APPENDIX H

Minnesota Power 2013 Advanced Forecast Report

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0120 REGISTRATION

ENTITY ID#	68
REPORT YEAR	2012

Number of Power Plants	18

UTILITY DETAILS	
UTILITY NAME	Minnesota Power
STREET ADDRESS	30 West Superior Street
CITY	Duluth
STATE	MN
ZIP CODE	55802-2093
TELEPHONE	218-722-5642
* UTILITY TYPE	Private

CONTACT INFORMATION	
CONTACT NAME	Julie Pierce
CONTACT TITLE	Manager - Resource Planning
CONTACT STREET ADDRESS	30 West Superior Street
CITY	Duluth
STATE	MN
ZIP CODE	55802-2093
TELEPHONE	(218) 722-5642 x 3829
CONTACT E-MAIL	Jpierce@Mnpower.com

UTILITY OFFICERS

NAME	TITLE
Alan R. Hodnik	President, Chief Exec Officer, Chairman
David J. McMillan	Exec & Snr VP, Mrktg, Reglty & Public Affairs
Mark A. Schober	Chief Financial Officer & Senior Vice Pres
Deborah A. Amberg	Senior VP, General Counsel & Secretary
Allan S. Rudeck, Jr.	Vice President, Strategy & Planning
Robert J. Adams	Vice Pres, Business Development & Chief Risk Officer
Patrick K. Mullen	Vice President, Marketing & Corporate Communications
Steven Q. DeVinck	Controller, Vice President, Business Support
Bradley W. Oachs	Chief Operating Officer
Margaret L. Hodnik	Vice Pres, Regulatory & Legislative Affairs
Jeffrey J. Paulseth	Vice President, Generation
Christopher E. Fleege	Vice President, Transmission and Distribution
Donald W. Stellmaker	Vice President, Corporate Treasurer
Timothy J. Thorp	Vice President, Investor Relations
Bonnie A. Keppers	Vice President, Human Resources

PREPARER INFORMATION	
PERSON PREPARING FORMS	
PREPARER'S TITLE	
DATE	

COMMENTS

ALLOWABLE UTILITY TYPES

Code
Private
Public
Co-op

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0150 FEDERAL OR STATE DATA SUBSTITUTION

			FILING CYCLE (enter an "X" in the cell)		
FEDERAL AGENCY	FORM NUMBER	FORM TITLE	MONTHLY	YEARLY	OTHER
FERC	FERC-1	Annual FERC Report		X	
FERC	FERC-5	Statement of Electric Operating Revenue and Income	X		
FERC	FERC-45	Part 45 Informational Repor			X
FERC	FERC-67	Steam Electric Plant, Air and Water Survey		X	
FERC	FERC-80	Licensed Projects Recreation Repor			X
FERC	FERC-82	Retail Rate Level Change			X
DOE/EIA	EIA-411	Coordinated Bulk Power Supply Program		X	
DOE/EIA	EIA-412	Annual Electric Industry Financial Report (Unregulated		X	
DOE/EIA	EIA-423	Report of Cost and Quality of Fuels for Electric Plant (Unregulated	X		
FERC	FERC-423	Fuel Data			X
FERC	FERC-469	Statement of Gross Generation by Licensed Project		X	
FERC	FERC-472	Regulation Number 582 - Assessment Calculation		X	
DOE/EIA	DOE-510	Response to FERC Operation Report		X	
		(Written Communication for each Licensed Project)			
FERC	FERC-561	Interlocking Directors and Officers		X	
FERC	FERC-566	Twenty Largest Customers		X	
DOE/EIA	EIA-714	Electric Power System Report		X	
DOE/EIA	EIA-767	Steam Electric Plant Air and Water Quality Control Data		X	
DOE/EIA	EIA-906	Power Plant Report (Regulated Facilities	X		
DOE/EIA	EIA-906	Power Plant Report (Unregulated Facilities	X		
DOE/EIA	FE781R	Report of International Electric Import/Expor		X	
DOE/EIA	EIA-826	Electric Utility Sales and Revenue Report with Distributions	X		
DOE/EIA	EIA-860	Electric Generator Report (Regulated Facilities		X	
DOE/EIA	EIA-860	Electric Generator Report (Unregulated Facilities		X	
DOE/EIA	EIA-861	Electric Utility Report (Regulated)		X	
DOE/EIA	EIA-861	Electric Utility Report (Unregulated)		X	
DOE/EIA	EIA-886	Alternative Fueled Vehicles/Transportation Fuels Repo		X	
DOE/EIA	EIA-196	Order Authorizing Electricity Exports to Canada		X	
FERC	FERC-69	PURPA Avoided Capacity Cost Filing			X
FRB		NAICS/SIC Listing of Electricity Delivered	X		
SEC	Form 10-K	Annual SEC Report		X	
SEC	Form 10-Q	Quarterly SEC Report			X
SEC	Form 8-K	Current SEC Report			X
SEC	Form S-8	SEC Registration Statement S-8			X
SEC	Form S-3	SEC Registration Statement S-3			X
SEC	Form 3	Initial Statement of Beneficial Ownership of Securities			X
SEC	Form 4	Statement of Changes of Beneficial Ownership of Securitie			X
SEC	Form 5	Annual Statement of Beneficial Ownership of Securities		X	
SEC	Proxy	Definitive Proxy Statemen		X	
SEC	U-3A-2	Statement by Holding Company Claiming Exemption Unde		X	
		Rule U-3A-2 from the Provisions of the Public Utility			
		Holding Company Act of 1935			
SEC	Form 11-K	Annual Report for RSOF		X	
SEC	Form 15	Certification and Notification of Termination of Registratio			X
SEC	Form S-1	SEC Registration Statement			X

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

A utility shall provide the following information for the last calendar year:

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

If applicable, the Largest Customer List must be submitted either in electronic or paper format. If information is Trade Secret, note it as such.

See "LargestCustomers" worksheet for data entry.

C. MINNESOTA SERVICE AREA MAP

The referenced map must be submitted either in electronic or paper format.

See Instructions for details of the information required on the Minnesota Service Area Map.

D. PURCHASES AND SALES FOR RESALE

UTILITY NAME	INTERCONNECTED UTILITY	MWH PURCHASED	RESALE ONLY MWH SOLD FOR RESALE
Dahlberg Light & Power			111,152
Superior Water Light & Power			698,410
City of Aitkin			37,873
City of Biwabik			7,064
City of Brainerd			247,092
City of Buhl			7,987
City of Ely			38,549
City of Gilbert			11,154
City of Grand Rapids			176,236
City of Keewatin			5,969
City of Mountain Iron			13,986
City of Nashwauk			10,094
City of Pierz			11,382
City of Proctor			26,292
City of Randall			5,160
City of Two Harbors			29,876
City of Hibbing			155,044
City of Virginia			125,499
Other Non-Required Sales			1,998,957
Non-Associated Utilities/Other		341,105	
Municipals			
Other Cooperatives		57,824	
Square Butte Electric Power		1,630,776	
Non-Utilities		53,547	
Power Marketers		94,000	
Other Public Authorities		2,363,229	
Utility			
Foreign		368,443	
City of Wadena	Western Area Power Administration	69,436	69,436
City of Staples	Western Area Power Administration	23,469	23,469
Great River Energy	Great River Energy	2,324,739	2,244,282
ES&AO	Minnkota Power	1,632,605	1,632,605

Contents

Introduction

The load forecast is the initial step in electric utility planning. Capacity and energy resource commitments are based on forecasts of seasonal peak demand, energy sales, and customer counts. Minnesota Power's forecast process combines sound econometric methodology and data from reputable sources to produce a reasonable long-term outlook suitable for planning.

Minnesota Power has continued to enhance its forecast process. This 2013 forecast methodology and documentation demonstrates Minnesota Power's commitment to process improvement. A highly systematic and replicable approach to model development and selection was implemented, and model documentation has been expanded to provide additional transparency and insight.

Minnesota Power has a history of accurate and reliable load forecasting, achieving just 1.5% in year-ahead forecast error, on average, over the last 13 AFR's. A commitment to explore innovative approaches and continually improve processes has improved forecast accuracy markedly in the last 3 years, despite uncertain economic conditions and substantial changes in industrial customer base.

Once again, the scenarios developed in this year's AFR address the uncertainty in the national and regional economic environments and the unique potential for local additions or losses to the Resale and Industrial customer classes, including the development of substantial mining operations in the region. This sound forecasting process can then be integrated into Minnesota Power's proactive and flexible planning to better inform the critical electric resource decisions ahead. Minnesota Power feels its forecasting approach helps keep the potential outcomes transparent and robust.

Minnesota Power has identified the "Moderate Growth" scenario (Section 2C) as its expected case outlook and has submitted this in its 2013 Annual Electric Utility Report filing. This scenario assumes steady underlying growth with notable load additions from a number of new and existing customers. This scenario results in average annual energy sales growth and average annual peak demand growth of 1.5% and 1.2%, respectively, from 2013 through 2027.

Document Structure

This report has been constructed to provide the most current energy sales and demand forecast for Minnesota Power. Each section is designed to convey all of the vital pieces of the report requirements and give insight into Minnesota Power's forecasting process and results.

Section 1: *Forecast Discussion* details the development of the customer count, seasonal peak, and energy sales forecasts. Included in this section are descriptions of the input data and sources as well as some of the key assumptions underlying the forecast, including the national and regional economic forecasts.

Other information included in Section 1:

- Descriptions of all forecast models used in the development of this year's forecasts, including:
    - Model specifications;
    - Model statistics;
    - Resulting forecast's growth rates; and
    - A discussion of each model's econometric merits and potential issues as well as an explanation/ justification of each variable.
- Additional steps taken in 2013 to improve the forecast process and product;
- The strengths and weaknesses of Minnesota Power's methodology;
- A discussion of Minnesota Power's sensitivity to Large Industrial customer contracts;
- Minnesota Power's confidence in the forecast.

Section 2 *Forecast Results* presents the five forecast scenarios Minnesota Power developed for the 2013 forecast. Each scenario's forecast is the product of a robust econometric modeling process and careful consideration of potential industrial and resale customer load developments. These industrial and resale assumptions were organized into scenarios based on the criteria outlined below:

- **Moderate Growth Scenario (AFR 2013 Expected Case);** additional loads served by Minnesota Power and its wholesale customers that are likely but not yet certain. The assumptions of this scenario were formed through close communication with customers on their planned expansions.
- **Current Contract Scenario;** additional loads served by Minnesota Power and its wholesale customers that are highly likely, i.e. the customer has a signed service agreement or is otherwise bound by contract to change its load.
- **Potential Upside Scenario:** specific industrial expansions, in addition to those in the Moderate Growth Scenario, that are plausible within the next 5 years.
- **Best Case Scenario**: specific additional industrial expansions, combined with those in scenarios above and simultaneous stronger national economic growth. These expansions may be in the initial review stages and are the most speculative, occurring at any point in the next 15 years.
- **Potential Downside Scenario**: permanent production slowdowns at specific customer facilities within the next 5 years and slower national economic growth. Projects deemed

to be highly likely under moderate economic conditions are delayed, and added later in the forecast timeframe.

- **Trended Weather Scenario:** the continuation of observed weather trends.
- **Electric Vehicle Scenario**: the continued integration of electric cars.
- **Industrial Customer Contract Expiration Scenario:** the expiration of Large Industrial customer contracts.

Section 3: presents other report information required by Minnesota law and cross-references the specific requirements to specific sections in this document.

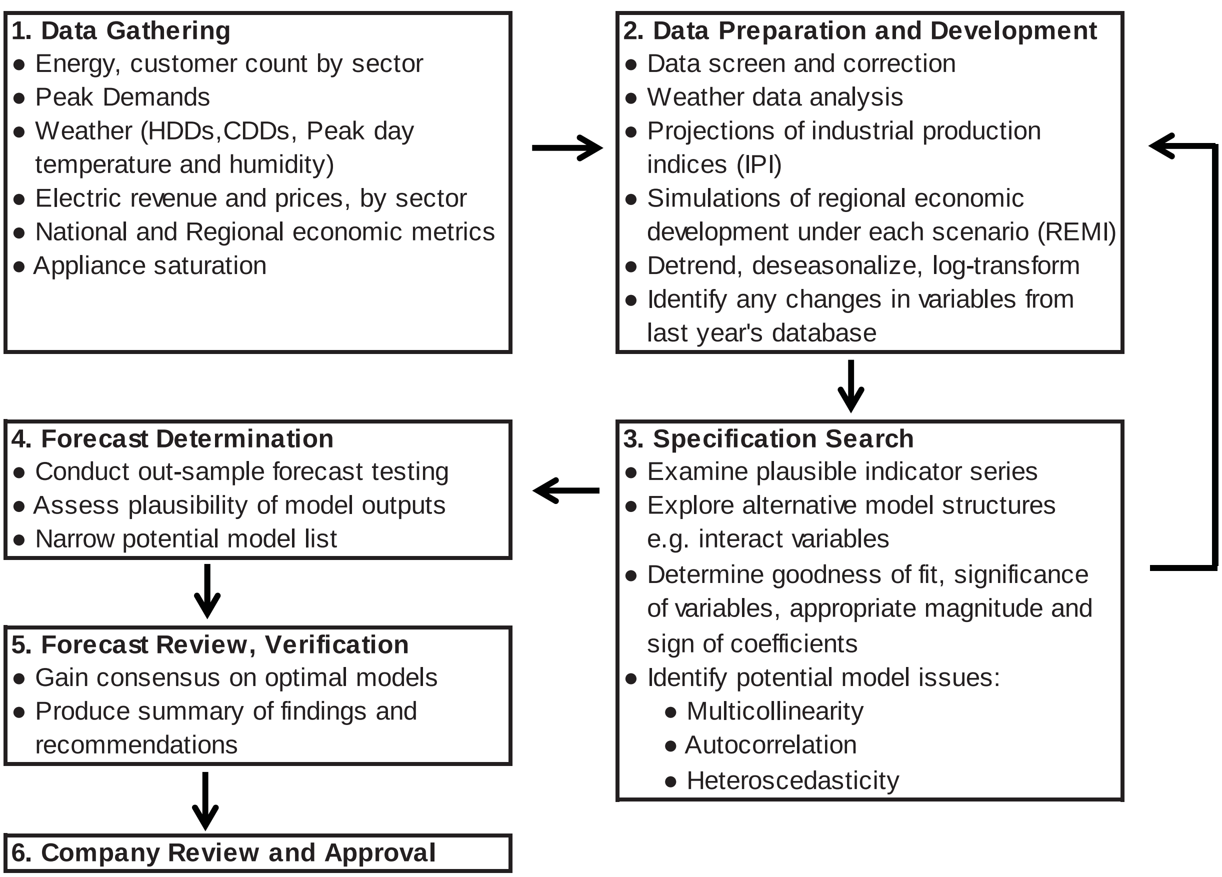
1. Forecast Methodology

A. Overall Framework

Minnesota Power's forecast models are the result of an analytical econometric methodology, extensive database organization, and quality economic indicators. Forecast models are structural, defined by the mathematical relationship between the forecast quantities and explanatory factors. The forecast models assume a normal distribution and are "50/50"; given the inputs, there is a 50% probability that a realized actual will be less than forecast and a 50% probability that the realized actual will be more than forecast.

The Minnesota Power forecast process involves several interrelated steps: 1) data gathering, 2) data preparation and development, 3) specification search, 4) forecast determination, 5) initial review and verification, and 6) internal Company review and approval. The steps of the forecast process are sequential, although because of the research dimension involves feedback loops between steps 2 and 3. The process is diagrammed in the figure below and discussed in more detail in the next section.

MINNESOTA POWER'S FORECAST PROCESS, 2013 AFR



B. Minnesota Power's Forecast Process

AFR 2013 Forecast Process

1. *Data Gathering* involves updating or adding to the forecast database. The data used in estimation can be broadly categorized as follows:
   - *Historical quantities of the variables to be forecast*, which consists of energy sales and customer counts for Minnesota Power's defined customer classes, plus system-level energy and peak demands.
   - *Demographic and Economic data for the Minnesota Power service territory* consists of population, households, sector-specific employment, and income metrics.
   - *Indicators of National economic activity* such as the Industrial Production Indexes or Macroeconomic indicators such as GDP or Unemployment.
   - *Weather and related data* including heating degree days, cooling degree days, temperature and humidity.
   - *Electricity and Alternative Fuel prices*, which includes the price of electricity, natural gas, heating oil, and propane by sector for the Minnesota Power service territory.

   After gathering these data, Minnesota Power compares all series to the previous year's database to identify any changes. The cause of any change to the historical data should be explained and justified. This is explained further in Section C: *Inputs and Sources*.

2. *Data Preparation and Development* includes reviewing the data through diagnostic testing and inspection. Minnesota power tests the stationary of independent variable series using an Augmented Dicky-Fuller test for unit root. Any series failing this test and found to be non-stationary is de-trended and de-seasonalized to avoid the potential for spurious correlation with the dependent variable during the *Specification Search* step of the forecast process.

   This step also includes transforming the data (logging the series, for example), creating dummy variables, and developing interaction terms. The final forecast database contains 237 independent variables.

3. *Specification Search* involves selecting an appropriate set of variables that serve as explanatory factors for the customer count, energy sales, and peak demand series being modeled[1]. Minnesota Power does this through a formalized modeling and documentation process involving 5 steps:

   a. Examine correlation matrices – A correlation matrix displays the correlation of each variable to all other variables included in the analysis. To narrow the list of probable economic variable combinations, Minnesota Power identifies two ideal configurations:

---

[1] Specific analytical techniques applied during this step are detailed in Section D.

   i. Variables that are highly correlated with the dependent variable – this shows which variables, if used as the sole economic/ demographic variable, would be highly indicative of energy sales or customer count.
   ii. Two variables that are highly correlated with the dependent variable, but have low correlation with each other. This suggests that each variable is explaining a unique aspect of the change in energy sales or customer count, and that both variables could be used in combination without issues of multicollinearity.

b. List plausible variable combinations – Use the ideal configurations identified by examination of the correlation matrixes to list plausible combinations of economic and demographic variables.

c. Construct models for each viable combination of economic/demographic variables – Apply weather variables, binaries, time-trends, lagged-dependent variables, etc… to explain other aspects of the dependent variable. In total, nearly 1,000 unique models were developed as part of the *Specification Search* step.

d. Archive model specifications for documentation and further analysis:
   i. Input data,
   ii. Correlation matrices,
   iii. Model statistics, and
   iv. Model outputs (Forecast)

e. Test models for:
   i. Goodness of fit: Adjusted R-Squared and MAPE (Mean Absolut Percent Error).
   ii. Model simplicity and efficiency: AIC and SIC
   iii. Heteroscedasticity: Breusch-Pegan F, Breusch-Pegan ChiSq, and White's F tests.
   iv. Multicollinearity: Variance Inflation Factor (VIF) of each input variable
   v. Autocorrelation: Breusch-Godfrey F & Chi-Squared, Durban-Watson, and Durban-H
   vi. Specification tests of non-linear variable combinations: Ramsey's RESET F

4. *Forecast Determination* is a process where models are compared against one another to narrow the list of potential models through more thorough review. Minnesota Power examines model statistics, conducts out-sample testing, and assesses the plausibility of the model's outputs (i.e. the forecast). This step narrowed the model list from nearly 1000 to just 62 select models.

5. *Forecast Review and Verification* produces a list of the optimal models for forecasting each of the customer count, energy sales, and peak demand series. Analysts compare the alternative models from the *Forecast Determination* step and come to a consensus on a single, preliminary model for each of the dependent series based on a number of criteria (14 models total). Where a consensus cannot be immediately reached because two models may be highly comparable in statistical quality and plausibility of outputs, objective measures (SIC and out-sample accuracy) determine the model put forward for *Company Review and Approval.*

5. *<u>Company Review and Approval</u>:* All forecasts are vetted internally to ensure that consistent use of forecast information was employed and that the forecasts are reasonable.

Methodological Improvements for the 2013 Forecast

1. *<u>Removing Trend and Seasonality:</u>* All independent variables are tested for trend using the Augmented Dickey-Fuller (ADF) test. If the ADF test determines the series is non-stationary, it is transformed using a log transformation or differenced. Regressing with de-trended data reduces the potential for spurious correlation and thus increases the accuracy of the estimates.

2. *<u>Temperature Range Stratification Approach (Peak Demand Model):</u>* Minnesota Power noted that temperature variables, as previously defined, were typically found to be insignificant in well-specified peak demand models. To address this issue, temperature variables were stratified by *Temperature Range* instead of by Month (via a *Monthly Interaction*). This alternative stratification method produced better estimates of temperature's impact on demand ("weather effect"), improved significance of the coefficients, and prevented some statistical issues such as multicollinearity.

This new approach stratifies temperature variables according to range: if the temperature on the peak day falls within a certain temperature range, it's reordered in that series. The *Temperature Range Arrangement* table below (left) demonstrates this stratification scheme. It shows that the average temperature on the day of the Jan-2012 peak was -9°, thus it falls under the -10° to 0° strata/ variable. The table *Monthly Interaction Arrangement* below (right) is an example of how the data were previously organized: by month.

Temperature Range Arrangement - Average Temperature on Day of Monthly Peak

	< n20	n20-n10	n10-0	0-10	10-20	20-30	30-40	40-50	50-60	60-70	70-80	80-90	90-100
Jan-12	-	-	(9)	-	-	-	-	-	-	-	-	-	-
Feb-12	-	-	-	-	17	-	-	-	-	-	-	-	-
Mar-12	-	-	-	-	-	-	-	-	-	-	-	-	-
Apr-12	-	-	-	-	-	-	33	-	-	-	-	-	-
May-12	-	-	-	-	-	-	-	-	-	-	71	-	-
Jun-12	-	-	-	-	-	-	-	-	-	-	73	-	-
Jul-12	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug-12	-	-	-	-	-	-	-	-	-	-	75	-	-
Sep-12	-	-	-	-	-	-	-	-	-	-	71	-	-
Oct-12	-	-	-	-	-	-	38	-	-	-	-	-	-
Nov-12	-	-	-	-	19	-	-	-	-	-	-	-	-
Dec-12	-	-	-	-	17	-	-	-	-	-	-	-	-

Monthly Interaction Arrangement - Average Temperature on Day of Monthly Peak

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Jan-12	(9)	-	-	-	-	-	-	-	-	-	-	-
Feb-12	-	17	-	-	-	-	-	-	-	-	-	-
Mar-12	-	-	30	-	-	-	-	-	-	-	-	-
Apr-12	-	-	-	33	-	-	-	-	-	-	-	-
May-12	-	-	-	-	71	-	-	-	-	-	-	-
Jun-12	-	-	-	-	-	73	-	-	-	-	-	-
Jul-12	-	-	-	-	-	-	80	-	-	-	-	-
Aug-12	-	-	-	-	-	-	-	75	-	-	-	-
Sep-12	-	-	-	-	-	-	-	-	71	-	-	-
Oct-12	-	-	-	-	-	-	-	-	-	38	-	-
Nov-12	-	-	-	-	-	-	-	-	-	-	19	-
Dec-12	-	-	-	-	-	-	-	-	-	-	-	17

Appropriate stratification of the temperature variables improves the estimates of temperature's impact on demand (coefficients) in two ways:

a. *Isolation and identification of significant and insignificant ranges* allows for the inclusion of only the most indicative observations. Insignificant observations (e.g. mild temperatures from 50° to 60°) and significant ones (e.g. extreme temperatures from 80° to 90°) are organized into separate series via the *Temperature Range Stratification Approach.* The 50°to 60° variable can be omitted since these observations contribute nothing to the model, while the 80°to 90° variable is be retained.

Further, the model's estimates of weather affects are not diluted by irrelevant observations. Under the *Temperature Range Stratification Approach*, the model can accurately and confidently estimate how a 1° change would affect peak demand when temperatures are in the 80° - 90° range. This would not be possible in the previously utilized *Monthly Interaction* approach; the historical average temperatures on July peaks, for example, range from 56° to 82° and the model would assign a single coefficient to this entire temperature series. Weather impact estimates using the *Monthly Interaction* approach would be dilute, and therefore, less accurate.

b. *Cross-month analysis* allows the regression to draw parallels between observations of similar temperatures in multiple months; the model's estimation is not restrained to observations of weather that have occurred historically in a single month., This means the model can draw on more observations of the interaction between Peak Demand and temperature, which increases accuracy and confidence.

The *Temperature Range Stratification Approach* also avoids some multicollinearity as compared to a more traditional arrangement with monthly interactions of temperature. The latter arrangement is almost guaranteed to result in multicollinearity since monthly binaries and monthly temperature interactions are highly correlated with each other.

The example table *"Monthly Interaction Arrangement"* (above) shows the stratification of the *Average* temperature on the day of the peak into 13 strata. Minnesota Power also stratified the High temperature on the day of the peak (adjusted for humidity, THI) and the Low temperature on the day of the peak (adjusted for wind-chill). Stratification of the Average, High, and Low temperatures on the day of the peak into the 13 temperature ranges resulted in 39 individual variables.

All 39 temperature variables were then tested in the model and only the most indicative temperature strata were retained. Variables were then grouped together where they shared similar coefficients and/ or covered similar temperature ranges (e.g. "Temp 0-40" = 3 strata: 0-10, 10-20, 20-30, and 30-40)

The variables that were retained and utilized in the final model are intuitive. The significant range and whether the Average, High, or Low was utilized corresponds to when in the day the peak typically occurs.

For example: Historically, peaks occurring on extremely cold days occur in the mid to late-morning when temperatures are closer to the daily low then to the daily average. Thus, the "Temp < -10°," strata utilizing the daily low, was found to be the most significant indicator of demand behavior. The daily average temperature was found to be most significant in the "Temp -10 ° to 0 °" strata range. This suggests that in these less extreme situations the average temperature is more indicative of peak demand behavior. This seems plausible as peaks occurring in these conditions either peak in the morning when it's coldest or in the evening when it's close to the warmest. Average temperature as an indicator likely serves to split the difference.

Specific Analytical Techniques

For the 2013 forecast, Minnesota Power has instituted a more systematic and thorough model development process which is described in the *Specification Search* step of Minnesota Power's Forecast Process. This section defines the specific statistical metrics and tests, and explains how these diagnostic criteria are applied.

As a rule, all models are ordinary least squares (OLS) and all input variables' coefficients must be significant at a 90% level (as indicated by p-values less than 10%). OLS models are simple, transparent, explainable, and produce optimal estimates of the coefficients. Confidence in the significance of these coefficients is maintained as long as the model is not negatively affected by autocorrelation or heteroscedasticity.

During the *Specification Search* and *Forecast Determination* step, each model is subject to the criteria below:

1. <u>Test for autocorrelation using:</u>
    a. ACF and PACF Plots
    b. Breusch-Godfrey test - Low p-value (below 5%) rejects the initial hypothesis and indicates presence of potentially problematic autocorrelation.
    c. Durban-Watson and Durban-H

    If autocorrelation is present:
    d. First, attempt to solve with use of a lagged-dependent variable
    e. If a lagged-dependent variable does not resolve the serial-correlation:
        i. Include ARMA terms to solve for autocorrelation and obtain accurate estimates of coefficient's t-stats and p-values
        ii. Remove truly insignificant variables (as indicated by high p-values)
        iii. Remove ARMA terms to revert to a corrected OLS model

    ARMA terms are only used to assess p-values and the process results in an OLS model where autocorrelation may still be present. However; the presence of this autocorrelation is known to have minimal effect on model coefficients and the every coefficient is truly significant.

2. <u>Test for multicollinearity using VIFs (Variance Inflation Factors) -</u> multicollinearity is generally unacceptable in the final models but correlation of variables is assessed in context of other variables and model statistics. The VIF of a variable is a measurement of its correlation with every other variable in the model whereas a correlation matrix would only identify the correlation of two variables to each other at each point in the matrix. Thus, VIF's are superior to a correlation matrix as a method of identifying multicollinearity. VIF's are assessed according to these criteria:

    a. VIF less than 3 is optimal - correlation with the remaining variables is less than 82%.
    b. VIF of 3-5 is acceptable, but is assessed in context with other diagnostics.

c. VIF of 5-10 is generally unacceptable, but is assessed in context with other diagnostics. A VIF > 5 implies correlation with remaining variables is greater than 90%.
d. VIF greater than 10 is strictly unacceptable correlation for any economic or weather variable. In this case the correlation with the remaining variables is greater than 95%.

VIF's on all economic and demographic variables in all models are well within acceptable limits. Monthly weather variables also had low VIF's. The only variables found in final models with VIF's greater than 10 (indicating high multicollinearity) were lagged-dependent, time-trend, and monthly binary variables. This is entirely expected and acceptable since these variables should exhibit high degrees of correlation with all other variables in the model.

3. Test for heteroscedasticity using:
   a. Breusch-Pegan F and Chi-squared
   b. White's F tests.

Presence of heteroscedasticity cannot bias the estimates of the coefficients. However, heteroscedasticity can affect the measured standard errors of the estimates, which may bias the estimates of t-statistics and p-values.

Where possible, Minnesota Power utilized models that passed at least one of the above mentioned tests rejecting the presence of heteroscedastic conditions. This was not possible in all cases as no plausible alternative models could be identified. Alternative models either contained similar levels of heteroscedastic conditions or failed other statistical tests. In these cases, Minnesota Power had no choice but to accept that estimates of p-values in these models may be biased. As a result, four of the fourteen final models in this year's forecast may be affected by heteroscedasticity.

Models that meet the above criteria, have plausible outputs (forecasts), and have intuitive econometric interpretations are put forward as potential final models for review during the *Forecast Determination* and *Forecast Review and Verification* steps (AFR 2013 Forecast Process pg. 5).

Treatment of Demand-Side Management (DSM) and Conservation Improvement Programs (CIP)

DSM programs represent activities that a utility undertakes to change the configuration or magnitude of the load shape of individual customers or a class of customers in the interest of reducing environmental impact and postponing construction of new capital.

Minnesota Power has engaged in several different types of DSM:

- *Conservation* - Conservation results in a reduction in total electric energy consumed by a customer and the potential to reduce both on-peak and off-peak demand. Conservation generally results in a reduction in the overall rate of growth of electric energy demand. Conservation, in the context of Minnesota Power conservation programs, may also include process efficiency, which results in the potential to reduce the total electric energy consumed by a customer as well as to decrease on-peak and/or off-peak demand. Process efficiency reduces the overall growth rate of electric demand because it results in greater production, through more efficient equipment or processes, from a facility for the same energy inputs. If the facility failed to implement process efficiency projects, more electric energy would be required to meet production requirements. Process efficiency generally results in avoided energy production and capacity additions over the long-term.

- *Peak Shaving* - Peak shaving reduces peak demand without affecting off-peak demand. Minnesota Power's dual-fuel load control and the Large Power (LP) interruptible programs are peak shaving programs.

- *Load Shifting* - Electric demand is shifted from on-peak to off-peak hours.

Minnesota Power excluded any exogenous DSM/CIP data adjustment to the energy sales and demand forecasts. The impact of conservation and DSM/CIP programs are present in the historical data upon which all AFR 2013 models were constructed, and are therefore implicit in the forecasts. An exogenous adjustment on top of the embedded impacts will double count the effects of conservation and misstate energy consumption.

Methodological Strengths and Weaknesses

Minnesota Power's forecast process combines econometric modeling with a sensible approach to modifying model outputs for assumed changes in large customer loads. An econometric approach, utilizing regression modeling, is optimal for estimating a baseline projection with a given economic outlook. However; a fully econometric process would not imply any of the substantial industrial expansion that's likely in the Minnesota Power service territory. A combined "econometric/ large customer load addition" approach produces the most reasonable forecast.

That said, there are some weaknesses to this approach. There is some subjectivity in the perceived likelihood of individual large customer load addition/ losses since their magnitude or timing is difficult to estimate in a probabilistic way. Minnesota Power is also highly sensitive to large industrial customer decisions as large taconite, paper, and pipeline customers represent more than half of Minnesota Power's system demand and energy sales at any given point in time.

Minnesota Power addresses this potential for error by maintaining close contact with existing and potential customers. Approximation of the large customer load additions are based on this contact and reflect Minnesota Power's best estimate of changes in load and energy under each scenario.

Two key strengths of the newly instituted formalized modeling process: 1) highly replicable, and 2) adept at narrowing the list of potential models to only those that are most likely to produce quality results which allows more time for in-depth statistical testing and critical review of each model.

C. Inputs and Sources

Minnesota Power draws on a number of external data sources and vendors for its indicator variables. Each year, the forecast database is updated with the most current economic and demographic data available. This involves an update of the entire historical timeframe since these data are frequently revised. Special attention is given to identifying any changes from previous years' data and data sources. Changes from last year's database are clarified later in this section.

AFR 2013 Forecast Database Inputs

Weather

Weather data for Duluth, MN was collected for historical periods from the National Oceanic and Atmospheric Administration (NOAA) and from Weather Underground[2]. Monthly Heating Degree Days (HDD) and Cooling Degree Days (CDD) form NOAA are used to model monthly energy sales. The monthly HDD and CDD values are normalized for the number of days in a month by dividing the monthly HDD or CDD count by the number of days in the month. This result in the "per-day" series HDDpd and CDDpd. For example:

The "per-day" value of 46.1 HDDpd in January 1990 was calculated as follows:

> Duluth Minnesota's HDD count for January 1990 (1428) is divided by the number of days in January (31) to produce an HDDpd value of 46.1.

