

2009 Load Forecast

Traverse City Light and Power

July 2009



July 7, 2009



Ms. Karen Feahr
General Manager
Traverse City Light & Power
Address
Traverse City, Michigan Zip

Subject: Load Forecast Final Report

Dear Ms. Feahr:

Transmitted herewith is our final report on the Light & Power 2009 Load Forecast Report (the "Report"). This Report includes an Executive Summary identifying the major findings of the study and a detailed discussion of the methodology, data sources, assumptions, and results set forth in five sections and four appendices, as outlined below.

Section 1 – Methodology

Section 2 – Data Sources

Section 3 – Principal Consideration & Assumptions

Section 4 – Forecast Results

Section 5 – Forecast Uncertainty

Appendices:

Appendix A – Forecast Results

Appendix B – Regression Equation Output

Appendix C – Economic Data

Appendix D – Weather Data

In addition, R. W. Beck provided Light & Power with a working model, programmed in Microsoft Excel® from which the results were produced. This model allows for limited changes to certain assumptions and independent projections for Light & Power's on-going use.

I appreciate the input and assistance you and other Light & Power staff provided throughout this assignment. If you have any questions or need anything further, please feel free to contact me at (407) 648-3539.

Respectfully submitted,
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JPN/jpn
attachments

05-01499-10101 | 005829



R. W. BECK
2009 LOAD FORECAST
Traverse City Power & Light

Table of Contents

Table of Contents

List of Tables

List of Figures

EXECUTIVE SUMMARY

Section 1 OVERVIEW OF METHODOLOGY

1.1	Equation Specifications	1-1
1.2	Integration of Determinants	1-3

Section 2 DATA SOURCES

2.1	Historical System Data	2-1
2.2	Weather Data	2-1
2.3	Economic and Demographic Data	2-4
2.4	Real Electricity Price Data.....	2-4

Section 3 PRINCIPAL CONSIDERATIONS AND ASSUMPTIONS

Section 4 FORECAST RESULTS

4.1	Residential Class	4-1
4.1.1	Residential Customers	4-1
4.1.2	Residential Average Use.....	4-4
4.1.3	Residential Sales	4-5
4.2	Commercial Sales	4-6
4.3	Industrial Sales.....	4-7
4.4	Sales to Other Classes.....	4-8
4.5	Total Retail Electricity Sales	4-8
4.6	Energy Requirements.....	4-9
4.7	Load Factor Analysis	4-10
4.8	Peak Demand	4-12
4.9	Energy Optimization Plan.....	4-14

Section 5 FORECAST UNCERTAINTY

APPENDICES

- Appendix A – Forecast Results
- Appendix B – Regression Equation Output
- Appendix C – Economic Data
- Appendix D – Weather Data

This report has been prepared for the use of the client for the specific purposes identified in the report. The conclusions, observations and recommendations contained herein attributed to R. W. Beck, Inc. (R. W. Beck) constitute the opinions of R. W. Beck. To the extent that statements, information and opinions provided by the client or others have been used in the preparation of this report, R. W. Beck has relied upon the same to be accurate, and for which no assurances are intended and no representations or warranties are made. R. W. Beck makes no certification and gives no assurances except as explicitly set forth in this report.

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List of Tables

Table ES-1 Energy Optimization Plan Standard..... 1
 Table ES-2 Projected NEL and Peak Demand for Selected Years 3
 Table 4-1 Historical and Projected Net Energy for Load and Peak Demand
 (Unadjusted for EOP)..... 4-13
 Table 4-2 Energy Optimization Plan Standard 4-14
 Table 4-3 Impact of EOP on System Forecast 4-16

List of Figures

Figure 1-1: Forecast Determinants Derivation..... 1-3
 Figure 2-1: Historical and Normal Heating and Cooling Degree Days 2-2
 Figure 2-2: Long-term v. Recent Average Peak Day Maximum Temperature..... 2-3
 Figure 2-3: Historical Real Residential Average Revenue 2-5
 Figure 4-1: Fiscal Year-end Residential Customer Counts..... 4-2
 Figure 4-2: Historical and Projected Residential Customer Counts 4-3
 Figure 4-3: Historical and Projected Residential Average Use 4-5
 Figure 4-4: Historical and Projected Residential Sales..... 4-6
 Figure 4-5: Historical and Projected Commercial Sales 4-7
 Figure 4-6: Historical and Projected Industrial Sales 4-8
 Figure 4-7: Historical and Projected Total Retail Electricity Sales 4-9
 Figure 4-8: Historical and Projected Net Energy for Load 4-10
 Figure 4-9: Historical and Projected Annual Load Factor 4-12
 Figure 4-10: Historical and Projected Annual Peak Demand 4-13
 Figure 4-11: Net Energy for Load Forecast – Unadjusted v. Adjusted for
 EOP 4-15
 Figure 4-12: Peak Demand Forecast – Unadjusted v. Adjusted for EOP 4-15

EXECUTIVE SUMMARY

R. W. Beck, Inc. was retained by Traverse City Light & Power (TCLP) to prepare a forecast of retail electricity sales, energy requirements, and peak demand of the TCLP electric system (Load Forecast). A load forecast is a critical input to many utility planning activities including power supply planning, transmission and distribution facilities planning, fuel and purchased power budgeting, financial planning and budgeting, and staffing. Hence, a rigorous, objective, and detailed process that relies on widely accepted standards of practice, as well as a thorough review of the methodology and results, is essential.

The Load Forecast has been prepared for a 20 year period, beginning fiscal year 2009 through 2028. The load forecast relies on an econometric approach to forecast retail electricity sales as a function of certain explanatory factors that were found to be highly related to retail sales generally over fiscal year 1986 through 2008 (Study Period). A forecast of system energy requirements, or net energy for load (NEL), was then derived from the retail sales forecast and an estimate of distribution system losses. Finally, a forecast of the calendar year system peak demand was derived from the forecasted fiscal year NEL and load factors forecasted based on a regression analysis of historical load factor.

The Load Forecast accounts for the impact of TCLP's Energy Optimization Plan (EOP) in the form of post-analysis adjustments across the customer classes. The filing of an EOP is required by the Michigan Public Service Commission pursuant to legislation enacted by the state of Michigan in October 2008. Table ES-1 below shows the annual incremental reductions in retail sales that are required under the legislation, in terms of the percentage of actual sales averaged over the preceding three years.

Table ES-1
Energy Optimization Plan Standard

Year	Incremental Reduction
2009	0.30%
2010	0.50%
2011	0.75%
2012 and beyond	1.00%

Although the requirements pertain to energy only, and many of the programs implemented by TCLP may be aimed at off-peak load more so than on-peak load, it is assumed that peak demand is affected proportionally to energy sales. It is also assumed that TCLP meets the energy reduction standard outlined in the legislation

EXECUTIVE SUMMARY

proportionally across the customer classes. However, forecast results after accounting for the EOP are only shown at the total system level within the text of this report. The appendix tables show a wider range of results both before and after accounting for the EOP.

The econometric forecast of electric sales relies on system data provided by TCLP and a variety of other data provided by third parties. TCLP staff provided historical data regarding retail customer counts, sales, and revenues; net energy for load; and peak demand, as well as certain information regarding its customers and expected customer growth, including the historical and planned future transfers of customers from Consumers Energy. Historical and projected economic and demographic data for Grand Traverse County, which surrounds TCLP's service area, were obtained from Woods & Poole Economics, Inc. Weather data for the region were obtained from the National Oceanic and Atmospheric Administration (NOAA).

The results of the load forecast, prior to reflecting the EOP, reflect that TCLP system energy requirements are expected to grow at annual average rates of 1.7% from 2009-2018 and 1.8% from 2019-2028¹. System annual peak demand is expected to grow slightly more slowly, at 1.5% per year over the entire forecast horizon. This compares to historical growth in system energy requirements and peak demand of 2.2% and 1.5%, respectively, over 1999-2008. On a normal weather basis, the Base Case projected fiscal year 2009 energy requirements and calendar year 2009 peak demand are 348.8 GWh and 74.8 MW, respectively. The results of the load forecast reflect energy requirements growing to 406.8 GWh in 2018 and to 486.7 GWh in 2028 and annual peak demand growing to 85.4 MW by 2018 and to 99.3 MW by 2028, again without considering TCLP's EOP.

As a result of the EOP standards, the forecasted load growth is significantly reduced. Assuming implementation of an EOP meeting the legislated standard, the results of the load forecast reflect that TCLP system energy requirements can be expected to grow at annual average rates of 0.8% from 2009-2018 and 0.9% from 2019-2028. Growth in system annual peak demand is similarly reduced, to 0.6% per year over the entire forecast horizon. The forecasted energy requirements grow only to 375.2 GWh in 2018 and to 411.0 GWh in 2028, and annual peak demand grows only to 78.7 MW by 2018 and to 83.5 MW by 2028.

Table ES-2 below shows historical and projected fiscal year energy requirements and calendar year peak demand, as well as associated growth rates, for selected years.

¹ Unless otherwise indicated, annual data reflect TCLP's fiscal year, July of the prior year through June of the current year (i.e., 2008 reflects July 2007 through June 2008). However, annual peak demand data reflect the calendar summer (to maintain a contiguous summer season).

Table ES-2
Projected NEL and Peak Demand for Selected Years

Year	Unadjusted Results				Adjusted for Energy Optimization Plan			
	Net Energy for Load (MWh)	Percent Change (%)	Peak Demand (MW)	Percent Change (%)	Net Energy for Load (MWh)	Percent Change (%)	Peak Demand (MW)	Percent Change (%)
1997	245,890	--	50.7	--				
2000	298,711	6.7%	56.1	3.4%				
2005	337,159	2.5%	68.7	4.2%				
2007	345,680	1.5%	70.3	1.1%				
2008	341,152	-1.3%	64.9	-7.6%				
2009	348,829	1.7%	74.8	15.2%	347,786	1.4%	74.6	14.9%
2010	352,668	1.1%	75.5	0.9%	349,887	0.6%	74.9	0.4%
2011	357,218	1.3%	76.3	1.1%	351,813	0.6%	75.1	0.3%
2012	362,307	1.4%	77.0	0.9%	353,373	0.4%	75.1	-0.1%
2013	367,871	1.5%	78.2	1.6%	355,363	0.6%	75.5	0.6%
2018	406,849	2.0%	85.4	1.8%	375,211	1.1%	78.7	0.8%
2028	486,708	1.8%	99.3	1.5%	411,023	0.9%	83.5	0.6%

The following report details the methodology, data sources, assumptions, and results of the 2009 Load Forecast. The first section of the report provides an overview of the underlying methodology, including a general description of the econometric equations and a discussion of the derivation of net energy for load and peak demand. This overview is followed by a description of the sources from which various types of data have been obtained for the load forecast. Next, a list of principal considerations and assumptions that have been relied upon are included to provide context for the results. The forecast results, including the implications of the econometric equations, are then discussed in detail. Finally, a discussion regarding forecast uncertainty is included to provide guidance as to the use of the numerical results and the underlying methodology in planning analyses.

Section 1

OVERVIEW OF METHODOLOGY

At its core, the Load Forecast relies on an econometric analysis of retail sales by major rate classification. This analysis and the independent projections of driving variables represent the primary driver of system load growth. A separate econometric analysis is relied on to determine the relationship between system energy and peak demand.

Econometric forecasting makes use of regression to establish historical relationships between a variable of interest, such as energy consumption, and various explanatory variables based on economic theory and experience. In this approach, the significance and validity of historical relationships are evaluated using various statistical measures and theoretical tests. Regression equations that, in the view of the analyst, best explain the historical variation of energy consumption are selected. The historical relationships that comprise the final equations are generally assumed to continue into the future, and the selected models are then simulated using projections of the explanatory variables, resulting in projections of energy sales.

Econometric forecasting can be a more reliable technique for long-term forecasting than trend-based approaches and other techniques, because the approach results in an explanation of variations in electric consumption rather than simply an extrapolation of history. As a result of this approach, utilities are more likely to anticipate departures from historical trends in energy consumption, given accurate projections of the driving variables. In addition, understanding the underlying relationships that affect energy consumption allows utilities to perform scenario and risk analyses, thereby improving the robustness decisions.

Econometric equations are used to forecast residential customer accounts, residential average usage per customer, and energy sales by major rate classification for non-residential classes. A similar equation is used to forecast load factor, from which system peak demand is derived. The equations are annual in nature, and monthly projections are not produced herein.

1.1 Equation Specifications

In order to estimate, or forecast, a particular variable as a function of other variables, a common approach is to explain the “dependent variable” as a linear combination of several “independent variables,” each multiplied by a coefficient, as in equation (1-1) below.

$$Y_t = \alpha + \beta_1 X_{1t} + \beta_2 X_{2t} + \dots + \beta_n X_{nt} + \epsilon_t \quad (1-1)$$

In this equation, Y_t is the dependent variable. X_{1t} through X_{nt} are independent, or explanatory, variables. The Greek characters α , or alpha, and each β , or beta, are

coefficients to be estimated by the statistics program. In this functional form, β represents the amount of change in Y that can be expected from a 1 point change in the associated X term. The variable ϵ_t , or epsilon, is the error in the resulting estimate of the dependent variable and represents other sources of variation that are not explained by the equation. This functional form is referred to as, simply, linear.

However, in many situations, this linear equation does not accurately capture how the variables interact to produce the dependent variable. For example, the impact of weather on electric load is not well represented by a simple multiplier, which might be measured in MWh per degree Fahrenheit. Instead, the impact of weather tends to grow as the system grows. Accordingly, a functional form that results in a multiplicative combination of such factors is typically more appropriate. Equation 1-2 below is a commonly-used theoretical equation.

$$Y_t = \alpha \times X_{1t}^{\beta_1} \times X_{2t}^{\beta_2} \times \dots \times X_{nt}^{\beta_n} \times \epsilon_t \quad (1-2)$$

Through a few algebraic transformations, this equation is made easily estimable using ordinary least squares as the following equation, commonly referred to as the “double-log” or “log-linear” (i.e., linear in log space) form:

$$\ln Y_t = \alpha + \beta_1 \ln X_{1t} + \beta_2 \ln X_{2t} + \dots + \beta_n \ln X_{nt} + \epsilon_t \quad (1-3)$$

In this equation, Y_t is again the dependent variable, such as average residential usage. X_{1t} through X_{nt} are explanatory variables, such as average income, electricity price, and weather. The Greek characters α , or alpha, and each β , or beta, are estimated by the statistics program. In this functional form, β represents the percentage change in Y that can be expected from a 1% change in the associated X term and is often referred to as “elasticity”. The coefficient for the average income variable would then represent the income elasticity of average residential sales.

Again, the variable ϵ_t , or epsilon, is the amount of error in the equation’s estimate of the dependent variable and represents other impacts that are not explained by the equation. Typically, these impacts are simply not significant enough to model or are associated with data that is not recorded or easily obtainable. For the residential sales equation, an example of such a variable might be the average thermostat setting of TCLP’s residential customers. Clearly, such a variable matters to average consumption, but the data is not easily obtainable.

Variables that can have the value of zero, such as certain weather variables or binary variables, cannot be logged, because the natural log of zero is undefined. These variables are in the equation in non-logged form and can be interpreted to represent the percentage change in Y that can be expected from a one *point* change in X. While these coefficients are not actually elasticity measurements, they are still often referred to in that way for simplicity.

The customer and sales equations are of this functional form.

The form of equation 1-3 (and 1-2 for that matter) yields several benefits over equation 1-1. First, as discussed above, it more accurately represents the multiplicative combination of factors, which is common in a variety of situations. Second, it assures constant elasticity, which is a typical assumption in economic

forecasts and desirable in equations intended to forecast trending variables. Finally, as the coefficients are measured in percentage terms, they can be readily compared between other forecast equations for the same utility or between different utilities. As importantly, they can similarly be compared to theoretical or expected values. For instance, a coefficient for price elasticity should be significantly below 1.0 in absolute terms (and negative, of course). An elasticity estimate that deviates from this preconceived notion, which is backed up by other empirical work in the utility and other industries, may be an indicator of some data or empirical problem. The coefficients on other variables should similarly be subjected to theoretical or preceding empirical benchmarks.

The equation used to estimate load factor conforms to Equation 1-1. This functional form choice is appropriate because elasticity measurements are not of special interest, and the dependent variable is typically not trending to a significant degree.

The equation parameters are estimated using ordinary least squares in the computer program Econometric Views™. While the resulting parameterized equations can be programmed into a spreadsheet program, the majority of the forecasts for the Load Forecast were computed directly in the statistics program and exported. An Excel™ spreadsheet is then used to perform further calculations which derive the remaining forecasted variables. Given that TCLP desires that the forecast model allows for user adjustment of results, and the load factor equation was impacted by the customer sales mix, the load factor equation was programmed into the model.

1.2 Integration of Determinants

The diagram below provides an illustration of the flow of calculations used to produce the forecast.

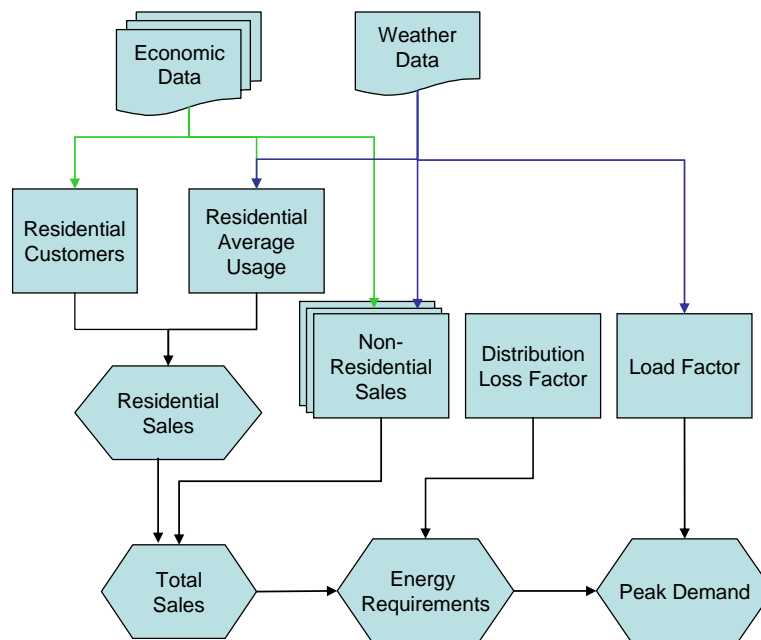


Figure 1-1: Forecast Determinants Derivation

2.1 Historical System Data

Data on fiscal year number of customer accounts, electric sales, and revenues by major customer classification were provided by TCLP. Revenue data were verified to reflect the full retail costs of electricity, including power cost adjustments, and were used to estimate the cost of electricity experienced by TCLP's customers. Data were available and analyzed over fiscal year 1986 through 2008 (Study Period).

Data regarding monthly historical system energy requirements, or NEL, and calendar year peak demand were provided by TCLP. Certain resources that dispatch behind the wholesale meter (i.e., load-side generation) were added back to the energy requirements data obtained from TCLP's wholesale provider, Michigan Public Power Agency, so that all of the system energy requirements were included. The peak demand data provided by TCLP included generation from those resources at the time of the peak.

System energy requirements are typically greater than total retail sales by the amount of losses incurred over distribution lines and related equipment (e.g., transformers) and unbilled sales, such as energy use at a utility's offices and certain system facilities (e.g., substations). Distribution loss factors computed for purposes of this load forecast represent a percentage adjustment to account for these differences between total sales and system NEL.

2.2 Weather Data

Historical weather data for the Traverse City Cherry Capital airport was obtained from the National Oceanic and Atmospheric Administration (NOAA). Weather data was also obtained for other weather stations in the region for testing and benchmarking purposes.

The influence on electricity sales of weather has been represented through the use of two data series—heating and cooling degree days (HDD and CDD, respectively.) Degree days are derived by comparing the average daily temperature and a base temperature, typically 65 degrees Fahrenheit (dF), which was the base relied on herein. To the extent the average daily temperature exceeds the base temperature, the difference between that average temperature and the base is the number of CDD for the day in question. Conversely, HDD result from average daily temperatures which are below the base temperature. Heating and cooling degree days are then summed over the period of interest—in this case, the fiscal year. The analysis of TCLP's retail

Section 2

sales and load factor involved some experimentation with the base temperature, which resulted in a few different bases across the forecast equations, as follows:

- Residential usage – HDD base of 45 dF, CDD base of 70 dF
- Commercial sales – no measurable weather influence
- Industrial sales – CDD base of 55 dF
- Load factor – HDD base of 45 dF, CDD base of 70 dF

The assumed values over the forecast horizon for these annual weather determinants were based on the average over the study period (1986-2008).

Figure 2-1 shows a graphical comparison of historical and long-term average annual HDD and CDD for the Traverse City airport weather station, using various bases indicated by the values at the end of the variable name (i.e., HDD45 indicates a temperature base of 45 dF). The data reflects that the region is dominated by cool weather and that, in recent years, winter weather has been decidedly mild by long-term historical standards. Historical weather data of greater detail is provided in Appendix D.

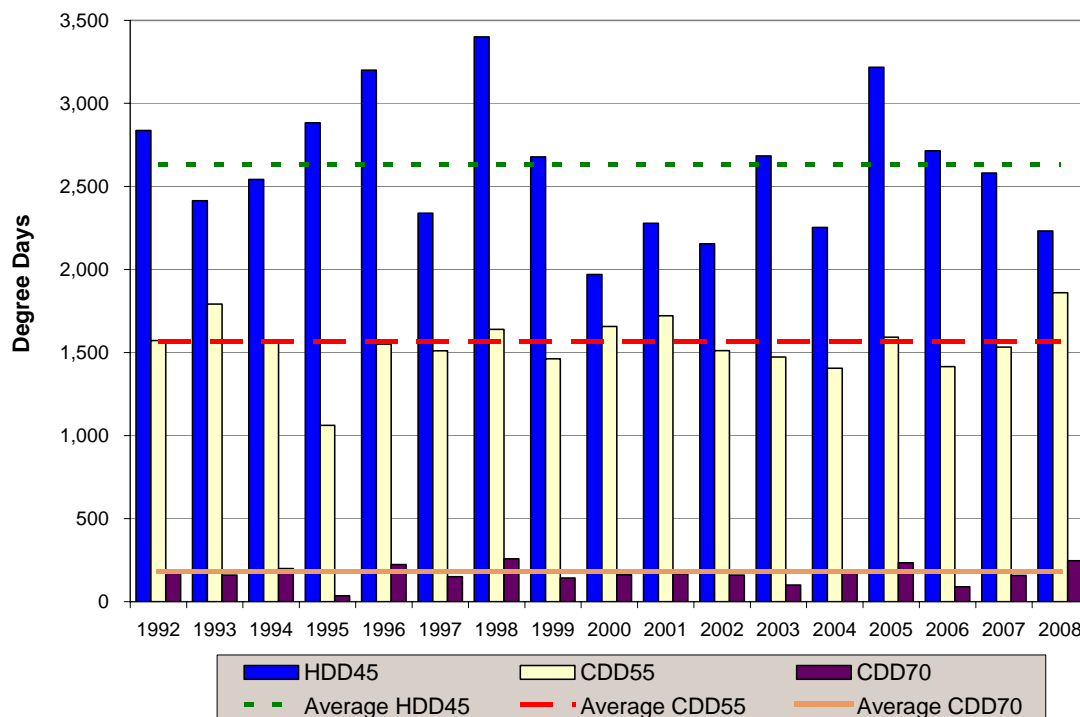


Figure 2-1: Historical and Normal Heating and Cooling Degree Days

The influence of weather on load factor was represented and tested using several weather-related data series. In addition to the HDD and CDD series discussed above, several weather variables associated with the peak day weather were constructed. Daily weather statistics were compiled, including high and low “dry bulb” temperatures, average dewpoint, average humidity, and rainfall. Peak day weather determinants were then determined based on information regarding the timing of the

annual peak demand from TCLP. In addition, high and low temperatures from the day prior to the peak day were similarly determined. Finally, multiple temperature-humidity indices were constructed to test for the usefulness of a combined heat index in explaining variations in load factor resulting from its impact on peak demand.

