APPENDIX A: MINNESOTA POWER'S 2014 ANNUAL ELECTRIC UTILITY FORECAST REPORT

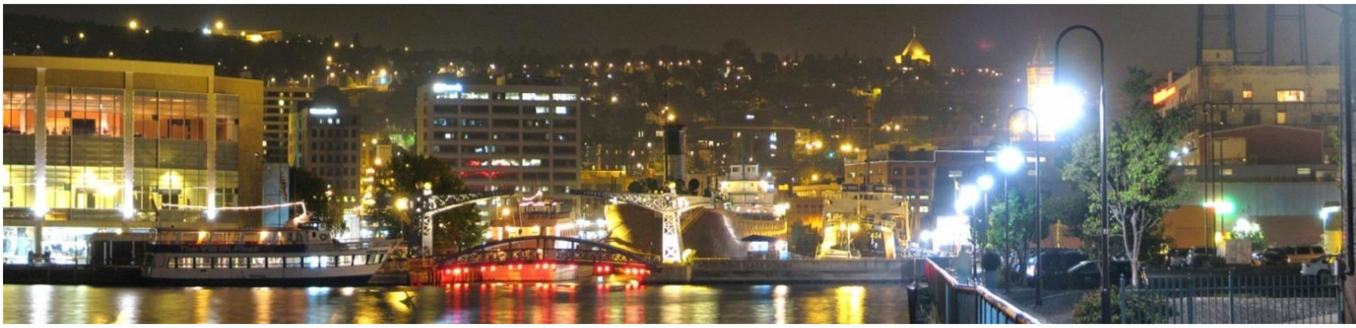
Minnesota laws and reporting rules governing electric utilities require that electric utilities with Minnesota service area submit to the Minnesota Department of Commerce an annual report containing historical and forecast customer sales and demand values, including forecast methodology and discussion. This report is submitted annually by July 1 of each year. Minnesota Power's 2014 Annual Electric Utility Forecast Report ("AFR2014") contains all of the forms and information necessary to meet this annual requirement. Per Order Point 10 of the 2013 Integrated Resource Plan's November 12, 2013 Order,[1] Minnesota Power is required to file its energy and demand forecast and Strategist commands thirty days prior to its next resource plan filing date, which is September 1, 2015. Therefore, the Company used the AFR2014 as the basis for the 2015 Integrated Resource Plan ("2015 Plan") due to the inability to conduct the extensive analysis required for the 2015 Plan between the July 1 submittal of Minnesota Power's 2015 Annual Electric Utility Forecast Report ("AFR2015") and August 1 when the forecasts and commands were required to be submitted. A sensitivity case using data from the AFR2015 was performed in July and the results are discussed in Appendix K beginning on page 30.

Minnesota Power's AFR2014 contains historical sales and demand data, and contains the customer energy sales and demand forecast that serves as the starting point for the 2015 Plan. The forecast report includes several scenarios that reflect the uncertainty in sales and demand facing Minnesota Power over the next few years. This uncertainty is largely due to the potential for several industrial customers that will be added in Minnesota Power's service territory during the 15 year planning horizon. The scenarios were developed to reflect potential for customer changes and the projected timing of those changes.

While the AFR2014 contains a number of scenarios,[2] the scenario that forms the basis for the 2015 Plan evaluation projects 175 MW of new demand requirements by 2020 when compared to current levels.[3] In the AFR2014, this is referred to as the 'Moderate Growth with Deferred Resale' forecast. Most of this growth is comprised of a new industrial facility served by a Minnesota Power wholesale customer, the City of Nashwauk. Other discrete load additions are included to reflect new demand by large industrial customers served at retail by Minnesota Power.

The 2015 Plan also contemplates other customer sales outlooks in the analysis process. These include 1) a scenario reflecting lower national and regional economic growth and specific industrial slowdowns referred to in the AFR2014 as the 'Downside' forecast, and 2) a scenario reflecting even higher growth than the 2015 Plan with another large industrial addition later in the planning period referred to as the 'Best Case' forecast. These scenarios provide a rigorous range of sensitivities for the 2015 Plan to consider with up to 670 MW of new growth from current levels and a slowdown scenario that captures a significant downturn in key industries in northeastern Minnesota.

[1] Docket No. E015/RP-13-53.
[2] Descriptions and results of the scenarios begin on page 44 of the AFR2014 document.
[3] December 2014 demand was 1820.7 MW.



Minnesota Power's 2014 Annual Electric Utility Report

PUBLIC DOCUMENT
TRADE SECRET DATA
HAS BEEN EXCISED

PUBLIC DOCUMENT
TRADE SECRET DATA
HAS BEEN EXCISED

July 1, 2014

Minnesota Department of Commerce
85 – 7th Place East
St. Paul, MN 55101

RE: Docket No. E-999/PR-14-11

Re: MINNESOTA POWER'S 2014 ANNUAL ELECTRIC UTILITY FORECAST REPORT
Minnesota laws and reporting rules governing electric utilities require that electric utilities with Minnesota service areas submit to the Minnesota Department of Commerce an annual report. This report is to be submitted by July 1 of each year. Attached is a copy of Minnesota Power's 2014 Annual Electric Utility Forecast Report that contains all of the forms and information necessary to meet this requirement.

Trade Secret information is included in the "2014ElectricUtilityDataReport_68.xlsx" and "2014Forecast_68.xlsx" Excel workbooks as well as the methodology document "METHOD14.pdf."

Minnesota Power has excised material from the public version of the attached report documents as they identify and contain confidential, competitive information regarding Minnesota Power's methods, techniques and process for supplying electric service to its customers. The energy usage by specific customers and generation by fuel type has been consistently treated as Trade Secret in individual filings before the Minnesota Public Utilities Commission. Minnesota Power follows strict internal procedures to maintain the privacy of this information. The public disclosure of this information would have severe competitive implications for customers and Minnesota Power.

Minnesota Power is providing this justification for the information excised from the attached report and why the information should remain trade secret under Minn. Stat. 13.37. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the Trade Secret designation provided herein.

The following documents have been uploaded to the Minnesota Department of Commerce and Public Utilities Commission eDockets/eFiling system: METHOD14.pdf, 2014Forecast.xls, 2014ElectricUtilityDataReport.xls, MP System Map.pdf, and MP Ratebook.pdf. As of this date, the report form EIA 861 has not been filed with the US Department of Energy and cannot be submitted with Annual Electric Utility Report. The report form EIA 861 will be filed with the Minnesota Department of Commerce and Public Utilities Commission eDockets system as soon as possible. If you need additional paper copies or have any questions, please contact myself or the Minnesota Power Resource Planning area.

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Contents

Introduction

The utility customer load forecast is the initial step in electric utility planning. Capacity and energy resource commitments are based on forecasts of energy consumption, and seasonal peak demand requirements. 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 is committed to continuous forecast process improvement, process transparency, forecast accuracy, and gaining customer insight. This 2014 forecast methodology document demonstrates Minnesota Power's continued efforts to meet these goals through comprehensive documentation, implementation of more systematic and replicable processes, and thorough analysis of results.

A history of increasing accuracy in load forecasting also speaks to Minnesota Power's commitment to innovate and enhance its forecast processes. Since 2000, year-ahead forecast error has decreased by an average 0.04 percent per-year; current-year forecast error has decreased at an average rate of 0.16 percent per-year.[1] Minnesota Power owes its record of forecast accuracy to a combination of close cooperation with customers, continuous validation of forecast model inputs, and steady improvements in statistical analytic capabilities.

