Due to the questionable meaning of statistics in this study, other statistics are not reported.

In order to reduce the variance of the estimators in the equations due to multicollinearity or low degrees of freedom, some of the variables

will be eliminated. This changes the meaning of the estimators as specified in Section II-A.[5] The remainder of the state variables will be eliminated if they show high correlation with service area variables. For example, service area income often is highly correlated with the income for the remainder of the state. Therefore, the income for the remainder of the state will be eliminated in those equations and the coefficient for service area income will estimate the difference between the coefficient for service area income and the coefficient for income in the remainder of the state.

When coefficient estimates of two corresponding variables show little difference except sign the ratio of the variables will be used instead of each variable separately. The coefficient of the ratio variable would then be the coefficient of each separate variable except for the sign which would be opposite. If both cases occur the variables will be dropped from the equation, as they would have little or no effect on the demand ratio. The variables would increase or decrease relatively the same and they would both affect the demand ratio similarly but opposite. The combined effect then would be small or zero.

Consolidated Edison is an extreme example of a service area differing from the remainder of the state and will be discussed in detail. "Differing" refers to the variables explaining price and demand having different growth rates or responsiveness of price and demand to these explanatory variables are different between the service area and the remainder of the state. If the service area does indeed differ, one would expect that the variables explaining why the two areas differ would be statistically significant and explain a substantial part of the variation of the differing demand and price. Conversely, if the service area and the remainder of the state do not differ, why they differ will be insignificant and explain little of the variation between the two areas.

As can be seen in Appendix B, pages B-1 to B-3, all the asymptotic t-statistics are greater than 1 and usually significantly greater than 2. In addition all of the R^2 values are greater than .9. With the low degrees of freedom and the two-stage least squares estimation procedure though, one is cautioned not to place a high degree of significance on these statistics.

In the residential demand equation for Consolidated Edison, the estimated coefficients seem reasonable. If the price and income are growing at approximately the same rate at the service area level as at the remainder of the state, then from the equations on page 6, β_{20SA} should be close to one and the estimated coefficients for Consolidated Edison should be approximately the difference between the elasticities for the service area and the remainder of the state. From the results reported on page B-1, the difference between the elasticities for both price and income have negative signs indicating that the price elasticity is higher for Consolidated Edison and the income elasticity lower. During the period of time under consideration, the proportion of income spent on electricity in Consolidated Edison's service area is less than the remainder of the state, 16% in 1974. Consumers may perceive electricity is less important in their budget and hence the income elasticity would be lower. Other studies,[6] have indicated that higher prices for electricity in the residential sector may lead to higher – more negative – price elasticities. This study agrees with this finding in that since the difference between the price elasticity of demands is negative, the elasticity at the service area must be higher. The residential average price for electricity for Consolidated Edison is approximately 88% higher than the average price in the remainder of the state in 1974. The response to a price change can be broken down into an income effect and a substitution effect. The income effect is a response due to the consumer having a different real income after the price change. The income elasticities discussed above indicate that this response is less for consolidated Edison's customers than the remainder of the state's. For the total price effect on demand to be higher for Consolidated Edison, the substitution effect would have to be substantially higher in its service area overcoming the difference in the income effect as well as the remainder of the state's substitution effect.

In the commercial sector, the price elasticity is less than the remainder of the state and the income and population elasticities greater. This probably reflects the unique nature of the commercial sector of the City of New York. There is substantially higher concentration of office space in the city as opposed to the remainder of the state. Given the

climate-controlled aspects of office buildings, one would expect the results indicated by this analysis.

Also reflecting the unique character of New York City are the demand determinants in the industrial sector. The price elasticity is higher and the value added elasticity lower than the remainder of the state. Since the price of elasticity in the industrial sector is substantially higher than the remainder of the state, 3.4 times as high in 1974, electricity intensive industries probably do not locate in the service area. Electricity would not be an important input for these firms. A change in price then, would not have as significant effect on the cost structure of the firms as in other regions leading to a lower elasticity. Likewise, a change in value added would add relatively little to electricity demand as compared to other regions if electricity is a minor input. The service area is significantly different from the remainder of the state and the elasticity estimates reflect this.

IV. FORECASTING

Each of the three customer classes in the model have two equations. However, there are four unknowns in each of the three sets of equations Q_{SA}, Q_0, P_{SA} and P_0. Therefore, the system cannot be solved for service area demands and prices unless additional restrictions are imposed. However, by incorporating information on state level demands and prices the system can be solved. The SLED model developed at ORNL forecasts demand and price by customer class at the state level. The model makes use of the extensive data available at the state level although the model has a manageable size. Estimation and forecasts have been prepared for the 45 states and have demonstrated the accuracy of the model. Therefore, the service area model will use the SLED model as an input to determine a solution for the service area's and the remainder of the state's demand and price by customer class.

Two restrictions are immediately apparent. One is that the quantity demanded in the service area plus the quantity demanded in the rest of the state must add to the total sold in the state for a particular customer class.

$$Q_{RSA} + Q_{RO} = Q_{RS}$$

$$Q_{CSA} + Q_{CO} = Q_{CS}$$

$$Q_{ISA} + Q_{IO} = Q_{IS} \qquad (1)$$

where Q_{RS}, Q_{CS} and Q_{IS} are the quantities sold in the state by the residential commercial and industrial customer classes. The second restriction involves the prices P_{SA} and P_{O}. Prices are calculated by dividing the total revenue derived from a particular customer class by the quantity sold to that class in a given area. The prices times the quantity then would produce the total revenue for the class in the area. The total revenue for the class in the service area plus the total revenue for the class in the other part of the state must add to the total revenue for the class in the state. This implies the following three equations:

$$(Q_{RSA} \cdot P_{RSA}) + (Q_{RO} \cdot P_{RO}) = Q_{RS} \cdot P_{RS}$$

$$(Q_{CSA} \cdot P_{CSA}) + (Q_{CO} \cdot P_{CO}) = Q_{CS} \cdot P_{CS}$$

$$(Q_{ISA} \cdot P_{ISA}) + (Q_{IO} \cdot P_{IO}) = Q_{IS} \cdot P_{IS} \qquad (2)$$

These two sets of equations (1) and (2) create a system of four equations for the four unknowns but introduce two more unknowns, the price and quantity in the state. The value of these variables though, can be obtained from the State-Level Electricity Demand Model (SLED). The four equation system for each class is nonlinear in that the demand ratio and the price ratio equations are linear in log, but the quantity and total revenue state-level restriction equations are non-linear in the endogenous variables and/or non-log.

The system cannot be solved in closed form, so an iterative technique must be used. The method used was developed by Kenneth M. Brown[7] and is a variation of Newton's method incorporating Gaussian elimination in such

a way that the most recent information is always used at each step of the process. In the Newton method for solving a set of simultaneous equations, all calculations are performed on all equations at the same time. In Brown's method though, information generated by calculations performed on the previous equations enter into computations performed on the next equations. Less function evaluations are required per iterative step, the method appears to converge more often and faster than the Newton method.

The solution of the system is the system's estimate or forecast of the demand and price for a specific customer class in the service area. The estimates can be calculated for three different time periods: (1) is the period during which the model was estimated, usually from 1960-1974; (2) is the period from the end of the estimation period to the present time, 1974-1978; (Such estimates are usually called ex post forecasts since the model is forecasting the future from the estimation period but in the past from present time), and (3) is the future period from the present or the ex ante forecast period, 1979-1990.

Periods (1) and (2) are useful in that they enable one to obtain some idea of how well the model performs in forecasting. One would expect that in period (1) the model would forecast better than the other two periods. In the estimation period the parameter estimates are unbiased estimates of the true parameters which may not be the case in the second period if there were structural change in the model. Also, in the estimation period the exogenous variables are known with certainty which in this analysis does not occur in the second period. Period two, therefore, would be a more accurate indication of the reliability of the forecasts.

As a measure of how closely the estimated or forecasted value of the endogenous variables track the historical value of the variables in periods (1) and (2), the root mean square percent error (RMSPE) will be used. This value is defined in the following equation:

$$\text{RMSPE} = 100 \cdot \sqrt{\frac{1}{T} \sum_{t=1}^{T} \frac{(\hat{y}_t - y_t)^2}{y_t^2}}$$

where

$\hat{y}_t$ = estimated value of the endogenous variable in year t

y_t = actual value of the endogenous variable in year t

T = number of years in the period being considered.

In this report only the estimates in period (1) will be presented and the results in period (2) and (3) assuming that the growth rates of the variables external to the model are the same at the service area level and the remainder of the state. A future report will present the estimates in period (2) from 1975-1978 and the future demand from 1980-1995 with growth rates for the external variables specific for the service area and the remainder of the state.

Table 1 lists the root mean squared percent error in the estimation period for each of the customer classes of the six service areas. In all service areas, the residential class had the lowest error, being always below 1%. In the commercial and industrial sectors only Central Hudson and San Diego Gas and Electric have an error over 1%. Even for these two service areas, when one considers that the error is over 12-15 years and the error in one year may compensate for an error in another year, the effect on growth rates will be small. For example, over 14 years the predicted growth rate of San Diego Gas and Electric's industrial differs from the actual by only .17%, that is, 8.87 versus 9.04 respectively.

The following figures illustrate the estimated future growth of demand for Consolidated Edison using the assumption that the growth rates of the variables external to the model are the same at the service area level and the remainder of the state. The growth rates of these variables are listed in Appendix C. This method illustrates the differences in responsiveness between the two areas and the state as a whole.

As discussed in the previous section, the price response in the residential sector is higher for Consolidated Edison and the income response is lower. Both effects would tend to reduce the growth rate of residential demand at the service area level as opposed to the remainder of the state. This is indeed what the forecasted values as illustrated in Fig. 1 show. The growth rates of the state as a whole from 1974-1990 is estimated to be 2.9% versus the growth rate of the service area of 2.3%.

Table 1. RMSPE in estimation period (percent)

	Residential	Commercial	Industrial
Consolidated Edison	.66	.83	2.0
Central Hudson	.57	1.57	3.15
Commonwealth Edison	.75	.78	.75
San Diego Gas & Electric	.93	2.79	4.34
Carolina Power & Light	.66	.77	.94
Detroit Edison	.29	.39	.94

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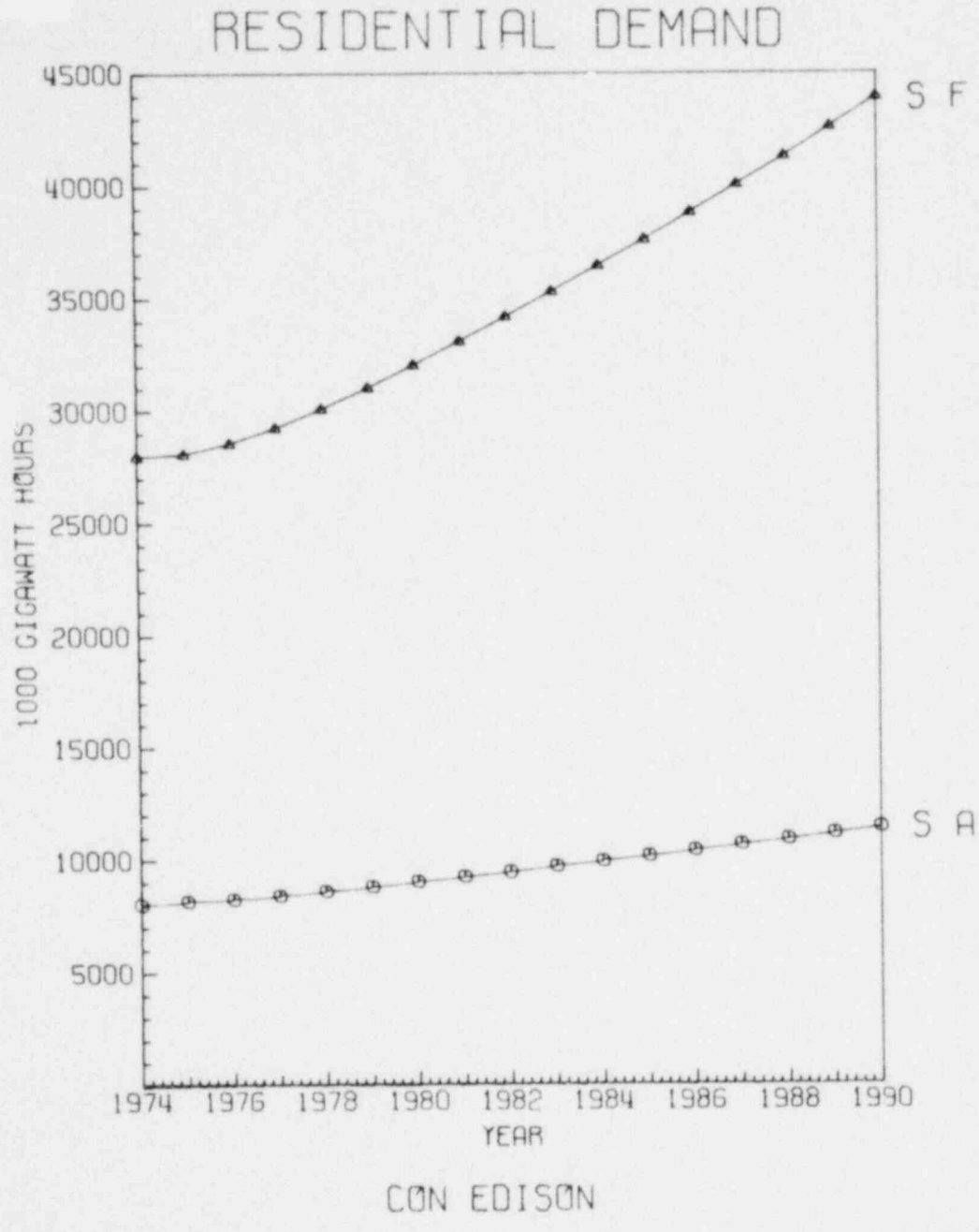