In order to develop a forecast, it was necessary to determine peak weather conditions that reflect conditions that could be expected on TCLP’s peak load day. Data regarding temperatures on the hottest day of each year and the day prior to the hottest day were compiled and averaged over 1980 through 2008. While it is typically the case that a utility’s peak day is not necessarily the hottest day of each year, the period of available data regarding the timing of peak demand and therefore, the weather on the peak load day, was not sufficient to develop a defensible assumption. Therefore, the absolute hottest day was utilized.

Figure 2-2 below shows the historical daily high temperature on the peak day and day prior to the peak day over 1996-2008, as well as the long-term averages corresponding to the hottest day of the year. It is noteworthy that the average of the daily high temperature on TCLP’s peak day over 1996-2008 is 91.9 dF, while the average of the absolute hottest day over the same period was 93.8 dF (very similar to the long-term average of 94.5 dF shown in the chart below). Given additional years of annual peak timing data, it might be sensible to revisit the assumption regarding peak day temperatures used in the forecast to reflect that TCLP’s peak is not always the absolute hottest day.

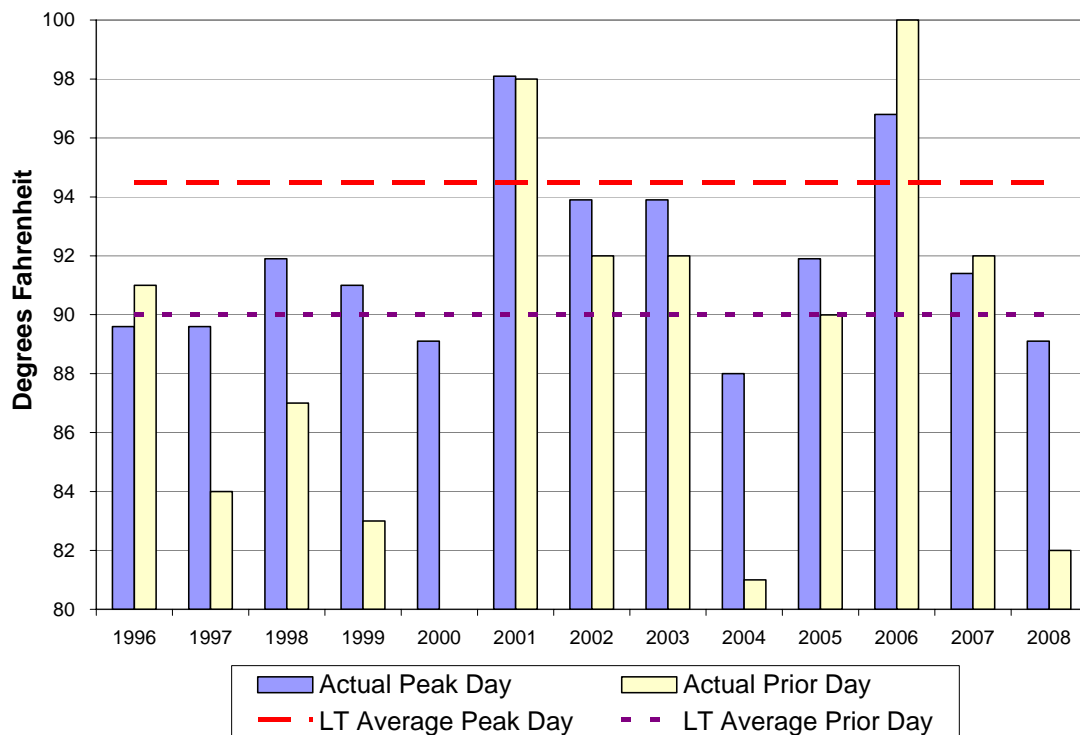


Figure 2-2: Long-term v. Recent Average Peak Day Maximum Temperature

2.3 Economic and Demographic Data

Data regarding the economy and population of Grand Traverse County were obtained from Woods & Poole Economics, Inc., a nationally recognized provider of such data. These data include county population, households, employment, personal income, retail sales, and gross domestic product. Although all data was not necessarily utilized in each of the forecast equations, each was examined for its potential to explain changes in historical electric sales. Note that personal income refers to the total income earned by the population in the geographic region rather than average personal income per capita, thereby combining population and income per capita concepts. The vintage of the Woods & Poole data was approximately July 2008.

After the initial historical analysis was completed additional economic data for a limited number of data concepts was also obtained from Moody's Economy.com, dated March 2009, as a benchmark to the somewhat outdated Woods & Poole data. The comparison of the two data sources showed that the two projections were not significantly different. In fact, the Economy.com data appeared slightly more optimistic over the long-term.

Appendix C contains a table showing the economic and demographic series from Woods & Poole that were analyzed for potential use in the forecasting equations. Of these determinants, county households, total personal income, and mean household personal income were utilized in the resulting forecast.

2.4 Real Electricity Price Data

The real price of electricity by customer classification is represented by real average revenue, which is calculated by dividing revenue by electricity sales and normalizing for inflation using the implicit price deflator for personal consumption expenditures (PCEd), which is published quarterly by the U.S. Bureau of Economic Analysis. The adjustment for inflation is accomplished by dividing annual nominal average revenue by the associated annual PCEd value.

The forecast model for average residential usage includes this price term using a multi-year moving average to reflect that the demand response from price changes take some time to be felt. However, it is important to recognize that this lagged demand response may only capture changes in discretionary use, and changes to electric consumption resulting from the replacement of the stock of electric appliances, which increase the average efficiency of appliances, take much longer to be felt but may be more significant. However, TCLP's average revenues are strongly negatively correlated with most of the economic series, and this inhibits the ability of the statistics software from discerning this long-run price influence. See the discussion in Section 3, "Principal Considerations and Assumptions," for further information.

For purposes of this Forecast, projected electricity prices are assumed to increase at the rate of inflation. Consequently, the real price is projected to be essentially constant.

Figure 2-4 below depicts the historical and projected trend of real average revenue, or real electricity prices, for the residential class of TCLP, as compared to similar data for the state of Michigan. The trend of average revenue for the other major rate classifications is very similar. The data reflect that residential electricity prices have declined somewhat in real terms for most of the historical period but have increased significantly in recent years.

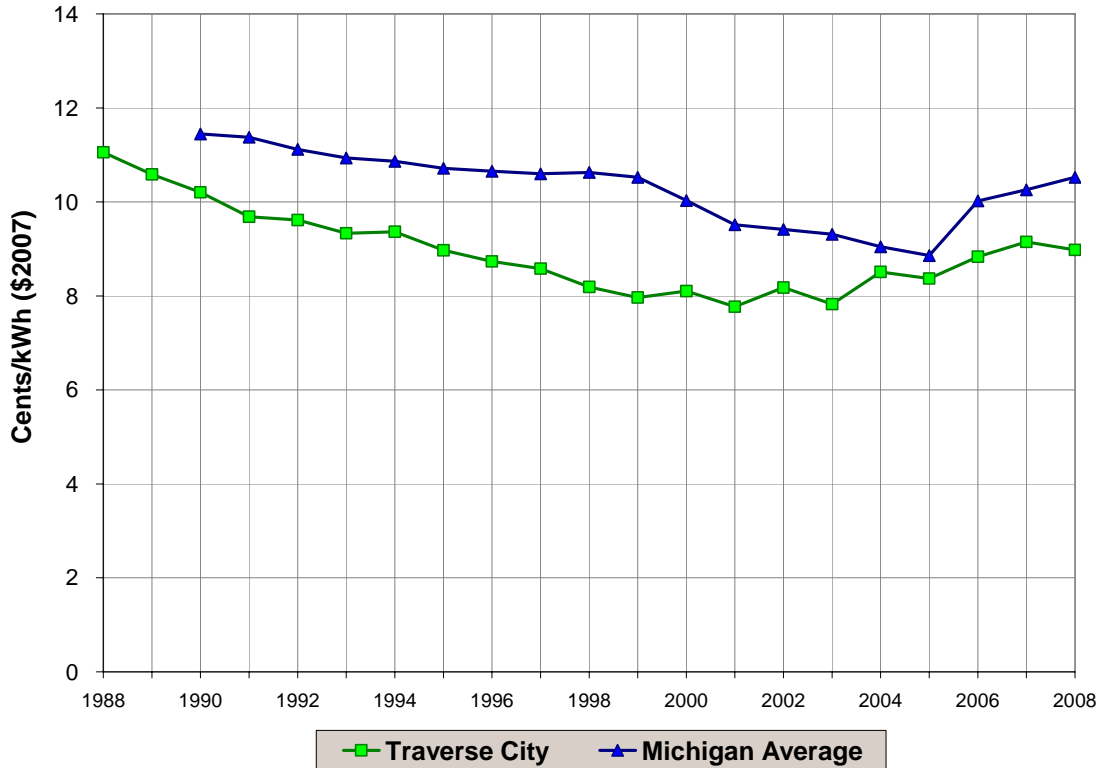


Figure 2-3: Historical Real Residential Average Revenue

Section 3

PRINCIPAL CONSIDERATIONS AND ASSUMPTIONS

In preparing the 2009 Load Forecast, as summarized in this report, we have made certain assumptions with respect to conditions that may occur in the future. These assumptions primarily relate to economic, demographic, and weather conditions. With regard to certain of these factors, we have used and relied upon information provided to us, or prepared by others. While we believe the assumptions made by us in preparing the 2009 Load Forecast are reasonable for the purposes of the forecast, they are dependent on future events, and actual conditions may differ from those assumed. While we believe the sources of the information provided to us, or prepared by others, to be reliable and the use of such information to be reasonable for the purposes of the forecast, we offer no other assurances with respect thereto.

To the extent that economic, demographic, weather, or other conditions occur that are different from those assumed by us or from the information provided to us or prepared by others, the actual future TCLP load can be expected to vary from the forecast. It should be emphasized that the confidence associated with any forecast varies inversely with the length of the forecast horizon. The probability of other factors affecting forecasted values increases with uncertainty about future developments; this uncertainty increases with the length of the forecast horizon. With this in mind, the 2009 Load Forecast should be seen as providing reasonable estimates of TCLP's future demand and energy requirements for the purposes for which the Load Forecast is intended. However, these estimates are subject to the future effects of factors that cannot be reasonably foreseen at this time.

The development of the 2009 Load Forecast was based upon the following principal consideration and assumptions:

- The data on which this forecast is based, both external (economic, weather, etc.) and internal (energy sales, peak demands, etc.) are assumed to be accurate. While R. W. Beck has reviewed the data for major anomalies, we can give no assurances that the data are without error. In particular, recent historical economic data (for the period after 2006) actually represents projections by Woods & Poole, as actual data is unavailable. Further, even "actual" economic and demographic data for the most recent several years is subject to substantial revision as more supporting data becomes available. Therefore, the relationships upon which the forecast is based may be in error, as the "true" data could show a different quantitative relationship.
- The future influence on energy sales of the economic, demographic, and weather factors, on which the econometric models are based, was assumed to be similar to

Section 3

the estimated influence of such factors generally over the period 1986 through 2008².

- Although the econometric models implicitly account for the historical relationships between energy usage and the following factors to the extent they have occurred in the past, the Load Forecast does not explicitly reflect extraordinary potential future effects of: (a) increases in appliance design efficiency or building insulation standards; (b) development of substitute energy sources; (c) consumers switching to traditional or new types of electrical appliances from other alternatives (e.g., electric vehicles); (d) consumers switching from electrical appliances to other alternatives; or (e) variations in load that might result from legal, legislative, regulatory, or policy actions.

² For the load factor equation and associated peak demand forecast, the period of analysis covers only 1996-2008.

Section 4

FORECAST RESULTS

The following discussion details the forecasting models that resulted from the regression analysis and the projections of energy sales by major rate classification, system NEL, and peak demand. Unless stated otherwise, all results discussed in this section are prior to accounting for the impact of the EOP standards. The impact of EOP standards on system NEL and peak demand are discussed separately. Given the simplified treatment of the EOP impacts, data regarding reductions on a class-specific basis are not provided.

Appendix A contains several tables that provide detailed projections for each of these variables on an annual basis. Further information regarding the regression models is included in Appendix B.

4.1 Residential Class

The residential class model reflects that energy sales are dependent on, or driven by: (i) the number of residential customers; (ii) real personal income per household; (iii) real electricity prices; (iv) real natural gas prices; and (v) weather variables. For the residential class, the analysis of electric sales was separated into independent analyses of the number of customers and residential usage per customer, the product of which is total residential sales. This process is common for highly homogenous customer groups. For other rate classifications, the total sales series is the primary forecasted variable.

4.1.1 Residential Customers

The number of residential customers is typically projected on the basis of the historical relationship between residential customers and population or the number of households, either in the utility's service area or surrounding county. If such data are reported and are accurate, historical households in the utility's service area should be nearly perfectly correlated and, indeed, essentially analogous to residential customers. Population should also similarly be highly correlated with residential customer counts, given a fairly stable number of persons per household. However, utility forecasting typically must rely on demographic and economic data that represents a larger geographic area than, or some amalgamation of reported geographic areas that correspond fairly closely to, the exact service territory. The typical econometric model of residential utility customers then reflects the portion of the households in the total geographic area that are served by the utility or perhaps how that proportion might be trending through time.

Section 4

The analysis was preceded by a simple visual inspection of the customer count data to determine whether there were any significant anomalies and generally how the data has trended. Figure 4-1 below depicts the historical residential customer count data. Note that there are periodic spikes in the data, notably 1991 and 1995. While the latter might be attributable to the transfer of some customers from Consumers Energy, the trend of customer growth has been volatile, partly due to the fact that the data represent year-end values rather than annual averages. Most importantly, the trend exhibits significantly higher growth over 2005-2007, coinciding with the housing boom that has been experienced across most of the nation over that period.

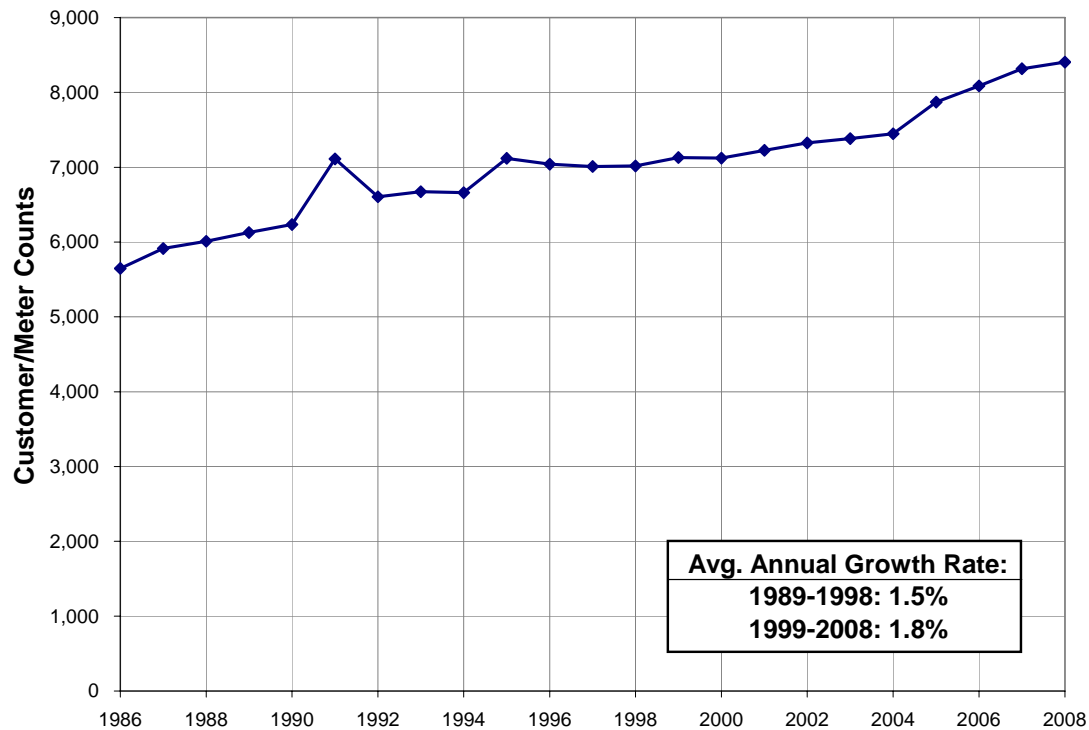


Figure 4-1: Fiscal Year-end Residential Customer Counts

TCLP Residential customer counts are explained by a combination of the number of households in Grand Traverse County, a pair of binary variables to capture the 1991 spike and slightly higher customer counts thereafter, and an adjustment variable to capture the run-up in customer counts over 2005-2007. The adjustment variable is zero over the historical period through 2004, rises to 1.0 in 2005, and increases by 0.25 in 2006 and 2007. For 2008 and thereafter, it is assumed to remain at a value of 1.5. This ad hoc treatment is intended to capture the impact of the housing boom and the sudden introduction of large multi-family housing in TCLP's service area. It is expected that housing development and customer growth will return to the long-run trends. The forecasting equation reflects that each percentage of growth in households in Grand Traverse County typically translates into about 0.4% growth in TCLP

Residential customers. This coefficient is referred to as the elasticity³ between TCLP Residential customers and county households. The equation explains about 98% of the variation in customer counts.

The history and resulting projection of Residential customers are depicted in Figure 4-2. Historical growth in Residential customer accounts averaged approximately 1.8% over 1999-2008. The results of this Load Forecast reflect that Residential customers are expected to grow at average annual rates of 0.7% over 2009-2018 and 0.5% over 2019-2028. This reflects an expected level of approximately 8,972 customers by 2018 and 9,424 by 2028. Note that 2014 reflects the addition of about 100 customers (about 1% of TCLP’s base of residential customers) transferred from Consumers Energy service to TCLP.

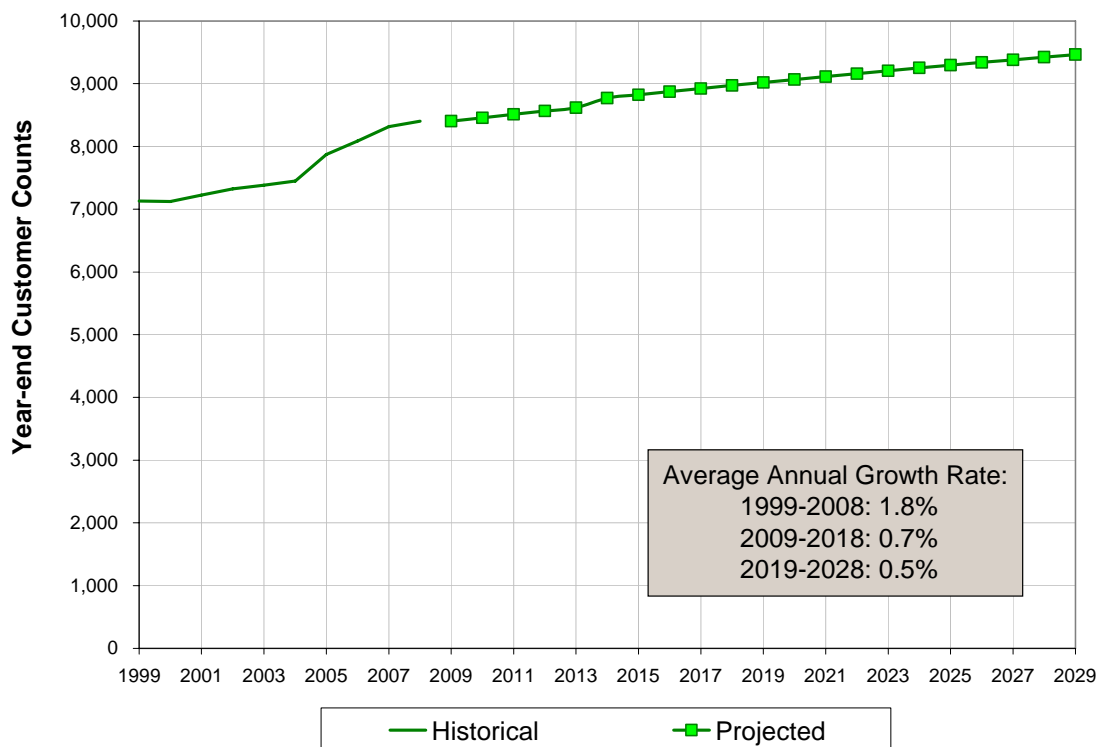


Figure 4-2: Historical and Projected Residential Customer Counts

The growth in customer counts discussed above is directly comparable to the projected growth rates for households in Grand Traverse County, albeit significantly lower. Over 2009-2018, growth in county households is expected to average approximately 1.1%, and over 2019-2028, 1.0%. Note that these values are nearly double the growth in Residential customers reflected in this Load Forecast for TCLP, particularly considering the customers transferred from Consumers Energy. This is directly the result of the estimated elasticity of 0.4 with respect to county households.

³ Elasticity measures the influence of one variable on another in terms of the percentage change that can be expected in one variable from a one percent change in another. An elasticity of Y with respect to X of 0.5, for example, means that a 10% change in X would cause a 5% change in Y.

Additional information regarding the resulting model parameters and statistics are included in Appendix B.

4.1.2 Residential Average Use

Residential average use is calculated simply by dividing total billed Residential sales by customer counts and is modeled as a function of the following variables as shown in Appendix B:

- Average personal income per household (GRTRAV_PYHH),
- The price of electricity for the residential class (PR_TVC_RES),
- The price of natural gas for consumers in Michigan (PR_NG_RES),
- The number of heating and cooling degree days using bases of 45 dF and 70 dF, respectively (HDD45/CDD70), and
- Binary variables to account for a one-time drop in average usage in 1991 and a slightly lower usage level in the post-2004 period.

Income and electricity and natural gas prices are included in the model as a reflection of a considerable weight of economic theory suggesting that these variables affect consumers' purchasing habits. In the case of income, the effect is somewhat indirect. As average incomes rise, current residents and new residents will tend to build larger homes or add on to existing homes, upgrade other aspects of their homes resulting in greater electric use, or purchase new and/or larger electric appliances. In the case of electricity and natural gas prices, the influence is more direct. When electricity prices go up in real terms, TCLP's residential customers will tend to conserve in various ways to some degree and, in the longer term, will be encouraged to replace electric appliances with more efficient ones. Similarly, when natural gas prices go up in real terms and relative to electricity prices, TCLP's customers will rely more on secondary electric heat sources (e.g., portable resistance heaters, electric blankets) and less on central gas heat.