The range of scenarios developed for the 2014 Advance Forecast Report (AFR 2014) 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 scenario approach to forecasting can then be integrated into Minnesota Power's proactive and flexible planning to better inform the critical electric resource decisions ahead. Minnesota Power's forecasting approach helps keep the potential demand and energy outcomes transparent and robust.

2014 Forecast Results Overview

This year, Minnesota Power has identified the "Moderate Growth" scenario as its expected case outlook and has submitted this in its 2014 Annual Electric Utility Report filing. This scenario is similar to last year's submittal and assumes steady underlying growth with new and existing large customers adding about 215 MW by 2020.

Table 1 below shows the Moderate Growth scenario forecast for annual energy sales and seasonal peak demand. Annual energy sales and peak demand are both projected to grow at about 1.1 percent per year (on average) from 2014 through 2028. The large increase in projected sales and demand in the 2015-2016 timeframe is due to the start-up of a new mining customer's facility in Nashwauk, Minnesota.

[1] Both error figures are Mean Absolute Percent Error (MAPE) of the energy sales forecast, and were calculated excluding the recessionary years of 2009 and 2010, in which there's significant and unpredictable fluctuations in large industrial loads.

Table 1: Moderate Growth Energy Sales and Seasonal Peak Demand Outlook

	Total Energy Sales		Peak Demand			
	MWh	Y/Y Growth	Summer (MW)	Y/Y Growth	Winter (MW)	Y/Y Growth
2007	10,680,509		1,758		1,763	
2008	10,839,446	1.5%	1,699	-3.3%	1,719	-3.3%
2009	8,065,090	-25.6%	1,350	-20.6%	1,545	-20.6%
2010	10,417,422	29.2%	1,732	28.3%	1,789	28.3%
2011	10,988,200	5.5%	1,746	0.8%	1,779	0.8%
2012	11,107,358	1.1%	1,790	2.5%	1,774	2.5%
2013	10,985,809	-1.1%	1,782	-0.5%	1,751	-0.5%
2014	11,005,984	**0.2%**	1,727	**-3.0%**	1,772	**-3.0%**
2015	11,455,560	**4.1%**	1,807	**4.6%**	1,931	**4.6%**
2016	12,210,706	**6.6%**	1,923	**6.4%**	1,958	**6.4%**
2017	12,139,526	**-0.6%**	1,941	**0.9%**	1,973	**0.9%**
2018	12,226,004	**0.7%**	1,954	**0.7%**	1,979	**0.7%**
2019	12,282,442	**0.5%**	1,962	**0.4%**	1,988	**0.4%**
2020	12,373,073	**0.7%**	1,970	**0.4%**	1,996	**0.4%**
2021	12,383,656	**0.1%**	1,976	**0.3%**	2,003	**0.3%**
2022	12,428,847	**0.4%**	1,982	**0.3%**	2,010	**0.3%**
2023	12,483,154	**0.4%**	1,990	**0.4%**	2,019	**0.4%**
2024	12,565,416	**0.7%**	1,997	**0.4%**	2,028	**0.4%**
2025	12,587,817	**0.2%**	2,004	**0.4%**	2,035	**0.4%**
2026	12,645,886	**0.5%**	2,011	**0.4%**	2,044	**0.4%**
2027	12,706,022	**0.5%**	2,019	**0.4%**	2,053	**0.4%**
2028	12,802,330	**0.8%**	2,027	**0.4%**	2,063	**0.4%**

Document Structure

This report has been constructed to provide the energy sales and demand forecast for Minnesota Power for the 2014-2028 timeframe. Each section is designed to convey the report requirements per MN Rules Chapter 7610, and give insight into Minnesota Power's forecasting process and results.

Section 1: *Forecast Methodology, Data Inputs, and Assumptions* details the development of customer count, peak demand, and energy sales forecasts. This section contains a step-by-step description of Minnesota Power's forecasting process and details the development of databases and models.

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
  - A discussion of each model's econometric merits and potential issues as well as an explanation/ justification of each variable
- Additional steps taken in 2014 to improve the forecast process and product
- Strengths and weaknesses of Minnesota Power's methodology
- All data inputs and sources, including an overview of key economic assumptions
- A description of all changes made to the forecast database since last year's forecast
- 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 six forecast scenarios Minnesota Power developed for the AFR 2014 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 2014 Expected Case):** includes additional loads served by Minnesota Power and its wholesale customers that are likely but not yet certain. This scenario's assumptions were formed through close communication with customers on their planned expansions and utilize any publicly-communicated schedules from prospective customers.

- **Moderate Growth Scenario with Deferred Resale:** includes additional loads served by Minnesota Power and its wholesale customers that are likely but not yet certain. This scenario's assumptions are identical to those in the Moderate Growth scenario except the start of a new mining customer's facility in Nashwauk is delayed by one year. This scenario demonstrates the sensitivity of Minnesota Power's demand and energy outlook to the timing of this prospective customer's start-up.

- **Current Contract Scenario:** includes 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:** includes specific industrial expansions, in addition to those in the Moderate Growth Scenario, that are plausible within the next five years.
- **Best Case Scenario:** includes 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:** includes permanent production slowdowns at specific customer facilities within the next five 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.

This section also includes several sensitivities to identify the range of possible outcomes due to non-economic factors such as extreme weather, disruptive technologies, and non-renewal of customer contracts.

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

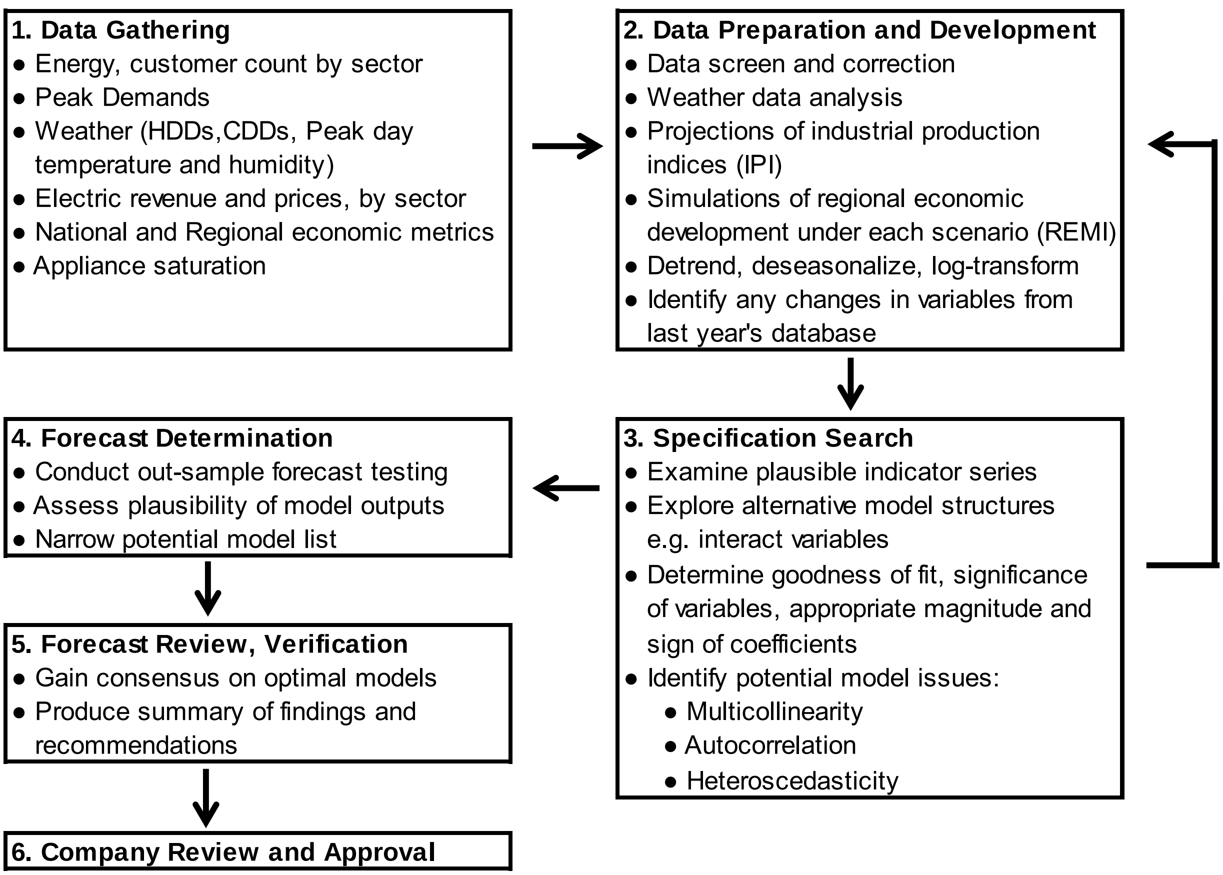
1. Forecast Methodology, Inputs, and Assumptions