Fig. 1. Residential demand forecasts for Consolidated Edison

As shown in Fig. 2, in the commercial sector, the price response is also greater for Consolidated Edison than for the remainder of the state. However, the income and population response also are higher in the service area. The first and the last two effects are opposite from one another, but it appears that the price effect on demand is stronger due to both a high elasticity and a high growth rate of price. Commercial demand in the service area rises at an annual growth rate from 1974-1990 of 4.1% while in the state the growth rate is 5.7%.

The industrial sector of Consolidated Edison has a growth rate in demand from 1974-1990 substantially below the value for the state, -.4% for the former and 4.1% for the latter as illustrated in Fig. 3. Price has a higher elasticity in the service area and value added has a lower elasticity. The two effects together combine in the same direction to lower, substantially, the growth rate of the service area as compared to the remainder of the state.

The demand growth rate for all classes combined in the service area is 3.3% as compared to the state growth rate of 4.3%, see Fig. 4. The dramatic difference in industrial demand is not reflected in the total since industrial demand is relatively small for Consolidated Edison.

The forecasts for the remainder of the service areas, as shown in Table 2 and Appendix D, show a growth rate in demand fairly similar to that of the state. However, the change in the mix of demand growth among customer classes is significant. In many cases the growth of demand for one class differs substantially from service area to state. For example, in the service area of San Diego Gas and Electric the growth rate of industrial demand is estimated to be .4% while at the state level 3.0% even though the growth rate for all classes is 3.9 and 4.0, respectively. It appears as if the difference in responsiveness for a particular service area to demand determinants is substantial. If the future pattern in the growth rates of demand determinants for a service area differ in their growth rates from the state — which they do not here — the effect on total demand could be important.

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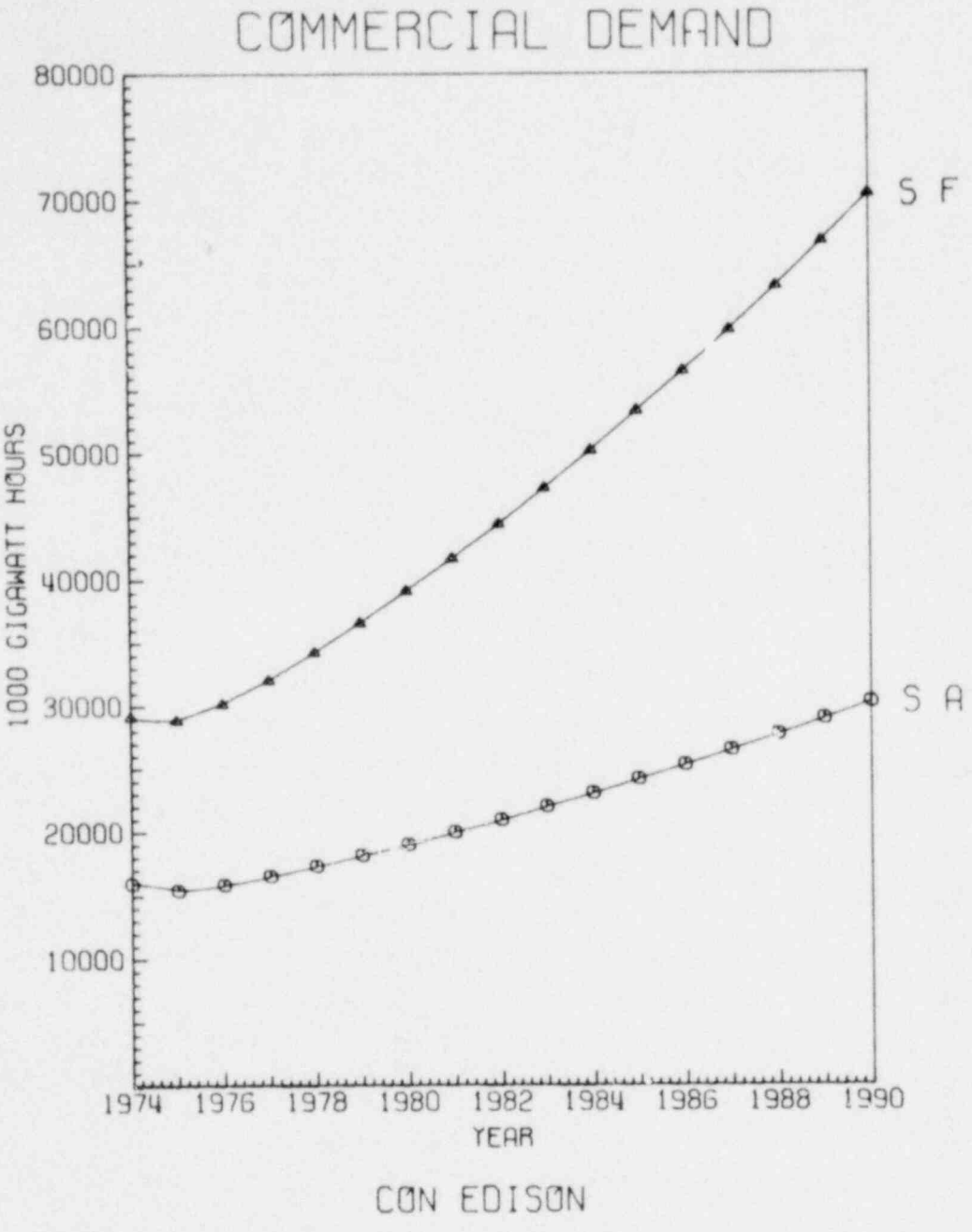

Fig. 2. Commercial demand forecasts for Consolidated Edison

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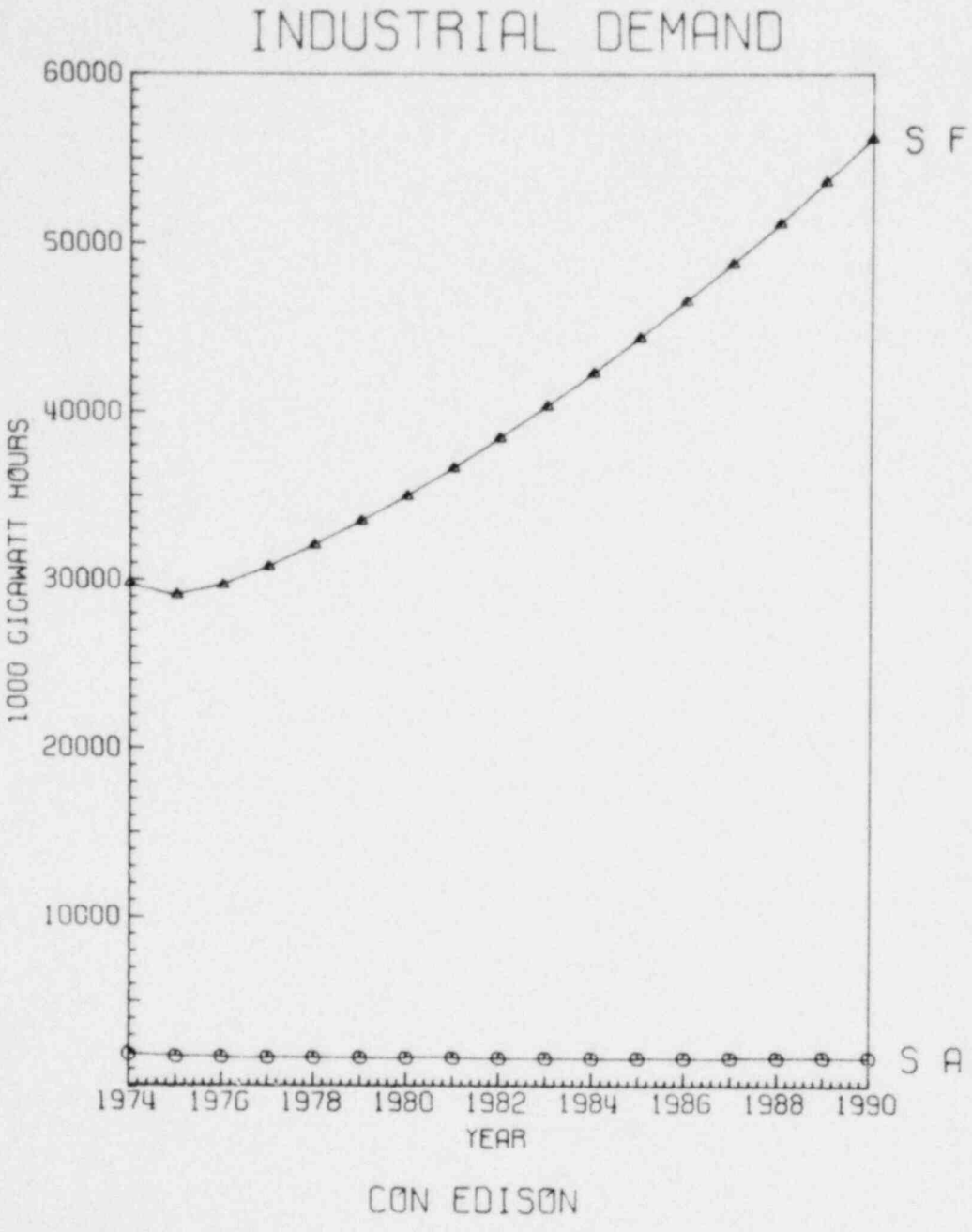

