NP

2010-2029 Integrated Resource Plan
for
The Empire District Electric Company

Volume II
Load Analysis and Forecasting (4 CSR 240-22.030)

****Denotes Highly Confidential****

September 2010

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S.0 Volume II Summary

S.1 Background

Per 4 CSR 240-22, The Empire District Electric Company (Empire) is required to file an Integrated Resource Plan (IRP) in 2010. Through an order dated June 16, 2010 (EE-2010-0246), the Missouri Public Service Commission (MPSC) approved Empire's application for variance related to the filing of this IRP. The portions of the Load Analysis and Forecasting Portion of the Integrated Resource Planning Rules (4 CSR 240-22.030) (IRP Rule) for which variances were requested (and granted) related to the requirement to perform end-use forecasting and load analysis as part of the IRP filings and the starting points for data retention for use in the forecast of net system loads and system peak demand. The order also approved Empire's requests for clarifications regarding subclasses and major rate classes.

The load forecast that is required as part of the Integrated Resource Plan was accomplished by using a combination of techniques:

1) the load forecasting model *MetrixND*
2) regression analysis in a spreadsheet model
3) information about load increases for specific customers based on input from the Commercial Services Department
4) review by Senior Management
5) compilation of monthly variance reports

The load analysis techniques used and the load forecast developed from this work effort are provided in this document.

S-2 Load Forecast

The annual peak demand and energy forecast associated with the base case are shown in Figures S-1 and S-2 and Table S-1. As per the IRP Rule, implemented demand side management programs (DSM) are incorporated into the load forecast, but future DSM programs contemplated by this IRP process, which can vary by plan, are not shown in any of the load forecast data in this volume. The historical (actual) load data have not been weather normalized throughout this volume, unless noted otherwise.

The base forecast reflects an average growth rate of **____** for the annual energy and **____** for peak demand growth over the 20-year planning horizon. The base case forecast is based on average customer growth of about **_____** per year over the entire 20-year planning horizon.

Figure S-1

Annual System Peak Demand
****Highly Confidential in its Entirety****

Figure S-2

Total Annual System Energy
****Highly Confidential in its Entirety****

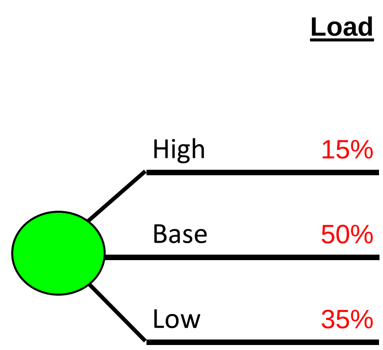
Table S-1
Base Case Forecast*

Year	Net Peak Demand (MW)	Peak Load Growth (%)	Annual Energy (MWh)	Energy Load Growth (%)	Load Factor (%)
1999	979		4,473,229		52.2
2000	993	1.4	4,794,585	7.2	55.0
2001	1,001	0.8	4,800,756	0.1	54.7
2002	987	-1.4	4,917,875	2.4	56.9
2003	1,041	5.5	4,950,161	0.7	54.3
2004	1,014	-2.6	4,972,159	0.4	55.8
2005	1,087	7.2	5,293,643	6.5	55.6
2006	1,159	6.6	5,330,214	0.7	52.5
2007	1,173	1.2	5,485,658	2.9	53.4
2008	1,153	-1.7	5,493,653	0.1	54.2
2009	1,085	-5.9	5,263,206	-4.2	55.4
2010	**_____**	**_____**	**_________**	**_____**	**__**
2011	**_____**	**_____**	**_________**	**_____**	**__**
2012	**_____**	**_____**	**_________**	**_____**	**__**
2013	**_____**	**_____**	**_________**	**_____**	**__**
2014	**_____**	**_____**	**_________**	**_____**	**__**
2015	**_____**	**_____**	**_________**	**_____**	**__**
2016	**_____**	**_____**	**_________**	**_____**	**__**
2017	**_____**	**_____**	**_________**	**_____**	**__**
2018	**_____**	**_____**	**_________**	**_____**	**__**
2019	**_____**	**_____**	**_________**	**_____**	**__**
2020	**_____**	**_____**	**_________**	**_____**	**__**
2021	**_____**	**_____**	**_________**	**_____**	**__**
2022	**_____**	**_____**	**_________**	**_____**	**__**
2023	**_____**	**_____**	**_________**	**_____**	**__**
2024	**_____**	**_____**	**_________**	**_____**	**__**
2025	**_____**	**_____**	**_________**	**_____**	**__**
2026	**_____**	**_____**	**_________**	**_____**	**__**
2027	**_____**	**_____**	**_________**	**_____**	**__**
2028	**_____**	**_____**	**_________**	**_____**	**__**
2029	**_____**	**_____**	**_________**	**_____**	**__**
*Note: Historical data not weather normalized.					

In accordance with the IRP Rule, high and low load forecasts were also prepared. The high load forecast reflects average customer growth of about **_____** per year and the low load forecast reflects average customer growth of about **______**. Since future load growth is one of the critical uncertain factors in this IRP, the following probabilities were assumed for each level of the load forecast: low – 35%, base – 50%, and high –

15%, as also shown on the branches of the critical uncertain factors decision tree in Figure S-3.

Figure S-3
Load Portion of the Critical Uncertain Factors Decision Tree



S.3 Load Forecast Methodology

Regression analysis techniques were used to determine weather-normalized peak demands and energies for Empire's historical load. The load impacts of implemented demand-side management (DSM) programs are incorporated in the base load forecast as the Rule requires.

Empire used the load forecasting computer model *MetrixND* to perform portions of the load forecasting effort. In addition, annual peak demand and net system energy were forecast using linear regression analysis employing a least-squares method to determine the best fit line through a set of observations. The analysis considered revenue class data, historical weather, customer count, trend variables, and relevant input from the Commercial Services Department. The Commercial class was disaggregrated into smaller subclasses to incorporate the knowledge about customers held by Empire pertaining to growth tendencies and future expansion plans. In addition, like Commercial subclasses were forecasted together and then aggregated back into the Commercial class level forecast.

The annotated summary provided in the Introduction (Section 1.0) of this report demonstrates Empire's compliance with the Load Analysis and Forecasting Rules from 4 CSR 240-22.030.

1.0 Introduction

1.1 Background

The Empire District Electric Company (Empire) is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. Empire's service territory includes an area of about 10,000 square miles with a population of over 450,000. The service territory is located principally in southwestern Missouri and also includes smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. The principal activities of these areas include light industry, agriculture and tourism.

Empire's total 2009 retail electric revenues were derived approximately 89.1% from Missouri customers, 5.1% from Kansas customers, 3.0% from Oklahoma customers and 2.8% from Arkansas customers. Empire supplies electric service at retail to 120 incorporated communities and to various unincorporated areas and at wholesale to four municipally owned distribution systems. The largest urban area served is the city of Joplin, Missouri, and its immediate vicinity, with a population of approximately 157,000. Empire's system hit a new maximum hourly demand of 1,199 MW on January 8, 2010. The previous maximum demand of 1,173 MW was set on August 15, 2007. Empire's 2009 native customer load was 5,263,206 MWh (net system input or NSI). Empire's electric operating revenues in 2009 were derived as follows: residential 41.6%, commercial 31.4%, industrial 15.2%, wholesale on-system 4.2%, wholesale off-system 3.3% and other 4.3%.

1.2 Regulatory Requirements

Per 4 CSR 240-22, The Empire District Electric Company (Empire) is required to file an Electric Resource Plan in 2010.

1.3 Annotated Summary

4 CSR 240-22.030 (8) describes the reporting requirements for the load analysis and forecasting effort undertaken as part of an integrated resource plan. 4 CSR 240-22.030 (8) (H) requires the inclusion of an annotated summary that shows how the methods used to develop all forecasts required by the Electric Utility Resource Planning Rule comply with the specific provisions of those rules. The annotated summary tables that follow demonstrate Empire's compliance with the provisions of the rules and denote those sections of the rules for which Empire was granted a variance or for which Empire requested and received clarification.

4 CSR 240-22.030 Load Analysis and Forecasting

PURPOSE: This rule sets minimum standards for the maintenance and updating of historical data, the level of detail required in analyzing and forecasting loads, and for the documentation of the inputs, components and methods used to derive the load forecasts.

(1) Historical Data Base. The utility shall develop and maintain data on the actual historical patterns of energy usage within its service territory. The following information shall be maintained and updated on an ongoing basis:

(A) Customer Class Detail. The historical data base shall be maintained for each of the following major classes: residential, commercial, industrial, interruptible and other classes that may be required for forecasting (for example, large power, wholesale, outdoor lighting and public authorities).

1. Taking into account the requirement for an unbiased forecast as well as the cost of developing data at the subclass level, the utility shall determine what level of subclass detail is required for forecasting and what methods to use in gathering subclass information for each major class. [CLARIFICATION PROVIDED]
2. The utility shall consider the following categories of subclasses: for residential, dwelling type; for commercial, building or business type; and for industrial, product type. If the utility uses subclasses which do not fit into these categories, it must explain the reasons for its choice of subclasses; [CLARIFICATION PROVIDED]

Table 1-1
Clarification– Forecasting with Subclasses

Applies to: **4 CSR 240-22.030 (1) (A) 1** **4 CSR 240-22.030 (1) (A) 2** **4 CSR 240-22.030 (2) (C)**
The existing IRP Rule states that the utility shall *consider* the use of subclasses when forecasting, but does not appear to require the utility to use subclasses. As such, Empire will forecast at the subclass level for certain sectors within the Commercial class and will consider subclasses within the Industrial class as a possible source of trending binaries. However, Empire will not consider subclass level data for the Residential class.

(B) Load Data Detail. The historical load data base shall contain the following data:

1. For each jurisdiction under which the utility has rates established and for which it prepares customer and energy forecasts, each major class, and to the extent data is required to support the detail specified in paragraph (1)(A)1., for each subclass, actual monthly energy usage and number of customers and weather-normalized monthly energy usage;
2. For each major class, estimated actual and weather-normalized demands at the time of monthly system peaks; and
3. For the system, actual and weather-normalized hourly net system load;

(C) Load Component Detail. The historical data base for major class monthly energy usage and demands at time of monthly peaks shall be disaggregated into a number of units component and a use kilowatt-hour (kWh) per unit component, for both actual and weather-normalized loads.

1. Typical units for the major classes are—residential, number of customers; commercial, square feet of floor space or commercial employment level; and industrial, production output or employment level. If the utility uses a different unit measure, it must explain the reason for choosing different units.
2. The utility shall develop and implement a procedure to routinely measure and regularly update estimates of the effect of departures from normal weather on class and system electric loads.
   A. The estimates of the effect of weather on class and system loads shall incorporate the nonlinear response of loads to daily weather and seasonal variations in loads.
   B. For at least the base year of the forecast, the utility shall estimate the cooling, heating and non-weather-sensitive components of the weather-normalized major class loads.
   C. The utility shall document the methods used to develop weather measures and the methods used to estimate the effect of weather on electric loads. If statistical models are used, the documentation shall include at least: the functional form of the models; the estimation techniques employed; the data used to estimate the models, including the development of model input data from basic data; and the relevant statistical results of the models, including parameter estimates and tests of statistical significance; and

(D) Length of Data Base. Once the utility has developed the historical data base, it shall retain that data base for the ten (10) most recent years or for the period of time used as the basis of the utility's forecast, whichever is longer.

1. The development of actual and weather- normalized monthly class and system energy usage and actual hourly net system loads shall start from January 1982 or for the period of time used as the basis of the utility's forecast of these loads, whichever is longer. [VARIANCE GRANTED]
2. Estimated actual and weather-normalized class and system monthly demands at the time of the system peak and weather-normalized hourly system loads shall start from January 1990 or for the period of time used as the basis of the utility's forecast of these loads, whichever is longer. [VARIANCE GRANTED]

Table 1-2
Variance Granted – Starting Point of the Data Base

Applies to: **4 CSR 240-22.030 (1) (D) 1** **4 CSR 240-22.030 (1) (D) 2**
Justification: Some of the historical load information by class that is required by the rule is not available. The existing IRP Rule states that the forecasting data base shall have net system loads starting from January 1982 and system peak data from January 1990. Since these dates were written into the rule when the rule was published in the mid-1990s, Empire has interpreted this to be a requirement of approximately ten years of historical data base information.
Proposed Alternative for the 2010 IRP Filing: Empire will use ten years of historical data in the forecast of both energy and demand in the upcoming IRP. The starting point of this information is the month of January 1999.

(2) Analysis of Number of Units. For each major class or subclass, the utility shall analyze the historical relationship between the number of units and the economic or demographic factors (driver variables) that affect the number of units for that major class or subclass. These relationships shall be specified as statistical or mathematical models that relate the number of units to the driver variables.

(A) Choice of Driver Variables. The utility shall identify appropriate driver variables as predictors of the number of units for each major class or subclass. The critical assumptions that influence the driver variables shall also be identified.

(B) Documentation of statistical models shall include the elements specified in subparagraph (1)(C)2.C. Documentation of mathematical models shall include a specification of the functional form of the equations.

(C) Where the utility has modeled the relationship between the number of units and the driver variables for a major class, but not for subclasses within that major class, it shall consider how a change in the subclass shares of major class units could affect the major class forecast. [CLARIFICATION PROVIDED]

(3) Analysis of Use Per Unit. For each major class, the utility shall analyze historical use per unit by end use. [VARIANCE GRANTED]

(A) End-Use Detail. For each major class, use per unit shall be disaggregated by end use where information permits. [VARIANCE GRANTED]

1. Where applicable for each major class, end-use information shall be developed for at least lighting, process equipment, space cooling, space heating, water heating and refrigeration. [VARIANCE GRANTED]
2. For each major class and each end use, including those listed in paragraph (3)(A)1., if information is not available, the utility shall provide a schedule for acquiring this end-use information or demonstrate that either the expected costs of acquisition were found to outweigh the expected benefits over the planning horizon or that gathering the end-use information has proven to be infeasible. [VARIANCE GRANTED]
3. If the utility has not yet acquired end-use information on space cooling or space heating for a major class, the utility shall determine the effect that weather has on the total load of that major class by disaggregating the load into its cooling, heating and non-weather- sensitive components. If the cooling

or heating components are a significant portion of the total load of the major class, then the cooling or heating components of that load shall be designated as end uses for that major class. [VARIANCE GRANTED]

4. The difference between the total load of a major class and all end uses for which the utility has acquired end-use information shall be designated as an end use for that major class. [VARIANCE GRANTED]

(B) The data base and historical analysis required for each end use shall include at least the following: [VARIANCE GRANTED]

1. Measures of the stock of energy-using capital goods. For each major class and end use, the utility shall implement a procedure to develop and maintain survey data on the energy- related characteristics of the building, appliance and equipment stock including saturation levels, efficiency levels and sizes where applicable. The utility shall update these surveys before each scheduled filing pursuant to 4 CSR 240-22.080; and [VARIANCE GRANTED]
2. Estimates of end-use energy and demand. For each end use, the utility shall estimate end-use monthly energies and demands at time of monthly system peaks and shall calibrate these energies and demands to equal the weather-normalized monthly energies and demands at time of monthly peaks for each major class for the most recently available data. [VARIANCE GRANTED]

(4) Analysis of Load Profiles. The utility shall develop a consistent set of daily load profiles for the most recent year for which data is available. For each month, load profiles shall be developed for a peak weekday, a representative of at least one (1) weekday and a representative of at least one (1) weekend day.