Normalizing the series by converting to a per-day unit allows for a more accurate estimate of the weather's impact on energy sales.

The temperature, humidity, and wind-chill data used to model peak demand are derived from Weather Underground. This is a source change, but it does not result in any difference in the historical timeframe. The change was prompted by the ease of access and need for more weather metrics to test as potential model inputs.

Development of the historical weather series involves establishing the date of historical monthly peaks using Minnesota Power's edited electronic database for 1999-2013). Minnesota Power used FERC Form 1 recorded peak dates for the timeframe prior to the establishment of the current electronic database (1990-1999). Weather data for these dates is then gathered and organized into monthly-frequency peak-day temperature series.

A Temperature-Humidity Index (THI) is utilized to take into account the effect of heat and, when applicable, humidity on summer peaks[3]. The THI is only applicable when temperatures exceed 80 degrees and relative humidity exceeds 40%. If both conditions are not met, humidity's impact is assumed to be minimal and is excluded; the daily high temperature is used as the sole weather variable in this situation. A Wind-chill index[4] (WC) was also utilized to capture the cold temperatures and, when applicable, the cooling effect of wind speed.

The forecast assumptions for all weather series is an average of the most recent 20 year period, ending in March 2013.

IHS Global Insight

IHS Global Insight Inc. provides historical and projected monthly employment and income series for Minnesota Power's 13 county planning area. The data is calculated through a "Top-down/ Bottom-up" approach; the area's economy is modeled independently, considering unique local conditions, and is linked to the national economy to ensure consistency across the national, regional, state, and MSA levels.

Minnesota Power utilizes the historical monthly employment series as delivered by Global Insight. Income series are converted to 2005 dollars for consistency with other dollar-denominated series in the AFR database. Global Insight's forecasts of the employment and income series are adjusted using Regional Economic Models, Inc. (REMI) for each of Minnesota Power's economic forecast scenarios, explained below.

Global Insight utilizes the most current data available from public data sources to produce Minnesota Power's regional employment and income variables. The historical data is updated frequently by these public data sources and Global Insight's estimates of these historical series are updated accordingly. Thus, the regional employment and income data has changed from last year's database.

Regional Economic Models, Inc. (REMI)

Minnesota Power subscribes to the latest REMI Policy Insight version, PI+, for northeastern Minnesota. This input/output and econometric simulation regional forecast model is used to quantify a national economic outlook and regional economic development in terms of economic gains and losses for the Minnesota Power area. The REMI model captures the indirect economic effects from expansions, layoffs, and closures in the planning region, allowing Minnesota Power to examine the potential impacts of these events.

For the 2013 AFR, REMI was used to incorporate known and expected changes in the region's mining employment. The REMI model historical and forecast results are used as an expected regional outlook for employment by sector, demographics, economic output by sector, and gross regional product (GRP) variables in the monthly forecast. Sensitivities are developed for other outlooks using a bandwidth of possible employment and production scenarios.

3 http://www.srh.noaa.gov/images/ffc/pdf/ta_htindx.PDF
[4] http://www.nws.noaa.gov/os/windchill/index.shtml

The annual expected regional output from REMI was combined with the employment and income data, provided by Global Insight Inc., to obtain measures of economic activity, which were used as explanatory variables in the 2013 AFR. The monthly estimates from Global Insight Inc. were calibrated to the REMI expected-case results for the regional economy. As the REMI outlook is adjusted for alternative planning scenarios, the monthly employment and income outlooks are changed accordingly.

Like Global Insight, REMI relies on data from public sources that is subject to revision. These revised data result in revised historical values for the economic and demographic indicators used in Minnesota Power's database.

Blue Chip Economic Indicators

Blue Chip Economic Indicators issues a long-term national economic forecast twice per year. Minnesota Power used the March 2013 issue for long-term forecasts of economic growth (real GDP), inflation (GDP chain-type price deflator index in 2005 dollars), real disposable personal income, and other macroeconomic metrics. The consensus GDP forecast is a major driver of the regional REMI model. Historical values of macroeconomic variables were obtained from the Bureau of Economic Analysis (BEA) and the Bureau of Labor Statistics (BLS).

Blue Chip Economic Indicators also provides alternative economic scenarios. High and low cases are represented by the top 10 and the bottom 10 survey respondents, which are used as primary economic drivers in Minnesota Power's alternative scenarios.

Indexes of Industrial Production (IPI series)

The indexes of industrial production relate all sector-specific production in a given month to a base year, 2007 in this case (that is, 2007 = 100). The indexes exhibit a high degree of correlation with Minnesota Power's historical industrial energy sales and are therefore ideal for forecasting future energy sales to the class.

The historical IPI data were obtained from the Board of Governors of the Federal Reserve. The historical data is regularly revised to incorporate better data, better methods, and to update the base year. To capture these revisions, Minnesota Power updates the entire historical data series each year. These revisions are discussed in Federal Reserve documents[5].

Forecasts for each IPI were developed from the projections of macroeconomic data in the March 2013 issue of Blue Chip Economic Indicators, and are therefore consistent with all other AFR 2013 assumptions. These macroeconomic drivers are used model the IPI series.

Energy Prices

[5] http://www.federalreserve.gov/releases/g17/revisions/Current/g17rev.pdf

Estimates of future Minnesota Power rate changes are incorporated into the average electric price forecasts as generally indicative of the intention and anticipation of changes in Minnesota Power's rate structure and prices.

Average energy prices, history and forecast data, are from the Department of Energy (DOE) and Energy Information Administration (EIA). The fuel types considered are electricity and natural gas. End-use class energy price data is categorized by DOE/EIA into residential, commercial, and industrial. DOE's Annual Energy Outlook (AEO) is used for the forecast period. DOE provides historical energy price data for Minnesota, forecast energy price data for the West North Central (WNC) region, and the national total. Minnesota Power's historical average electric price data are from the Company's Federal Energy Regulatory Commission (FERC) Form 1 and represent annual class revenue divided by annual class energy. All energy prices are deflated by the 2005 base year GDP implicit price deflator (IPD).

Appliance Saturation

Estimates of historical and forecast central air conditioning (CAC) saturation in the residential customer class are developed by synthesizing several pieces of information. Minnesota Power drew on past and on-going customer surveys to construct a historical CAC saturation series from respondents' answers regarding age of the CAC, dwelling age, etc... The constructed CAC saturation series was then modeled using Duluth MSA housing starts.

A clear statistical relationship was noted between CAC growth and the number of housing starts in the preceding year. Minnesota Power used this correlation to develop the forecast assumption of area CAC saturation.

Electric Heat (EH) saturation is calculated as the share of total Residential customers that are either Space Heating or Dual Fuel. Minnesota Power then fits a fourth-degree polynomial function to the historical EH saturation series. This polynomial function is carried out into the forecast timeframe to generate an EH saturation assumption.

Data Revisions Since Previous AFR

Minnesota Power made no changes to its database concerning internally derived data (customer counts, energy sales, and peak demand) except for updating with an additional year of observation.

Regarding externally derived data, Minnesota Power noted several changes in the historical database. None of these changes resulted in an unexplainable or implausible transition; therefore, Minnesota Power was confident moving forward with the database updates. The table below shows series that were utilized in both the 2012 and the 2013 forecast.

Economic and Demographic Variables	Changes to Database 2012 to 2013
MP Area Population	Change #1
MP Area Households	Change #1
MP Area Personal Income	Change #2
MP Area Wage Disbursements	Change #2
MP Area Employment in Education and Health	Change #2
MP Area Employment in Manufacturing	Change #2
MP Area Employment in Trade, Transport, Utilities	Change #2
Industrial Production Index: Iron Ore Mining	Change #3
Industrial Production Index: Paper	Change #3

Change #1 (MP Area Population and Households) – Annual data for the intercensal timeframe 2001-2009 was updated by REMI per updates to other economic and demographic series used as inputs in the REMI model. The largest difference in any one historical year in this timeframe is a 0.6% increase in both population (3,400 people) and area households (1,400 households). Note that this is raw data derived directly from the REMI model and has not been adjusted by Minnesota Power. The 2011 population and household data were also found to differ. This year's historical database shows an estimated 2011 population that's about 4,500 higher (0.8%) than in last year's database. This change was due to recalibration of the model to an alternative national economic outlook (Blue Chip Economic Indicators' outlook) which has the effect of changing the more recent historical timeframe.

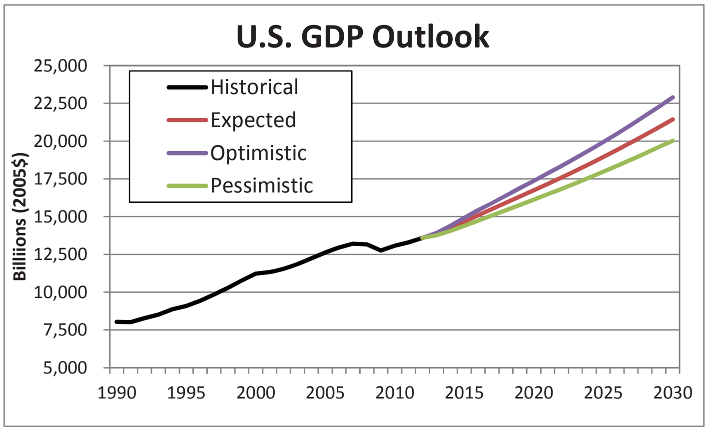
Change #2 (IHS Global Insight Economic Data) – When aggregated to annual values, the income and employment series show minimal variation from the last year's historical data. Differences prior to the 2008-2011 timeframe are minor; a difference of just 15 jobs (0.03%) in MP Area trade, transportation, and utilities employment represents the largest single-year difference. In the 2008-2011 timeframe differences between last year's and this year's database are slightly larger; a difference of about 500 jobs (1%) in MP Area trade, transportation, and utilities employment represents the largest single-year difference in this timeframe. All historical data utilized in the forecast database was provided by IHS Global Insight and was not adjusted by Minnesota Power in any way.

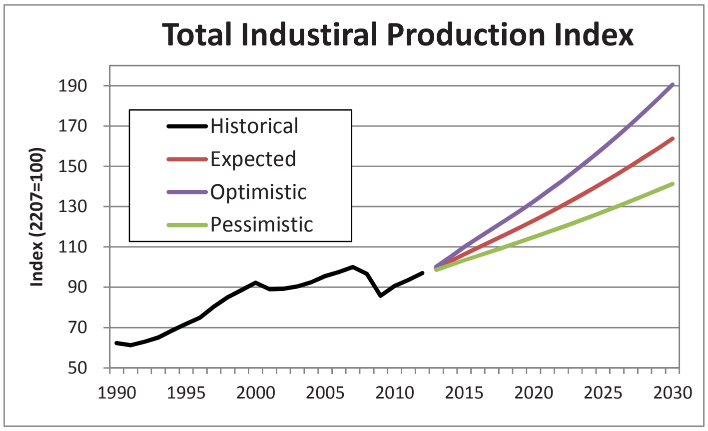
Change #3 (Industrial Production Indexes) – Differences in the historical IPI series between last year's and this year's database are very small. The Federal Reserve Board reduced the historical Iron IP index by a fairly constant 0.1% except in the recent historical timeframe (2009-2011) where the index was increased slightly (0.46% on average). The Paper IP index was unchanged at any significant decimal place. Both historical IPI series were downloaded from the Federal Reserve Board's Data Download Program and were not adjusted by Minnesota Power.

D. Overview of Key Inputs/Assumptions

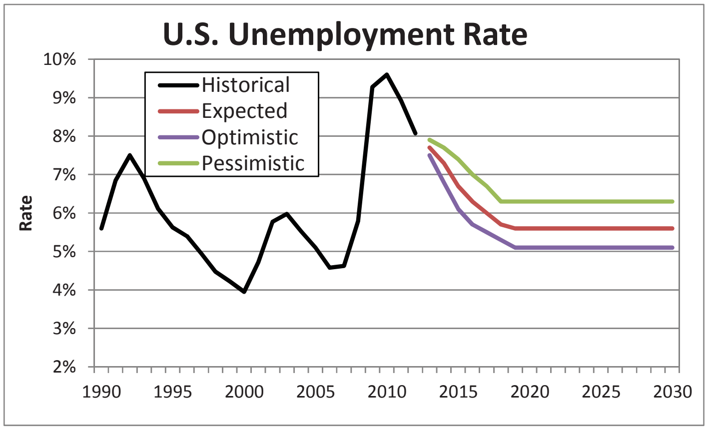
National Economic Assumptions

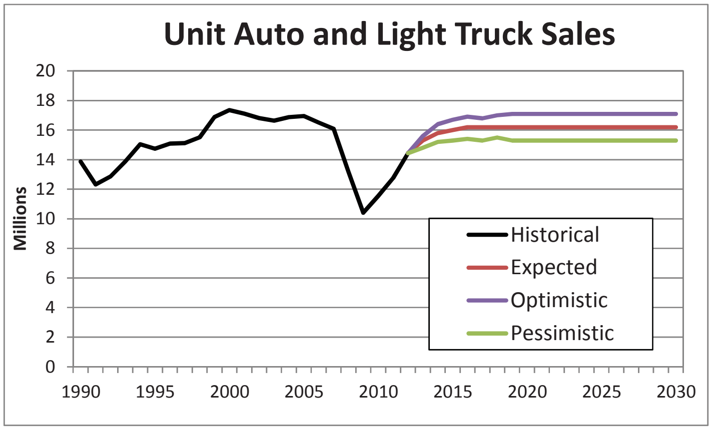
The national economic outlook is derived from Blue Chip Economic Indicators and serves as the basis for Minnesota Power's regional economic model simulations. Some of the key outputs of the national economic forecast are GDP, IPI, unemployment rates, and auto sales. These variables are shown below, for the Expected, Optimistic, and Pessimistic cases.





In the Expected case, U.S. GDP growth averages 2.6% per year from 2013-2027 and IPI growth averages 3.0% in the same timeframe. The Expected case macroeconomic outlooks are the underlying assumptions of the Current Contract, Moderate Growth, and Potential Upside scenarios. The Pessimistic case macroeconomic assumptions serve as the basis for the Potential Downside scenario; in this case, GDP growth averages just 2.2% per year and IPI growth averages just 2.1% per year in the forecast timeframe. The Optimistic macroeconomic outlook drives the Best Case scenario; in the Optimistic outlook GDP growth averages 3.0% per year and IPI growth averages 3.9% per year in the forecast timeframe.



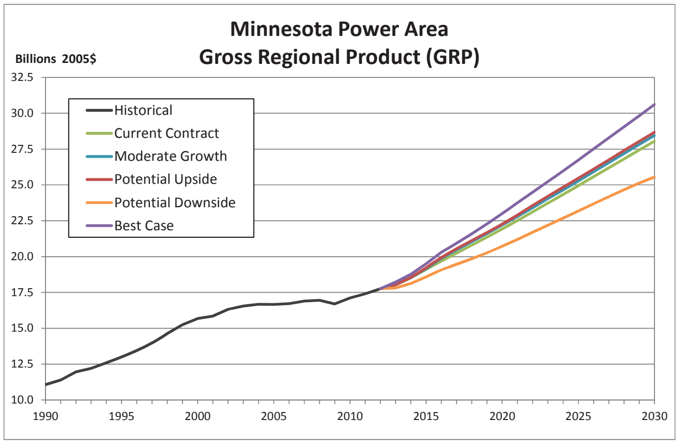


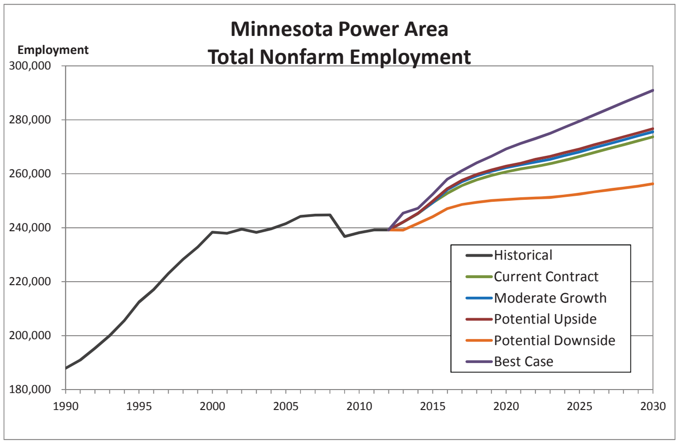
The unemployment rates in the three national outlooks all fall steadily in the first few years of the forecast timeframe before reaching long term labor market stability consistent with the assumed rate of GDP growth. Assumptions of unit auto and light truck sales show similar pattern in the forecast timeframe with substantial improvement in the medium-term and stabilization in the long term.

Regional Economic Assumptions

The Regional Economic Model provided by REMI is calibrated to the geographic area additively defined as 13 counties, 12 counties in Minnesota (Carlton, Cass, Crow Wing, Hubbard, Itasca, Koochiching, Lake, Morrison, Pine, Saint Louis, Todd, and Wadena) and one county in Wisconsin (Douglas). This is referred to as the Minnesota Power "planning area" or the Minnesota Power area.

Alternative economic outlooks for the Minnesota Power planning area are based on the, high, and low outlooks for the nation. The regional economic outlooks are further specified by incorporating scenario-specific inputs into REMI, as described in Section 1.C. Two key series are graphed below to demonstrate the potential economic development of the region.





The Minnesota Power area (Gross Regional Product) (GRP) 2013-2027 is forecast to average 2.7% annual growth in the Current Contract scenario. The growth is slightly higher in the Moderate Growth and Potential Upside scenarios, averaging 2.8% and 2.9% annual growth, respectively. Average annual GRP growth in the Best Case scenario is forecast to average 3.2%, and 2.2% in the Potential Downside scenario.

Minnesota Power area Employment 2013-2027 is forecast to average 0.8% annual growth in the Current Contract, Moderate Growth, and Potential Upside scenarios. Average annual employment growth in the Best Case scenario is forecast to average 1.1%, and 0.4% in the Potential Downside scenario.

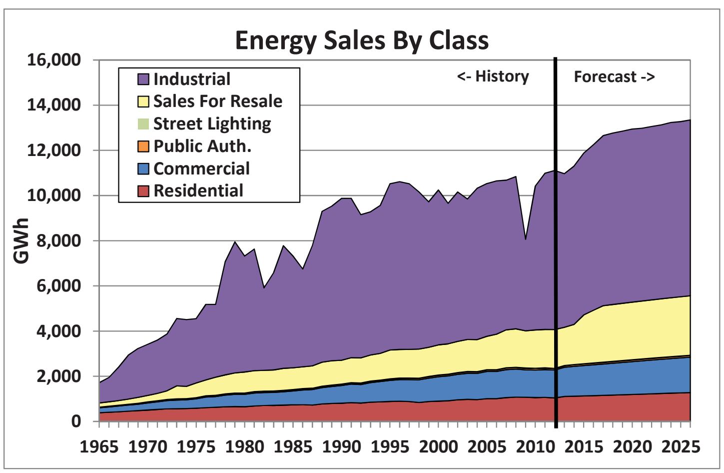
E. Model Documentation

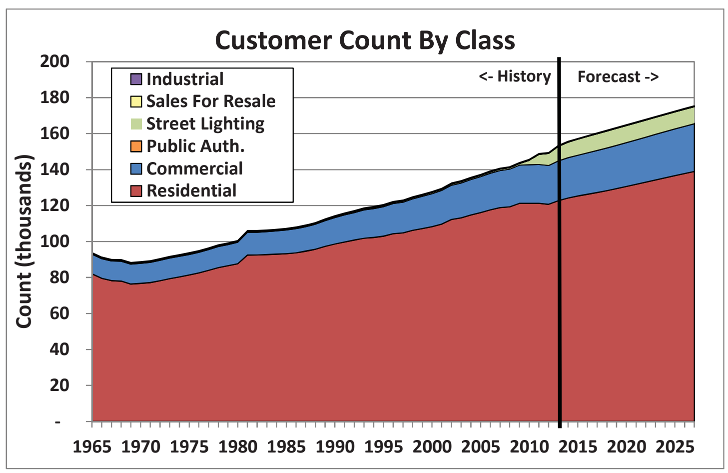
This section presents the statistical detail of all models utilized in the development of the AFR 2013 forecast. The models' structure, key diagnostic statistics, forecast results, and a discussion of the model are provided for added transparency.

Models are shown with each variable's coefficient, t-stat, p-value, and VIF. A graph displays the historical series, growth rates for time-frames of interest, and compares this year's forecast to last year's. A table shows a more focused view of the forecast with a shorter historical timeframe to examine year-over-year growth rates. Key diagnostic statistics for both the final OLS model and its ARMA-corrected corollary are shown in a table in the bottom left corner of each page. Specific diagnostic criteria and modeling techniques discussed in this section are described in detail in Section B. Minnesota Power's Forecast Process under the heading *Specific Analytical Techniques***.**

For each model, Minnesota Power offers a discussion of the modeling approach, econometric interpretations of key variables, and potential model issues. This portion of the model documentation also compares this year's model with last year's and notes any interesting findings or insights gained.

All forecast values shown in this section are the 2013 expected case "Moderate Growth" scenario. The outputs of each model are combined with specific load, energy, and customers count additions, and then aggregated. The total energy sales outlook is shown below (left) with the total customer count outlook (right).



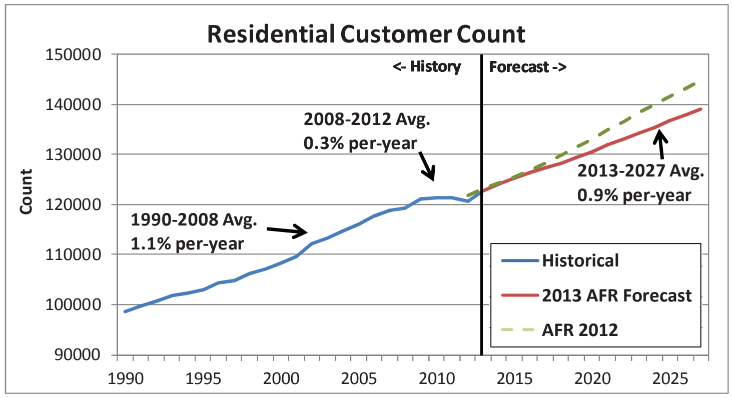


Minnesota Power did not develop a model to forecast Sales for Resale customer count. Minnesota Power currently has 18 resale customers, each of which has signed a service agreement. The loss or gain of a resale customer is therefore better accounted for by reviewing these agreements and communicating with customers. Econometric models are not appropriate for estimating future resale customer counts.

Residential Customer Count

Estimation Starting/Ending: 1/1992, 3/2013
Unit Forecast: Monthly Customer Count (Calendar Cycle)

Variable	Coefficient	T-Stat	P-Value	VIF
Constant	(5,185.98)	(4.38)	0.00%	
MP Area Households (Lag-24)	289.03	11.75	0.00%	40.15
Seasonal Billing Binary1	(1,830.25)	(9.32)	0.00%	1.26
Seasonal Billing Binary2	(2,124.75)	(11.76)	0.00%	1.93
Jan. 2008 Binary	(7,221.83)	(10.04)	0.00%	1.01
Apr. 2012 Binary	(8,871.41)	(12.34)	0.00%	1.01
LagDep(1)	0.19	5.49	0.00%	31.20
LagDep(12)	0.31	8.54	0.00%	35.61



Residential Customer Count

	Level	Y/Y Growth
2007	118,870	
2008	119,301	0.4%
2009	121,216	1.6%
2010	121,235	0.0%
2011	121,251	0.0%
2012	120,697	-0.5%
2013	**122,725**	**1.7%**
2014	**124,191**	**1.2%**
2015	**125,317**	**0.9%**
2020	***130,633***	***0.8%***
2025	***136,644***	***0.9%***

	OLS		ARMA Corrected	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	99.1%		99.5%	
AIC	13.1739		12.5680	
SIC	13.2850		12.7352	
MAPE	0.4%		0.3%	
Model F Test	3784.8	0.0%	4459.8	0.0%
Estimates Residual S.D.	714.47		523.73	
SSres	126084913		66378721	
Degrees of Freedom	247		242	
Breusch-Pegan F	4.2	0.02%	3.9	0.05%
Breusch-Pegan ChiSq	27.0	0.0%	25.3	0.1%
White's F	5.7	0.4%	3.7	2.6%
Breusch-Godfrey AIC F	14.7	0.0%	0.4	55.2%
Breusch-Godfrey AIC ChiSq	76.1	0.0%	1.6	21.1%
Breusch-Godfrey SIC F	27.4	0.0%	0.4	55.2%
Breusch-Godfrey SIC ChiSq	64.2	0.0%	1.6	21.1%
Durban-Watson	1.4	BAD	1.9	GOOD
Durban-H	5.3	N/A	0.6	N/A
FIT^2 Ramsey's RESET F	0.5	48.3%	-15.7	N/A
FIT^3 Ramsey's RESET F	2.4	9.6%	1.6	20.0%
FIT^4 Ramsey's RESET F	18.2	0.0%	3.0	3.3%
Out-of-Sample RMSE	1085.81		1087.96	
Out-of-Sample MAE	652.31		654.41	
Out-of-Sample MAPE	0.574%		0.576%	

Discussion of model:

The forecast of customer count growth has moderated due to persistently low growth in recent years despite improving economic conditions. This year's analysis revealed a strong statistical relationship between Residential customer count growth and MP area household formation (lagged-24 months). The relative improvement in indicative ability due to lagging the term was not surprising as many of Minnesota Power's previous Residential Customer Count models also contained lagged economic or demographic indicators. The main difference between the 2012 forecast and the 2013 forecast is the use of an alternative economic/ demographic variable (Households-Lag24 instead of Per-Capita Wages&Salaries-Lag12 and Population).

Minnesota Power's interpretation of the 2-year lag between MP area household formation and Residential customer count growth is as follows: During poor economic conditions, households may be constrained to more affordable housing situations such as multi-family residences where it's not uncommon to have multifamily residences under a single meter. When economic conditions improve and consumers are less constrained, those dwelling in multifamily residences are better able to purchase homes and become MP residential customers.

The "MP area household" variable is in levels and there is likely some spurious correlation because of this. However, few other variables were found to be truly significant – as identified by resolving autocorrelation with the addition of ARMA terms and examining the resulting p-values. Of those models containing significant variables that were either logged or differenced, none produced plausible forecasts. Thus, Minnesota Power had no choice but to accept this and commit to expanding its database in the future to identify more appropriate combinations of variables.

The model contains two sets of binary variables used to account for anomalies in the historical timeframe. One set of binary variables account for seasonal billing between 1994 and 2001. Due to accounting practices, during this timeframe the recorded customer counts from November to May are 2,000-6,000 lower than from June to October. The other set of binary variables "Jan. 2008 Binary" and "Apr. 2012 Binary" denote two billing anomalies where counts dropped (7,000 and 8,000 respectively) suddenly before returning to the previous level.

High VIF's on the lagged dependent variables and the "MP area household" variable are expected from a highly trended and autoregressive series. Of all alternative models examined, few were able to fully solve issues of heteroskedasticity and these alternatives had more significant issues with other statistical measures such as unsolvable autocorrelation or implausible outputs. Note that heteroskedasticity cannot cause coefficients to be biased, but can bias the estimate of standard errors.

Resolving autocorrelation with the inclusion of ARMA terms results in a model that implies Households-Lag24 is still significant at the 99% level of certainty. Adding ARMA terms to the model caused insignificance only in the constant and lagged-dependent variables. This is expected since the ARMA terms utilized (AR 1 & 12) are simply replicating the impact of dependent variables of lag 1 and 12. The OLS model should use lagged-dependent variables.

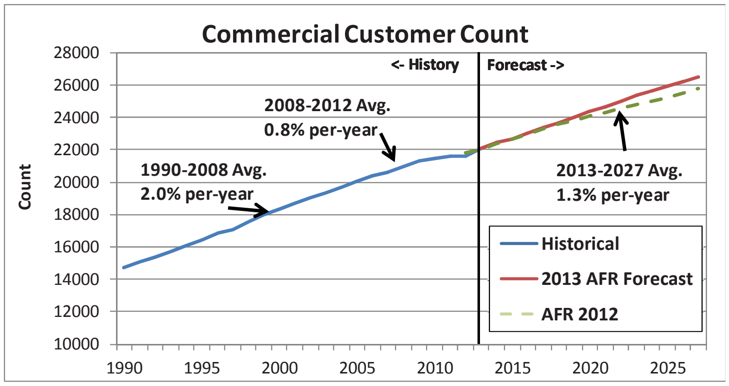
Out-of-sample testing confirms the model is superior to last year's model in applied performance: Out of sample forecast error of 2013 model = 0.6% vs. 1.1% in the 2012 model.

Commercial Customer Count

Estimation Starting/Ending: 1/1990, 3/2013
Unit Forecast: Monthly Customer Count (Calendar Cycle)

Variable	Coefficient	T-Stat	P-Value	VIF
Constant	(193,959.3)	(170.1)	0.00%	
MP Area Households (LN)	39,471.7	186.3	0.00%	1.01
Apr. 2012 Binary	(1,951.2)	(9.6)	0.00%	1.01

	Commercial Customer Count	
	Level	Y/Y Growth
2007	20,630	
2008	20,968	1.6%
2009	21,287	1.5%
2010	21,489	1.0%
2011	21,603	0.5%
2012	21,614	0.1%
2013	22,129	**2.4%**
2014	22,421	**1.3%**
2015	22,695	**1.2%**
2020	24,350	***1.4%***
2025	25,940	***1.3%***



Model Statistics	OLS Magnitude	OLS P-Value	ARMA Corrected Magnitude	ARMA Corrected P-Value
Adjusted R^2	99.2%		99.8%	
AIC	10.6229		9.3630	
SIC	10.6619		9.4579	
MAPE	0.9%		0.4%	
Model F Test	17384.1	0.0%	17530.3	0.0%
Estimates Residual S.D.	201.56		106.53	
SSres	11213297		2916685	
Degrees of Freedom	276		257	
Breusch-Pegan F	0.4	65.70%	2.9	5.81%
Breusch-Pegan ChiSq	0.8	65.4%	5.7	5.8%
White's F	6.6	0.2%	3.6	2.9%
Breusch-Godfrey AIC F	45.5	0.0%	0.0	88.6%
Breusch-Godfrey AIC ChiSq	189.3	0.0%	0.3	56.5%
Breusch-Godfrey SIC F	214.9	0.0%	0.0	88.6%
Breusch-Godfrey SIC ChiSq	194.6	0.0%	0.3	56.5%
Durban-Watson	0.4	BAD	2.0	GOOD
Durban-H	N/A	N/A	N/A	N/A
FIT^2 Ramsey's RESET F	114.4	0.0%	-59.5	N/A
FIT^3 Ramsey's RESET F	129.6	0.0%	1.8	16.2%
FIT^4 Ramsey's RESET F	150.4	0.0%	2.4	6.6%
Out-of-Sample RMSE	248.24		236.05	
Out-of-Sample MAE	189.02		172.18	
Out-of-Sample MAPE	1.035%		0.918%	

Discussion of model:

The current Commercial Customer count model is very simple, utilizing just one demographic variable. This is a from last year's model, which utilized a number of economic and demographic terms. Although some of the high-level model statistics such as "Adjusted R-Squared" appear inferior, the model is far more parsimonious.

The logged transformation of "MP Area Households" was found to be the most significant indicator of Commercial customer count growth. The applied log transformation suggests that relative change (i.e. the percentage increases) in the area households is more indicative than level change (i.e. the absolute increase) in the number of households.

The binary variable "Apr. 2012 Binary" denotes a transition in billing practices which resulted in a recorded month-to-month change of approximately 2,000 Commercial customers or about 8%. Since the count returned to a normal level in the following month, this is viewed as an anomalous point and a binary is applied to avoid biasing the results of the regression.

Heteroskedasticity was not an issue in the final model as 2 of 3 tests would reject its presence. Tests for autocorrelation show that it is present in the final OLS model. However, addition of ARMA terms to solve for this autocorrelation result in a model which validates these input variables; low p-values on all variables' coefficients are maintained with the addition of these ARMA terms.

Specification tests of non-linear variable combinations (Ramsey's RESET F tests) appear to suggest non-linear combinations would be more appropriate than the current linear specification. However, after correcting for autocorrelation (see "ARMA Corrected" results), Ramsey's RESET tests confirm linear inputs are appropriate for modeling Commercial customer count.

Out-of-sample testing shows a small decline in applied performance of the model compared to last year's model: Out of sample forecast error of 2013 model = 1.0% vs. 0.5% in the 2012 model.