The elasticity of average usage with respect to average income, also referred to as the "income elasticity", is estimated in the residential average use model to be 0.26. Accordingly, a 10% change in average income can be expected to result in a 2.6% increase in average residential use and, all else equal, total residential sales. Similarly, the price elasticity is estimated to be -0.29. Accordingly, a sustained 10% increase in the real price of electricity can then be expected to yield a 2.9% decrease in average usage, after a lag. The estimated elasticity of natural gas prices, referred to as the "cross-price elasticity," is 0.24.

The historical trend and resulting projection of average use per Residential customer are depicted in Figure 4-3. Historical growth in Residential average use over 1999-2008 averaged approximately 0.6% per year. The forecast reflects that Residential use is expected to grow at average annual rates of 0.2% over 2009-2018 and 0.3% over 2019-2028 from approximately 6,300 kWh per customer per year in 2009 to about 6,600 kWh per customer per year by 2028.

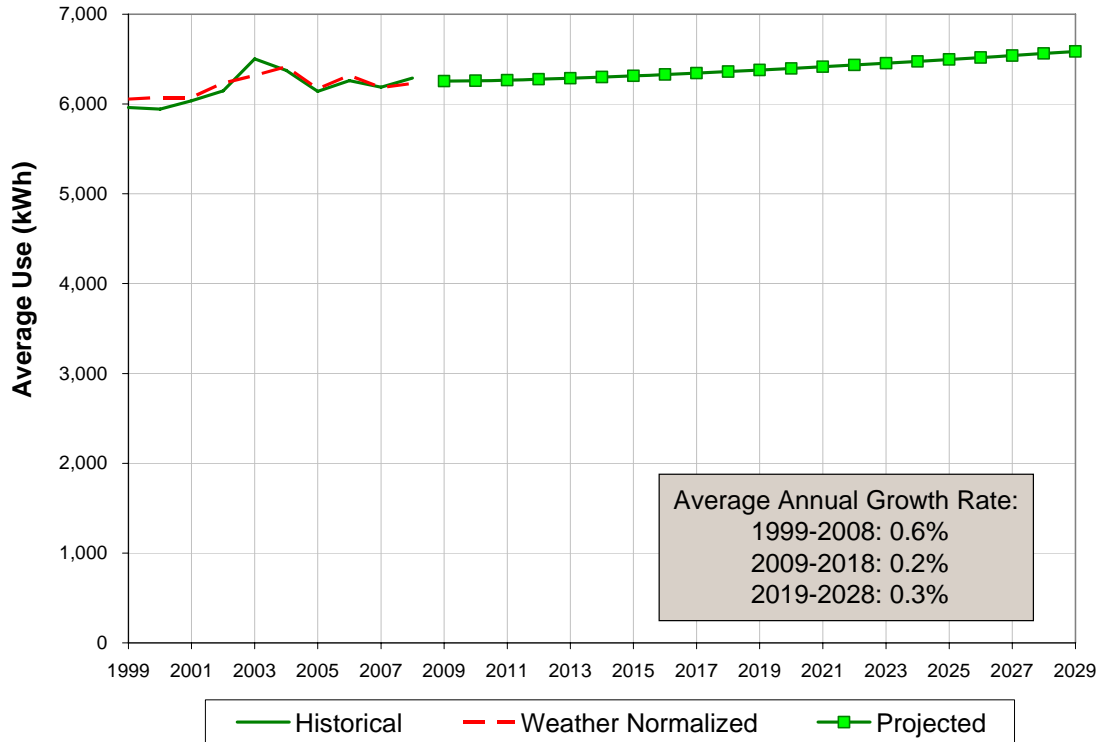


Figure 4-3: Historical and Projected Residential Average Use

4.1.3 Residential Sales

The above forecasts of Residential customer counts and average use are combined to derive total Residential sales. The historical trend and resulting projection of Residential sales are depicted in Figure 4-4 below. Historical growth in Residential sales over 1999-2008 averaged approximately 2.4% per year. The forecast reflects that Residential sales are expected to grow at average annual rates of 0.9% over 2009-2018 and 0.8% over 2019-2028.

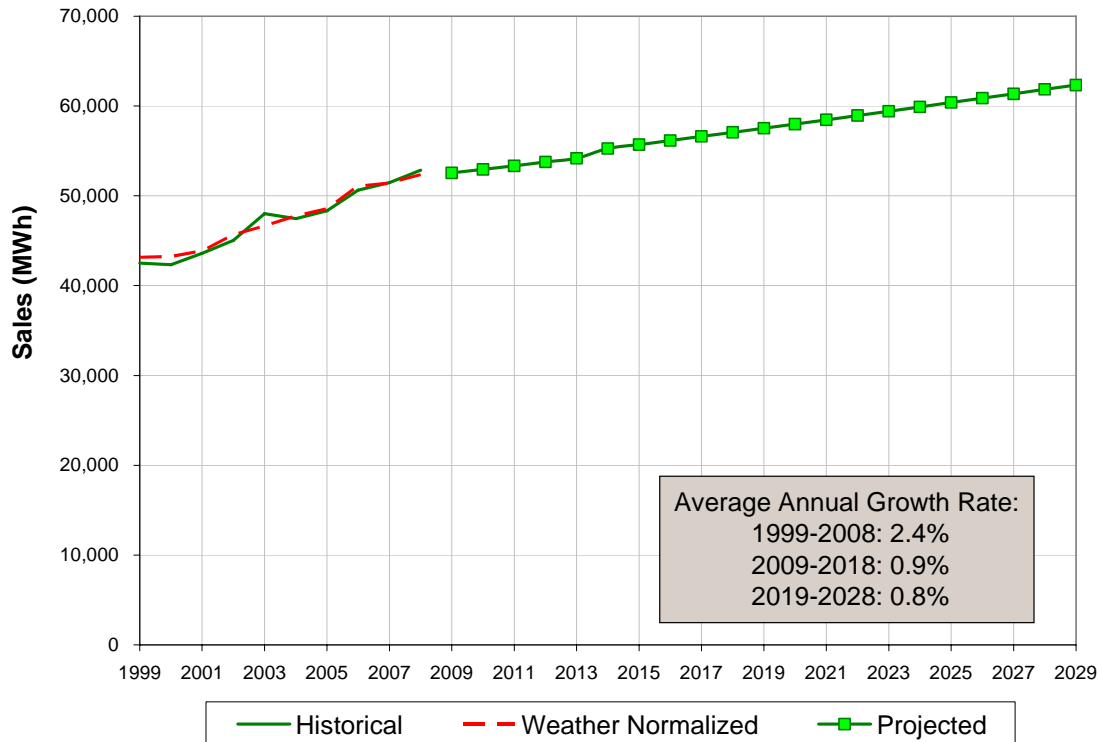


Figure 4-4: Historical and Projected Residential Sales

4.2 Commercial Sales

The Commercial sales model reflects that sales are best explained by the combination of:

- Total personal income in Grand Traverse County and
- A binary variable addressing an otherwise unexplained increase in sales beginning 2003.

The inclusion of total personal income in the model captures the total earning and spending power of the region’s residents. The binary variable may be related to customer transfers from Consumers Energy that occurred in 2004 or perhaps migration among TCLP’s customer classes. It is noteworthy that weather conditions did not appear to explain variations in commercial sales in any significant way.

The historical data and resulting projection of sales for the Commercial Class are depicted in Figure 4-5. Historical growth in Commercial sales over 1999-2008 averaged approximately 2.3% per year. The forecast reflects that sales are expected to grow at average rates of 1.3% over 2009-2018 and 1.2% over 2019-2028. Note that the forecast reflects some additional sales resulting from a further transfer of customers from Consumers Energy in 2014, equivalent to about 2% of the class sales.

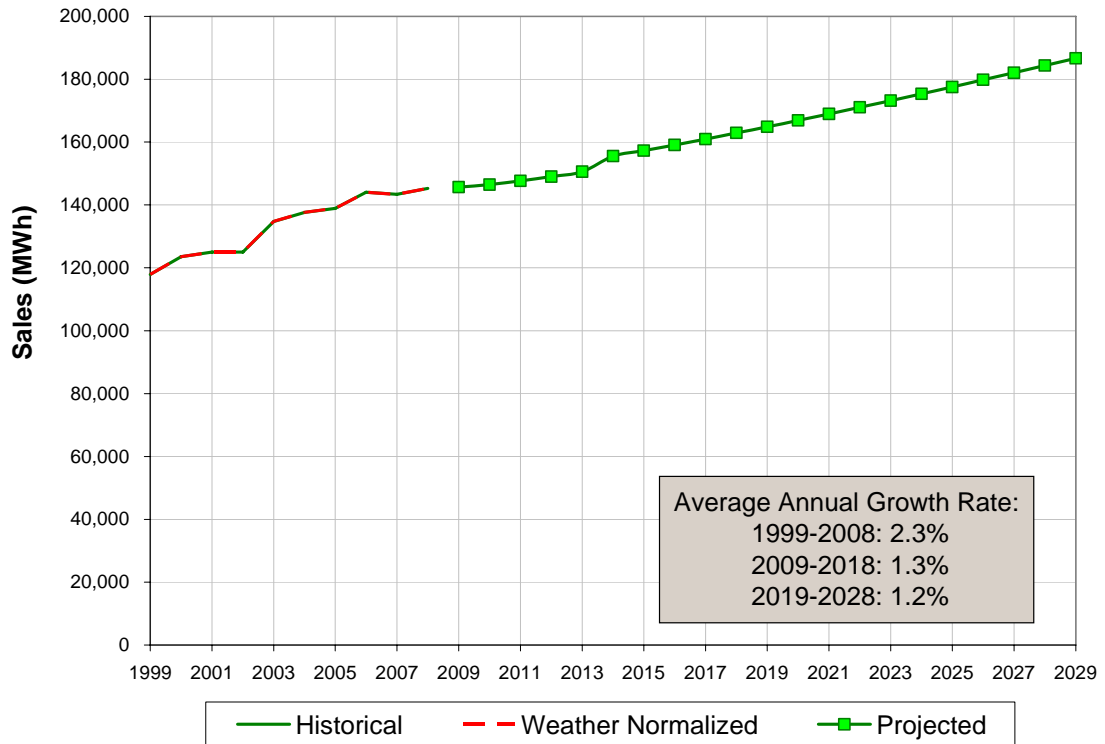


Figure 4-5: Historical and Projected Commercial Sales

4.3 Industrial Sales

The Industrial sales equation reflects that sales can be explained primarily as a function of:

- Total personal income in Grand Traverse County and
- Cooling degree days using a base of 55 degrees Fahrenheit.

The inclusion of income in the equation is similar to the Commercial sales equation discussed above. However, Industrial sales have grown a good deal more over the historical period than Commercial sales have, and this trend is effectively embedded in the resulting forecast equation in the form of a much higher coefficient on total personal income. This higher coefficient in the Industrial sales equation and the expectation of continued economic growth in Grand Traverse County results in a faster growing Industrial class than other classes and an increase in the mix of Industrial load over the forecast horizon. The fact that Industrial sales appears to be influenced by weather conditions is a reflection of that fact that this class also comprises many large commercial businesses (e.g., big box retailers).

The historical data and resulting projection of Industrial sales are depicted in Figure 4-6. Historical growth in sales over 1999-2008 averaged approximately 2.8% per year. The results reflect that Industrial sales are expected to grow at average annual rates of 2.6% over 2009-2018 and 2.7% over 2019-2028, growing from approximately 128.4 GWh in 2009 to about 210.4 GWh by 2028. Note that the forecast reflects some

additional sales resulting from a transfer of three customers from Consumers Energy in 2014, equivalent to about 2% of the class sales.

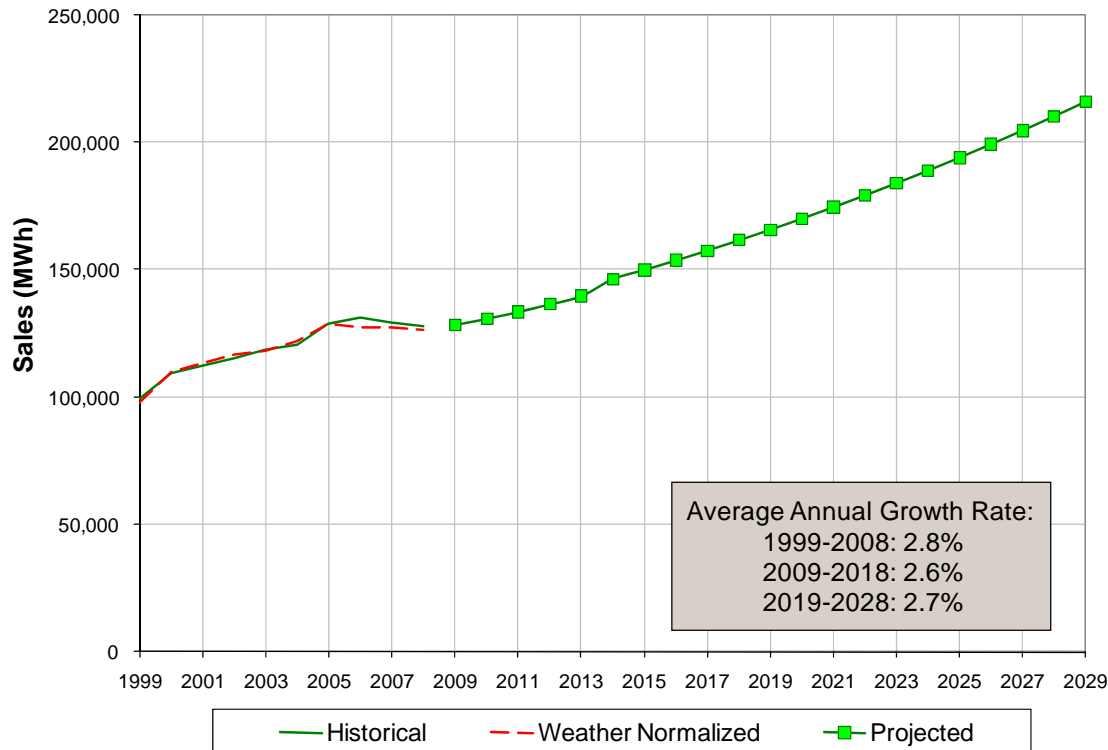


Figure 4-6: Historical and Projected Industrial Sales

4.4 Sales to Other Classes

The remaining classifications of customers account for approximately 1.5% of TCLP sales and consist of the following:

- Public Use, or City accounts, and
- Lighting.

These classes were modeled in similar fashion to the Commercial class, using Grand Traverse total personal income and gross regional product, respectively, as primary driving variables. However, the Public Use class equation also adjusts for a significant reclassification of customers away from this class beginning 2005 via a binary variable. The resulting forecasts are shown in detail in Appendix A, and the forecast equations, in Appendix D.

4.5 Total Retail Electricity Sales

Based on a summation of the independent forecasts of sales for each customer classification discussed above, total system retail sales are projected to grow at average annual rates of 1.7% over 2009-2018 and 1.8% over 2019-2028. These growth rates are somewhat slower than the recent historical growth rate of 2.4% per

year over 1999-2008. This differential is driven primarily by the relatively high growth rate in residential customer additions and sales growth over 2005-2007, as well as the pickup of some customers that were acquired from Consumers Energy in 2004. Total retail sales are projected to grow from 331.1 GWh in 2009 to 462.4 GWh in 2028. Figure 4-7 below depicts the historical and projected trend of total retail electricity sales in TCLP’s service territory. The projection includes some pickup of additional customers across the classes in 2014 as discussed in the sections above.

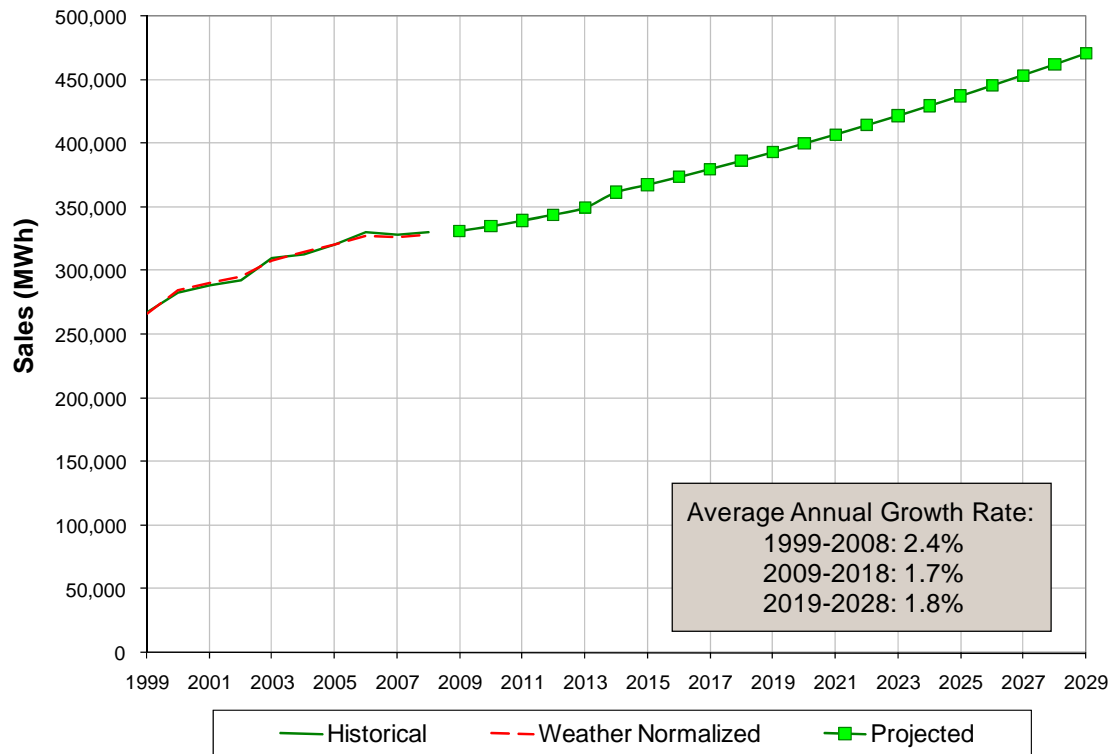


Figure 4-7: Historical and Projected Total Retail Electricity Sales

4.6 Energy Requirements

The forecast of system energy requirements, or Net Energy for Load (NEL), is derived from the forecasted total sales above and estimated distribution losses of 5.0%. This estimate was based on a simplified average of losses over the last several years, excluding the most recent year, which was believed to be affected by erroneous energy requirements data, based on consultation with TCLP staff. The resulting forecasted Net Energy for Load generally follows the projected trend of total sales discussed above and is projected to grow at annual average rates of 1.7% over 2009-2018 and 1.8% over 2019-2028. Net Energy for Load is projected to be 348.8 GWh during fiscal year 2009 and to grow to 486.7 GWh in 2028, an overall increase of 40% over the 20-year period. Historical and projected Net Energy for Load are depicted in Figure 4-8 below and shown in Table 4-1 in Section 4.8. Note that the 2008 value may be erroneous and is likely understated by about 1.0%.

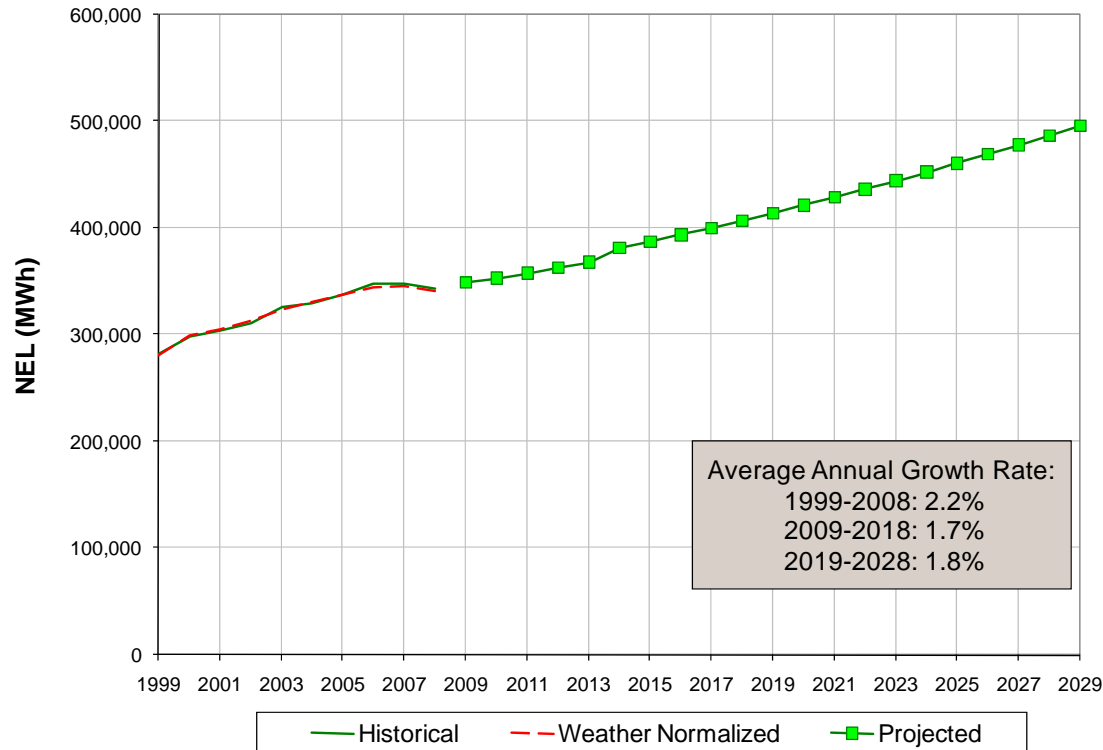


Figure 4-8: Historical and Projected Net Energy for Load

4.7 Load Factor Analysis

The next step in developing an integrated power requirements forecast is to develop a methodology to estimate load factor, which describes the relationship between energy requirements and peak demand. R. W. Beck's preferred methodology involves an effort to directly analyze load factor to (i) determine whether statistically significant trends are discernable, (ii) be able to more accurately capture long-term normal weather conditions, and (iii) be able to estimate the volatility of peak demand with respect to peak-producing weather. The methodology relies on the resulting load factor equation to explicitly integrate the forecasts of energy and peak demand, which are simply two measures of the same phenomenon—electricity demand.

Other load forecasting methodologies either rely on simple load factor averages to derived peak demand or separate econometric analyses of peak demand. While the latter satisfies the needs above to some degree, independent forecasts of energy and peak demand frequently exhibit diverging growth rates that suggest a trend in load factor that may be somewhat artificial and simply due to minor differences in the mathematics of the regression process. The direct analysis of load factor explicitly determines whether a trend is discernable, what the causes might be, and most importantly, whether those explanatory conditions are likely to continue in the future. An independent analysis of peak demand is less likely to uncover these issues.