(A) Load profiles for each day type shall be developed for each end use, for each major class and for the net system load. [VARIANCE GRANTED]

(B) For each day type, the estimated end-use load profiles shall be calibrated to sum to the estimated major class load profiles and the estimated major class load profiles shall be calibrated to sum to the net system load profiles. [VARIANCE GRANTED]

Table 1-3
Variance Granted – End-Use Forecasting Methodology and End-Use Load Analysis

Applies to:	**4 CSR 240-22.030 (4) (A)**
4 CSR 240-22.030 (3)	**4 CSR 240-22.030 (4) (B)**
4 CSR 240-22.030 (3) (A)	**4 CSR 240-22.030 (5) (B) 2**
4 CSR 240-22.030 (3) (A) 1	**4 CSR 240-22.030 (5) (B) 2 B**
4 CSR 240-22.030 (3) (A) 3	**4 CSR 240-22.030 (5) (B) 2 C**
4 CSR 240-22.030 (3) (A) 4	**4 CSR 240-22.030 (8) (A) 2 B**
4 CSR 240-22.030 (3) (B)	**4 CSR 240-22.030 (8) (B) 2**
4 CSR 240-22.030 (3) (B) 1	**4 CSR 240-22.030 (8) (E) 1**
4 CSR 240-22.030 (3) (B) 2	

Table 1-3 (continued)
Variance Granted – End-Use Forecasting Methodology and End-Use Load Analysis

Justification

Empire is requesting a variance from the requirement to perform end-use forecasting and load analysis as part of its upcoming IRP filing. Empire does not have the data or access to the models required to perform the end-use forecasts required in the existing rule, and it is not feasible from a cost or time standpoint for Empire to attempt to change its forecasting approach to the End-Use method contemplated in the Missouri IRP rule. Empire has researched the requirements of developing an end-use forecast. There are a number of reasons why a variance from end-use forecasting should be granted:

- **Software-**It appears that the necessary end-use modeling tools are no longer available. In the past, The Electric Power Research Institute (EPRI) models were widely utilized to aid those utilities that had access to survey results in building appropriate end-use forecasting models. Since utility specific end-use forecasting has not been widely practiced in the electric industry since the late 1990s, EPRI no longer offers its Residential End-Use Energy Planning (REEPS) software.
- **Saturation Surveys**-The customer saturation surveys that are needed to perform end-use forecasting are expensive. The survey itself can range from $50,000 to $100,000. In addition to the cost of the survey itself, the required analysis of the survey itself by experienced consultants creates an additional cost of $30,000 to $50,000. Including more details in the survey such as home square footage, number of windows and types of insulation can double these cost estimates.
- **Time-**The customer surveys are also labor intensive and time consuming to create, approve, distribute, allow for response time and analyze. Typically the survey results are analyzed by outside consultants. Selecting an outside consultant creates an additional time requirement. The time required to prepare and analyze customer surveys is not available to Empire for the upcoming IRP filing due in September 2010.

Proposed Alternative for the 2010 IRP Filing:

Empire will produce class level load forecasts by season using regression analysis at the customer class level using customer, weather, energy usage and trend variables when applicable. In addition, certain industries/companies from the Commercial class will be disaggregated and forecast individually. This method will serve to generate a more accurate forecast by employing intimate knowledge that includes historical consumption trends as well as current and future expansion plans. This method of load forecasting will be used for the upcoming IRP instead of a forecast developed from the sum of energy consumption in end uses such as space heating, air conditioning, etc. that are combined with appliance saturation levels, socio-economic data, and efficiency trend quantifications to reach an "end-use" energy demand. Empire's forecasting models will be fully explained in the IRP report.

After the completion of the September 2010 IRP, Empire has agreed to provide the Missouri Public Service Commission Staff with a plan that addresses the feasibility of changing the Company's forecasting method for the IRP filing that will follow the September 2010 filing. This plan will include a proposed time line and cost estimate that can be used for further discussions. The plan will consider the use of economic variables; forecasting at the class cost of service level; and the requirements in the Load Analysis and Forecasting rule that will be in place at the time of the IRP filing that is subsequent to the September 2010 filing.

(5) Base-Case Load Forecast. The utility's base-case load forecast shall be based on projections of the major economic and demographic driver variables that utility

decision-makers believe to be most likely. All components of the base-case forecast shall be based on the assumption of normal weather conditions. The load impacts of implemented demand-side programs shall be incorporated in the base-case load forecast but the load impacts of proposed demand-side programs shall not be included in the base-case forecast.

(A) Customer Class and Total Load Detail. The utility shall produce forecasts of monthly energy usage and demands at the time of the summer and winter system peaks by major class for each year of the planning horizon. Where the utility anticipates that jurisdictional levels of forecasts will be required to meet the requirements of a specific state, then the utility shall determine a procedure by which the major class forecasts can be separated by jurisdictional component.

(B) Load Component Detail. For each major class, the utility shall produce separate forecasts of the number of units and use per unit components based on the analysis described in sections (2) and (3) of this rule.

1. Number of units forecast. The utility's forecast of number of units for each major class shall be based on the analysis of the relationship between number of units and driver variables described in section (2). Where judgment has been applied to modify the results of a statistical or mathematical model, the utility shall specify the factors which caused the modification and shall explain how those factors were quantified.
   A. The forecasts of the driver variables shall be specified and clearly documented. These forecasts shall be compared to historical trends and significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.
   B. The forecasts of the number of units for each major class shall be compared to historical trends. Significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.
2. Use per unit forecast. The utility's forecast of monthly energy usage per unit and seasonal peak demands per unit for each major class shall be based on the analysis described in section (3). [VARIANCE GRANTED]
   A. The forecasts of the driver variables for the use per unit shall be specified. The utility shall document how the forecast of use per unit has taken into account the effects of real prices of electricity, real prices of competitive energy sources, real incomes and any other relevant economic and demographic factors.
   B. End-use detail. For each major class and for each end use, the utility shall forecast both monthly energy use and demands at time of the summer and winter system peaks. [VARIANCE GRANTED]
   C. The stock of energy-using capital goods. For each end use for which the utility has developed measures of the stock of energy-using capital goods and where the utility has determined that forecasting the use of electricity associated with these energy-using capital goods is cost-effective and feasible, it shall forecast those measures and document the relationship between the forecasts of the measures to the forecasts of end-use energy and demands at time of the summer and winter system peaks. The values of the driver variables used to generate forecasts of the measures of the

stock of energy-using capital goods shall be specified and clearly documented. [VARIANCE GRANTED]

D. The major class forecasted use per unit shall be compared to historical trends in weather-normalized use per unit. Significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.

(C) Net System Load Forecast. The utility shall produce a forecast of net system load profiles for each year of the planning horizon. The net system load forecast shall be consistent with the utility's forecasts of monthly energy and demands at time of summer and winter system peaks for the major rate classes. [CLARIFICATION PROVIDED]

Table 1-4
Clarification – Forecasting with Major Rate Classes

Applies to: **4 CSR 240-22.030 (5) (C)**
Notes Empire is employing forecasting techniques that mirror the existing internal budgeting process that ensures a more efficient forecasting process and enables the use of human capital to help drive some key assumptions and variables within the forecast. The major rate classes that Empire will utilize in the IRP process include the Residential, Commercial, and Industrial classes.

(6) Sensitivity Analysis. The utility shall analyze the sensitivity of the components of the base-case forecast for each major class to variations in the key driver variables, including the real price of electricity, the real price of competing fuels and economic and demographic factors identified in section (2) and subparagraph (5)(B)2.A.

(7) High-Case and Low-Case Load Forecasts. Based on the sensitivity analysis described in section (6), the utility shall produce at least two (2) additional load forecasts (a high-growth case and a low-growth case) that bracket the base-case load forecast. Subjective probabilities shall be assigned to each of the load forecast cases. These forecasts and associated subjective probabilities shall be used as inputs to the strategic risk analysis required by 4 CSR 240-22.070.

(8) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall prepare a report that contains at least the following information:

(A) For each major class specified in subsection(1)(A), the utility shall provide plots of number of units, energy usage per unit and total class energy usage.

1. Plots shall be produced for the summer period (June through September), the remaining non-summer months and the calendar year.
2. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years.
   A. The historical period shall include both actual and weather-normalized energy usage per unit and total class energy usage.
   B. The plots for the forecast period shall show each end-use component of major class energy usage per unit and total class energy usage for the base-case forecast. [VARIANCE GRANTED]

(B) For each major class specified in subsection (1)(A), the utility shall provide plots of class demand per unit and class total demand at time of summer and winter system peak. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years.

1. The plots for the historical period shall include both actual and weather-normalized class demands per unit and total demands at the time of summer and winter system peak demands.
2. The plots for the forecast period shall show each end-use component of major class coincident demands per unit and total class coincident demands for the base-case forecast. [VARIANCE GRANTED]

(C) For the forecast of class energy and peak demands, the utility shall provide a summary of the sensitivity analysis required by section (6) of this rule that shows how changes in the driver variables affect the forecast.

(D) For the net system load, the utility shall provide plots of energy usage and peak demand.

1. The energy plots shall include the summer, non-summer and total energy usage for each calendar year.
2. The peak demand plots shall include the summer and winter peak demands.
3. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years. The historical period shall include both actual and weather-normalized values. The forecast period shall include the base-case, low-case and high-case forecasts.
4. The utility shall describe how the subjective probabilities assigned to each forecast were determined.

(E) For each major class, the utility shall provide estimated load profile plots for the summer and winter system peak days.

1. The plots shall show each end-use component of the hourly load profile. [VARIANCE GRANTED]
2. The plots shall be provided for the base year of the load forecast and for the fifth, tenth and twentieth years of the forecast.

(F) For the net system load profiles, the utility shall provide plots for the summer peak day and the winter peak day.

1. The plots shall show each of the major class components of the net system load profile in a cumulative manner.
2. The plots shall be provided for the base year of the forecast and for the fifth, tenth and twentieth years of the forecast.

(G) The data presented in all plots also shall be provided in tabular form.

(H) The utility shall provide a description of the methods used to develop all forecasts required by this rule, including an annotated summary that shows how these methods comply with the specific provisions of this rule. If end-use methods have not been used in forecasting, an explanation as to why they have not been used shall be included. Also included shall be the utility's schedule to acquire end-use information and to develop end-use forecasting techniques or a discussion as to why the acquisition of end-use information and the development of end-use forecasting techniques are either impractical or not cost effective.

Table 1-5 shows where in this Volume II of the IRP report the Reporting Requirements of 4 CSR 240-22.030 (8), the IRP Rules for Load Analysis and Forecasting, has been addressed. Table 1-6 shows where in this Volume II of the IRP report a specific portion of 4 CSR 240-22.030, the IRP Rules for Load Analysis and Forecasting, has been addressed.

Table 1-5
Summary of Reporting Requirement Compliance with IRP Rule for Load Analysis and Forecasting (4 CSR 240-22.030 (8))

Rule	Description	Location in Report
22.030 (8) (A)	Plot specifications	Section 4.0, Figures 4-5, 4-6, 4-7 Section 5.0, Figures 5-3, 5-4, 5-5 Section 6.0, Figures 6-3, 6-4 Appendix B Variance granted for (8) (A) 2 B
22.030 (8) (B)	Plots for summer and winter peak	Appendix B Variance granted for (8) (B) 2
22.030 (8) (C)	Sensitivity analysis summary	Sections 4.0, 5.0, 6.0, 7.0, 8.0
22.030 (8) (D)	Net system load plot specifications	Figures 2-1, 2-2, 2-11, 2-12, B-1, B-2, B-3 Section 2.2
22.030 (8) (E)	Load profile plots – summer & winter peaks	Sections 4.0 – 8.0 Variance granted for (8) (E) 1
22.030 (8) (F)	Net system load – peak days	Figures 2-3 – 2-10
22.030 (8) (G)	Tables to accompany plots	Tables 2-1 – 2-14, Tables 4-1, 5-1, 6-1, 7-1, 8-1 Appendix C
22.030 (8) (H)	Annotated summary	Table 1-2 and Table 1-3

Table 1-6
Annotated Summary of Compliance with IRP Rule for Load Analysis and Forecasting
(4 CSR 240-22.030)

Rule	Description	Location in Report
22.030 (1) (A)	Historical data base – customer class detail	Appendix C
22.030 (1) (A) (1)	Historical data base - determination of subclasses	Appendix C Clarification provided
22.030 (1) (A) (2)	Historical data base – consideration of subclasses	Appendix C Clarification provided
22.030 (1) (B)	Load data detail	Appendix C
22.030 (1) (B) (1)	Data by class and subclass	Appendix C
22.030 (1) (B) (2)	By class, actual and weather-normalized monthly peaks	Appendix C
22.030 (1) (B) (3)	System, actual and weather-normalized hourly net system load	Maintained by Regulatory and Planning – Available to MPSC staff via EFIS on request.