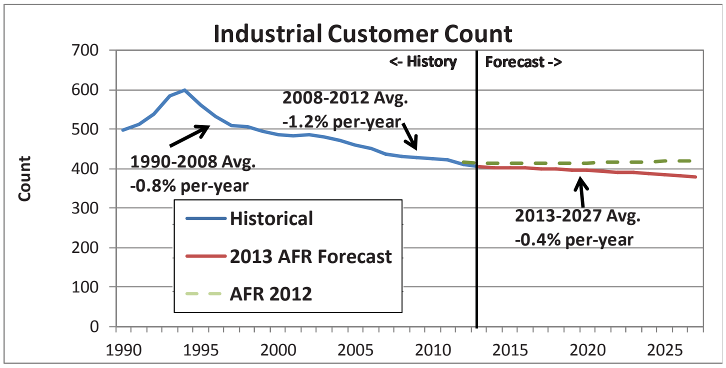
Industrial Customer Count

Estimation Starting/Ending: 2/1990, 3/2013
Unit Forecast: Monthly Customer Count (Calendar Cycle)

Variable	Coefficient	T-Stat	P-Value	VIF
MP Area Manufacturing Empl. (LN, Diff, Lead 24)	73.97	1.68	9.35%	1.01
LagDep(1)	1.00	1,236.1	0.00%	1.01

	Industrial Customer Count	
	Level	Y/Y Growth
2007	435	
2008	431	-1.0%
2009	429	-0.4%
2010	424	-1.3%
2011	421	-0.5%
2012	411	-2.5%
2013	404	-1.8%
2014	402	-0.3%
2015	403	0.2%
2020	*395*	*-0.4%*
2025	*384*	*-0.6%*

	OLS		ARMA Corrected	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	98.7%		98.8%	
AIC	3.5411		3.4677	
SIC	3.5674		3.5206	
MAPE	0.8%		0.8%	
Model F Test	N/A	N/A	N/A	N/A
Estimates Residual S.D.	5.85		5.62	
SSres	9352		8501	
Degrees of Freedom	273		269	
Breusch-Pegan F	1.8	17.08%	1.2	28.83%
Breusch-Pegan ChiSq	3.6	16.9%	2.5	28.6%
White's F	6.7	0.1%	3.3	4.0%
Breusch-Godfrey AIC F	5.6	0.0%	3.1	0.0%
Breusch-Godfrey AIC ChiSq	56.1	0.0%	34.7	0.1%
Breusch-Godfrey SIC F	20.1	0.0%	0.0	98.2%
Breusch-Godfrey SIC ChiSq	19.2	0.0%	0.1	79.4%
Durban-Watson	2.5	BAD	2.0	GOOD
Durban-H	-4.4	N/A	0.1	N/A
FIT^2 Ramsey's RESET F	0.7	41.7%	-17.7	N/A
FIT^3 Ramsey's RESET F	4.1	1.8%	0.7	50.8%
FIT^4 Ramsey's RESET F	5.1	0.2%	0.7	57.7%
Out-of-Sample RMSE	13.07		13.10	
Out-of-Sample MAE	8.25		8.25	
Out-of-Sample MAPE	1.620%		1.620%	



Discussion of model:

This year's model is fairly similar to previous industrial count models which, instead, utilized manufacturing output-per-employee, but produced similar projections. This model utilizes just one economic variable "MP Area Employment in the Manufacturing Sector – logged and lead" to predict changes in the industrial customer count. The applied log transformation suggests that relative change (i.e. the percentage increases) is more indicative than level change (i.e. the absolute increase).

The lead that is applied to the employment series suggests that increases in industrial customer count should precede any increase in employment. This is not surprising as employment is most typically classified as a lagging indicator, i.e. change in employment follows the change in another metric.

The series is highly autoregressive and the applied lagged-dependent term's coefficient of nearly 1 essentially makes this a "difference" model: the customer count in the current month is equal to the count in the previous month – plus whatever impact the relative change in manufacturing-sector employment would imply.

The constant was dropped from this model because of low significance (p-value = 50.6%). The low significance of the constant is not surprising given the coefficient on the lagged-dependent is 1.

Tests for autocorrelation show that it is present in the final OLS model. However, addition of ARMA terms to solve for this autocorrelation result in a model which validates these input variables; low p-values on all variables' coefficients are maintained with the addition of these ARMA terms.

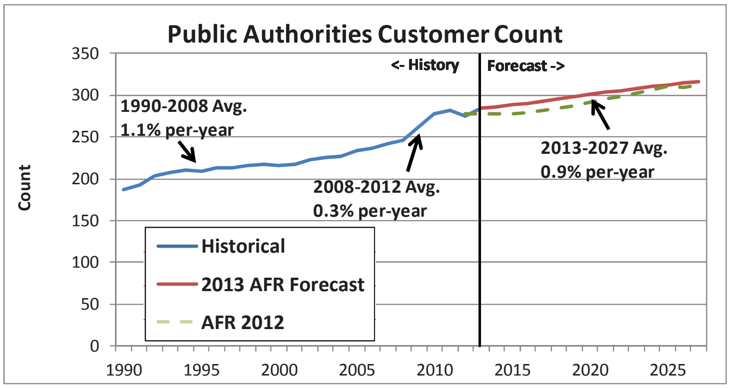
Out-of-sample testing confirms the model is superior to last year's model in applied performance: Out of sample forecast error of 2013 model = 1.6% vs. 5.4% in the 2012 model.

Public Authorities Customer Count

Estimation Starting/Ending: 1/1990, 3/2013
Unit Forecast: Monthly Customer Count (Calendar Cycle)

Variable	Coefficient	T-Stat	P-Value	VIF
Constant	(1,340.49)	(32.81)	0.00%	
MP Area Households (LN)	296.68	39.65	0.00%	1.49
Apr. 2012 Binary	(62.51)	(10.54)	0.00%	1.02
1990-2009 Binary	(34.20)	(28.96)	0.00%	1.50

	Public Auth. Customer Count	
	Level	Y/Y Growth
2007	241	
2008	246	1.9%
2009	262	6.7%
2010	278	5.8%
2011	281	1.2%
2012	275	-2.3%
2013	285	**3.6%**
2014	286	**0.4%**
2015	288	**0.7%**
2020	300	***0.8%***
2025	312	***0.8%***



	OLS		ARMA Corrected	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	95.2%		97.4%	
AIC	3.5518		2.8640	
SIC	3.6038		2.9863	
MAPE	2.0%		1.2%	
Model F Test	1825.6	0.0%	1228.0	0.0%
Estimates Residual S.D.	5.86		4.12	
SSres	9455		4306	
Degrees of Freedom	275		254	
Breusch-Pegan F	3.4	1.78%	4.4	0.49%
Breusch-Pegan ChiSq	10.0	1.8%	12.7	0.5%
White's F	2.4	8.9%	9.6	0.0%
Breusch-Godfrey AIC F	47.4	0.0%	2.1	3.8%
Breusch-Godfrey AIC ChiSq	141.9	0.0%	17.2	2.8%
Breusch-Godfrey SIC F	86.9	0.0%	0.4	53.6%
Breusch-Godfrey SIC ChiSq	135.8	0.0%	1.7	19.7%
Durban-Watson	0.7	BAD	2.1	GOOD
Durban-H	N/A	N/A	N/A	N/A
FIT^2 Ramsey's RESET F	13.9	0.0%	0.7	40.6%
FIT^3 Ramsey's RESET F	6.9	0.1%	1.9	15.2%
FIT^4 Ramsey's RESET F	115.6	0.0%	5.0	0.2%
Out-of-Sample RMSE	7.31		7.42	
Out-of-Sample MAE	5.14		5.12	
Out-of-Sample MAPE	2.282%		2.237%	

Discussion of model:

As with previous year's models, this year's Public Authorities customer count model utilizes MP Area Households as the sole economic/ demographic indicator. The logged form of the variable ("MP Area Households") was found to be the most significant indicator of Public Authorities customer count growth. The applied log transformation suggests that relative change (i.e. the percentage increases) in the area households is more indicative than level change (i.e. the absolute increase) in the number of households.

The binary variable "Apr. 2012 Binary" denotes a transition in billing practices which resulted in a recorded month-to-month change of approximately 60 Public Authorities customers or about 20%. Since the count returned to a normal level in the following month, this is viewed as an anomalous point and a binary is applied to avoid biasing the results of the regression.

The binary variable "1990-2009 Binary" denotes the timeframe from January 1990 to July 2009 and accounts for a transition that took place in August of 2009, when a single Public Authorities customer added 14 new pumping stations, each with its own account. This had the effect of increasing the Public Authorities customer count by 7% in one month. Since the cause is known and cannot be explained by an economic or demographic variable, it was accounted for with a binary to avoid biasing estimates of the other variable's coefficients.

Of all alternative models examined, few were able to fully solve issues of heteroskedasticity or autocorrelation and these alternatives had more significant issues with other statistical metrics and unsolvable implausible outputs.

Out-of-sample testing confirms the model is superior to last year's model in applied performance: Out of sample forecast error of 2013 model = 2.3% vs. 4.1% in the 2012 model.

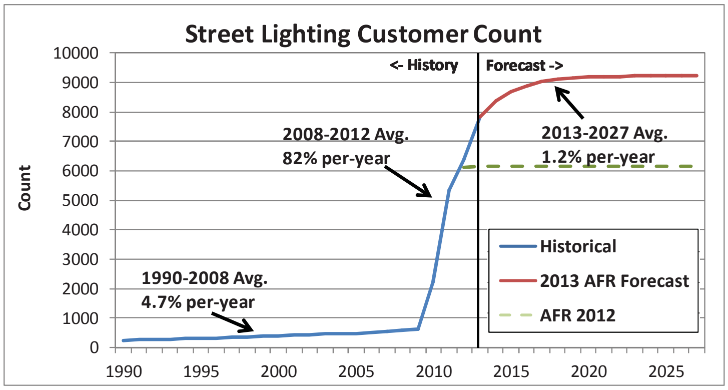
Lighting Customer Count

Estimation Starting/Ending: 4/1990, 3/2013
Unit Forecast: Monthly Customer Count (Calendar Cycle)

Variable	Coefficient	T-Stat	P-Value	VIF
Constant	244.89	7.35	0.00%	
1990-2009 Binary	(232.81)	(7.38)	0.00%	5.90
LagDep(1)	1.47	24.66	0.00%	485.72
LagDep(2)	(0.66)	(6.71)	0.00%	1,264.7
LagDep(3)	0.17	2.96	0.34%	405.25

Lighting Customer Count	Level	Y/Y Growth
2007	548	
2008	585	6.8%
2009	617	5.6%
2010	2,207	257.4%
2011	5,335	141.8%
2012	6,409	20.1%
2013	7,815	**21.9%**
2014	8,361	**7.0%**
2015	8,694	**4.0%**
2020	9,182	***1.1%***
2025	9,226	***0.1%***

Model Statistics	OLS Magnitude	OLS P-Value	ARMA Corrected Magnitude	ARMA Corrected P-Value
Adjusted R^2	99.8%		99.8%	
AIC	8.6565		8.5242	
SIC	8.7221		8.6454	
MAPE	2.2%		2.9%	
Model F Test	36214.6	0.0%	20834.0	0.0%
Estimates Residual S.D.	75.13		69.79	
SSres	1529801		1251672	
Degrees of Freedom	271		257	
Breusch-Pegan F	48.8	0.00%	42.7	0.00%
Breusch-Pegan ChiSq	115.5	0.0%	105.3	0.0%
White's F	58.0	0.0%	50.3	0.0%
Breusch-Godfrey AIC F	6.7	0.0%	4.6	0.0%
Breusch-Godfrey AIC ChiSq	94.3	0.0%	83.6	0.0%
Breusch-Godfrey SIC F	8.5	0.0%	6.3	0.0%
Breusch-Godfrey SIC ChiSq	44.6	0.0%	38.3	0.0%
Durban-Watson	2.1	GOOD	2.1	GOOD
Durban-H	-2.9	N/A	N/A	N/A
FIT^2 Ramsey's RESET F	1.1	29.4%	-46.4	N/A
FIT^3 Ramsey's RESET F	0.6	54.5%	-20.3	N/A
FIT^4 Ramsey's RESET F	0.9	44.3%	-11.2	N/A
Out-of-Sample RMSE	4735.85		4819.87	
Out-of-Sample MAE	1061.90		1092.86	
Out-of-Sample MAPE	62.219%		61.604%	



Discussion of model:

The sudden, substantial growth in this series is due to entirely to a change in billing practices, and could not be predicted by any economic or demographic indicator. Therefore, this year's model was developed using only binaries and lagged-dependent variables and contains no economic terms. However, this is not a substantive change from previous models which utilized only ARMA terms to project this series.

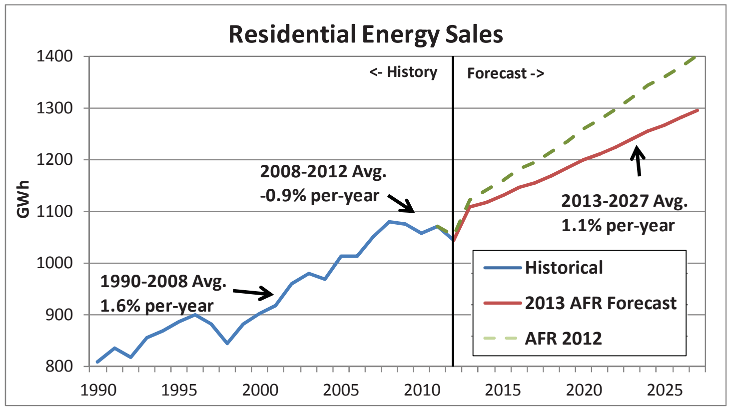
Of all alternative models examined, none were able to fully solve issues of heteroscedasticity and autocorrelation.

High VIF's are due to high correlation between lagged-dependent variables. However, this should be expected and this correlation is known to have no negative affect on the forecast of the dependent variable.

Residential Energy Sales

Estimation Starting/Ending: 1/1990, 3/2013
Unit Forecast: Monthly kWh per Customer per Day (Calendar Cycle)

Variable	Coefficient	T-Stat	P-Value	VIF
Constant	17.58	41.09	0.00%	
Jul Binary	2.11	3.55	0.05%	3.28
Aug Binary	2.31	3.76	0.02%	3.51
Jan Trend	0.01	3.53	0.05%	4.13
Dec Trend	0.03	5.80	0.00%	4.83
Jan HDDpD*EHSat	2.21	15.26	0.00%	5.96
Feb HDDpD	0.22	20.78	0.00%	2.66
Mar HDDpD*EHSat	1.87	13.77	0.00%	2.66
Apr HDDpD	0.20	9.37	0.00%	2.60
May HDDpD	0.16	4.33	0.00%	2.56
June CDDpD	0.75	2.15	3.24%	2.15
Jul CDDpD*ACSat	1.77	5.00	0.00%	1.66
Aug CDDpD*ACSat	2.53	3.84	0.02%	1.89
Sep HDDpD*EHSat	2.08	3.84	0.02%	2.52
Oct HDDpD	0.12	5.04	0.00%	2.59
Nov HDDpD*EHSat	1.81	12.12	0.00%	2.59
Dec HDDpD*EHSat	1.72	9.95	0.00%	6.64



	Residential Energy Sales	
	Level	Y/Y Growth
2007	1,051,453	
2008	1,079,836	2.7%
2009	1,075,117	-0.4%
2010	1,057,476	-1.6%
2011	1,069,856	1.2%
2012	1,043,281	-2.5%
2013	**1,107,296**	**6.1%**
2014	**1,116,245**	**0.8%**
2015	**1,130,672**	**1.3%**
2020	***1,198,678***	***1.2%***
2025	***1,266,553***	***1.1%***

	OLS		ARMA Corrected	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	89.2%		94.0%	
AIC	0.8784		0.3138	
SIC	1.0997		0.5967	
MAPE	5.0%		3.6%	
Model F Test	145.1	0.0%	209.8	0.0%
Estimates Residual S.D.	1.51		1.13	
SSres	595		311	
Degrees of Freedom	262		245	
Breusch-Pegan F	3.2	0.00%	4.3	0.00%
Breusch-Pegan ChiSq	45.6	0.0%	57.8	0.0%
White's F	17.4	0.0%	3.7	2.5%
Breusch-Godfrey AIC F	4.6	0.0%	0.0	85.6%
Breusch-Godfrey AIC ChiSq	59.8	0.0%	63.8	0.0%
Breusch-Godfrey SIC F	2.6	10.5%	0.0	85.6%
Breusch-Godfrey SIC ChiSq	3.8	5.1%	63.8	0.0%
Durban-Watson	2.2	N/A	1.9	N/A
Durban-H	N/A	N/A	N/A	N/A
FIT^2 Ramsey's RESET F	0.7	41.7%	91.4	0.0%
FIT^3 Ramsey's RESET F	1.8	16.2%	49.3	0.0%
FIT^4 Ramsey's RESET F	2.1	10.3%	32.8	0.0%
Out-of-Sample RMSE	1.60		1.58	
Out-of-Sample MAE	1.26		1.25	
Out-of-Sample MAPE	5.341%		5.316%	

Discussion of model:

The unit being forecast is "per-customer" usage and the outputs of this model are combined with the Residential Customer Count forecast to produce a projection of total Residential monthly energy use. The approach is superior to directly modeling total Residential class energy usage. Forecasting on a "per-customer" basis simplifies the model considerably because it does not have to account for the effect of increasing customers, which would be the case when modeling total Residential class energy usage.

Residential per-customer energy use is primarily driven by weather. The previous year's model addressed this relationship fairly well and this year's model is very similar. However; the 2013 model suggests appliance saturation is not indicative of energy use in some months. The model shows that energy use is driven only by weather in some months and by an interaction of weather and appliance saturation in others. This is a difference between this year's model and the 2012 Forecast model which implied all months were affected by both weather and appliance saturation.

Of all alternative models examined, few were able to fully solve issues of heteroskedasticity and these alternatives had more significant issues with other statistical metrics or produced implausible outputs. Note that heteroskedasticity cannot cause coefficients to be biased, but can bias the estimate of standard errors.

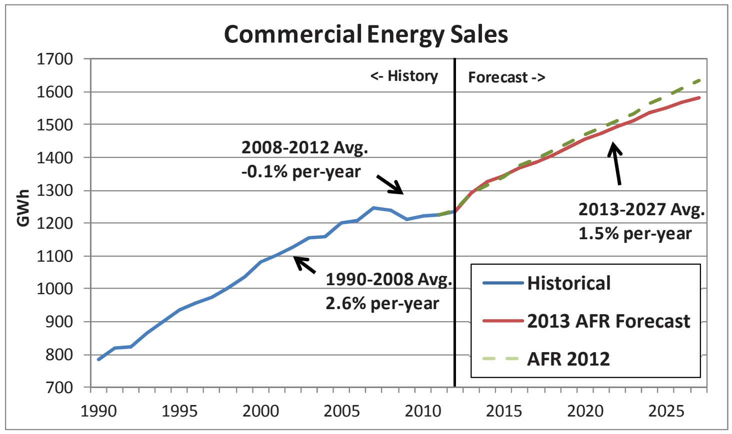
Autocorrelation in the OLS model is present but is not severe. After solving for autocorrelation with the addition of ARMA terms, the significance of all independent variables was affirmed, except for Aug Binary and June CDDpD. However, these 2 variables appear insignificant in the ARMA model because their coefficients declined in magnitude significantly compared to the OLS model. Thus, the original OLS model is satisfactory.

Out-of-sample testing shows the model is similar to last year's model in applied performance: Out of sample forecast error of 2013 model = 5.3% vs. 5.4% in the 2012 model.

Commercial Energy Sales

Estimation Starting/Ending: 1/1990, 3/2013
Unit Forecast: Monthly kWh per Customer per Day (Calendar Cycle)

Variable	Coefficient	T-Stat	P-Value	VIF
MP Area Edu. and Health Services (LN)	0.0139	130.66	0.00%	1.03
JanHDDpD	0.0003	7.56	0.00%	1.18
FebHDDpD	0.0005	11.24	0.00%	1.19
MarHDDpD	0.0004	7.33	0.00%	1.19
JuneCDDpD	0.0062	3.76	0.02%	1.13
JulHDDpD	(0.0039)	(2.34)	2.03%	3.57
SepHDDpD	0.0017	6.87	0.00%	1.19
NovHDDpD	0.0002	2.88	0.44%	1.18
DecHDDpD	0.0005	11.30	0.00%	1.19
Aug 2003 Binary	0.0405	4.04	0.01%	1.04
Apr 2010 Binary	(0.0287)	(2.91)	0.40%	1.02
Jul Binary	0.0226	5.52	0.00%	3.73
Aug Binary	0.0208	8.79	0.00%	1.23



Commercial Energy Sales

	Level	Y/Y Growth
2007	1,244,929	
2008	1,240,327	-0.4%
2009	1,212,778	-2.2%
2010	1,221,753	0.7%
2011	1,226,174	0.4%
2012	1,237,386	0.9%
2013	1,292,826	**4.5%**
2014	1,325,392	**2.5%**
2015	1,345,031	**1.5%**
2020	1,456,330	***1.6%***
2025	1,549,171	***1.2%***

Model Statistics	OLS Magnitude	OLS P-Value	ARMA Corrected Magnitude	ARMA Corrected P-Value
Adjusted R^2	54.2%		64.0%	
AIC	-9.2039		-9.4400	
SIC	-9.0347		-9.2239	
MAPE	4.9%		4.3%	
Model F Test	N/A	N/A	N/A	N/A
Estimates Residual S.D.	0.01		0.01	
SSres	0		0	
Degrees of Freedom	266		249	
Breusch-Pegan F	0.7	75.26%	1.0	47.65%
Breusch-Pegan ChiSq	9.4	74.2%	12.7	46.8%
White's F	1.7	18.6%	2.8	6.0%
Breusch-Godfrey AIC F	8.2	0.0%	2.6	0.0%
Breusch-Godfrey AIC ChiSq	91.8	0.0%	64.6	0.0%
Breusch-Godfrey SIC F	9.9	0.0%	0.1	78.3%
Breusch-Godfrey SIC ChiSq	88.6	0.0%	4.2	4.0%
Durban-Watson	2.3	N/A	1.9	GOOD
Durban-H	N/A	N/A	N/A	N/A
FIT^2 Ramsey's RESET F	3.0	8.4%	3.7	5.4%
FIT^3 Ramsey's RESET F	2.1	12.1%	1.9	14.7%
FIT^4 Ramsey's RESET F	2.2	9.1%	1.4	25.9%
Out-of-Sample RMSE	0.01		0.01	
Out-of-Sample MAE	0.01		0.01	
Out-of-Sample MAPE	5.253%		5.213%	

Discussion of model:

The unit being forecast is "per-customer" usage and outputs of this model are combined with the Commercial Customer Count forecast to produce a projection of total Commercial monthly energy use. The approach is superior to directly modeling total Commercial class energy usage. Forecasting on a "per-customer" basis simplifies the models considerably because it does not have to account for the effect of increasing customer count, which would be the case when modeling total Commercial class energy usage.

Compared to last year's model, key statistical measures such as the Adjusted R-square appear to have deteriorated (0.856 vs. 0.542). However, this is entirely due to a "per-customer" approach being implemented for Commercial energy use modeling. The per-customer use series is more volatile than the total energy use series that was modeled last year.

When modeling total Commercial class energy usage, multicollinearity was a common issue. Analysis revealed that this was because the model would have to simultaneously solve for a growing customer count and changing use-per customer. Customer count should be solved for using "customer count" as a direct input, while the best indicator of per-customer use was "Employment in Education and Health Services." However, these variables (customer count and Employment in Education and Health Services) could not be used in combination because they were so highly correlated. The obvious solution was to implement a "per-customer" approach and isolate the customer growth effect from the per-customer effect. Because of this transition, variables utilized in previous year's models were not optimal.

Employment in Education and Health Services has been utilized in many of Minnesota Power's past commercial energy sales models. Duluth has both a relatively large medical and educational services presence as the city is a hub for both, containing a large number of hospitals and schools. Since these hospitals are some of the larger commercial customers, increases in Health Services employment is likely to correspond well with added medical equipment or facility expansions resulting in greater energy use per-customer.

Two binary variables "Aug 2003 Binary" and "Apr 2010 Binary" account for anomalies in the historical sales data. Aug 2003 sales to commercial customers were unseasonably high after accounting for weather. The cause of this spike in sales is unknown, but Minnesota Power deemed it appropriate to apply a binary to avoid biasing the results of the regression. The Apr 2010 Binary denotes a similar event; however, sales in this month were unseasonably low with no apparent cause.

Analysis revealed that July HDD count is a statistically superior indicator, compared to CDD count (p-value of 2.03% compared to 10.04%). This result may not seem immediately intuitive, but the variable is correctly signed (negative) and there is nothing theoretically inappropriate about using HDD instead: how cool it is in the month is a fine indicator of how energy is not needed. Minnesota Power's modeling policy dictates use of the most significant variable when results are plausible and econometrically interpretable.

Autocorelation in the OLS model is present but is not severe. After solving for autocorrelation with the addition of ARMA terms, the significance of all independent variables was affirmed. Thus, the original OLS model is satisfactory.

Out-of-sample testing shows the model is similar to last year's model in applied performance: Out of sample forecast error of 2013 model = 5.3% vs. 5.0% in the 2012 model.

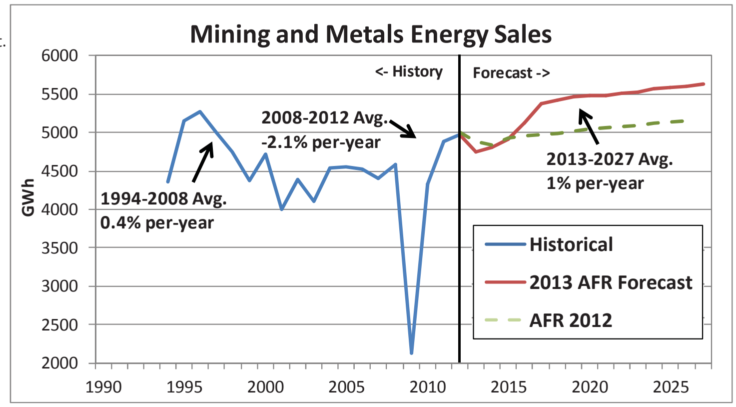
Mining and Metals Energy Sales

Estimation Starting/Ending: 2/1994, 3/2013
Unit Forecast: Monthly MWh per Day (Calendar Cycle) - Recent New Cust.

Variable	Coefficient	T-Stat	P-Value	VIF
Constant	(12,910)	(11.00)	0.00%	
Industrial Production Index - Iron (LN)	4,102.60	12.72	0.00%	3.08
Jun 2009 Binary	2,278.20	2.91	0.39%	1.26
Jan Binary	304.81	1.77	7.76%	1.07
Mar Binary	455.11	2.74	0.67%	1.05
Jul Binary	(498.02)	(2.93)	0.37%	1.04
Aug Binary	(347.58)	(2.03)	4.38%	1.06
LagDep(1)	0.51	13.45	0.00%	2.78

Mining and Metals Energy Sales

	Level	Y/Y Growth
2007	4,408,337	
2008	4,579,234	3.9%
2009	2,124,675	-53.6%
2010	4,324,450	103.5%
2011	4,874,331	12.7%
2012	4,968,517	1.9%
2013	4,624,335	**-6.9%**
2014	4,623,124	**0.0%**
2015	4,648,672	**0.6%**
2020	4,744,581	***0.4%***
2025	4,847,467	***0.4%***



	OLS		ARMA Corrected	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	88.1%		89.6%	
AIC	13.1205		13.0027	
SIC	13.2401		13.1531	
MAPE	4.5%		4.6%	
Model F Test	243.8	0.0%	219.0	0.0%
Estimates Residual S.D.	694.49		651.92	
SSres	107073153		92650219	
Degrees of Freedom	222		218	
Breusch-Pegan F	0.8	62.01%	1.5	16.04%
Breusch-Pegan ChiSq	5.4	61.2%	10.5	16.0%
White's F	3.7	2.6%	3.8	2.4%
Breusch-Godfrey AIC F	4.9	0.0%	2.5	8.4%
Breusch-Godfrey AIC ChiSq	43.4	0.0%	9.9	0.7%
Breusch-Godfrey SIC F	6.3	0.0%	1.1	30.2%
Breusch-Godfrey SIC ChiSq	23.9	0.0%	5.8	1.6%
Durban-Watson	1.8	N/A	2.1	GOOD
Durban-H	1.7	N/A	-3.9	N/A
FIT^2 Ramsey's RESET F	0.4	52.4%	-8.0	N/A
FIT^3 Ramsey's RESET F	0.4	70.1%	3.5	3.3%
FIT^4 Ramsey's RESET F	0.3	86.1%	2.7	4.8%
Out-of-Sample RMSE	922.03		925.43	
Out-of-Sample MAE	721.07		724.40	
Out-of-Sample MAPE	6.634%		6.680%	

Discussion of model:

This year's model is similar to previous models. It utilizes the Index of Industrial Production (IPI) for Iron Mining as an indicator of energy sales to this industrial sector. However, this year's model utilizes a logged form of the IPI as it proved more significant in the regression and resulted in better model statistics.

The logged form's improved significance over a level variable indicates the month-to-month change in energy sales to Mining and Metals customer is better predicted by the relative change in iron production - rather than the absolute, or level change in production. This is possibly due to the non-linear relationship between product and inputs, i.e. one should expect there to be some efficiency of scale or diminishing marginal energy requirements as producers advance from low capacity utilization to typical operating levels.

The unit being forecast is "Monthly MWh per Day (Calendar Cycle) - Recent New Cust." A new large customer began operations in mid-2012. It was decided that the addition of the customer to this sector was, in effect, a very recent definitional change which presents a problem for a key forecasting assumption: consistency of definition. This sudden step-change would not be adequately predicted by economic indicators and as a result, the econometric output would under-forecast of the future energy needs of this sector.

To address this, Minnesota Power adjusted the historical series for consistency by removing, or "backing-out," sales to this customer. This adjusted series (excluding sales to this customer) was then modeled and forecast. Finally, projected sales to this customer were added back to the econometric model output to ensure that this customer's future energy needs are accounted for in the forecast.

Statistical testing reveals the presence of autocorrelation in the OLS model. However, this is solved with the addition of ARMA terms without affecting the significance of input variables. Significance of only the lagged dependent variable was affected. This was expected as the AR(1) term has a similar impact on the model as the lagged-dependent. Thus, the original OLS model inputs are satisfactory.

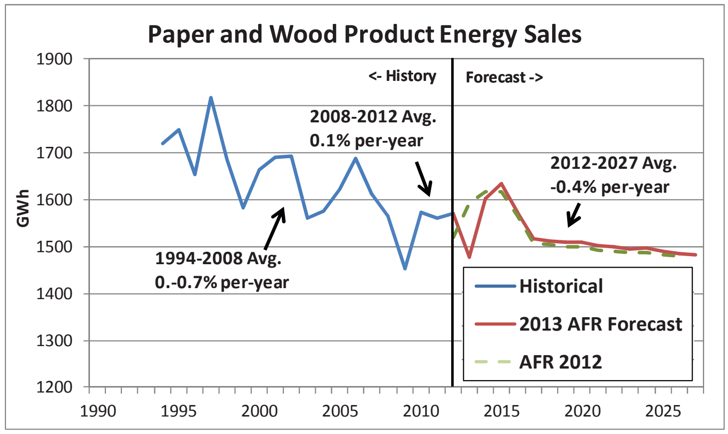
Compared to last year's model, key statistical measures such as the Adjusted R-square appear to have deteriorated (0.925 vs. 0.881). However, this is almost entirely due to Minnesota Power's newly implemented modeling policy which advances OLS over models with ARMA adjustments. The "ARMA Corrected" model shows a higher Adjusted R-square, a lower SIC, and a lower, MAPE. However, out of sample forecast tests affirm Minnesota Power's approach by proving OLS is the optimal model despite the appearance lower statistical measures traditionally used for assessing model quality. Out of sample forecast error of 2013 model = 6.6% vs. 7.5% in the 2012 model.

Note that the sales shown in the table and graph have been adjusted from the econometric output to reflect expected changes in large customer loads per Minnesota Power's methodology.

Paper Energy Sales

Estimation Starting/Ending: 1/1994, 3/2013
Unit Forecast: Monthly MWh per Day (Calendar Cycle)

Variable	Coefficient	T-Stat	P-Value	VIF
Industrial Production Index - Paper (LN)	892.58	102.53	0.00%	2.94
Feb Binary	118.54	1.99	4.82%	1.41
Mar Binary	202.48	3.40	0.08%	1.40
Apr Binary	166.53	2.75	0.66%	1.39
May Binary	125.83	2.08	3.89%	1.37
Jun Binary	304.93	5.02	0.00%	1.40
Jul Binary	241.05	3.90	0.01%	1.43
Aug Binary	395.87	6.53	0.00%	1.39
Sep Binary	356.77	5.83	0.00%	1.41
Oct Binary	356.88	5.82	0.00%	1.43
Nov Binary	154.67	2.55	1.13%	1.37
Jan 1990 -Dec 2002	275.49	8.58	0.00%	1.52
Jul 2001 Binary	(616.54)	(2.77)	0.62%	3.42
Oct 2005 - Sep 2008	189.03	4.37	0.00%	1.06
Sep 2010 - Oct 2010	441.39	2.79	0.58%	1.07



	Paper/ Wood Energy Sales	
	Level	Y/Y Growth
2007	1,612,560	
2008	1,566,402	-2.9%
2009	1,453,928	-7.2%
2010	1,572,565	8.2%
2011	1,559,519	-0.8%
2012	1,570,852	0.7%
2013	1,529,800	**-2.6%**
2014	1,521,999	**-0.5%**
2015	1,520,850	**-0.1%**
2020	1,508,708	***-0.2%***
2025	1,488,116	***-0.3%***

	OLS		ARMA Corrected	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	54.9%		69.9%	
AIC	10.8172		10.4357	
SIC	11.0408		10.7064	
MAPE	3.7%		3.0%	
Model F Test	N/A	N/A	N/A	N/A
Estimates Residual S.D.	216.43		177.69	
SSres	10117475		6630189	
Degrees of Freedom	216		210	
Breusch-Pegan F	2.2	0.66%	2.4	0.30%
Breusch-Pegan ChiSq	31.0	0.9%	33.3	0.4%
White's F	1.1	34.5%	0.4	68.0%
Breusch-Godfrey AIC F	23.3	0.0%	0.8	50.9%
Breusch-Godfrey AIC ChiSq	82.0	0.0%	3.6	31.1%
Breusch-Godfrey SIC F	96.9	0.0%	0.1	73.8%
Breusch-Godfrey SIC ChiSq	71.9	0.0%	0.9	34.4%
Durban-Watson	0.9	BAD	2.0	N/A
Durban-H	N/A	N/A	N/A	N/A
FIT^2 Ramsey's RESET F	1.0	30.9%	-1.4	N/A
FIT^3 Ramsey's RESET F	0.5	58.5%	0.7	51.6%
FIT^4 Ramsey's RESET F	0.4	78.3%	0.5	70.4%
Out-of-Sample RMSE	238.03		239.76	
Out-of-Sample MAE	189.53		191.38	
Out-of-Sample MAPE	4.282%		4.323%	

Discussion of model:

This year's model is similar to previous models. It utilizes the Index of Industrial Production (IPI) for Paper products as an indicator of energy sales to this industrial sector. However, this year's model utilizes a logged form of the IPI as it proved more significant in the regression and resulted in better model statistics. All other model inputs are the same as last year's model.