The variables found to be most useful in explaining load factor are the following:

- Heating degree days (base of 45 degrees Fahrenheit)

- Cooling degree days (base of 70 degrees Fahrenheit)\
- The weighted average of maximum temperature on the peak day and the day prior, with an 80% and 20% weighting, respectively
- Peak day precipitation
- A two year moving average of TCLP's inflation-adjusted average retail revenue
- The percentage of TCLP's sales that are classified as Industrial

The first few variables above primarily explain the year-to-year volatility of peak demand. Heating and cooling degree days have positive coefficients, implying that higher values for these variables, all else equal, tend to increase load factor. This is intuitive, as weather across the year tends to influence energy requirements but not peak demand. Conversely, higher temperature on and just prior to the peak day tends to depress load factor, as peak demand is influenced more by peak day conditions than is annual energy. Similarly, precipitation on the peak day tends to be associated with higher load factors, as peak day rainfall tends to depress peak demand.

The last two variables above are more trend-related. Increases in electricity prices generally cause consumers to curtail energy use. However, the reduction in energy consumption tends to be more focused on non-peak periods. Consumers are more likely to reduce "non-essential" consumption; when it is the peak period during the summer, consumption for space conditioning is typically viewed as essential. TCLP's effective retail rates have increased somewhat over the last few years, which has likely depressed load factor somewhat. Conversely, TCLP has increased its Industrial customer mix significantly over the last several years. This has lent some support to load factor.

It is important to recognize that the period over which analysis of load factor and peak demand, 1996-2008, was significantly shorter than available for the retail load analysis, 1986-2008. Accordingly, each observation carries considerable weight in the resulting equation parameters. Any future analysis of load factor or peak demand incorporating additional observations may yield significantly different results on the load factor equation and the resulting forecast.

Figure 4-9 below depicts the recent historical and near-term projected annual load factor of TCLP's system. Note that much of the volatility in load factor is attenuated as a result of weather-normalization, and a large part of the increase in load factor over 2007-2008 is estimated to be the impact of considerably cooler weather during the peak period. Please refer back to the discussion regarding assumed normal peak weather conditions in Section 2. It is also important to recognize that the 2008 load factor may have been affected by the economic downturn, which may have impacted the peak demand more than the fiscal year energy that generally precedes the peak.

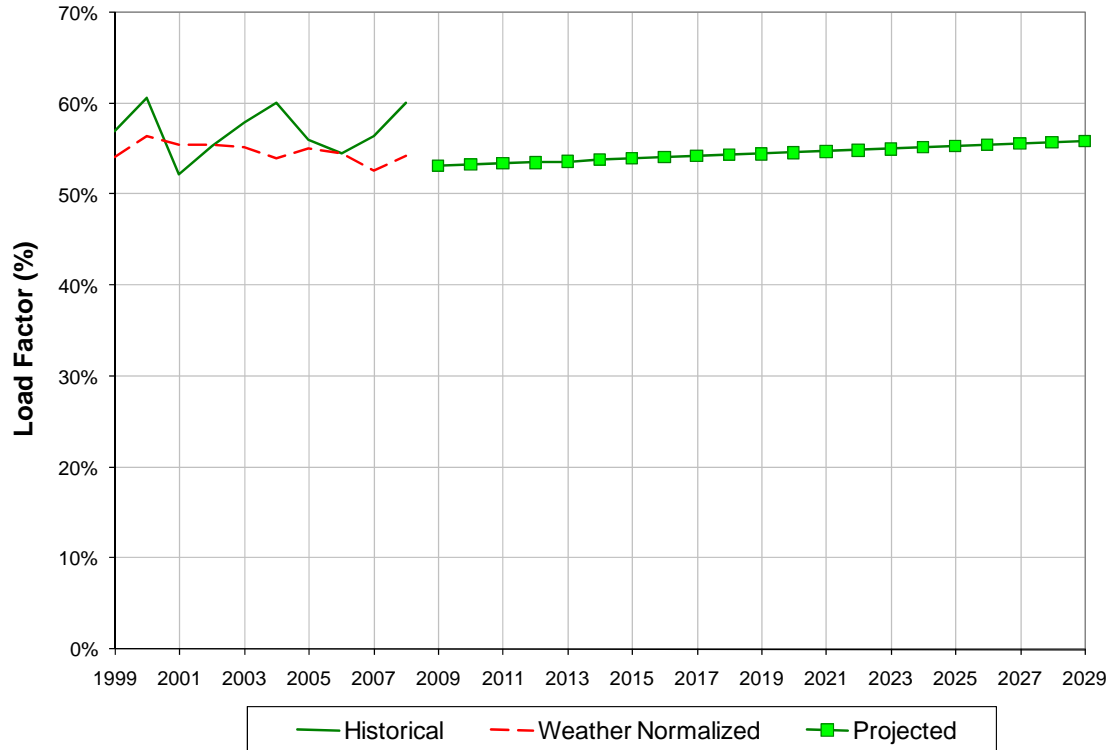


Figure 4-9: Historical and Projected Annual Load Factor

4.8 Peak Demand

Annual peak demand is derived from Net Energy for Load based on estimated load factors determined as discussed above. As a result of the expected trend in the customer mix toward industrial load over time and the resulting projected increasing trend in load factor, growth rates in peak demand are somewhat less than the growth rates in NEL. Annual peak demand is projected to grow at annual average rates of 1.5% over 2009-2018 and 1.5% over 2019-2028. This compares to an historical growth rate over 1999-2008 of 1.5% per year. Peak demand is projected to be 74.8 MW, on a weather-normalized basis and is projected to grow to 85.4 MW by 2018 and 99.3 MW by 2028.

Historical, weather-normalized, and projected annual peak demand are depicted below in Figure 4-10 below. Note that a large part of the recent drop in peak demand is estimated to be the impact of considerably cooler weather during the peak period, as well as the economic downturn.

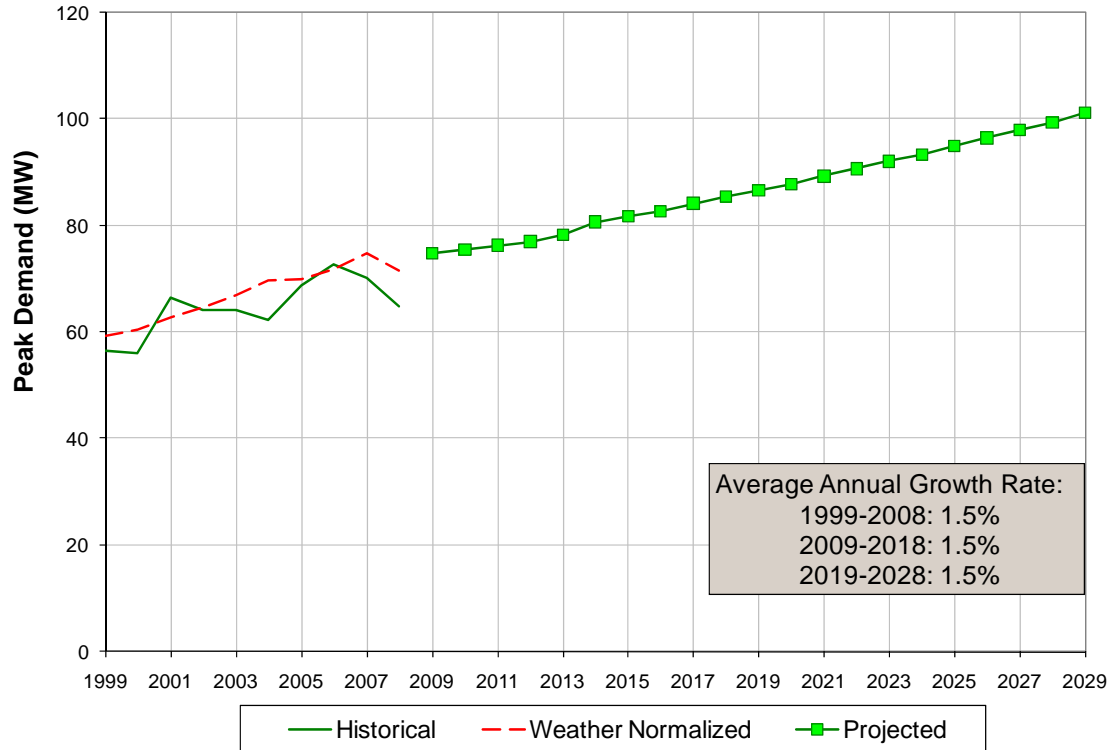


Figure 4-10: Historical and Projected Annual Peak Demand

Table 4-1 below shows historical and projected fiscal year net energy for load and calendar year peak demand, as well as associated growth rates and load factor, for selected years.

Table 4-1
Historical and Projected Net Energy for Load and Peak Demand (Unadjusted for EOP)

Year	Fiscal Year		Calendar Year		Load Factor (%)
	Net Energy for Load (MWh)	Percent Change (%)	Peak Demand (MW)	Percent Change (%)	
1997	245,890	--	50.7	--	55.4%
2000	298,711	6.7%	56.1	3.4%	60.7%
2005	337,159	2.5%	68.7	4.2%	56.0%
2007	345,680	1.5%	70.3	1.1%	56.4%
2008	341,152	-1.3%	64.9	-7.6%	60.1%
2009	348,829	1.7%	74.8	15.2%	53.2%
2010	352,668	1.1%	75.5	0.9%	53.3%
2011	357,218	1.3%	76.3	1.1%	53.5%
2012	362,307	1.4%	77.0	0.9%	53.6%
2013	367,871	1.5%	78.2	1.6%	53.7%

Year	Fiscal Year		Calendar Year		Load Factor (%)
	Net Energy for Load (MWh)	Percent Change (%)	Peak Demand (MW)	Percent Change (%)	
2018	406,849	2.0%	85.4	1.8%	54.4%
2028	486,708	1.8%	99.3	1.5%	55.8%

4.9 Energy Optimization Plan

In October 2008, the State of Michigan enacted Public Act No. 295 (PA 295), which requires electric service providers to establish renewable energy and energy efficiency programs that meet specific goals. PA 295 and a related Temporary Order by the Michigan Public Service Commission requires the filing of an Energy Optimization Plan (EOP) describing how each utility intends to achieve the energy efficiency goals, the costs of doing so, and how the utility intends to recover those costs. Municipal utilities, including TCLP, were to have filed by April 3, 2009.

The Load Forecast accounts for the impact of the implementation of the EOP in the form of post-analysis adjustments across the customer classes. Table 4-2 below shows the annual incremental reductions in energy sales that are required under the legislation, in terms of the percentage of actual sales averaged over the preceding three years⁴ that are to be reduced through each utility's programs.

Table 4-2
Energy Optimization Plan Standard

Year	Incremental Reduction
2009	0.30%
2010	0.50%
2011	0.75%
2012 and beyond	1.00%

Although the requirements pertain to energy only, and many of the programs implemented by TCLP may be aimed at off-peak load more so than on-peak load, it is assumed that peak demand is affected proportionally to energy sales. It is also assumed that TCLP meets the energy reduction standard outlined in the legislation proportionally across the customer classes. The forecast results discussed to this point have not accounted for the impact of the EOP standards.

Figures 4-11 and 4-12 show the impact of the EOP on fiscal year system NEL and calendar year peak demand, respectively.

⁴ The legislation allows each utility to decide whether the basis of the reductions is to be the preceding year's weather-normalized sales or the average of the preceding three years. TCLP decided in its EOP filing to rely on the latter.

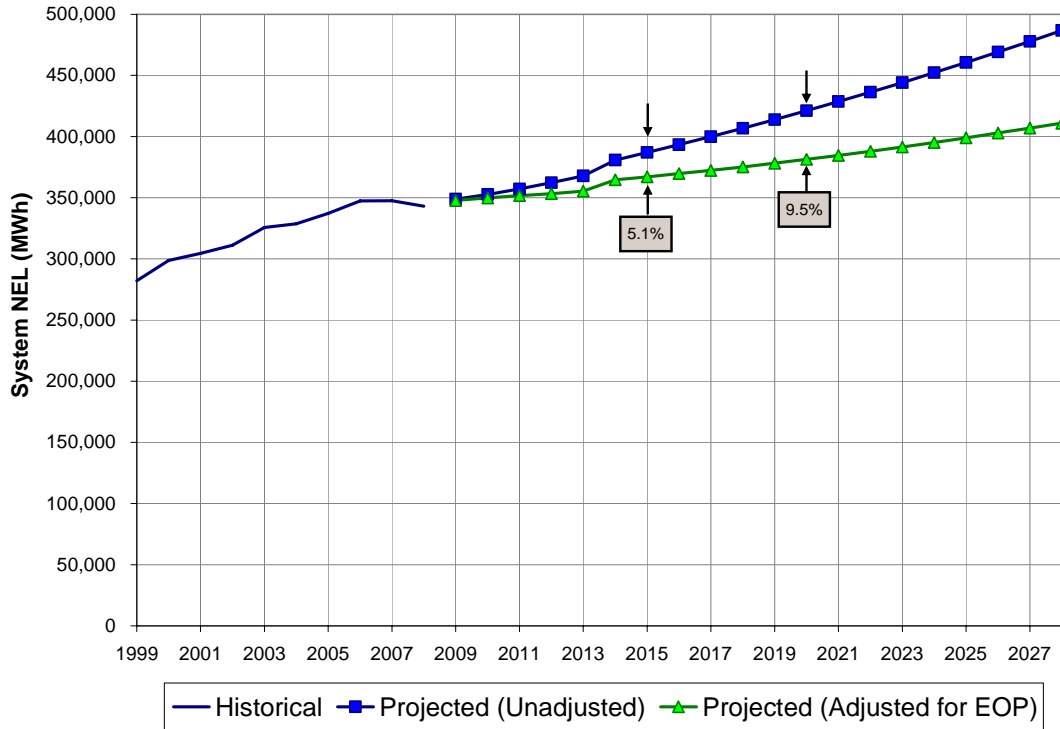


Figure 4-11: Net Energy for Load Forecast – Unadjusted v. Adjusted for EOP

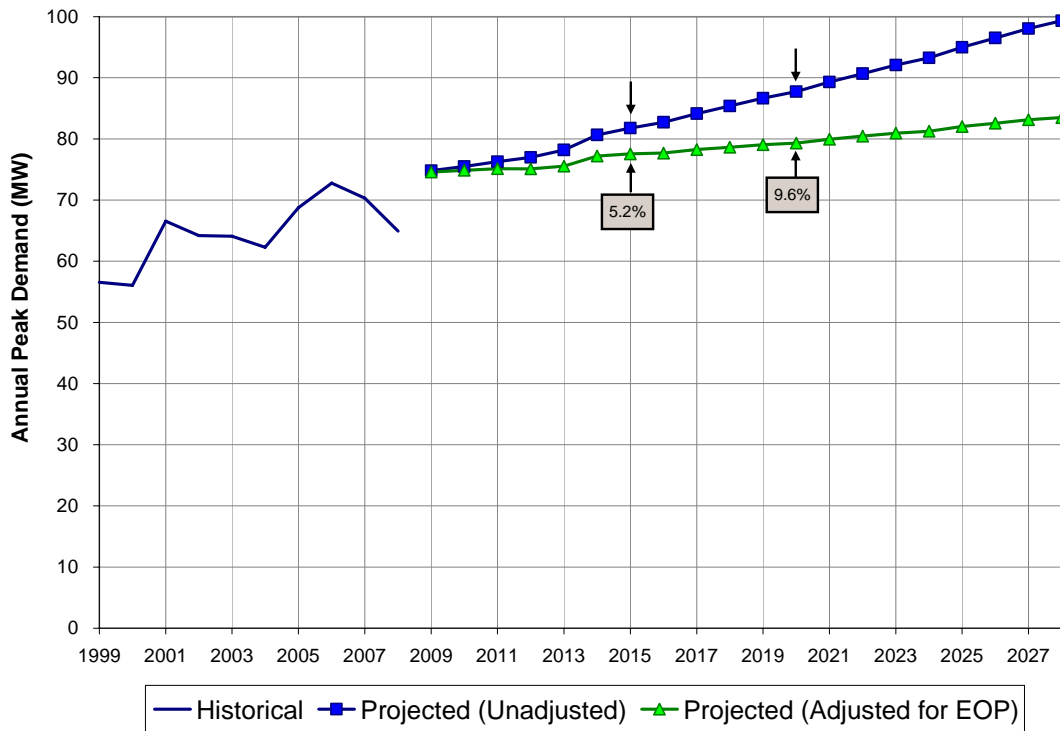


Figure 4-12: Peak Demand Forecast – Unadjusted v. Adjusted for EOP

Section 4

Table 4-3 shows the impact of the EOP standards on fiscal year system NEL and calendar year peak demand. Results are shown in the appendix tables across each of the customer classes, but it should be recognized that there may ultimately be some variation across the classes as to the proportion of total system energy savings that are achieved.

**Table 4-3
Impact of EOP on System Forecast**

Year	Unadjusted Results				Adjusted for Energy Optimization Plan			
	Net Energy for Load (MWh)	Percent Change (%)	Peak Demand (MW)	Percent Change (%)	Net Energy for Load (MWh)	Percent Change (%)	Peak Demand (MW)	Percent Change (%)
1997	245,890	--	50.7	--				
2000	298,711	6.7%	56.1	3.4%				
2005	337,159	2.5%	68.7	4.2%				
2007	345,680	1.5%	70.3	1.1%				
2008	341,152	-1.3%	64.9	-7.6%				
2009	348,829	1.7%	74.8	15.2%	347,786	1.4%	74.6	14.9%
2010	352,668	1.1%	75.5	0.9%	349,887	0.6%	74.9	0.4%
2011	357,218	1.3%	76.3	1.1%	351,813	0.6%	75.1	0.3%
2012	362,307	1.4%	77.0	0.9%	353,373	0.4%	75.1	-0.1%
2013	367,871	1.5%	78.2	1.6%	355,363	0.6%	75.5	0.6%
2018	406,849	2.0%	85.4	1.8%	375,211	1.1%	78.7	0.8%
2028	486,708	1.8%	99.3	1.5%	411,023	0.9%	83.5	0.6%

Section 5

FORECAST UNCERTAINTY

Forecasting the direction of the nation's economy is no easy task. Population growth is fairly predictable, but migration rates are highly uncertain and subject to volatile regional pressures. The pace of economic activity is also highly uncertain. At a regional level, the uncertainty of future population and economic growth increases dramatically, both due to increased migration volatility and the focus on a smaller number of economic agents (residents, businesses, industries, etc). It is in this environment that forecasts of the power requirements of a small region must be developed.

It is important to recognize that no point estimate forecast will prove to be perfectly accurate once projected periods become history. This Load Forecast is no exception. It can only be as accurate as the numerous assumptions and data sources it relies on are or later prove to be. The econometric equations that the forecast is based on demonstrate that energy consumption is driven by population, economic forces, and weather in fairly predictable ways. However these drivers are anything but predictable. Many of these will deviate from the projections shown herein only briefly or in volatile ways but will maintain the trend over the long term; certain others may deviate in a way that suggests a somewhat different trend altogether. Importantly, as discussed in Section 3, a significant portion of the historical period upon which the forecast is based is not known with certainty but is in fact only estimated.

Accordingly, a forecast must be viewed as a guide only, and plans for large capital expenditures, which are based on such forecasts, made with care and with an allowance for flexibility.

This forecast should be updated periodically, particularly when events occur that are expected to impact growth or when projections of driving variables change significantly. In addition, it may become useful to create projections that directly estimate the range of uncertainty that can be expected in future electric demand on the TCLP system. Several techniques are available to address the sources of potential error in the forecast. The appropriate technique depends on the several issues, including the tractability of the downstream planning analyses that rely on the forecast (e.g., budgets, power supply simulations, rate studies, etc) to risk analysis. However, the forecasting equations and the infrastructure developed for this forecast are capable of addressing a range of potential risk analysis methods.

Appendix A
FORECAST RESULTS

Table A-1

Historical and Projected Electricity Sales by Customer Class and Net Energy for Load
(Not Adjusted for Energy Optimization Plan)