Table 1-6 (continued)
Annotated Summary of Compliance with IRP Rule for Load Analysis and Forecasting
(4 CSR 240-22.030)

22.030 (1) (C)	Load component detail	Maintained by Regulatory and Planning
22.030 (1) (C) (1)	Determination of typical units by class	Maintained by Regulatory and Planning
22.030 (1) (C) (2)	Procedure for measuring and estimating effects of departure from normal weather on system loads	Maintained by Regulatory and Planning
22.030 (1) (C) (2) (A)	Incorporation of nonlinear response of loads to weather and seasonal variations	Maintained by Regulatory and Planning
22.030 (1) (C) (2) (B)	Estimation of cooling, heating and nonweather-sensitive components of the weather-normalized major class loads	Maintained by Regulatory and Planning
22.030 (1) (C) (2) (C)	Documentation of weather measures	Maintained by Regulatory and Planning
22.030 (1) (C) (2) (D)	Length of data base	Appendix C
22.030 (1) (C) (2) (D) (1)	Start from January 1982	Variance granted
22.030 (1) (C) (2) (D) (2)	Actual and weather-normalized class and system monthly demands from January 1990	Variance granted
22.030 (2)	Analysis of number of units	Sections 4.0-8.0
22.030 (2) (A)	Choice of driver variables	Sections 4.0-8.0
22.030 (2) (B)	Documentation of statistical models	Sections 4.0-8.0
22.030 (2) (C)	Modeling issue	Sections 4.0-8.0 Clarification provided
22.030 (3)	Analysis of use per unit	Variance granted
22.030 (3) (A)	End-use detail	Variance granted
22.030 (3) (A) (1)	Major class end-use	Variance granted
22.030 (3) (A) (2)	Schedule for acquiring information	Variance granted
22.030 (3) (A) (3)	Weather impacts on class	Variance granted
22.030 (3) (A) (4)	End use issues for major class	Variance granted
22.030 (3) (B)	End-use data base	Variance granted
22.030 (3)(B) (1)	Measures for stock of energy-using capital goods	Variance granted
22.030 (3) (B) (2)	Estimates of end-use energy and demand	Variance granted
22.030 (4)	Analysis of load profiles	Maintained by Regulatory and Planning
22.030 (4) (A)	Load profile for each day type for each end use	Variance granted
22.030 (4) (B)	Calibration of end use profiles	Variance granted

Table 1-6 (continued)
Annotated Summary of Compliance with IRP Rule for Load Analysis and Forecasting
(4 CSR 240-22.030)

22.030 (5)	Base Case Load Forecast	Sections 4.0-8.0
22.030 (5) (A)	Customer class and total load detail	Sections 4.0-8.0
22.030 (5) (B)	Load component detail	Sections 4.0-8.0
22.030 (5) (B) (1)	Number of units forecast	Sections 4.0-8.0
22.030 (5) (B) (1) (A)	Driver variables	Sections 4.0-8.0
22.030 (5) (B) (1) (B)	Number of units	Sections 4.0-8.0
22.030 (5) (B) (2)	Use per unit forecast	Variance granted
22.030 (5) (B) (2) (A)	Documentation	Sections 4.0-8.0
22.030 (5) (B) (2) (B)	End-use detail	Variance granted
22.030 (5) (B) (2) (C)	Stock of energy-using capital goods	Variance granted
22.030 (5) (B) (2) (D)	Comparison with historical trends	Maintained by Regulatory and Planning
22.030 (5) (C)	Net system load forecast	Section 2.0 Clarification provided
22.030 (6)	Sensitivity analysis of components of base case forecast	Sections 4.0-8.0
22.030 (7)	High case and low case load forecasts	Section 2.2

1.3.1 Variance Request

Through an order dated June 16, 2010 in case No. EE-2010-0246, the MPSC approved Empire's application for variance related to the filing of this IRP. The portions of the Load Analysis and Forecasting portion of the Integrated Resource Planning Rules (4 CSR 240-22.030) for which variances were requested (and granted) related to the requirement to perform end-use forecasting and load analysis as part of the IRP filings and the starting points for data retention for use in the forecast of net system loads and system peak demand. The order also approved Empire's requests for clarifications regarding subclasses and major rate classes. The portions of the rule for which variances were granted and clarifications provided are documented in Tables 1-5 and 1-6 and in the writeup of Section 1.3.

The order provided, subject to a condition agreed upon by Empire and The Missouri Department of Natural Resources (MDNR), that:

The Empire District Electric Company agrees to provide full disclosure of its IRP load forecasting methodology, to include a description of all assumptions, equations and the rationale for any decisions made concerning any adjustments made to the data used to develop the forecast. As one aspect of this disclosure, The Empire District Electric Company will describe any assumptions concerning future economic conditions that influence or were incorporated into the company's specification or assignment of values to variables, coefficients or relationships in the equations used to forecast load over the 20-year planning horizon. The Empire District Electric Company will provide all work *papers supporting the IRP load forecast when it is completed. In addition, The Empire District Electric Company's IRP load forecast work papers will be provided to The Missouri Department of Natural Resources in an electronic format.*

In compliance with this requirement, prior to the filing of the IRP in September 2010, Empire provided MDNR with the load forecasting methodology, once it was completed, in an electronic format.

1.3.2 Follow up to the 2007 IRP Unanimous Stipulation and Agreement (dated May 6, 2008)

In the 2007 IRP Unanimous Stipulation and Agreement, Empire agreed to undertake the following task related to load analysis and forecasting prior to or as a part of its next IRP filing:

- Include a summary of the economic outlook of Empire's service territory that includes conditions that encourage and impede growth and how the economic drivers that Empire has selected for each of its models capture these conditions. The economic driver descriptions will include 1) graphs and/or tables of historical and forecasted data; 2) the statistical rationale for selecting the economic variables used in the regression analysis; and 3) a discussion of the effect of using the economic indicator in the model.

The order (June 2010 in EE-2010-0246) provided, subject to a condition agreed upon by Empire and MPSC Staff, that:

After the completion of the September 2010 IRP, Empire has agreed to provide the Missouri Public Service Commission Staff with a plan that addresses the feasibility of changing the Company's forecasting method for the IRP filing that will follow the September 2010 filing. This plan will include a proposed time line and cost estimate that can be used for further discussions. The plan will consider the use of economic variables; forecasting at the class cost of service level; and the requirements in the Load Analysis and Forecasting rule that will be in place at the time of the IRP filing that is subsequent to the September 2010 filing.

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2.0 Load Forecast Results

2.1 Base Case

The annual peak demand and energy forecast associated with the base case are shown in Figures 2-1 and 2-2 and Table 2-1. Historical (actual) load data are not weather normalized throughout this volume, unless noted otherwise. This forecast reflects an average growth rate of **_____** for the annual energy and **____** for peak demand growth over the 20-year planning horizon. Figure 2-3 shows regression statistics from spreadsheet modeling conducted during the course of developing the peak load forecast.

Figure 2-1

Annual System Peak Demand
****Highly Confidential in its Entirety****

Figure 2-2

Total Annual System Energy
Highly Confidential in its Entirety

Figure 2-3
Regression Analysis Results – Peak Load Forecast

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.995945542
R Square	0.991907523
Adjusted R Square	0.991008359
Standard Error	16.77596816
Observations	21

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	620922.5226	310461.261	1103.14406	1.48845E-19
Residual	18	5065.795939	281.433108		
Total	20	625988.3185			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-1124.152697	114.4156241	-9.82516772	1.1708E-08	-1364.531003	-883.7743908	-1364.531003	-883.7743908	-1503.026067	-868.1906219
CUSTOMERS	0.009501683	0.000232767	40.8206167	3.3884E-19	0.009012658	0.009990708	0.009012658	0.009990708	0.009017954	0.010302147
3DWTHI	8.248751914	1.476240179	5.58767607	2.6506E-05	5.147286391	11.35021744	5.147286391	11.35021744	4.913403386	12.56703735

Table 2-1
Base Case Forecast*

Year	Net Peak Demand (MW)	Peak Load Growth (%)	Annual Energy (MWh)	Energy Load Growth (%)	Load Factor (%)
1999	979		4,473,229		52.2
2000	993	1.4	4,794,585	7.2	55.0
2001	1,001	0.8	4,800,756	0.1	54.7
2002	987	-1.4	4,917,875	2.4	56.9
2003	1,041	5.5	4,950,161	0.7	54.3
2004	1,014	-2.6	4,972,159	0.4	55.8
2005	1,087	7.2	5,293,643	6.5	55.6
2006	1,159	6.6	5,330,214	0.7	52.5
2007	1,173	1.2	5,485,658	2.9	53.4
2008	1,153	-1.7	5,493,653	0.1	54.2
2009	1,085	-5.9	5,263,206	-4.2	55.4
2010	**____**	**__**	**________**	**__**	**__**
2011	**____**	**__**	**________**	**__**	**__**
2012	**____**	**__**	**________**	**__**	**__**
2013	**____**	**__**	**________**	**__**	**__**
2014	**____**	**__**	**________**	**__**	**__**
2015	**____**	**__**	**________**	**__**	**__**
2016	**____**	**__**	**________**	**__**	**__**
2017	**____**	**__**	**________**	**__**	**__**
2018	**____**	**__**	**________**	**__**	**__**
2019	**____**	**__**	**________**	**__**	**__**
2020	**____**	**__**	**________**	**__**	**__**
2021	**____**	**__**	**________**	**__**	**__**
2022	**____**	**__**	**________**	**__**	**__**
2023	**____**	**__**	**________**	**__**	**__**
2024	**____**	**__**	**________**	**__**	**__**
2025	**____**	**__**	**________**	**__**	**__**
2026	**____**	**__**	**________**	**__**	**__**
2027	**____**	**__**	**________**	**__**	**__**
2028	**____**	**__**	**________**	**__**	**__**
2029	**____**	**__**	**________**	**__**	**__**
*Historical data not weather normalized.					

A comparison of historical and forecast energy consumption by revenue class is provided on Table 2-2. No historical peak demand by rate or revenue class has been provided as such values would only be estimates based on energy allocations, and cannot be calculated or determined directly. Figure 2-4 shows regression statistics from spreadsheet modeling conducted during the course of developing the residential revenue class forecast shown in Table 2-2. Figure 2-5 shows regression statistics from

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spreadsheet modeling conducted the course of developing the commercial revenue class forecast shown in Table 2-2.

Table 2-2
Revenue Class Energy Usage – Historical and Forecast (MWh)*

Year	Residential	Commercial	Industrial	Other Retail	On-System Wholesale	Total Sales
2000	1,664,719	1,333,095	1,009,284	97,698	309,633	4,414,429
2001	1,681,085	1,375,620	1,004,899	101,784	322,336	4,485,724
2002	1,726,449	1,378,165	1,027,446	102,803	323,103	4,557,968
2003	1,728,315	1,386,807	1,058,730	103,899	308,574	4,586,324
2004	1,703,858	1,417,307	1,085,380	108,059	305,711	4,620,314
2005	1,881,441	1,485,034	1,106,700	112,919	328,803	4,914,897
2006	1,898,846	1,547,077	1,145,490	112,727	337,658	5,041,798
2007	1,930,493	1,610,814	1,110,328	116,751	342,347	5,110,733
2008	1,952,869	1,622,048	1,073,250	123,809	344,525	5,116,502
2009	1,866,473	1,579,832	992,165	123,410	332,061	4,893,941
2010	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2011	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2012	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2013	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2014	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2015	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2016	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2017	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2018	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2019	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2020	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2021	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2022	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2023	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2024	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2025	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2026	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2027	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2028	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
2029	**_______**	**_______**	**_______**	**_______**	**_______**	**_______**
*Historical data not weather normalized.						

Figure 2-4
Regression Analysis Results – Residential Class Energy Forecast

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.976991432
R Square	0.954512259
Adjusted R Square	0.946601347
Standard Error	8834681.25
Observations	109

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	16	1.5068E+17	9.41752E+15	120.6576835	2.05412E-54
Residual	92	7.18075E+15	7.80516E+13		
Total	108	1.57861E+17			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-133495858.9	22346301.39	-5.973957683	4.32302E-08	-177877541.3	-89114176.45	-177877541.3	-89114176.45
HDD	97401.79856	10989.63249	8.863062406	5.63072E-14	75575.44034	119228.1568	75575.44034	119228.1568
CDD	170568.3093	19200.29977	8.883627405	5.09732E-14	132434.8575	208701.761	132434.8575	208701.761
Cust	1688.66022	168.4514203	10.02461254	2.02787E-16	1354.101167	2023.219274	1354.101167	2023.219274
Jan	24211209.15	8776422.855	2.75866484	0.007002007	6780476.206	41641942.1	6780476.206	41641942.1
Feb	2367670.322	7299129.227	0.324377093	0.746388927	-12129030.03	16864370.68	-12129030.03	16864370.68
Mar	6640265.963	5151477.326	1.289002269	0.200628991	-3591012.434	16871544.36	-3591012.434	16871544.36
May	-15319358.68	5244764.96	-2.920885644	0.004390127	-25735914.36	-4902802.993	-25735914.36	-4902802.993
Jun	-224502.2509	7419621.129	-0.030257913	0.975926905	-14960509.92	14511505.42	-14960509.92	14511505.42
Jul	18002172.47	9979583.954	1.803900098	0.07451974	-1818142.22	37822487.16	-1818142.22	37822487.16
Aug	21230210.88	10353082.52	2.050617374	0.043148836	668095.8295	41792325.94	668095.8295	41792325.94
Sep	12711617.19	6254997.71	2.032233709	0.045013258	288652.1126	25134582.27	288652.1126	25134582.27
Oct	-11885217.25	4201626.784	-2.828717984	0.00573631	-20230010.52	-3540423.972	-20230010.52	-3540423.972
Nov	-13259584.36	5157805.658	-2.570780141	0.011751838	-23503431.37	-3015737.349	-23503431.37	-3015737.349
Dec	16519930.63	8231845.372	2.00683199	0.047702745	170775.5454	32869085.72	170775.5454	32869085.72
Trend	-14267150.82	3767735.619	-3.786664529	0.000271983	-21750198.81	-6784102.834	-21750198.81	-6784102.834
Ice Storm	-13870284.44	6758025.95	-2.05241657	0.042969981	-27292307	-448261.8741	-27292307	-448261.8741

Figure 2-5
Regression Analysis Results – Commercial Class Energy Forecast

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.920620151
R Square	0.847541463
Adjusted R Square	0.794180975
Standard Error	314.6164733
Observations	55

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	14	22010611.76	1572186.554	15.88331543	4.13831E-12
Residual	40	3959341.01	98983.52524		
Total	54	25969952.77			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	3530.445438	217.6640078	16.21970243	3.44716E-19	3090.530072	3970.360803	3090.530072	3970.360803	3986.391495	4552.863722
Jan	-981.7614541	412.4924223	-2.38007149	0.022164748	-1815.439729	-148.0831793	-1815.439729	-148.0831793	0.355750737	1.270253032
Feb	-1121.882553	330.9486096	-3.389899582	0.001583688	-1790.754637	-453.0104698	-1790.754637	-453.0104698	3.372037593	5.183233464
Mar	-433.7932693	231.2342456	-1.875990592	0.067967346	-901.1351077	33.54856905	-901.1351077	33.54856905	-506.8217005	319.2548036
May	842.47869	251.5988176	3.348500196	0.001779717	333.9785166	1350.978863	333.9785166	1350.978863		
Jun	1264.710982	382.6488031	3.305148145	0.002009694	491.3489104	2038.073053	491.3489104	2038.073053		
Jul	1216.756734	457.839554	2.6576051	0.011255628	291.4284879	2142.08498	291.4284879	2142.08498		
Aug	1179.501042	508.6693193	2.318797295	0.025599346	151.442009	2207.560074	151.442009	2207.560074		
Sep	1078.229564	307.4435465	3.507081468	0.001134448	456.8629849	1699.596144	456.8629849	1699.596144		
Oct	655.4499152	216.5886594	3.026243003	0.004315946	217.7079102	1093.19192	217.7079102	1093.19192		
Nov	-57.09494507	249.6419673	-0.228707319	0.820261688	-561.6401764	447.4502862	-561.6401764	447.4502862		
Dec	-609.2353658	405.8615904	-1.501091456	0.141185153	-1429.51223	211.0414981	-1429.51223	211.0414981		
Leap Year	170.172853	361.397681	0.470874225	0.640288412	-560.2390988	900.5848047	-560.2390988	900.5848047		
ActHDD	2.701940561	0.583050948	4.634141445	3.76887E-05	1.523550652	3.880330471	1.523550652	3.880330471		
ActCDD	3.055251712	0.969934554	3.149956562	0.003086823	1.094940875	5.015562549	1.094940875	5.015562549		

The projections for loads by major class for the summer and winter peak days for 2010 (first year of the planning horizon), 2014 (fifth year of the planning horizon), 2019 (tenth year of the planning horizon), and 2029 (twentieth year of the planning horizon) are shown in Figures 2-6 – 2-13. For these graphs, please note that the 2010 loads are projected, not actual. The load by hour by revenue class was derived by allocating the total energy load to each class. Subclasses were only used in the Commercial revenue class. Tables 2-3 through 2-10 contain the data reflected in Figures 2-6 through 2-13.