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 percent probability that a realized actual will be less than forecast and a 50 percent 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, the process involves feedback loops between steps 2 and 3. The process is diagrammed in Figure 1 below and discussed in more detail in Section B.

Figure 1: Minnesota Power's Forecast Process



B. Minnesota Power's Forecast Process

i. Process Description

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, energy sales, and peak demand.
    - *Demographic and Economic data for the 13-County Minnesota Power service territory and Duluth Metropolitan Statistical Area (MSA)* consists of population, households, sector-specific employment, income metrics, regional product, and other local indicators.
    - *Indicators of National economic activity* such as the Industrial Production Indexes or Macroeconomic indicators such as U.S. GDP (Gross Domestic Product) or Unemployment.
    - *Weather and related data* including heating degree days, cooling degree days, temperature, humidity, dew point, and wind speed.
    - *Appliance saturation data* including air-conditioning, electric space heating, and electric water heating.
    - *Electricity and Alternative Fuel prices,* which includes the price of electricity, natural gas, and heating oil 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* involves adjusting raw data inputs and then reviewing the data through diagnostic testing. The purpose of this step is to develop consistently defined and formatted data series for use in regression analysis. Adjustments made to specific raw data inputs are described in the "Inputs and Source" section of this document. General data preparation techniques such as *Data Transformation* and *Interpolation* are described in the *Specific Analytical Techniques* section of this document.

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[2]. Minnesota Power does this through a formalized two-step modeling and documentation process:

    Preliminary Model Generation – involves systematically generating all models that satisfy a set of basic criteria. Model generation is conducted using a VBA (Visual Basic for Application) tool designed and programmed by Minnesota Power.

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

The user first identifies the model's basic structure, including: binary variables, trend, verified weather variables, etc. The software then models every combination of economic variables[3] using the specified binary variable structure, and retains all models that meet a predefined set of statistical criteria. This step produced nearly three million plausible regression models[4]. The program then identifies extremely similar models and removes inferior redundancies to reduce the pool of models for consideration to about 220,000 models[5]. All models generated as part of the *Preliminary Model Generation* step of AFR 2014 are archived for later review.

Model diagnosis – involves in-depth analysis of the top 50 models[6] for each dependent variable generated by the *Preliminary Model Generation* process. During model diagnosis, another custom-programed VBA tool is leveraged to calculate and compare the models' critical statistics. At this stage, review of the model results may show an alternative binary variable structure or interaction variable could add value and both *Preliminary Model Generation* and *Model Diagnosis* are repeated. If alternative specifications cannot improve model quality, the process moves on to Step 4: *Forecast Determination*.

During *Model Diagnosis*, Minnesota Power's custom-programed VBA tool identifies the following statistical metrics:

- Goodness of fit: Adjusted R-Squared and MAPE (Mean Absolute Percent Error).
- Model simplicity and efficiency: AIC and SIC[7]
- Heteroscedasticity: Breusch-Pegan F, Breusch-Pegan ChiSq, and White's F tests.
- Multicollinearity: Variance Inflation Factor (VIF) of each input variable
- Autocorrelation: Breusch-Godfrey F & Chi-Squared, Durban-Watson, and Durban-H
- Specification tests of non-linear variable combinations: Ramsey's RESET F
- Out-sample forecast error: RMSE (Root-Mean Squared Error), MAE, and MAPE

4. <u>*Forecast Determination*</u> narrows the list of potential models via a thorough review. Minnesota Power evaluates and compares model statistics, plausibility of the model's outputs (i.e. the forecast), and model structure. This step involves the utilization of objective metrics as far as is possible to inform judgment on the part of the forecaster.

   The forecast determination process begins by identifying the apparent statistically-superior model. If the model's forecast growth rate is implausible or predictor variables are unintuitive, Minnesota Power moves on to the second most statistically-superior model. This continues until Minnesota Power identifies a plausible model. This top-ranked model is then selected as a preferred or preliminary AFR model for the specified dependent variable (customer count, energy sales, peak demand).

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[3] Only two economic variables are modeled at a time because 1) a third or fourth economic variable is unlikely to add considerable predictive value, and 2) three or more variables is computationally intensive.

[4] This figure is the total of all preliminary models generated for all dependent variables.

[5] This figure is the total of all filtered preliminary models generated for all dependent variables.

[6] Models are ranked by a 2-year Out-sample Root-Mean-Squared Error (RMSE)

[7] Akaike information criterion and Schwarz information criterion

However, the difference in statistical quality among top models is usually negligible and there are reasons to dismiss the top-ranked model in favor of a lower ranking model. For example, having a weather variable for each month is ideal because it allows for accurate after-the-fact weather normalization later by the company. If the top-ranked model lacks a specific month's weather variable, it may be passed-over in favor of one that has a full complement of weather variables, and is nearly identical in statistical quality.

This step narrows the model list further; from fifty to just two or three select models for each dependent variable.

5. *Forecast Review and Verification* produces a list containing a single, preliminary model for each of the dependent series. During this step, analysts compare and debate the quality of models to reach a consensus around a final set of optimal models. Where a consensus cannot be immediately reached because two models may be highly comparable in statistical quality and plausibility of outputs, out-sample forecast accuracy determines the model put forward for *Company Review and Approval.*

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

ii. Specific Analytical Techniques

Data Transformation Schema for Economic Variables: Transformations are used to maintain consistency among variables or to identify non-linear relationships between predictor variables and the dependent variable within the confines of simple linear regression. Minnesota Power uses several data transformations in data development: constant-dollar deflating/inflating, per-day conversion, de-trending/ de-seasonalizing, first difference, natural log de-trending, and first difference of natural log.

Constant-dollar Deflating/Inflating - is the process of deflating/inflating all dollar-denominated series to the same base year to maintain consistency of definition. Minnesota Power utilized 2009 as its base year in the 2014 forecast. The 2009 base year is the current standard among public and private data providers such as IHS Global Insight and the Bureau of Economic Analysis (BEA).