	Fiscal Year	Residential						Commercial						Industrial						Public Use		Lights		Total Sales		Distr. Losses	Net Energy for Load	
		Sales (MWh)	% Chg	Y/E Cust. (#)	% Chg	Sales/ Cust. (kWh)	% Chg	Sales (MWh)	% Chg	Y/E Cust. (#)	% Chg	Sales/ Cust. (MWh)	% Chg	Sales (MWh)	% Chg	Y/E Cust. (#)	% Chg	Sales/ Cust. (MWh)	% Chg	Sales (MWh)	% Chg	Sales (MWh)	% Chg	(MWh)	% Chg	(MW)	(MWh)	% Chg
Historical	1999	42,510		7,130		5,962		117,891		2,288		51.5		99,301		30		3,310		6,072		1,427		267,201		14,954	282,155	
	2000	42,344	-0.4%	7,123	-0.1%	5,945	-0.3%	123,552	4.8%	2,537	10.9%	48.7	-5.5%	109,496	10.3%	31	3.3%	3,532	6.7%	6,368	4.9%	1,457	2.1%	283,217	6.0%	15,494	298,711	5.9%
	2001	43,600	3.0%	7,225	1.4%	6,035	1.5%	124,999	1.2%	2,671	5.3%	46.8	-3.9%	112,565	2.8%	33	6.5%	3,411	-3.4%	6,431	1.0%	1,482	1.7%	289,078	2.1%	15,474	304,552	2.0%
	2002	45,024	3.3%	7,325	1.4%	6,147	1.9%	124,996	0.0%	2,735	2.4%	45.7	-2.3%	115,072	2.2%	33	0.0%	3,487	2.2%	6,253	-2.8%	1,655	11.7%	293,001	1.4%	18,165	311,166	2.2%
	2003	48,004	6.6%	7,382	0.8%	6,503	5.8%	134,760	7.8%	2,774	1.4%	48.6	6.3%	118,827	3.3%	33	0.0%	3,601	3.3%	6,953	11.2%	1,533	-7.4%	310,078	5.8%	15,570	325,648	4.7%
	2004	47,468	-1.1%	7,448	0.9%	6,373	-2.0%	137,668	2.2%	2,825	1.8%	48.7	0.3%	120,587	1.5%	35	6.1%	3,445	-4.3%	5,632	-19.0%	1,536	0.2%	312,891	0.9%	15,901	328,792	1.0%
	2005	48,343	1.8%	7,871	5.7%	6,142	-3.6%	138,898	0.9%	2,788	-1.3%	49.8	2.2%	128,641	6.7%	37	5.7%	3,477	0.9%	3,087	-45.2%	1,526	-0.7%	320,494	2.4%	16,665	337,159	2.5%
	2006	50,636	4.7%	8,088	2.8%	6,261	1.9%	144,026	3.7%	3,057	9.6%	47.1	-5.4%	131,193	2.0%	39	5.4%	3,364	-3.2%	3,226	4.5%	1,533	0.5%	330,613	3.2%	16,767	347,380	3.0%
	2007	51,457	1.6%	8,317	2.8%	6,187	-1.2%	143,344	-0.5%	2,962	-3.1%	48.4	2.7%	129,268	-1.5%	40	2.6%	3,232	-3.9%	3,149	-2.4%	1,768	15.3%	328,985	-0.5%	18,654	347,639	0.1%
2008	52,855	2.7%	8,404	1.0%	6,289	1.7%	145,284	1.4%	2,951	-0.4%	49.2	1.7%	127,778	-1.2%	38	-5.0%	3,363	4.0%	3,225	2.4%	1,435	-18.8%	330,576	0.5%	12,497	343,073	-1.3%	
Projected	2009	52,552	-0.6%	8,403	0.0%	6,254	-0.6%	145,652	0.3%	2,958	0.2%	49.2	0.0%	128,352	0.4%	39	3.4%	3,266	-2.9%	3,252	0.9%	1,579	10.0%	331,387	0.2%	17,441	348,829	1.7%
	2010	52,935	0.7%	8,458	0.7%	6,258	0.1%	146,495	0.6%	2,977	0.6%	49.2	-0.1%	130,724	1.8%	40	2.4%	3,247	-0.6%	3,292	1.2%	1,589	0.7%	335,035	1.1%	17,633	352,668	1.1%
	2011	53,339	0.8%	8,513	0.6%	6,266	0.1%	147,656	0.8%	3,005	0.9%	49.1	-0.1%	133,427	2.1%	41	2.6%	3,229	-0.6%	3,335	1.3%	1,599	0.6%	339,357	1.3%	17,861	357,218	1.3%
	2012	53,761	0.8%	8,567	0.6%	6,276	0.2%	149,040	0.9%	3,039	1.1%	49.0	-0.2%	136,400	2.2%	42	2.8%	3,211	-0.5%	3,381	1.4%	1,610	0.6%	344,192	1.4%	18,115	362,307	1.4%
	2013	54,189	0.8%	8,619	0.6%	6,287	0.2%	150,604	1.0%	3,078	1.3%	48.9	-0.2%	139,634	2.4%	44	2.9%	3,195	-0.5%	3,430	1.4%	1,620	0.6%	349,477	1.5%	18,394	367,871	1.5%
	2014	55,343	2.1%	8,771	1.8%	6,310	0.4%	154,913	2.9%	3,209	4.3%	48.3	-1.4%	146,376	4.8%	49	12.1%	2,988	-6.5%	3,481	1.5%	1,630	0.6%	361,742	3.5%	19,039	380,781	3.5%
	2015	55,790	0.8%	8,823	0.6%	6,323	0.2%	156,673	1.1%	3,255	1.4%	48.1	-0.3%	149,958	2.4%	50	2.8%	2,979	-0.3%	3,533	1.5%	1,641	0.6%	367,594	1.6%	19,347	386,941	1.6%
	2016	56,238	0.8%	8,873	0.6%	6,338	0.2%	158,521	1.2%	3,304	1.5%	48.0	-0.3%	153,735	2.5%	52	2.8%	2,970	-0.3%	3,587	1.5%	1,651	0.6%	373,732	1.7%	19,670	393,402	1.7%
	2017	56,693	0.8%	8,923	0.6%	6,353	0.2%	160,393	1.2%	3,354	1.5%	47.8	-0.3%	157,598	2.5%	53	2.8%	2,962	-0.3%	3,641	1.5%	1,662	0.6%	379,987	1.7%	19,999	399,986	1.7%
	2018	57,148	0.8%	8,972	0.5%	6,370	0.3%	162,337	1.2%	3,406	1.6%	47.7	-0.3%	161,652	2.6%	55	2.9%	2,953	-0.3%	3,697	1.5%	1,672	0.6%	386,507	1.7%	20,342	406,849	1.7%
	2019	57,604	0.8%	9,019	0.5%	6,387	0.3%	164,320	1.2%	3,460	1.6%	47.5	-0.4%	165,842	2.6%	56	2.9%	2,945	-0.3%	3,754	1.5%	1,683	0.6%	393,203	1.7%	20,695	413,898	1.7%
	2020	58,066	0.8%	9,066	0.5%	6,405	0.3%	166,364	1.2%	3,516	1.6%	47.3	-0.4%	170,222	2.6%	58	2.9%	2,937	-0.3%	3,813	1.6%	1,694	0.6%	400,159	1.8%	21,061	421,220	1.8%
	2021	58,538	0.8%	9,114	0.5%	6,423	0.3%	168,416	1.2%	3,573	1.6%	47.1	-0.4%	174,681	2.6%	60	2.9%	2,929	-0.3%	3,872	1.6%	1,704	0.6%	407,213	1.8%	21,432	428,645	1.8%
	2022	59,016	0.8%	9,161	0.5%	6,442	0.3%	170,525	1.3%	3,632	1.6%	47.0	-0.4%	179,330	2.7%	61	3.0%	2,920	-0.3%	3,933	1.6%	1,715	0.6%	414,519	1.8%	21,817	436,336	1.8%
	2023	59,494	0.8%	9,207	0.5%	6,462	0.3%	172,663	1.3%	3,692	1.6%	46.8	-0.4%	184,113	2.7%	63	3.0%	2,912	-0.3%	3,995	1.6%	1,726	0.6%	421,991	1.8%	22,210	444,201	1.8%
	2024	59,971	0.8%	9,252	0.5%	6,482	0.3%	174,853	1.3%	3,753	1.7%	46.6	-0.4%	189,085	2.7%	65	3.0%	2,904	-0.3%	4,059	1.6%	1,737	0.6%	429,706	1.8%	22,616	452,322	1.8%
	2025	60,455	0.8%	9,297	0.5%	6,503	0.3%	177,070	1.3%	3,816	1.7%	46.4	-0.4%	194,193	2.7%	67	3.0%	2,895	-0.3%	4,124	1.6%	1,748	0.6%	437,590	1.8%	23,031	460,621	1.8%
	2026	60,938	0.8%	9,340	0.5%	6,524	0.3%	179,336	1.3%	3,880	1.7%	46.2	-0.4%	199,492	2.7%	69	3.0%	2,887	-0.3%	4,190	1.6%	1,759	0.6%	445,715	1.9%	23,459	469,174	1.9%
2027	61,420	0.8%	9,382	0.5%	6,546	0.3%	181,603	1.3%	3,945	1.7%	46.0	-0.4%	204,872	2.7%	71	3.0%	2,878	-0.3%	4,256	1.6%	1,770	0.6%	453,920	1.8%	23,891	477,811	1.8%	
2028	61,907	0.8%	9,424	0.4%	6,569	0.3%	183,916	1.3%	4,011	1.7%	45.8	-0.4%	210,444	2.7%	73	3.0%	2,870	-0.3%	4,324	1.6%	1,781	0.6%	462,372	1.9%	24,335	486,708	1.9%	
AAGR	1999-2008		2.4%		1.8%		0.6%		2.3%		2.9%		-0.5%		2.8%		2.7%		0.2%		-6.8%		0.1%		2.4%			2.2%
	2009-2018		0.9%		0.7%		0.2%		1.2%		1.6%		-0.4%		2.6%		3.7%		-1.1%		1.4%		0.6%		1.7%			1.7%
	2019-2028		0.8%		0.5%		0.3%		1.3%		1.7%		-0.4%		2.7%		3.0%		-0.3%		1.6%		0.6%		1.8%			1.8%

Table A-2

Historical and Projected Net Energy for Load and Non-Coincident Peak Demand
(Not Adjusted for Energy Optimization Plan)

	Fiscal Year	Net Energy for Load					Calendar Year Peak Demand						
		Actual (MWh)	Percent Change	Normalized (MWh)	Percent Change	Percent Diff	Actual (MW)	Percent Change	Load Factor	Normalized (MW)	Percent Change	Percent Diff	Load Factor
Historical	1999	282,155	7.8%	281,366	7.3%	-0.3%	56.6	1.1%	56.9%	59.3	4.2%	4.9%	54.1%
	2000	298,711	5.9%	300,292	6.7%	0.5%	56.1	-0.9%	60.8%	60.6	2.1%	8.1%	56.6%
	2001	304,552	2.0%	305,920	1.9%	0.4%	66.5	18.7%	52.2%	62.9	3.8%	-5.5%	55.5%
	2002	311,166	2.2%	313,738	2.6%	0.8%	64.2	-3.5%	55.3%	64.6	2.8%	0.7%	55.4%
	2003	325,648	4.7%	323,941	3.3%	-0.5%	64.1	-0.2%	58.0%	66.9	3.5%	4.4%	55.3%
	2004	328,792	1.0%	330,942	2.2%	0.7%	62.3	-2.9%	60.3%	69.7	4.2%	12.0%	54.2%
	2005	337,159	2.5%	337,855	2.1%	0.2%	68.7	10.4%	56.0%	70.1	0.5%	1.9%	55.0%
	2006	347,380	3.0%	344,156	1.9%	-0.9%	72.8	5.8%	54.5%	72.0	2.8%	-1.0%	54.6%
	2007	347,639	0.1%	345,680	0.4%	-0.6%	70.3	-3.4%	56.4%	74.9	4.0%	6.6%	52.7%
	2008	343,073	-1.3%	341,152	-1.3%	-0.6%	64.9	-7.6%	60.3%	71.6	-4.4%	10.3%	54.4%
Projected	2009	348,829	1.7%	348,829	2.3%		74.8	15.2%	53.2%	74.8	4.5%		53.2%
	2010	352,668	1.1%	352,668	1.1%		75.5	0.9%	53.3%	75.5	0.9%		53.3%
	2011	357,218	1.3%	357,218	1.3%		76.3	1.1%	53.5%	76.3	1.1%		53.5%
	2012	362,307	1.4%	362,307	1.4%		77.0	0.9%	53.7%	77.0	0.9%		53.7%
	2013	367,871	1.5%	367,871	1.5%		78.2	1.6%	53.7%	78.2	1.6%		53.7%
	2014	380,781	3.5%	380,781	3.5%		80.7	3.1%	53.9%	80.7	3.1%		53.9%
	2015	386,941	1.6%	386,941	1.6%		81.8	1.4%	54.0%	81.8	1.4%		54.0%
	2016	393,402	1.7%	393,402	1.7%		82.7	1.2%	54.3%	82.7	1.2%		54.3%
	2017	399,986	1.7%	399,986	1.7%		84.1	1.7%	54.3%	84.1	1.7%		54.3%
	2018	406,849	1.7%	406,849	1.7%		85.4	1.5%	54.4%	85.4	1.5%		54.4%
	2019	413,898	1.7%	413,898	1.7%		86.7	1.5%	54.5%	86.7	1.5%		54.5%
	2020	421,220	1.8%	421,220	1.8%		87.7	1.2%	54.8%	87.7	1.2%		54.8%
	2021	428,645	1.8%	428,645	1.8%		89.3	1.8%	54.8%	89.3	1.8%		54.8%
	2022	436,336	1.8%	436,336	1.8%		90.7	1.5%	54.9%	90.7	1.5%		54.9%
	2023	444,201	1.8%	444,201	1.8%		92.1	1.5%	55.1%	92.1	1.5%		55.1%
	2024	452,322	1.8%	452,322	1.8%		93.3	1.3%	55.4%	93.3	1.3%		55.4%
	2025	460,621	1.8%	460,621	1.8%		95.0	1.9%	55.4%	95.0	1.9%		55.4%
2026	469,174	1.9%	469,174	1.9%		96.5	1.6%	55.5%	96.5	1.6%		55.5%	
2027	477,811	1.8%	477,811	1.8%		98.0	1.6%	55.6%	98.0	1.6%		55.6%	
2028	486,708	1.9%	486,708	1.9%		99.3	1.3%	55.9%	99.3	1.3%		55.9%	
AAGR	1999-2008		2.2%		2.2%			1.5%	57.1%		2.1%		54.8%
	2009-2018		1.7%		1.7%			1.5%	53.8%		1.5%		53.8%
	2019-2028		1.8%		1.8%			1.5%	55.2%		1.5%		55.2%

Table A-3

Historical and Projected Electricity Sales by Customer Class and Net Energy for Load
(Adjusted for Energy Optimization Plan)

	Fiscal Year	Residential						Commercial						Industrial						Public Use		Lights		Total Sales		Distr. Losses	Net Energy for Load					
		Sales (MWh)	% Chg	Y/E Cust. (#)	% Chg	Sales/Cust. (kWh)	% Chg	Sales (MWh)	% Chg	Y/E Cust. (#)	% Chg	Sales/Cust. (MWh)	% Chg	Sales (MWh)	% Chg	Y/E Cust. (#)	% Chg	Sales/Cust. (MWh)	% Chg	Sales (MWh)	% Chg	Sales (MWh)	% Chg	Sales (MWh)	% Chg	(MWh)	% Chg	(MW)	(MWh)	% Chg		
Historical	1999	42,510		7,130		5,962		117,891		2,288		51.5		99,301		30		3,310		6,072		1,427		267,201		14,954		282,155				
	2000	42,344	-0.4%	7,123	-0.1%	5,945	-0.3%	123,552	4.8%	2,537	10.9%	48.7	-5.5%	109,496	10.3%	31	3.3%	3,532	6.7%	6,368	4.9%	1,457	2.1%	283,217	6.0%	15,494		298,711	5.9%			
	2001	43,600	3.0%	7,225	1.4%	6,035	1.5%	124,999	1.2%	2,671	5.3%	46.8	-3.9%	112,565	2.8%	33	6.5%	3,411	-3.4%	6,431	1.0%	1,482	1.7%	289,078	2.1%	15,474		304,552	2.0%			
	2002	45,024	3.3%	7,325	1.4%	6,147	1.9%	124,996	0.0%	2,735	2.4%	45.7	-2.3%	115,072	2.2%	33	0.0%	3,487	2.2%	6,253	-2.8%	1,655	11.7%	293,001	1.4%	18,165		311,166	2.2%			
	2003	48,004	6.6%	7,382	0.8%	6,503	5.8%	134,760	7.8%	2,774	1.4%	48.6	6.3%	118,827	3.3%	33	0.0%	3,601	3.3%	6,953	11.2%	1,533	-7.4%	310,078	5.8%	15,570		325,648	4.7%			
	2004	47,468	-1.1%	7,448	0.9%	6,373	-2.0%	137,668	2.2%	2,825	1.8%	48.7	0.3%	120,587	1.5%	35	6.1%	3,445	-4.3%	5,632	-19.0%	1,536	0.2%	312,891	0.9%	15,901		328,792	1.0%			
	2005	48,343	1.8%	7,871	5.7%	6,142	-3.6%	138,898	0.9%	2,788	-1.3%	49.8	2.2%	128,641	6.7%	37	5.7%	3,477	0.9%	3,087	-45.2%	1,526	-0.7%	320,494	2.4%	16,665		337,159	2.5%			
	2006	50,636	4.7%	8,088	2.8%	6,261	1.9%	144,026	3.7%	3,057	9.6%	47.1	-5.4%	131,193	2.0%	39	5.4%	3,364	-3.2%	3,226	4.5%	1,533	0.5%	330,613	3.2%	16,767		347,380	3.0%			
	2007	51,457	1.6%	8,317	2.8%	6,187	-1.2%	143,324	-0.5%	2,962	-3.1%	48.4	2.7%	129,268	-1.5%	40	2.6%	3,232	-3.9%	3,149	-2.4%	1,768	15.3%	328,985	-0.5%	18,654		347,639	0.1%			
2008	52,855	2.7%	8,404	1.0%	6,289	1.7%	145,284	1.4%	2,951	-0.4%	49.2	1.7%	127,778	-1.2%	38	-5.0%	3,363	4.0%	3,225	2.4%	1,435	-18.8%	330,576	0.5%	12,497		343,073	-1.3%				
Projected	2009	52,397	-0.9%	8,403	0.0%	6,235	-0.9%	145,220	0.0%	2,958	0.2%	49.1	-0.3%	127,964	0.1%	39	3.4%	3,256	-3.2%	3,243	0.6%	1,574	9.7%	330,397	-0.1%	17,389		347,786	1.4%			
	2010	52,518	0.2%	8,458	0.7%	6,209	-0.4%	145,339	0.1%	2,977	0.6%	48.8	-0.6%	129,693	1.4%	40	2.4%	3,221	-1.1%	3,266	0.7%	1,576	0.1%	332,393	0.6%	17,494		349,887	0.6%			
	2011	52,527	0.0%	8,513	0.6%	6,171	-0.6%	145,406	0.0%	3,005	0.9%	48.4	-0.9%	131,430	1.3%	41	2.6%	3,180	-1.3%	3,285	0.6%	1,575	-0.1%	334,223	0.6%	17,591		351,813	0.6%			
	2012	52,419	-0.2%	8,567	0.6%	6,119	-0.8%	145,324	-0.1%	3,039	1.1%	47.8	-1.2%	133,094	1.3%	42	2.8%	3,134	-1.5%	3,298	0.4%	1,569	-0.4%	335,705	0.4%	17,669		353,373	0.4%			
	2013	52,314	-0.2%	8,619	0.6%	6,070	-0.8%	145,411	0.1%	3,078	1.3%	47.2	-1.2%	134,993	1.4%	44	2.9%	3,089	-1.4%	3,314	0.5%	1,564	-0.4%	337,595	0.6%	17,768		355,363	0.6%			
	2014	52,930	1.2%	8,771	1.8%	6,035	-0.6%	148,228	1.9%	3,209	4.3%	46.2	-2.2%	140,370	4.0%	49	12.1%	2,865	-7.2%	3,330	0.5%	1,558	-0.4%	346,417	2.6%	18,232		364,649	2.6%			
	2015	52,830	-0.2%	8,823	0.6%	5,988	-0.8%	148,465	0.2%	3,255	1.4%	45.6	-1.2%	142,532	1.5%	50	2.8%	2,831	-1.2%	3,348	0.5%	1,552	-0.4%	348,728	0.7%	18,354		367,082	0.7%			
	2016	52,723	-0.2%	8,873	0.6%	5,942	-0.8%	148,754	0.2%	3,304	1.5%	45.0	-1.3%	144,834	1.6%	52	2.8%	2,798	-1.2%	3,367	0.6%	1,547	-0.4%	351,225	0.7%	18,486		369,711	0.7%			
	2017	52,613	-0.2%	8,923	0.6%	5,896	-0.8%	149,033	0.2%	3,354	1.5%	44.4	-1.3%	147,163	1.6%	53	2.8%	2,766	-1.2%	3,386	0.6%	1,541	-0.4%	353,736	0.7%	18,618		372,354	0.7%			
	2018	52,499	-0.2%	8,972	0.5%	5,851	-0.8%	149,365	0.2%	3,406	1.6%	43.8	-1.3%	149,646	1.7%	55	2.9%	2,734	-1.1%	3,406	0.6%	1,535	-0.4%	356,451	0.8%	18,761		375,211	0.8%			
	2019	52,380	-0.2%	9,019	0.5%	5,808	-0.7%	149,717	0.2%	3,460	1.6%	43.3	-1.3%	152,226	1.7%	56	2.9%	2,703	-1.1%	3,427	0.6%	1,529	-0.4%	359,279	0.8%	18,909		378,189	0.8%			
	2020	52,264	-0.2%	9,066	0.5%	5,765	-0.7%	150,111	0.3%	3,516	1.6%	42.7	-1.3%	154,955	1.8%	58	2.9%	2,673	-1.1%	3,449	0.6%	1,523	-0.4%	362,302	0.8%	19,069		381,371	0.8%			
	2021	52,152	-0.2%	9,114	0.5%	5,722	-0.7%	150,494	0.3%	3,573	1.6%	42.1	-1.3%	157,722	1.8%	60	2.9%	2,644	-1.1%	3,471	0.6%	1,517	-0.4%	365,356	0.8%	19,229		384,585	0.8%			
	2022	52,042	-0.2%	9,161	0.5%	5,681	-0.7%	150,912	0.3%	3,632	1.6%	41.6	-1.3%	160,634	1.8%	61	3.0%	2,616	-1.1%	3,494	0.7%	1,511	-0.4%	368,593	0.9%	19,400		387,993	0.9%			
	2023	51,927	-0.2%	9,207	0.5%	5,640	-0.7%	151,340	0.3%	3,692	1.6%	41.0	-1.3%	163,636	1.9%	63	3.0%	2,588	-1.1%	3,517	0.7%	1,504	-0.4%	371,924	0.9%	19,575		391,499	0.9%			
	2024	51,808	-0.2%	9,252	0.5%	5,600	-0.7%	151,798	0.3%	3,753	1.7%	40.4	-1.3%	166,781	1.9%	65	3.0%	2,561	-1.0%	3,541	0.7%	1,498	-0.4%	375,426	0.9%	19,759		395,186	0.9%			
	2025	51,689	-0.2%	9,297	0.5%	5,560	-0.7%	152,261	0.3%	3,816	1.7%	39.9	-1.3%	170,014	1.9%	67	3.0%	2,535	-1.0%	3,566	0.7%	1,492	-0.4%	379,022	1.0%	19,949		398,971	1.0%			
	2026	51,565	-0.2%	9,340	0.5%	5,521	-0.7%	152,752	0.3%	3,880	1.7%	39.4	-1.3%	173,388	2.0%	69	3.0%	2,509	-1.0%	3,592	0.7%	1,485	-0.4%	382,783	1.0%	20,146		402,929	1.0%			
	2027	51,436	-0.3%	9,382	0.5%	5,482	-0.7%	153,222	0.3%	3,945	1.7%	38.8	-1.3%	176,792	2.0%	71	3.0%	2,484	-1.0%	3,617	0.7%	1,479	-0.4%	386,544	1.0%	20,344		406,889	1.0%			
2028	51,306	-0.3%	9,424	0.4%	5,444	-0.7%	153,715	0.3%	4,011	1.7%	38.3	-1.3%	180,335	2.0%	73	3.0%	2,459	-1.0%	3,643	0.7%	1,472	-0.4%	390,472	1.0%	20,551		411,023	1.0%				
AAGR	1999-2008		2.4%		1.8%		0.6%		2.3%		2.9%		-0.5%		2.8%		2.7%		0.2%		-6.8%		0.1%		2.4%					2.2%		
	2009-2018		0.0%		0.7%		-0.7%		0.3%		1.6%		-1.2%		1.8%		3.7%		-1.9%		0.5%		-0.3%		0.8%					0.8%		
	2019-2028		-0.2%		0.5%		-0.7%		0.3%		1.7%		-1.3%		1.9%		3.0%		-1.0%		0.7%		-0.4%		0.9%					0.9%		

Table A-4

Historical and Projected Net Energy for Load and Non-Coincident Peak Demand
(Adjusted for Energy Optimization Plan)