Fig. 3. Industrial demand forecasts for Consolidated Edison

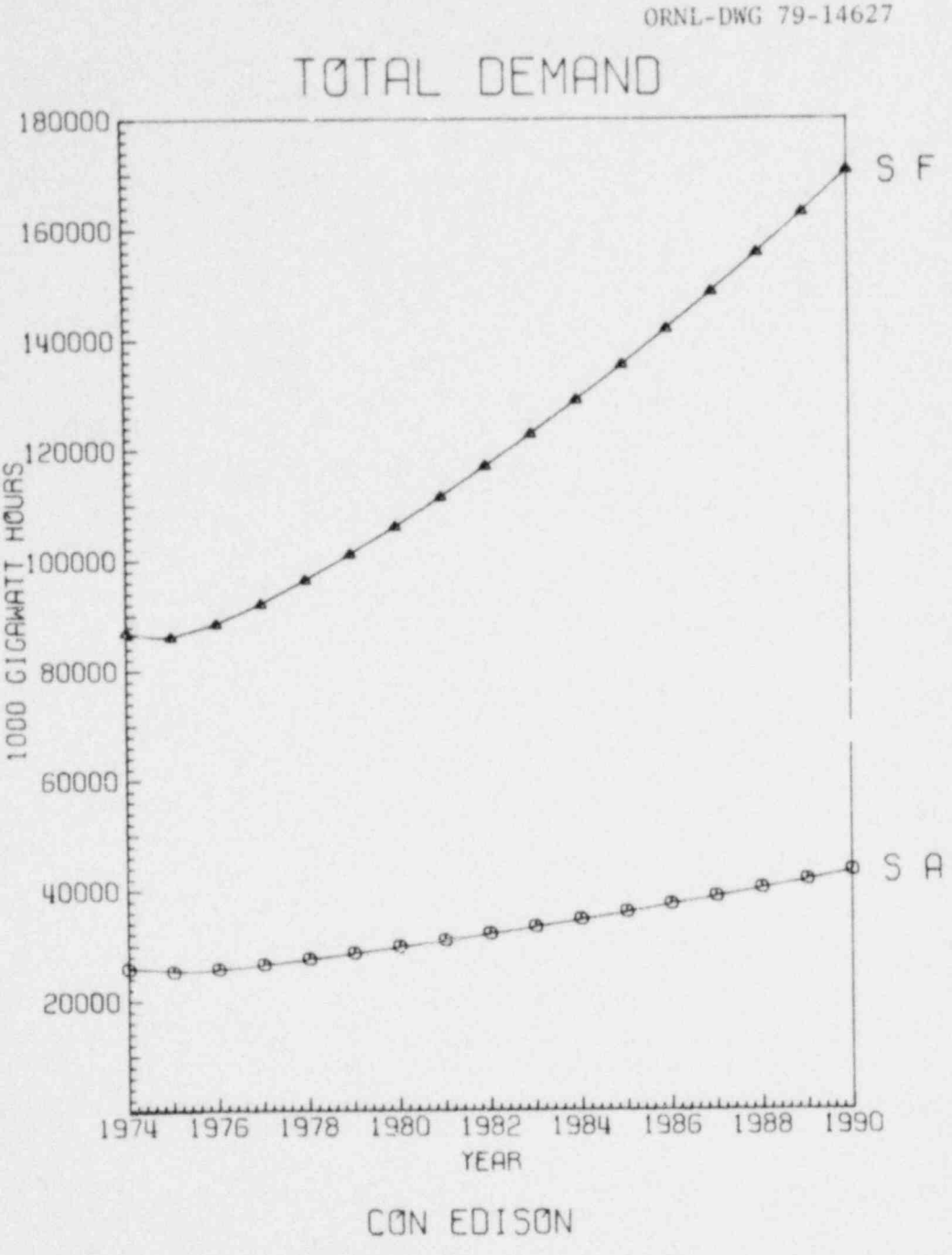

Fig. 4. Industrial demand forecasts for Consc idated Edison

Table 2. Forecasted annual growth rates of electricity demand of service areas and their corresponding state for 1974-1990 (percent)

Area	Customer class			
	Residential	Commercial	Industrial	Total
New York State	2.9	5.0	4.2	4.1
Consolidated Edison Co. of New York, Inc.	2.3	4.0	-0.4	3.3
Central Hudson Gas and Electric Corp.	2.4	7.9	2.7	4.1
Illinois	3.0	4.5	3.4	3.6
Commonwealth Edison Co.	2.9	3.6	4.8	3.9
California	4.1	4.9	3.0	4.0
San Diego Gas and Electric Co.	5.4	5.9	0.4	3.9
North Carolina	2.4	2.2	2.9	2.6
Carolina Power and Light Co.	1.7	0.2	4.5	2.9
Michigan	2.3	5.0	4.7	4.0
Detroit Edison	1.7	3.9	5.0	4.0

V. CONCLUSION

The service area forecasting model described in this paper builds upon the state level forecasting model which has been developed at ORNL. The state level model has advantages in that the available data are extensive and the model has a detailed though manageable size, three customer classes for each of the 48 states. Estimation and forecasts have been prepared for the 48 states and have demonstrated the accuracy of the model.

However, there is often a great diversity between the electricity demand structure of a service area and its surrounding region. Although the climatic difference may be slight, economic and demographic growth, preferences, lifestyles, and income levels can differ significantly. The application of regional growth rates in electricity demand to service areas can cause significant errors. However, there are service areas which are similar to their region, in which case the application of regional growth rates would be satisfactory. The identification of these service areas, though, may require a service-area modeling effort.

The method of service-area forecasting discussed in this report is able to take into account the major differences between the service area and its surrounding region, usually its state. In addition, the regional demand determinants are also incorporated in the model. This is accomplished by explaining the service area's share of the regional demand through the use of the major explanatory variables of demand in both areas and then applying the forecasted share to the regional forecast to determine the service-area forecast. This approach enables the model to capture the major effects and causes of the diversity between the two areas. Specifically, the model can handle different elasticities of demand between the two areas and also differences in economic and demographic growth in the areas.

A substantial part of the variation between the areas is due to differences between levels and responsiveness to price, income, customer or population growth and industrial activity. Data on these variables even at the service-area level, fortunately, can usually be found in published sources. Climatic differences and the adjustment process to

changes in the demand determinants were less important in those service areas investigated in this study. In the estimation period, the model estimated demand for each customer class to be within 5% of the actual value on the average and usually within 1% of the actual value.

There are problems, however, with this method. The first is that it is now becoming common, especially for the larger service areas, to develop very detailed models of their service areas. The effort involved in these studies can be substantial including model development, data collection and validation. If this model is believed to be in competition with the model developed by the utility, some people may tend to put more confidence in the utility's model. The increased accuracy and scope of the utility's data base and the ability to take into account many different factors may be a valid reason as to why it might be a better model, but three things should be noted. (1) This model, as used by the NRC, should not be considered to be in competition with the utility's model but as an aid in evaluating the utility's model. (2) Often simpler models outperform more complicated models in forecasting. (3) A detailed model usually requires the ability to forecast many exogenous variables which may be difficult or impossible to do accurately. The second problem with this model is the time required to collect the data, estimate the model, and forecast the results. With sufficient lead time, as is usually the case with NRC environmental impact statements, this should not be a substantial problem. Finally, the accuracy and length of time for which data is available is a problem especially for value added. Methods of solving these problems are being tried such as using employment as a proxy for value added.

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APPENDIX A: DATA AND VARIABLES FOR SERVICE AREA

DATA AND VARIABLES FOR SERVICE AREA

1. $\ln Q_R$, $\ln Q_C$, $\ln Q_I$ are the natural logarithm of the residential, commercial and industrial sales of electricity as reported in the *Statistics of Privately Owned Utilities in the United States*. Since utilities which cross state borders have separate subsidiaries, they present no special problem.

   SOURCE: Federal Economic Regulatory Commission (F.E.R.C.), *Statistics of Privately Owned Utilities in the United States*

   UNITS: 10^6 kWh

2. $\ln P_R$, $\ln P_C$, $\ln P_I$ are the natural logarithm of the real average residential, commercial and industrial prices of electricity. They are derived by dividing the revenue of each sector by the demand as reported in the *Statistics of Privately Owned Utilities in the United States*. The ratio is then deflated by the consumer price index of the state or of the particular service area for the residential and commercial sectors and the national wholesale price index of intermediate materials and supplies for the industrial sector.

   SOURCE: F.E.R.C., *Statistics of Privately Owned Utilities in the United States*

   UNITS: Dollars per kWh

3. $\ln L_R$, $\ln L_C$, $\ln L_I$ are the lagged one period natural logarithm of sales of electricity in the residential, commercial and industrial sectors corresponding to $\ln Q_R$, $\ln Q_C$ and $\ln Q_I$.

4. $\ln C_R$, $\ln C_C$, $\ln C_I$ are the natural logarithm of the number of electric customers for the residential, commercial and industrial classes.

   SOURCE: F.E.R.C., *Statistics of Privately Owned Utilities in the United States*

   UNITS: 10^3 Number of Customers

5. $\ln W$ is the natural logarithm of the heating and/or cooling degree days. For heating and cooling degree days we used a weighted average of different stations in the service area. The weights depend on the percentage of the population in the service area most likely to

have similar climate as the weather station. This was done by comparing maps of the service area, one showing the weather stations and the other showing population. To approximate the percentage of the population covered by station iso-heating and cooling degree days were drawn for 1972-1973. This was done with the aid of geographers at ORNL. The accuracy of this method varies among service areas due to the variance in the number of reporting weather stations.

Heating degree days are obtained for each station from the *Monthly Climatalogical Data* publication for each state. Cooling degree days are not calculated before 1969, so they would have to be calculated from daily temperature data involving a substantial amount of time and expense. Instead, an approximation was used which should capture the yearly variation:

$$\frac{\text{Average high for the month} + \text{Average low for the month}}{2}$$

This method will produce degree days consistently higher than the actual values. Such a method is used, though, in the 30 year climatic averages calculated by the Weather Service.

SOURCE: National Oceanic and Atmospheric Administration, *Climatological Data* and *Annual Summary of Climatological Data*

6. ln I is the natural logarithm of the per capita income of the service area deflated by the consumer price index of the state or the service area if reported. The per capita income of the service area is a weighted average of the county per capita income. The weights were determined by the percentage of the population of the service area which lies in a particular county.

   SOURCE: Bureau of Economic Analysis, *Income and Population by County*, Various state publications

   UNITS: 10^3 Dollars

7. ln POP is the natural logarithm of the population in the service area. Population of the service area was found by multiplying the percentage of the population in each county served by the utility, by the

population of the counties and then summing. The percentage of the population in each county served by the utility was determined by the process described in Appendix E which also lists the results of the study. County population was obtained from the sources mentioned below.

SOURCE: Bureau of Economic Analysis, *Income and Population by County* Bureau of the Census, *Current Population Reports* Various state publications

UNITS: 10^3 Number of People

8. ln VA is the natural logarithm of the value added in manufacturing. The data did not exist for all counties, so in those cases values were developed using the data of surrounding counties. The assumption is that surrounding counties' value added would behave somewhat alike.

SOURCE: Bureau of the Census, *Annual Survey of Manufactures*, various state publications

UNITS; 10^6 Dollars

9. ln TOC is the natural logarithm of the real average total cost of the utility. The average total cost includes the cost of fuels, operation, maintenance, taxes, interest, and capital depreciation of generation, transmission, and distribution. The average total cost is then deflated by the consumer price index.

SOURCE: F.E.R.C., *Statistics of Privately Owned Utilities in the United States*

UNITS: Mills per kWh

APPENDIX B: ESTIMATION RESULTS

Table E.1. Estimated residential demand and price equations for Consolidated Edison Company of New York, Inc.

(The figures in parenthesis are estimated t-ratios.)

Variable	Demand Ratio $= \ell n \frac{Q_{RSA}}{Q_{RO}}$	Price Ratio $= \ell n \frac{P_{RSA}}{P_{RO}}$
Constant	-47.6714 (-2.72)	-98.3982 (-5.46)
$\ell n Q_{RSA}$		-0.3006 (-1.01)
$\ell n P_{RSA}$	-0.264 (-6.45)	
$\ell n I_{SA}$	-0.6123 (-2.40)	
$\ell n C_{RSA}$	3.4272 (2.89)	5.3986 (4.36)
$\ell n C_{RO}$		1.3963 (1.42)
$\ell n L_{SA}$	-0.1931 (-3.34)	
$\ell n TOC_{SA}$		0.3910 (2.71)
R^2	0.9787	0.9567

Table B.2. Estimated commercial demand and price equations for Consolidated Edison Company of New York, Inc.

(The figures in parenthesis are estimated t-ratios)

Variable	Demand Ratio $= \ell n \frac{Q_{CSA}}{Q_{CO}}$	Price Ratio $= \ell n \frac{P_{CSA}}{P_{CO}}$
Constant	-41.5182 (-6.98)	-27.2772 (-1.54)
$\ell n Q_{CSA}$		0.8927 (2.31)
$\ell n P_{CSA}$	-0.5465 (-6.93)	
$\ell n P_{CO}$	1.3766 (6.79)	
$\ell n I_{SA}$	0.3786 (1.58)	
$\ell n POP_{SA}$	4.2891 (6.83)	
$\ell n L_{CSA}$		1.2719 (1.20)
$\ell n TOC_{SA}$		0.8073 (5.74)
R^2	0.9876	0.9437

Table B.3. Estimated industrial demand and price equations for Consolidated Edison Company of New York, Inc.