The binary variables: Jan 1990 -Dec 2002, Jul 2001 Binary, Oct 2005 - Sep 2008, and Sep 2010 - Oct 2010 account for changes in specific customer's generation which affected energy sales to the sector.

Compared to last year's model, key statistical measures such as the Adjusted R-square appear to have deteriorated (0.693 vs. 0.549). However, this is entirely due to Minnesota Power's newly implemented modeling policy which advances OLS over models with ARMA adjustments. The "ARMA Corrected" model shows a higher Adjusted R-square (very close to last year's), a lower SIC, and a lower, MAPE. However, out of sample forecast tests affirm Minnesota Power's approach by proving OLS is the optimal model despite the appearance lower statistical measures traditionally used for assessing model quality. Out of sample forecast error of 2013 model = 4.3% vs. 4.5% in the 2012 model.

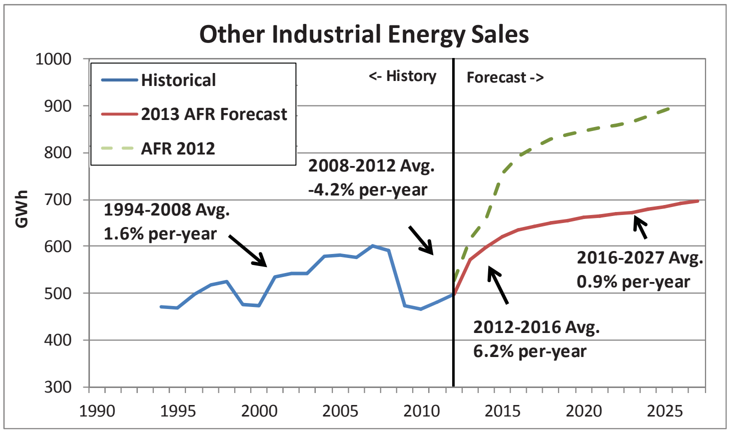
Statistical testing reveals the presence of autocorrelation in the OLS model. However, this is solved with the addition of ARMA terms without affecting the significance of input variables. Thus, the original OLS model inputs are satisfactory.

Note that the sales shown in the table and graph have been adjusted from the econometric output to reflect expected changes in large customer loads per Minnesota Power's methodology.

Other Energy Sales

Estimation Starting/Ending: 2/1994, 3/2013
Unit Forecast: Monthly MWh per Day (Calendar Cycle)

Variable	Coefficient	T-Stat	P-Value	VIF
Constant	(26,065.3)	(6.16)	0.00%	
MP Area Trade, Transport, Utilities Empl. (LN)	1,898.12	6.28	0.00%	1.32
MP Area Population (LN)	1,092.62	2.90	0.41%	1.22
OtherInd Binary #1	(502.00)	(5.04)	0.00%	1.02
OtherInd Binary #2	(1,185.75)	(8.00)	0.00%	1.13
OtherInd Binary #3	(1,013.38)	(7.12)	0.00%	1.04
OtherInd Binary #4	553.12	5.37	0.00%	1.09
OtherInd Binary #5	433.68	4.22	0.00%	1.08
OtherInd Binary #6	(878.23)	(6.06)	0.00%	1.08
OtherInd Binary #7	662.95	4.72	0.00%	1.01
LagDep(1)	0.15	2.85	0.48%	1.43



Other Industrial Energy Sales

	Level	Y/Y Growth
2007	601,154	
2008	591,696	-1.6%
2009	472,751	-20.1%
2010	467,062	-1.2%
2011	479,799	2.7%
2012	498,474	3.9%
2013	**538,381**	**8.0%**
2014	**539,406**	**0.2%**
2015	**549,384**	**1.8%**
2020	***591,130***	***1.5%***
2025	***614,094***	***0.8%***

Model Statistics	OLS Magnitude	OLS P-Value	ARMA Corrected Magnitude	ARMA Corrected P-Value
Adjusted R^2	58.3%		68.4%	
AIC	9.9285		9.6666	
SIC	10.0924		9.8621	
MAPE	7.5%		6.4%	
Model F Test	33.2	0.0%	42.0	0.0%
Estimates Residual S.D.	139.91		122.20	
SSres	4306516		3210410	
Degrees of Freedom	220		215	
Breusch-Pegan F	1.4	16.08%	2.2	2.02%
Breusch-Pegan ChiSq	14.3	16.1%	20.8	2.3%
White's F	0.4	64.2%	0.4	64.7%
Breusch-Godfrey AIC F	6.4	0.0%	3.5	0.0%
Breusch-Godfrey AIC ChiSq	87.1	0.0%	73.1	0.0%
Breusch-Godfrey SIC F	20.7	0.0%	3.8	5.4%
Breusch-Godfrey SIC ChiSq	64.3	0.0%	5.2	2.3%
Durban-Watson	1.6	BAD	2.1	N/A
Durban-H	4.0	N/A	-1.8	N/A
FIT^2 Ramsey's RESET F	19.6	0.0%	3.2	7.3%
FIT^3 Ramsey's RESET F	10.3	0.0%	2.9	5.6%
FIT^4 Ramsey's RESET F	8.2	0.0%	2.0	11.3%
Out-of-Sample RMSE	204.14		203.65	
Out-of-Sample MAE	140.13		138.36	
Out-of-Sample MAPE	14.115%		14.007%	

Discussion of model:

This year's model is structurally similar to last year's, but produces different results. It utilizes MP Area Employment in Trade, Transportation, and Utilities sectors whereas last year's model utilized MP Area Employment in Construction, Natural Resources, and Mining sectors. The transition to the new employment series as an indicator is the primary reason for the more conservative outlook.

The assumptions of the two employment series follow different courses in the forecast timeframe with Trade, Transportation, and Utilities employment growing at an average annual rate of just 0.4%. Construction, Natural Resources, and Mining employment grows at a more robust rate of 2.1% on average in the forecast timeframe with the majority of this growth front loaded; the average annual growth rate in the 2014-2017 timeframe is about 7.5%.

Until recently, the two series were equally good indicators of energy sales to Other Industrial customers. The last year of historical observation definitively revealed that Construction, Natural Resources, and Mining employment is no longer the best indicator of energy sales to this sector and should not be utilized again in this year's forecast.

Prior to the recent recession, the two employment series showed fairly strong correlation in the historical timeframe (R-squared = 0.73), and both correlated well with energy sales to this sector. However, the relationship between Construction, Natural Resources, and Mining employment and Other Industrial energy sales broke-down throughout the recession and post-recessionary timeframe. Therefore, Employment in Trade, Transportation, and Utilities sectors was used instead.

Statistical testing reveals the presence of autocorrelation in the OLS model. However, some of this autocorrelation, as well as the Ramsey's RESET F tests, can be resolved with the addition of ARMA terms without affecting the significance of input variables. Thus, the original OLS model inputs are satisfactory.

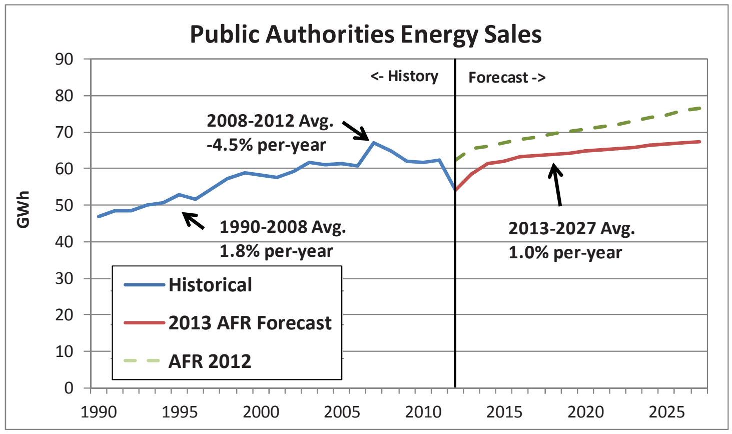
Note that the sales shown in the table and graph have been adjusted from the econometric output to reflect expected changes in large customer loads per Minnesota Power's methodology.

Out-of-sample testing shows the model is superior to last year's model in applied performance: Out of sample forecast error of 2013 model = 14.1% vs. 14.9% in the 2012 model.

Public Authorities Energy Sales

Estimation Starting/Ending: 1/1990, 3/2013
Unit Forecast: Monthly kWh per Customer per Day (Calendar Cycle)

Variable	Coefficient	T-Stat	P-Value	VIF
Constant	(862.18)	(11.16)	0.00%	
MP Area Wage Disbursements (LN)	107.61	13.24	0.00%	1.02
Dummies.APR_12	(65.81)	(3.55)	0.05%	1.04
NovHDDpD	1.87	2.99	0.31%	31.75
DecHDDpD	1.58	3.45	0.07%	31.96
Jan Binary	63.91	2.85	0.47%	33.53
Feb Binary	71.19	3.18	0.17%	33.52
Mar Binary	70.81	3.16	0.18%	33.52
Apr Binary	65.18	2.91	0.40%	32.34
May Binary	62.81	2.80	0.54%	32.29
Jun Binary	66.89	2.99	0.31%	32.29
Jul Binary	82.31	3.67	0.03%	32.28
Aug Binary	76.78	3.43	0.07%	32.27
Sep Binary	75.00	3.35	0.09%	32.27
Oct Binary	68.63	3.06	0.24%	32.27



Public Auth. Energy Sales

	Level	Y/Y Growth
2007	67,057	
2008	64,912	-3.2%
2009	62,036	-4.4%
2010	61,766	-0.4%
2011	62,457	1.1%
2012	54,074	-13.4%
2013	58,621	**8.4%**
2014	61,505	**4.9%**
2015	62,162	**1.1%**
2020	64,876	***0.9%***
2025	66,604	***0.5%***

Model Statistics	OLS Magnitude	OLS P-Value	ARMA Corrected Magnitude	ARMA Corrected P-Value
Adjusted R^2	42.6%		41.5%	
AIC	5.8454		5.8492	
SIC	6.0407		6.0782	
MAPE	8.7%		8.8%	
Model F Test	15.7	0.0%	12.7	0.0%
Estimates Residual S.D.	18.11		18.06	
SSres	86605		81215	
Degrees of Freedom	264		249	
Breusch-Pegan F	1.2	27.01%	1.1	39.19%
Breusch-Pegan ChiSq	16.8	26.8%	14.9	38.6%
White's F	5.7	0.4%	3.1	4.7%
Breusch-Godfrey AIC F	7.1	0.0%	3.7	1.3%
Breusch-Godfrey AIC ChiSq	21.2	0.0%	11.6	0.9%
Breusch-Godfrey SIC F	11.4	0.1%	0.0	95.2%
Breusch-Godfrey SIC ChiSq	11.6	0.1%	0.4	54.2%
Durban-Watson	2.4	BAD	2.0	GOOD
Durban-H	N/A	N/A	N/A	N/A
FIT^2 Ramsey's RESET F	4.4	3.7%	1.8	17.7%
FIT^3 Ramsey's RESET F	2.2	11.4%	1.2	30.8%
FIT^4 Ramsey's RESET F	1.6	19.0%	1.1	33.5%
Out-of-Sample RMSE	18.94		19.29	
Out-of-Sample MAE	14.14		14.52	
Out-of-Sample MAPE	9.406%		9.615%	

Discussion of model:

This year's model is similar to previous models. It utilizes MP Area Wages and Salary Disbursements as an indicator of energy sales to this sector. However, this year's model utilizes a logged form of the variable. Minnesota Power's interpretation of the strong indicative nature of this variable concerns area incomes as they relate to the ability of Public Authorities to deliver public goods, which would require energy consumption. As Area incomes and population increase, the demand for, and ability to fund, public goods also increase.

This year's analysis assessed weather variables on a monthly basis by splitting the HDD and CDD variables into monthly interactions. The findings suggest that weather is only definitively indicative of energy sales to this customer class during the months of November and December. Minnesota Power also removed the monthly trending variables used in last year's model as few proved to be truly significant in the presence of autoregressive terms sufficient to solve for autocorrelation.

The "Apr. 2012 Binary" variable accounts for an unseasonably large decrease in energy sales that occurred in this month. Sales dropped by 50% from the previous month. Minnesota Power deemed it appropriate to apply a binary to avoid biasing the results of the regression. Statistical testing reveals the presence of autocorrelation in the OLS model. However, this can be resolved with the addition of ARMA terms without affecting the significance of input variables. Thus, the original OLS model inputs are satisfactory.

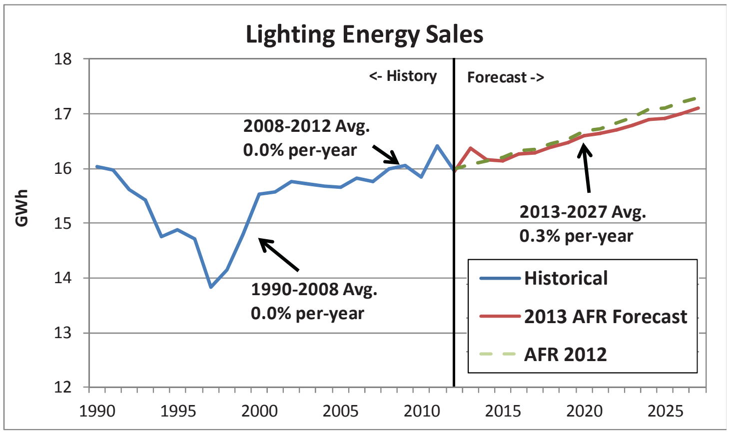
The monthly binaries utilized in the model to explain seasonal variation exhibit high multicollinearity as indicated by the VIF's above 10 associated with each variable. However, this correlation appears to be exclusively among these binaries, i.e. it is not affecting the main economic indicator "MP Area Wage Disbursements (LN)". The p-values associated with these monthly binaries suggest they are significant, but Minnesota Power fully recognizes that estimates of these binaries' significance may be biased by the presence of multicollinearity.

Out-of-sample testing shows the model is similar to last year's model in applied performance: Out of sample forecast error of 2013 model = 9.4% vs. 9.5% in the 2012 model.

Lighting Energy Sales

Estimation Starting/Ending: 1/1992, 3/2013
Unit Forecast: Monthly MWh per Day (Calendar Cycle)

Variable	Coefficient	T-Stat	P-Value	VIF
Constant	39.26	13.25	0.00%	
MP Area Total Personal Income (Lag-24)	0.0005	6.05	0.00%	1.22
Feb Binary	(4.79)	(6.75)	0.00%	1.48
Mar Binary	(9.86)	(14.14)	0.00%	1.43
Apr Binary	(15.60)	(18.27)	0.00%	2.06
May Binary	(19.63)	(17.19)	0.00%	3.68
Jun Binary	(22.31)	(15.90)	0.00%	5.55
Jul Binary	(20.65)	(12.95)	0.00%	7.17
Aug Binary	(16.94)	(11.03)	0.00%	6.66
Sep Binary	(11.69)	(8.81)	0.00%	4.97
Oct Binary	(7.02)	(6.76)	0.00%	3.04
Nov Binary	(2.68)	(3.29)	0.11%	1.87
LagDep(1)	0.17	2.71	0.71%	12.67



Lighting Energy Sales

	Level	Y/Y Growth
2007	15,751	
2008	15,981	1.5%
2009	16,050	0.4%
2010	15,834	-1.3%
2011	16,420	3.7%
2012	15,954	-2.8%
2013	16,359	**2.5%**
2014	16,150	**-1.3%**
2015	16,134	**-0.1%**
2020	16,610	***0.6%***
2025	16,921	***0.4%***

Model Statistics	OLS Magnitude	OLS P-Value	ARMA Corrected Magnitude	ARMA Corrected P-Value
Adjusted R^2	92.4%		97.5%	
AIC	1.9712		0.8751	
SIC	2.1517		1.0972	
MAPE	4.0%		2.3%	
Model F Test	258.7	0.0%	659.2	0.0%
Estimates Residual S.D.	2.61		1.50	
SSres	1653		540	
Degrees of Freedom	242		239	
Breusch-Pegan F	1.2	29.63%	1.5	11.36%
Breusch-Pegan ChiSq	14.1	29.3%	18.0	11.6%
White's F	3.4	3.5%	5.4	0.5%
Breusch-Godfrey AIC F	5.2	0.0%	2.9	9.1%
Breusch-Godfrey AIC ChiSq	30.2	0.0%	18.9	0.0%
Breusch-Godfrey SIC F	6.1	1.5%	2.9	9.1%
Breusch-Godfrey SIC ChiSq	6.3	1.2%	18.9	0.0%
Durban-Watson	2.1	N/A	2.0	GOOD
Durban-H	-4.5	N/A	0.1	N/A
FIT^2 Ramsey's RESET F	0.5	46.3%	-0.2	N/A
FIT^3 Ramsey's RESET F	2.0	13.2%	18.4	0.0%
FIT^4 Ramsey's RESET F	1.5	21.8%	14.3	0.0%
Out-of-Sample RMSE	2.73		2.73	
Out-of-Sample MAE	1.86		1.86	
Out-of-Sample MAPE	4.497%		4.497%	

Discussion of model:

This year's model is slightly different form last year's lighting energy sales model. It uses Total Personal Income instead of Regional Population as an indicator of sales to this class. This change in variable is interesting and likely beneficial. Personal Income has two components to it: population and per-capita income. Thus the new variable contains an additional aspect (per-capita incomes) which may be more indicative of the demand for, and ability to fund, public goods such as street lighting.

The forecast of street lighting growth has moderated due to persistently low growth in recent years despite improving economic conditions. Utilization of an alternative variable is the primary reason for the moderation in the outlook.

Statistical testing reveals the presence of autocorrelation in the OLS model. However, this can be resolved with the addition of ARMA terms without affecting the significance of input variables. Thus, the original OLS model inputs are satisfactory.

Out-of-sample testing shows the model is similar to last year's model in applied performance: Out of sample forecast error of 2013 model = 4.5% vs. 4.7% in the 2012 model.

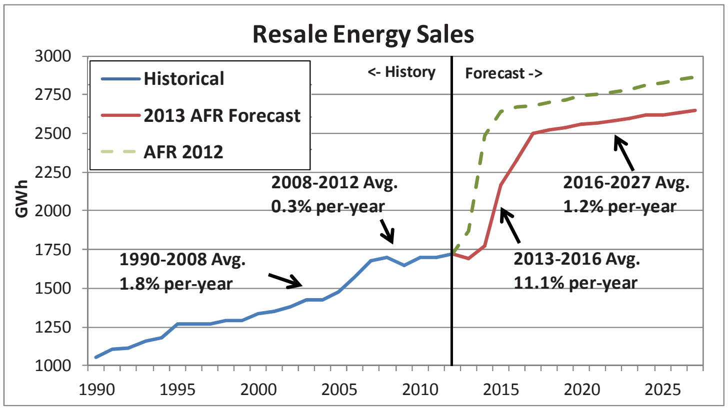
Resale Energy Sales

Estimation Starting/Ending: 1/1996, 3/2013
Unit Forecast: Monthly MWh per Day (Calendar Cycle)

Variable	Coefficient	T-Stat	P-Value	VIF
Constant	(5,419.19)	(3.64)	0.04%	
MP Area Financial Activities Empl. (LN)	942.72	5.61	0.00%	3.50
Time-Trend	2.79	6.55	0.00%	8.45
JanHDDpD*EHSat	79.19	9.94	0.00%	2.00
FebHDDpD*EHSat	78.84	8.88	0.00%	2.06
MarHDDpD*EHSat	21.86	2.06	4.06%	1.82
MayCDDpD*ACSat	1,480.77	3.30	0.12%	1.30
JunCDDpD*ACSat	216.15	1.65	10.07%	2.04
JulCDDpD*ACSat	294.18	7.23	0.00%	3.10
AugCDDpD	105.79	6.23	0.00%	1.83
SepCDDpD*ACSat	421.56	2.11	3.60%	2.13
NovHDDpD*EHSat	55.13	4.35	0.00%	1.93
DecHDDpD*EHSat	86.64	9.36	0.00%	2.10
JAN Resale Binary	743.57	10.16	0.00%	2.29
Feb Resale Binary	674.06	9.10	0.00%	2.35
Mar Resale Binary	631.70	8.96	0.00%	2.12
Apr Resale Binary	376.90	5.99	0.00%	1.46
Jun Resale Binary	345.07	4.41	0.00%	2.26
Jul Resale Binary	269.87	3.11	0.22%	3.21
Aug Resale Binary	426.71	6.11	0.00%	2.08
Sep Resale Binary	253.73	3.43	0.08%	2.34
Oct Resale Binary	411.90	6.90	0.00%	1.52
Nov Resale Binary	466.42	6.51	0.00%	2.20
Dec Resale Binary	644.73	8.75	0.00%	2.32

	Resale Energy Sales	
	Level	Y/Y Growth
2007	1,679,273	
2008	1,701,058	1.3%
2009	1,647,753	-3.1%
2010	1,696,508	3.0%
2011	1,699,644	0.2%
2012	1,718,819	1.1%
2013	**1,720,901**	**0.1%**
2014	**1,740,220**	**1.1%**
2015	**1,755,888**	**0.9%**
2020	***1,827,817***	***0.8%***
2025	***1,895,231***	***0.7%***

	OLS		ARMA Corrected	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	94.7%		N/A	
AIC	9.7774		N/A	
SIC	10.1638		N/A	
MAPE	2.3%		N/A	
Model F Test	162.0	0.0%	N/A	
Estimates Residual S.D.	125.76		N/A	
SSres	2894269		N/A	
Degrees of Freedom	183		N/A	
Breusch-Pegan F	1.2	21.54%	N/A	
Breusch-Pegan ChiSq	27.9	21.8%	N/A	
White's F	0.0	95.4%	N/A	
Breusch-Godfrey AIC F	1.8	16.7%	N/A	
Breusch-Godfrey AIC ChiSq	4.2	12.4%	N/A	
Breusch-Godfrey SIC F	1.3	26.1%	N/A	
Breusch-Godfrey SIC ChiSq	1.4	23.0%	N/A	
Durban-Watson	1.8	N/A	N/A	
Durban-H	N/A	N/A	N/A	
FIT^2 Ramsey's RESET F	0.4	55.4%	N/A	
FIT^3 Ramsey's RESET F	1.8	16.6%	N/A	
FIT^4 Ramsey's RESET F	2.2	9.5%	N/A	
Out-of-Sample RMSE	135.27		N/A	
Out-of-Sample MAE	105.64		N/A	
Out-of-Sample MAPE	2.623%		N/A	



Discussion of model:

This year's model is different from previous models which utilized MP Area Household Income or Per-Capita Income. The best indicator of sales to this class, by any statistical measure, was MP Area Financial Activities Employment (logged). Minnesota Power must conclude that the real indicative nature of this variable arises from the "Real Estate, Rental, and Leasing" component of Financial Activities rather than the "Finance and Insurance" component. The former component is highly indicative of housing demand and area population. MP Area Financial Activities Employment may be more indicative than MP Area Population of Households because it shows more month-to-month variation. Therefore, the model can associate changes in energy sales with changes in this sector's employment with a greater degree of certainty.

Note that the sales shown in the table and graph have been adjusted from the econometric output to reflect expected changes in large customer loads per Minnesota Power's methodology.

Weather alone (i.e. independent of appliance saturation) was found to be more significant and indicative of energy consumption in some months. The model shows that energy use in some months is driven only by weather and in other months is driven by an interaction of weather and appliance saturation; Daily Heating Degree Days(HDDpD) and Electric Heat Saturation (EHSat), for example. This is a difference between this year's model and the 2012 Forecast model.

This model contains the only independent variable with an associate p-value greater than 10%: the "JuneCDDpD*ACSat" variable has a p-value of 10.07%. This was included in the model, despite the p-value higher than 10%, because June is a key month for summer energy sales. It was deemed inappropriate to have no modeled estimate of how weather may impact sales in this month. Weather-normalization of this month's energy sales, for example, would be impossible without this estimate.

This model utilizes a number of "Resale Binary" variables that denote the timeframe from 2007 to present where a specific customer elected to purchase energy from Minnesota Power instead of self-supplying with their owned generation. This approach to accounting for this step change in energy sales was utilized in past models.

Out-of-sample testing confirms the model is superior to last year's model in applied performance: Out of sample forecast error of 2013 model = 2.6% vs. 3.2% in the 2012 model.

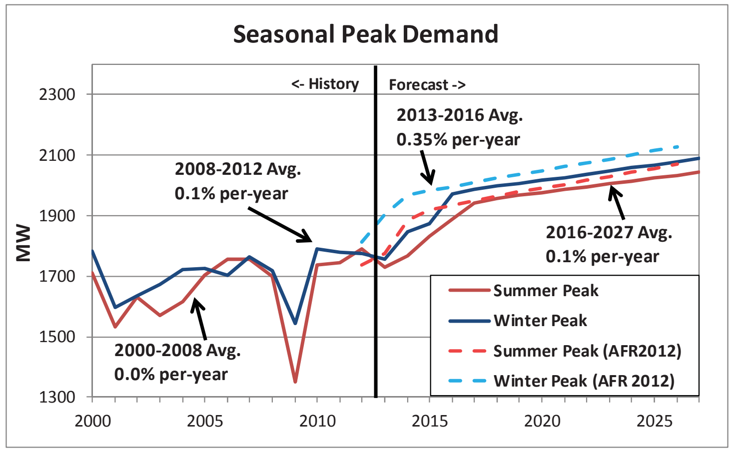
Peak Demand

Estimation Starting/Ending: 1/1990, 3/2013
Unit Forecast: FERC load coincident w/ Monthly MP System peak (MW)

Variable	Coefficient	T-Stat	P-Value	VIF
Constant	727.24	9.49	0.00%	
MWh PerDay (De-trended, De-Seasonalized)	0.02	7.67	0.00%	10.98
MWh PerDay Apr	(0.00)	(7.81)	0.00%	1.36
MWh PerDay Jun	(0.00)	(5.41)	0.00%	1.24
Time-Trend	0.53	8.17	0.00%	2.29
Mar-Trend	(0.17)	(4.27)	0.00%	1.27
Sep-Trend	(0.20)	(4.63)	0.00%	1.36
SeasPeak-Winter	26.51	2.62	0.97%	1.87
Apr 2000 Binary	(59.30)	(2.08)	3.96%	1.15
Sep 2000 Binary	(60.68)	(2.16)	3.28%	1.12
Aug 2001 Binary	(60.73)	(2.22)	2.83%	1.06
Sep 2001 Binary	(86.42)	(3.16)	0.20%	1.06
Sep 2003 Binary	(84.06)	(3.01)	0.31%	1.11
Mar 2008 Binary	56.63	2.02	4.56%	1.12
Nov 2008 Binary	70.51	2.41	1.74%	1.22
Dec 2008 Binary	162.41	5.68	0.00%	1.16
Jan 2010 Binary	(49.96)	(1.70)	9.22%	1.23
Aug 2010 Binary	91.61	3.37	0.10%	1.05
May Binary	(85.49)	(9.99)	0.00%	1.25
Oct Binary	(77.28)	(9.20)	0.00%	1.29
LP Cust - Load 1	(2.13)	(4.69)	0.00%	3.84
LP Cust - Load 2	(2.87)	(3.22)	0.16%	2.41
LP Cust - Load 3	(1.96)	(4.34)	0.00%	3.90
Temp - Less Than Zero	(0.89)	(4.24)	0.00%	2.15
Temp - Zero to 40	(0.55)	(2.50)	1.35%	1.27
Temp - 70 to 80	0.32	3.48	0.07%	1.50
Temp 80 to 100	0.40	3.54	0.05%	1.09

	Peak Demand			
	Summer	Y/Y Growth	Winter	Y/Y Growth
2007	1,758		1,763	
2008	1,699	-3.3%	1,719	-2.5%
2009	1,350	-20.6%	1,545	-10.1%
2010	1,737	28.7%	1,789	15.7%
2011	1,746	0.5%	1,779	-0.5%
2012	1,790	2.5%	1,774	-0.3%
2013	1,731	**-3.3%**	1,757	**-0.9%**
2014	1,766	**2.0%**	1,848	**5.2%**
2015	1,832	**3.7%**	1,874	**1.4%**
2020	1,976	***1.5%***	2,016	***1.5%***
2025	2,024	***0.5%***	2,068	***0.5%***

	OLS		ARMA Corrected	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	94.3%		95.2%	
AIC	6.7007		6.5590	
SIC	7.2069		7.1049	
MAPE	1.3%		1.3%	
Model F Test	106.9	0.0%	116.0	0.0%
Estimates Residual S.D.	26.48		24.54	
SSres	97477		81917	
Degrees of Freedom	139		136	
Breusch-Pegan F	0.7	88.64%	0.6	92.45%
Breusch-Pegan ChiSq	18.4	86.1%	17.2	90.4%
White's F	1.4	25.0%	1.2	31.4%
Breusch-Godfrey AIC F	6.7	0.0%	0.1	93.0%
Breusch-Godfrey AIC ChiSq	21.6	0.0%	4.0	13.6%
Breusch-Godfrey SIC F	15.4	0.0%	0.1	79.1%
Breusch-Godfrey SIC ChiSq	16.8	0.0%	3.5	6.2%
Durban-Watson	1.4	BAD	2.0	N/A
Durban-H	N/A	N/A	N/A	N/A
FIT^2 Ramsey's RESET F	1.6	21.4%	-1.5	N/A
FIT^3 Ramsey's RESET F	0.8	46.0%	1.3	28.3%
FIT^4 Ramsey's RESET F	0.6	63.5%	1.3	27.6%
Out-of-Sample RMSE	38.67		38.54	
Out-of-Sample MAE	29.05		29.06	
Out-of-Sample MAPE	2.098%		2.097%	



Model Discussion

This year's peak demand model has incorporated several improvements over previous years' models. The same basic inputs such as monthly energy sales and peak day temperatures have been used, but are introduced to the model in different ways than in the past, including:

1. The "MWh PerDay" variables are the monthly energy sales divided by the number of days in the month. This series is then de-trended and de-seasonalized to remove the potential for spurious correlation with the dependent variable. Analysis showed that the "MWh PerDay" variable in April and June have a significantly different coefficient from the other months, so these were introduced as separate variables.

2. The "LP Cust – Load" variables are monthly series that indicates the number of days in a month that the load for a specific large industrial customer was below the lower bound of a 95% confidence interval. This variable was developed for a number of large customers, but the operation of only 3 proved to be significant in estimating historical demand. The variable was implemented because of peak demand's sensitivity to large power customers. It accounts for anomalous behavior of large customers in the historical timeframe by explaining why the relationship of monthly energy use to peak demand (load factor) may vary from month-to-month.

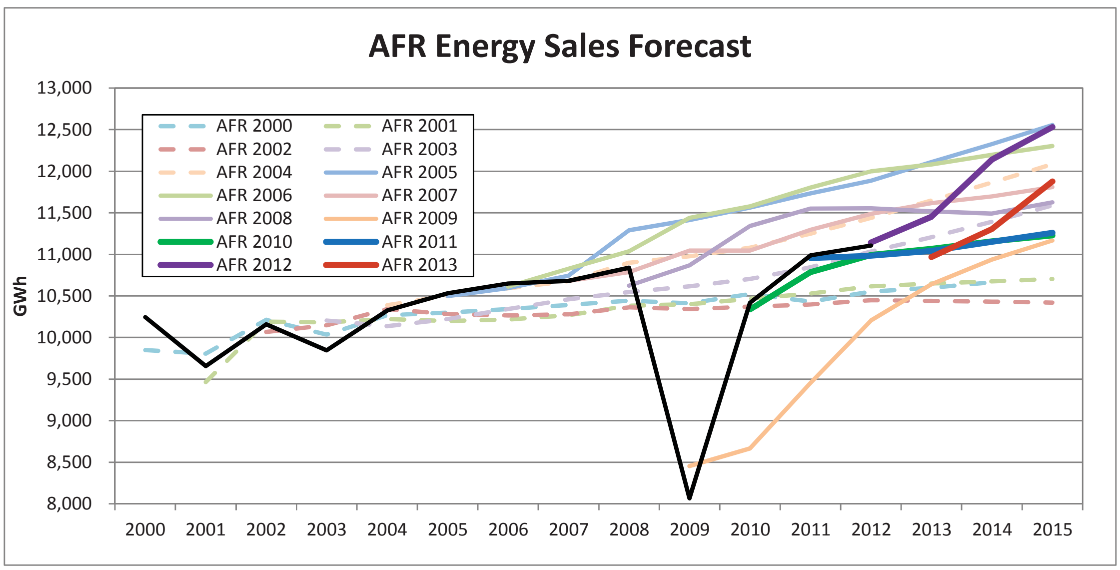
For example: If all large customers operated at full load until one customer shut down on the 6th day of the month and then remained down for the rest of the month, the load factor would decrease substantially. The peak would occur on one of the first 5 days in the month and would be relatively high compared to the energy consumption in that month, which, overall for the month, would be low because a customer ceased operations for the majority of the month.