Fiscal Year		Net Energy for Load					Calendar Year Peak Demand						
		Actual (MWh)	Percent Change	Normalized (MWh)	Percent Change	Percent Diff	Actual (MW)	Percent Change	Load Factor	Normalized (MW)	Percent Change	Percent Diff	Load Factor
Historical	1999	282,155	7.8%	281,366	7.3%	-0.3%	56.6	1.1%	56.9%	59.3	4.2%	4.9%	54.1%
	2000	298,711	5.9%	300,292	6.7%	0.5%	56.1	-0.9%	60.8%	60.6	2.1%	8.1%	56.6%
	2001	304,552	2.0%	305,920	1.9%	0.4%	66.5	18.7%	52.2%	62.9	3.8%	-5.5%	55.5%
	2002	311,166	2.2%	313,738	2.6%	0.8%	64.2	-3.5%	55.3%	64.6	2.8%	0.7%	55.4%
	2003	325,648	4.7%	323,941	3.3%	-0.5%	64.1	-0.2%	58.0%	66.9	3.5%	4.4%	55.3%
	2004	328,792	1.0%	330,942	2.2%	0.7%	62.3	-2.9%	60.3%	69.7	4.2%	12.0%	54.2%
	2005	337,159	2.5%	337,855	2.1%	0.2%	68.7	10.4%	56.0%	70.1	0.5%	1.9%	55.0%
	2006	347,380	3.0%	344,156	1.9%	-0.9%	72.8	5.8%	54.5%	72.0	2.8%	-1.0%	54.6%
	2007	347,639	0.1%	345,680	0.4%	-0.6%	70.3	-3.4%	56.4%	74.9	4.0%	6.6%	52.7%
	2008	343,073	-1.3%	341,152	-1.3%	-0.6%	64.9	-7.6%	60.3%	71.6	-4.4%	10.3%	54.4%
Projected	2009	347,786	1.4%	347,786	1.9%		74.6	14.9%	53.2%	74.6	4.1%		53.2%
	2010	349,887	0.6%	349,887	0.6%		74.9	0.4%	53.3%	74.9	0.4%		53.3%
	2011	351,813	0.6%	351,813	0.6%		75.1	0.3%	53.5%	75.1	0.3%		53.5%
	2012	353,373	0.4%	353,373	0.4%		75.1	-0.1%	53.7%	75.1	-0.1%		53.7%
	2013	355,363	0.6%	355,363	0.6%		75.5	0.6%	53.7%	75.5	0.6%		53.7%
	2014	364,649	2.6%	364,649	2.6%		77.2	2.2%	53.9%	77.2	2.2%		53.9%
	2015	367,082	0.7%	367,082	0.7%		77.6	0.4%	54.0%	77.6	0.4%		54.0%
	2016	369,711	0.7%	369,711	0.7%		77.7	0.2%	54.3%	77.7	0.2%		54.3%
	2017	372,354	0.7%	372,354	0.7%		78.3	0.7%	54.3%	78.3	0.7%		54.3%
	2018	375,211	0.8%	375,211	0.8%		78.7	0.5%	54.5%	78.7	0.5%		54.5%
	2019	378,189	0.8%	378,189	0.8%		79.1	0.5%	54.6%	79.1	0.5%		54.6%
	2020	381,371	0.8%	381,371	0.8%		79.3	0.3%	54.9%	79.3	0.3%		54.9%
	2021	384,585	0.8%	384,585	0.8%		80.0	0.8%	54.9%	80.0	0.8%		54.9%
	2022	387,993	0.9%	387,993	0.9%		80.5	0.6%	55.1%	80.5	0.6%		55.1%
	2023	391,499	0.9%	391,499	0.9%		81.0	0.6%	55.2%	81.0	0.6%		55.2%
	2024	395,186	0.9%	395,186	0.9%		81.3	0.4%	55.5%	81.3	0.4%		55.5%
	2025	398,971	1.0%	398,971	1.0%		82.0	0.9%	55.5%	82.0	0.9%		55.5%
	2026	402,929	1.0%	402,929	1.0%		82.6	0.7%	55.7%	82.6	0.7%		55.7%
2027	406,889	1.0%	406,889	1.0%		83.1	0.7%	55.9%	83.1	0.7%		55.9%	
2028	411,023	1.0%	411,023	1.0%		83.5	0.4%	56.2%	83.5	0.4%		56.2%	
AAGR	1999-2008		2.2%		2.2%			1.5%	57.1%		2.1%		54.8%
	2009-2018		0.8%		0.8%			0.6%	53.8%		0.6%		53.8%
	2019-2028		0.9%		0.9%			0.6%	55.3%		0.6%		55.3%

Appendix B

REGRESSION EQUATION OUTPUT

Figure B - 1
Forecast Equation Variable Index

VARIABLE NAME	DESCRIPTION
Economic Variables	
GRTRAV_HH	County Households
GRTRAV_PY	County Total Personal Income
GRTRAV_PYHH	County Mean Household Income
PR_TVC_RES	Real Average Residential Price of Electricity
PR_NG_RES	Real Average Residential Price of Natural Gas
PR_TVC_ALL	Real Average Price of Electricity
Weather Variables	
CDD55	Cooling Degree Days: Base=55 dF
HDD45	Heating Degree Days: Base=45 dF
CDD70	Cooling Degree Days: Base=70 dF
PKPRMAX	Weighted Average Peak Temperature (80% peak day, 20% prior day)
PEAKPREC	Peak Day Precipitation (inches)
Other Variables	
AR	Autoregressive Residual Term (of given lag)
C	Constant Term
LN	Natural Log
MA	Moving Average (of given period)
SAL_IND	Industrial Electricity Sales
SAL_TOT	Total Electricity Sales
T_RESCUST	Trend Term Capturing Residential Customer Growth

Figure B - 2
Forecast Equations - Residential Customers

Dependent Variable: LN(CUST_RES)				
Method: Least Squares				
Date: 02/27/09 Time: 16:31				
Sample (adjusted): 1986 2008				
Included observations: 23 after adjustments				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	7.343	0.153	47.90	0.000
LN(GRTRAV_HH)	0.432	0.049	8.84	0.000
BINARY: YEAR=1991	0.145	0.018	8.23	0.000
BINARY: YEAR>1991	0.064	0.014	4.56	0.000
T_RESCUST	0.058	0.009	6.43	0.000
R-squared	0.982	Mean dependent var	8.851	
Adjusted R-squared	0.978	S.D. dependent var	0.106	
S.E. of regression	0.016	Akaike info criterion	(5.27)	
Sum squared resid	0.004	Schwarz criterion	(5.02)	
LN likelihood	65.6	F-statistic	242.2	
Durbin-Watson stat	1.428	Prob(F-statistic)	0.000	

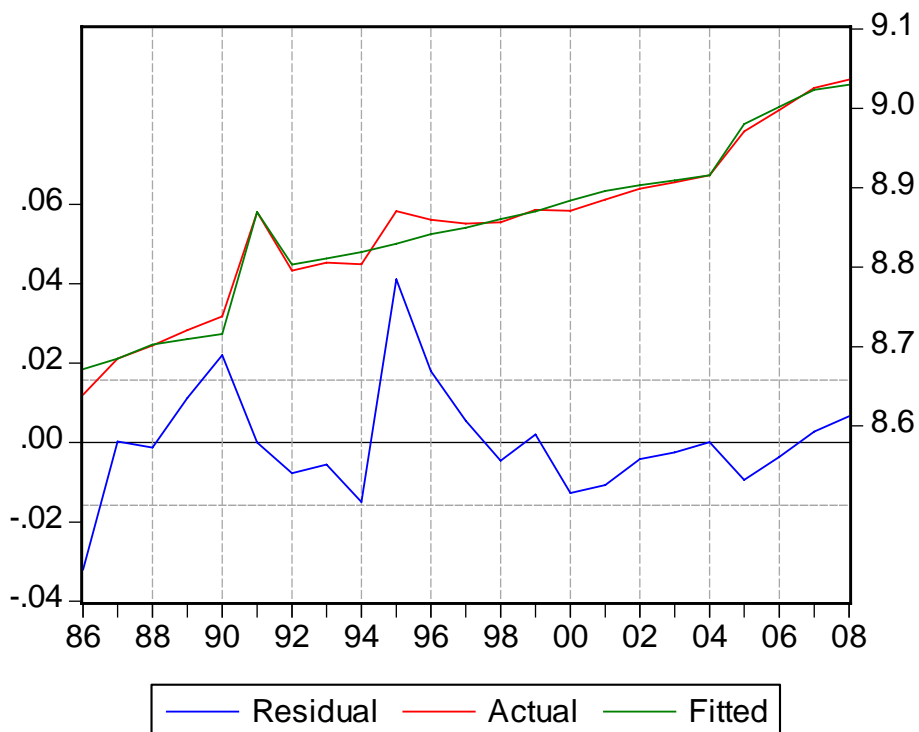


Figure B - 3
Forecast Equations - Average Residential Use

Dependent Variable: LN(USE_RES)				
Method: Least Squares				
Date: 03/03/09 Time: 19:03				
Sample (adjusted): 1987 2007				
Included observations: 21 after adjustments				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	6.42	1.63	3.93	0.002
LN(GRTRAV_PYHH)	0.26	0.12	2.28	0.040
LN(@MA(PR_TVC_RES,2))	(0.29)	0.09	(3.33)	0.005
LN(@MA(PR_NG_RES,2))	0.24	0.04	6.54	0.000
HDD45	4.01E-05	1.05E-05	3.82	0.002
CDD70	1.03E-04	5.31E-05	1.94	0.074
BINARY: YEAR=1991	(0.08)	0.02	(4.94)	0.000
BINARY: YEAR>2004	(0.09)	0.02	(4.80)	0.000
R-squared	0.964	Mean dependent var	8.675	
Adjusted R-squared	0.944	S.D. dependent var	0.059	
S.E. of regression	0.014	Akaike info criterion	(5.44)	
Sum squared resid	0.002	Schwarz criterion	(5.04)	
LN likelihood	65.1	F-statistic	49.5	
Durbin-Watson stat	1.573	Prob(F-statistic)	0.000	

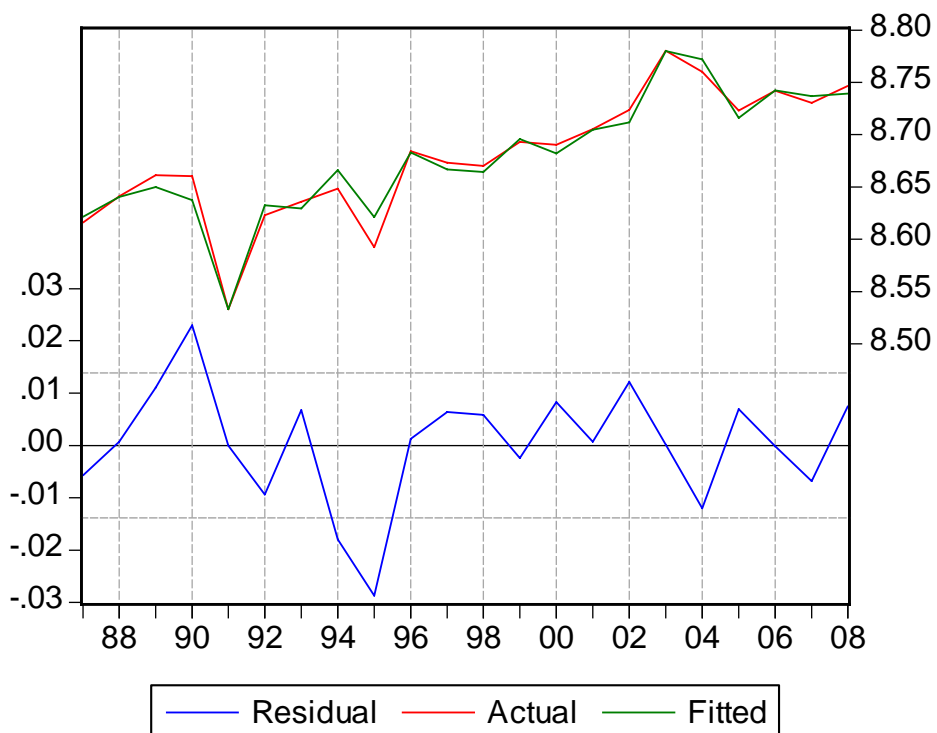


Figure B - 4
Forecast Equations - Commercial Customer

Dependent Variable: LN(CUST_COMM)				
Method: Least Squares				
Date: 02/19/09 Time: 15:42				
Sample (adjusted): 1987 2008				
Included observations: 22 after adjustments				
Convergence achieved after 30 iterations				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	2.114	1.15494879	1.83	0.083
LN(GRTRAV_PY)	0.736	0.1490933	4.94	0.000
AR(1)	0.736	0.16040884	4.59	0.000
R-squared	0.962	Mean dependent var	7.723	
Adjusted R-squared	0.959	S.D. dependent var	0.201	
S.E. of regression	0.041	Akaike info criterion	(3.42)	
Sum squared resid	0.032	Schwarz criterion	(3.27)	
LN likelihood	40.6	F-statistic	243.6	
Durbin-Watson stat	2.020	Prob(F-statistic)	0.000	

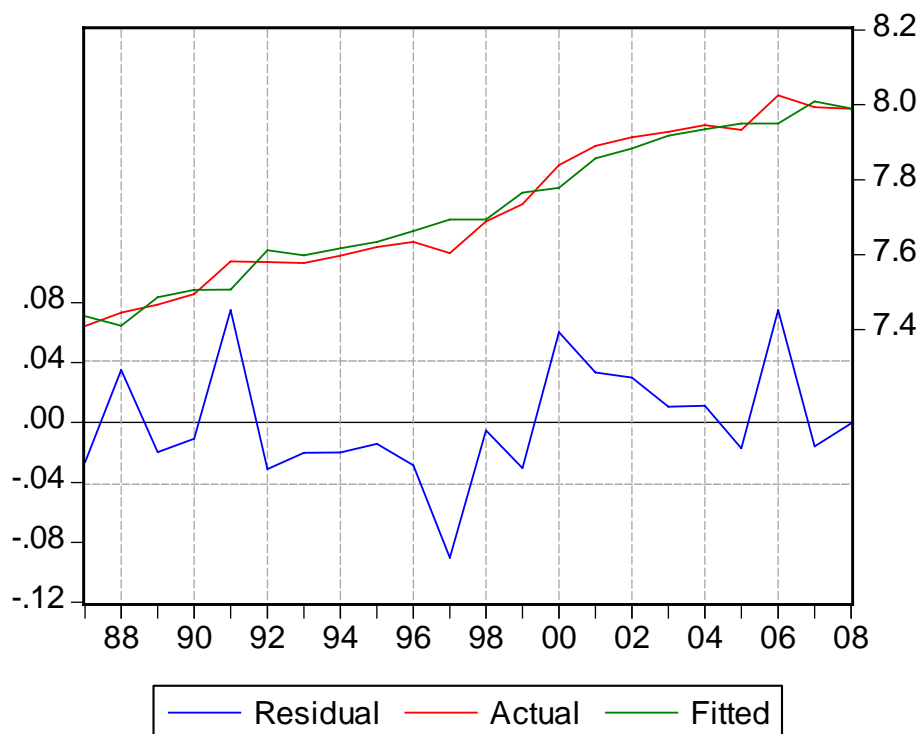


Figure B - 5
Forecast Equations - Commercial Sales

Dependent Variable: LN(SAL_COMM)				
Method: Least Squares				
Date: 03/03/09 Time: 19:04				
Sample (adjusted): 1987 2008				
Included observations: 22 after adjustments				
Convergence achieved after 9 iterations				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	7.398	0.709	10.43	0.000
LN(GRTRAV_PY)	0.553	0.092	5.99	0.000
BINARY: YEAR>2002	0.079	0.028	2.78	0.012
AR(1)	0.668	0.165	4.05	0.001
R-squared	0.979	Mean dependent var		11.636
Adjusted R-squared	0.976	S.D. dependent var		0.173
S.E. of regression	0.027	Akaike info criterion		(4.22)
Sum squared resid	0.013	Schwarz criterion		(4.03)
LN likelihood	50.5	F-statistic		281.1
Durbin-Watson stat	1.512	Prob(F-statistic)		0.000

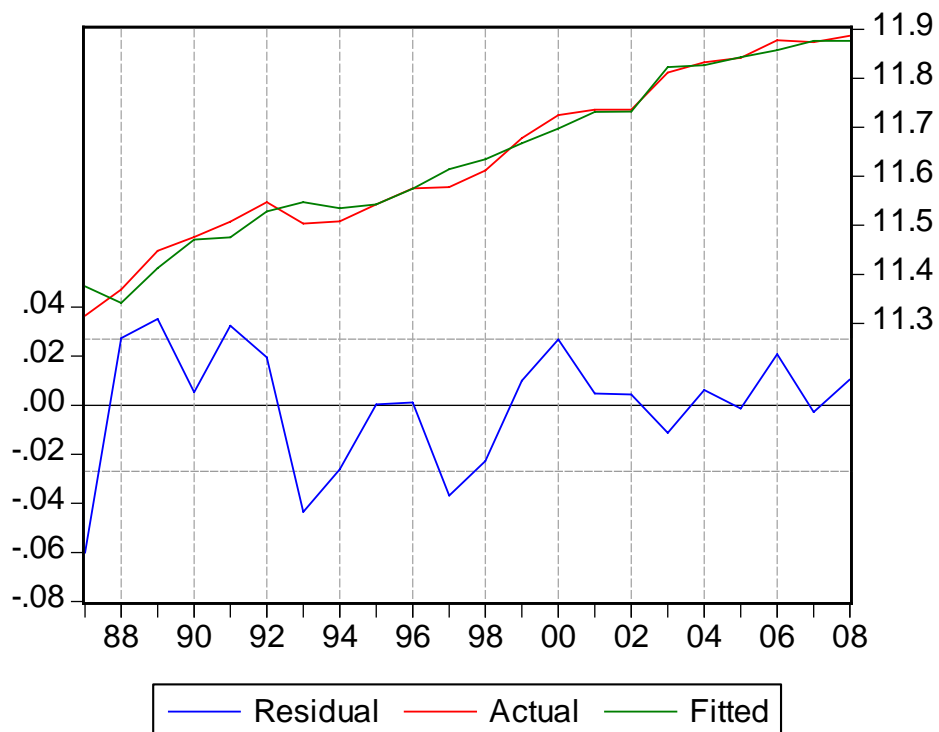


Figure B - 6
Forecast Equations - Industrial Customers

Dependent Variable: LN(CUST_IND)				
Method: Least Squares				
Date: 02/27/09 Time: 17:25				
Sample (adjusted): 1986 2008				
Included observations: 23 after adjustments				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	(7.142)	0.409	(17.45)	0.000
LN(GRTRAV_PY)	1.360	0.054	25.36	0.000
BINARY: YEAR=1991	0.265	0.062	4.27	0.000
R-squared	0.970	Mean dependent var	3.232	
Adjusted R-squared	0.967	S.D. dependent var	0.325	
S.E. of regression	0.059	Akaike info criterion	(2.70)	
Sum squared resid	0.070	Schwarz criterion	(2.55)	
LN likelihood	34.1	F-statistic	323.1	
Durbin-Watson stat	1.491	Prob(F-statistic)	0.000	

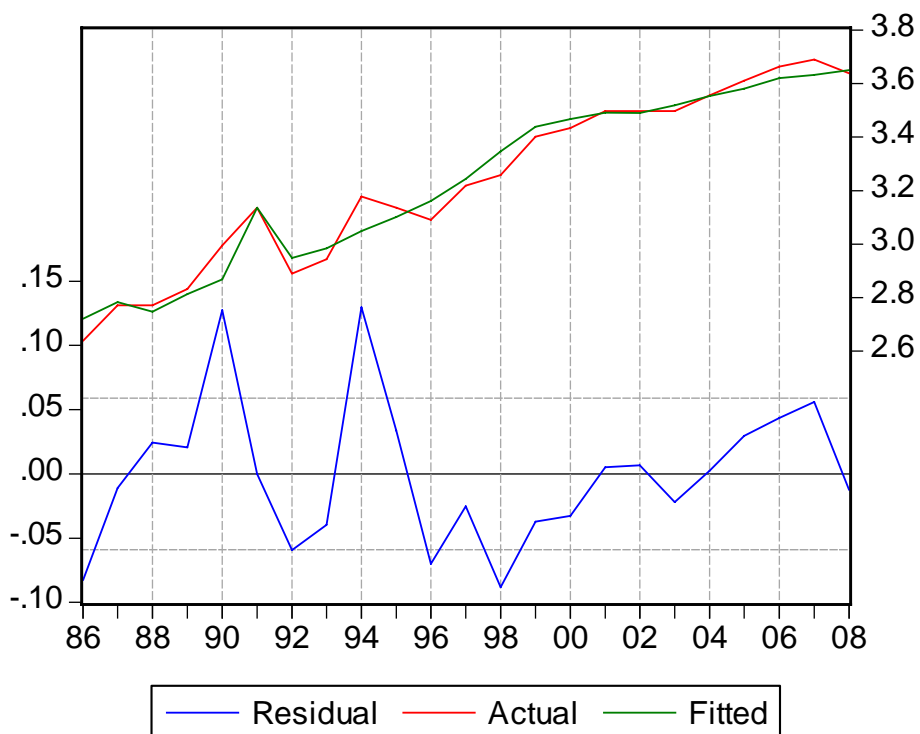


Figure B - 7
Forecast Equations - Industrial Sales

Dependent Variable: LN(SAL_IND)				
Method: Least Squares				
Date: 03/06/09 Time: 18:25				
Sample (adjusted): 1987 2008				
Included observations: 22 after adjustments				
Convergence achieved after 33 iterations				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	2.246	1.620	1.39	0.183
LN(GRTRAV_PY)	1.177	0.209	5.64	0.000
CDD55	9.37E-05	5.17E-05	1.81	0.086
AR(1)	0.799	0.143	5.61	0.000
R-squared	0.979	Mean dependent var		11.382
Adjusted R-squared	0.976	S.D. dependent var		0.301
S.E. of regression	0.047	Akaike info criterion		(3.13)
Sum squared resid	0.039	Schwarz criterion		(2.93)
LN likelihood	38.4	F-statistic		286.5
Durbin-Watson stat	1.828	Prob(F-statistic)		0.000

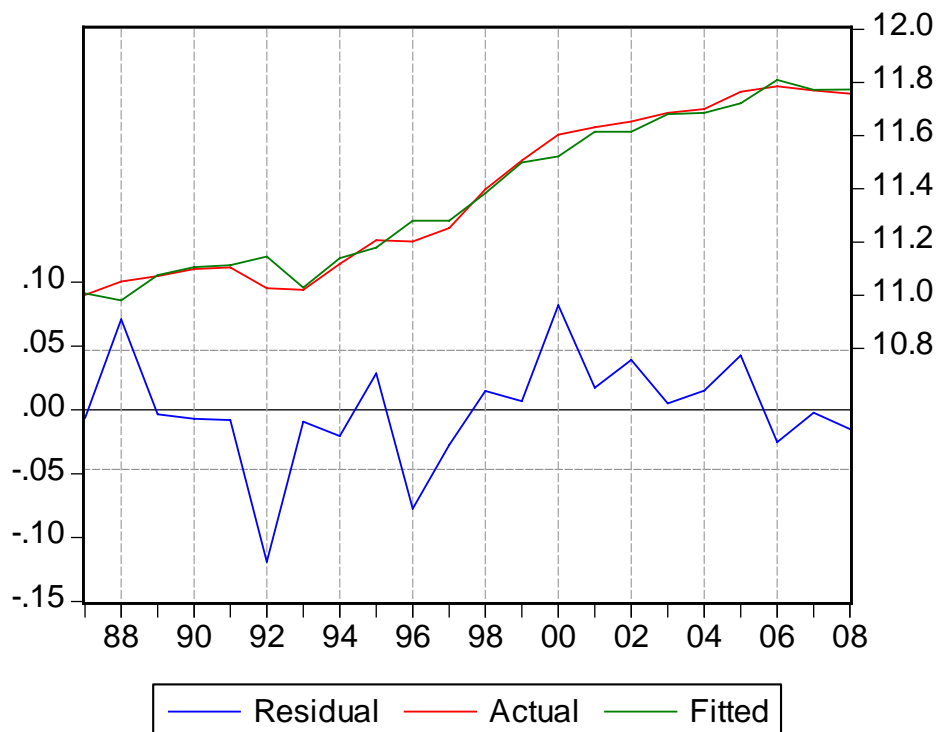


Figure B - 8
Forecast Equations - Public Use Customers

Dependent Variable: LN(CUST_PUB)				
Method: Least Squares				
Date: 03/09/09 Time: 19:25				
Sample (adjusted): 1986 2008				
Included observations: 23 after adjustments				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	(3.861)	1.182	(3.27)	0.004
LN(GRTRAV_HH)	1.767	0.366	4.83	0.000
BINARY: YEAR>1998	0.638	0.100	6.38	0.000
BINARY: YEAR>2003	(0.311)	0.082	(3.81)	0.001
R-squared	0.951	Mean dependent var		2.248
Adjusted R-squared	0.944	S.D. dependent var		0.504
S.E. of regression	0.119	Akaike info criterion		(1.26)
Sum squared resid	0.271	Schwarz criterion		(1.06)
LN likelihood	18.4	F-statistic		124.2
Durbin-Watson stat	1.271	Prob(F-statistic)		0.000