Per-day Conversion – divides monthly billed energy use or monthly Heating/Cooling Degree Days by the number of days in the specified month. This transformation normalizes for the effect of varying days-per-month on a monthly aggregate like energy use or Heating/Cooling Degree Days. This results in consistently defined series that are more appropriate for linear regression modeling.

De-trend and De-seasonalize – is the process of removing the historical trend/ seasonality from a data series. This reduces the potential for the spurious, or *false*, correlation that often results from mistaking similarity of *trends* with similarity of *variation* between a predictor and the dependent variable.

Natural Log De-trend – takes the natural log (ln) of each observation in the series and then removes the historical trend/ seasonality from the series. This transformation allows a linear regression processes to identify non-linear relationships between variables. For example: a 10 *percent* increase in X causes a 1 *unit* increase in Y.

First Difference – changes the definition of the series from *level* (e.g. the number of customers in a month) to *change* (e.g. the customers gained or lost from one month to the next) by subtracting the previous value from the current. The *first difference* transformation reduces the series to only *variation* (change) so there is no trend of potential to mistake similarity of *trend* with similarity of *variation*.

First Difference of Natural Log – calculates the month-to-month change in the natural log series.

<u>*Interpolation Technique*</u> – Minnesota Power collects and utilizes raw monthly-frequency data whenever possible. However, some data series are not available at a monthly-frequency (e.g. U.S. GDP is only available in Quarterly and Annual frequencies). Interpolation allows annual or quarterly data to be used in monthly-frequency regression modeling by converting it to a monthly variable.

The specific interpolation function utilized in Minnesota Power's 2014 forecast process is known as a "Cubic Spline" interpolation. This technique is widely used because it produces a smooth monthly series by constraining the first and second derivatives of the variable to be continuous on the entire time interval.

The cubic spline interpolation function is in piecewise cubic polynomial form:[8]

$$Y_i(t) = a_i + b_i t + c_i t^2 + d_i t^3$$

Where: $0 \leq t \leq 1$

$i = 1, 2, \ldots, n - 1$

$Y_i = i^{th}$ piece of the spline

a_i, b_i, c_i, and d_i are estimated polynomial coefficients

Annual-to-monthly interpolation assumes the annual value as June, and July through May are interpolated points. Quarterly-to-monthly interpolation assumes Quarter 1 as February, Quarter 2 as May, Quarter 3 as August, and Quarter 4 as November; all other months are interpolated points.

Utilization of a cubic spline function for interpolation is new to the AFR 2014 process and is an improvement over previous interpolation methods. In previous forecasts, Minnesota Power used some variant of a simple "straight-line" interpolation function. The change in the interpolation methods will cause the historical monthly data in the forecast database to differ slightly from the previous years.

[8] http://mathworld.wolfram.com/CubicSpline.html

Modeling Techniques - As a rule, all models are ordinary least squares (OLS) and all input variables' coefficients must be significant at a 90 percent level (as indicated by p-values less than 10 percent). 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.

Each dependent variable (14) is modeled in both levels and logs, but is not de-trended. If a trend is present in the historical count or sales data, it should be accounted for with a trend variable. The trend variable explains general, underlying growth, whereas the de-trended or differenced independent (indicator) variables explain variation around this trend.

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

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

    If autocorrelation is present:
    a. Include ARMA[9] terms to solve for autocorrelation and obtain accurate estimates of coefficient's t-stats and p-values
    b. Remove truly insignificant economic variables (as indicated by high p-values). Seasonal binaries, trends, and constants are not subject to this rule because their apparent insignificance results from the ARMA terms appropriating their role in the model and not from autocorrelation
    c. Remove ARMA terms to revert to a corrected OLS model

    ARMA terms are only used to assess or un-bias the P-values of the OLS models. Autocorrelation may still be present in the final OLS, but it's been shown to have minimal impact on model coefficients and has not biased P-values.

2. Test for multicollinearity using VIFs (Variance Inflation Factors) - multicollinearity is generally unacceptable in the final models but is assessed in the 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, VIFs are superior to a correlation matrix as a method of identifying multicollinearity. VIFs are assessed according to these criteria:

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

[9] Autoregressive Integrated Moving Average

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 percent.
d. VIF greater than 10 is unacceptable correlation for any economic variable. In this case the correlation with the remaining variables is greater than 95 percent.

VIFs on all economic and demographic variables in all models are well within acceptable limits. Minnesota Power considers high VIFs on seasonal binaries variables inconsequential since the cause of this correlation is clear; it's interacting with the intercept, weather variables, or other binaries. Because these binaries are important to the structure of the model, they are not excluded in the same way an economic variable would be if found to have high multicollinearity with other variables.

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.

When heteroscedastic conditions are present in the preferred OLS model, Minnesota Power follows the same process as with autocorrelation. ARMA terms are added in an attempt to solve heteroscedasticity and examine the unbiased P-values. Occasionally, heteroscedasticity cannot be solved for and plausible alternative models cannot be identified. In these cases, Minnesota Power had no choice but to accept that estimates of P-values in these models may be biased.

Models that meet the above criteria, have plausible outputs (forecasts), and have an intuitive econometric interpretations are put forward as potential final models for review during the *Forecast Determination* and *Forecast Review and Verification* steps (AFR 2014 Forecast Process pg. 5).

Once forecast models are verified and finalized, they form the basis of the "econometrically-determined" outlook for energy sales, peak demand, and customer count. Assumptions for future load additions/ losses and adjustments to account for recent customer expansions are applied to the econometric outlook to produce Minnesota Power's final energy sales, peak demand, and customer count outlook.

iii. Methodological Adjustments for the 2014 Forecast

Minnesota Power is continuously improving its forecast methodologies to better model and predict customer energy requirements. This year's forecast features an expansion of the forecast database, an enhanced *Specification Search* process, and key methodological enhancements.

Adjustment of the Historical Energy Sales and Peak Demand Data to Account for Recent Customer Expansions: To avoid biasing estimates due to structural breaks in the historical timeframe, Minnesota Power removes the impact of recent large load additions/ losses from historical energy sales and peak demand prior to regression modeling. The adjusted series is then modeled, an econometric forecast is produced, and then projected sales to these large customers are added back to the econometric forecast.

In the past, Minnesota Power modeled raw historical sales data and made no adjustments to the raw sales data prior to regression. Instead, post-regression arithmetic adjustments were applied to the econometric forecast to account for large load additions in the forecast timeframe. This is no longer a suitable approach to forecasting given the sizable impact of recent load additions/ losses on the *historical timeframe* used for estimation; there's a high potential for double-counting or understating the impact of recent load additions or losses.

In econometrics, clear definitional shifts affecting the historical series (such as the recent addition of a large customer) are referred to as "Structural Breaks," and, if left unaccounted for, can lead to large forecasting errors and unreliability of the model in general[10].

Ideally, structural breaks are modeled with a binary variable that denotes the sudden break, but this requires abundant observations both before and after the break. Minnesota Power's large additions/ losses are so recent that there are not enough observations for a binary variable to effectively account for any structural breaks. Thus, the only option for avoiding the negative effects of structural breaks is to adjust the historical data. Minnesota Power will evaluate this approach each year and revert to use of raw (unadjusted) data if and when structural breaks can be accurately accounted for using a binary variable.

For consistency of application, a structural break is defined as the addition or loss of a customer that comprises more than one percent of sales to its respective customer class in any given historical year. Adjustments for structural break are only made when metered sales data is available[11]. These adjustments are described in detail in the *Data Revisions Since Previous AFR* section.