Out-of-sample testing confirms the model is superior to last year's model in applied performance: Out of sample forecast error of 2013 model = 2.1% vs. 5.9% in the 2012 model.

F. Confidence in Forecast & Historical Accuracy

Over the longer term, the Blue Chip macroeconomic outlook has converged on slow, steady growth in the major indicators. Despite the recent strong sales climate for iron and steel, a weaker economic outlook makes Minnesota Power's energy sales to those sectors vulnerable. The potential for substantial regional growth as a result of mineral development indicates the value of examining alternatives. Minnesota Power will continue to evaluate the status of key industrial and wholesale developments in its service territory to determine the most appropriate scenario on which to develop plans.

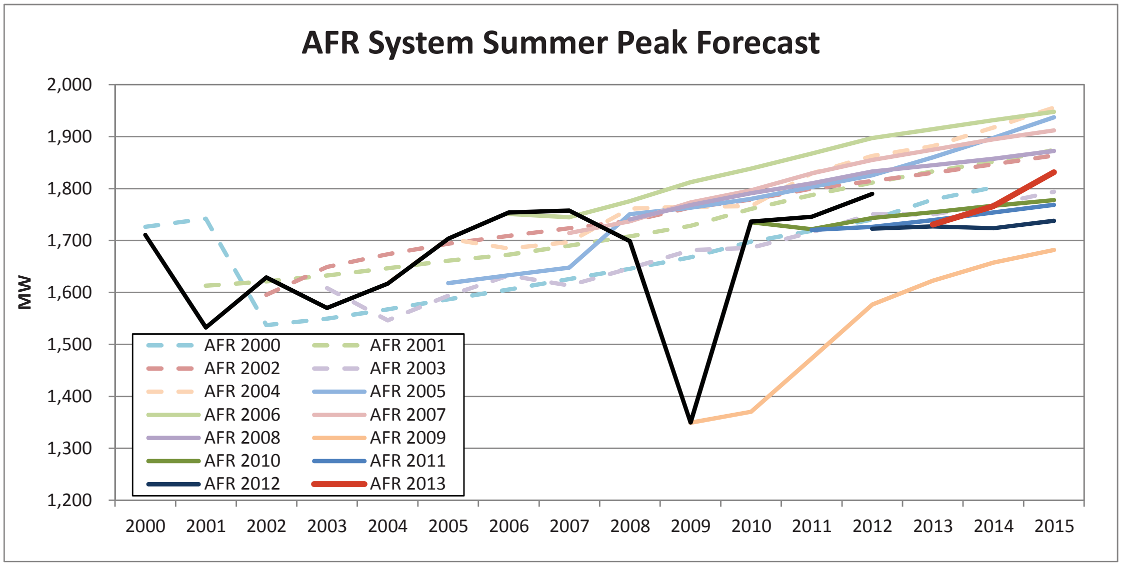
Minnesota Power has a solid track record of accurate forecasting. The tables and graphs below show Minnesota Power's past AFR forecast accuracy for aggregate energy use, Winter Peak and Summer Peak demand. The bottom values in each column (**Bold**) represent the forecast accuracy in the current year, or the year it was produced. For example, the lower right value of 0.3% is the difference between the forecast produced in 2012 (AFR 2012) and the 2012 year-end actual. Similarly, the cell just above the current year accuracy (***Bold, Italic***) represents the accuracy of the forecast in the year immediately after its formulation. For example, AFR 2011 (formulated in 2011) forecast of 2012 was 0.3% (36 GWh) above the actual.



Total Energy Sales Forecast Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Average Error of AFR
AFR 2000	**-3.9%**	**1.5%**	0.5%	1.9%	-0.6%	**-2.2%**	-2.9%	-2.7%	-3.7%	29.1%	1.0%	-5.1%	-5.0%	0.6%
AFR 2001		**-2.0%**	***0.3%***	3.4%	-1.0%	-3.1%	**-4.1%**	-3.9%	-4.2%	29.0%	0.5%	-4.2%	-4.4%	0.5%
AFR 2002			**-0.9%**	***3.1%***	0.2%	-2.4%	-3.6%	**-3.8%**	-4.4%	28.2%	-0.4%	-5.4%	-5.9%	0.4%
AFR 2003				**3.6%**	***-1.8%***	-2.9%	-2.9%	-2.1%	**-2.7%**	31.6%	2.8%	-1.3%	-0.6%	2.4%
AFR 2004					**0.6%**	***-0.3%***	-0.5%	0.0%	0.6%	**36.1%**	6.4%	2.4%	3.0%	5.4%
AFR 2005						**-0.3%**	***-0.5%***	0.6%	4.1%	41.5%	**11.0%**	6.8%	7.0%	8.8%
AFR 2006							**-0.3%**	***1.4%***	1.8%	41.8%	11.1%	**7.4%**	8.0%	10.2%
AFR 2007								**0.0%**	***-0.5%***	37.0%	6.0%	2.8%	**3.4%**	8.1%
AFR 2008									**-2.0%**	***34.8%***	8.9%	5.1%	4.0%	10.2%
AFR 2009										**4.8%**	***-16.8%***	-13.9%	-8.1%	-8.5%
AFR 2010											**-0.8%**	***-1.8%***	-1.0%	-1.2%
AFR 2011												**-0.3%**	***-1.1%***	-0.7%
AFR 2012													**0.3%**	0.3%

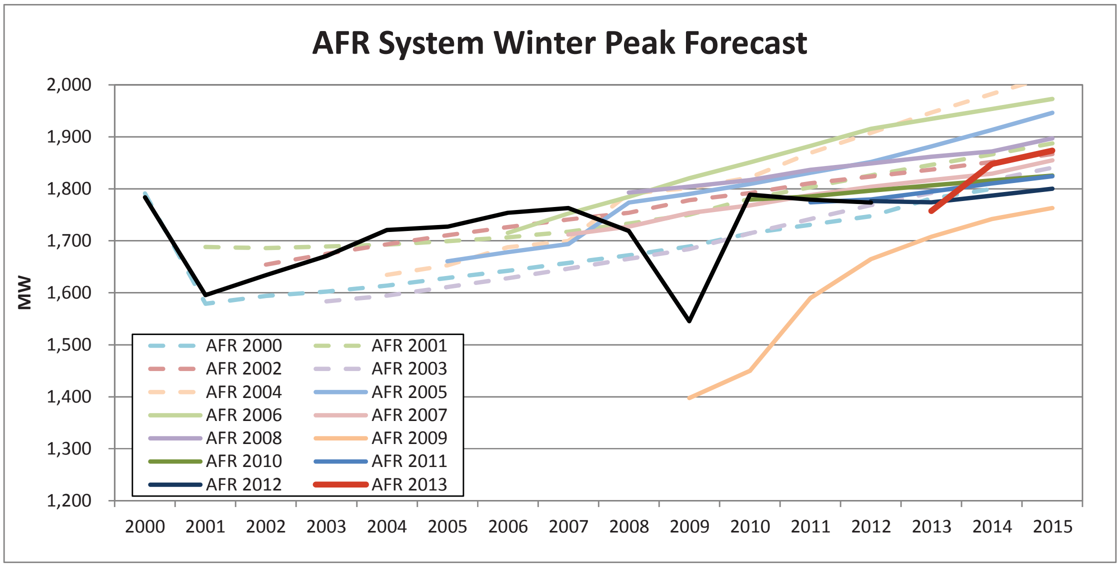
N.n%	= *Year-Ahead Foreast*	Avg Year-Ahead Error =	1.5%
N.n%	= Current Year Forecast	Avg Current Year Error =	-0.1%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	5.7%



Summer System Peak Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Average Error of AFR
AFR 2000	**0.9%**	***13.7%***	-5.6%	-1.3%	-3.1%	**-6.8%**	-8.5%	-7.5%	-3.1%	23.6%	-2.2%	-1.6%	-2.8%	-0.3%
AFR 2001		**5.2%**	***-0.5%***	4.0%	1.8%	-2.5%	**-4.6%**	-3.8%	0.5%	28.0%	1.4%	2.4%	1.2%	2.8%
AFR 2002			**-2.0%**	***5.0%***	3.5%	-0.6%	-2.6%	**-1.9%**	2.3%	30.7%	2.4%	3.1%	1.4%	3.8%
AFR 2003				**2.4%**	***-4.4%***	-6.4%	-6.9%	-8.2%	**-3.1%**	24.6%	-2.9%	-1.7%	-2.2%	-0.9%
AFR 2004					**0.0%**	***0.0%***	-3.9%	-3.5%	3.7%	**30.8%**	1.7%	4.8%	4.1%	4.2%
AFR 2005						**-5.0%**	***-6.9%***	-6.3%	3.1%	30.7%	**2.5%**	3.3%	2.0%	2.9%
AFR 2006							**-0.2%**	***-0.7%***	4.5%	34.3%	5.9%	**7.0%**	6.0%	8.1%
AFR 2007								**-2.4%**	***2.2%***	31.4%	3.5%	4.8%	**3.6%**	7.2%
AFR 2008									**2.5%**	***31.0%***	3.2%	3.7%	2.4%	8.5%
AFR 2009										**0.0%**	***-21.1%***	-15.6%	-11.9%	-12.2%
AFR 2010											**-0.1%**	***-1.4%***	-2.6%	-1.4%
AFR 2011												**-1.5%**	***-3.5%***	-2.5%
AFR 2012													**-3.7%**	-3.7%

N.n%	= *Year-Ahead Foreast*	Avg Year-Ahead Error =	1.1%
N.n%	= Current Year Forecast	Avg Current Year Error =	-0.3%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	3.4%



Winter System Peak Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Average Error of AFR
AFR 2000	**0.4%**	**-1.0%**	-2.5%	-4.1%	-6.2%	**-5.7%**	-6.4%	-6.0%	-2.7%	9.3%	-4.1%	-2.7%	-1.5%	-2.6%
AFR 2001		**5.8%**	***3.2%***	1.1%	-1.6%	-1.6%	**-2.7%**	-2.6%	0.8%	13.3%	-0.4%	1.4%	2.9%	1.6%
AFR 2002			**1.2%**	***0.2%***	-1.6%	-0.9%	-1.6%	**-1.3%**	2.0%	15.1%	0.2%	1.8%	2.8%	1.6%
AFR 2003				**-5.2%**	***-7.3%***	-6.7%	-7.2%	-6.6%	**-3.1%**	9.0%	-4.1%	-2.1%	-0.3%	-3.4%
AFR 2004					**-5.0%**	***-4.3%***	-3.8%	-3.6%	4.2%	**16.6%**	1.9%	5.1%	7.6%	2.1%
AFR 2005						**-3.8%**	***-4.3%***	-3.9%	3.2%	15.8%	**1.2%**	2.9%	4.4%	1.9%
AFR 2006							**-2.2%**	***-0.6%***	3.8%	17.8%	3.5%	**5.8%**	8.0%	5.2%
AFR 2007								**-2.9%**	***0.5%***	13.5%	-1.1%	0.5%	**1.7%**	2.0%
AFR 2008									**4.3%**	***16.8%***	1.6%	3.2%	4.2%	6.0%
AFR 2009										**-9.6%**	***-18.9%***	-10.6%	-6.2%	-11.3%
AFR 2010											**-0.5%**	***0.4%***	1.3%	0.4%
AFR 2011												**-0.3%**	***0.3%***	0.0%
AFR 2012													**0.1%**	0.1%

N.n%	= *Year-Ahead Foreast*	Avg Year-Ahead Error =	-1.3%
N.n%	= Current Year Forecast	Avg Current Year Error =	-1.4%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	1.6%

2. AFR 2013 Forecast Results

A. Forecast Scenario Descriptions

Minnesota Power's developed several scenarios for system peak demand and energy forecasts. All scenarios assume some load additions and/or losses from specific Industrial customers, served directly by Minnesota Power or through a wholesale customer. These load additions are applied to the econometric outputs for the forecast timeframe.

Moderate Growth Demand and Energy Scenario

This scenario includes changes in customer operations that are not certain, but have high likelihood of occurring. This high likelihood is characterized by formal communication from the customer, plus one or more of the following:

- An Electric Service Agreement is either executed or is in negotiation;
- The change in operation is supported by customer actions, such as construction or investment that will result in additional power requirements;
- A timeframe for the operation and resulting power need.

Moderate Growth scenario assumes additional load from a number of new and existing customers. Most notably, this scenario accounts for a new industrial facility to be served by a Minnesota Power wholesale customer, the City of Nashwauk. The facility is expected to reach full demand in 2017. Other possible additional phases of this project are not included in this scenario.

This scenario results in average annual energy sales growth and average annual peak demand growth of 1.5% and 1.2%, respectively, from 2013 through 2027. The results are presented in the Moderate Growth table.

The scenario assumes a moderate, or "expected," rate of national economic growth as the basis for the regional economic model.

Current Contract Demand and Energy Scenario

This case reflects the results of the econometric models, with discrete adjustments for announced changes in demand with a specific starting date. Examples of these adjustments are executed and approved electric service agreements and expiring electric service agreements that will not be renewed. The largest of these adjustments accounts for the new industrial facility served by a Minnesota Power wholesale customer, the City of Nashwauk. Load additions begin in 2014, and increase sharply through 2014 and 2015. Full demand and energy levels in this scenario are only about 65% of those in the Moderate Growth scenario and are reached in 2015.

This scenario results in average annual energy sales growth and average annual peak demand growth of 1% and 0.9%, respectively, from 2013 through 2027.

The scenario assumes a moderate, or "expected," rate of national economic growth as the basis for the regional economic model.

Potential Upside Demand and Energy Scenario

In this scenario, customer-specific additions are added to those in the Moderate Growth scenario. These additions have a moderate likelihood of occurring in the next 5 years, and have been publicly communicated as potential additions. This results in average annual energy sales growth and average annual peak demand growth of 1.9% and 1.6%, respectively, from 2013 through 2027. The results are presented in the Potential Upside table.

The scenario assumes a moderate, or "expected," rate of national economic growth as the basis for the regional economic model.

Potential Downside Demand and Energy Scenario

Minnesota Power has also developed a scenario reflecting plausible permanent capacity reductions by specific customers in the next 5 years. The scenario includes some additions, but these are more than offset by substantial load reductions.

The scenario assumes a slow, or "pessimistic," rate of national economic growth as the basis for the regional economic model.

Best Case Demand and Energy Scenario

This scenario adds customer-specific impacts in addition to those in the Moderate Growth and Potential Upside scenarios above. The additions in this scenario are possible, but speculative, requiring highly favorable economic conditions.

The peak and energy impacts are identified in the Best Case table, which show average annual energy sales growth and average annual peak demand growth of 3.1% and 2.4%, respectively, from 2013 through 2027.

The scenario assumes an accelerated, or "optimistic," rate of national economic growth as the basis for the regional economic model.

Trended Weather Demand and Energy Scenario

In the trended weather scenario, all weather sensitive class energy forecasts, as well as the demand forecast, were developed under the assumption that the observed trend in weather continued through the forecast timeframe instead of the Moderate Growth Scenario's 20 year average weather assumption. This implies warmer winters and warmer summers than the Moderate Growth Scenario. Model specifications and other assumptions remain unchanged.

Trended weather results in annual energy sales just 0.05% (5,000 MWh) below the Moderate Growth Scenario. Summer peaks are increased by about 0.05% (1 MW) and Winter peaks are decreased by about 0.35% (7 MW).

Electric Vehicles Demand and Energy Scenario

The 2013 Advanced Forecast Report builds on analysis first presented in the 2011 AFR, and considers the continued integration of plug-in electric vehicles (PEVs). Minnesota Power's regional PEV adoption rate was scaled from the U.S. PEV adoption rate using Minnesota Power area population and regional (Minnesota and Wisconsin) hybrid vehicle registrations as a proxy for regional attributes.

Using reasonable assumptions and credible sources, the projected impact on Minnesota Power's system is small, an estimated 1.7 GWh by 2015, 8.1 GWh by 2020, and 22 GWh by 2025. The additional electric demand at time of system peak for the Moderate Adoption Rate assumption is estimated to be 0.13 MW in 2015, 0.6 MW in 2020, and 1.7 MW in 2025.

It's estimated that the energy and demand levels will be low and manageable for Minnesota Power's territory under any of these Adoption Rate assumptions. Minnesota Power will continue to monitor the electric car market at both the national and regional level; the projected impacts will continue to be re-evaluated.

Industrial Customer Contract Expiration Demand and Energy Scenario

The contract expiration scenario assumes several of Minnesota Power's largest customers do not renew their current contracts with Minnesota Power. The typical demand of each large customer is arithmetically removed from the Base Case forecasts at the time of contract expiration. To preserve confidentiality, the customer demands are summed into a single column. This scenario results in peak demands that about 40% lower than current levels by about 2017.

B. Other Adjustments to Econometric Forecast

Each of Minnesota Power's forecast scenarios is the summation of the econometric model results and arithmetic adjustments for impacts which cannot be accurately modeled. These exogenous impacts are documented as separate seasonal peak and energy adjustments in all of the specific scenario tables. These adjustments fall into the following categories:

1. **Coincident Customer's Net Load (CCNL):** demand on Minnesota Power system that is met by customer owned generation. CCNL can fluctuate without clear economic causes so this component of Minnesota Power system peak is removed to more accurately model demand for an econometric forecast. The process for this adjustment can be outlined in 3 steps:

    - Remove CCNL from the historical peak series.
    - Econometrically project a less volatile "FERC load coincident w/ Monthly MP System peak (MW)" monthly peak series.

- Arithmetically account for CCNL after forecasting.

This procedure has been a methodological staple of Minnesota Power forecasting for over a decade and increases the quality of the econometric processes and resulting forecasts.

The amount of the adjustment for CCNL is determined by averaging the historical customer generation coincident with the monthly peak over an 11-year historical timeframe. The result is a set of 12 distinct monthly values for each month of the year. The CCNL values shown under the summer and winter adjustments in the scenario tables are the estimated CCNL at the time of the July and January peaks. The MWh adjustment is determined similarly; through averaging the most recent 11-year historical timeframe, but excluding 2009 due to its irregularly low value. These adjustments are credits that increase the estimated peaks and energy by the estimated amount.

2. **Customer Generation Adjustments:** adjustments that account for expected changes in the operation or ownership of generating assets that would affect deliveries to customers. These adjustments are added to the econometric energy sales forecast to most accurately represent Minnesota Power's future sales to ultimate consumers under each scenario.

3. **Load Addition/Loss Adjustments**: in all scenarios, there are exogenous adjustments accounting for new customer loads, lost loads, and/or customer load scenarios. To preserve customer confidentiality, the seasonal demand and energy impacts are netted to a single value before being combined with the econometric values.

4. **Dual Fuel**: Minnesota Power will discontinue the dual fuel adjustment to the load forecast. The estimated magnitude of potential reduction is questionable. Also, to some extent, historical interruptions are inherent in the data since there were curtailments in effect at the time of about 45% of historical seasonal peaks. Application of post-regression adjustments for dual fuel has high potential for producing artificially low peaks. Minnesota Power will account for dual fuel interruption as a resource and not as an adjustment to the load forecast.

C. Scenario Outlooks

i. Moderate Growth Scenario – AFR Expected Case

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000					1,469	1,503	242	281	1,711	1,784	1,784	2000
2001					1,383	1,421	150	175	1,533	1,595	1,595	2001
2002					1,464	1,456	165	180	1,629	1,636	1,636	2002
2003					1,408	1,496	163	175	1,570	1,671	1,671	2003
2004					1,449	1,533	168	189	1,617	1,721	1,721	2004
2005					1,535	1,555	169	172	1,703	1,727	1,727	2005
2006					1,586	1,534	168	170	1,754	1,704	1,754	2006
2007					1,582	1,584	176	179	1,758	1,763	1,763	2007
2008					1,552	1,575	147	145	1,699	1,719	1,719	2008
2009					1,200	1,370	150	176	1,350	1,545	1,545	2009
2010					1,597	1,599	140	190	1,737	1,789	1,789	2010
2011					1,573	1,629	173	150	1,746	1,779	1,779	2011
2012					1,603	1,605	187	169	1,790	1,774	1,790	2012
2013	1,554	1,596	20	26	**1,574**	**1,622**	157	136	**1,731**	**1,757**	***1,757***	2013
2014	1,567	1,609	72	104	**1,639**	**1,712**	128	136	**1,766**	**1,848**	***1,848***	2014
2015	1,582	1,618	116	120	**1,698**	**1,738**	134	136	**1,832**	**1,874**	***1,874***	**2015**
2016	1,586	1,629	169	203	**1,755**	**1,832**	132	140	**1,887**	**1,972**	***1,972***	2016
2017	1,602	1,639	203	207	**1,805**	**1,846**	138	140	**1,943**	**1,985**	***1,985***	2017
2018	1,612	1,649	207	208	**1,819**	**1,857**	138	140	**1,956**	**1,997**	***1,997***	2018
2019	1,622	1,659	208	208	**1,830**	**1,867**	138	140	**1,967**	**2,007**	***2,007***	2019
2020	1,631	1,668	208	208	**1,839**	**1,876**	138	140	**1,976**	**2,016**	***2,016***	**2020**
2021	1,641	1,679	208	208	**1,849**	**1,886**	138	140	**1,986**	**2,026**	***2,026***	2021
2022	1,650	1,689	208	208	**1,858**	**1,897**	138	140	**1,996**	**2,036**	***2,036***	2022
2023	1,660	1,699	208	208	**1,868**	**1,907**	138	140	**2,005**	**2,047**	***2,047***	2023
2024	1,669	1,710	208	208	**1,877**	**1,917**	138	140	**2,015**	**2,057**	***2,057***	2024
2025	1,678	1,721	208	208	**1,886**	**1,928**	138	140	**2,024**	**2,068**	***2,068***	**2025**
2026	1,688	1,731	208	208	**1,896**	**1,939**	138	140	**2,033**	**2,079**	***2,079***	2026
2027	1,697	1,742	208	208	**1,905**	**1,949**	138	140	**2,042**	**2,089**	***2,089***	2027

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	*Load Factor*	
2000			10,245,420					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	*1,636*	*0.79*	2002
2003			9,846,294	1,232,635	11,078,929	*1,671*	*0.76*	2003
2004			10,324,412	1,267,728	11,592,140	*1,721*	*0.77*	2004
2005			10,531,272	1,258,895	11,790,167	*1,727*	*0.78*	2005
2006			10,649,101	1,195,070	11,844,171	*1,754*	*0.77*	2006
2007			10,680,514	1,252,965	11,933,479	*1,763*	*0.77*	2007
2008			10,839,446	1,276,158	12,115,604	*1,719*	*0.80*	2008
2009			8,065,088	1,108,014	9,173,102	*1,545*	*0.68*	2009
2010			10,417,414	1,299,292	11,716,706	*1,789*	*0.75*	2010
2011			10,988,200	1,422,107	12,410,307	*1,779*	*0.80*	2011
2012			11,107,357	1,200,317	12,307,674	*1,790*	*0.78*	2012
2013	10,888,519	79,017	**10,967,536**	1,133,504	**12,101,040**	***1,757***	***0.79***	2013
2014	10,944,041	362,053	**11,306,094**	965,038	**12,271,132**	***1,848***	***0.76***	2014
2015	11,028,794	848,261	**11,877,055**	965,038	**12,842,093**	***1,874***	***0.78***	**2015**
2016	11,141,548	1,109,885	**12,251,434**	984,372	**13,235,805**	***1,972***	***0.76***	2016
2017	11,175,467	1,475,513	**12,650,981**	998,326	**13,649,307**	***1,985***	***0.78***	2017
2018	11,246,498	1,521,222	**12,767,720**	998,326	**13,766,046**	***1,997***	***0.79***	2018
2019	11,323,838	1,529,675	**12,853,514**	998,326	**13,851,840**	***2,007***	***0.79***	2019
2020	11,408,729	1,533,866	**12,942,596**	1,001,062	**13,943,657**	***2,016***	***0.79***	**2020**
2021	11,451,848	1,529,675	**12,981,523**	998,326	**13,979,850**	***2,026***	***0.79***	2021
2022	11,525,608	1,529,675	**13,055,283**	998,326	**14,053,610**	***2,036***	***0.79***	2022
2023	11,597,016	1,529,675	**13,126,691**	998,326	**14,125,018**	***2,047***	***0.79***	2023
2024	11,701,167	1,533,866	**13,235,034**	1,001,062	**14,236,095**	***2,057***	***0.79***	2024
2025	11,744,157	1,529,675	**13,273,832**	998,326	**14,272,159**	***2,068***	***0.79***	**2025**
2026	11,819,736	1,529,675	**13,349,411**	998,326	**14,347,738**	***2,079***	***0.79***	2026
2027	11,893,551	1,529,675	**13,423,226**	998,326	**14,421,553**	***2,089***	***0.79***	2027

Customer Count Forecast by Class

Year	Residential	Commercial	Industrial	Street Lighting	Public Authorities	Resale	Total
2005	116,072	20,040	460	490	233	18	137,313
2006	117,596	20,419	451	509	237	18	139,229
2007	118,870	20,630	435	548	241	18	140,742
2008	119,301	20,968	431	585	246	18	141,548
2009	121,216	21,287	429	617	262	18	143,830
2010	121,235	21,489	424	2,207	278	18	145,651
2011	121,251	21,603	421	5,335	281	18	148,909
2012	120,697	21,614	411	6,409	275	18	149,423
2013	**122,725**	**22,129**	**404**	**7,815**	**285**	**18**	**153,375**
2014	**124,191**	**22,421**	**402**	**8,361**	**286**	**17**	**155,678**
2015	**125,317**	**22,695**	**403**	**8,694**	**288**	**17**	**157,415**
2016	**126,286**	**23,027**	**402**	**8,900**	**290**	**17**	**158,922**
2017	**127,247**	**23,359**	**400**	**9,026**	**293**	**17**	**160,342**
2018	**128,331**	**23,687**	**399**	**9,104**	**295**	**17**	**161,834**
2019	**129,473**	**24,017**	**397**	**9,153**	**298**	**17**	**163,354**
2020	**130,633**	**24,350**	**395**	**9,182**	**300**	**17**	**164,878**
2021	**131,811**	**24,684**	**393**	**9,201**	**303**	**17**	**166,408**
2022	**133,009**	**25,013**	**391**	**9,212**	**305**	**17**	**167,947**
2023	**134,222**	**25,336**	**389**	**9,219**	**308**	**17**	**169,490**
2024	**135,437**	**25,646**	**386**	**9,223**	**310**	**17**	**171,020**
2025	**136,644**	**25,940**	**384**	**9,226**	**312**	**17**	**172,523**
2026	**137,827**	**26,221**	**381**	**9,227**	**314**	**17**	**173,988**
2027	**138,966**	**26,485**	**379**	**9,228**	**316**	**17**	**175,391**

Energy Sales Forecast (MWh) by Customer Class

Year	Residential	Commercial	Industrial	Street Lighting	Public Authorities	Resale	Total
2005	1,013,156	1,200,075	6,761,669	15,647	61,395	1,479,330	10,531,272
2006	1,011,698	1,206,607	6,782,975	15,830	60,883	1,571,108	10,649,101
2007	1,051,453	1,244,929	6,622,051	15,751	67,057	1,679,273	10,680,514
2008	1,079,836	1,240,327	6,737,332	15,981	64,912	1,701,058	10,839,446
2009	1,075,117	1,212,778	4,051,354	16,050	62,036	1,647,753	8,065,088
2010	1,057,476	1,221,753	6,364,077	15,834	61,766	1,696,508	10,417,414
2011	1,069,856	1,226,174	6,913,648	16,420	62,457	1,699,644	10,988,200
2012	1,043,281	1,237,386	7,037,843	15,954	54,074	1,718,819	11,107,357
2013	**1,107,296**	**1,292,826**	**6,797,977**	**16,359**	**58,621**	**1,694,456**	**10,967,536**
2014	**1,116,245**	**1,325,392**	**7,011,888**	**16,150**	**61,505**	**1,774,913**	**11,306,094**
2015	**1,130,672**	**1,345,031**	**7,159,774**	**16,134**	**62,162**	**2,163,282**	**11,877,055**
2016	**1,145,632**	**1,370,138**	**7,328,929**	**16,268**	**63,300**	**2,327,167**	**12,251,434**
2017	**1,155,761**	**1,386,482**	**7,526,423**	**16,292**	**63,576**	**2,502,447**	**12,650,981**
2018	**1,168,980**	**1,408,134**	**7,590,049**	**16,387**	**63,995**	**2,520,175**	**12,767,720**
2019	**1,182,640**	**1,430,694**	**7,625,319**	**16,477**	**64,349**	**2,534,035**	**12,853,514**
2020	**1,198,678**	**1,456,330**	**7,650,196**	**16,610**	**64,876**	**2,555,906**	**12,942,596**
2021	**1,210,158**	**1,472,640**	**7,653,344**	**16,637**	**65,089**	**2,563,654**	**12,981,523**
2022	**1,224,061**	**1,493,804**	**7,677,105**	**16,711**	**65,424**	**2,578,178**	**13,055,283**
2023	**1,238,203**	**1,513,077**	**7,700,149**	**16,779**	**65,763**	**2,592,720**	**13,126,691**
2024	**1,254,834**	**1,535,397**	**7,746,695**	**16,903**	**66,373**	**2,614,831**	**13,235,034**
2025	**1,266,553**	**1,549,171**	**7,753,253**	**16,921**	**66,604**	**2,621,331**	**13,273,832**
2026	**1,280,571**	**1,566,734**	**7,782,652**	**17,004**	**67,056**	**2,635,394**	**13,349,411**
2027	**1,293,845**	**1,583,295**	**7,810,867**	**17,102**	**67,491**	**2,650,627**	**13,423,226**

ii. **Current Contract Scenario**

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000					1,469	1,503	242	281	1,711	1,784	1,784	2000
2001					1,383	1,421	150	175	1,533	1,595	1,595	2001
2002					1,464	1,456	165	180	1,629	1,636	1,636	2002
2003					1,408	1,496	163	175	1,570	1,671	1,671	2003
2004					1,449	1,533	168	189	1,617	1,721	1,721	2004
2005					1,535	1,555	169	172	1,703	1,727	1,727	2005
2006					1,586	1,534	168	170	1,754	1,704	1,754	2006
2007					1,582	1,584	176	179	1,758	1,763	1,763	2007
2008					1,552	1,575	147	145	1,699	1,719	1,719	2008
2009					1,200	1,370	150	176	1,350	1,545	1,545	2009
2010					1,597	1,599	140	190	1,737	1,789	1,789	2010
2011					1,573	1,629	173	150	1,746	1,779	1,779	2011
2012					1,603	1,605	187	169	1,790	1,774	1,790	2012
2013	1,554	1,596	14	18	**1,568**	**1,614**	157	136	**1,725**	**1,750**	***1,750***	2013
2014	1,566	1,608	57	88	**1,623**	**1,697**	128	136	**1,750**	**1,833**	***1,833***	2014
2015	1,582	1,618	101	101	**1,683**	**1,719**	134	136	**1,817**	**1,855**	***1,855***	**2015**
2016	1,593	1,628	93	93	**1,686**	**1,722**	138	140	**1,824**	**1,861**	***1,861***	2016
2017	1,601	1,638	93	93	**1,695**	**1,731**	138	140	**1,832**	**1,871**	***1,871***	2017
2018	1,611	1,647	93	93	**1,704**	**1,741**	138	140	**1,842**	**1,881**	***1,881***	2018
2019	1,620	1,657	93	93	**1,714**	**1,751**	138	140	**1,851**	**1,890**	***1,890***	2019
2020	1,629	1,666	93	93	**1,722**	**1,759**	138	140	**1,859**	**1,899**	***1,899***	**2020**
2021	1,639	1,676	93	93	**1,732**	**1,769**	138	140	**1,870**	**1,909**	***1,909***	2021
2022	1,648	1,686	93	93	**1,741**	**1,779**	138	140	**1,879**	**1,919**	***1,919***	2022
2023	1,657	1,696	93	93	**1,751**	**1,789**	138	140	**1,888**	**1,929**	***1,929***	2023
2024	1,667	1,706	93	93	**1,760**	**1,800**	138	140	**1,897**	**1,939**	***1,939***	2024
2025	1,676	1,717	93	93	**1,769**	**1,811**	138	140	**1,906**	**1,950**	***1,950***	**2025**
2026	1,685	1,728	93	93	**1,778**	**1,821**	138	140	**1,916**	**1,961**	***1,961***	2026
2027	1,694	1,738	93	93	**1,787**	**1,831**	138	140	**1,925**	**1,971**	***1,971***	2027