(The figures in parenthesis are estimated t-ratios)

Variable	Demand Ratio $= \ell n \frac{Q_{ISA}}{Q_{IO}}$	Price Ratio $= \ell n \frac{P_{ISA}}{P_{IO}}$
Constant	1.2377 (6.73	-8.3734 (-1.30)
ℓnQ_{ISA}		1.1431 (1.99)
ℓnP_{ISA}	-0.7204 (-12.55)	
ℓnVA_{SA}	-0.4771 (-7.10)	
ℓnC_{ISA}		-0.2553 (-1.86)
$\ell nATOC_{SA}$		0.7807 (2.21)
R^2	0.9776	0.9617

Table B.4. Estimated residential demand and price equations for Central Hudson Gas and Electric Corporation

(The figures in parenthesis are estimated t-ratios)

Variable	Demand Ratio $= \ell n \frac{Q_{RSA}}{Q_{RO}}$	Price Ratio $= \ell n \frac{P_{RSA}}{P_{RO}}$
Constant	23.3547 (1.46)	12.9405 (0.83)
$\ell n Q_{RSA}$		0.0357 (0.07)
$\ell n P_{RSA}$	-0.0435 (-1.05)	
$\ell n I_{SA}$	0.1232 (0.73)	
$\ell n C_{RSA}$	2.2992 (3.75)	-1.1363 (-0.70
$\ell n C_{RO}$	-3.446 (-2.36)	
$\ell n L_{SA}$	-0.1131 (-0.83)	
$\ell n TOC_{SA}$		0.0558 (0.39)
R^2	0.9976	0.9341

Table B.5. Estimated commercial demand and price equations for Central Hudson Gas and Electric Corporation

(The figures in parenthesis are estimated t-ratios)

Variables	Demand Ratio $= \ell n \frac{Q_{CSA}}{Q_{CO}}$	Price Ratio $= \ell n \frac{P_{CSA}}{P_{CO}}$
Constant	-15.393 (-1.54)	-17.5881 (-4.56)
$\ell n Q_{CSA}$		-1.7685 (-7.44)
$\ell n P_{CSA}$	0.0258 (0.18)	
$\ell n I_{SA}$	-0.6850 (-2.15)	
$\ell n POP_{SA}$	1.3996 (0.77)	
$\ell n L_{CSA}$	0.6019 (1.68)	
$\ell n C_{CSA}$		2.9570 (5.50)
$\ell n TOC_{SA}$		-0.2959 (-4.43)
R^2	0.9555	0.9723

Table B.6. Estimated industrial demand and price equations for Central Hudson Gas and Electric Corporation

(The figures in parenthesis are estimated t-ratios)

Variable	Demand Ratio $= \ell n \frac{Q_{ISA}}{Q_{IO}}$	Price Ratio $= \ell n \frac{P_{ISA}}{P_{IO}}$
Constant	-4.3072 (-8.77)	0.5234 (0.187)
ℓnQ_{ISA}		-0.1682 (-2.51)
ℓnP_{ISA}	-0.6204 (-5.17)	
ℓnVA_{SA}	0.0645 (2.03)	
ℓnL_{ISA}	0.3317 (6.91)	
ℓnC_{ISA}		0.0296 (0.08)
$\ell nTOC_{SA}$		0.2397 (2.12)
R^2	0.9662	0.8568

Table B.7. Estimated residential demand and price equations for Commonwealth Edison Company

(The figures in parenthesis are estimated t-ratios)

Variables	Demand Ratio $= \ell n \frac{Q_{RSA}}{Q_{RO}}$	Price Ratio $= \ell n \frac{P_{RSA}}{P_{RA}}$
Constant	-13.5201 (-1.08)	-9.6998 (-2.25)
$\ell n Q_{RSA}$		0.2153 (2.11)
$\ell n P_{RSA}$	-0.5596 (-2.58)	
$\ell n I_{SA}$	-0.4513 (-2.08)	
$\ell n C_{RSA}$	1.1311 (1.35)	0.3633 (0.96)
$\ell n TOC_{SA}$		0.9921 (7.92)
$\ell n TOC_{O}$		-0.2077 (-0.77)
R^2	0.8598	0.9831

Table B.8. Estimated commercial demand and price equations for Commonwealth Edison Company

(The figures in parenthesis are estimated t-ratios)

Variables	Demand Ratio $= \ell n \frac{Q_{CSA}}{Q_{CO}}$	Price Ratio $= \ell n \frac{P_{CSA}}{P_{CO}}$
Constant	-0.02909 (-0.0086)	-10.8064 (-0.84)
ℓnQ_{CSA}		0.4148 (6.11)
ℓnP_{CSA}	-1.3063 (-4.83)	
ℓnP_{CO}	1.2742 (1.49)	
ℓnI_{SA}	0.4402 (1.15)	
ℓnC_{CSA}		0.2939 (0.27)
$\ell nTOC_{SA}$		1.5001 (3.77)
$\ell nTOC_{O}$		-0.5075 (0.73)
R^2	0.8334	0.9219

Table B.9. Estimated industrial demand and price equations for Commonwealth Edison Company

(The figures in parenthesis are estimated t-ratios)

Variables	Demand Ratio $= \ell n \frac{Q_{ISA}}{Q_{IO}}$	Price Ratio $= \ell n \frac{P_{ISA}}{P_{IO}}$
Constant	-3.0392 (-1.35)	-5.7863 (-3.77
ℓnQ_{ISA}		0.8364 (1.64)
ℓnP_{ISA}	0.4140 (1.49)	
ℓnVA_{SA}	0.3332 (1.48)	
ℓnL_{ISA}	0.2556 (0.72)	
ℓnL_{IO}	-0.3588 (-1.03)	
ℓnC_{ISA}		-0.6968 (-0.71)
$\ell nATOC_{SA}$		0.8537 (3.83)
R^2	0.4758	0.9209

Table B.10. Estimated residential demand and price equations for San Diego Gas and Electric Company

(The figures in parenthesis are estimated t-ratios)

Variable	Demand Ratio $= \ell n \frac{Q_{RSA}}{Q_{RO}}$	Price Ratio $= \ell n \frac{P_{ISA}}{P_{IO}}$
Constant	-3.5486 (-0.50)	-11.2552 (-0.60)
ℓnQ_{RSA}		-0.8785 (-0.63)
ℓnP_{RSA}	-0.0964 (-1.03)	
ℓnI_{SA}	0.2706 1.78	
ℓnC_{RSA}	0.5012 (0.69)	1.4263 (0.60)
ℓnL_{SA}	0.5301 (1.34)	
ℓnL_{O}	-0.9474 (-6.75)	
$\ell nTOC_{SA}$		-0.2349 (-0.40)
R^2	0.9861	0.6518

Table B.11. Estimated commercial demand and price equations for San Diego Gas and Electric Company

(The figures in parenthesis are estimated t-ratios)

Variable	Demand Ratio $= \ell n \frac{Q_{CSA}}{Q_{CO}}$	Price Ratio $= \ell n \frac{P_{ISA}}{P_{IO}}$
Constant	13.329 (1.32)	3.0438 (0.42)
ℓnQ_{CSA}		-0.0643 (-0.15)
ℓnP_{CSA}	0.1592 (0.35)	
ℓnI_{SA}	1.4465 (2.79)	
$\ell nPOP_{SA}$	-1.7301 (-0.92)	
ℓnL_{CSA}	0.4681 (1.14)	
ℓnL_{CO}	-0.9669 (-8.25)	
ℓnC_{CSA}		-0.6272 (-0.55)
ℓnC_{CO}		0.3847 (0.59)
$\ell nTOC_{SA}$		-0.3416 (-0.69)
R^2	0.9661	0.4146

Table B.12. Estimated industrial demand and price equations for San Diego Gas and Electric Company

(The figures in parenthesis are estimated t-ratios)

Variable	Demand Ratio $= \ell n \frac{Q_{ISA}}{Q_{IO}}$	Price Ratio $= \ell n \frac{P_{ISA}}{P_{IO}}$
Constant	-0.2575 (0.15)	7.1149 (3.82)
ℓnQ_{ISA}		0.1772 (0.22)
ℓnQ_{IO}		-0.8159 (-3.79
ℓnP_{ISA}	-0.9081 (-3.82)	
ℓnVA_{SA}	-0.4266 (-2.35)	
ℓnL_{ISA}	0.79 (7.31)	
ℓnL_{IO}	-0.3757 (-1.88)	
ℓnC_{ISA}		0.132 (0.18)
$\ell nATOC_{SA}$		-0.2304 (-0.71)
R^2	0.9838	0.8008

Table B.13. Estimated residential demand and price equations for Carolina Power and Light Company

(The figures in parenthesis are estimated t-ratios)

Variable	Demand Ratio $= \ell n \frac{Q_{RSA}}{Q_{RO}}$	Price Ratio $= \ell n \frac{P_{RSA}}{P_{RO}}$
Constant	-0.6430 (-1.67)	-1.2935 (-0.72)
ℓnQ_{RSA}		0.1651 (2.71)
ℓnP_{RSA}	-0.1434 (-1.99)	
ℓnI_{SA}	0.08175 (1.98)	
ℓnI_{o}	-0.2475 (-1.36)	
ℓnC_{RSA}		-0.1116 (-0.61)
$\ell nTOC_{SA}$		0.4874 (11.44)
R^2	0.7236	0.9847

Table B.14. Estimated commercial demand and price equations for Carolina Power and Light Company

(The figures in parenthesis are estimated t-ratios)

Variable	Demand Ratio $= \ell n \frac{Q_{CSA}}{Q_{CO}}$	Price Ratio $= \ell n \frac{P_{CSA}}{P_{CO}}$
Constant	15.9845 (1.53)	-21 7765 (-2.:7)
ℓnQ_{CSA}		-0.8925 (-2.11)
ℓnP_{CSA}	-0.06695 (-0.48)	
ℓnI_{SA}	0.3833 (2.25)	
ℓnI_{O}	-0.3449 (-1.30)	
$\ell nPOP_{SA}$	-2.2219 (-1.55)	
ℓnC_{CSA}		2.5424 (2.38)
$\ell nTOC_{SA}$		0.09343 (0.35)
$\ell nTOC_{O}$		-0.09343 (0.35)
R^2	0.8236	0.8325

Table B.15. Estimated industrial demand and price equations for Carolina Power and Light Company

(The figures in parenthesis are estimated t-ratios)

Variable	Demand Ratio $= \ell n \frac{Q_{ISA}}{Q_{IO}}$	Price Ratio $= \ell n \frac{P_{ISA}}{P_{IO}}$
Constant	-4.5772 (-8.70)	0.2016 (0.15)
ℓnQ_{ISA}		0.07259 (0.59)
ℓnP_{IO}	0.09233 (0.98)	
ℓnVA_{SA}	0.04919 (0.36)	
ℓnL_{ISA}	0.3161 (1.93)	
ℓnC_{ISA}		-0.2816 (-0.92)
$\ell nTOC_{SA}$		1.0887 (3.43)
$\ell nTOC_{S}$		-0.6054 (-2.63)
R^2	0.9918	0.8407

Table B.16. Estimated residential demand and price equations for Detroit Edison Company

(The figures in parenthesis are estimated t-ratios)

Variable	Demand Ratio $= \ell n \frac{Q_{RSA}}{Q_{RO}}$	Price Ratio $= \ell n \frac{P_{RSA}}{P_{RO}}$
Constant	15.517 (7.02)	12.8244 (1.20)
$\ell n Q_{RSA}$		0.3442 (0.97)
$\ell n P_{RSA}$	-0.584 (-10.13)	
$\ell n I_{SA}$	0.3214 (3.22)	
$\ell n C_{RSA}$	-1.0054 (-6.60)	-1.2298 (-1.13)
$\ell n TOC_{SA}$		0.4806 (2.05)
R^2	0.9571	0.8339

Table B.17. Estimated commercial demand and price equations for Detroit Edison Company

(The figures in parenthesis are estimated t-ratios)

Variable	Demand Ratio $= \ell n \frac{Q_{CSA}}{Q_{CO}}$	Price Ratio $= \ell n \frac{P_{CSA}}{P_{CO}}$
Constant	-0.6473 (0.15)	1.15 (0.11)
ℓnQ_{CSA}		0.1438 (1.42)
ℓnP_{CSA}	-0.4803 (-4.23)	
ℓnP_{CO}	0.4605 (2.92)	
$\ell nPOP_{SA}$	0.514 (1.06)	
ℓnL_{CSA}	-0.6036 (-17.46)	
ℓnC_{CSA}		-0.2703 (-0.28)
$\ell nTOC_{O}$		0.2301 (1.64)
R^2	0.9880	0.4593

Table B.18. Estimated industrial demand and price equations for Detroit Edison Company

The figures in parenthesis are estimated t-ratios)

Variable	Demand Ratio $= \ell n \frac{Q_{ISA}}{Q_{IO}}$	Price Ratio $= \ell n \frac{P_{ISA}}{P_{IO}}$
Constant	-1.5894 (-3.10)	-2.446 (-1.73)
ℓnQ_{ISA}		0.0843 (0.33)
ℓnP_{ISA}	-0.01769 (-0.084)	
ℓnVA_{SA}	-0.06013 (-0.61)	
ℓnL_{ISA}	0.2544 (3.34)	
ℓnC_{ISA}		0.1256 (0.61)
$\ell nATOC_{S}$		0.246 (1.35)
R^2	0.8235	0.7004