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Figure 2-6

2010 Winter Peak Day – First Forecast Year
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Table 2-3
2010 Projected Winter Peak Day Loads (MW)
****Highly Confidential in its Entirety****

Figure 2-7

2010 Summer Peak Day – First Forecast Year
****Highly Confidential in its Entirety****

Table 2-4
2010 Projected Summer Gross Peak Day Loads (MW)
****Highly Confidential in its Entirety****

Figure 2-8

2014 Winter Peak Day – Fifth Forecast Year
****Highly Confidential in its Entirety****

Table 2-5
2014 Winter Peak Day Loads (MW)
****Highly Confidential in its Entirety****

Figure 2-9

2014 Summer Peak Day – Fifth Forecast Year
****Highly Confidential in its Entirety****

Table 2-6
2014 Summer Gross Peak Day Loads (MW)
****Highly Confidential in its Entirety****

Figure 2-10

2019 Winter Peak Day – Tenth Forecast Year
****Highly Confidential in its Entirety****

Table 2-7
2019 Winter Peak Day Loads (MW)
****Highly Confidential in its Entirety****

Figure 2-11

2019 Summer Peak Day – Tenth Forecast Year
****Highly Confidential in its Entirety****

Table 2-8
2019 Summer Gross Peak Day Loads (MW)
****Highly Confidential in its Entirety****

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Figure 2-12

2029 Winter Peak Day – Twentieth Forecast Year
****Highly Confidential in its Entirety****

Table 2-9
2029 Winter Peak Day Loads (MW)
****Highly Confidential in its Entirety****

Figure 2-13

2029 Summer Peak Day – Twentieth Forecast Year
****Highly Confidential in its Entirety****

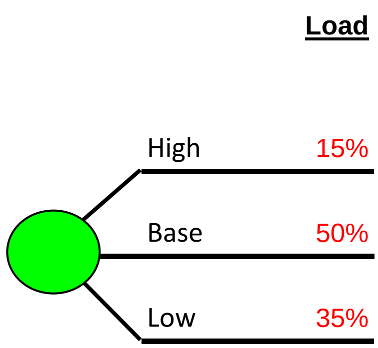
Table 2-10
2029 Summer Gross Peak Day Loads (MW)
****Highly Confidential in its Entirety****

2.2 High and Low Load Forecast Analysis

The development of the high and low load forecasts began by changing the Residential class forecast based on different levels of customer growth and different levels of use per customer. Then, market share analysis was used to modify the other Revenue Classes accordingly. The market share analysis proceeded only after detailed analysis was conducted that determined Empire's Revenue class market share had remained very consistent for more than 12 years.

Similar to the 2007 IRP, an analysis of 30 years of load history yielded information about the frequency of lower load growth, average load growth, and higher load growth. Since future load growth is one of the critical uncertain factors in this IRP, the following probabilities were assumed for each level of the load forecast: low – 35%, base – 50%, and high – 15%, as also shown on the branches of the critical uncertain factors decision tree in Figure 2-14. The important trend from the historical data is that lower loads are more likely than higher loads. Current economic conditions and the possibility of the enactment of future CO_2 legislation, all argue for a bias towards lower growth as opposed to higher growth.

Figure 2-14
Load Portion of the Critical Uncertain Factors Decision Tree



The peak demand forecasts for each of these levels are shown in Table 2-11. The peak demands for each of the three forecasts as compared to the actual historical load and the weather-normalized historical load are shown in Figure 2-15. The data of the historical and weather-normalized peaks are contained in Table 2-12. Figure 2-16 shows regression statistics from spreadsheet modeling conducted the course of developing the weather normalized peaks shown in Table 2-12.

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Figure 2-15

Annual On-System Peak Data
****Highly Confidential in its Entirety****

Table 2-11
Net Peak Demand Forecast Comparison
****Highly Confidential in its Entirety****

Table 2-12
Historical and Weather-Normalized Peak Loads (MW)

Year	Historical Peak	Weather-Normalized Peak
1980	518	490
1981	506	507
1982	505	515
1983	536	530
1984	524	547
1985	543	568
1986	612	588
1987	610	610
1988	624	629
1989	638	649
1990	668	670
1991	678	688
1992	680	712
1993	739	749
1994	741	794
1995	815	837
1996	842	867
1997	876	893
1998	916	916
1999	979	942
2000	993	964
2001	1,001	987
2002	987	1,005
2003	1,045	1,029
2004	1,014	1,053
2005	1,087	1,081
2006	1,159	1,113
2007	1,173	1,138
2008	1,153	1,145
2009	1.085	1,148

Figure 2-16
Regression Analysis Results – Weather Normalized Peaks

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.997891701
R Square	0.995787847
Adjusted R Square	0.995540073
Standard Error	17.21146085
Observations	37

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2381096.758	1190548.379	4018.940545	4.13591E-41
Residual	34	10071.96908	296.2343846		
Total	36	2391168.727			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-1064.962589	99.65028476	-10.68699996	2.07107E-12	-1267.476332	-862.4488465	-1267.476332	-862.4488465
Customers	0.009423194	0.000111991	84.1426644	4.82179E-41	0.009195602	0.009650786	0.009195602	0.009650786
3-Day WAT	7.411058285	1.214899048	6.100143299	6.3867E-07	4.94208638	9.88003019	4.94208638	9.88003019

The annual energy forecasts for the low, base, and high load forecasts are shown in Table 2-13. The annual energy projections for each of the three forecasts as compared to the actual historical energy and the weather-normalized energy are shown in Figure 2-17. The data for the historical and weather-normalized annual energy are contained in Table 2-14. Figure 2-18 shows regression statistics from spreadsheet modeling conducted the course of developing the weather normalized energies shown in Table 2-14.

Table 2-13
Annual Energy Forecast Comparison
Highly Confidential in its Entirety

Figure 2-17

Annual Net System Input Data
****Highly Confidential in its Entirety****

Figure 2-18
Regression Analysis Results – Weather Normalized Energy

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.997495977
R Square	0.994998224
Adjusted R Square	0.994543517
Standard Error	91387.32821
Observations	37

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	5.48257E+13	1.82752E+13	2188.218832	5.07453E-38
Residual	33	2.75604E+11	8351643757		
Total	36	5.51013E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-3087576.508	272051.7381	-11.34922544	6.20745E-13	-3641069.929	-2534083.088	-3641069.929	-2534083.088
Customers	46.47244957	0.590262258	78.73186693	3.84543E-39	45.27155198	47.67334716	45.27155198	47.67334716
HDD	114.0706418	45.34776912	2.515463143	0.016935599	21.80991234	206.3313713	21.80991234	206.3313713
CDD	205.2513767	71.33294993	2.877371214	0.006979798	60.12339963	350.3793538	60.12339963	350.3793538

Table 2-14
Historical and Weather-Normalized Annual Energy (MWh)

Year	Historical Annual Energy	Weather-Normalized Energy
1980	2,392,227	2,262,171
1981	2,300,145	2,343,683
1982	2,334,300	2,386,066
1983	2,450,833	2,460,980
1984	2,497,672	2,542,121
1985	2,614,848	2,644,174
1986	2,576,653	2,744,276
1987	2,727,506	2,852,975
1988	2,883,278	2,948,244
1989	2,936,071	3,046,719
1990	3,029,425	3,151,793
1991	3,208,554	3,238,139
1992	3,151,977	3,358,502
1993	3,552,901	3,537,561
1994	3,720,515	3,758,630
1995	3,937,177	3,972,218
1996	4,204,598	4,122,649
1997	4,250,155	4,250,169
1998	4,471,314	4,365,049
1999	4,473,229	4,490,804
2000	4,794,585	4,597,830
2001	4,800,756	4,714,336
2002	4,917,875	4,804,028
2003	4,950,161	4,918,629
2004	4,972,159	5,036,505
2005	5,293,643	5,177,155
2006	5,330,214	5,335,022
2007	5,485,658	5,449,623
2008	5,493,653	5,503,996
2009	5,263,206	5,520,494

3.0 Load Forecast Methodology Overview

Empire produced class level forecasts by season using regression analysis at the customer class level. Customer, weather, energy usage, and trend variables were utilized when applicable. Additionally, a system level peak and net system input (energy) forecast was developed to check and support the multiple rate class forecasts. Eleven years (1999-2009) of historical sales and weather data were used. The load impacts of implemented demand-side management (DSM) programs are incorporated in the base load forecast.

3.1 Historical Data Base

The customer classes included:

- Residential
- Commercial
- Industrial
- Street and Highway
- Public Authority
- Interdepartmental
- Wholesale customers

Historical data by customer class were used for some of the modeling.

3.2 Weather Normalization

Weather normalization is the process of determining how historical usage would have differed had normal weather conditions existed. The process involves using a statistical model to adjust actual sales levels under normal weather conditions.

Empire used regression analysis techniques to determine weather-normalized peak demands and energies for portions of its weather-sensitive historical load. A regression equation was developed independently for each of the monthly peaks. For some of the peak demand regression equations, variables included used actual values for annual customer numbers and the three-day weighted average temperature of the peak day and the two days prior to the peak day. The weighting assigned 70% to the peak day, 20% to the day before the peak day, and 10% to the day before that. Variables were utilized for the regression equations that suitably forecast the actual system energy and peak loads.

The technique for weather normalization of the customer class was to substitute actual heating degree days (HDD) and cooling degree days (CDD) with normal HDD and CDD as reported by the National Oceanographic and Atmospheric Administration (NOAA) at the Springfield, Missouri airport.

The results for weather-normalized NSI and annual peaks are shown in Figures 3-1 and 3-2. The tabular data can be found in Tables 2-12 and 2-14. Figures 3-3 and 3-4 show regression statistics from spreadsheet modeling conducted the course of developing the weather normalized peaks and energies shown in Figures 3-1 and 3-2.

Figure 3-1

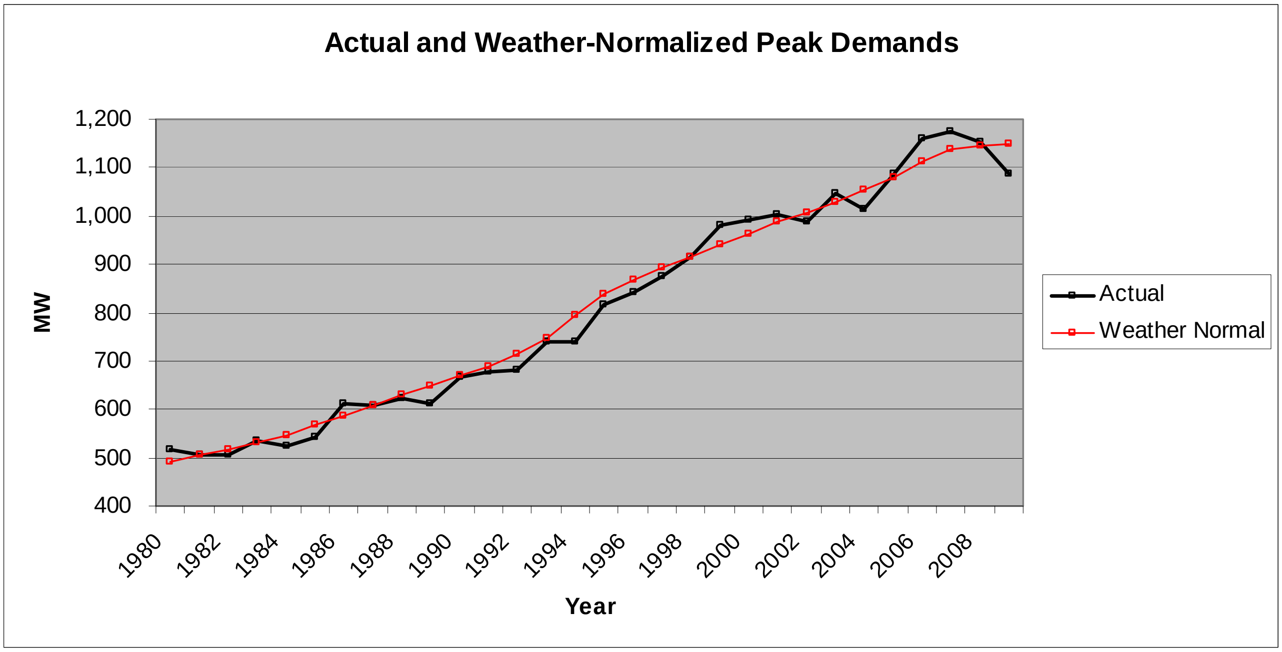
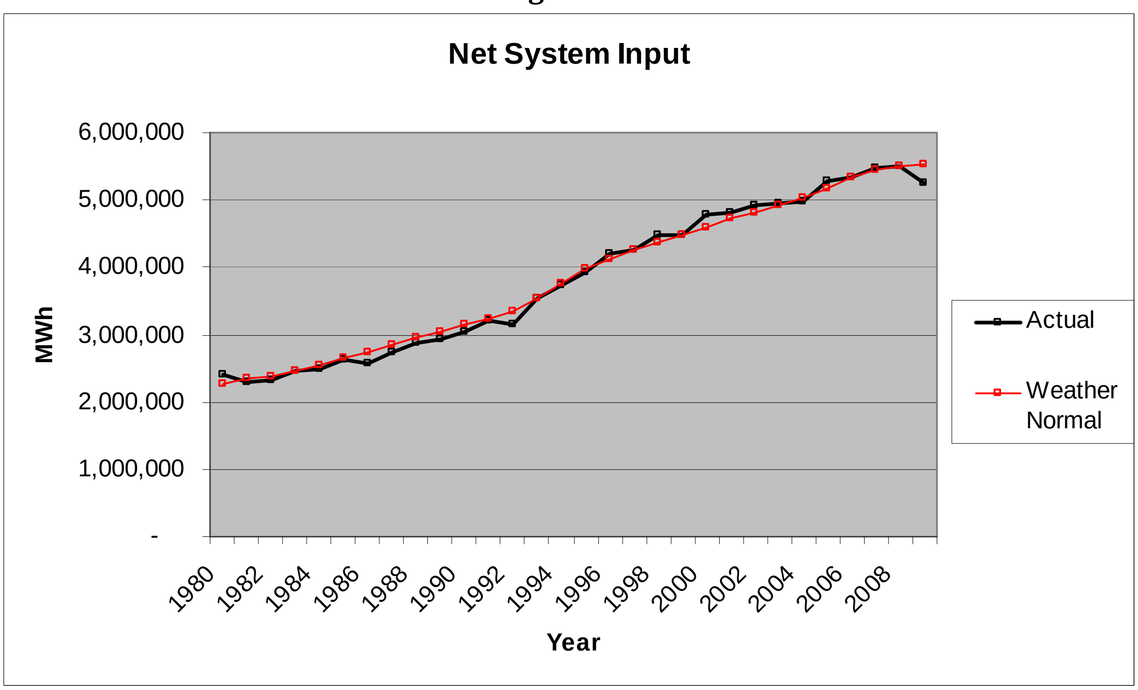