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	*Load Factor*	
2000			10,245,420					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	*1,636*	*0.79*	2002
2003			9,846,294	1,232,635	11,078,929	*1,671*	*0.76*	2003
2004			10,324,412	1,267,728	11,592,140	*1,721*	*0.77*	2004
2005			10,531,272	1,258,895	11,790,167	*1,727*	*0.78*	2005
2006			10,649,101	1,195,070	11,844,171	*1,754*	*0.77*	2006
2007			10,680,514	1,252,965	11,933,479	*1,763*	*0.77*	2007
2008			10,839,446	1,276,158	12,115,604	*1,719*	*0.80*	2008
2009			8,065,088	1,108,014	9,173,102	*1,545*	*0.68*	2009
2010			10,417,414	1,299,292	11,716,706	*1,789*	*0.75*	2010
2011			10,988,200	1,422,107	12,410,307	*1,779*	*0.80*	2011
2012			11,107,357	1,200,317	12,307,674	*1,790*	*0.78*	2012
2013	10,888,089	51,072	**10,939,161**	1,133,504	**12,072,665**	***1,750***	***0.79***	2013
2014	10,943,375	276,665	**11,220,039**	965,038	**12,185,078**	***1,833***	***0.76***	2014
2015	11,027,119	726,453	**11,753,572**	965,038	**12,718,611**	***1,855***	***0.78***	**2015**
2016	11,131,193	713,510	**11,844,703**	984,372	**12,829,075**	***1,861***	***0.78***	2016
2017	11,160,251	660,753	**11,821,004**	998,326	**12,819,331**	***1,871***	***0.78***	2017
2018	11,225,325	660,753	**11,886,078**	998,326	**12,884,405**	***1,881***	***0.78***	2018
2019	11,298,387	660,753	**11,959,140**	998,326	**12,957,466**	***1,890***	***0.78***	2019
2020	11,377,865	662,563	**12,040,429**	1,001,062	**13,041,490**	***1,899***	***0.78***	**2020**
2021	11,417,701	660,753	**12,078,454**	998,326	**13,076,781**	***1,909***	***0.78***	2021
2022	11,487,025	660,753	**12,147,778**	998,326	**13,146,104**	***1,919***	***0.78***	2022
2023	11,555,970	660,753	**12,216,723**	998,326	**13,215,049**	***1,929***	***0.78***	2023
2024	11,657,113	662,563	**12,319,676**	1,001,062	**13,320,738**	***1,939***	***0.78***	2024
2025	11,697,623	660,753	**12,358,376**	998,326	**13,356,702**	***1,950***	***0.78***	**2025**
2026	11,770,828	660,753	**12,431,581**	998,326	**13,429,908**	***1,961***	***0.78***	2026
2027	11,842,576	660,753	**12,503,329**	998,326	**13,501,656**	***1,971***	***0.78***	2027

iii. **Potential Upside Scenario**

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	*Annual*	
2000					1,469	1,503	242	281	1,711	1,784	*1,784*	2000
2001					1,383	1,421	150	175	1,533	1,595	*1,595*	2001
2002					1,464	1,456	165	180	1,629	1,636	*1,636*	2002
2003					1,408	1,496	163	175	1,570	1,671	*1,671*	2003
2004					1,449	1,533	168	189	1,617	1,721	*1,721*	2004
2005					1,535	1,555	169	172	1,703	1,727	*1,727*	2005
2006					1,586	1,534	168	170	1,754	1,704	*1,754*	2006
2007					1,582	1,584	176	179	1,758	1,763	*1,763*	2007
2008					1,552	1,575	147	145	1,699	1,719	*1,719*	2008
2009					1,200	1,370	150	176	1,350	1,545	*1,545*	2009
2010					1,597	1,599	140	190	1,737	1,789	*1,789*	2010
2011					1,573	1,629	173	150	1,746	1,779	*1,779*	2011
2012					1,603	1,605	187	169	1,790	1,774	*1,790*	2012
2013	1,554	1,596	20	27	**1,574**	**1,623**	157	136	**1,731**	**1,759**	***1,759***	2013
2014	1,567	1,609	71	124	**1,637**	**1,732**	128	136	**1,765**	**1,868**	***1,868***	2014
2015	1,583	1,618	156	239	**1,739**	**1,857**	134	136	**1,872**	**1,993**	***1,993***	**2015**
2016	1,594	1,629	248	282	**1,841**	**1,911**	138	140	**1,979**	**2,051**	***2,051***	2016
2017	1,603	1,639	289	311	**1,892**	**1,950**	138	140	**2,030**	**2,090**	***2,090***	2017
2018	1,613	1,650	311	312	**1,923**	**1,961**	138	140	**2,061**	**2,101**	***2,101***	2018
2019	1,623	1,660	312	312	**1,934**	**1,972**	138	140	**2,072**	**2,112**	***2,112***	2019
2020	1,632	1,669	312	312	**1,943**	**1,981**	138	140	**2,081**	**2,120**	***2,120***	**2020**
2021	1,642	1,680	312	312	**1,953**	**1,991**	138	140	**2,091**	**2,131**	***2,131***	2021
2022	1,651	1,690	312	312	**1,963**	**2,002**	138	140	**2,101**	**2,141**	***2,141***	2022
2023	1,661	1,700	312	312	**1,973**	**2,012**	138	140	**2,110**	**2,152**	***2,152***	2023
2024	1,670	1,711	312	312	**1,982**	**2,023**	138	140	**2,120**	**2,163**	***2,163***	2024
2025	1,680	1,722	312	312	**1,991**	**2,034**	138	140	**2,129**	**2,174**	***2,174***	**2025**
2026	1,689	1,733	312	312	**2,001**	**2,045**	138	140	**2,138**	**2,184**	***2,184***	2026
2027	1,698	1,743	312	312	**2,010**	**2,055**	138	140	**2,148**	**2,195**	***2,195***	2027

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	*Load Factor*	
2000			10,245,420					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	*1,636*	*0.79*	2002
2003			9,846,294	1,232,635	11,078,929	*1,671*	*0.76*	2003
2004			10,324,412	1,267,728	11,592,140	*1,721*	*0.77*	2004
2005			10,531,272	1,258,895	11,790,167	*1,727*	*0.78*	2005
2006			10,649,101	1,195,070	11,844,171	*1,754*	*0.77*	2006
2007			10,680,514	1,252,965	11,933,479	*1,763*	*0.77*	2007
2008			10,839,446	1,276,158	12,115,604	*1,719*	*0.80*	2008
2009			8,065,088	1,108,014	9,173,102	*1,545*	*0.68*	2009
2010			10,417,414	1,299,292	11,716,706	*1,789*	*0.75*	2010
2011			10,988,200	1,422,107	12,410,307	*1,779*	*0.80*	2011
2012			11,107,357	1,200,317	12,307,674	*1,790*	*0.78*	2012
2013	10,888,521	79,017	**10,967,537**	1,133,504	**12,101,041**	***1,759***	***0.79***	2013
2014	10,944,347	368,005	**11,312,352**	965,038	**12,277,390**	***1,868***	***0.75***	2014
2015	11,033,007	1,076,026	**12,109,032**	965,038	**13,074,071**	***1,993***	***0.75***	**2015**
2016	11,146,007	1,889,660	**13,035,667**	984,372	**14,020,039**	***2,051***	***0.78***	2016
2017	11,181,751	2,171,199	**13,352,951**	998,326	**14,351,277**	***2,090***	***0.78***	2017
2018	11,255,071	2,329,762	**13,584,833**	998,326	**14,583,159**	***2,101***	***0.79***	2018
2019	11,333,152	2,338,215	**13,671,367**	998,326	**14,669,694**	***2,112***	***0.79***	2019
2020	11,419,361	2,344,621	**13,763,982**	1,001,062	**14,765,044**	***2,120***	***0.79***	**2020**
2021	11,463,682	2,338,215	**13,801,897**	998,326	**14,800,223**	***2,131***	***0.79***	2021
2022	11,540,514	2,338,215	**13,878,729**	998,326	**14,877,055**	***2,141***	***0.79***	2022
2023	11,613,576	2,338,215	**13,951,791**	998,326	**14,950,117**	***2,152***	***0.79***	2023
2024	11,719,393	2,344,621	**14,064,014**	1,001,062	**15,065,076**	***2,163***	***0.79***	2024
2025	11,764,661	2,338,215	**14,102,876**	998,326	**15,101,203**	***2,174***	***0.79***	**2025**
2026	11,840,728	2,338,215	**14,178,943**	998,326	**15,177,270**	***2,184***	***0.79***	2026
2027	11,915,721	2,338,215	**14,253,936**	998,326	**15,252,263**	***2,195***	***0.79***	2027

iv. Potential Downside Scenario

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000					1,469	1,503	242	281	1,711	1,784	1,784	2000
2001					1,383	1,421	150	175	1,533	1,595	1,595	2001
2002					1,464	1,456	165	180	1,629	1,636	1,636	2002
2003					1,408	1,496	163	175	1,570	1,671	1,671	2003
2004					1,449	1,533	168	189	1,617	1,721	1,721	2004
2005					1,535	1,555	169	172	1,703	1,727	1,727	2005
2006					1,586	1,534	168	170	1,754	1,704	1,754	2006
2007					1,582	1,584	176	179	1,758	1,763	1,763	2007
2008					1,552	1,575	147	145	1,699	1,719	1,719	2008
2009					1,200	1,370	150	176	1,350	1,545	1,545	2009
2010					1,597	1,599	140	190	1,737	1,789	1,789	2010
2011					1,573	1,629	173	150	1,746	1,779	1,779	2011
2012					1,603	1,605	187	169	1,790	1,774	1,790	2012
2013	1,553	1,594	(61)	(18)	**1,492**	**1,577**	157	136	**1,649**	**1,713**	***1,713***	2013
2014	1,571	1,606	(18)	(14)	**1,553**	**1,593**	134	136	**1,687**	**1,728**	***1,728***	2014
2015	1,580	1,615	(14)	(6)	**1,566**	**1,609**	134	136	**1,700**	**1,745**	***1,745***	**2015**
2016	1,583	1,578	29	55	**1,611**	**1,633**	132	140	**1,743**	**1,773**	***1,773***	2016
2017	1,598	1,633	(10)	(52)	**1,588**	**1,581**	138	140	**1,726**	**1,721**	***1,726***	2017
2018	1,607	1,642	(52)	(58)	**1,555**	**1,584**	138	140	**1,692**	**1,724**	***1,724***	2018
2019	1,616	1,652	(58)	(65)	**1,558**	**1,586**	138	140	**1,695**	**1,726**	***1,726***	2019
2020	1,624	1,660	(65)	(65)	**1,558**	**1,595**	138	140	**1,696**	**1,734**	***1,734***	**2020**
2021	1,633	1,670	(65)	(65)	**1,568**	**1,605**	138	140	**1,705**	**1,745**	***1,745***	2021
2022	1,642	1,680	(65)	(65)	**1,577**	**1,615**	138	140	**1,714**	**1,754**	***1,754***	2022
2023	1,651	1,690	(65)	(65)	**1,586**	**1,625**	138	140	**1,723**	**1,765**	***1,765***	2023
2024	1,660	1,700	(65)	(65)	**1,595**	**1,635**	138	140	**1,733**	**1,775**	***1,775***	2024
2025	1,669	1,711	(65)	(65)	**1,604**	**1,645**	138	140	**1,742**	**1,785**	***1,785***	**2025**
2026	1,679	1,721	(65)	(65)	**1,613**	**1,656**	138	140	**1,751**	**1,796**	***1,796***	2026
2027	1,688	1,732	(65)	(65)	**1,622**	**1,666**	138	140	**1,760**	**1,806**	***1,806***	2027

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	*Load Factor*	
2000			10,245,420					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	*1,636*	*0.79*	2002
2003			9,846,294	1,232,635	11,078,929	*1,671*	*0.76*	2003
2004			10,324,412	1,267,728	11,592,140	*1,721*	*0.77*	2004
2005			10,531,272	1,258,895	11,790,167	*1,727*	*0.78*	2005
2006			10,649,101	1,195,070	11,844,171	*1,754*	*0.77*	2006
2007			10,680,514	1,252,965	11,933,479	*1,763*	*0.77*	2007
2008			10,839,446	1,276,158	12,115,604	*1,719*	*0.80*	2008
2009			8,065,088	1,108,014	9,173,102	*1,545*	*0.68*	2009
2010			10,417,414	1,299,292	11,716,706	*1,789*	*0.75*	2010
2011			10,988,200	1,422,107	12,410,307	*1,779*	*0.80*	2011
2012			11,107,357	1,200,317	12,307,674	*1,790*	*0.78*	2012
2013	10,878,212	(57,990)	**10,820,222**	1,133,504	**11,953,726**	***1,713***	***0.80***	2013
2014	10,915,829	(145,790)	**10,770,039**	965,038	**11,735,078**	***1,728***	***0.78***	2014
2015	10,986,525	(131,380)	**10,855,145**	965,038	**11,820,184**	***1,745***	***0.77***	**2015**
2016	11,084,600	67,042	**11,151,642**	984,372	**12,136,013**	***1,773***	***0.78***	2016
2017	11,102,704	(165,753)	**10,936,951**	998,326	**11,935,278**	***1,726***	***0.79***	2017
2018	11,158,773	(501,392)	**10,657,380**	998,326	**11,655,707**	***1,724***	***0.77***	2018
2019	11,220,785	(546,901)	**10,673,884**	998,326	**11,672,211**	***1,726***	***0.77***	2019
2020	11,291,374	(602,508)	**10,688,865**	1,001,062	**11,689,927**	***1,734***	***0.77***	**2020**
2021	11,325,754	(600,862)	**10,724,892**	998,326	**11,723,218**	***1,745***	***0.77***	2021
2022	11,391,552	(600,862)	**10,790,689**	998,326	**11,789,016**	***1,754***	***0.77***	2022
2023	11,456,813	(600,862)	**10,855,951**	998,326	**11,854,277**	***1,765***	***0.77***	2023
2024	11,557,884	(602,508)	**10,955,375**	1,001,062	**11,956,437**	***1,775***	***0.77***	2024
2025	11,598,380	(600,862)	**10,997,518**	998,326	**11,995,844**	***1,785***	***0.77***	**2025**
2026	11,671,321	(600,862)	**11,070,459**	998,326	**12,068,785**	***1,796***	***0.77***	2026
2027	11,745,902	(600,862)	**11,145,040**	998,326	**12,143,367**	***1,806***	***0.77***	2027

V. Best Case Scenario

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	*Annual*	
2000					1,469	1,503	242	281	1,711	1,784	*1,784*	2000
2001					1,383	1,421	150	175	1,533	1,595	*1,595*	2001
2002					1,464	1,456	165	180	1,629	1,636	*1,636*	2002
2003					1,408	1,496	163	175	1,570	1,671	*1,671*	2003
2004					1,449	1,533	168	189	1,617	1,721	*1,721*	2004
2005					1,535	1,555	169	172	1,703	1,727	*1,727*	2005
2006					1,586	1,534	168	170	1,754	1,704	*1,754*	2006
2007					1,582	1,584	176	179	1,758	1,763	*1,763*	2007
2008					1,552	1,575	147	145	1,699	1,719	*1,719*	2008
2009					1,200	1,370	150	176	1,350	1,545	*1,545*	2009
2010					1,597	1,599	140	190	1,737	1,789	*1,789*	2010
2011					1,573	1,629	173	150	1,746	1,779	*1,779*	2011
2012					1,603	1,605	187	169	1,790	1,774	*1,790*	2012
2013	1,555	1,597	21	28	**1,576**	**1,625**	157	136	**1,733**	**1,761**	***1,761***	2013
2014	1,567	1,610	78	132	**1,645**	**1,742**	128	136	**1,772**	**1,877**	***1,877***	2014
2015	1,584	1,620	164	254	**1,748**	**1,873**	134	136	**1,881**	**2,009**	***2,009***	**2015**
2016	1,595	1,631	263	315	**1,857**	**1,946**	138	140	**1,995**	**2,086**	***2,086***	2016
2017	1,604	1,640	322	351	**1,926**	**1,991**	138	140	**2,064**	**2,131**	***2,131***	2017
2018	1,614	1,651	435	438	**2,049**	**2,089**	73	75	**2,122**	**2,164**	***2,164***	2018
2019	1,616	1,661	480	599	**2,096**	**2,260**	67	75	**2,163**	**2,335**	***2,335***	2019
2020	1,633	1,670	653	653	**2,286**	**2,324**	73	75	**2,359**	**2,398**	***2,398***	**2020**
2021	1,643	1,681	653	653	**2,296**	**2,334**	73	75	**2,368**	**2,409**	***2,409***	2021
2022	1,652	1,691	653	653	**2,305**	**2,344**	73	75	**2,378**	**2,419**	***2,419***	2022
2023	1,661	1,701	653	653	**2,315**	**2,354**	73	75	**2,387**	**2,429**	***2,429***	2023
2024	1,671	1,711	653	653	**2,325**	**2,364**	73	75	**2,397**	**2,439**	***2,439***	2024
2025	1,680	1,721	653	653	**2,334**	**2,375**	73	75	**2,406**	**2,449**	***2,449***	**2025**
2026	1,689	1,732	653	653	**2,343**	**2,385**	73	75	**2,415**	**2,460**	***2,460***	2026
2027	1,698	1,742	653	653	**2,352**	**2,395**	73	75	**2,424**	**2,470**	***2,470***	2027

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	*Load Factor*	
2000			10,245,420					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	*1,636*	*0.79*	2002
2003			9,846,294	1,232,635	11,078,929	*1,671*	*0.76*	2003
2004			10,324,412	1,267,728	11,592,140	*1,721*	*0.77*	2004
2005			10,531,272	1,258,895	11,790,167	*1,727*	*0.78*	2005
2006			10,649,101	1,195,070	11,844,171	*1,754*	*0.77*	2006
2007			10,680,514	1,252,965	11,933,479	*1,763*	*0.77*	2007
2008			10,839,446	1,276,158	12,115,604	*1,719*	*0.80*	2008
2009			8,065,088	1,108,014	9,173,102	*1,545*	*0.68*	2009
2010			10,417,414	1,299,292	11,716,706	*1,789*	*0.75*	2010
2011			10,988,200	1,422,107	12,410,307	*1,779*	*0.80*	2011
2012			11,107,357	1,200,317	12,307,674	*1,790*	*0.78*	2012
2013	10,895,966	87,426	**10,983,392**	1,133,504	**12,116,896**	***1,761***	***0.79***	2013
2014	10,959,818	402,629	**11,362,447**	965,038	**12,327,485**	***1,877***	***0.75***	2014
2015	11,052,940	1,139,755	**12,192,695**	965,038	**13,157,733**	***2,009***	***0.75***	**2015**
2016	11,166,584	2,002,359	**13,168,943**	984,372	**14,153,314**	***2,086***	***0.77***	2016
2017	11,206,952	2,393,966	**13,600,918**	998,326	**14,599,245**	***2,131***	***0.78***	2017
2018	11,277,815	2,984,055	**14,261,871**	697,870	**14,959,741**	***2,164***	***0.79***	2018
2019	11,354,186	3,620,394	**14,974,580**	485,866	**15,460,447**	***2,335***	***0.76***	2019
2020	11,439,023	4,837,773	**16,276,796**	487,198	**16,763,993**	***2,398***	***0.80***	**2020**
2021	11,483,009	4,989,497	**16,472,506**	485,866	**16,958,372**	***2,409***	***0.80***	2021
2022	11,558,280	4,918,923	**16,477,203**	485,866	**16,963,069**	***2,419***	***0.80***	2022
2023	11,629,683	4,918,923	**16,548,606**	485,866	**17,034,473**	***2,429***	***0.80***	2023
2024	11,732,582	4,837,773	**16,570,355**	487,198	**17,057,552**	***2,439***	***0.80***	2024
2025	11,773,421	4,989,497	**16,762,919**	485,866	**17,248,785**	***2,449***	***0.80***	**2025**
2026	11,843,845	4,918,923	**16,762,768**	485,866	**17,248,635**	***2,460***	***0.80***	2026
2027	11,913,496	4,918,923	**16,832,419**	485,866	**17,318,286**	***2,470***	***0.80***	2027

vi. Moderate Growth with Trended Weather Scenario

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000					1,469	1,503	242	281	1,711	1,784	1,784	2000
2001					1,383	1,421	150	175	1,533	1,595	1,595	2001
2002					1,464	1,456	165	180	1,629	1,636	1,636	2002
2003					1,408	1,496	163	175	1,570	1,671	1,671	2003
2004					1,449	1,533	168	189	1,617	1,721	1,721	2004
2005					1,535	1,555	169	172	1,703	1,727	1,727	2005
2006					1,586	1,534	168	170	1,754	1,704	1,754	2006
2007					1,582	1,584	176	179	1,758	1,763	1,763	2007
2008					1,552	1,575	147	145	1,699	1,719	1,719	2008
2009					1,200	1,370	150	176	1,350	1,545	1,545	2009
2010					1,597	1,599	140	190	1,737	1,789	1,789	2010
2011					1,573	1,629	173	150	1,746	1,779	1,779	2011
2012					1,603	1,605	187	169	1,790	1,774	1,790	2012
2013	1,555	1,591	20	26	**1,574**	**1,617**	157	136	**1,732**	**1,752**	***1,757***	2013
2014	1,567	1,603	72	104	**1,639**	**1,707**	128	136	**1,766**	**1,843**	***1,848***	2014
2015	1,583	1,612	116	120	**1,699**	**1,732**	134	136	**1,832**	**1,868**	***1,874***	**2015**
2016	1,587	1,623	169	203	**1,756**	**1,826**	132	140	**1,888**	**1,966**	***1,972***	2016
2017	1,603	1,633	203	207	**1,806**	**1,839**	138	140	**1,943**	**1,979**	***1,985***	2017
2018	1,613	1,643	207	208	**1,820**	**1,850**	138	140	**1,957**	**1,990**	***1,997***	2018
2019	1,623	1,653	208	208	**1,831**	**1,860**	138	140	**1,968**	**2,000**	***2,007***	2019
2020	1,632	1,661	208	208	**1,840**	**1,869**	138	140	**1,977**	**2,009**	***2,016***	**2020**
2021	1,642	1,671	208	208	**1,849**	**1,879**	138	140	**1,987**	**2,019**	***2,026***	2021
2022	1,651	1,681	208	208	**1,859**	**1,889**	138	140	**1,997**	**2,029**	***2,036***	2022
2023	1,661	1,691	208	208	**1,868**	**1,899**	138	140	**2,006**	**2,039**	***2,047***	2023
2024	1,670	1,701	208	208	**1,878**	**1,909**	138	140	**2,015**	**2,049**	***2,057***	2024
2025	1,679	1,712	208	208	**1,887**	**1,920**	138	140	**2,025**	**2,060**	***2,068***	**2025**
2026	1,689	1,723	208	208	**1,897**	**1,930**	138	140	**2,034**	**2,070**	***2,079***	2026
2027	1,698	1,733	208	208	**1,906**	**1,940**	138	140	**2,043**	**2,080**	***2,089***	2027

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	Load Factor	
2000			10,245,420					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	1,636	0.79	2002
2003			9,846,294	1,232,635	11,078,929	1,671	0.76	2003
2004			10,324,412	1,267,728	11,592,140	1,721	0.77	2004
2005			10,531,272	1,258,895	11,790,167	1,727	0.78	2005
2006			10,649,101	1,195,070	11,844,171	1,754	0.77	2006
2007			10,680,514	1,252,965	11,933,479	1,763	0.77	2007
2008			10,839,446	1,276,158	12,115,604	1,719	0.80	2008
2009			8,065,088	1,108,014	9,173,102	1,545	0.68	2009
2010			10,417,414	1,299,292	11,716,706	1,789	0.75	2010
2011			10,988,200	1,422,107	12,410,307	1,779	0.80	2011
2012			11,107,357	1,200,317	12,307,674	1,790	0.78	2012
2013	10,894,176	79,017	**10,973,193**	1,133,504	**12,106,697**	***1,757***	***0.79***	2013
2014	10,939,570	362,053	**11,301,622**	965,038	**12,266,661**	***1,848***	***0.76***	2014
2015	11,024,842	848,261	**11,873,103**	965,038	**12,838,141**	***1,874***	***0.78***	**2015**
2016	11,138,375	1,109,885	**12,248,260**	984,372	**13,232,632**	***1,972***	***0.76***	2016
2017	11,171,105	1,475,513	**12,646,619**	998,326	**13,644,945**	***1,985***	***0.78***	2017
2018	11,242,050	1,521,222	**12,763,272**	998,326	**13,761,598**	***1,997***	***0.79***	2018
2019	11,318,516	1,529,675	**12,848,192**	998,326	**13,846,518**	***2,007***	***0.79***	2019
2020	11,405,003	1,533,866	**12,938,869**	1,001,062	**13,939,930**	***2,016***	***0.79***	**2020**
2021	11,446,262	1,529,675	**12,975,937**	998,326	**13,974,264**	***2,026***	***0.79***	2021
2022	11,519,799	1,529,675	**13,049,475**	998,326	**14,047,801**	***2,036***	***0.79***	2022
2023	11,590,165	1,529,675	**13,119,841**	998,326	**14,118,167**	***2,047***	***0.79***	2023
2024	11,697,223	1,533,866	**13,231,089**	1,001,062	**14,232,151**	***2,057***	***0.79***	2024
2025	11,736,485	1,529,675	**13,266,161**	998,326	**14,264,487**	***2,068***	***0.79***	**2025**
2026	11,811,512	1,529,675	**13,341,188**	998,326	**14,339,514**	***2,079***	***0.79***	2026
2027	11,884,040	1,529,675	**13,413,715**	998,326	**14,412,041**	***2,089***	***0.79***	2027

vii. Moderate Growth with Electric Vehicle Scenario

Peak Forecast (MW)

	Econometric		+ PEV Load Added		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000							1,469	1,503	242	281	1,711	1,784	1,784	2000
2001							1,383	1,421	150	175	1,533	1,595	1,595	2001
2002							1,464	1,456	165	180	1,629	1,636	1,636	2002
2003							1,408	1,496	163	175	1,570	1,671	1,671	2003
2004							1,449	1,533	168	189	1,617	1,721	1,721	2004
2005							1,535	1,555	169	172	1,703	1,727	1,727	2005
2006							1,586	1,534	168	170	1,754	1,704	1,754	2006
2007							1,582	1,584	176	179	1,758	1,763	1,763	2007
2008							1,552	1,575	147	145	1,699	1,719	1,719	2008
2009							1,200	1,370	150	176	1,350	1,545	1,545	2009
2010							1,597	1,599	140	190	1,737	1,789	1,789	2010
2011							1,573	1,629	173	150	1,746	1,779	1,779	2011
2012							1,603	1,605	187	169	1,790	1,774	1,790	2012
2013	1,554	1,596	0.0	0.0	20	26	1,574	1,622	157	136	1,731	1,758	1,750	2013
2014	1,567	1,609	0.0	0.1	72	104	1,639	1,712	128	136	1,766	1,848	1,833	2014
2015	1,582	1,618	0.0	0.1	116	120	1,698	1,738	134	136	1,832	1,874	1,855	**2015**
2016	1,586	1,629	0.1	0.2	169	203	1,755	1,832	132	140	1,887	1,972	1,861	2016
2017	1,602	1,639	0.1	0.3	203	207	1,805	1,846	138	140	1,943	1,986	1,871	2017
2018	1,612	1,649	0.1	0.4	207	208	1,819	1,857	138	140	1,957	1,997	1,881	2018
2019	1,622	1,659	0.1	0.5	208	208	1,830	1,868	138	140	1,968	2,007	1,890	2019
2020	1,631	1,668	0.2	0.6	208	208	1,839	1,876	138	140	1,976	2,016	1,899	**2020**
2021	1,641	1,679	0.2	0.8	208	208	1,849	1,887	138	140	1,986	2,027	1,909	2021
2022	1,650	1,689	0.3	0.9	208	208	1,858	1,897	138	140	1,996	2,037	1,919	2022
2023	1,660	1,699	0.3	1.2	208	208	1,868	1,908	138	140	2,005	2,048	1,929	2023
2024	1,669	1,710	0.4	1.4	208	208	1,877	1,919	138	140	2,015	2,059	1,939	2024
2025	1,678	1,721	0.4	1.7	208	208	1,887	1,930	138	140	2,024	2,070	1,950	**2025**
2026	1,688	1,731	0.5	2.0	208	208	1,896	1,941	138	140	2,034	2,081	1,961	2026
2027	1,697	1,742	0.6	2.3	208	208	1,905	1,952	138	140	2,043	2,091	1,971	2027

Energy Sales Forecast (MWh)

	Econometric	+ PEV Energy Added	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
							Peak	Load Factor	
2000				10,245,420					
2001				9,658,073					
2002				10,160,143	1,187,858	11,348,001	1,636	0.79	2002
2003				9,846,294	1,232,635	11,078,929	1,671	0.76	2003
2004				10,324,412	1,267,728	11,592,140	1,721	0.77	2004
2005				10,531,272	1,258,895	11,790,167	1,727	0.78	2005
2006				10,649,101	1,195,070	11,844,171	1,754	0.77	2006
2007				10,680,514	1,252,965	11,933,479	1,763	0.77	2007
2008				10,839,446	1,276,158	12,115,604	1,719	0.80	2008
2009				8,065,088	1,108,014	9,173,102	1,545	0.68	2009
2010				10,417,414	1,299,292	11,716,706	1,789	0.75	2010
2011				10,988,200	1,422,107	12,410,307	1,779	0.80	2011
2012				11,107,357	1,200,317	12,307,674	1,790	0.78	2012
2013	10,888,519	618	79,017	10,968,154	1,133,504	12,101,658	1,750	0.79	2013
2014	10,944,041	1,082	362,053	11,307,176	965,038	12,272,214	1,833	0.76	2014
2015	11,028,794	1,724	848,261	11,878,779	965,038	12,843,817	1,855	0.79	**2015**
2016	11,141,548	2,602	1,109,885	12,254,036	984,372	13,238,408	1,861	0.81	2016
2017	11,175,467	3,773	1,475,513	12,654,754	998,326	13,653,081	1,871	0.83	2017
2018	11,246,498	4,921	1,521,222	12,772,641	998,326	13,770,967	1,881	0.84	2018
2019	11,323,838	6,361	1,529,675	12,859,874	998,326	13,858,201	1,890	0.84	2019
2020	11,408,729	8,123	1,533,866	12,950,719	1,001,062	13,951,780	1,899	0.84	**2020**
2021	11,451,848	10,232	1,529,675	12,991,755	998,326	13,990,082	1,909	0.84	2021
2022	11,525,608	12,711	1,529,675	13,067,995	998,326	14,066,321	1,919	0.84	2022
2023	11,597,016	15,576	1,529,675	13,142,267	998,326	14,140,593	1,929	0.84	2023
2024	11,701,167	18,843	1,533,866	13,253,877	1,001,062	14,254,939	1,939	0.84	2024
2025	11,744,157	22,528	1,529,675	13,296,360	998,326	14,294,687	1,950	0.84	**2025**
2026	11,819,736	26,640	1,529,675	13,376,052	998,326	14,374,378	1,961	0.84	2026
2027	11,893,551	31,187	1,529,675	13,454,413	998,326	14,452,740	1,971	0.84	2027

viii. **Current Contract with Industrial Customer Contract Expiration Scenario**

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000					1,469	1,503	242	281	1,711	1,784	1,784	2000
2001					1,383	1,421	150	175	1,533	1,595	1,595	2001
2002					1,464	1,456	165	180	1,629	1,636	1,636	2002
2003					1,408	1,496	163	175	1,570	1,671	1,671	2003
2004					1,449	1,533	168	189	1,617	1,721	1,721	2004
2005					1,535	1,555	169	172	1,703	1,727	1,727	2005
2006					1,586	1,534	168	170	1,754	1,704	1,754	2006
2007					1,582	1,584	176	179	1,758	1,763	1,763	2007
2008					1,552	1,575	147	145	1,699	1,719	1,719	2008
2009					1,200	1,370	150	176	1,350	1,545	1,545	2009
2010					1,597	1,599	140	190	1,737	1,789	1,789	2010
2011					1,573	1,629	173	150	1,746	1,779	1,779	2011
2012					1,603	1,605	187	169	1,790	1,774	1,790	2012
2013	1,554	1,596	0	0	**1,554**	**1,596**	157	136	**1,711**	**1,732**	***1,732***	2013
2014	1,566	1,608	(17)	(17)	**1,549**	**1,591**	157	136	**1,706**	**1,727**	***1,727***	2014
2015	1,582	1,618	(54)	(54)	**1,528**	**1,564**	157	136	**1,685**	**1,699**	***1,699***	**2015**
2016	1,593	1,628	(59)	(59)	**1,534**	**1,569**	157	136	**1,691**	**1,705**	***1,705***	2016
2017	1,601	1,638	(680)	(703)	**921**	**935**	157	136	**1,078**	**1,070**	***1,078***	2017
2018	1,611	1,647	(703)	(703)	**908**	**944**	157	136	**1,065**	**1,080**	***1,080***	2018
2019	1,620	1,657	(703)	(703)	**917**	**954**	157	136	**1,075**	**1,090**	***1,090***	2019
2020	1,629	1,666	(703)	(703)	**926**	**963**	157	136	**1,083**	**1,099**	***1,099***	**2020**
2021	1,639	1,676	(703)	(703)	**936**	**973**	157	136	**1,093**	**1,109**	***1,109***	2021
2022	1,648	1,686	(703)	(758)	**945**	**928**	157	136	**1,102**	**1,064**	***1,102***	2022
2023	1,657	1,696	(758)	(758)	**899**	**938**	157	136	**1,056**	**1,074**	***1,074***	2023
2024	1,667	1,706	(758)	(758)	**908**	**948**	157	136	**1,065**	**1,084**	***1,084***	2024
2025	1,676	1,717	(758)	(758)	**917**	**959**	157	136	**1,074**	**1,095**	***1,095***	**2025**
2026	1,685	1,728	(758)	(758)	**927**	**969**	157	136	**1,084**	**1,105**	***1,105***	2026
2027	1,694	1,738	(758)	(758)	**936**	**979**	157	136	**1,093**	**1,115**	***1,115***	2027

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	*Load Factor*	
2000			10,245,420					
2001			9,658,073					
2002			10,160,143	1,187,858	11,348,001	*1,636*	*0.79*	2002
2003			9,846,294	1,232,635	11,078,929	*1,671*	*0.76*	2003
2004			10,324,412	1,267,728	11,592,140	*1,721*	*0.77*	2004
2005			10,531,272	1,258,895	11,790,167	*1,727*	*0.78*	2005
2006			10,649,101	1,195,070	11,844,171	*1,754*	*0.77*	2006
2007			10,680,514	1,252,965	11,933,479	*1,763*	*0.77*	2007
2008			10,839,446	1,276,158	12,115,604	*1,719*	*0.80*	2008
2009			8,065,088	1,108,014	9,173,102	*1,545*	*0.68*	2009
2010			10,417,414	1,299,292	11,716,706	*1,789*	*0.75*	2010
2011			10,988,200	1,422,107	12,410,307	*1,779*	*0.80*	2011
2012			11,107,357	1,200,317	12,307,674	*1,790*	*0.78*	2012
2013	10,888,089	0	**10,888,089**	1,133,504	**12,021,593**	***1,732***	***0.79***	2013
2014	10,943,375	(69,066)	**10,874,308**	965,038	**11,839,347**	***1,727***	***0.78***	2014
2015	11,027,119	(287,327)	**10,739,792**	965,038	**11,704,830**	***1,699***	***0.79***	**2015**
2016	11,131,193	(456,703)	**10,674,490**	984,372	**11,658,862**	***1,705***	***0.78***	2016
2017	11,160,251	(2,998,442)	**8,161,809**	998,326	**9,160,136**	***1,078***	***0.97***	2017
2018	11,225,325	(5,665,618)	**5,559,708**	998,326	**6,558,034**	***1,080***	***0.69***	2018
2019	11,298,387	(5,665,618)	**5,632,770**	998,326	**6,631,096**	***1,090***	***0.69***	2019
2020	11,377,865	(5,681,140)	**5,696,725**	1,001,062	**6,697,787**	***1,099***	***0.69***	**2020**
2021	11,417,701	(5,665,618)	**5,752,084**	998,326	**6,750,410**	***1,109***	***0.69***	2021
2022	11,487,025	(5,665,618)	**5,821,407**	998,326	**6,819,734**	***1,102***	***0.71***	2022
2023	11,555,970	(6,110,092)	**5,445,877**	998,326	**6,444,204**	***1,074***	***0.69***	2023
2024	11,657,113	(6,128,035)	**5,529,078**	1,001,062	**6,530,140**	***1,084***	***0.69***	2024
2025	11,697,623	(6,111,291)	**5,586,331**	998,326	**6,584,658**	***1,095***	***0.69***	**2025**
2026	11,770,828	(6,111,291)	**5,659,537**	998,326	**6,657,863**	***1,105***	***0.69***	2026
2027	11,842,576	(6,111,291)	**5,731,285**	998,326	**6,729,611**	***1,115***	***0.69***	2027

D. Sensitivities

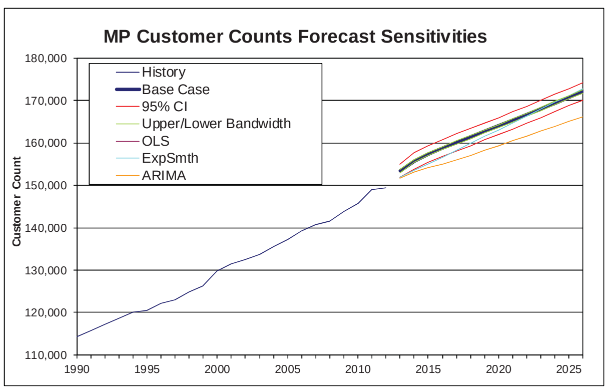
Minnesota Power conducts tests to identify the sensitivity of the forecast to changes in major model drivers and to alternative forecast methodologies. Forecast sensitivities were developed for customer counts, energy sales, and seasonal peak demand models to demonstrate a range of outcomes resulting from these changes.