APPENDIX C: GROWTH RATES OF EXOGENOUS VARIBLES

GROWTH RATES FOR EXOGENOUS VARIABLES

Consolidated Edison

Variable	Annual growth rate		
	1980	1985	1990
C_{RSA}	0.56	0.56	0.56
C_{RO}	0.56	0.56	0.56
C_{CSA}	1.00	0.60	0.60
C_{CO}	.00	0.60	0.60
C_{ISA}	1.00	1.00	1.00
C_{IO}	1.00	1.00	1.00
W_{SA}	0.0	0.0	0.0
W_{O}	0.0	0.0	0.0
I_{SA}	3.12	3.12	3.12
I_{O}	3.12	3.12	3.12
POP_{SA}	0.24	0.24	0.24
POP_{O}	0.24	0.24	0.24
TOC_{SA}	1.26	1.34	1.05
TOC_{O}	1.26	1.34	1.05
VA_{SA}	2.60	4.51	3.66
VA_{O}	2.60	4.51	3.66

GROWTH RATES FOR EXOGENOUS VARIABLES

Central Hudson

Variable	Annual growth rate		
	1980	1985	1990
C_{RSA}	0.56	0.56	0.56
C_{RO}	0.56	0.56	0.56
C_{CSA}	1.00	0.60	0.60
C_{CO}	1.00	0.60	0.60
C_{ISA}	1.00	1.00	1.00
C_{IO}	1.00	1.00	1.00
W_{SA}	0.0	0.0	0.0
W_{O}	0.0	0.0	0.0
I_{SA}	3.12	3.12	3.12
I_{O}	3.12	3.12	3.12
POP_{SA}	0.24	0.24	0.24
POP_{O}	0.24	0.24	0.24
TOC_{SA}	1.26	1.34	1.05
TOC_{O}	1.26	1.34	1.05
VA_{SA}	2.60	4.51	3.66
VA_{O}	2.60	4.51	3.66

GROWTH RATES FOR EXOGENOUS VARIABLES

Commonwealth Edison

Variable	Annual growth rate		
	1980	1985	1990
C_{RSA}	1.06	1.06	1.06
C_{RO}	1.06	1.06	1.06
C_{CSA}	0.86	0.65	0.65
C_{CO}	0.86	0.65	0.65
C_{ISA}	1.01	1.01	1.01
C_{IO}	1.01	1.01	1.01
W_{SA}	0.0	0.0	0.0
W_{O}	0.0	0.0	0.0
I_{SA}	2.97	2.97	2.97
I_{O}	2.97	2.97	2.97
POP_{SA}	0.23	0.23	0.23
POP_{O}	0.23	0.23	0.23
TOC_{SA}	2.15	2.24	1.14
TOC_{O}	2.15	2.24	1.14
VA_{SA}	3.54	4.95	4.12
VA_{O}	3.54	4.95	4.12

GROWTH RATES FOR EXOGENOUS VARIABLES

San Diego Gas and Electric

Variable	Annual growth rate		
	1980	1985	1990
C_{RSA}	2.02	2.02	2.02
C_{RO}	2.02	2.02	2.02
C_{CSA}	1.96	1.59	1.59
C_{CO}	1.96	1.59	1.59
C_{ISA}	2.48	2.48	2.48
C_{IO}	2.48	2.48	2.48
W_{SA}	0.0	0.0	0.0
W_{O}	0.0	0.0	0.0
I_{SA}	2.96	2.96	2.96
I_{O}	2.96	2.96	2.96
POP_{SA}	0.9	1.1	1.0
POP_{O}	0.9	1.1	1.0
TOC_{SA}	1.66	2.02	1.09
TOC_{O}	1.66	2.02	1.09
VA_{SA}	3.85	5.13	4.30
VA_{O}	3.85	5.13	4.30

GROWTH RATES FOR EXOGENOUS VARIABLES

Carolina Power and Light

Variable	Annual growth rate		
	1980	1985	1990
C_{RSA}	2.70	2.00	1.70
C_{RO}	2.70	2.00	1.70
C_{CSA}	3.52	2.99	2.99
C_{CO}	3.52	2.99	2.99
C_{ISA}	6.43	6.43	6.43
C_{IO}	6.43	6.43	6.43
W_{SA}	0.0	0.0	0.0
W_{O}	0.0	0.0	0.0
I_{SA}	2.70	3.80	1.80
I_{O}	2.70	3.80	1.80
POP_{SA}	1.10	0.90	0.80
POP_{O}	1.10	0.90	0.80
TOC_{SA}	5.38	4.93	1.24
TOC_{O}	5.38	4.93	1.24
VA_{SA}	4.21	5.89	5.03
VA_{O}	4.21	5.89	5.03

GROWTH RATES FOR EXOGENOUS VARIABLES

Detroit Edison

Variable	Annual growth rate		
	1980	1985	1990
C_{RSA}	1.85	1.85	1.85
C_{RO}	1.85	1.85	1.85
C_{CSA}	1.64	1.28	1.28
C_{CO}	1.64	1.28	1.28
C_{ISA}	0.69	0.69	0.69
C_{IO}	0.69	0.69	0.69
W_{SA}	0.0	0.0	0.0
W_{O}	0.0	0.0	0.0
I_{SA}	3.16	3.16	3.16
I_{O}	3.16	3.16	3.16
POP_{SA}	1.04	1.04	1.04
POP_{O}	1.04	1.04	1.04
TOC_{SA}	2.55	2.70	1.28
TOC_{O}	2.55	2.70	1.28
VA_{SA}	5.03	4.91	4.07
VA_{O}	5.03	4.91	4.07

APPENDIX D: FORECASTS OF DEMAND AND GROWTH RATES FOR SERVICE AREAS AND STATES

Forecasts of Demand and Growth Rates for Service Areas and States

Forecasts of Electricity Demand (1000 Gigawatt Hours):

	1974 Actual				1980				1985				1990			
	Res	Comm	Ind	Total	Res	Comm	Ind	Total	Res	Comm	Ind	Total	Res	Comm	Ind	Total
Consolidated Edison	8.0	15.9	1.8	28.4	9.1	18.9	1.7	32.7	10.2	23.9	1.7	39.6	11.5	29.8	1.7	47.6
New York State	27.9	29.0	29.7	95.8	32.0	37.3	34.7	115.0	37.5	48.6	44.5	144.5	43.8	63.7	57.1	181.9

Forecasted Annual Growth Rates of Electricity Demand for 1974-1990 (Percent):

	Res	Comm	Ind	Total
Consolidated Edison	2.3	4.0	-0.4	3.3
New York State	2.9	5.0	4.2	4.1

RMSPE in Estimation Period (Percent):

	Res	Comm	Ind
Consolidated Edison	0.66	0.83	2.0

Forecasts of Demand and Growth Rates for Service Areas and States

Forecasts of Electricity Demand (1000 Gigawatt Hours):

	1974 Actual				1980				1985				1990			
	Res	Comm	Ind	Total	Res	Comm	Ind	Total	Res	Comm	Ind	Total	Res	Comm	Ind	Total
Central Hudson	1.2	0.6	1.1	3.2	1.3	0.8	0.9	3.4	1.5	1.4	1.2	4.5	1.7	2.1	1.7	6.1
New York State	27.9	29.0	29.7	95.8	32.0	37.3	34.7	115.0	37.5	48.6	44.5	144.5	43.8	63.7	57.1	181.9

Forecasted Annual Growth Rates of Electricity Demand for 1974-1990 (Percent):

	Res	Comm	Ind	Total
Central Hudson	2.4	7.9	2.7	4.1
New York State	2.9	5.0	4.2	4.1

RMSPE in Estimation Period (Percent):

	Res	Comm	Ind
Central Hudson	0.57	1.57	3.15

Forecasts of Demand and Growth Rates for Service Areas and States

Forecasts of Electricity Demand (1000 Gigawatt Hours):

	1974 Actual				1980				1985				1990			
	Res	Comm	Ind	Total	Res	Comm	Ind	Total	Res	Comm	Ind	Total	Res	Comm	Ind	Total
Commonwealth Edison	15.1	16.2	18.0	52.9	19.6	21.5	20.5	66.1	21.7	24.9	28.7	80.8	23.7	28.7	37.8	96.8
Illinois	24.1	20.6	32.3	82.5	31.3	29.1	33.9	101.1	35.2	35.3	43.9	122.7	38.9	41.9	55.3	145.9

Forecasted Annual Growth Rates of Electricity Demand for 1974-1990 (Percent):

	Res	Comm	Ind	Total
Commonwealth Edison	2.9	3.6	4.8	3.9
Illinois	3.0	4.5	3.4	3.6

RMSPE in Estimation Period (Percent):

	Res	Comm	Ind
Commonwealth Edison	0.75	0.78	0.75

San Diego Gas and Electric

FORECASTS OF DEMAND AND GROWTH RATES FOR SERVICE AREAS AND STATES

Forecasts of Electricity Demand (1000 Gigawatt Hours):

	1974 Actual				1980				1985				1990			
	Res	Comm	Ind	Total	Res	Comm	Ind	Total	Res	Comm	Ind	Total	Res	Comm	Ind	Total
San Diego	2.9	1.6	3.1	8.1	4.4	2.5	2.4	10.1	5.4	3.2	2.6	12.0	6.8	4.0	3.2	15.0
California	41.4	44.7	43.6	139.0	54.7	60.7	47.5	174.5	66.0	76.1	57.5	213.9	78.7	95.6	69.8	261.5

Forecasted Annual Growth Rates of Electricity Demand for 1974-1990 (Percent):

	Res	Comm	Ind	Total
San Diego	5.4	5.9	0.4	3.9
California	4.1	4.9	3.0	4.0

RMSPE in Estimation Period (Percent):

	Res	Comm	Ind
San Diego	0.93	2.79	4.34

Carolina Power and Light

FORECASTS OF DEMAND AND GROWTH RATES FOR SERVICE AREAS AND STATES

Forecasts of Electricity Demand (1000 Gigawatt Hours):

	1974 Actual				1980				1985				1990			
	Res	Comm	Ind	Total	Res	Comm	Ind	Total	Res	Comm	Ind	Total	Res	Comm	Ind	Total
Carolina Power and Light	5.9	3.6	8.3	18.3	6.6	3.3	10.4	20.9	7.0	3.4	13.2	24.2	7.7	3.7	16.6	28.8
North Carolina	27.3	15.7	33.7	78.9	31.8	17.0	38.6	89.8	35.6	19.3	44.9	102.5	40.2	22.4	53.0	118.8

Forecasted Annual Growth Rates of Electricity Demand for 1974-1990 (Percent):

	Res	Comm	Ind	Total
Carolina Power and Light	1.7	0.2	4.5	2.9
North Carolina	2.4	2.2	2.9	2.6

RMSPE in Estimation Period (Percent):

	Res	Comm	Ind
Carolina Power and Light	0.66	0.77	0.94

Detroit Edison

FORECASTS OF DEMAND AND GROWTH RATES FOR SERVICE AREAS AND STATES

Forecasts of Electricity Demand (1000 Gigawatt Hours):

	1974 Actual				1980				1985				1990			
	Res	Comm	Ind	Total	Res	Comm	Ind	Total	Res	Comm	Ind	Total	Res	Comm	Ind	Total
Detroit Edison	9.6	5.6	16.4	33.8	11.1	7.3	21.2	42.4	11.6	8.7	28.1	51.9	12.5	10.3	36.0	63.0
Michigan	20.2	12.6	29.0	63.7	24.3	17.4	37.0	81.0	26.5	22.0	48.0	99.3	29.0	27.6	60.3	120.2

Forecasted Annual Growth Rates of Electricity Demand for 1974-1990 (Percent):

	Res	Comm	Ind	Total
Detroit Edison	1.7	3.9	5.0	4.0
Michigan	2.3	5.0	4.7	4.0

RMSPE in Estimation Period (Percent):

	Res	Comm	Ind
Detroit Edison	0.29	0.39	0.94

APPENDIX E: DELINEATION OF UTILITY SERVICE AREAS BY COUNTY AND THE PERCENTAGE OF POPULATION SERVED

DELINEATION OF UTILITY SERVICE AREAS BY COUNTY AND THE PERCENTAGE OF POPULATION SERVED

Overview

The purpose of this section is to describe the spatial delineation of utility company service areas at the subcounty level for the 48 contiguous states. Once the utility company's boundaries are established, the percentage of the population served by a particular utility in a county in 1970 is estimated from the *1970 Census of Population*. This information is then used to determine the population served by the utility as discussed previously in Appendix A.