Figure 3-2



NP

Figure 3-3
Regression Analysis Results – Weather Normalized Peaks

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.997891701
R Square	0.995787847
Adjusted R Square	0.995540073
Standard Error	17.21146085
Observations	37

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2381096.758	1190548.379	4018.940545	4.13591E-41
Residual	34	10071.96908	296.2343846		
Total	36	2391168.727			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-1064.962589	99.65028476	-10.68699996	2.07107E-12	-1267.476332	-862.4488465	-1267.476332	-862.4488465
Customers	0.009423194	0.000111991	84.1426644	4.82179E-41	0.009195602	0.009650786	0.009195602	0.009650786
3-Day WAT	7.411058285	1.214899048	6.100143299	6.3867E-07	4.94208638	9.88003019	4.94208638	9.88003019

Figure 3-4
Regression Analysis Results – Weather Normalized Energy

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.997495977
R Square	0.994998224
Adjusted R Square	0.994543517
Standard Error	91387.32821
Observations	37

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	5.48257E+13	1.82752E+13	2188.218832	5.07453E-38
Residual	33	2.75604E+11	8351643757		
Total	36	5.51013E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-3087576.508	272051.7381	-11.34922544	6.20745E-13	-3641069.929	-2534083.088	-3641069.929	-2534083.088
Customers	46.47244957	0.590262258	78.73186693	3.84543E-39	45.27155198	47.67334716	45.27155198	47.67334716
HDD	114.0706418	45.34776912	2.515463143	0.016935599	21.80991234	206.3313713	21.80991234	206.3313713
CDD	205.2513767	71.33294993	2.877371214	0.006979798	60.12339963	350.3793538	60.12339963	350.3793538

3.3 Forecast Methodology Summary

Empire performed “bottom up” forecasting at the revenue class level. Subclasses were used in the Commercial revenue class to disaggregate customers with similar load patterns. In addition, some of the Commercial subclass customers were forecasted together before being aggregated back into the class level forecast.

The customer classes were forecast using historical sales, weather, customer counts, and, at times, trend binaries and input from the Commercial Services Department. System energy and peak demands were forecast with linear regression analysis employing the “least squares” method to determine a best fit line through a set of historical observations. All of these methods fall into the category of statistical modeling, not end-use modeling. Empire has been granted variances from the rule’s requirements for end-use modeling.

4.0 Residential

The Residential class was forecast using a combination of *MetrixND* and spreadsheet analysis.

4.1 Modeling Methodology

The forecast for the Residential class began with an examination of residential use-per customer (UPC). UPC is determined by dividing monthly residential sales by the number of residential customers. The use of UPC allows the forecaster to focus on capturing the weather signature with respect to sales volatility without the need to consider customer count fluctuations. UPC can be weather normalized using a multiple regression technique in either Excel or *MetrixND*. Subsequent to the *MetrixND* modeling, spreadsheet analysis was undertaken using Microsoft Excel. In the process, multiple methods were used to forecast the Residential class loads.

4.1.1 *MetrixND*

Empire used the *MetrixND* model to perform regression analysis and weather normal simulations to capture the weather effects. The variables used in establishing a weather normal historical period are:

- Heating Degree Days (HDD) (<65º F)
- Cooling Degree Days (CDD) (>65º F)
- Monthly binary variables
- Lag HDD
- Lag CDD
- Bad binaries

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used to provide a weather reference point for consumption that is largely reflective of heating/cooling response. Since the heating and cooling load responses have differing slopes, separate variables are created to capture the load response.

HDD were established by cataloging daily average temperatures from the National Oceanographic and Atmospheric Administration (NOAA) to determine those days when temperatures were less than 65º F. For those days, the temperatures are subtracted from 65º F. The results are summed for each month. HDD are a variable that when used in the model can provide a measure of how cool or cold weather will result in customers using their heating systems.

CDD were established by cataloging daily average temperatures from NOAA to determine those days when temperatures were greater than 65º F. For those days, 65º F is subtracted from the temperatures. The results are summed for each month. CDD are variables that when used in the model can provide a measure of how warm or hot weather will result in customers using their air conditioning systems.

Monthly binary or dummy variables were used in the regression to isolate monthly consumptions and separate each month from the trends and tendencies of adjacent months. This process endeavors to capture monthly observations such that more like trends will be grouped together. For instance, HDD in April would not be expected to have the same weather-related response as HDD in January. The overall weather is more temperate in April and often oscillates between cooling and heating temperatures. Customers may not want to switch between heating and air conditioning regularly and may instead opt to use fans for cooling or additional clothing instead of heating their homes.

Lag variables for both HDD and CDD are used to capture consumption patterns that occur in the prior month due to revenue cycle billing and calendar cycle forecasting.

Bad binaries were used in the regression analysis to capture historical periods where weather-related consumption patterns appeared to be anomalous. The forecaster developed these data points based on scatter plots of the consumption patterns and/or historical anomalies, e.g. ice storm outages, and so forth. The months with the abnormal consumption patterns were then removed from the regression analysis and visual changes as well as revised coefficients of determination (R^2) were examined.

The multivariate regression analysis capabilities of *MetrixND* were used for the first portion of the Residential UPC forecast. Weather relationships were defined via regression. The results from the regression analysis were then used in the Simulation Model within *MetrixND*. The output of the Simulation Model provided a weather-normalized UPC for the Residential class. This weather-normalized UPC was one component used in the forecast of Residential class sales.

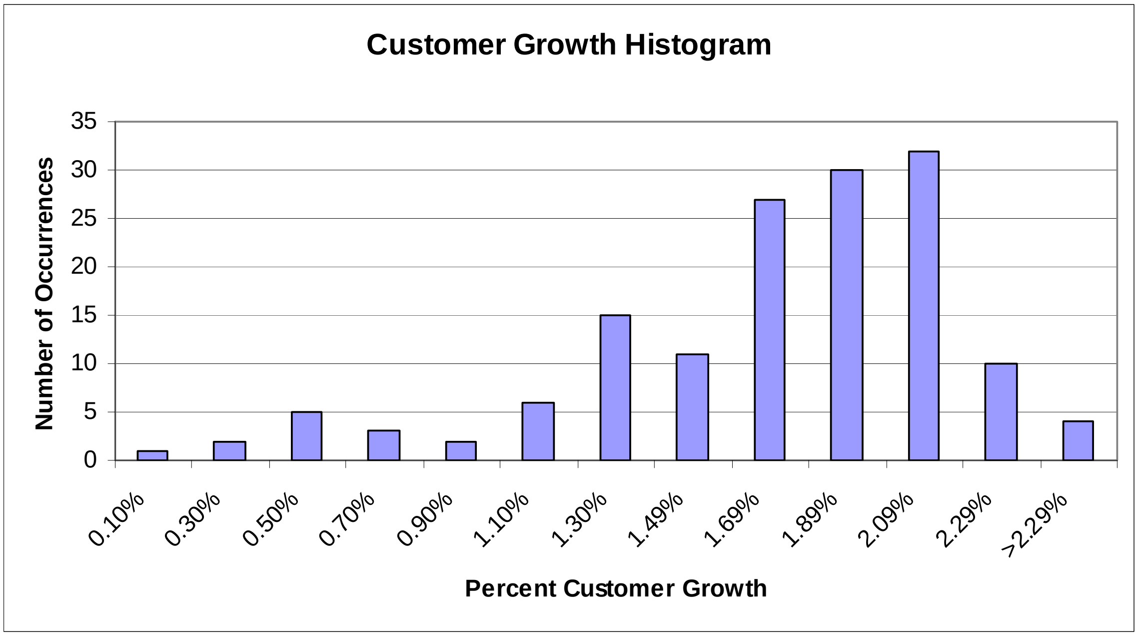
4.1.2 Spreadsheet Analysis

The regression capabilities of Microsoft Excel were another component of the Residential class forecast. The variables used in the spreadsheet analysis were:

- Customer growth
- Heating Degree Days (HDD) (<65º F)
- Cooling Degree Days (CDD) (>65º F)
- Monthly binary variables
- Trend variable
- Ice storm bad data variable

Empire believes that customer growth is not just a driver variable, but a variable that captures the economic impacts of the service territory. The customer counts used in the regression analysis were based on customer growth percentages during 1996-2009. Compound annual growth rates were calculated for three-, five- and ten-year periods. A histogram was created with historical growth percentages to organize values into bins (see Figure 4-1). A high and low customer growth percentage was calculated using the mean and standard deviation from the historical period.

Figure 4-1



A trend variable was used as an additional growth variable when the model was not adequately capturing the consumption in some of the months, and thus this trend variable was used to better reflect current customer behavior in the Empire service territory.

The ice storm bad data variable was created to capture not only the energy that was lost due to the ice storm outages but also the accrual that captured unread meters and the true-up for bill estimation that took place after power was restored. The ice storm variable was used for two separate incidents that occurred in three months.

The regression capabilities of the model were then used based on this selection of variables. The final Residential class forecast was chosen based on correlation coefficients, P values, and other statistical measures. Figure 4-2 shows regression statistics from spreadsheet modeling conducted during the course of developing the residential revenue class forecast.

Figure 4-2
Regression Analysis Results – Residential Class Energy Forecast

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.976991432
R Square	0.954512259
Adjusted R Square	0.946601347
Standard Error	8834681.25
Observations	109

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	16	1.5068E+17	9.41752E+15	120.6576835	2.05412E-54
Residual	92	7.18075E+15	7.80516E+13		
Total	108	1.57861E+17			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-133495858.9	22346301.39	-5.973957683	4.32302E-08	-177877541.3	-89114176.45	-177877541.3	-89114176.45
HDD	97401.79856	10989.63249	8.863062406	5.63072E-14	75575.44034	119228.1568	75575.44034	119228.1568
CDD	170568.3093	19200.29977	8.883627405	5.09732E-14	132434.8575	208701.761	132434.8575	208701.761
Cust	1688.66022	168.4514203	10.02461254	2.02787E-16	1354.101167	2023.219274	1354.101167	2023.219274
Jan	24211209.15	8776422.855	2.75866484	0.007002007	6780476.206	41641942.1	6780476.206	41641942.1
Feb	2367670.322	7299129.227	0.324377093	0.746388927	-12129030.03	16864370.68	-12129030.03	16864370.68
Mar	6640265.963	5151477.326	1.289002269	0.200628991	-3591012.434	16871544.36	-3591012.434	16871544.36
May	-15319358.68	5244764.96	-2.920885644	0.004390127	-25735914.36	-4902802.993	-25735914.36	-4902802.993
Jun	-224502.2509	7419621.129	-0.030257913	0.975926905	-14960509.92	14511505.42	-14960509.92	14511505.42
Jul	18002172.47	9979583.954	1.803900098	0.07451974	-1818142.22	37822487.16	-1818142.22	37822487.16
Aug	21230210.88	10353082.52	2.050617374	0.043148836	668095.8295	41792325.94	668095.8295	41792325.94
Sep	12711617.19	6254997.71	2.032233709	0.045013258	288652.1126	25134582.27	288652.1126	25134582.27
Oct	-11885217.25	4201626.784	-2.828717984	0.00573631	-20230010.52	-3540423.972	-20230010.52	-3540423.972
Nov	-13259584.36	5157805.658	-2.570780141	0.011751838	-23503431.37	-3015737.349	-23503431.37	-3015737.349
Dec	16519930.63	8231845.372	2.00683199	0.047702745	170775.5454	32869085.72	170775.5454	32869085.72
Trend	-14267150.82	3767735.619	-3.786664529	0.000271983	-21750198.81	-6784102.834	-21750198.81	-6784102.834
Ice Storm	-13870284.44	6758025.95	-2.05241657	0.042969981	-27292307	-448261.8741	-27292307	-448261.8741

4.2 Residential Class Forecast

The residential forecast reflects an average annual energy growth rate of approximately **____** from 2010 to 2029 as shown in Table 4-1 and displayed on Figure 4-3. Historical residential energy from 2000-2009 is also provided on Table 4-1 and reflected in Figure 4-3.