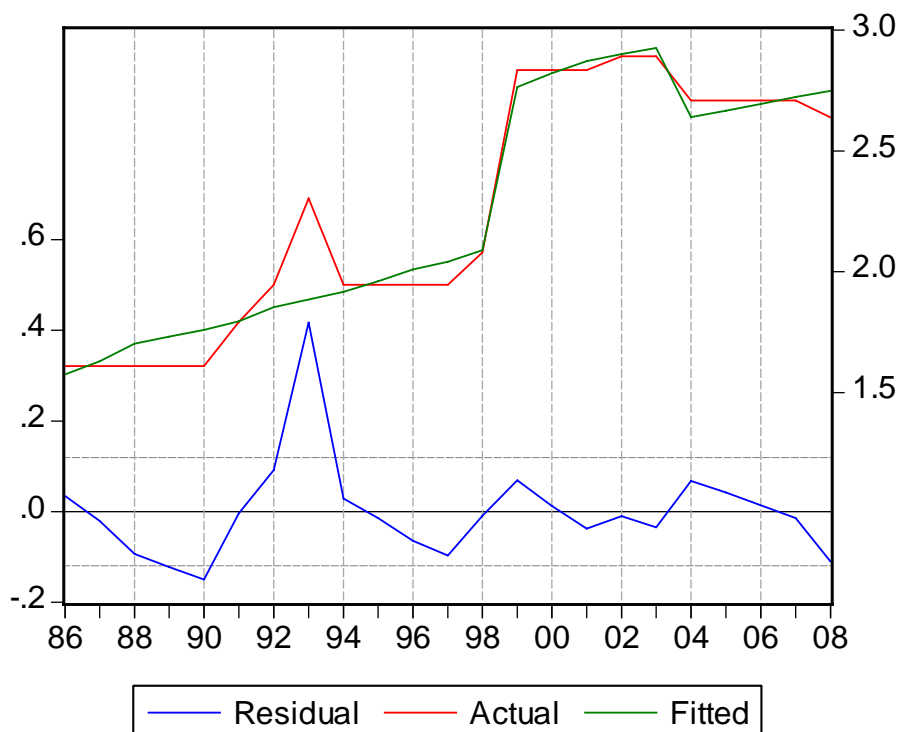


Figure B - 9
Forecast Equations - Public Use Sales

Dependent Variable: LN(SAL_PUB)				
Method: Least Squares				
Date: 02/23/09 Time: 11:34				
Sample (adjusted): 1990 2008				
Included observations: 19 after adjustments				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	3.38	0.74	4.57	0.000
LN(GRTRAV_PY)	0.68	0.10	7.04	0.000
BINARY: YEAR>2004	(0.72)	0.05	(15.43)	0.000
R-squared	0.939	Mean dependent var	8.480	
Adjusted R-squared	0.931	S.D. dependent var	0.256	
S.E. of regression	0.067	Akaike info criterion	(2.41)	
Sum squared resid	0.073	Schwarz criterion	(2.27)	
LN likelihood	25.9	F-statistic	122.3	
Durbin-Watson stat	1.636	Prob(F-statistic)	0.000	

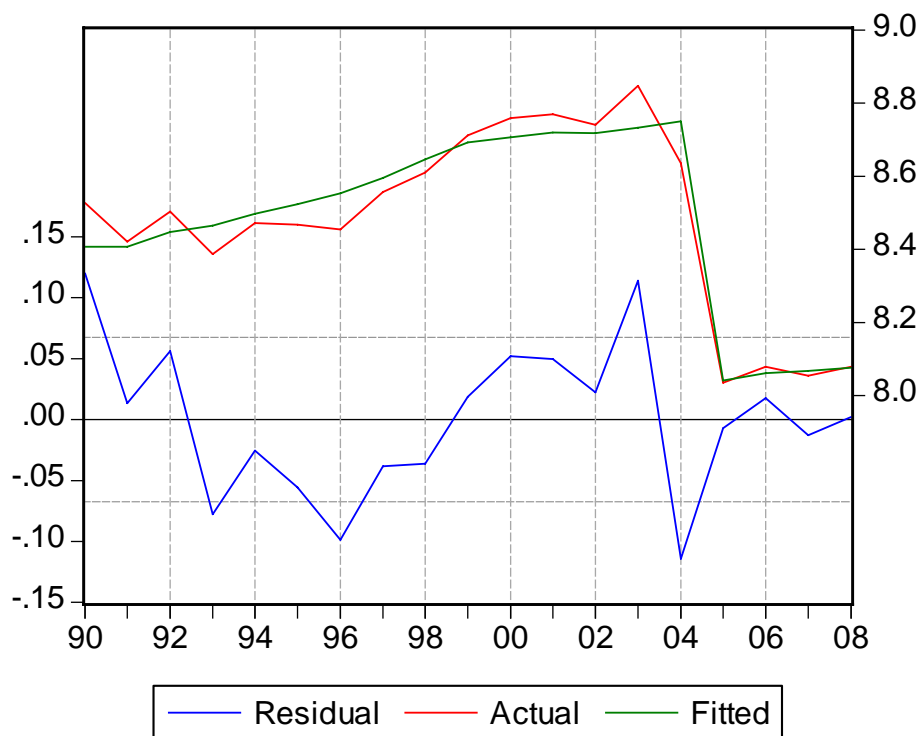


Figure B - 10
Forecast Equations - Lights Sales

Dependent Variable: LOG(SAL_LTS)				
Method: Least Squares				
Date: 02/23/09 Time: 11:39				
Sample (adjusted): 1986 2008				
Included observations: 23 after adjustments				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	4.66	0.49	9.49	0.000
LOG(GRTRAV_GRP)	0.33	0.06	5.29	0.000
R-squared	0.571	Mean dependent var	7.256	
Adjusted R-squared	0.551	S.D. dependent var	0.099	
S.E. of regression	0.066	Akaike info criterion	(2.51)	
Sum squared resid	0.092	Schwarz criterion	(2.42)	
Log likelihood	30.9	F-statistic	28.0	
Durbin-Watson stat	1.472	Prob(F-statistic)	0.000	

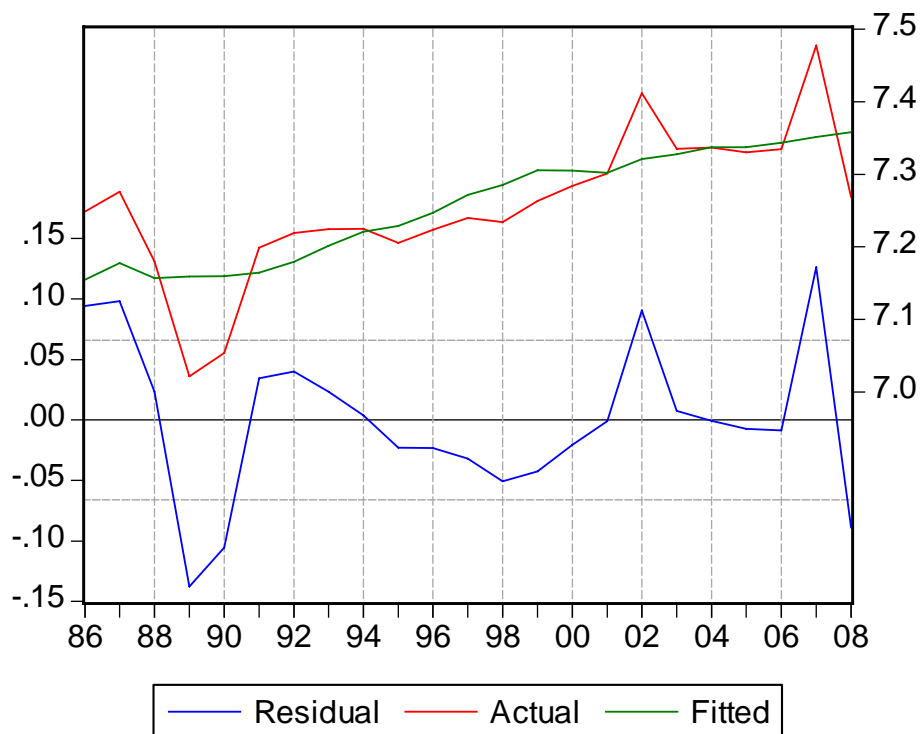
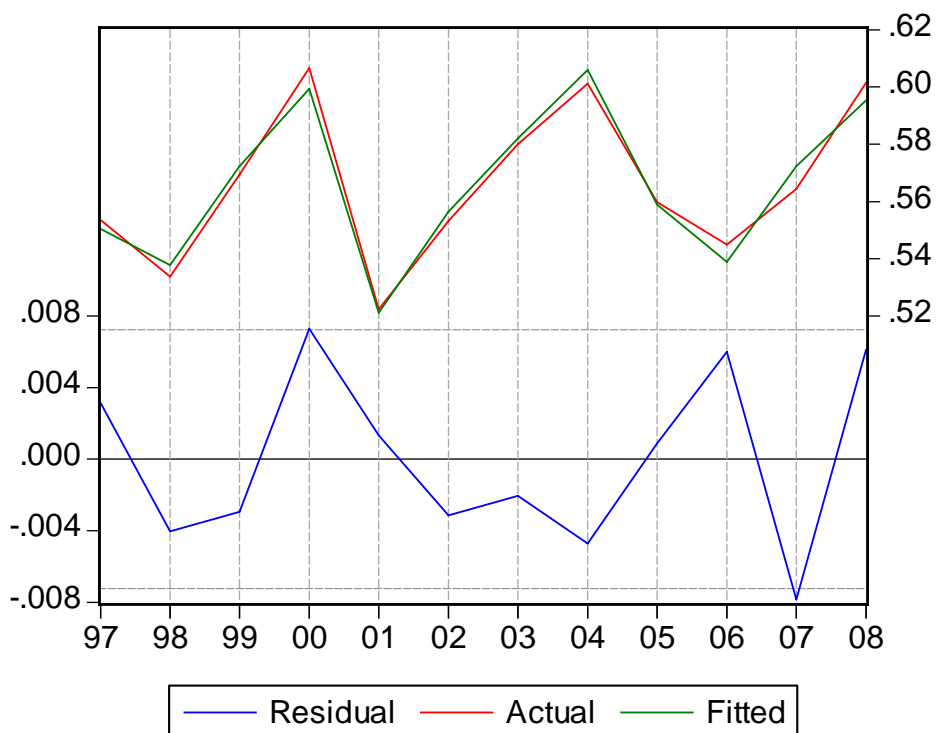


Figure B - 11
Forecast Equations - Annual Peak Load Factor

Dependent Variable: LOADFACTOR				
Method: Least Squares				
Date: 03/06/09 Time: 17:57				
Sample (adjusted): 1997 2008				
Included observations: 12 after adjustments				
Newey-West HAC Standard Errors & Covariance (lag truncation=2)				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	1.348	0.129	10.48	0.000
HDD45	1.34E-05	4.71E-06	2.83	0.036
CDD70	3.59E-04	4.68E-05	7.67	0.001
PKPRMAX	-8.96E-03	7.98E-04	(11.23)	0.000
@MA(PR_TVC_ALL,2)	(0.003)	0.001	(3.23)	0.023
SAL_IND/SAL_TOT	0.376	0.072	5.24	0.003
PEAKPREC	0.077	0.015	5.23	0.003
R-squared	0.968	Mean dependent var		0.566
Adjusted R-squared	0.929	S.D. dependent var		0.027
S.E. of regression	0.0072	Akaike info criterion		(6.73)
Sum squared resid	0.0003	Schwarz criterion		(6.45)
LN likelihood	47.4	F-statistic		25.0
Durbin-Watson stat	2.543	Prob(F-statistic)		0.001



Appendix C
ECONOMIC DATA

Table C-1
Historical and Projected Economic Trends of Grand Traverse County
(Source: Woods & Poole)

Mid-range Economic Case	Population (Ths.)		Households (Ths.)		Total Employment (Ths.)		Manufacturing Employment (Ths.)		Gross Regional Product (\$M; \$2004)		Total Earnings (\$M; \$2004)		Personal Income, (\$M; \$2004)		Income per Household (\$2004)		Retail Sales (\$M; \$2004)	
	Value	% Chg	Value	% Chg	Value	% Chg	Value	% Chg	Value	% Chg	Value	% Chg	Value	% Chg	Value	% Chg	Value	% Chg
1992	67.4	-	25.4	-	48.8	-	14.1	-	2,104	-	1,396	-	1,671	-	64,669	-	1,074.7	-
1993	68.8	2.1%	25.8	1.8%	48.9	0.3%	14.3	1.4%	2,248	6.9%	1,478	5.9%	1,714	2.6%	65,127	0.7%	1,140.8	6.2%
1994	69.9	1.6%	26.3	1.8%	52.8	7.9%	15.3	7.3%	2,387	6.2%	1,537	4.0%	1,797	4.9%	67,127	3.1%	1,226.2	7.5%
1995	71.3	2.0%	27.0	2.5%	55.0	4.2%	16.0	4.2%	2,444	2.4%	1,623	5.6%	1,869	4.0%	68,131	1.5%	1,282.0	4.5%
1996	72.7	2.0%	27.7	2.9%	56.9	3.4%	16.2	1.6%	2,584	5.8%	1,684	3.8%	1,952	4.4%	69,133	1.5%	1,355.0	5.7%
1997	73.8	1.4%	28.2	1.8%	58.3	2.5%	17.0	4.5%	2,784	7.7%	1,795	6.6%	2,075	6.3%	72,168	4.4%	1,404.6	3.7%
1998	75.3	2.1%	29.0	2.6%	59.8	2.6%	17.0	0.5%	2,902	4.2%	1,946	8.4%	2,237	7.8%	75,780	5.0%	1,474.8	5.0%
1999	76.7	1.8%	29.6	2.2%	61.0	1.9%	17.2	0.8%	3,088	6.4%	2,087	7.2%	2,394	7.0%	79,351	4.7%	1,589.5	7.8%
2000	78.0	1.7%	30.6	3.2%	62.2	2.0%	17.4	1.5%	3,080	-0.3%	2,127	1.9%	2,444	2.1%	78,426	-1.2%	1,664.8	4.7%
2001	79.9	2.5%	31.4	2.9%	61.7	-0.7%	17.1	-1.9%	3,053	-0.9%	2,152	1.2%	2,489	1.8%	77,059	-1.7%	1,702.2	2.2%
2002	81.0	1.3%	32.0	1.7%	62.9	1.9%	17.4	2.0%	3,237	6.1%	2,213	2.8%	2,486	-0.1%	75,703	-1.8%	1,729.1	1.6%
2003	81.8	1.0%	32.4	1.4%	64.3	2.3%	17.4	-0.2%	3,300	1.9%	2,283	3.2%	2,539	2.2%	76,283	0.8%	1,767.0	2.2%
2004	82.6	1.1%	32.9	1.5%	65.6	1.9%	17.3	-0.4%	3,400	3.0%	2,353	3.1%	2,604	2.5%	77,107	1.1%	1,832.5	3.7%
2005	83.5	1.1%	33.4	1.5%	66.4	1.3%	16.6	-4.0%	3,400	0.0%	2,343	-0.4%	2,659	2.1%	77,445	0.4%	1,891.0	3.2%
2006	84.5	1.1%	33.9	1.6%	67.7	1.9%	16.6	-0.5%	3,463	1.8%	2,372	1.2%	2,736	2.9%	78,475	1.3%	1,941.6	2.7%
2007	85.5	1.2%	34.5	1.6%	68.5	1.1%	16.7	0.5%	3,547	2.4%	2,430	2.5%	2,762	1.0%	77,989	-0.6%	1,970.8	1.5%
2008	86.4	1.1%	35.0	1.5%	69.2	1.1%	16.7	0.5%	3,618	2.0%	2,479	2.0%	2,797	1.2%	77,779	-0.3%	1,982.2	0.6%
2009	87.4	1.1%	35.5	1.5%	70.0	1.1%	16.8	0.5%	3,690	2.0%	2,529	2.0%	2,841	1.6%	77,820	0.1%	2,025.0	2.2%
2010	88.4	1.1%	36.1	1.5%	70.8	1.1%	16.9	0.5%	3,763	2.0%	2,579	2.0%	2,892	1.8%	78,041	0.3%	2,067.7	2.1%
2011	89.3	1.1%	36.6	1.5%	71.5	1.1%	17.0	0.5%	3,838	2.0%	2,630	2.0%	2,948	1.9%	78,396	0.5%	2,110.5	2.1%
2012	90.3	1.1%	37.2	1.5%	72.3	1.1%	17.1	0.5%	3,914	2.0%	2,682	2.0%	3,008	2.0%	78,856	0.6%	2,154.0	2.1%
2013	91.3	1.1%	37.7	1.4%	73.1	1.1%	17.2	0.5%	3,991	2.0%	2,735	2.0%	3,072	2.1%	79,401	0.7%	2,198.1	2.0%
2014	92.3	1.1%	38.2	1.4%	73.9	1.1%	17.3	0.5%	4,070	2.0%	2,789	2.0%	3,138	2.2%	80,010	0.8%	2,243.1	2.0%
2015	93.3	1.1%	38.8	1.4%	74.7	1.1%	17.4	0.5%	4,149	2.0%	2,844	2.0%	3,207	2.2%	80,678	0.8%	2,288.9	2.0%
2016	94.3	1.1%	39.3	1.3%	75.5	1.1%	17.5	0.5%	4,231	2.0%	2,900	2.0%	3,279	2.2%	81,399	0.9%	2,335.6	2.0%
2017	95.3	1.1%	39.8	1.3%	76.3	1.1%	17.5	0.5%	4,313	2.0%	2,957	2.0%	3,352	2.2%	82,166	0.9%	2,383.3	2.0%
2018	96.3	1.1%	40.3	1.3%	77.1	1.1%	17.6	0.5%	4,397	1.9%	3,014	2.0%	3,428	2.3%	82,980	1.0%	2,431.9	2.0%
2019	97.3	1.1%	40.8	1.3%	78.0	1.1%	17.7	0.5%	4,483	1.9%	3,073	1.9%	3,506	2.3%	83,838	1.0%	2,481.6	2.0%
2020	98.3	1.0%	41.3	1.2%	78.8	1.1%	17.8	0.5%	4,570	1.9%	3,133	1.9%	3,587	2.3%	84,741	1.1%	2,532.2	2.0%
2021	99.3	1.0%	41.8	1.2%	79.6	1.1%	17.9	0.5%	4,658	1.9%	3,193	1.9%	3,669	2.3%	85,673	1.1%	2,583.9	2.0%
2022	100.4	1.0%	42.3	1.2%	80.5	1.1%	18.0	0.5%	4,748	1.9%	3,255	1.9%	3,754	2.3%	86,648	1.1%	2,636.7	2.0%
2023	101.4	1.0%	42.8	1.2%	81.3	1.1%	18.1	0.5%	4,839	1.9%	3,318	1.9%	3,841	2.3%	87,668	1.2%	2,690.5	2.0%
2024	102.4	1.0%	43.3	1.2%	82.2	1.1%	18.1	0.5%	4,932	1.9%	3,381	1.9%	3,931	2.3%	88,728	1.2%	2,745.4	2.0%
2025	103.4	1.0%	43.8	1.1%	83.0	1.1%	18.2	0.5%	5,027	1.9%	3,446	1.9%	4,023	2.3%	89,833	1.2%	2,801.5	2.0%
2026	104.5	1.0%	44.3	1.1%	83.9	1.0%	18.3	0.5%	5,123	1.9%	3,512	1.9%	4,118	2.3%	90,978	1.3%	2,858.7	2.0%
2027	105.5	1.0%	44.8	1.1%	84.8	1.0%	18.4	0.5%	5,220	1.9%	3,579	1.9%	4,214	2.3%	92,160	1.3%	2,917.1	2.0%
2028	106.5	1.0%	45.2	1.0%	85.7	1.0%	18.5	0.5%	5,319	1.9%	3,647	1.9%	4,313	2.3%	93,380	1.3%	2,976.7	2.0%
Average Percent Change																		
1999-2008		1.3%		1.9%		1.4%		-0.3%		1.8%		1.9%		1.7%		-0.2%		2.5%
2009-2018		1.1%		1.4%		1.1%		0.5%		2.0%		2.0%		2.1%		0.7%		2.1%
2019-2028		1.0%		1.1%		1.1%		0.5%		1.9%		1.9%		2.3%		1.2%		2.0%

Appendix D
WEATHER DATA

Table D-1
 Monthly and Annual Weather Data for Traverse City Capital Airport

	HDD	CDD	HDD50	CDD60	HDD45	CDD55	CDD70	Precip
Jan-85	1,394	0	929	0	774	0	0	4.0
Feb-85	1,258	0	838	0	698	0	0	3.4
Mar-85	1,007	0	544	0	394	0	0	2.1
Apr-85	574	23	226	46	149	75	7	3.0
May-85	327	4	25	24	0	78	0	2.2
Jun-85	160	36	3	99	0	203	5	1.1
Jul-85	19	121	0	257	0	412	35	2.6
Aug-85	39	90	0	211	0	362	22	3.1
Sep-85	179	80	7	149	1	237	26	6.2
Oct-85	491	0	85	0	18	13	0	1.1
Nov-85	876	0	438	0	307	0	0	4.0
Dec-85	1,341	0	876	0	721	0	0	3.0
Jan-86	1,308	0	843	0	688	0	0	1.8
Feb-86	1,202	0	782	0	642	0	0	0.5
Mar-86	979	0	537	1	407	10	0	1.2
Apr-86	538	9	182	23	93	56	3	1.5
May-86	295	29	30	62	12	129	6	1.8
Jun-86	125	35	0	101	0	217	6	5.0
Jul-86	14	188	0	331	0	485	85	4.2
Aug-86	65	56	0	165	0	305	3	1.9
Sep-86	185	23	8	79	0	175	0	6.9
Oct-86	522	0	109	0	32	8	0	1.9
Nov-86	906	0	460	0	321	0	0	0.8
Dec-86	1,095	0	630	0	475	0	0	0.9
Jan-87	1,199	0	734	0	579	0	0	2.2
Feb-87	1,057	0	637	0	497	0	0	0.2
Mar-87	923	0	463	0	324	0	0	0.6
Apr-87	553	1	162	6	85	19	0	0.9
May-87	265	65	24	125	0	196	32	0.8
Jun-87	44	157	0	275	0	414	64	2.8
Jul-87	21	291	0	431	0	580	168	0.5
Aug-87	24	129	0	262	0	415	49	6.7
Sep-87	139	22	0	77	0	186	2	2.9
Oct-87	605	0	166	0	63	3	0	2.5
Nov-87	737	0	322	3	197	15	0	1.9
Dec-87	1,033	0	568	0	413	0	0	2.4
Jan-88	1,353	0	888	0	733	0	0	2.0
Feb-88	1,301	0	866	0	721	0	0	2.3
Mar-88	1,050	0	585	0	435	0	0	1.3
Apr-88	642	0	204	0	92	2	0	4.5
May-88	253	48	6	89	0	152	15	0.6
Jun-88	78	167	0	262	0	391	95	1.9
Jul-88	7	237	0	385	0	540	104	1.9
Aug-88	28	246	0	375	0	528	152	2.2
Sep-88	148	34	0	95	0	193	6	1.6
Oct-88	637	0	212	5	103	17	0	3.7
Nov-88	772	0	328	0	194	0	0	3.6
Dec-88	1,184	0	719	0	564	0	0	2.1
Jan-89	1,158	0	693	0	538	0	0	1.1
Feb-89	1,299	0	879	0	739	0	0	0.7
Mar-89	1,198	0	743	0	598	1	0	1.9
Apr-89	720	0	273	0	151	0	0	1.1