Use of Binary Variables Account for Shift in Customer Count Growth: Since the recession, Minnesota Power has observed a divergence of economic indicators and energy sales. Although economic conditions have improved, employment has rebounded, and population growth in the region has resumed, there has been little to no growth in electricity use by several customer classes.

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10 Structural Breaks should not be confused with sizeable shifts that results from a measurable change in the economy. For example: The change in the composition of the Mining and Metals sector due to the closing of LTV, while sudden and sizeable, had a clear economic cause and economic metrics can be used to accurately model this loss of energy sales and load.

11 Minnesota Power has a number of resale customers that have experienced recent load additions and losses, but these data are not available to Minnesota Power. In this case, a post-regression adjustment is still applied to account for the load addition in the forecast timeframe. When it's evident that this load addition or loss is reflected in the econometric forecast, Minnesota Power will cease the post-regression adjustment.

For example, Residential customer count has grown by just 97 customers or 0.08 percent (net) since 2009 and sales have stagnated as well. However, key economic and demographic indicators continued to grow in this timeframe. A model using these indicators would over-forecasts in the later years of the estimation timeframe (2012-2013) and, presumably, the first period in the forecast timeframe (2014). To account for this divergence, Minnesota Power utilizes binary variables in several customer count models to effectively shift the first forecast year (2014) to align with the last historical year (2013). Although the forecast is shifted by the binary viable (a constant), the trajectory (growth rate) of the forecast is still determined by the economic variables.

Refined Temperature Range Stratification Approach (Peak Demand Model): Last year, Minnesota Power adopted a stratified temperature variable approach to better estimate temperature's impact on demand ("weather effect"). This approach involved stratifying temperature variables according to temperature range rather than by month (via a *Monthly Interaction*). This weather variable specification improved the significance of coefficients and prevented some statistical issues such as multicollinearity; however, the specific method of stratification created variables that were not mutually exclusive, which complicated the interpretation of the coefficient.

This year, each temperature series (high, low, and average temperature for the day) is stratified based only on the average temperature for the day. Stratification based on a single series produces mutually exclusive variables and eliminates the possibility for overlap to clarify the definition/ interpretation of the coefficients.

For consistency with this change, the temperature humidity index and the wind chill index are also based on the average temperature for the day.

iv. 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 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 2014 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.

v. 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 expansions that are likely in the Minnesota Power service territory. A combined "econometric/ large customer load addition" approach produces the most reasonable forecast.

Minnesota Power's econometric modeling process has two key strengths; it's both highly replicable, and 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.

That said, there are some weaknesses to a combined "econometric/ large customer load addition" approach. For instance, 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. To minimize subjectivity on the part of Minnesota Power, the Company utilizes any information that has been publicly communicated by prospective customers in its scenario planning.

Minnesota Power is 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 to identify their plans, and then creating a range of plausible scenarios to address the uncertainty.

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.

i. AFR 2014 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 (WU)[12]. Minnesota Power utilizes Monthly Heating Degree Days (HDD) and Cooling Degree Days (CDD) in energy sales forecasting and peak-day weather conditions in peak demand forecasting.

Monthly total HDD and CDD are sourced from NOAA. The monthly total 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 transforming to a per-day unit allows for a more accurate estimate of the weather's impact on energy sales. The forecast assumes a 20-year historical average for each month (Apr 1994 – Mar 2014). January's forecast assumption (for example) is an average of Jan-95, Jan-96,…, Jan-14.

Temperature, humidity, and wind-chill data used to model peak demand are derived from WU. This source has been in use for daily-frequency weather data over the last two forecasting cycles instead of NOAA data. WU's weather data rarely differs from NOAA, and the WU online tools and data format are more conducive to variable development.

Development of the historical weather series begins by establishing the date of historical monthly peaks. Weather data for these dates is then gathered and organized into monthly-frequency peak-day weather series.

Calculating a 20-year historical average of peak-day weather for use as a forecast assumption requires recorded peak dates for the timeframe prior to the establishment of the current electronic

[12] http://www.wunderground.com/

database (1994-1999). Minnesota Power uses the Federal Energy Regulatory Commission (FERC) Form 1 to identify the dates for peaks prior to 1999 and then gathers the corresponding weather data. Forecast assumptions for peak-day weather can be calculated from the completed 20-year history.

A Temperature-Humidity Index[13] (THI) is utilized to take into account the effect of heat and, when applicable, humidity on summer peaks. The THI is only applicable when temperatures exceed 80 degrees and relative humidity exceeds 40 percent. If both conditions are not met, humidity's impact is assumed to be minimal and is excluded. A Wind-chill index[14] (WC) was also utilized to capture the cold temperatures and, when applicable, the cooling effect of wind speed.

IHS Global Insight

Since 2009, Minnesota Power has utilized IHS Global Insight estimates of historical and forecast economic activity in Northeast Minnesota[15] as key inputs to energy and customer count models. This year's forecast process features an expansion of IHS Global Insight data use.

Duluth Metropolitan Statistical Area (Duluth MSA)[16] economic indicators were added to the forecast database, along with the 13-County economic indicators. The more geographically-granular indicators were expected to add predictive power by more closely aligning with the area containing Minnesota Power's customer base. This database expansion also simply adds to the pool of potential predictor variables during modeling.

National-level economic indicators from IHS Global Insight replace Blue Chip Economic Indicators[17] as inputs to Industrial Production Index (IPI) modeling. IHS Global Insight provides access to more national-level variables and allowed Minnesota Power to expand the IPI forecast database. The data source change also maintains consistency of assumption in all areas of Minnesota Power's forecast process and among all levels of geographic granularity.

IHS Global Insight County-level data for Northeast Minnesota[13] is calculated through a "Top-down/ Bottom-up" approach; the Minnesota Power area economy is modeled independently, considering unique local conditions, and is then linked to the national economy to ensure consistency across the national, regional, state, and MSA levels. IHS Global Insight utilizes the most current historical data available from public data sources, which is updated frequently. These updates flow through IHS Global Insight's process to ultimately effect historical series used in Minnesota Power's forecast database. Thus, the historical regional employment and income data has changed from last year's database.

[13] http://www.srh.noaa.gov/images/ffc/pdf/ta_htindx.PDF
[14] http://www.nws.noaa.gov/os/windchill/index.shtml
[15] Minnesota Power's 13-County Planning Area is defined as: Carlton, Cass, Crow Wing, Hubbard, Itasca, Koochiching, Lake, Morrison, Pine, Saint Louis, Todd, and Wadena counties in MN, and Douglas county WI
[16] The Duluth MSA is defined as St. Louis Co. MN, Carlton Co MN, and Douglas Co. WI
[17] Blue Chip Economic Indicators was the only source of national economic indicators used in previous forecasts

The frequency of the raw Duluth MSA and National-level economic data is quarterly, and interpolation to a monthly frequency is necessary for use in Minnesota Power's monthly forecasting process. The interpolation method used is described in the *Specific Analytical Techniques* section.

Regional Economic Models, Inc. (REMI)

Minnesota Power subscribes to the latest REMI Policy Insight version (PI+) for northeastern Minnesota. This input/output econometric simulation software combines a national economic outlook[18] with specified regional economic conditions to produce a forecast for a 13-County Planning Area such as employment by sector, population, economic output by sector, and gross regional product (GRP).

For the 2014 AFR, REMI was used to quantify the indirect economic effects of known and expected changes in regional employment (i.e. expansions and layoffs/ closures) to produce an expected economic outlook for the region.