Table 4-1
Residential Customer Class Forecast

Year	Annual Energy (MWh)	% Growth
2000	1,664,719	
2001	1,681,085	1.0
2002	1,726,449	2.7
2003	1,728,315	0.1
2004	1,703,858	-1.4
2005	1,881,441	10.4
2006	1,898,846	1.0
2007	1,930,493	1.7
2008	1,952,869	1.1
2009	1,866,473	-4.2
2010	**________**	**__**
2011	**________**	**__**
2012	**________**	**__**
2013	**________**	**__**
2014	**________**	**__**
2015	**________**	**__**
2016	**________**	**__**
2017	**________**	**__**
2018	**________**	**__**
2019	**________**	**__**
2020	**________**	**__**
2021	**________**	**__**
2022	**________**	**__**
2023	**________**	**__**
2024	**________**	**__**
2025	**________**	**__**
2026	**________**	**__**
2027	**________**	**__**
2028	**________**	**__**
2029	**________**	**__**

Figure 4-3

Residential Forecast Energy
****Highly Confidential in its Entirety****

A comparison of the peak demands projected for the residential class in each of the low, base and high forecasts is provided on Figure 4-4.

Figure 4-4

Residential Demand
****Highly Confidential in its Entirety****

Load profiles for the summer peak days and winter peak days for 2010 (base year of the IRP), 2014 (fifth year of IRP), 2019 (tenth year of IRP), and 2029 (20th year of IRP) for the residential forecast are shown in Figures 4-5 through 12. The supporting data are found in Table 4-2 and 4-3.

Table 4-2
Residential Summer Peak Day (MW) – Forecast
Highly Confidential in its Entirety*

Table 4-3
Residential Winter Peak Day (MW) – Forecast
Highly Confidential in its Entirety*

Figure 4-5

Residential Summer Peak Day - 2010
****Highly Confidential in its Entirety****

Figure 4-6

Residential Winter Peak Day - 2010
****Highly Confidential in its Entirety****

Figure 4-7

Residential Summer Peak Day - 2014
****Highly Confidential in its Entirety****

Figure 4-8

Residential Winter Peak Day - 2014
****Highly Confidential in its Entirety****

Figure 4-9

Residential Summer Peak Day - 2019
****Highly Confidential in its Entirety****

Figure 4-10

Residential Winter Peak Day - 2019
****Highly Confidential in its Entirety****

Figure 4-11

Residential Summer Peak Day - 2029
****Highly Confidential in its Entirety****

Figure 4-12

Residential Winter Peak Day - 2029
****Highly Confidential in its Entirety****

Actual residential sales versus residential sales for the historical years as predicted by the modeling are shown on Figure 4-13.

Figure 4-13

Historical Residential Actual versus Residential Predicted
****Highly Confidential in its Entirety****

Actual residential customer count and forecast customer counts are shown in Figure 4-14.

Figure 4-14

Actual Residential Customers and Forecast Customers
****Highly Confidential in its Entirety****

Residential UPC actual and forecast are shown on Figure 4-15.

Figure 4-15

Residential UPC Actual and Forecast
****Highly Confidential in its Entirety****

Residential class kWh for 1999-2009 and the projections through the planning horizon are shown on Figure 4-16.

Figure 4-16

Residential Actual with Forecast **Highly Confidential in its Entirety**

5.0 Commercial

The Commercial class was forecast using a combination of *MetrixND* and spreadsheet analysis.

5.1 Modeling Methodology

The first step in conducting the Commercial class forecast was to disaggregate the Commercial accounts. Some were forecast individually and some were forecast by subclass. Some of the larger customers were removed from the Commercial sales database and were forecast individually. The remaining sales were divided by the actual customer count to create a UPC for the Commercial class. Weather effects can then be captured during the MetrixND modeling. Subsequent to the *MetrixND* modeling, spreadsheet analysis was undertaken using Microsoft Excel. In the process, multiple methods were used to forecast the Commercial class loads.

5.1.1 *MetrixND*

The regression analysis capabilities of *MetrixND* were used to perform a weather normal simulation model to capture weather effects from the historical period. The variables used in establishing a weather normal historical period are:

- Heating Degree Days (HDD) (<65º F)
- Cooling Degree Days (CDD) (>65º F)
- Monthly binary variables
- Lag HDD
- Lag CDD
- Bad binaries

HDD were established by cataloging daily average temperatures from the National Oceanographic and Atmospheric Administration (NOAA) to determine those days when temperatures were less than 65º F. For those days, the temperatures are subtracted from 65º F. The results are summed for each month. HDD are a variable that when used in the model can provide a measure of how cool or cold weather will result in customers using their heating systems.

CDD were established by cataloging daily average temperatures from NOAA to determine those days when temperatures were greater than 65º F. For those days, 65º F is subtracted from the temperatures. The results are summed for each month. CDD are variables that when used in the model can provide a measure of how warm or hot weather will result in customers using their air conditioning systems.

Monthly binary or dummy variables were used in the regression to isolate monthly consumptions and separate each month from the trends and tendencies of adjacent months. This process endeavors to capture monthly observations that that more like trends will be grouped together. For instance, HDD in April would not be expected to have the same weather-related response as HDD in January. The overall weather is more temperate in April and often oscillates between cooling and heating temperatures. Commercial building HVAC systems may or may not be capable of switching between heating and cooling and may tend toward one or the other but not both in these shoulder months.

Lag variables for both HDD and CDD are used to capture consumption patterns that occur in the prior month due to revenue cycle billing and calendar cycle forecasting.

Bad binaries were used in the regression analysis to capture historical periods where weather-related consumption patterns appeared to be anomalous. The forecaster developed these data points based on scatter plots of the consumption patterns. The months with the abnormal consumption patterns were then removed from the regression analysis and visual changes as well as revised coefficients of determination (R^2) were examined.

MetrixND was used for the first portion of the Commercial UPC forecast. Once the weather relationships were defined using the regression capabilities of the model, the regression results were transferred to the Simulation Model within *MetrixND*. The Simulation Model created a weather-normalized UPC for the Commercial class. These results were one component of the final forecast.

5.1.2 Spreadsheet Analysis

Commercial class sales without subclasses were forecast using a linear regression in Microsoft Excel employing monthly binaries, actual HDD and CDD, and a leap year binary. A forecast of Commercial sales with customers as an independent variable was created and a forecast of Commercial UPC was also created during this stage of the forecast process. The UPC forecast was chosen for its correlation coefficient, P Values and other statistical measures. The number of customers was then applied to the Commercial UPC to calculate a Commercial sales total. The number of Commercial customers was determined by using an allocation of historical Commercial customers as a percentage of total customers.

Total customers and customer growth was derived similarly to the process used for Residential customer growth.

At the request of MPSC staff, Empire disaggregated the Commercial class such that individual large customers could be examined and forecasted separately. Empire's Commercial Operations staff provided insight into growth rates, future expansion plans, and current projects to develop specific individualized growth rates for specific Commercial class customers for the next five years. The projections for the individual customers were combined with the other Commercial sales data to create a total Commercial class sales forecast. Figure 5-1 shows regression statistics from spreadsheet modeling conducted the course of developing the commercial revenue class forecast.

Figure 5-1
Regression Analysis Results – Commercial Class Energy Forecast

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.920620151
R Square	0.847541463
Adjusted R Square	0.794180975
Standard Error	314.6164733
Observations	55

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	14	22010611.76	1572186.554	15.88331543	4.13831E-12
Residual	40	3959341.01	98983.52524		
Total	54	25969952.77			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	3530.445438	217.6640078	16.21970243	3.44716E-19	3090.530072	3970.360803	3090.530072	3970.360803	3986.391495	4552.863722
Jan	-981.7614541	412.4924223	-2.38007149	0.022164748	-1815.439729	-148.0831793	-1815.439729	-148.0831793	0.355750737	1.270253032
Feb	-1121.882553	330.9486096	-3.389899582	0.001583688	-1790.754637	-453.0104698	-1790.754637	-453.0104698	3.372037593	5.183233464
Mar	-433.7932693	231.2342456	-1.875990592	0.067967346	-901.1351077	33.54856905	-901.1351077	33.54856905	-506.8217005	319.2548036
May	842.47869	251.5988176	3.348500196	0.001779717	333.9785166	1350.978863	333.9785166	1350.978863		
Jun	1264.710982	382.6488031	3.305148145	0.002009694	491.3489104	2038.073053	491.3489104	2038.073053		
Jul	1216.756734	457.839554	2.6576051	0.011255628	291.4284879	2142.08498	291.4284879	2142.08498		
Aug	1179.501042	508.6693193	2.318797295	0.025599346	151.442009	2207.560074	151.442009	2207.560074		
Sep	1078.229564	307.4435465	3.507081468	0.001134448	456.8629849	1699.596144	456.8629849	1699.596144		
Oct	655.4499152	216.5886594	3.026243003	0.004315946	217.7079102	1093.19192	217.7079102	1093.19192		
Nov	-57.09494507	249.6419673	-0.228707319	0.820261688	-561.6401764	447.4502862	-561.6401764	447.4502862		
Dec	-609.2353658	405.8615904	-1.501091456	0.141185153	-1429.51223	211.0414981	-1429.51223	211.0414981		
Leap Year	170.172853	361.397681	0.470874225	0.640288412	-560.2390988	900.5848047	-560.2390988	900.5848047		
ActHDD	2.701940561	0.583050948	4.634141445	3.76887E-05	1.523550652	3.880330471	1.523550652	3.880330471		
ActCDD	3.055251712	0.969934554	3.149956562	0.003086823	1.094940875	5.015562549	1.094940875	5.015562549		

5.2 Commercial Class Forecast

The commercial forecast reflects an average annual energy growth rate of approximately **____** from 2010 to 2029 as shown in Table 5-1 and Figure 5-2. Historical information for this class from 2000-2009 are also shown on the table and figure.

Figure 5-2

Commercial
****Highly Confidential in its Entirety****

Table 5-1
Commercial Revenue Class Forecast

Year	Annual Energy (MWh)	% Growth
2000	1,333,095	
2001	1,375,620	3.2
2002	1,378,165	0.2
2003	1,386,807	0.6
2004	1,417,307	2.2
2005	1,485,034	4.8
2006	1,547,077	4.2
2007	1,610,814	4.1
2008	1,622,048	0.7
2009	1,579,832	-2.6
2010	**________**	**__**
2011	**________**	**__**
2012	**________**	**__**
2013	**________**	**__**
2014	**________**	**__**
2015	**________**	**__**
2016	**________**	**__**
2017	**________**	**__**
2018	**________**	**__**
2019	**________**	**__**
2020	**________**	**__**
2021	**________**	**__**
2022	**________**	**__**
2023	**________**	**__**
2024	**________**	**__**
2025	**________**	**__**
2026	**________**	**__**
2027	**________**	**__**
2028	**________**	**__**
2029	**________**	**__**

A comparison of the peak demands projected for the commercial class in each of the low, base and high forecasts is provided on Figure 5-3.

NP

Figure 5-3

Commercial Demand
****Highly Confidential in its Entirety****

Load profiles for the summer peak days and winter peak days for 2010 (base year of the IRP), 2014 (fifth year of IRP), 2019 (tenth year of IRP), and 2029 (20th year of IRP) for the commercial forecast are shown in Figures 5-4 through 5-11. The supporting data are found in Table 5-2 and 5-3.

NP

Table 5-2
Commercial Summer Peak Day (MW) – Forecast
Highly Confidential in its Entirety*

Table 5-3
Commercial Winter Peak Day (MW) – Forecast
Highly Confidential in its Entirety*

Figure 5-4

Commercial Summer Peak Day - 2010
****Highly Confidential in its Entirety****

Figure 5-5

Commercial Winter Peak Day - 2010
****Highly Confidential in its Entirety****

Figure 5-6

Commercial Summer Peak Day - 2014
****Highly Confidential in its Entirety****

Figure 5-7

Commercial Winter Peak Day - 2014
****Highly Confidential in its Entirety****

Figure 5-8

Commercial Summer Peak Day - 2019
****Highly Confidential in its Entirety****

Figure 5-9

Commercial Winter Peak Day - 2019
****Highly Confidential in its Entirety****

Figure 5-10

Commercial Summer Peak Day - 2029
****Highly Confidential in its Entirety****

Figure 5-11

Commercial Winter Peak Day - 2029
****Highly Confidential in its Entirety****

Actual commercial customer count and forecasted numbers of customers are reflected on Figure 5-12.

Figure 5-12

Actual Commercial Customers and Forecasted Customers
****Highly Confidential in its Entirety****

Commercial UPC actual and forecast are shown on Figure 5-13.

Figure 5-13

Commercial UPC Actual and Forecast
****Highly Confidential in its Entirety****

Commercial actual and forecasted sales are shown on Figure 5-14.

Figure 5-14
****Highly Confidential in its Entirety****

Commercial Actual with Forecast
****Highly Confidential in its Entirety****

6.0 Industrial

The Industrial class is divided into large volume customers, oil pipeline pumping (OPP), and other industrial. The forecast methodology for each subcategory is customized to the needs of that group of customers.

6.1 Modeling Methodology

6.1.1 Large Volume Customers

Electricity usage for the large volume customers is determined in consultation with Empire's Manager of Industrial and Commercial Energy Sales based on Empire's knowledge of the customers and their expected change in operation in the future.

6.1.2 OPP

The OPP load is difficult to forecast as it follows no discernable pattern. There is no specific correlation with any of weather, oil prices, or environmental concerns. Many factors were considered in preparing the forecast for OPP including the impact of Cash for Clunkers (a government stimulus program designed to remove older automobiles from service and expected to reduce demand for gasoline, and thus oil), airplane fuel use expectations, home heating fuel projections, domestic transportation forecasts, and current pipeline capacity. These conditions were considered in consultation with Empire's Manager of Industrial and Commercial Energy Sales.

6.1.3 Other Industrials

During 2010, a reduction in the use of electricity from other industrials was attributed to the slowdown in the economy. To address the decreases, Empire personnel put together two reports – the EDE Industrial Report and the EDE Demand Analysis Report. The EDE Industrial Report was issued monthly and provided detailed information on the customers that comprise about 85% of the Industrial class energy consumption. The report stratified the customers by sector: Food Processing/Feedmills, Food Packaging Manufacturing/Food Warehousing, Construction Material Manufacturing, and Other. The report compared the monthly consumption and twelve-month ending (TME) consumption to comparable data from one year prior and two years prior.

The information from these reports served as confirmation of the trends observed in the load usage patterns of the other industrials for forecasting purposes. Based on input from Empire's Manager of Industrial and Commercial Energy Sales, growth has been assumed at **----** per year for the first five years of the planning horizon increasing to **------** growth thereafter.

6.2 Industrial Class Forecast

The Industrial class forecast (the total of the three above industrial categories) reflects an average annual energy growth rate of approximately **____** from 2010 to 2029 as shown in Table 6-1 and Figure 6-1. Historical energy values for 2000-2009 are also included in the table and figure.