Table D-1
 Monthly and Annual Weather Data for Traverse City Capital Airport

	HDD	CDD	HDD50	CDD60	HDD45	CDD55	CDD70	Precip
May-89	355	1	73	28	32	93	0	3.7
Jun-89	127	43	0	114	0	224	8	1.7
Jul-89	8	203	0	350	0	505	82	0.9
Aug-89	40	118	0	242	0	388	41	1.3
Sep-89	200	33	17	88	2	180	9	0.7
Oct-89	457	0	119	14	56	60	0	2.8
Nov-89	947	0	497	0	347	0	0	1.4
Dec-89	1,476	0	1,011	0	856	0	0	0.9
Jan-90	1,084	0	619	0	464	0	0	4.1
Feb-90	1,104	0	684	0	544	0	0	0.9
Mar-90	956	0	521	4	391	13	0	2.1
Apr-90	610	45	256	70	164	100	22	1.5
May-90	431	6	61	12	12	41	1	2.2
Jun-90	86	62	2	157	0	285	16	6.2
Jul-90	13	122	0	264	0	419	42	1.1
Aug-90	24	86	0	218	0	373	23	3.4
Sep-90	181	52	7	117	0	210	10	4.1
Oct-90	528	2	125	11	46	30	0	2.6
Nov-90	706	0	298	5	188	14	0	1.7
Dec-90	1,125	0	660	0	505	0	0	2.0
Jan-91	1,358	0	893	0	738	0	0	1.2
Feb-91	1,055	0	635	0	495	0	0	0.6
Mar-91	960	0	504	0	355	4	0	1.8
Apr-91	529	8	172	19	79	52	2	1.2
May-91	237	70	41	150	9	237	15	0.8
Jun-91	13	168	0	305	0	455	68	0.2
Jul-91	11	192	0	336	0	491	85	0.2
Aug-91	7	191	0	339	0	494	89	0.0
Sep-91	221	53	22	118	2	205	16	0.0
Oct-91	476	4	94	14	29	40	0	1.0
Nov-91	892	0	448	0	313	0	0	1.7
Dec-91	1,110	0	645	0	490	0	0	2.5
Jan-92	1,198	0	733	0	578	0	0	1.3
Feb-92	1,088	0	653	0	508	0	0	0.6
Mar-92	1,062	0	597	0	442	0	0	0.6
Apr-92	711	0	294	7	171	18	0	1.8
May-92	318	20	52	50	11	115	3	0.4
Jun-92	162	33	4	95	0	197	7	1.4
Jul-92	70	19	0	113	0	261	1	0.0
Aug-92	77	61	0	153	0	295	23	0.3
Sep-92	214	16	9	62	0	144	0	0.0
Oct-92	561	0	152	7	71	26	0	0.0
Nov-92	900	0	450	0	304	0	0	1.2
Dec-92	1,123	0	658	0	503	0	0	1.7
Jan-93	1,270	0	805	0	650	0	0	0.9
Feb-93	1,276	0	856	0	716	0	0	0.9
Mar-93	1,096	0	631	0	476	0	0	0.5
Apr-93	731	0	290	0	163	3	0	1.1
May-93	356	17	34	33	1	79	3	0.9
Jun-93	106	47	2	133	0	255	8	2.4
Jul-93	1	192	0	347	0	502	78	0.1
Aug-93	14	185	0	326	0	481	75	0.0

Table D-1
Monthly and Annual Weather Data for Traverse City Capital Airport

	HDD	CDD	HDD50	CDD60	HDD45	CDD55	CDD70	Precip
Sep-93	271	11	20	34	5	98	2	0.4
Oct-93	551	2	138	7	46	17	0	0.0
Nov-93	844	0	394	0	245	0	0	0.9
Dec-93	1,137	0	672	0	517	0	0	1.8
Jan-94	1,605	0	1,140	0	985	0	0	1.3
Feb-94	1,376	0	957	0	822	0	0	1.0
Mar-94	1,065	0	600	0	445	0	0	1.7
Apr-94	647	0	234	4	125	16	0	0.6
May-94	367	28	50	55	12	104	10	1.2
Jun-94	83	111	0	211	0	334	59	1.4
Jul-94	20	131	0	266	0	421	37	2.1
Aug-94	57	72	0	180	0	325	15	1.8
Sep-94	111	49	0	128	0	245	15	0.8
Oct-94	413	0	53	9	7	40	0	0.7
Nov-94	718	0	279	0	167	2	0	0.7
Dec-94	984	0	519	0	365	0	0	0.2
Jan-95	1,233	0	768	0	613	0	0	0.0
Feb-95	1,219	0	799	0	659	0	0	0.0
Mar-95	952	0	496	0	358	1	0	0.0
Apr-95	756	0	306	0	168	0	0	0.0
May-95	357	5	25	13	3	49	0	0.0
Jun-95	49	173	0	294	0	428	84	0.0
Jul-95	17	217	0	355	0	510	99	0.0
Aug-95	0	246	0	401	0	556	105	0.0
Sep-95	233	32	16	83	1	153	6	0.0
Oct-95	441	11	73	26	24	48	1	0.0
Nov-95	995	0	545	0	400	0	0	3.0
Dec-95	1,276	0	811	0	656	0	0	3.2
Jan-96	1,385	0	920	0	768	0	0	0.0
Feb-96	1,283	0	848	0	703	0	0	0.0
Mar-96	1,193	0	728	0	574	0	0	0.0
Apr-96	801	0	371	0	250	4	0	0.0
May-96	427	23	78	40	26	72	11	0.0
Jun-96	79	76	0	171	0	298	36	0.0
Jul-96	23	82	0	214	0	369	19	0.8
Aug-96	9	149	0	295	0	450	55	2.3
Sep-96	167	57	1	113	0	205	9	3.6
Oct-96	463	0	88	6	29	37	0	2.8
Nov-96	920	0	473	0	335	0	0	4.8
Dec-96	1,107	0	642	0	487	0	0	6.1
Jan-97	1,329	0	864	0	709	0	0	9.8
Feb-97	1,079	0	659	0	519	0	0	3.6
Mar-97	1,042	0	577	0	428	0	0	2.6
Apr-97	681	0	250	0	150	2	0	0.4
May-97	514	0	96	0	20	9	0	2.5
Jun-97	47	136	0	252	0	390	59	0.9
Jul-97	25	166	0	301	0	452	74	4.0
Aug-97	47	74	0	186	0	337	20	3.9
Sep-97	137	21	0	80	0	193	2	1.0
Oct-97	460	18	139	58	60	104	3	1.2
Nov-97	866	0	419	0	274	0	0	2.1
Dec-97	992	0	527	0	372	0	0	1.6

Table D-1
 Monthly and Annual Weather Data for Traverse City Capital Airport

	HDD	CDD	HDD50	CDD60	HDD45	CDD55	CDD70	Precip
Jan-98	1,156	0	691	0	538	0	0	5.1
Feb-98	868	0	448	0	308	0	0	0.2
Mar-98	923	1	502	11	372	26	0	5.4
Apr-98	540	0	128	5	46	14	0	2.2
May-98	164	69	0	129	0	227	31	1.2
Jun-98	99	90	0	189	0	305	33	2.3
Jul-98	3	149	0	301	0	456	53	0.7
Aug-98	8	150	0	297	0	452	40	3.8
Sep-98	100	53	0	135	0	259	9	3.5
Oct-98	428	2	46	7	6	25	0	1.6
Nov-98	723	0	286	0	157	4	0	3.3
Dec-98	1,019	0	560	0	424	0	0	0.9
Jan-99	1,363	0	898	0	743	0	0	1.8
Feb-99	1,014	0	594	0	456	0	0	0.8
Mar-99	1,035	0	581	0	433	5	0	0.2
Apr-99	600	0	167	0	62	3	0	2.1
May-99	243	31	20	85	0	163	4	1.1
Jun-99	91	139	0	236	0	355	61	3.1
Jul-99	8	229	0	376	0	531	108	10.0
Aug-99	30	70	0	200	0	351	9	2.0
Sep-99	186	35	0	84	0	169	11	3.0
Oct-99	523	1	119	6	33	23	0	1.6
Nov-99	670	0	249	4	139	9	0	1.1
Dec-99	1,095	0	630	0	479	0	0	1.9
Jan-00	1,322	0	857	0	702	0	0	1.4
Feb-00	1,017	0	587	0	449	0	0	0.9
Mar-00	783	0	345	5	224	12	0	1.4
Apr-00	700	0	257	0	130	2	0	1.1
May-00	282	32	9	63	0	121	14	3.0
Jun-00	77	68	0	157	0	294	18	3.0
Jul-00	39	111	0	234	0	382	26	3.5
Aug-00	36	88	0	214	0	363	17	3.7
Sep-00	197	43	17	107	3	195	11	5.1
Oct-00	408	9	80	36	30	76	0	0.9
Nov-00	796	0	364	0	238	8	0	2.4
Dec-00	1,348	0	883	0	728	0	0	0.8
Jan-01	1,166	0	701	0	546	0	0	1.1
Feb-01	1,146	0	726	0	586	0	0	1.3
Mar-01	1,099	0	634	0	479	0	0	0.5
Apr-01	562	4	176	15	74	34	0	1.5
May-01	270	17	9	45	0	114	2	5.2
Jun-01	129	100	5	183	0	301	45	3.1
Jul-01	41	129	0	250	0	398	42	0.4
Aug-01	19	157	0	294	0	449	82	2.4
Sep-01	253	19	14	48	0	117	6	4.5
Oct-01	514	0	127	7	51	30	0	2.1
Nov-01	632	0	209	0	105	5	0	2.1
Dec-01	1,006	0	547	0	402	1	0	1.7
Jan-02	1,120	0	655	0	500	0	0	0.6
Feb-02	1,008	0	588	0	448	0	0	2.2
Mar-02	1,139	0	674	0	519	0	0	2.2
Apr-02	665	26	290	41	185	62	12	3.0

Table D-1
Monthly and Annual Weather Data for Traverse City Capital Airport

	HDD	CDD	HDD50	CDD60	HDD45	CDD55	CDD70	Precip
May-02	500	5	122	22	44	49	0	3.8
Jun-02	135	113	0	195	0	295	50	2.5
Jul-02	2	272	0	425	0	580	147	0.4
Aug-02	15	127	0	267	0	422	32	4.5
Sep-02	91	85	0	179	0	302	27	0.6
Oct-02	627	10	223	18	115	38	5	2.0
Nov-02	885	0	443	0	307	0	0	0.9
Dec-02	1,122	0	657	0	503	0	0	0.4
Jan-03	1,391	0	926	0	771	0	0	0.3
Feb-03	1,338	0	918	0	778	0	0	0.4
Mar-03	1,114	0	651	0	510	0	0	1.6
Apr-03	741	5	340	11	226	30	0	3.2
May-03	402	0	40	8	9	25	0	1.9
Jun-03	156	41	3	89	0	196	21	1.9
Jul-03	15	120	0	260	0	415	30	3.2
Aug-03	12	151	0	294	0	449	43	2.9
Sep-03	170	30	13	100	0	200	3	2.6
Oct-03	535	1	150	11	64	35	0	3.4
Nov-03	799	0	349	0	210	0	0	3.7
Dec-03	1,077	0	612	0	457	0	0	1.7
Jan-04	1,500	0	1,035	0	880	0	0	1.3
Feb-04	1,184	0	749	0	604	0	0	1.2
Mar-04	941	0	478	0	340	0	0	2.4
Apr-04	659	3	256	10	142	28	0	2.4
May-04	398	7	59	29	16	64	2	5.9
Jun-04	112	35	0	107	0	226	11	1.8
Jul-04	42	101	0	219	0	369	21	1.7
Aug-04	73	69	0	167	0	307	21	3.4
Sep-04	82	79	0	173	0	302	23	1.0
Oct-04	460	0	82	10	17	37	0	4.3
Nov-04	749	0	303	0	176	0	0	1.7
Dec-04	1,180	0	715	0	561	0	0	2.9
Jan-05	1,371	0	906	0	751	0	0	1.6
Feb-05	1,039	0	619	0	479	0	0	0.8
Mar-05	1,114	0	655	0	511	0	0	0.8
Apr-05	578	0	166	4	69	9	0	1.2
May-05	403	2	68	12	19	42	0	2.1
Jun-05	26	192	0	319	0	466	92	1.1
Jul-05	4	214	0	364	0	519	96	1.6
Aug-05	9	169	0	315	0	470	63	4.3
Sep-05	68	81	0	180	0	316	26	2.6
Oct-05	434	37	100	62	30	105	20	0.8
Nov-05	774	0	336	0	218	1	0	4.3
Dec-05	1,188	0	723	0	568	0	0	1.0
Jan-06	1,016	0	551	0	396	0	0	2.0
Feb-06	1,133	0	713	0	573	0	0	0.7
Mar-06	976	0	521	0	378	5	0	1.1
Apr-06	527	0	145	2	64	26	0	1.9
May-06	305	32	38	67	5	135	16	3.9
Jun-06	80	62	0	153	0	284	26	1.9
Jul-06	6	255	0	405	0	560	128	1.6
Aug-06	17	132	0	270	0	425	43	2.9

Table D-1
 Monthly and Annual Weather Data for Traverse City Capital Airport

	HDD	CDD	HDD50	CDD60	HDD45	CDD55	CDD70	Precip
Sep-06	208	12	7	65	1	144	0	1.7
Oct-06	603	0	187	5	91	22	0	6.2
Nov-06	741	0	301	0	178	1	0	1.4
Dec-06	974	0	509	0	354	0	0	2.1
Jan-07	1,195	0	730	0	576	0	0	0.8
Feb-07	1,316	0	896	0	756	0	0	0.7
Mar-07	902	0	452	5	322	10	0	1.6
Apr-07	742	0	327	6	216	18	0	2.2
May-07	260	45	23	87	1	163	23	1.4
Jun-07	48	124	0	239	0	379	46	1.4
Jul-07	28	144	0	271	0	425	54	1.7
Aug-07	18	178	50	297	45	446	64	2.0
Sep-07	112	90	4	179	0	292	35	1.7
Oct-07	311	40	45	85	7	154	19	2.0
Nov-07	867	0	417	0	275	0	0	1.3
Dec-07	1,166	0	701	0	546	0	0	1.4
Jan-08	1,223	0	758	0	603	0	0	3.4
Feb-08	1,277	0	855	0	710	0	0	1.5
Mar-08	1,167	0	702	0	547	0	0	1.1
Apr-08	568	0	188	1	106	27	0	3.9
May-08	434	2	57	8	5	32	0	3.1
Jun-08	73	77	0	179	0	306	18	3.5
Jul-08	7	162	0	311	0	466	52	2.4
Aug-08	10	123	50	254	45	404	29	0.4
Sep-08	137	35	0	87	0	199	12	2.8
Oct-08	511	4	115	14	45	30	0	1.9
Nov-08	805	0	397	3	275	20	0	1.7
Dec-08	1,282	0	817	0	665	0	0	4.2

Table D-1
 Monthly and Annual Weather Data for Traverse City Capital Airport

	HDD	CDD	HDD50	CDD60	HDD45	CDD55	CDD70	Precip
Fiscal Year								
1986	7,391	363	3,779	805	2,888	1,435	98	31.6
1987	6,827	490	3,227	981	2,313	1,601	184	24.0
1988	7,234	657	3,603	1,123	2,654	1,744	328	29.5
1989	7,632	561	3,919	1,001	2,920	1,596	269	25.3
1990	7,397	466	3,788	937	2,838	1,573	172	25.0
1991	6,728	508	3,334	1,090	2,415	1,793	160	20.6
1992	7,255	492	3,542	958	2,543	1,560	200	11.5
1993	7,780	160	3,888	500	2,883	1,061	35	9.7
1994	7,959	528	4,204	984	3,200	1,551	223	10.4
1995	6,868	429	3,244	889	2,339	1,510	151	6.3
1996	8,130	605	4,389	1,076	3,401	1,640	258	6.2
1997	7,379	424	3,650	880	2,678	1,462	142	40.2
1998	6,275	440	2,854	957	1,969	1,658	163	30.3
1999	6,626	524	3,152	1,062	2,279	1,722	168	22.7
2000	6,692	436	3,053	893	2,156	1,512	160	30.3
2001	7,196	371	3,596	834	2,685	1,472	100	29.0
2002	7,030	450	3,225	856	2,253	1,405	191	27.6
2003	7,885	540	4,202	997	3,218	1,593	233	17.9
2004	7,402	347	3,702	811	2,714	1,415	89	32.4
2005	7,116	444	3,512	903	2,581	1,533	157	22.8
2006	6,513	594	3,127	1,143	2,232	1,861	247	26.0
2007	7,010	568	3,431	1,082	2,494	1,721	239	23.9
2008	7,245	531	3,778	1,020	2,845	1,683	190	26.6

Table D-2
Annual Peak Day Weather Data for Traverse City Capital Airport

Year	Peak Date	Peak Time	Peak Day								Prior Day		
			Max	Min	Avg	DewPt	Hum	THI1	THI2	Precip	Max	Min	
1993	08/25/93	15	91.9	66.0	78.3	68.4						86.0	63.9
1994	06/17/94	16	98.1	66.9	85.2	67.7						96.1	73.0
1995	07/31/95	12	93.9	73.9	74.8	53.2						91.9	55.9
1996	08/07/96	15	89.6	75.2	80.3	70.8					0.03	91.4	71.6
1997	07/16/97	11	89.6	68.0	76.7	68.1	76	78	74	0.01		84.2	68.0
1998	07/14/98	15	91.9	63.0	74.0	58.3	73	75	72	0.00		87.1	53.1
1999	06/10/99	13	91.0	61.0	69.5	61.0	73	73	68	0.00		82.9	60.1
2000	08/31/00	13	89.1	63.0	62.7	53.6	69	76	62	0.00		80.1	46.9
2001	08/09/01	14	98.1	69.1	83.4	68.2	73	90	80	0.46		98.1	72.0
2002	07/01/02	15	93.9	64.0	77.6	66.0	66	79	74	0.00		91.9	64.0
2003	06/25/03	14	93.9	68.0	77.0	58.6	54	79	72	0.00		89.6	68.0
2004	07/21/04	13	88.0	61.0	73.6	63.5	80	74	72	0.39		82.9	54.0
2005	08/09/05	14	91.9	59.0	74.8	58.0	67	77	72	0.00		90.0	59.0
2006	08/01/06	12	96.8	82.4	83.5	68.2	68	89	79	0.20		100.4	71.6
2007	07/31/07	14	91.4	68.0	76.1	55.9	58	78	72	0.00		91.9	61.0
2008	08/04/08	16	89.1	60.1	68.2	55.0	72	73	67	0.00		82.4	55.4

Table D-3
Long-term Historical Peak Weather Data for Traverse City Capital Airport

	Peak Temperature Day				Prior Day				
	Date	Max	Min	Diff from Max	Date	Max	Diff from Peak	Min	Diff from Max
1980	08/21/80	90.0	72.0	18.0	08/20/80	90.0	0.0	65.8	24.2
1981	07/08/81	95.0	66.9	28.1	07/07/81	95.0	0.0	61.9	33.1
1982	07/07/82	92.8	68.9	23.9	07/06/82	91.9	0.9	74.8	17.1
1983	07/14/83	95.0	64.9	30.1	07/13/83	90.0	5.0	56.8	33.2
1984	08/29/84	93.0	64.9	28.1	08/28/84	87.1	5.9	71.1	16.0
1985	07/14/85	93.0	72.0	21.0	07/13/85	90.0	3.0	55.9	34.1
1986	07/18/86	96.1	75.0	21.1	07/17/86	95.0	1.1	75.0	20.0
1987	06/25/87	97.0	63.0	34.0	06/24/87	91.0	6.0	55.0	36.0
1988	07/07/88	99.0	73.0	26.0	07/06/88	98.1	0.9	60.1	38.0
1989	08/05/89	100.0	70.0	30.0	08/04/89	91.0	9.0	73.9	17.1
1990	07/04/90	91.0	79.0	12.0	07/03/90	87.1	3.9	59.0	28.1
1991	06/27/91	97.0	78.1	18.9	06/26/91	93.0	4.0	59.0	34.0
1992	08/25/92	91.0	69.1	21.9	08/24/92	89.1	1.9	68.0	21.1
1993	07/04/93	93.9	68.0	25.9	07/03/93	82.0	11.9	64.9	17.1
1994	06/17/94	98.1	66.9	31.2	06/16/94	96.1	2.0	73.0	23.1
1995	07/14/95	98.1	79.0	19.1	07/13/95	96.1	2.0	70.0	26.1
1996	06/28/96	93.0	66.0	27.0	06/27/96	87.1	5.9	64.9	22.2
1997	06/24/97	93.2	75.2	18.0	06/23/97	91.4	1.8	59.0	32.4
1998	05/15/98	93.2	55.4	37.8	05/14/98	78.8	14.4	46.4	32.4
1999	07/30/99	93.0	62.1	30.9	07/29/99	88.0	5.0	62.1	25.9
2000	07/13/00	89.1	55.0	34.1	07/12/00	81.0	8.1	51.1	29.9
2001	08/08/01	98.1	72.0	26.1	08/07/01	95.0	3.1	72.0	23.0
2002	07/01/02	93.9	64.0	29.9	06/30/02	91.9	2.0	64.0	27.9
2003	06/25/03	93.9	68.0	25.9	06/24/03	89.6	4.3	68.0	21.6
2004	06/08/04	89.6	73.4	16.2	06/07/04	88.0	1.6	55.0	33.0
2005	06/24/05	95.0	77.0	18.0	06/23/05	89.6	5.4	57.2	32.4
2006	07/31/06	100.4	71.6	28.8	07/30/06	89.6	10.8	66.2	23.4
2007	07/08/07	96.1	72.0	24.1	07/07/07	89.1	7.0	64.0	25.1
2008	09/02/08	91.4	60.8	30.6	09/01/08	89.1	2.3	60.1	29.0