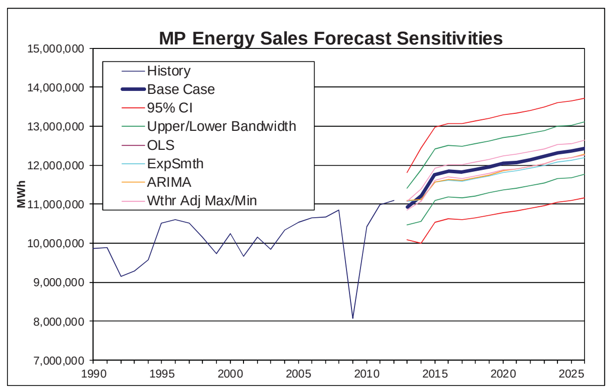
The following Base Case sensitivities and alternative forecast methods have been conducted on the AFR 2013 forecasts:

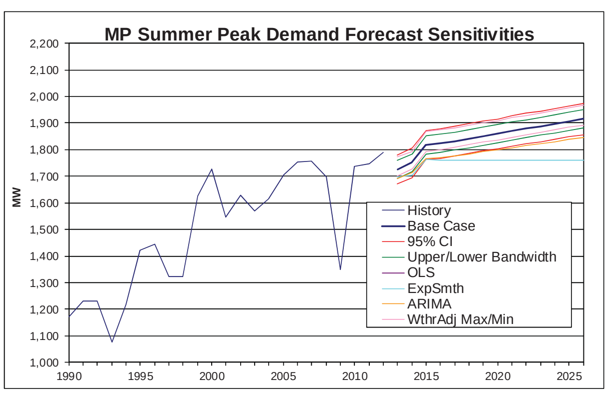
- Wthr Adj Max Min – Weather is adjusted to historical maximum and minimums.
- OLS – Ordinary least squares regression models only.
- ExpSmth – Exponential smoothing models only.
- ARIMA – Autoregressive integrated moving average (Box-Jenkins) models only.
- 95% CI – 95% confidence level range based on the standard error of input variables and the model's inherent estimation of error as calculated by MetrixND.

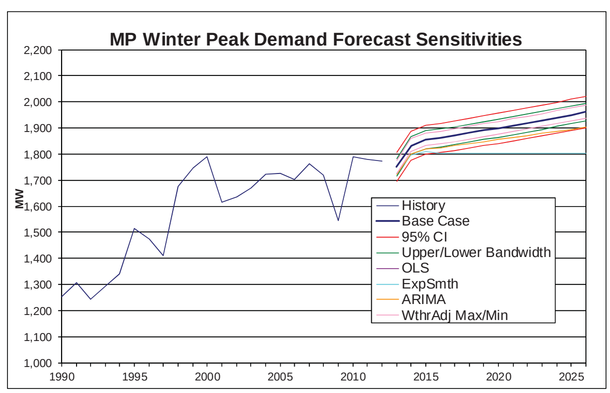
Maximum and minimum weather sensitivities simulate historically high and low monthly temperatures, heating degree days, and cooling degree days instead of the 20 year average weather assumptions used in the Base Case.

Sensitivity results for customer counts, energy, and demand are shown below:









3. Other Information

A. Subject of Assumption

Section 7610.0320, Subpart 4, lists specific assumptions to be discussed. The following list contains the discussion of each assumption and Minnesota Power's response.

- Assumptions made regarding the availability of alternative sources of energy.
  - Minnesota Power makes no assumptions regarding the availability of alternative sources of energy.
- Assumptions made regarding expected conversion from other fuels to electricity or vice versa.
  - Minnesota Power's assumptions regarding conversion are explicitly included in the saturation rates for electric heating.
- Assumptions made regarding future prices of electricity for customers and the effect that such prices would have on system demand.
  - See Section 1.C.
- Assumptions made in arriving at the data requested (historical reporting).
  - Minnesota Power makes no such assumptions.
- Assumptions made regarding the effect of existing energy conservations programs under Federal or State legislation on long-term electricity demand
  - See Demand Side Management above.
- Assumptions made regarding the projected effect of new conservations programs the utility deems likely to occur through Fed or State.
  - See Section 1.F.
- Assumptions made regarding current and future saturation levels of appliances and electric space heating.
  - See Section 1.F.

B. Coordination of Forecasts with Other Systems

Minnesota Power is a member of MRO, MISO, Edison Electric Institute (EEI), Upper Midwest Utility Forecasters (UMUF), and other trade associations. While each member of these groups independently determines its power requirements, periodic meetings are held to share information and discuss forecasting techniques and methodologies.

C. Compliance with 7610.0320 Forecast Documentation

Statute or Rule	***Requirement***	***Reference Section***
7610.0320, Subp. 1(A)	The overall methodological framework that is used.	Section 1.A
7610.0320, Subp. 1(B)	The specific analytical techniques that are used, their purpose, and the components of the forecast to which they have been applied.	Sections 1.D, 1.F
7610.0320, Subp. 1(C)	The manner in which these specific techniques are related in producing the forecast.	Section 1.D
7610.0320, Subp. 1(D)	The purpose of the technique, typical computations specifying variables and data, and the results of appropriate statistical tests.	Section 1.F
7610.0320, Subp. 1(E)	Forecast confidence levels or ranges of accuracy for annual peak demand and annual electrical consumption.	Section 1.F
7610.0320, Subp. 1(F)	A brief analysis of the methodology used, including its strengths and weaknesses, its suitability to the system, cost considerations, data requirements, past accuracy, and any other factors considered significant to the utility.	Sections 1.B, 1.F
7610.0320, Subp. 2(A)	A complete list of data sets used in making the forecast, including a brief description of each data set and an explanation of how each was obtained, or a citation to the source.	Sections 1.C
7610.0320, Subp. 2(B)	A clear identification of any adjustments made to the raw data to adapt them for use in forecasts, including the nature of the adjustment, the reason for the adjustment, and the magnitude of the adjustment.	Section 1.F
7610.0320, Subp. 3	Discussion of essential assumptions.	Sections 1.E, 1.F
7610.0320, Subp. 4	Subject of assumption.	Section 3
7610.0320, Subp. 5(A)	Description of the extent to which the utility coordinates its load forecasts with those of other systems.	Section 3
7610.0320, Subp. 5(B)	Description of the manner in which such forecasts are coordinated.	Section 3

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

A utility shall provide the following information for the last calendar year:

E. RATE SCHEDULES

The rate schedule and monthly power cost adjustment information must be submitted in electronic or paper format.

See Instructions for details of the information required on the Rate Schedules and Monthly Power Cost Adjustments.

Billing Month	Retail Fuel Adjustments
Jun-12	0.00756
Jul-12	0.00973
Aug-12	0.01084
Sep-12	0.01185
Oct-12	0.01077
Nov-12	0.00915
Dec-12	0.01088
Jan-13	0.01291
Feb-13	0.01196
Mar-13	0.01120
Apr-13	0.01028
May-13	0.00894
Jun-13	0.01031

F. REPORT FORM EIA-861

A copy of report form EIA-861 filed with the US Dept. of Energy must be submitted in electronic or paper format.

A copy of the report form EIA-861 filed with the Energy Information Administration of the US Dept. of Energy must be submitted.

G. FINANCIAL AND STATISTICAL REPORT

If applicable, a copy of the Financial and Statistical Report filed with the US Dept. of Agriculture must be submitted in electronic or paper format.

For rural electric cooperatives, a copy of the Financial and Statistical Report to the US Dept of Agriculture must be submitted.

H. GENERATION DATA

If the utility has Minnesota power plants, enter the fuel requirements and generation data on the Plant1, Plant2, etc. worksheets.

I. ELECTRIC USE BY MINNESOTA RESIDENTIAL SPACE HEATING USERS

See Instructions for details of the information required for residential space heating users.

COL. 1 NO. OF RESIDENTIAL ELECTRICAL SPACE HEATING CUSTOMERS	COL. 2 NO. OF RESIDENTIAL UNITS SERVED WITH ELECTRICAL SPACE HEATING	COL. 3 TOTAL MWH USED BY THESE CUSTOMERS AND UNITS
13,783	13,783	164,932

Comments

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY COUNTY FOR THE LAST CALENDAR YEAR

ENERGY DELIVERED TO ULTIMATE CONSUMERS BY COUNTY

COUNTY CODE	COUNTY NAME	MWH DELIVERED	COUNTY CODE	COUNTY NAME	MWH DELIVERED
1	Aitkin	0	46	Martin	
2	Anoka		47	Meeker	
3	Becker		48	Mille Lacs	
4	Beltrami		49	Morrison	285399
5	Benton	24091	50	Mower	
6	Big Stone		51	Murray	
7	Blue Earth		52	Nicollet	
8	Brown		53	Nobles	
9	Carlton	402932	54	Norman	
10	Carver		55	Olmstead	
11	Cass	116850	56	Otter Tail	397
12	Chippewa		57	Pennington	
13	Chisago		58	Pine	74366
14	Clay		59	Pipestone	
15	Clearwater		60	Polk	
16	Cook		61	Pope	
17	Cottonwood		62	Ramsey	
18	Crow Wing	124327	63	Red Lake	
19	Dakota		64	Redwood	
20	Dodge		65	Renville	
21	Douglas		66	Rice	
22	Faribault		67	Rock	
23	Fillmore		68	Roseau	
24	Freeborn		69	St. Louis	7252076
25	Goodhue		70	Scott	
26	Grant		71	Sherburne	
27	Hennepin		72	Sibley	
28	Houston		73	Stearns	7530
29	Hubbard	93723	74	Steele	
30	Isanti		75	Stevens	
31	Itasca	271724	76	Swift	
32	Jackson		77	Todd	198902
33	Kanabec		78	Traverse	
34	Kandiyohi		79	Wabasha	
35	Kittson		80	Wadena	93073
36	Koochiching	218952	81	Waseca	
37	Lac Qui Parle		82	Washington	
38	Lake	224195	83	Watonwan	
39	Lake of the Woods		84	Wilkin	
40	Le Sueur		85	Winona	
41	Lincoln		86	Wright	
42	Lyon		87	Yellow Medicine	
43	McLeod				
44	Mahnomen			GRAND TOTAL (Entered)	9388538
45	Marshall				
				GRAND TOTAL (Calculated)	9388538

<= (Should equal "Megawatt-hours" column total on ElectricityByClass worksheet)

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY MONTH FOR THE LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers.

Past Year Entire System		A Non-Farm Residential	B Residential With Space Heat	C Farm	D Small Commercial & Industrial	E Irrigation	F Large Commercial & Industrial	G Street & Highway Lighting	H Other (Include Municipals)	I Total (Columns A through H)
January	No. of Customers	105,007	13,869	2,420	21,794	8	409	6,005	281	149,793
	MWH	88,810	25,044	5,735	100,659	420,403	170,597	1,540	4,657	817,445
February	No. of Customers	104,860	13,837	2,421	21,723	8	408	6,022	280	149,559
	MWH	61,344	27,052	5,953	102,801	396,859	163,831	1,576	4,620	764,034
March	No. of Customers	104,926	13,869	2,421	21,720	8	409	6,065	278	149,696
	MWH	56,955	23,702	6,152	107,508	424,431	171,926	1,721	5,764	798,160
April	No. of Customers	98,313	12,648	2,102	19,891	8	374	5,942	219	139,497
	MWH	49,590	12,162	4,199	80,534	388,538	160,790	1,009	2,932	699,754
May	No. of Customers	104,933	13,872	2,416	21,704	8	407	6,223	268	149,831
	MWH	53,271	11,330	4,572	93,703	418,341	171,756	1,122	3,980	758,074
June	No. of Customers	104,790	13,924	2,412	21,731	8	410	6,227	271	149,773
	MWH	60,988	6,665	4,671	108,704	414,144	175,737	1,007	4,325	776,240
July	No. of Customers	106,259	13,891	2,412	21,766	8	409	6,345	287	151,377
	MWH	86,457	5,679	5,562	112,282	430,293	176,933	1,015	3,893	822,114
August	No. of Customers	105,366	13,920	2,417	21,792	8	409	6,606	283	150,801
	MWH	77,809	5,638	6,057	119,935	420,255	180,233	1,118	5,024	816,070
September	No. of Customers	105,152	13,883	2,415	21,828	8	406	6,724	287	150,703
	MWH	57,231	4,886	5,353	111,266	417,403	174,893	1,099	4,914	777,045
October	No. of Customers	104,961	13,887	2,410	21,846	8	400	6,713	288	150,513
	MWH	59,983	7,231	4,792	86,630	406,383	176,635	1,482	4,451	747,586
November	No. of Customers	105,038	13,905	2,405	21,928	8	398	6,737	288	150,707
	MWH	71,763	14,048	5,059	94,834	410,935	169,864	1,642	4,316	772,462
December	No. of Customers	104,719	13,887	2,392	21,648	8	396	7,293	266	150,609
	MWH	90,433	21,495	5,611	118,529	420,436	176,228	1,623	5,198	839,553
	Total MWH	814,633	164,932	63,717	1,237,386	4,968,421	2,069,423	15,954	54,074	9,388,538

Comments

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

ELECTRICITY DELIVERED TO ULTIMATE CONSUMERS IN MINNESOTA SERVICE AREA IN LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers.

Exclude station use, distribution losses, and unaccounted for energy losses from this table altogether.

Classification of Energy Delivered to Ultimate Consumers (include energy used during the year for irrigation and drainage pumping)	Number of Customers at End of Year (In this column report the number of farms, residences, commercial establishments, etc., and not the number of meters, where different.)	Megawatt-hours (round to nearest MWH) (This column total should equal the grand total in the worksheet labeled "ElectricityByCounty" which provides deliveries by county.)	Revenue ($) (This column total will be used for the Alternative Energy Assessment and should not include revenues from sales for resale (MN Statutes Sec. 216B.62, Subd. 5).)
Farm	2,387	63,717	6,449,028
Nonfarm-residential	118,310	979,564	89,344,759
Commercial	21,614	1,237,386	100,259,094
Industrial	411	7,037,843	365,647,862
Street and highway lighting	6,409	15,954	2,030,358
All other	275	54,074	4,112,880
Entered Total	149,405	9,388,538	567,843,983
CALCULATED TOTAL	149,405	9,388,538	567,843,983

Comments

Non-farm ($/kWh)	Residential ($/customer)
0.091209	755.1772
CHECK	CHECK

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

PLEASE PROVIDE THE FOLLOWING INFORMATION FOR THOSE CUSTOMERS USING IN EXCESS OF 10,000 MWH. BE SURE TO INCLUDE YOUR LARGE CUSTOMERS LOCATED IN AND OUTSIDE MINNESOTA.

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

[TRADE SECRET DATA BEGINS

ID#	CUSTOMER NAME	ADDRESS	CITY	STATE	ZIP	MWH

TRADE SECRET DATA ENDS]

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Boswell Energy Center	PLANT ID	68003
STREET ADDRESS	1210 NW 3rd Street		
CITY	Cohasset		
STATE	MN	NUMBER OF UNITS	4
ZIP CODE	55721		
COUNTY	Itasca		
CONTACT PERSON	William Boutwell		
TELEPHONE	218-328-5036 x4433		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1958	COAL	467,471	
2	USE	ST	1960	COAL	476,921	
3	USE	ST	1973	COAL	2,405,291	
4	USE	ST	1980	COAL	3,134,413	MP share
					6,484,096	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1		67.125	79.43	96.62	1.46	
2	67.325	67.325	81.04	94.82	2.18	
3	357.225	357.225	78.01	85.19	4.33	
4	466.974	466.974	76.71	83.01	2.2	
	891.524	958.649	78.80	89.91	2.54	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE (START UP)					
Unit ID #	Fuel Type ***	Quantity		BTU Content (for coal only)			Unit of Measure ****	GAS***	QUANITY	UNITS OF MEASURE****
1	SUB	287,551	TONS	8,959	FO2	0	GAL	NG	22489	Mbtu's
2	SUB	298,280	TONS	8,951	FO2	0	GAL	NG	15245	Mbtu's
3	SUB	1,406,990	TONS	8,955	FO2	0	GAL	NG	71053	Mbtu's
4	SUB	2,232,027	TONS	9,057	FO2	0	GAL	NG	52223	Mbtu's

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Laskin Energy Center	PLANT ID	68015
STREET ADDRESS	PO Box 166		
CITY	Aurora		
STATE	MN	UNITS	2
ZIP CODE	55705		
COUNTY	Saint Louis		
CONTACT PERSON	William Boutwell		
TELEPHONE	218-328-5036 x4433		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1953	COAL	191,860	
2	USE	ST	1953	COAL	176,506	
					368,366	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	48.8	48.8	46.77	81.95	4.08	
2	49.4	49.4	40.19	75.81	5.69	
	98.2	98.2	43.48	78.88	4.89	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity		BTU Content (for coal only)			Unit of Measure ****	
1	SUB	146,219		8682	FO2	2,070	GAL	
2	SUB	133,984		8680		2,070		
					NG	23,594	Mbtu's	
						23,594		

NOTE: Fuels are not metered separately for these units

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant

Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields

Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	M.L. Hibbard	PLANT ID	68009
STREET ADDRESS	4913 Main Street		
CITY	Duluth		
STATE	MN	NUMBER OF UNITS	2
ZIP CODE	55807		
COUNTY	Saint Louis		
CONTACT PERSON	David Pessenda		
TELEPHONE	218-628-3627 x5713		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
3	USE	ST	1949	SUB/WOOD	4,258	
4	USE	ST	1951	SUB/WOOD	16,074	
					20,332.0	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
3	25.603	25.603	1.51	84.68	52.88	
4	32.85	32.85	7.48	85.29	5.28	
	58.5	58.5	4.50	84.99	29.08	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity		BTU Content (for coal only)			Unit of Measure ****	BTU Content (for coal only)
3	SUB	0		n/a	NG	8,959	MCF	
	WOOD	9,114		8,983				
4	SUB	0		n/a				
	WOOD	24,160		8,983				

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Rapids Energy Center	PLANT ID	68025
STREET ADDRESS	502 NW 3rd Street		
CITY	Grand Rapids		
STATE	MN	NUMBER OF UNITS	4
ZIP CODE	55744		
COUNTY	Itasca		
CONTACT PERSON	Frank Frederickson		
TELEPHONE	218-326-6083 x6990		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
6	USE	ST	1969	GAS/WOOD/COAL	43,152	
7	USE	ST	1980	WOOD/COAL	65,219	
4	USE	HC	1917	HYD	2,742	
5	USE	HC	1948	HYD	2,084	
					113,197	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
6	11.4	11.4	43.2	90.6	3.32	
7	13.0	13.0	57.3	90.4	7.37	
4 & 5	0.8	0.8	36.0	57.0	43.01	
	25.2	25.2	45.5	79.3	17.9	

D. UNIT FUEL USED

					PRIMARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity					Unit of Measure ****	BTU Content (for coal only)
6	NG	50,515	MCF					
6	SUB	11,804	TONS					9,313
7	WOOD	185,374	TONS					

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	SAPPI Cloquet Turb Genr #5	PLANT ID	68020
STREET ADDRESS	2201 Avenue B		
CITY	Cloquet		
STATE	MN	UNITS	1
ZIP CODE	55720		
COUNTY	Carlton		
CONTACT PERSON	Rochon Kinney		
TELEPHONE	218-722-5642 x3297		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
5	USE	ST	2001	WOOD/GAS	66,803	
					66,803	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
5	22.785	22.785	51%	96.5%	2.0%	
	22.785	22.785	51%	96.5%	2.0%	

D. UNIT FUEL USED

PRIMARY FUEL USE					SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity					Unit of Measure ****	BTU Content (for coal only)
5	WOOD	14,860	tons		Gas	133,740	MCF	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Taconite Harbor	PLANT ID	68026
STREET ADDRESS	PO Box 64		
CITY	Schroeder		
STATE	MN	UNITS	3
ZIP CODE	55705		
COUNTY	Cook		
CONTACT PERSON	William Boutwell		
TELEPHONE	218-370-0650		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1953	COAL	329,536	
2	USE	ST	1953	COAL	154,724	
3	USE	ST	1954	COAL	386,055	
					872319*	

*THEC unit figures may not total net figures due to station service

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	78.7	78.7	53.11	86.56	11.24	
2	76.05	76.05	24.85	83.78	11.14	
3	83	83	61.05	84.84	12.54	
	237.75	237.75	46.34	85.06	11.64	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity		BTU Content (for coal only)			Unit of Measure ****	
1	SUB	224,487	TONS	9,020	FO2	31,477	GAL	
2	SUB	102,755	TONS	9,006	FO2	32,417	GAL	
3	SUB	237,173	TONS	9,020	FO2	47,404	GAL	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Thomson Hydroelectric Station	PLANT ID	68016
STREET ADDRESS	180 St, Hwy 210		
CITY	Carlton		
STATE	MN	UNITS	6
ZIP CODE	55718		
COUNTY	Carlton		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1907	HYD	25,090.0	
2	USE	HC	1907	HYD	22,979.4	
3	USE	HC	1907	HYD	19,624.7	
4	USE	HC	1914	HYD	24,050.5	
5	USE	HC	1918	HYD	20,794.0	
6	USE	HC	1949	HYD	23,768.4	
					136,467.6	

Unit net figures may not add up to the station net figurs due to station service.

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	11.5	11.5	22.94%	44.90%	55.10%	
2	11.5	11.5	21.04%	45.92%	52.88%	
3	11.5	11.5	17.74%	45.96%	53.12%	
4	11.9	11.9	24.37%	46.26%	52.88%	
5	10.4	10.4	21.95%	46.21%	52.89%	
6	13.6	13.6	21.97%	25.66%	53.20%	
	70.4	70.4	21.67%	42.48%	53.34%	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE (START UP)			
Unit ID #	**Fuel Type *** **	**Quantity**	**Unit of Measure ******	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Blanchard Hydroelectric Statior	PLANT ID	68001
STREET ADDRESS	PO Box 157		
CITY	Little Falls		
STATE	MN	UNITS	3
ZIP CODE	56345		
COUNTY	Morrison		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1925	HYD	25,437.3	
2	USE	HC	1925	HYD	33,167.4	
3	USE	HC	1988	HYD	16,953.0	
					75,557.7	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	3.427	3.427	48.54%	99.94%	0.06%	
2	4.013	4.013	63.06%	99.94%	0.06%	
3	3.26	3.26	29.81%	99.75%	0.25%	
	10.7	10.7	47.14%	99.88%	0.12%	

D. UNIT FUEL USED

PRIMARY FUEL USE Unit ID #	Fuel Type ***	Quantity			SECONDARY FUEL USE (START UP)		Unit of Measure ****	BTU Content (for coal only)

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Pillager Hydroelectric Station	PLANT ID	68011
STREET ADDRESS	13449 Pillager Dam Road		
CITY	Pillager		
STATE	MN	UNITS	2
ZIP CODE	56473		
COUNTY	Cass		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1917	HYD	4,528.1	
2	USE	HC	1917	HYD	3,510.4	
					8,038.6	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.65	0.65	64.61%	99.98%	0.02%	
2	0.65	0.65	50.09%	99.98%	0.02%	
	1.30	1.29	57.35%	99.98%	0.02%	

D. UNIT FUEL USED

PRIMARY FUEL USE Unit ID #	Fuel Type ***	Quantity			SECONDARY FUEL USE (START UP)		Unit of Measure ****	BTU Content (for coal only)

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Little Falls Hydroelectric Statior	PLANT ID	68007
STREET ADDRESS	1 Hydro Street		
CITY	Little Falls		
STATE	MN	NUMBER OF UNITS	6
ZIP CODE	56345		
COUNTY	Morrison		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1919	HYD	5459.5	
2	USE	HC	1919	HYD	5861.6	
3	USE	HC	1920	HYD	7255.6	
4	USE	HC	1979	HYD	6054.2	
5	USE	HC	1906	HYD	2513.1	
6	USE	HC	1906	HYD	2002.9	
					29382.6	

THOM unit totals may not equal the total due to station service calculations.

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.60	0.60	32.49%	83.94%	0.00%	
2	0.60	0.60	81.89%	100.00%	0.00%	
3	0.60	0.60	75.43%	100.00%	0.00%	
4	0.60	0.60	35.37%	83.64%	0.07%	
5	0.60	0.60	73.24%	100.00%	0.00%	
6	0.60	0.60	57.20%	99.92%	0.08%	
	3.60	3.60	59.27%	94.58%	0.02%	

D. UNIT FUEL USED

PRIMARY FUEL USE					SECONDARY FUEL USE (START UP)			
Unit ID #	**Fuel Type *** **	**Quantity**	**Unit of Measure ******	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Scanlon Hydroelectric Station	PLANT ID	68013
STREET ADDRESS			
CITY	Scanlon		
STATE	MN	UNITS	4
ZIP CODE	55720		
COUNTY	Carlton		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1923	HYD	944.7	
2	USE	HC	1923	HYD	2,057.3	
3	USE	HC	1923	HYD	1,114.4	
4	USE	HC	1923	HYD	1,703.9	
					5,925.1	

Unit net figues may not total station net figures due to station service calculations.

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.02	0.02	26.96%	98.37%	1.63%	
2	0.02	0.02	58.71%	98.37%	1.63%	
3	0.02	0.02	31.80%	97.82%	1.91%	
4	0.02	0.02	48.63%	97.01%	2.18%	
	0.08	0.08	41.53%	97.89%	1.84%	

D. UNIT FUEL USED

PRIMARY FUEL USE Unit ID #	Fuel Type ***	Quantity		BTU Content (for coal only)	SECONDARY FUEL USE (START UP)		Unit of Measure ****	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Sylvan Hydroelectric Station	PLANT ID	68014
STREET ADDRESS	13753 Sylvan Dam Road		
CITY	Pillager		
STATE	MN	UNITS	3
ZIP CODE	56473		
COUNTY	Cass		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1913	HYD	3,445.6	
2	USE	HC	1913	HYD	3,308.4	
3	USE	HC	1915	HYD	2,056.4	
					8,926.1	

Unit net figures may not total the station net due to station service calculations

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.4	0.4	65.56%	92.67%	7.24%	
2	0.4	0.4	62.95%	93.55%	6.36%	
3	0.4	0.4	39.12%	93.56%	6.36%	
	1.2	1.2	55.88%	93.26%	6.65%	

D. UNIT FUEL USED

PRIMARY FUEL USE					SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity					Unit of Measure ****	BTU Content (for coal only)

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Winton Hydroelectric Station	PLANT ID	68019
STREET ADDRESS	PO Box 156		
CITY	Winton		
STATE	MN	UNITS	2
ZIP CODE	55796		
COUNTY	Lake		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
2	USE	HC	1923	HYD	4,932.5	
3	USE	HC	1923	HYD	7,531.5	
					12,472.0	

Unit net figures may not total the station net figures due to station service calculati

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
2	1.10	1.10	28.15%	96.44%	3.54%	
3	1.20	1.20	42.99%	99.98%	0.00%	
	2.30	2.30	35.57%	98.21%	1.77%	

D. UNIT FUEL USED

PRIMARY FUEL USE					SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity					Unit of Measure ****	BTU Content (for coal only)

ons

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Knife Falls Hydroelectric Station	PLANT ID	68006
STREET ADDRESS			
CITY	Cloquet		
STATE	MN	UNITS	3
ZIP CODE	55720		
COUNTY	Carlton		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1922	HYD	1,847.3	
2	USE	HC	1922	HYD	3,042.7	
3	USE	HC	1922	HYD	3,448.0	
					8,348.2	

Unit net figures may not total the station net figures due to station service calculatioı

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.3	0.3	26.26%	98.46%	1.54%	
2	0.3	0.3	42.89%	98.72%	1.28%	
3	0.3	0.3	45.89%	99.06%	0.94%	
	0.9	0.9	38.35%	98.75%	1.25%	

D. UNIT FUEL USED

PRIMARY FUEL USE					SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity					Unit of Measure ****	BTU Content (for coal only)

ns.