Table 6-1
Industrial Revenue Class Forecast

Year	Annual Energy (MWh)	% Growth
2000	1,009,284	
2001	1,004,899	-0.4
2002	1,027,446	2.2
2003	1,058,730	3.0
2004	1,085,380	2.5
2005	1,106,700	2.0
2006	1,145,490	3.5
2007	1,110,328	-3.1
2008	1,073,250	-3.3
2009	992,165	-7.4
2010	**________**	**___**
2011	**________**	**___**
2012	**________**	**___**
2013	**________**	**___**
2014	**________**	**___**
2015	**________**	**___**
2016	**________**	**___**
2017	**________**	**___**
2018	**________**	**___**
2019	**________**	**___**
2020	**________**	**___**
2021	**________**	**___**
2022	**________**	**___**
2023	**________**	**___**
2024	**________**	**___**
2025	**________**	**___**
2026	**________**	**___**
2027	**________**	**___**
2028	**________**	**___**
2029	**________**	**___**

Figure 6-1

Industrial
****Highly Confidential in its Entirety****

A comparison of the peak demands projected for the industrial class in each of the low, base and high forecasts is provided on Figure 6-2.

Figure 6-2

Industrial Demand
****Highly Confidential in its Entirety****

Load profiles for the summer peak days and winter peak days for 2010 (base year of the IRP), 2014 (fifth year of IRP), 2019 (tenth year of IRP), and 2029 (20th year of IRP) for the industrial forecast are shown in Figures 6-3 through 6-10. The supporting data are found in Table 6-2 and 6-3.

NP

Table 6-2
Industrial Summer Peak Day (MW) – Forecast
Highly Confidential in its Entirety*

Table 6-3
Industrial Winter Peak Day (MW) – Forecast
Highly Confidential in its Entirety*

Figure 6-3

Industrial Summer Peak Day - 2010
****Highly Confidential in its Entirety****

Figure 6-4

Industrial Winter Peak Day - 2010
****Highly Confidential in its Entirety****

Figure 6-5

Industrial Summer Peak Day - 2014
****Highly Confidential in its Entirety****

Figure 6-6

Industrial Winter Peak Day - 2014
****Highly Confidential in its Entirety****

Figure 6-7

Industrial Summer Peak Day - 2019
****Highly Confidential in its Entirety****

Figure 6-8

Industrial Winter Peak Day - 2019
****Highly Confidential in its Entirety****

Figure 6-9

Industrial Summer Peak Day - 2029
****Highly Confidential in its Entirety****

Figure 6-10

Industrial Winter Peak Day - 2029
****Highly Confidential in its Entirety****

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Historical and forecast UPC for the industrial revenue class are reflected on Figure 6-11. Actual and forecast industrial customer counts are shown on Figure 6-12.

Figure 6-11

Industrial UPC Actual and Forecast
****Highly Confidential in its Entirety****

Figure 6-12

Industrial Customer Count – Actual and Forecast
****Highly Confidential in its Entirety****

7.0 Other

The other category in Empire's load forecast includes Street and Highway Lighting, Public Authority, and Interdepartmental.

7.1 Modeling Methodology

Each of Street and Highway Lighting, Public Authority and Interdepartmental were forecasted using the regression analysis capabilities of Microsoft Excel.

7.1.1 Street and Highway Lighting

Street and Highway Lighting has maintained a steady and consistent consumption pattern for many years. This pattern persisted even when one of the larger cities in the service territory implemented a new street lighting program. The spreadsheet regression analysis conducted for Street and Highway Lighting used monthly binaries and customer growth as the variables. The customer growth used in the forecast was the compound growth rate from 2002-2008.

7.1.2 Public Authority

Public Authority customers are the municipal accounts for the cities in Empire's service territory. A relationship between weather and consumption was found in heating load, but not in cooling load. Thus, the spreadsheet regression analysis for Public Authority was created using monthly binaries, HDD and customers.

7.1.3 Interdepartmental

Interdepartmental sales is a very small percentage of the revenue class and has little to no volatility. Thus, a projection of consumption was made for the 2009 calendar year and sales were projected to remain relatively flat for the first five years of the planning horizon.

7.2 Other Forecast

The forecast for these revenue classes as well as historical data from 2000-2009 are shown on Table 7-1.

Table 7-1
Energy Forecasts for Other Categories (MWh)

Year	Street & Highway Lighting	% Growth	Public Authority	% Growth	Inter-departmental	% Growth
2000	21,733		74,670		1,179	
2001	22,518	3.6	77,608	3.9	1,659	40.8
2002	22,666	0.7	78,522	1.2	1,616	-2.6
2003	22,754	0.4	79,584	1.4	1,561	-3.4
2004	22,977	1.0	83,439	4.8	1,643	5.3
2005	23,560	2.5	87,685	5.1	1,675	1.9
2006	22,939	-2.6	88,028	0.4	1,613	-3.7
2007	23,471	2.3	91,638	4.1	1,570	-2.7
2008	22,959	-2.2	99,416	8.5	1,434	-8.6
2009	23,113	0.7	98,703	-0.7	1,594	11.2
2010	**_____**	**__**	**_____**	**__**	**____**	**__**
2011	**_____**	**__**	**_____**	**__**	**____**	**__**
2012	**_____**	**__**	**_____**	**__**	**____**	**__**
2013	**_____**	**__**	**_____**	**__**	**____**	**__**
2014	**_____**	**__**	**_____**	**__**	**____**	**__**
2015	**_____**	**__**	**_____**	**__**	**____**	**__**
2016	**_____**	**__**	**_____**	**__**	**____**	**__**
2017	**_____**	**__**	**_____**	**__**	**____**	**__**
2018	**_____**	**__**	**_____**	**__**	**____**	**__**
2019	**_____**	**__**	**_____**	**__**	**____**	**__**
2020	**_____**	**__**	**_____**	**__**	**____**	**__**
2021	**_____**	**__**	**_____**	**__**	**____**	**__**
2022	**_____**	**__**	**_____**	**__**	**____**	**__**
2023	**_____**	**__**	**_____**	**__**	**____**	**__**
2024	**_____**	**__**	**_____**	**__**	**____**	**__**
2025	**_____**	**__**	**_____**	**__**	**____**	**__**
2026	**_____**	**__**	**_____**	**__**	**____**	**__**
2027	**_____**	**__**	**_____**	**__**	**____**	**__**
2028	**_____**	**__**	**_____**	**__**	**____**	**__**
2029	**_____**	**__**	**_____**	**__**	**____**	**__**

Load profiles for the summer peak days and winter peak days for 2010 (base year of the IRP), 2014 (fifth year of IRP), 2019 (tenth year of IRP), and 2029 (20th year of IRP) for the other forecast are shown in Figures 7-1 through 7-8. The supporting data are found in Table 7-2 and 7-3.

Table 7-2
Other Summer Peak Day (MW) – Forecast
Highly Confidential in its Entirety*

Table 7-3
Other Winter Peak Day (MW) – Forecast
Highly Confidential in its Entirety*

NP

Figure 7-1

Other Summer Peak Day - 2010
****Highly Confidential in its Entirety****

Figure 7-2

Other Winter Peak Day - 2010
****Highly Confidential in its Entirety****

NP

Figure 7-3

Other Summer Peak Day - 2014
****Highly Confidential in its Entirety****

Figure 7-4

Other Winter Peak Day - 2014
****Highly Confidential in its Entirety****

Figure 7-5

Other Summer Peak Day - 2019
****Highly Confidential in its Entirety****

Figure 7-6

Other Winter Peak Day - 2019
****Highly Confidential in its Entirety****

Figure 7-7

Other Summer Peak Day - 2029
****Highly Confidential in its Entirety****

Figure 7-8

Other Winter Peak Day - 2029
****Highly Confidential in its Entirety****

8.0 On-System Wholesale

Empire's on-system wholesale customers consist of the cities of Monett, Missouri; Mount Vernon, Missouri; Chetopa, Kansas; and Lockwood, Missouri.

8.1 Modeling Methodology

The different on-system wholesale customers are comprised of varying levels of Residential, Commercial, and Industrial load. The first step in the forecast was to create a weighted average based on the different allocations to the revenue classes and the expected growth rates for each of the classes. Then adjustments were made to the weighted averages and allocations based on 1) prior year growth changes and 2) elimination of outliers (e.g. the addition of air conditioning to a school).

8.2 On-System Wholesale Forecast

The forecast for the on-system wholesale customers as well as historical data are shown in Table 8-1.

8.3 IRP Plan

**

**

Table 8-1
On-System Wholesale Load Forecast

Year	Energy (MWh)	% Growth
2000	292,359	
2001	304,740	4.2
2002	304,914	0.1
2003	308,574	1.2
2004	305,711	-0.9
2005	328,803	7.6
2006	314,402	-4.4
2007	342,347	8.9
2008	344,525	0.6
2009	332,061	-3.6
2010	**________**	**__**
2011	**________**	**__**
2012	**________**	**__**
2013	**________**	**__**
2014	**________**	**__**
2015	**________**	**__**
2016	**________**	**__**
2017	**________**	**__**
2018	**________**	**__**
2019	**________**	**__**
2020	**________**	**__**
2021	**________**	**__**
2022	**________**	**__**
2023	**________**	**__**
2024	**________**	**__**
2025	**________**	**__**
2026	**________**	**__**
2027	**________**	**__**
2028	**________**	**__**
2029	**________**	**__**

Over the entire planning horizon, the on-system wholesale load is projected to grow at an average rate of **____**

Load profiles for the summer peak days and winter peak days for 2010 (base year of the IRP), 2014 (fifth year of IRP), 2019 (tenth year of IRP), and 2029 (20th year of IRP) for the wholesale forecast are shown in Figures 8-1 through 8-8. The supporting data are found in Table 8-2 and 8-3.

NP

Table 8-2
Wholesale Summer Peak Day (MW) – Forecast
Highly Confidential in its Entirety*

NP

Table 8-3
Wholesale Winter Peak Day (MW) – Forecast
Highly Confidential in its Entirety*

Figure 8-1

Wholesale Summer Peak Day - 2010
****Highly Confidential in its Entirety****

Figure 8-2

Wholesale Winter Peak Day - 2010
****Highly Confidential in its Entirety****

Figure 8-3

Wholesale Summer Peak Day - 2014
****Highly Confidential in its Entirety****

Figure 8-4

Wholesale Winter Peak Day - 2014
****Highly Confidential in its Entirety****

NP

Figure 8-5

Wholesale Summer Peak Day - 2019
****Highly Confidential in its Entirety****

Figure 8-6

Wholesale Winter Peak Day - 2019
****Highly Confidential in its Entirety****

Figure 8-7

Wholesale Summer Peak Day - 2029
****Highly Confidential in its Entirety****

Figure 8-8

Wholesale Winter Peak Day - 2029
****Highly Confidential in its Entirety****

Abbreviations

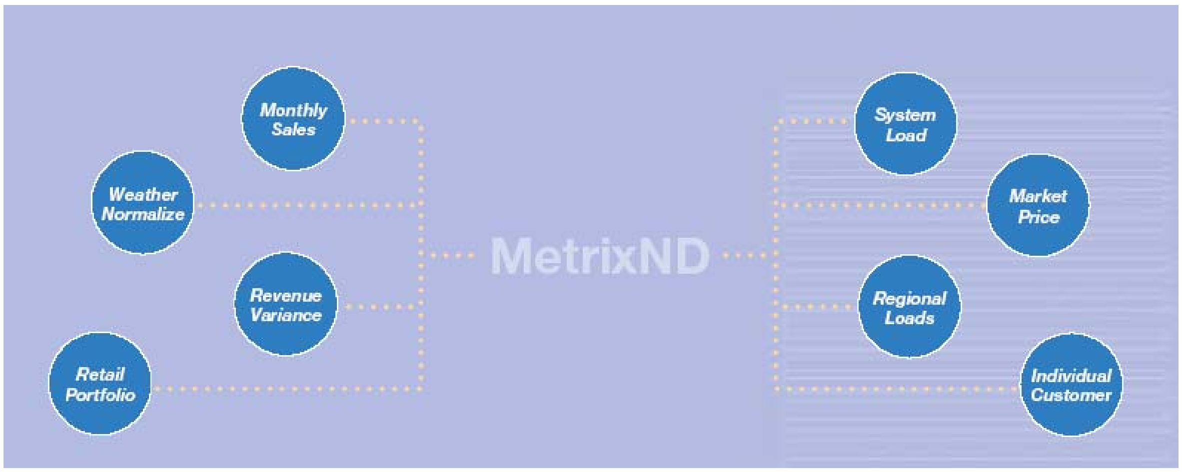
CDD – Cooling degree days
DSM – Demand-side management
HDD – Heating degree days
IRP – Integrated Resource Plan
kV – kilovolt
kW – kilowatt
kWh – kilowatthour
MPSC – Missouri Public Service Commission
MW – Megawatt
MWh – Megawatthour
NOAA – National Oceanographic and Atmospheric Administration
NSI – Net System Input
OPP – Oil Pipeline Pumping
REEPS – Residential End-Use Energy Planning Software
UPC – Use per customer

Appendix A

MetrixND

MetrixND, a product of Itron, is an energy forecasting tool designed to take advantage of advanced Microsoft Windows® capabilities. The model is equipped with an intuitive user interface and drag-and-drop architecture that streamlines the development of forecasting variables and models. The model's forecasting techniques include neural networks, multivariate regression, ARIMA and exponential smoothing.

Figure A-1
MetrixND



MetrixND facilitates the ability of utility personnel to:

- Use existing sources of meter and other data for more accurate forecasts. *MetrixND* works with Excel® spreadsheets and a variety of databases, including Microsoft Access®, SQL Server®, ORACLE®, MV-90, and MV-Star.
- Model all data frequencies: sub-hourly, hourly, daily, weekly, monthly, quarterly and annual data.
- Display all aspects of the forecasts with effective, easy-to-produce graphics.
- Create analysis variables on the fly using spreadsheet-like formulas to try different things instead of having to learn a programming language.
- Model hourly loads and calibrate automatically to forecasts of daily energy and peak demand.
- Compare alternative model specifications by selecting from competing models quickly and efficiently.
- Improve their understanding of historical outcomes by dragging and dropping alternative forecast drivers into their models to view the impact on their forecast.
- Improve their forecast by including a time series model of the residuals.
- Customize forecasting models by writing powerful macros using Microsoft Visual Basic® for Applications

MetrixND is a flexible modeling tool, widely used by the top energy forecasters at leading utilities and energy providers throughout the world. *MetrixND* puts the power of the most advanced modeling techniques at one's fingertips, enabling the development of accurate forecasts and their application to business decisions with confidence. These techniques, which can be used independently or in combination, include:

Exponential Smoothing
Ideal for projecting customer growth trends that support monthly sales and peak forecasting applications.