Minnesota Power also simulates alternative regional outlooks utilizing different employment scenarios; each employment scenario corresponds to a forecast scenario. The forecast scenarios described in Section 2 of this document are developed in two ways: 1) direct, post-regression load adjustments to the econometric output, and 2) indirect, simulated economic impacts incorporated through the predictor variables. Utilization of REMI to develop these economic impacts for each scenario allows Minnesota Power to maintain consistency of assumption across customer classes.

IHS Global Insight economic indicators for both 13-County Planning Area and the Duluth MSA are calibrated using the results of REMI's economic simulations. As the REMI outlook is adjusted for alternative planning scenarios, the monthly employment and income outlooks are changed accordingly.

Some indicators such as population and Gross Regional Product are not provided by IHS Global Insight Inc. for the 13-County Planning area. These series are derived directly from REMI outputs, and are of annual frequency. Interpolation to a monthly frequency is necessary for use in Minnesota Power's monthly forecasting process. The interpolation method used is described in the *Specific Analytical Techniques* section.

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

Indexes of Industrial Production (IPI series)

The indexes of industrial production are measures of sector-specific production in a given month relative to a base year, 2007 in this case (that is, 2007 = 100). The indexes exhibit a high degree

[18] Prior to simulation, REMI is calibrated to the IHS Global Insight National Economic Outlook

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 explained on the Federal Reserve's website[19].

Forecasts for each IPI were developed from the projections of National-level economic indicators from IHS Global Insight, and are therefore consistent with all other AFR 2014 forecast assumptions. These macroeconomic drivers are used model and forecast the IPI series.

Minnesota Power de-trends and de-seasonalizes all input variables prior to modeling and opted to utilize an already de-seasonalized series from the external source rather than applying its own de-seasonalizing function. Both the seasonally-adjusted and unadjusted series are available from the Board of Governors of the Federal Reserve. The 2014 forecast database utilizes the seasonally adjusted historical indexes whereas last year's AFR used the un-seasonally adjusted series. Differences between the seasonally-adjusted and unadjusted series at the annual level are very small.

<u>Energy Prices</u>

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 FERC Form 1 and represent annual class revenue divided by annual class energy. All energy prices are deflated by the 2009 base year GDP implicit price deflator (IPD).

<u>Appliance Saturation</u>

Residential appliance saturation rates are key determinants of residential energy use. Minnesota Power leverages customer survey data, EIA survey data, and key economic indicators to approximate the level of historical and forecast appliance ownership. Historical Central Air Conditioning, Electric Space Heat, and Electric Water Heat ownership rates were constructed from survey respondents' answers regarding age of appliances, dwelling age, etc. Forecasts of appliance saturation rates are produced by modeling the historical series using economic and demographic indicator variables such as Duluth MSA Housing Starts.

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

ii. Data Revisions Since Previous AFR

Minnesota Power made a number of adjustments to internally developed data for the 2014 AFR, which fall into four general categories:

1. Revisions of count, sales, and peak demand data
2. Adjustments to raw customer count data for billing anomalies
3. Adjustments to raw sales and peak demand data for large load additions and losses
4. Revision of customer appliance saturation rate estimates

Revisions of count, sales, and peak demand data - Constructing a monthly-frequency database for an extensive historical timeframe requires reconciliation of different records and data sources. Billing practices and customer class composition change over time, and sources occasionally disagree or differ in definition. Minnesota Power reviews and revises its forecast database each year if inaccuracies are identified. Only three substantive (more than a rounding error) changes were identified:

Change #1 – Energy sales to Mining customers in 2000 were lowered by about 55,000 MWh (1.2 percent) and sales to Other Industrial customers were increased by this amount. Total Industrial energy sales were unchanged. Two customers [**Trade Secret Data Excised**] were incorrectly classified as mining customers in Minnesota Power's historical records for this year. The difference in customer class composition was corrected. This small, isolated adjustment had minimal effect on the forecast.

Change #2 – The historical sales series for each industrial sector (Mining, Paper, Other) was limited to 1996. In previous AFR databases the data extended to 1994. Post-1996 data is of higher quality and customer-level detail is available so class composition can be verified. Pre-1996 data does not have this level of detail and class composition could not be verified; it was therefore excluded from the forecast database.

Change #3 – The historical count of lighting customers was reduced in the 2009-2013 timeframe by about 1000 per year. Minnesota Power changed billing practices in mid-2009 to count each service point as its own customer; this expanded the customer count by an unmanageable 2500 percent. For the 2014 AFR database, Minnesota Power used the old billing practices to identify and revise lighting customer counts in the 2009-2013 timeframe to create a constantly-defined series that can be accurately forecasted.

Adjustments to raw customer count and energy sales data for billing anomalies – Minnesota Power's historical customer count and energy sales data contain a number of anomalous or missing observations that can affect modeling and resulting forecasts.

Employing a binary variable during modeling or adjusting the raw data prior to modeling are two common techniques used to avoid biasing models with anomalous observations. In previous years, Minnesota Power used both techniques, but their application was not entirely consistent. The 2014 database policy is as follows:

Where there is a systemic shift (e.g. seasonal billing in residential customers count), Minnesota Power does not adjust the raw data and instead utilizes a binary variable in modeling. When there are less than 3 consecutive anomalous observations, Minnesota Power adjusts the raw data prior to regression using straight-line interpolation. In general, an observation was considered anomalous if it varied by more than 0.5 percent from a straight-line-interpolated value.

The 2014 customer count and energy sales database contains 115 monthly points (about 2.4 percent of all monthly points) that have been adjusted in this way.

Adjustments to raw sales and peak demand data to account for large load additions and losses – All adjustments to the historical database are described below in detail and organized by sector. The impact of this methodological change on the forecast for each customer class is discussed in the *Model Documentation* section.

[Trade Secret Data Excised]

Revision of customer appliance saturation rates – Air-conditioning and electric heat ownership are estimated based primarily on survey data. In recent years, Minnesota Power has used economic and demographic indicators to refine its estimations of historical saturation rates, and has been able to improve the predictive ability of weather variables as a result. This year, Minnesota Power leveraged survey results from the EIA for several geographic regions[20] to test and improve its historical estimation method. This had the effect of increasing Air-conditioning saturation in the early historical timeframe (1990-2003) by about 3 percent per year and reduced saturation in the later historical timeframe (2004-2013) by about 2 percent per year. Electric heat saturation was increased by about 2 percent per year in the years 1990-1998 and 2007-2013, and was reduced by about 2 percent per year in the 1999-2006 timeframe.

Regarding externally derived data, Minnesota Power noted several small changes between the AFR 2014 forecast database and the AFR 2013 database. None of the changes are unexplainable or implausible, and Minnesota Power is confident in moving forward with the database updates. Table 2 shows the series that were utilized in both the AFR 2013 and the AFR 2014 forecasts.

Table 2: Changes to Forecast Database

Economic and Demographic Variables	**Changes to Database** 2013 to 2014
MP Area Population	**Change #1**
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**
MP Area Employment in Finance	**Change #2**
MP Area Employment in Public Sector	**Change #2**
MP Area Employment in Construction, Natural Resources, and Mining	**Change #2**
MP Area Wage Disbursements	**Change #3**
Industrial Production Index: Iron Ore Mining	**Change #4**
Industrial Production Index: Paper	**Change #4**
Central Air Conditioning Saturation	**Change #5**
Electric Heat Saturation	**Change #5**

Change #1 (Minnesota Power Area Population) – Annual data for the post 2010 timeframe was updated by REMI per updates to other economic and demographic series used as inputs in the REMI model. Population in years 2011 and 2012 were reduced by about 6,000 (1 percent) and 9,000 (1.6 percent), respectively. Differences in the Population variable in the pre-2010 timeframe are due to the use of an alternate interpolation technique as noted in the *Specific Analytical Techniques* section.