Utility District Definition

The 48 states are served by 249 investor-owned companies, 1759 municipal companies, 940 rural electric cooperatives, 8 irrigation districts, and 111 public-owned companies. This total of 3067 companies presents too much detail into this analysis. Therefore, these utilities are aggregated to major service areas using the following criteria:

1. Only companies that generate electricity are considered. Since the main usage of this information is for forecasting electrical demand which is, in turn, used for evaluating capacity expansion, non-generating companies do not need to be considered. Although non-generating companies have demand, such demand will be passed to generating companies. In this study service areas of non-generating companies are assigned to their suppliers. Thus, a company's service area may be larger than the company itself would indicate. In some cases, electricity passes through several companies from producer to final consumer. For example, in Iowa, the Cascade Municipal Electric Department buys electricity from Maquoketa Valley Rural Electric Co-op, which, in turn, buys power from the Central Iowa Co-op. In this example, the trade areas and population served by both Cascade Municipal and Maquoketa Co-op are assigned to the Central Iowa Co-op. The Central Iowa Co-op, with a capacity of 231 MWe, supplies power to several other towns and co-ops, although the area it sells to directly is comparatively small.

Only about half the area assigned to it in this analysis is its own.

2. A company must have a minimum of 25 megawatts of base load capacity. Hydro plants, although not generally considered a base-load technology, are included if the yearly generation is more than 130 gigawatt hours. This approximates a 25 MWe coal-fired steam plant with a load factor of .60. A utility company's diesel and gas turbine limits are not included with the steam plant or hydro facilities to make the total of 25 MWe. The minimum megawattage is chosen because the utility company's commitment needed to maintain this size of electrical plant is sizable.
3. Utility companies that will meet the above two criteria in the future are also treated as major service areas. For example, Tri-State G&T, serving parts of Colorado, Wyoming, and Nebraska, currently does not have base-load capacity, but they are building two coal-fired steam plants with a total of 2260 MWe capacity that will provide about half their power demands.* It is believed that the utilities meeting these three criteria will be those likely to be facing capacity decisions in the future.

Method of Delineation

The method of delineating utility districts is accomplished by superimposing a county map over a map of utility company service areas. Oak Ridge National Laboratory's (ORNL) unique mapping capabilities provide an efficient means whereby maps of any scale can be produced. With this capacity, superimposition for comparison and analysis can be easily accomplished.

Two utility service area maps are currently available. One is the Electric Light and Power's *Investor-Owned Electric Utility Service Areas* map and the other is published by Electrical World, *Electric Utilities of the United States*.

EL&P's map has the disadvantage of only including investor owned utilities. But this map was drafted from utility company information

*One of these plants, the Laramie River Station, is a joint ownership project.

provided to the cartographers at the publishing house, and therefore, boundaries seem to be fairly accurately drawn.

Electrical World's map has both privately and publically owned utility companies. This map was drawn for the purpose of identifying the customers of a particular utility and, as such, the companies shown may or may not be generators of electric power.

Neither map has all the information needed to perform the analysis. EL&P's map, however, is used as a base for delineating privately-owned utilities since the map seems to be accurate when compared to utility company information. For publically-owned utilities, the Electrical World's map is used along with additional data obtained from Electrical World's *Directory of Electric Utilities* which lists all electric utilities and the cities which they serve in the United States. Additional information is obtained from personal contact with the companies, and when possible, individual company's yearly reports.

Each utility company is cross-referenced to ORNL's FPC Unit Generating File, which has present and projected capacity by technology by company, to find out if the company meets the generation criteria. If it is found that a company does not generate electricity, its supplier was identified by using Electric World's *Directory of Electric Utilities*.

The non-generating company's service area is then assigned to the generating company's service area. In the case that a non-generating company buys from more than one generating company, the company that provides the plurality of electricity is designated as the service area.

Once the service area is delineated, the portions of the counties served by each company is identified. If the utility serves the entire county, then the county's population is recorded from the *1970 Census of Population* and assigned to the utility. However, if two or more utility companies serve the same county, service areas are aproximated by the Census County Subdivisions and the populations in these subdivisions are then assigned to the appropriate utility. Municipal utility companies are assigned the entire population of the town which they serve and also suburbs of the town if it is stated that the suburbs are served by the municipality in the *Electric World Directory*. The population numbers are then divided by the population of the county in which they live to determine the percentage served by the particular utility.

Problems of Delineated Service Areas

The population of the service area may not adequately reflect the sales or demand of all utility companies. Some utility companies can be considered nonterritorial in the sense they do not sell to specific areas or to individual consumers. The Hetch Hetchy Company of San Francisco, California, is an example of this type of company. The company's electricity is produced by hydro facilities in the Great Valley area of California. Twenty-five percent of the electricity generated is sold to the City of San Francisco for public services, such as meeting needs for street lights, municipal buildings including police and fire departments, the airport, and the utility sector. About half of the generation is used by irrigation districts and the remaining power is sold to selected industries. This company, although having a total capacity of 147 MWe, is not included in the final listing because there is no way to apportion its demand to a specific population count.

A similar problem arises with the Power Authority of the State of New York. This company is underestimated in this analysis. In those cases where the Power Authority sells to municipal utility companies, the town's population is recorded and assigned to the Power Authority. The population accounted to the Power Authority is only one percent of the state's total population, and 28 percent of New York's total capacity is owned by the Power Authority. The reason for the discrepancy is that most of the Power Authority generation is sold to industry, with another 40 percent being sold out of state.

Another problem encountered is the overlapping of service areas in the same county. Cleveland Electric Illuminating Company and Cleveland Division of Light and Power both sell to industry as well as residential customers in the City of Cleveland. In essence, they are competitors. If a larger scale resolution were to be used, the separation of these two companies may be possible; however, at the scale employed in the analysis another means of dividing the population between the two had to be used. The companies were called and asked to estimate the number of customers from various sectors they serve. This information was used to estimate the population served by each in Cuyahoga County where Cleveland is located.

The problem of overlapping extends to rural electric cooperatives (REC). These companies sell to residential as well as to agricultural sectors. REC service areas tend to overlap with investor-owned companies to the extent it is almost a second layer. Their service areas and subsequent population totals are also underestimated. The only situations when REC are accounted for is when they sell to municipal companies or if they serve a whole county. These underestimations are not deemed critical since co-ops in Iowa, where co-ops are prevalent, have less than seven percent of the total capacity in the state with an estimated 2 percent of the state's total population served. Further, co-ops are not expected to expand since they do not have much capacity planned according to the F.P.C. Unit Generating File.

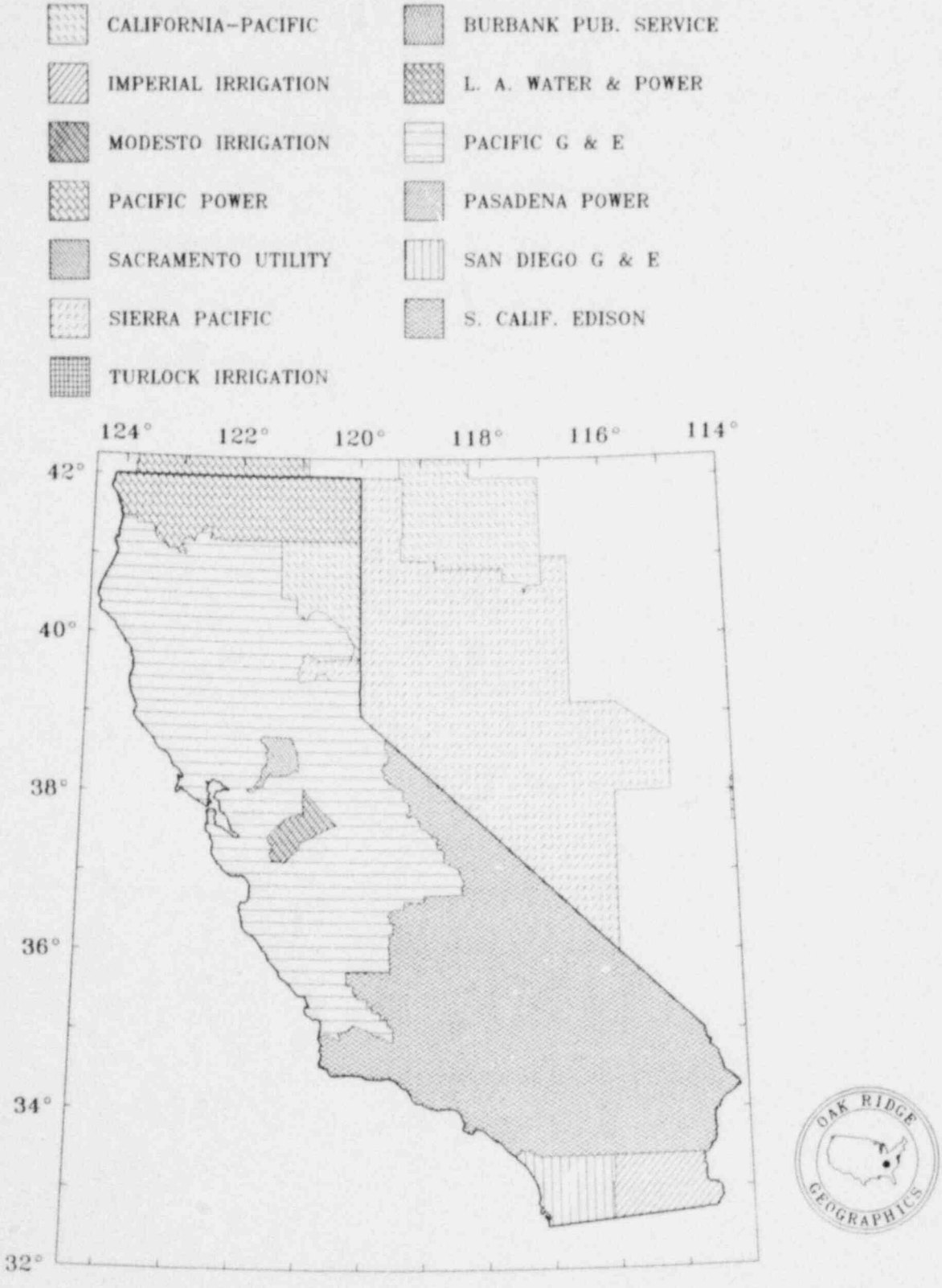
Conclusions

This method of delineation is relatively easy and requires very little time. Currently, 48 states have been analyzed by this method but the results will only be reported for the five states of concern to this paper. Further checks with utility companies have shown the finished product to be relatively accurate. Maps of the utility company service areas by county are shown in the Appendix.

These data are best used for residential population estimate of future electrical demands. The main problem with the data is when commercial usages are being estimated. Specifically, the method can adequately capture the spatial distributions of commercial demands only if these distributions are highly correlated with the spatial distribution of population. When more than one utility serves a particular county, the problem may become substantial. These data also indicate the spatial extent of utility systems in the U.S. for limitation of potential site selection.