ARIMA
For seasoned time series professionals who want to visualize how historical data patterns extend into the future.

Regression
The workhorse of the energy forecasting professional the fastest way to build multi-variate models.

Neural Networks
Essential for short-term forecasting where modeling the nonlinear response between loads and weather matters the most.

Appendix B. Additional Figures

Figure B-1
****Highly Confidential in its Entirety****

Figure B-2
****Highly Confidential in its Entirety****

Figure B-3
****Highly Confidential in its Entirety****

Figure B-4
****Highly Confidential in its Entirety****

Figure B-5
****Highly Confidential in its Entirety****

Figure B-6
****Highly Confidential in its Entirety****

NP

Figure B-7
****Highly Confidential in its Entirety****

Figure B-8
****Highly Confidential in its Entirety****

Figure B-9
****Highly Confidential in its Entirety****

Figure B-10
****Highly Confidential in its Entirety****

Figure B-11
****Highly Confidential in its Entirety****

Figure B-12
****Highly Confidential in its Entirety****

Figure B-13
****Highly Confidential in its Entirety****

Figure B-14
****Highly Confidential in its Entirety****

Figure B-15
****Highly Confidential in its Entirety****

Figure B-16
****Highly Confidential in its Entirety****

Figure B-17
****Highly Confidential in its Entirety****

Appendix C – Supporting Data

Table C-1. Customer Growth Histogram

Growth Rate %	Number of Observations
0.10	1
0.30	2
0.50	5
0.70	3
0.90	2
1.10	6
1.30	15
1.49	11
1.69	27
1.89	30
2.09	32
2.29	10
>2.29	4

Table C-2 Residential Demand (MW)
****Highly Confidential in Its Entirety****

Table C-3. Historical Residential Actual Versus Residential Predicted

Dt	Res Act Sales	Res Pred Sales
6/1/2000	117,725,092	119,699,447
7/1/2000	168,582,073	164,335,936
8/1/2000	198,107,927	162,414,759
9/1/2000	147,846,713	125,646,335
10/1/2000	92,798,247	93,878,179
11/1/2000	118,644,610	121,052,569
12/1/2000	206,789,997	182,326,016
1/1/2001	218,311,272	203,252,659
2/1/2001	144,653,930	157,803,504
3/1/2001	144,157,975	142,046,724
4/1/2001	100,225,976	111,284,119
5/1/2001	91,795,237	87,211,629
6/1/2001	135,402,118	123,189,908
7/1/2001	192,870,151	168,199,591
8/1/2001	176,018,553	165,466,168
9/1/2001	125,544,715	128,824,393
10/1/2001	91,067,026	96,882,306
11/1/2001	104,724,417	123,718,963
12/1/2001	156,313,345	185,059,957
1/1/2002	188,049,128	206,040,637
2/1/2002	139,255,857	160,834,650
3/1/2002	154,473,614	144,583,092
4/1/2002	103,475,155	113,697,214
5/1/2002	88,389,289	89,699,025
6/1/2002	147,507,315	125,952,556
7/1/2002	178,781,934	170,703,874
8/1/2002	175,194,751	168,249,080
9/1/2002	157,809,308	131,558,334
10/1/2002	93,074,411	100,109,335
11/1/2002	126,690,975	127,103,038
12/1/2002	173,747,702	188,565,616
1/1/2003	201,720,796	209,867,141
2/1/2003	168,829,060	164,318,356
3/1/2003	140,601,330	148,087,062
4/1/2003	108,324,986	117,660,500
5/1/2003	94,317,494	93,358,352
6/1/2003	120,075,921	129,566,289
7/1/2003	195,520,917	174,123,411
8/1/2003	197,194,293	172,046,877
9/1/2003	114,802,053	135,575,657
10/1/2003	92,310,234	103,609,928
11/1/2003	117,920,951	130,924,476
12/1/2003	176,697,079	192,478,242
1/1/2004	196,614,822	213,622,722
2/1/2004	173,455,719	168,224,227
3/1/2004	129,325,737	151,994,622
4/1/2004	102,542,577	121,302,940
5/1/2004	115,815,357	97,458,419
6/1/2004	135,102,130	133,823,401
7/1/2004	162,319,528	178,513,927
8/1/2004	154,034,613	175,988,210
9/1/2004	134,362,442	139,668,969
10/1/2004	103,110,465	107,764,032
11/1/2004	115,563,673	134,550,030
12/1/2004	181,610,748	196,198,360
1/1/2005	195,202,291	217,236,455
2/1/2005	150,556,916	171,971,364
3/1/2005	148,623,559	155,886,983
4/1/2005	110,946,436	125,414,828
5/1/2005	116,146,598	101,548,354
6/1/2005	159,180,621	138,053,495
7/1/2005	195,995,238	182,730,512
8/1/2005	204,169,348	180,334,821
9/1/2005	159,189,136	144,130,409
10/1/2005	118,567,791	112,343,679
11/1/2005	123,956,108	139,384,664
12/1/2005	198,906,576	200,778,007
1/1/2006	169,773,194	222,044,070
2/1/2006	157,742,259	176,888,742
3/1/2006	146,552,117	161,039,086
4/1/2006	114,239,549	130,229,198
5/1/2006	120,237,890	106,313,753
6/1/2006	157,871,518	143,161,692
7/1/2006	201,277,863	187,669,843
8/1/2006	220,752,263	185,698,006
9/1/2006	167,532,439	149,289,266
10/1/2006	109,087,928	117,423,168
11/1/2006	138,435,830	144,389,853
12/1/2006	195,343,523	205,744,356
1/1/2007	203,200,305	212,922,298
2/1/2007	206,342,963	181,529,181
3/1/2007	135,644,860	151,360,025
4/1/2007	117,642,235	120,700,428
5/1/2007	119,162,799	110,835,985
6/1/2007	141,901,811	146,655,530
7/1/2007	192,929,406	191,344,368
8/1/2007	222,535,317	188,827,093
9/1/2007	152,443,679	152,014,764
10/1/2007	110,069,584	105,400,247
11/1/2007	130,462,552	132,702,975
12/1/2007	198,157,150	194,376,666
1/1/2008	228,661,576	215,512,703
2/1/2008	204,255,855	184,026,709
3/1/2008	160,558,899	153,638,027
4/1/2008	123,997,531	122,441,436
5/1/2008	108,132,594	112,235,885
6/1/2008	149,475,075	148,268,201
7/1/2008	187,360,435	192,541,628
8/1/2008	195,011,329	189,823,403
9/1/2008	121,245,902	153,139,412
10/1/2008	102,956,551	106,923,419
11/1/2008	142,636,544	133,878,282
12/1/2008	228,576,915	209,381,730
1/1/2009	236,812,133	230,436,712
2/1/2009	168,644,669	184,568,769
3/1/2009	145,492,948	154,014,599
4/1/2009	125,466,558	123,331,360
5/1/2009	107,025,803	112,977,206
6/1/2009	154,684,949	148,854,166

Table C-4. Actual Residential and Forecast Customers

Year	Residential Customers	Forecast Residential Customers
1999	121,523	
2000	123,618	
2001	125,996	
2002	127,681	
2003	129,878	
2004	132,222	
2005	134,724	
2006	137,689	
2007	139,840	
2008	140,791	
2009	141,206	
2010		**______**
2011		**______**
2012		**______**
2013		**______**
2014		**______**
2015		**______**
2016		**______**
2017		**______**
2018		**______**
2019		**______**
2020		**______**
2021		**______**
2022		**______**
2023		**______**
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2025		**______**
2026		**______**
2027		**______**
2028		**______**
2029		**______**

Table C-5 Residential UPC Actual and Forecast
Highly Confidential in its Entirety

Table C-6 Residential Actual with Forecast
Highly Confidential in its Entirety

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Table C-7 Commercial Demand (MW)
****Highly Confidential in Its Entirety****

Table C-8 Actual Commercial Customers and Forecasted Customers
Highly Confidential in its Entirety

Table C-9 Commercial UPC Actual and Forecast
Highly Confidential in its Entirety

NP

Table C-10 Commercial Actual with Forecast
Highly Confidential in its Entirety

Table C-11 Industrial Demand (MW)
****Highly Confidential in Its Entirety****

Table C-12 Industrial UPC Actual and Forecast
Highly Confidential in its Entirety

NP

Table C-13 Industrial Customer Count – Actual and Forecast
Highly Confidential in its Entirety

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NP

Table C-14. Annual Summer NSI (MWh)

Year	Weather Normalized NSI	Actual NSI	Forecast NSI
2000	1,689,095	1,776,096	
2001	1,725,446	1,791,246	
2002	1,756,575	1,832,554	
2003	1,796,255	1,798,453	
2004	1,843,177	1,759,886	
2005	1,894,187	2,007,958	
2006	1,951,930	2,003,178	
2007	1,989,316	2,024,925	
2008	2,004,391	1,928,384	
2009	2,010,533	1,846,103	
2010			**________**
2011			**________**
2012			**________**
2013			**________**
2014			**________**
2015			**________**
2016			**________**
2017			**________**
2018			**________**
2019			**________**
2020			**________**
2021			**________**
2022			**________**
2023			**________**
2024			**________**
2025			**________**
2026			**________**
2027			**________**
2028			**________**
2029			**________**

Table C-15. Annual Non-Summer NSI (MWh)

Year	Weather Normalized NSI	Actual NSI	Forecast NSI
2000	2,944,329	3,018,489	
2001	3,011,797	3,099,510	
2002	3,071,110	3,085,321	
2003	3,145,849	3,151,708	
2004	3,221,270	3,212,273	
2005	3,308,385	3,285,685	
2006	3,409,073	3,327,036	
2007	3,486,741	3,460,733	
2008	3,536,387	3,565,269	
2009	3,537,167	3,416,742	
2010			**________**
2011			**________**
2012			**________**
2013			**________**
2014			**________**
2015			**________**
2016			**________**
2017			**________**
2018			**________**
2019			**________**
2020			**________**
2021			**________**
2022			**________**
2023			**________**
2024			**________**
2025			**________**
2026			**________**
2027			**________**
2028			**________**
2029			**________**

Table C-16 Annual Winter Peaks (MW)

Year	Actual Peak	Weather Normalized Peak	Forecast Peak
1999	828	798	
2000	941	834	
2001	915	855	
2002	888	875	
2003	983	903	
2004	945	929	
2005	1,035	957	
2006	1,031	990	
2007	1,059	985	
2008	1,100	1,015	
2009	1,082	1,053	
2010			**______**
2011			**______**
2012			**______**
2013			**______**
2014			**______**
2015			**______**
2016			**______**
2017			**______**
2018			**______**
2019			**______**
2020			**______**
2021			**______**
2022			**______**
2023			**______**
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2025			**______**
2026			**______**
2027			**______**
2028			**______**
2029			**______**

Table C-17 Residential June-September (MWh)

Year	Historical	Forecast
2000	632,262	
2001	629,836	
2002	659,293	
2003	627,593	
2004	585,819	
2005	718,534	
2006	747,434	
2007	709,810	
2008	653,093	
2009	625,686	
2010		**______**
2011		**______**
2012		**______**
2013		**______**
2014		**______**
2015		**______**
2016		**______**
2017		**______**
2018		**______**
2019		**______**
2020		**______**
2021		**______**
2022		**______**
2023		**______**
2024		**______**
2025		**______**
2026		**______**
2027		**______**
2028		**______**
2029		**______**

Table C-18 Commercial June-September (MWh)

Year	Historical	Forecast
2000	491,801	\
2001	509,312	
2002	530,478	
2003	512,021	
2004	516,895	
2005	577,965	
2006	608,393	
2007	606,747	
2008	593,869	
2009	573,235	
2010		**______**
2011		**______**
2012		**______**
2013		**______**
2014		**______**
2015		**______**
2016		**______**
2017		**______**
2018		**______**
2019		**______**
2020		**______**
2021		**______**
2022		**______**
2023		**______**
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2025		**______**
2026		**______**
2027		**______**
2028		**______**
2029		**______**

Table C-19 Industrial June-September (MWh)

Year	Historical	Forecast
2000	358,311	
2001	355,416	
2002	359,186	
2003	376,955	
2004	387,392	
2005	401,671	
2006	414,691	
2007	398,788	
2008	385,370	
2009	356,577	
2010		**______**
2011		**______**
2012		**______**
2013		**______**
2014		**______**
2015		**______**
2016		**______**
2017		**______**
2018		**______**
2019		**______**
2020		**______**
2021		**______**
2022		**______**
2023		**______**
2024		**______**
2025		**______**
2026		**______**
2027		**______**
2028		**______**
2029		**______**

Table C-20 Residential Non-Summer (MWh)

Year	Historical	Forecast
2000	1,032,457	
2001	1,051,249	
2002	1,067,156	
2003	1,110,722	
2004	1,118,039	
2005	1,162,906	
2006	1,151,412	
2007	1,220,682	
2008	1,299,776	
2009	1,240,788	
2010		**______**
2011		**______**
2012		**______**
2013		**______**
2014		**______**
2015		**______**
2016		**______**
2017		**______**
2018		**______**
2019		**______**
2020		**______**
2021		**______**
2022		**______**
2023		**______**
2024		**______**
2025		**______**
2026		**______**
2027		**______**
2028		**______**
2029		**______**

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Table C-21 Commercial Non-Summer (MWh)

Year	Historical	Forecast
2000	841,294	
2001	866,308	
2002	847,688	
2003	874,785	
2004	900,412	
2005	907,070	
2006	938,684	
2007	1,004,067	
2008	1,028,179	
2009	1,006,596	
2010		**_______**
2011		**_______**
2012		**_______**
2013		**_______**
2014		**_______**
2015		**_______**
2016		**_______**
2017		**_______**
2018		**_______**
2019		**_______**
2020		**_______**
2021		**_______**
2022		**_______**
2023		**_______**
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2025		**_______**
2026		**_______**
2027		**_______**
2028		**_______**
2029		**_______**

Table C-22 Industrial Non-Summer (MWh)

Year	Historical	Forecast
2000	650,973	
2001	649,483	
2002	668,261	
2003	681,775	
2004	697,987	
2005	705,029	
2006	730,799	
2007	711,540	
2008	687,880	
2009	635,588	
2010		**______**
2011		**______**
2012		**______**
2013		**______**
2014		**______**
2015		**______**
2016		**______**
2017		**______**
2018		**______**
2019		**______**
2020		**______**
2021		**______**
2022		**______**
2023		**______**
2024		**______**
2025		**______**
2026		**______**
2027		**______**
2028		**______**
2029		**______**