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Fond Du Lac Hydroelectric Station	PLANT ID	68005
STREET ADDRESS	14302 Oldenberg Parkway		
CITY	Duluth		
STATE	MN	UNITS	1
ZIP CODE	55808		
COUNTY	Saint Louis		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1924	HYD	0.0	OOS-overhaul
					0.0	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	11.1	11.1	0.0	0.0	100.0	
	11.1	11.1	0.0	0.0	100.0	

D. UNIT FUEL USED

PRIMARY FUEL USE					SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity					Unit of Measure ****	BTU Content (for coal only)

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Prairie River Hydroelectric Station	PLANT ID	68012
STREET ADDRESS			
CITY	Grand Rapids		
STATE	MN	UNITS	2
ZIP CODE	55734		
COUNTY	Itasca		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1921	HYD	0	
2	USE	HC	1921	HYD	0	
					0	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.5	0.5	0.0	0.0	100	
2	0.5	0.5	0.0	0.0	100	
	1	1	0.0	0.0	100	

D. UNIT FUEL USED

PRIMARY FUEL USE					SECONDARY FUEL USE (START UP)			
Unit ID #	Fuel Type ***	Quantity					Unit of Measure ****	BTU Content (for coal only)

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Taconite Ridge 1	PLANT ID	(leave this cell blank)
STREET ADDRESS	Co Rd 102		
CITY	Mountain Iron		
STATE	MN	NUMBER OF UNITS	1
ZIP CODE	55768		
COUNTY	St. Louis		
CONTACT PERSON	B. L. Carlson		
TELEPHONE	218-722-5642 x 2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	Use	WI	2008	Wind	62,392	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	25.0	25.0	29.6	92.3	5.9	

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	of Measure	BTU Content (for coal only)
1	Wind	n/a	n/a	n/a	n/a	n/a	n/a	n/a

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure field
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Bison 1	PLANT ID	(leave this cell blank)
STREET ADDRESS	5198 30th Street		
CITY	New Salem		
STATE	ND	NUMBER OF UNITS	1
ZIP CODE	58563		
COUNTY	Morton		
CONTACT PERSON	Todd Simmons		
TELEPHONE	218-843-6102		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	Use	WI	2010	Wind	280,869	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	81.8	291.8	36.35	93.67	6.01	

D. UNIT FUEL USED

PRIMARY FUEL USE					SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	of Measure	BTU Content (for coal only)
1	Wind	n/a	n/a	n/a	n/a	n/a	n/a	n/a

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0120 REGISTRATION

ENTITY ID#	68
REPORT YEAR	2012
RILS ID#	U10680

UTILITY DETAILS	
UTILITY NAME	Minnesota Power Co
STREET ADDRESS	30 W Superior St
CITY	Duluth
STATE	MN
ZIP CODE	55802-2093
TELEPHONE	218/722-5642 x3865
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	PRIVATE

CONTACT INFORMATION	
CONTACT NAME	Julie Pierce
CONTACT TITLE	Manager - Resource Planning
CONTACT STREET ADDRESS	30 West Superior Street
CITY	Duluth
STATE	MN
ZIP CODE	55802-2093
TELEPHONE	(218) 722-5642 x 3829
CONTACT E-MAIL	Jpierce@Mnpower.com

COMMENTS

PREPARER INFORMATION	
PERSON PREPARING FORMS	
PREPARER'S TITLE	
DATE	

ALLOWABLE UTILITY TYPES

Code

Private

Public

Co-op

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. SYSTEM FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your entire system for the past year, your estimate for the present year and all future forecast years.

Please remember that the number of customers should reflect the number of customers at year's end, not the number of meters

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Past Year	2012	No. of Cust.	2,387	118,310	21,614	9	402	6408.5	275	149,405	149,405
		MWH	63,717	979,564	1,237,386	4,968,517	2,069,327	15,954	54,074	9,388,538	9,388,538
Present Year	2013	No. of Cust.	2,387	120,338	22,129	9	395	7814.75	285	153,357	153,357
		MWH	63,717	1,043,579	1,292,826	4748552.004	2,049,425	16358.623	58,621	9,273,079	9,273,079
1st Forecast Year	2014	No. of Cust.	2,387	121,804	22,421	9	393	8360.916667	286	155,661	155,661
		MWH	63,717	1,052,528	1,325,392	4811748.525	2,200,140	16150.09	61,505	9,531,181	9,531,181
2nd Forecast Year	2015	No. of Cust.	2,387	122,931	22,695	11	392	8694.083333	288	157,398	157,398
		MWH	63,717	1,066,956	1,345,031	4907223.889	2,252,550	16134.161	62,162	9,713,773	9,713,773
3rd Forecast Year	2016	No. of Cust.	2,387	123,899	23,027	12	390	8899.583333	290	158,905	158,905
		MWH	63,717	1,081,915	1,370,138	5120552.407	2,208,377	16267.938	63,300	9,924,267	9,924,267
4th Forecast Year	2017	No. of Cust.	2,387	124,860	23,359	12	388	9026.25	293	160,325	160,325
		MWH	63,717	1,092,044	1,386,482	5368316.262	2,158,107	16291.695	63,576	10,148,534	10,148,534
5th Forecast Year	2018	No. of Cust.	2,387	125,944	23,687	12	387	9104.333333	295	161,817	161,817
		MWH	63,717	1,105,263	1,408,134	5427360.508	2,162,689	16386.744	63,995	10,247,545	10,247,545
6th Forecast Year	2019	No. of Cust.	2,387	127,086	24,017	12	385	9152.5	298	163,337	163,337
		MWH	63,717	1,118,923	1,430,694	5460052.285	2,165,266	16476.665	64,349	10,319,478	10,319,478
7th Forecast Year	2020	No. of Cust.	2,387	128,246	24,350	12	383	9182.166667	300	164,861	164,861
		MWH	63,717	1,134,961	1,456,330	5479099.096	2,171,097	16609.976	64,876	10,386,690	10,386,690
8th Forecast Year	2021	No. of Cust.	2,387	129,424	24,684	12	381	9200.583333	303	166,391	166,391
		MWH	63,717	1,146,442	1,472,640	5485837.508	2,167,507	16637.406	65,089	10,417,869	10,417,869
9th Forecast Year	2022	No. of Cust.	2,387	130,622	25,013	12	379	9211.75	305	167,930	167,930
		MWH	63,717	1,160,344	1,493,804	5508302.219	2,168,802	16711.345	65,424	10,477,105	10,477,105
10th Forecast Year	2023	No. of Cust.	2,387	131,835	25,336	12	377	9218.75	308	169,473	169,473
		MWH	63,717	1,174,486	1,513,077	5531433.571	2,168,715	16779.015	65,763	10,533,971	10,533,971
11th Forecast Year	2024	No. of Cust.	2,387	133,050	25,646	12	374	9222.916667	310	171,003	171,003
		MWH	63,717	1,191,117	1,535,397	5570390.564	2,176,304	16903.206	66,373	10,620,202	10,620,202
12th Forecast Year	2025	No. of Cust.	2,387	134,257	25,940	12	372	9225.666667	312	172,506	172,506
		MWH	63,717	1,202,836	1,549,171	5579978.011	2,173,275	16920.561	66,604	10,652,501	10,652,501
13th Forecast Year	2026	No. of Cust.	2,387	135,440	26,221	12	369	9227.333333	314	173,971	173,971
		MWH	63,717	1,216,854	1,566,734	5605455.076	2,177,197	17004.147	67,056	10,714,017	10,714,017
14th Forecast Year	2027	No. of Cust.	2,387	136,579	26,485	12	367	9228.25	316	175,374	175,374
		MWH	63,717	1,230,128	1,583,295	5631780.411	2,179,087	17101.837	67,491	10,772,600	10,772,600

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. MINNESOTA-ONLY FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your Minnesota service area only, for the past year, your best estimate for the present year and all future forecast years.

Please remember that the number of customers should reflect the number of customers at year's end, not the number of meters

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	MN-ONLY TOTALS	Calculated MN-Only Totals
Past Year	2012	No. of Cust.	2,387	118,310	21,614	9	402	6408.5	275	149,405	149,405
		MWH	63,717	979,564	1,237,386	4,968,517	2,069,327	15,954	54,074	9,388,538	9,388,538
Present Year	2013	No. of Cust.	2,387	120,338	22,129	9	395	7814.75	285	153,357	153,357
		MWH	63,717	1,043,579	1,292,826	4748552.004	2,049,425	16358.623	58,621	9,273,079	9,273,079
1st Forecast Year	2014	No. of Cust.	2,387	121,804	22,421	9	393	8360.916667	286	155,661	155,661
		MWH	63,717	1,052,528	1,325,392	4811748.525	2,200,140	16150.09	61,505	9,531,181	9,531,181
2nd Forecast Year	2015	No. of Cust.	2,387	122,931	22,695	11	392	8694.083333	288	157,398	157,398
		MWH	63,717	1,066,956	1,345,031	4907223.889	2,252,550	16134.161	62,162	9,713,773	9,713,773
3rd Forecast Year	2016	No. of Cust.	2,387	123,899	23,027	12	390	8899.583333	290	158,905	158,905
		MWH	63,717	1,081,915	1,370,138	5120552.407	2,208,377	16267.938	63,300	9,924,267	9,924,267
4th Forecast Year	2017	No. of Cust.	2,387	124,860	23,359	12	388	9026.25	293	160,325	160,325
		MWH	63,717	1,092,044	1,386,482	5368316.262	2,158,107	16291.695	63,576	10,148,534	10,148,534
5th Forecast Year	2018	No. of Cust.	2,387	125,944	23,687	12	387	9104.333333	295	161,817	161,817
		MWH	63,717	1,105,263	1,408,134	5427360.508	2,162,689	16386.744	63,995	10,247,545	10,247,545
6th Forecast Year	2019	No. of Cust.	2,387	127,086	24,017	12	385	9152.5	298	163,337	163,337
		MWH	63,717	1,118,923	1,430,694	5460052.285	2,165,266	16476.665	64,349	10,319,478	10,319,478
7th Forecast Year	2020	No. of Cust.	2,387	128,246	24,350	12	383	9182.166667	300	164,861	164,861
		MWH	63,717	1,134,961	1,456,330	5479099.096	2,171,097	16609.976	64,876	10,386,690	10,386,690
8th Forecast Year	2021	No. of Cust.	2,387	129,424	24,684	12	381	9200.583333	303	166,391	166,391
		MWH	63,717	1,146,442	1,472,640	5485837.508	2,167,507	16637.406	65,089	10,417,869	10,417,869
9th Forecast Year	2022	No. of Cust.	2,387	130,622	25,013	12	379	9211.75	305	167,930	167,930
		MWH	63,717	1,160,344	1,493,804	5508302.219	2,168,802	16711.345	65,424	10,477,105	10,477,105
10th Forecast Year	2023	No. of Cust.	2,387	131,835	25,336	12	377	9218.75	308	169,473	169,473
		MWH	63,717	1,174,486	1,513,077	5531433.571	2,168,715	16779.015	65,763	10,533,971	10,533,971
11th Forecast Year	2024	No. of Cust.	2,387	133,050	25,646	12	374	9222.916667	310	171,003	171,003
		MWH	63,717	1,191,117	1,535,397	5570390.564	2,176,304	16903.206	66,373	10,620,202	10,620,202
12th Forecast Year	2025	No. of Cust.	2,387	134,257	25,940	12	372	9225.666667	312	172,506	172,506
		MWH	63,717	1,202,836	1,549,171	5579978.011	2,173,275	16920.561	66,604	10,652,501	10,652,501
13th Forecast Year	2026	No. of Cust.	2,387	135,440	26,221	12	369	9227.333333	314	173,971	173,971
		MWH	63,717	1,216,854	1,566,734	5605455.076	2,177,197	17004.147	67,056	10,714,017	10,714,017
14th Forecast Year	2027	No. of Cust.	2,387	136,579	26,485	12	367	9228.25	316	175,374	175,374
		MWH	63,717	1,230,128	1,583,295	5631780.411	2,179,087	17101.837	67,491	10,772,600	10,772,600

* MINING needs to be reported as a separate category only if annual sales are greatere than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item B. FORECAST OF ANNUAL SYSTEM CONSUMPTION AND GENERATION DATA (Express in MWH)

NOTE: (Column 1 + Column 2) = (Column 3 + Column 5) - (Column 4 + Column 6)

It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell. If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet.

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED
		CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA in MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA in MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES in MWH [7610.0310 B(3)]	DELIVERED FOR RESALE in MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION in MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES in MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION in MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION in MWH [7610.0310 B(7)]	(GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO
Past Year	2012	9,388,538	0	4,989,381	3,717,776	8,440,294	323,361	5,634,321	5,542,175	0
Present Year	2013	9,273,079	0	2,060,780	3,108,218	10,995,464	674,947	5,590,685	5,341,394	0
1st Forecast Year	2014	9,531,181	0	2,311,804	3,631,139	11,572,180	721,664	5,961,785	5,592,503	0
2nd Forecast Year	2015	9,713,773	0	2,951,537	3,438,116	10,958,463	758,111	6,102,730	5,865,235	0
3rd Forecast Year	2016	9,924,267	0	3,174,147	3,399,360	10,931,489	782,010	6,376,854	6,046,139	0
4th Forecast Year	2017	10,148,534	0	3,601,105	3,481,943	10,836,882	807,510	6,447,247	6,249,596	0
5th Forecast Year	2018	10,247,545	0	3,549,943	3,470,093	10,982,654	814,959	6,494,584	6,301,583	0
6th Forecast Year	2019	10,319,478	0	3,886,747	3,471,022	10,724,189	820,435	6,563,970	6,344,024	0
7th Forecast Year	2020	10,386,690	0	3,424,032	3,261,330	11,050,108	826,120	6,561,566	6,368,929	0
8th Forecast Year	2021	10,417,869	0	3,287,467	3,196,021	11,155,030	828,607	6,601,712	6,405,729	0
9th Forecast Year	2022	10,477,105	0	3,540,137	2,979,331	10,749,619	833,320	6,639,899	6,439,644	0
10th Forecast Year	2023	10,533,971	0	3,461,930	3,113,963	11,023,877	837,872	6,712,719	6,473,399	0
11th Forecast Year	2024	10,620,202	0	3,371,933	3,223,428	11,316,488	844,790	6,717,544	6,508,269	0
12th Forecast Year	2025	10,652,501	0	3,676,999	3,109,640	10,932,409	847,267	6,758,037	6,542,299	0
13th Forecast Year	2026	10,714,017	0	3,821,833	3,091,270	10,834,587	851,133	6,797,880	6,577,089	0
14th Forecast Year	2027	10,772,600	0	3,769,757	3,070,032	10,930,631	857,757	6,872,172	6,611,785	0

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item C. PEAK DEMAND BY ULTIMATE CONSUMERS AT THE TIME OF ANNUAL SYSTEM PEAK (in MW)

		FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Last Year Peak Day	2012	12.3	204.6	249.3	605.1	354.0	2.3	362.0	1789.7	1789.7

7610.0310 Item D. PEAK DEMAND BY MONTH FOR THE LAST CALENDAR YEAR (in MW)

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
Last Year	2012	1779.1	1691.8	1653.6	1576.6	1621.6	1675.3	1789.7	1763.2	1689.1	1600.3	1689.9	1721.1

COMMENTS

Coincident non-Large Power load at peak hour is approximated by scaling by class energy consumption in peak month

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 1: FIRM PURCHASES (Express in MW)

		NAME OF OTHER UTILITY =>
Past Year	2012	Summer
		Winter
Present Year	2013	Summer
		Winter
1st Forecast Year	2014	Summer
		Winter
2nd Forecast Year	2015	Summer
		Winter
3rd Forecast Year	2016	Summer
		Winter
4th Forecast Year	2017	Summer
		Winter
5th Forecast Year	2018	Summer
		Winter
6th Forecast Year	2019	Summer
		Winter
7th Forecast Year	2020	Summer
		Winter
8th Forecast Year	2021	Summer
		Winter
9th Forecast Year	2022	Summer
		Winter
10th Forecast Year	2023	Summer
		Winter
11th Forecast Year	2024	Summer
		Winter
12th Forecast Year	2025	Summer
		Winter
13th Forecast Year	2026	Summer
		Winter
14th Forecast Year	2027	Summer
		Winter

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 2: FIRM SALES (Express in MW)

		NAME OF OTHER UTILITY =>	
Past Year	2012	Summer	
		Winter	
Present Year	2013	Summer	
		Winter	
1st Forecast Year	2014	Summer	
		Winter	
2nd Forecast Year	2015	Summer	
		Winter	
3rd Forecast Year	2016	Summer	
		Winter	
4th Forecast Year	2017	Summer	
		Winter	
5th Forecast Year	2018	Summer	
		Winter	
6th Forecast Year	2019	Summer	
		Winter	
7th Forecast Year	2020	Summer	
		Winter	
8th Forecast Year	2021	Summer	
		Winter	
9th Forecast Year	2022	Summer	
		Winter	
10th Forecast Year	2023	Summer	
		Winter	
11th Forecast Year	2024	Summer	
		Winter	
12th Forecast Year	2025	Summer	
		Winter	
13th Forecast Year	2026	Summer	
		Winter	
14th Forecast Year	2027	Summer	
		Winter	

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued

7610.0310 Item F. PART 1: PARTICIPATION PURCHASES (Express in MW)

NAME OF OTHER UTILITY =>			Laurentian Energy (LEA (Hibb&Virg)	Oliver Cty Wind (ND FPLE 1&2)	Manitoba Hydro (MHEB)	Minnkota Power Cooperative (MPC)	Ontario Hydro (OPGI)	Wing River Wind (CBED)
Past Year	2012	Summer	13.5	20.2	50	0	100	0.4
		Winter	13.5	20.2	50	0	0	0.4
Present Year	2013	Summer	13.5	20.2	50	0	0	0.4
		Winter	13.5	20.2	50	50	0	0.4
1st Forecast Year	2014	Summer	13.5	20.2	50	50	0	0.4
		Winter	13.5	20.2	50	50	0	0.4
2nd Forecast Year	2015	Summer	13.5	20.2	0	50	0	0.4
		Winter	13.5	20.2	0	50	0	0.4
3rd Forecast Year	2016	Summer	13.5	20.2	0	50	0	0.4
		Winter	13.5	20.2	0	50	0	0.4
4th Forecast Year	2017	Summer	13.5	20.2	0	50	0	0.4
		Winter	13.5	20.2	0	50	0	0.4
5th Forecast Year	2018	Summer	13.5	20.2	0	50	0	0.4
		Winter	13.5	20.2	0	50	0	0.4
6th Forecast Year	2019	Summer	13.5	20.2	0	50	0	0.4
		Winter	13.5	20.2	0	50	0	0.4
7th Forecast Year	2020	Summer	13.5	20.2	250	0	0	0.4
		Winter	13.5	20.2	250	0	0	0.4
8th Forecast Year	2021	Summer	13.5	20.2	250	0	0	0.4
		Winter	0	20.2	250	0	0	0.4
9th Forecast Year	2022	Summer	0	20.2	250	0	0	0.4
		Winter	0	20.2	250	0	0	0.4
10th Forecast Year	2023	Summer	0	20.2	250	0	0	0.4
		Winter	0	20.2	250	0	0	0.4
11th Forecast Year	2024	Summer	0	20.2	250	0	0	0.4
		Winter	0	20.2	250	0	0	0.4
12th Forecast Year	2025	Summer	0	20.2	250	0	0	0.4
		Winter	0	20.2	250	0	0	0.4
13th Forecast Year	2026	Summer	0	20.2	250	0	0	0.4
		Winter	0	20.2	250	0	0	0.4
14th Forecast Year	2027	Summer	0	20.2	250	0	0	0.4
		Winter	0	20.2	250	0	0	0.4

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Contin

7610.0310 Item F. PART 2: PARTICIPATION SALES (Express in MW)

NAME OF OTHER UTILITY =>			EDF	BEPC	Alliant	Minnkota Power Cooperative (MPC)	Ameren
Past Year	2012	Summer	35	100	50	0	120
		Winter	0	100	0	0	0
Present Year	2013	Summer	0	100	0	50	0
		Winter	0	100	0	0	0
1st Forecast Year	2014	Summer	0	100	0	0	0
		Winter	0	100	0	0	0
2nd Forecast Year	2015	Summer	0	100	0	0	0
		Winter	0	100	0	0	0
3rd Forecast Year	2016	Summer	0	100	0	0	0
		Winter	0	100	0	0	0
4th Forecast Year	2017	Summer	0	100	0	0	0
		Winter	0	100	0	0	0
5th Forecast Year	2018	Summer	0	100	0	0	0
		Winter	0	100	0	0	0
6th Forecast Year	2019	Summer	0	100	0	0	0
		Winter	0	100	0	0	0
7th Forecast Year	2020	Summer	0	0	0	0	0
		Winter	0	0	0	0	0
8th Forecast Year	2021	Summer	0	0	0	0	0
		Winter	0	0	0	0	0
9th Forecast Year	2022	Summer	0	0	0	0	0
		Winter	0	0	0	0	0
10th Forecast Year	2023	Summer	0	0	0	0	0
		Winter	0	0	0	0	0
11th Forecast Year	2024	Summer	0	0	0	0	0
		Winter	0	0	0	0	0
12th Forecast Year	2025	Summer	0	0	0	0	0
		Winter	0	0	0	0	0
13th Forecast Year	2026	Summer	0	0	0	0	0
		Winter	0	0	0	0	0
14th Forecast Year	2027	Summer	0	0	0	0	0
		Winter	0	0	0	0	0

COMMENTS

ued)

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item G. LOAD AND GENERATION CAF (Express in MW)

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			SEASONAL MAXIMUM DEMAND	SCHEDULE L. PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	SEASONAL SYSTEM DEMAND	ANNUAL SYSTEM DEMAND	SEASONAL FIRM PURCHASES (TOTAL)	SEASONAL FIRM SALES (TOTAL)	SEASONAL ADJUSTED NET DEMAND (3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)
Past Year	2012	Summer	1790		1790	1790			1790	1790	2070	184	305	1949	188	1978	-29
		Winter	1774		1774	1790			1774	1790	2013	84	100	1997	190	1964	33
Present Year	2013	Summer	1731		1731	1757			1731	1757	2051	84	150	1985	185	1916	69
		Winter	1757		1757	1757			1757	1757	1983	134	100	2017	188	1946	71
1st Forecast Year	2014	Summer	1766		1766	1848			1766	1848	1983	134	100	2017	189	1955	62
		Winter	1848		1848	1848			1848	1848	1999	134	100	2032	198	2046	-14
2nd Forecast Year	2015	Summer	1832		1832	1874			1832	1874	1927	84	100	1911	196	2028	-117
		Winter	1874		1874	1874			1874	1874	1941	84	100	1925	200	2073	-149
3rd Forecast Year	2016	Summer	1887		1887	1972			1887	1972	1941	84	100	1925	201	2088	-163
		Winter	1972		1972	1972			1972	1972	1941	84	100	1925	211	2182	-258
4th Forecast Year	2017	Summer	1943		1943	1985			1943	1985	1941	84	100	1925	207	2150	-226
		Winter	1985		1985	1985			1985	1985	1941	84	100	1925	212	2198	-273
5th Forecast Year	2018	Summer	1956		1956	1997			1956	1997	1941	84	100	1925	209	2165	-241
		Winter	1997		1997	1997			1997	1997	1941	84	100	1925	214	2210	-286
6th Forecast Year	2019	Summer	1967		1967	2007			1967	2007	1941	84	100	1925	210	2178	-253
		Winter	2007		2007	2007			2007	2007	1941	84	100	1925	215	2222	-297
7th Forecast Year	2020	Summer	1976		1976	2016			1976	2016	1941	284	0	2225	211	2188	37
		Winter	2016		2016	2016			2016	2016	1941	284	0	2225	216	2231	-7
8th Forecast Year	2021	Summer	1986		1986	2026			1986	2026	1941	284	0	2225	212	2199	26
		Winter	2026		2026	2026			2026	2026	1921	270	0	2191	217	2243	-52
9th Forecast Year	2022	Summer	1996		1996	2036			1996	2036	1921	270	0	2191	213	2209	-18
		Winter	2036		2036	2036			2036	2036	2101	270	0	2371	218	2254	117
10th Forecast Year	2023	Summer	2005		2005	2047			2005	2047	2101	270	0	2371	215	2220	152
		Winter	2047		2047	2047			2047	2047	2081	270	0	2351	219	2266	86
11th Forecast Year	2024	Summer	2015		2015	2057			2015	2057	2081	270	0	2351	216	2230	121
		Winter	2057		2057	2057			2057	2057	2061	270	0	2331	220	2278	54
12th Forecast Year	2025	Summer	2024		2024	2068			2024	2068	2061	270	0	2331	217	2240	91
		Winter	2068		2068	2068			2068	2068	2041	270	0	2311	222	2290	21
13th Forecast Year	2026	Summer	2033		2033	2079			2033	2079	2041	270	0	2311	218	2251	61
		Winter	2079		2079	2079			2079	2079	2041	270	0	2311	223	2302	10
14th Forecast Year	2027	Summer	2042		2042	2089			2042	2089	2041	270	0	2311	219	2261	50
		Winter	2089		2089	2089			2089	2089	2041	270	0	2311	224	2313	-2

COMMENTS

The deficit of 29 MW for the 2012 Summer period does not reflect non-compliance with MISO Resource Adequacy requirements. Minnesota Power was resource adequate for this historical timeframe. Per MISO rules, Minnesota Power submitted a peak demand estimate to MISO of 1729 MW based on a 50/50 forecast methodology (pg. 42 of AFR 2011 Forecast Methodology). Minnesota Power had sufficient capacity resources to meet the projected peak demand plus the planning reserve margin.

The actual peak demand for the 2012 summer timeframe was 1790 MW, which results in an apparent deficit of 29 MW. Based on the peak demand forecast submitted to MISO for Resource Adequacy compliance Minnesota Power was surplus capacity for the summer period by 32 MW. The difference between the peak demand forecast and actual peak was 61 MW. When the 61 MW change in the peak demand value is netted from the 32 MW surplus in capacity, the result is a 29

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item H. ADDITIONS AND RETIREMENTS (Express in MW)

		ADDITIONS	RETIREMENTS
Past Year	2012		
Present Year	2013		
1st Forecast Year	2014		
2nd Forecast Year	2015	40.4	71.7
3rd Forecast Year	2016		
4th Forecast Year	2017		
5th Forecast Year	2018		
6th Forecast Year	2019		
7th Forecast Year	2020		
8th Forecast Year	2021		
9th Forecast Year	2022		
10th Forecast Year	2023	200	
11th Forecast Year	2024		
12th Forecast Year	2025		
13th Forecast Year	2026		
14th Forecast Year	2027		

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

[TRADE SECRET DATA BEGINS]

Please use the appropriate code for the fuel type as shown in the list at the bottom of the worksheet.

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4		FUEL TYPE 5		FUEL TYPE 6	
		Name of Fuel	SUB	Name of Fuel	FO2	Name of Fuel	WOOD	Name of Fuel	NG	Name of Fuel	HYD	Name of Fuel	WIND
		Unit of Measure	TONS	Unit of Measure	GALLONS	Unit of Measure	TONS	Unit of Measure	MCF	Unit of Measure		Unit of Measure	
		QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED
Past Year	2012												
Present Year	2013												
1st Forecast Year	2014												
2nd Forecast Year	2015												
3rd Forecast Year	2016												
4th Forecast Year	2017												
5th Forecast Year	2018												
6th Forecast Year	2019												
7th Forecast Year	2020												
8th Forecast Year	2021												
9th Forecast Year	2022												
10th Forecast Year	2023												
11th Forecast Year	2024												
12th Forecast Year	2025												
13th Forecast Year	2026												
14th Forecast Year	2027												

LIST OF FUEL TYPES

BIT - Bituminous Coal
COAL - Coal (general)
DIESEL - Diesel
FO2 - Fuel Oil #2 (Mid-distillate)
FO6 - Fuel Oil #6 (Residual fuel oil)
LIG - Lignite
LPG - Liquefied Propane Gas
NG - Natural Gas
NUC - Nuclear
REF - Refuse, Bagasse, Peat, Non
STM - Steam
SUB - Sub-bituminous coal
HYD - Hydro (water)
WIND - Wind
WOOD - Wood
SOLAR - Solar

TRADE SECRET DATA ENDS]

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0500 TRANSMISSION LINES

Subpart 1. **Existing transmission lines**. Each utility shall report the following information in regard to each transmission line of 200 kilovolts now in existence:

A. a map showing the location of each line;
B. the design voltage of each line;
C. the size and type of conductor;
D. the approximate location of d.c. terminals or a.c. substations; and
E. the approximate length of each line in Minnesota.

7160.0500 TRANSMISSION LINES

EXISTING TRANSMISSION LINES (200 kV AND ABOVE)

VOLTAGE (kV)	LINE NUMBER	FROM*	TO*	MP OWNED MN MILES	MP TAP MILES	CONDUCTOR MCM TYPE
230 AC	80	FORBES	MINNTAC	25.53		954 ACSR
230 AC	81	ARROWHEAD	BEAR CREEK	55.26		795 ACSR
230 AC	83	BOSWELL	BLACKBERRY	18.4		1431/1590 ACSR
230 AC	90	ARROWHEAD	FORBES	47.53		954 ACSR
230 AC	91	RIVERTON	BADOURA	46.41		795 ACSR
230 AC	92	RIVERTON	BLACKBERRY	67.23		795 ACSR
230 AC	93	BLACKBERRY	FORBES	34.3		954 ACSR
230 AC	94	SHANNON	MCCARTHY LAKE	16.41		1590 ACSR
230 AC	95	BOSWELL	BLACKBERRY	18.84		1431/1590 ACSR
230 AC	96	SHANNON	MINNTAC	23.14		954 ACSR
230 AC	97	RIVERTON	'ING RIVER (STAPLES)	35.96		795 ACSR
230 AC	98	BLACKBERRY	ARROWHEAD	64.94	7.01	954 ACSR
230 AC	99	BADOURA	HUBBARD	14.99		795 ACSR
230 AC	100	CALUMET	MCCARTHY LAKE	3.32		1590 ACSR
230 AC	102	BOSWELL	CALUMET	25.86		1590 ACSR
230 AC	902	BEAR CREEK	REEK (KETTLE RIVER)	11.8		795 ACSR
230 AC	904	BOSWELL	CASS LAKE***	1.77		795 ACSS
230 AC	907	SHANNON	LITTLEFORK	81.62		954 ACSR
230 AC	909	HUBBARD	)UBON (SHELL RIVER)	4.53		795 ACSR
230 AC	R50M	RUNNING	MORANVILLE	7.51		954 ACSR
230 AC	n/a	CASS LAKE	WILTON***	4.65		795 ACSS
250 DC	DC LINE	ARROWHEAD :	BUTTE (ND BORDER)	231.56		2839 ACSR
345 AC	n/a	MONTICELLO	QUARRY**	4.23		2-954 ACSS/TW
500 AC	601	O (KETTLE RIVER)	FORBES (DENHAM)	7.79		3-1192 ACSR
	TOTAL	860.59		853.58	7.01	

* Point of interconnection in parenthesis for partially-owned tie lines
** MP-owned miles represent 14.7% of total circuit mileage under a "tenants in common" model
*** MP-owned miles represent 9.3% of total circuit mileage under a "tenants in common" model

Subpart 2. **Transmission line additions**. Each generating and transmission utility, as defined in part 7610.0100, shall report the information required in subpart 1 for all future transmission lines over 200 kilovolts that the utility plans to build within the next 15 years.

FUTURE TRANSMISSION LINE ADDITIONS (200 kV AND ABOVE)

In Use (enter X for selection)	To Be Built (enter X for selection)	To Be Retired (enter X for selection)	DESIGN VOLTAGE	SIZE OF CONDUCTOR	TYPE OF CONDUCTOR	D.C. OR A.C. (specify)	LOCATION OF D.C. TERMINALS OR A.C. SUBSTATIONS	INDICATE YEAR IF "TO BE BUILT" OR "RETIRED"	LENGTH IN MINNESOTA (miles)
		x	230 kV	1590	ACSR	AC	Boswell - Shannon	2013	
	x		345 kV	2-954 bundle	ACSS/TW	AC	Quarry - Alexandria	2013	70
	x		345 kV	2-954 bundle	ACSS/TW	AC	Alexandria - Bison	2015	135
	x		500 kV	3-1192 bundle	ACSR	AC	Dorsey - Blackberry	2020	270
	x		345 kV	2-954 bundle	ACSR	AC	Blackberry - Arrowhead	2025	60
	x		345 kV	2-954 bundle	ACSR	AC	Blackberry - Arrowhead	2025	60

COMMENTS
The retired 230 kV line represents a segment of the former Boswell-Shannon 230 kV line (formerly 94 Line) that was retired when the transmission system was reconfigured to serve Essar Steel. This line was reconfigured into three lines looping in and out of the Essar mine site: Boswell-Calumet (102 Line), Calumet-McCarthy Lake (100 Line), and McCarthy Lake-Shannon (new 94 Line)

Subpart 3. **Transmission line retirements**. Each generating and transmission utility, as defined in part 7610.0100, shall identify all present transmission lines over 200 kilovolts

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTI(

7610.0600, item A. 24 - HOUR PEAK DAY DEMAND

Each utility shall provide the following information for the last calendar year:

A table of the demand in megawatts by the hour over a 24-hour period for:

1. the 24-hour period during the summer season when the megawatt demand on the system was the greatest; and
2. the 24-hour period during the winter season when the megawatt demand on the system was the greatest

	DATE	DATE	
	7/16/12	1/19/12	<= ENTER DATES
TIME OF DAY	MW USED ON SUMMER PEAK DAY	MW USED ON WINTER PEAK DAY	
0100	1540	1585	
0200	1516	1591	
0300	1515	1588	
0400	1509	1616	
0500	1514	1632	
0600	1532	1650	
0700	1558	1710	
0800	1621	1743	
0900	1667	1735	
1000	1701	1731	
1100	1729	1713	
1200	1750	1720	
1300	1758	1689	
1400	1757	1679	
1500	1780	1679	
1600	**1790**	1685	
1700	1769	1715	
1800	1756	1764	
1900	1737	**1779**	
2000	1716	1763	
2100	1698	1733	
2200	1680	1706	
2300	1632	1688	
2400	1576	1656	

COMMENTS