[20] Very Cold/ Cold climate region, West North Central census region, Midwest census division, and the entire U.S.

Change #2 (IHS Global Insight Employment Data) – When aggregated to annual values, the income and employment series show minimal variation from the last year's historical data. Differences in employment series prior to 2011are fairly small. The largest difference was in 2010 financial sector employment, which was about 0.5 percent lower in the AFR 2014 database than it was in the AFR 2013 database. 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 (IHS Global Insight Income Data) – For consistency with all other dollar denominated series in this year's forecast database, Area Wage and Salary Disbursements was deflated to 2009$. In AFR 2013, this series was denominated in 2005$. Utilization of a different base year (2009$ instead of 2005$) is a simple constant transformation and cannot substantively affect regression results.

Change #4 (Industrial Production Indexes) – As noted in the *Inputs and Sources* section, Minnesota Power transitioned to a seasonally adjusted series from an un-seasonally adjusted series. Historical Industrial Production Indexes (IPI) series were downloaded from the Federal Reserve Board's Data Download Program and were not adjusted by Minnesota Power.

Generally, the seasonal adjustment had the effect of increasing the index in quarter 1 of each year and reducing the index in quarters 2-4. Adjusting for seasonality had almost no impact when the series are aggregated to an annual frequency. There was little to no change in the Iron IPI in all years except in 2009 where the annual values differ by about 1.5 percent. The Paper IP index was unchanged at any significant decimal place.

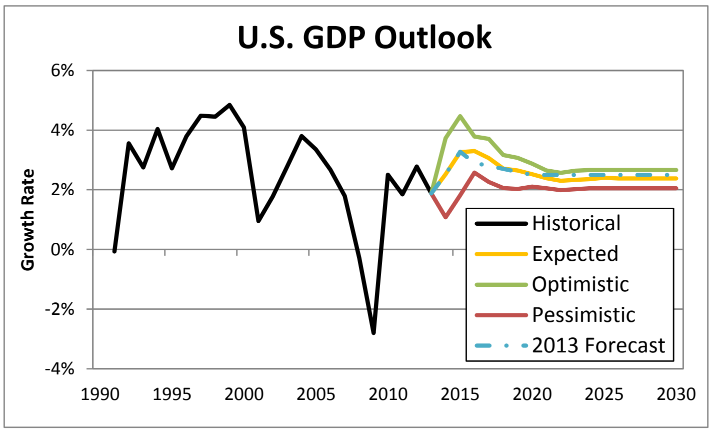
Temperature variables used in the peak demand model have been redefined and will therefore differ from those in last year's database. This change is described in the *Methodological Adjustments for the 2014 Forecast* section because it's not necessarily a revision of historical data; the method of incorporating this indicator variable into the forecast model has been adapted but is still based on the same historical temperature data for Duluth, MN.

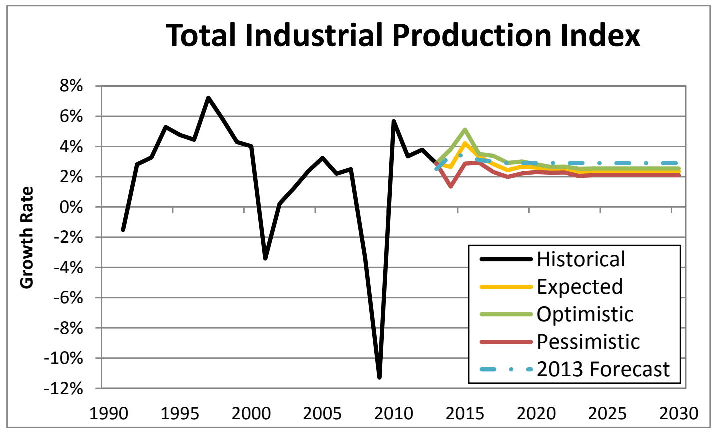
D. Overview of Key Inputs/Assumptions

i. National Economic Assumptions

The national economic outlook is derived from IHS Global Insight 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 in Figures 2-5 below, for the Expected, Optimistic, and Pessimistic cases.

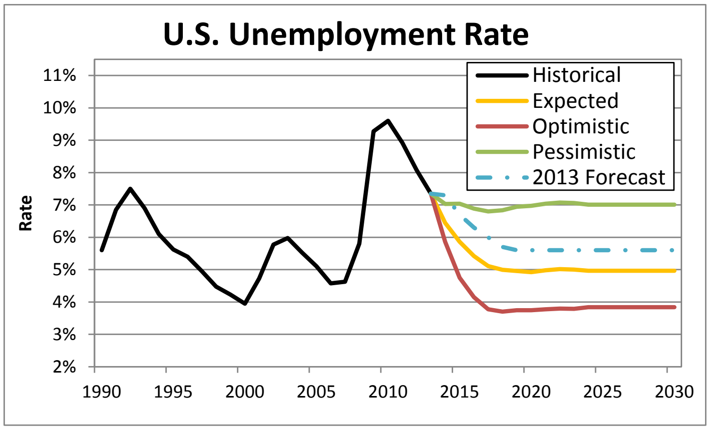
Figures 2 and 3: National Economic Outlook (GDP and Industrial Production)





In the Expected case, U.S. GDP and IPI growth average 2.6 percent per year from 2014-2028. The Expected case (yellow) macroeconomic outlook serves as the underlying assumption for 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 percent per year and IPI growth averages just 2.2 percent per year in the forecast timeframe. The Optimistic macroeconomic outlook drives the Best Case scenario; in the Optimistic outlook GDP and IPI growth average 3.0 percent per year.

Figures 4 and 5: National Economic Outlook (Unemployment Rate and Auto Sales)



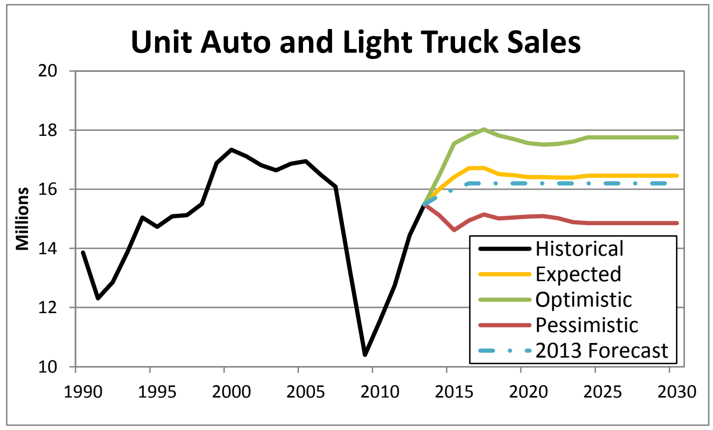
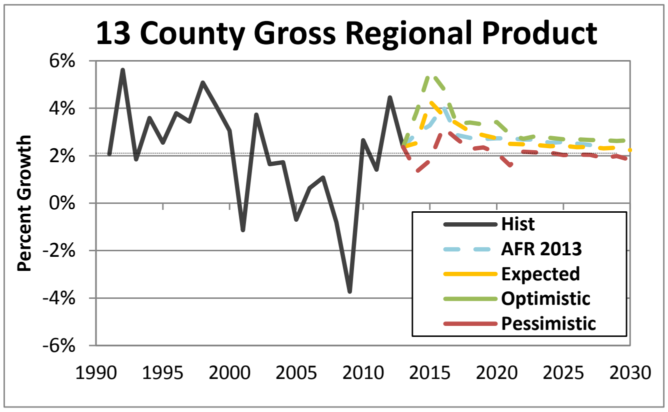