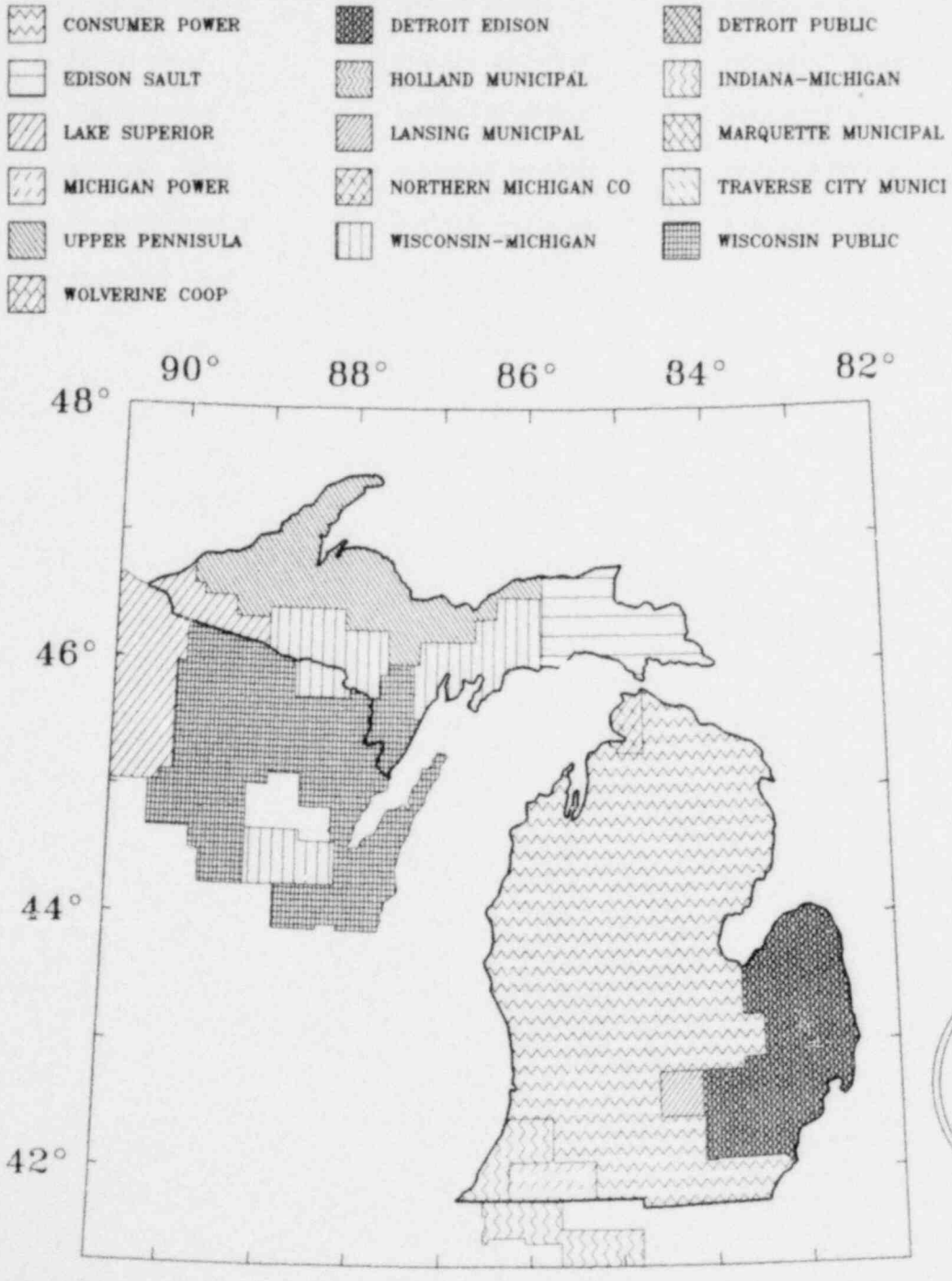
MAJOR UTILITY COMPANIES IN CALIFORNIA

UTILITY COMPANY WITH THE LARGEST POPULATION SERVED PER COUNTY



MAJOR UTILITY COMPANIES IN MICHIGAN

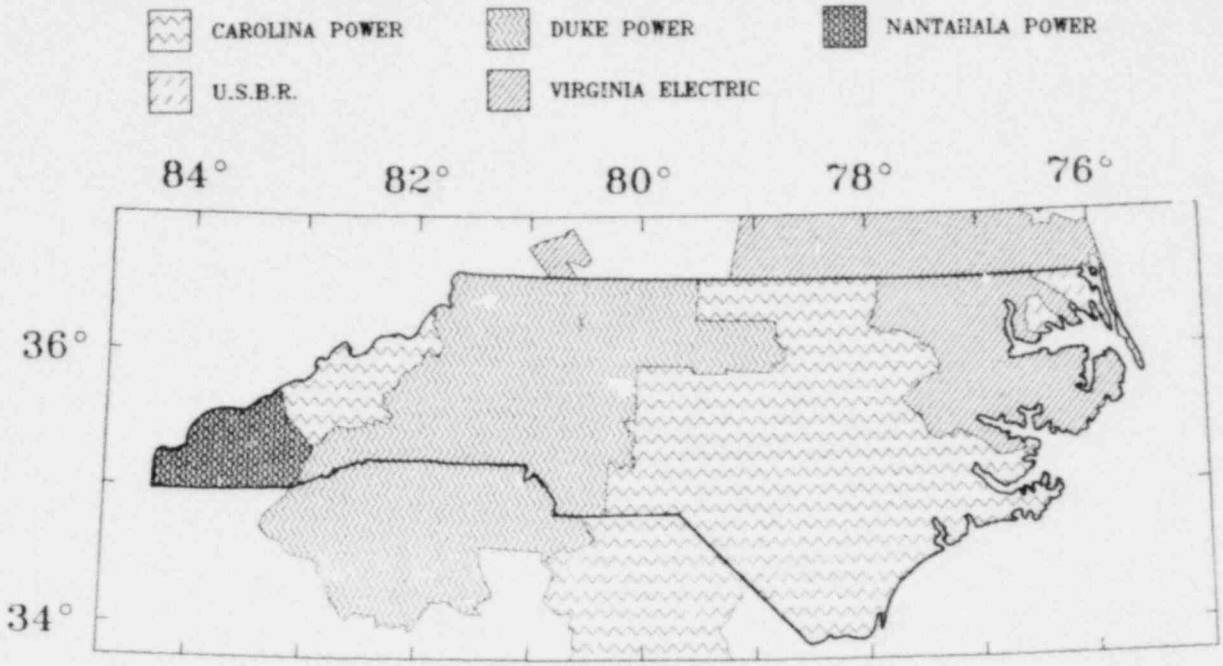
UTILITY COMPANY WITH THE LARGEST POPULATION SERVED PER COUNTY



OAK RIDGE GEOGRAPHICS

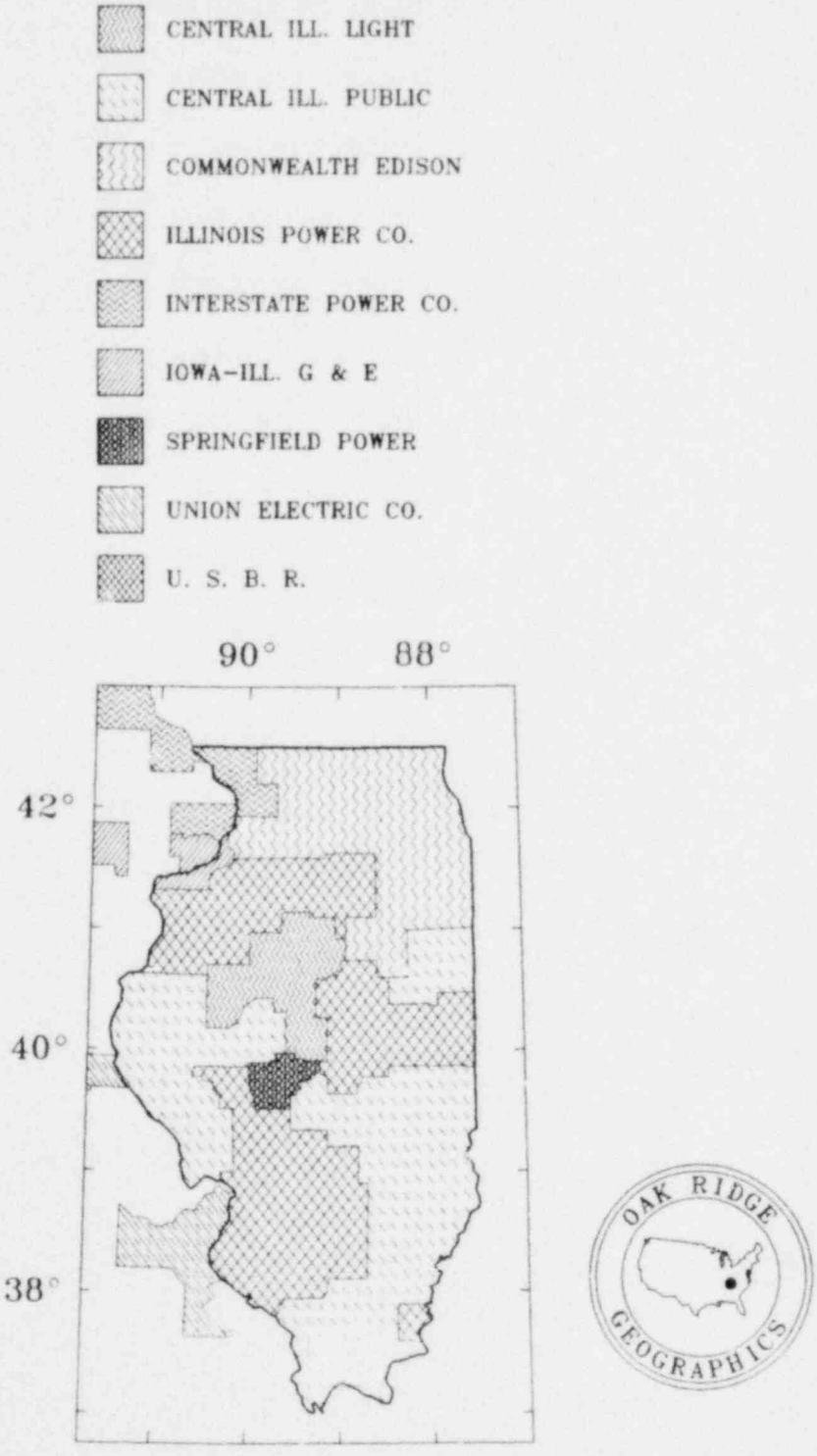
MAJOR UTILITY COMPANIES IN NORTH CAROLINA

UTILITY COMPANY WITH THE LARGEST POPULATION SERVED PER COUNTY



MAJOR UTILITY COMPANIES IN ILLINOIS

UTILITY COMPANY WITH THE LARGEST POPULATION SERVED PER COUNTY



NEW YORK

Utility Company	County Served	Percent Population
Central Hudson Gas and Electric Corp.	Albany	10
	Columbia	20
	Dutchess	90
	Greene	90
	Orange	47
	Ulster	98
Consolidated Edison Co. of New York, Inc.	Bronx	100
	Kings	100
	New York	100
	Putnam	23
	Queens	100
	Richmond	100
	Westchester	93
Long Island Lighting Co.	Nassau	100
	Suffolk	100
New York State Electric & Gas Corp.	Allegany	20
	Broome	93
	Cattaraugus	28
	Cayuga	83
	Chautauqua	11
	Chemung	100
	Chenango	92
	Clinton	67
	Columbia	36
	Cortland	74
	Delaware	100
	Dutchess	10
	Erie	38
	Essex	50
	Franklin	12
	Greene	10
	Hamilton	25
	Livingston	32
	Madison	50
	Oneida	2
	Onondaga	10
	Ontario	51
	Orleans	71
	Otsego	95
	Putnam	77
	Rensselaer	84
	Saratoga	4
	Schoharie	7
	Schuyler	84
	Seneca	100
	Steben	94
	Sullivan	49

NEW YORK

(Contd.)

Utility Company	County Served	Percent Population
New York State Electric & Gas Corp. (Contd.)	Tioga	100
	Tompkins	97
	Ulster	2
	Washington	17
	Wayne	39
	Westchester	7
	Wyoming	67
	Yates	71
New York Power Authority	Broome	7
	Cattaraugus	18
	Chautauqua	4
	Chenango	8
	Clinton	26
	Cortland	2
	Erie	1
	Essex	8
	Franklin	11
	Genesee	2
	Herkimer	26
	Madison	5
	Monroe	2
	Onondaga	2
	Orleans	5
	Schuyler	16
	Steuben	6
	Tompkins	3
	Wyoming	10
	Yates	
Niagara Mohawk Power Corp.	Albany	90
	Allegany	21
	Cattaraugus	54
	Cayuga	4
	Chautauqua	85
	Clinton	7
	Columbia	44
	Cortland	24
	Erie	61
	Essex	42
	Franklin	77
	Fulton	100
	Genesee	98
	Hamilton	75
	Herkimer	74
	Jefferson	100
	Lewis	100
	Livingston	68
	Madison	45

NEW YORK

(Contd.)

Utility Company	County Served	Percent Population
Niagara Mohawk Power Corp. (Contd.)	Monroe	68
	Montgomery	100
	Niagara	100
	Oneida	98
	Onondaga	88
	Ontario	6
	Orleans	24
	Oswego	100
	Otsego	5
	Rensselaer	16
	St. Lawrence	100
	Saratoga	96
	Schenectady	100
	Schoharie	93
	Warren	100
	Washington	83
	Wyoming	23
Orange and Rockland Utilities, Inc.	Orange	53
	Rockland	100
	Sullivan	51
Rochester Gas and Electric Corp.	Allegany	42
	Cayuga	13
	Monroe	94
	Ontario	43
	Wayne	61

ILLINOIS

Utility Company	County Served	Percent Population
Central Illinois Light Co.	Christian	8
	Fulton	49
	Knox	6
	Logan	70
	Marshall	100
	Peoria	100
	Putnam	31
	Sangamon	13
	Stark	19
	Tazewell	97
	Woodford	87
Central Illinois Public Service	Adams	100
	Alexander	100
	Brown	100
	Calhoun	100
	Cass	79
	Champaign	7
	Christian	84
	Clark	100
	Clay	100
	Coles	100
	Crawford	100
	Cumberland	100
	Douglas	100
	Edgar	100
	Edwards	80
	Effingham	100
	Fayette	28
	Ford	100
	Franklin	100
	Fulton	43
	Greene	100
	Hamilton	100
	Hancock	70
	Hardin	100
	Iroquois	100
	Jackson	95
	Jasper	100
	Jefferson	7
	Jersey	100
	Johnson	100
	Lawrence	100
	Livingston	28
	McDonough	93
	McLean	8
	Macon	3
	Macoupin	30
	Marion	11
	Mason	100

ILLINOIS

(Contd.)

Utility Company	County Served	Percent Population
Central Illinois Public Service (Contd.)	Massac	100
	Menard	100
	Montgomery	7
	Morgan	26
	Moultrie	80
	Pike	100
	Pope	100
	Pulaski	100
	Richland	100
	Saline	71
	Schuyler	100
	Scott	100
	Shelby	100
	Union	100
	Vermilion	15
	Wabash	100
	Warren	4
	Wayne	88
	White	100
	Williamson	100
Commonwealth Edison Co.	Boone	100
	Bureau	15
	Carroll	43
	Champaign	1
	Cook	100
	DeKalb	100
	DeWitt	1
	DuPage	100
	Edwards	20
	Grundy	97
	Henry	21
	Jo Daviess	41
	Kane	100
	Kendall	100
	Lake	100
	La Salle	34
	Lee	100
	Livingston	72
	Logan	30
	McHenry	100
	McLean	4
	Ogle	100
	Piatt	37
	Stephenson	100
	Tazewell	3
	Vermilion	6
	Whiteside	100
	Will	

ILLINOIS

(Contd.)

Utility Company	County Served	Percent Population
Commonwealth Edison Co. (Contd.)	Winnebago	100
Illinois Power Co.	Bond	100
	Bureau	85
	Cass	21
	Champaign	92
	Christian	8
	Clinton	100
	DeWitt	99
	Fayette	72
	Fulton	8
	Gallatin	100
	Grundy	3
	Henderson	100
	Henry	60
	Jackson	5
	Jefferson	93
	Knox	94
	La Salle	66
	McDonough	7
	McLean	88
	Macon	97
	Macoupin	70
	Madison	76
	Marion	89
	Mercer	72
	Monroe	100
	Montgomery	93
	Morgan	74
	Moultrie	20
	Perry	100
	Piatt	63
	Putnam	69
	Randolph	100
	St. Clair	60
	Saline	29
	Sangamon	4
	Stark	81
	Vermilion	79
	Warren	96
	Washington	100
	Wayne	12
	Woodford	13
Interstate Power Co.	Carroll	57
	Jo Daviess	59
Iowa-Illinois Gas & Electric Co.	Henry	19
	Rock Island	100

ILLINOIS

(Contd.)

Utility Company	County Served	Percent Population
Iowa Southern Utilities Co.	Mercer	28
Springfield Water, Light and Power Dept.	Sangamon	81
Union Electric Co.	Hancock	30
	Madison	22
	St. Clair	40

CALIFORNIA

Utility Company	County Served	Percent Population
California-Pacific Utilities Co.	Plumas	24
	San Bernardino	1
Imperial Irrigation District	Imperial	71
	Riverside	5
Los Angeles Dept. of Water & Power	Los Angeles	40
Modesto Irrigation District	Stanislaus	52
Pacific Gas and Electric Co.	Alameda	100
	Alpine	100
	Amador	100
	Butte	95
	Calaveras	100
	Colusa	100
	Contra Costa	100
	El Dorado	66
	Fresno	100
	Glenn	100
	Humboldt	100
	Kern	15
	Kings	66
	Lake	100
	Lassen	21
	Madera	100
	Marin	100
	Mariposa	100
	Mendocino	100
	Merced	98
	Monterey	100
	Napa	100
	Nevada	90
	Placer	92
	Plumas	63
	Sacramento	20
	San Benito	100
	San Francisco	100
	San Joaquin	100
	San Luis Obispo	100
	San Mateo	100
	Santa Barbara	30
	Santa Clara	87
	Santa Cruz	10
	Shasta	99
	Sierra	41
	Siskiyou	6
	Solan	100
	Sonoma	98
	Stanislaus	24

CALIFORNIA

(Contd.)

Utility Company	County Served	Percent Population
Pacific Gas and Electric Co. (Contd.)	Sutter	100
	Tehama	100
	Trinity	100
	Tulare	27
	Tuolumne	100
	Yolo	100
	Yuba	100
Pacific Power and Light Co.	Del Norte	100
	Modoc	100
	Shasta	1
	Siskiyou	94
Pasadena Water and Power Dept.	Los Angeles	2
Sacramento Municipal Utility Dist.	Sacramento	80
San Diego Gas and Electric Co.	Orange	15
	Riverside	1
	San Diego	100
Sierra Pacific Power Co.	El Dorado	34
	Nevada	10
	Placer	8
	Plumas	13
	Sierra	59
Southern California Edison Co.	Imperial	29
	Inyo	100
	Kern	85
	Kings	34
	Los Angeles	57
	Mono	100
	Orange	85
	Riverside	94
	San Bernardino	99
	Santa Barbara	70
	Tulare	73
	Ventura	100
Turlock Irrigation District	Merced	2
	Stanislaus	24
United States Bureau of Reclamation	Butte	5
	Lassen	1
	Santa Clara	13
	Sonoma	2

NORTH CAROLINA

Utility Company	County Served	Percent Population
Carolina Power and Light Co.	Anson	100
	Avery	100
	Bladen	100
	Brunswick	100
	Buncombe	100
	Carteret	100
	Caswell	53
	Chatham	100
	Columbus	100
	Craven	100
	Cumberland	100
	Duplin	100
	Edgecombe	60
	Franklin	100
	Granville	66
	Greene	100
	Halifax	33
	Harnett	100
	Haywood	100
	Hoke	100
	Johnston	100
	Jones	100
	Lee	100
	Lenoir	100
	Madison	100
	Mitchell	100
	Montgomery	100
	Moore	100
	Nash	100
	New Hanover	100
	Onslow	100
	Pamlico	100
	Pender	100
	Person	100
	Pitt	11
	Randolph	100
	Richmond	100
	Robeson	100
	Sampson	100
	Scotland	100
	Vance	100
	Wake	100
	Warren	100
	Wayne	100
	Wilson	100
	Yancey	100
	Chesterfield, S.C.	100
	Clarendon, S.C.	100
	Darlington, S.C.	100

NORTH CAROLINA

(Contd.)

Utility Company	County Served	Percent Population
Carolina Power and Light Co. (Contd.)	Dillon, S.C.	100
	Florence, S.C.	100
	Georgetown, S.C.	63
	Horry, S.C.	13
	Kershaw, S.C.	64
	Lee, S.C.	100
	Marion, S.C.	100
	Marlboro, S.C.	100
	Sumter, S.C.	100
	Williamsburg, S.C.	100
Duke Power Co.	Alamance	100
	Alexander	100
	Alleghany	100
	Ashe	100
	Burke	100
	Cabarrus	100
	Caldwell	100
	Caswell	7
	Catawba	100
	Cleveland	100
	Davidson	100
	Davie	100
	Durham	100
	Forsyth	100
	Gaston	100
	Granville	34
	Guilford	100
	Henderson	100
	Iredell	100
	Lincoln	100
	McDowell	100
	Mecklenburg	100
	Orange	100
	Polk	100
	Rockingham	100
	Rowan	100
	Rutherford	100
	Stanly	100
	Stokes	100
	Surry	100
	Transylvania	100
	Union	100
	Watauga	100
	Wilkes	100
	Yadkin	100

NORTH CAROLINA
(Contd.)

Utility Company	County Served	Percent Population
Nantahala Power and Light Company	Cherokee	100
	Clay	100
	Graham	100
	Jackson	100
	Macon	100
	Swain	100
Virginia Electric and Power Co.	Beaufort	100
	Bertie	100
	Chowan	100
	Dare	100
	Edgecombe	40
	Gates	100
	Halifax	67
	Hertford	100
	Hyde	100
	Martin	100
	Northampton	100
	Pasquotank	52
	Perquimans	24
	Pitt	89
	Tyrrell	100
	Washington	100
United States Bureau of Reclamation	Camden	100
	Currituck	100
	Pasquotank	43
	Perquimans	76

MICHIGAN

Utility Company	County Served	Percent Population
Consumer Power Co.	Alcona	100
	Allegan	95
	Alpena	100
	Antrim	100
	Arenac	100
	Barry	100
	Bay	100
	Benzie	100
	Branch	100
	Calhoun	100
	Charlevoix	100
	Cheboygan	100
	Clare	100
	Clinton	100
	Crawford	100
	Eaton	100
	Genesee	100
	Gladwin	100
	Grand Traverse	54
	Gratiot	100
	Hillsdale	100
	Ingham	26
	Ignia	100
	Iosco	100
	Isabella	100
	Jackson	100
	Kalamazoo	90
	Kalkaska	81
	Kent	100
	Lake	100
	Leelanau	100
	Lenawee	100
	Manistee	100
	Mason	100
	Mecosta	100
	Midland	100
	Missaukee	100
	Monroe	100
	Montcalm	100
	Montmorency	100
	Muskegon	100
	Newaygo	100
	Oceana	100
	Ogemaw	100
	Osceola	100
	Oscoda	100
	Otsego	100
	Ottawa	66
	Presque Isle	100
	Roscommon	100
	Saginaw	100

MICHIGAN
(Contd.)

Utility Company	County Served	Percent Population
Consumer Power Co. (Contd.)	St. Joseph	15
	Shiawassee	100
	Wexford	100
Detroit Edison	Huron	100
	Lapeer	100
	Livingston	100
	Macomb	100
	Oakland	100
	St. Clair	100
	Sanilac	100
	Tuscola	100
	Washtenaw	100
	Wayne	100
Detroit Public Lighting Department	Wayne	2
Edison Sault Electric Co.	Chippewa	100
	Luce	100
	Mackinac	100
Holland Board of Public Works	Allegan	5
	Ottawa	30
Indiana and Michigan Electric Co.	Adams	100
	Allen	100
	Blackford	100
	DeKalb	100
	Delaware	100
	Elkhart	61
	Grant	100
	Hamilton	10
	Henry	21
	Huntington	100
	Jay	100
	LaPorte	6
	Noble	100
	Randolph	100
	St. Joseph	99
	Wayne	15
	Wells	100
	Whitley	100
	Derrien	100
	Cass	48
	Van Buren	52
Lansing Board of Water and Light	Ingham	74

MICHIGAN
(Contd.)

Utility Company	County Served	Percent Population
Marquette Board of Light and Power	Marquette	34
Michigan Power Co.	Cass	52
	Kalamazoo	10
	St. Joseph	85
	Van Buren	48
Northern Michigan Electrical Coop.	Emmet	100
	Kalkaska	19
Traverse City Light and Power Dept.	Grand Traverse	46
Upper Peninsula Power Co.	Alger	89
	Baraga	88
	Houghton	97
	Keweenaw	100
	Marquette	54
	Ontonagon	49
	Schoolcraft	5
Wisconsin-Michigan Power Co.	Alger	11
	Baraga	12
	Delta	100
	Dickinson	100
	Gogebic	3
	Houghton	3
	Iron	100
	Marquette	12
	Menominee	37
	Ontonagon	42
	Schoolcraft	95
	Calumet	17
	Florence	100
	Forest	15
	Marinette	11
	Menomiee	100
	Outagamie	84
	Vilas	23
	Waupaca	50
	Waushara	19
	Winnebago	31
Wisconsin Public Service Corp.	Menominee	63
	Brown	100
	Calumet	83
	Door	100
	Forest	85

MICHIGAN
(Contd.)

Utility Company	County Served	Percent Population
Wisconsin Public Service Corp. (Contd.)	Kewaunee	100
	Langlade	76
	Lincoln	100
	Manitowoc	51
	Marathon	85
	Marinette	89
	Oconto	80
	Oneida	100
	Portage	80
	Shawano	20
	Vilas	64
	Waupaca	26
	Winnebago	48
Wolverine Electric Coop.	Ottawa	4

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