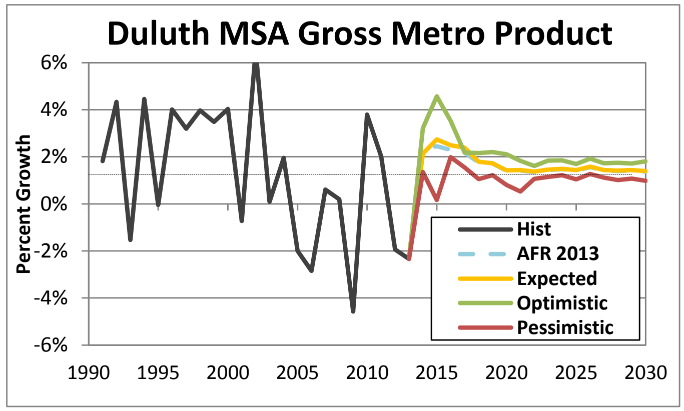
Figure 4 show the unemployment rates in the three national outlooks all fall steadily in the first few years of the forecast timeframe before reaching long term labor market stability consistent with the assumed rate of GDP growth. Assumptions of unit auto and light truck sales in Figure 5 show similar pattern in the forecast timeframe with substantial improvement in the medium-term and stabilization in the long term.

ii. 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 “13-County Planning Area.” Minnesota Power expanded its database to include economic and demographic indicators at the Metropolitan Statistical Area level (this includes St. Louis and Carlton counties in Minnesota and Douglas county Wisconsin). The graphs below show alternative economic outlooks for both regions 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. Figures 6 and 7 compare the historical and projected growth rate of both regions’ product.

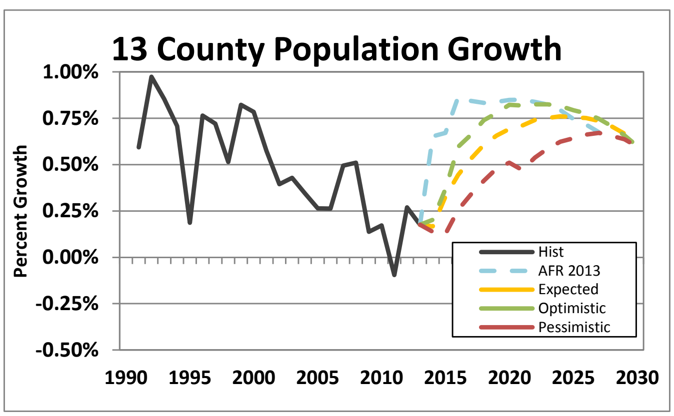
Figures 6 and 7: Regional Economic Outlooks (13-County Product and Duluth MSA Product)

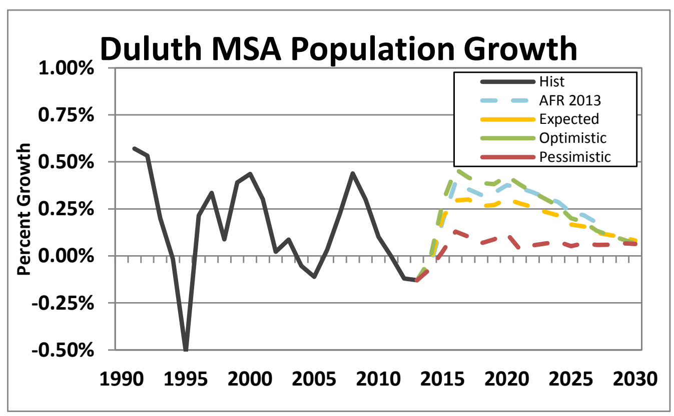




The 13-County Planning Area's Gross Regional Product (GRP) averages 2.7 percent per year growth in the forecast timeframe whereas the Duluth MSA product averages just 1.5 percent per year in the forecast timeframe. Population growth rates show a similar trend: the 13-County Planning Area grows at about 0.6 percent in the forecast timeframe and the Duluth MSA area population grows at just 0.2 percent per year. The difference in the two regions' historical and projected growth, shown below in Figures 8 and 9, demonstrates why Minnesota Power expanded its database.

Figures 8 and 9: Regional Economic Outlooks (13-County Population and Duluth MSA Population)





E. Econometric Model Documentation

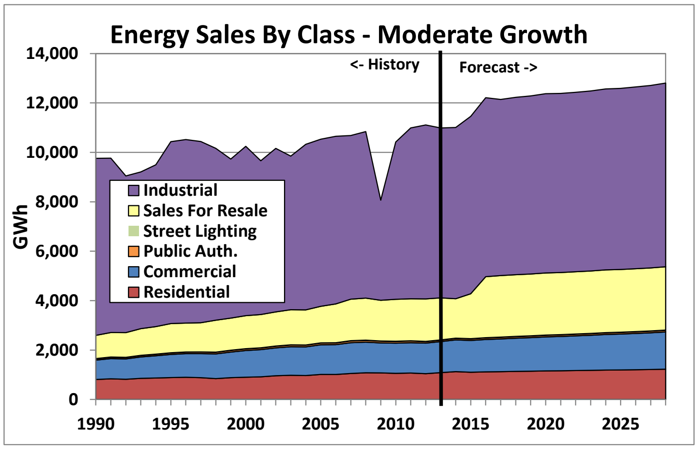
This section presents the statistical detail of all models utilized in the development of the AFR 2014 forecast. The model's structure, key diagnostic statistics, forecast results, and a discussion of the model are provided for added transparency.

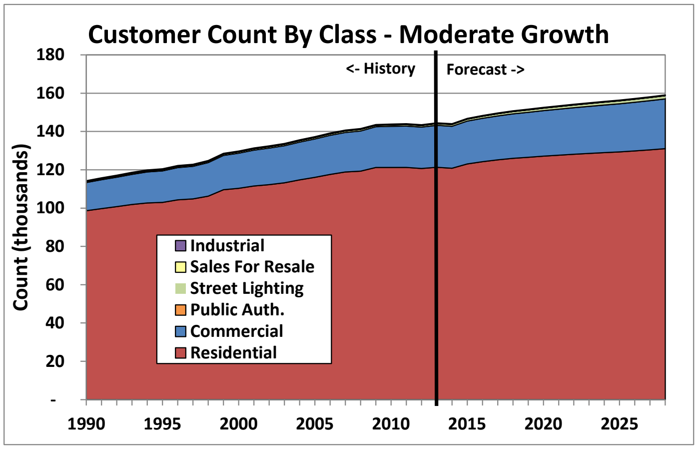
Models are shown with each variable's coefficient, t-stat, p-value, and VIF. A graph displays the historical series, growth rates for time-frames of interest, and compares this year's forecast to last year's forecast. A table shows a more focused view of the forecast with a shorter historical timeframe 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.*

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

All forecast values shown in this section are the 2014 expected case "Moderate Growth" scenario. The forecast values shown in the chart and tables for each model combine the econometric output with specific load, energy, and customers count additions. The total energy sales outlook is shown below (left) with the total customer count outlook (right).

Figures 10 and 11: Moderate Growth Scenario Projection of Energy Sales and Customer Count by Class





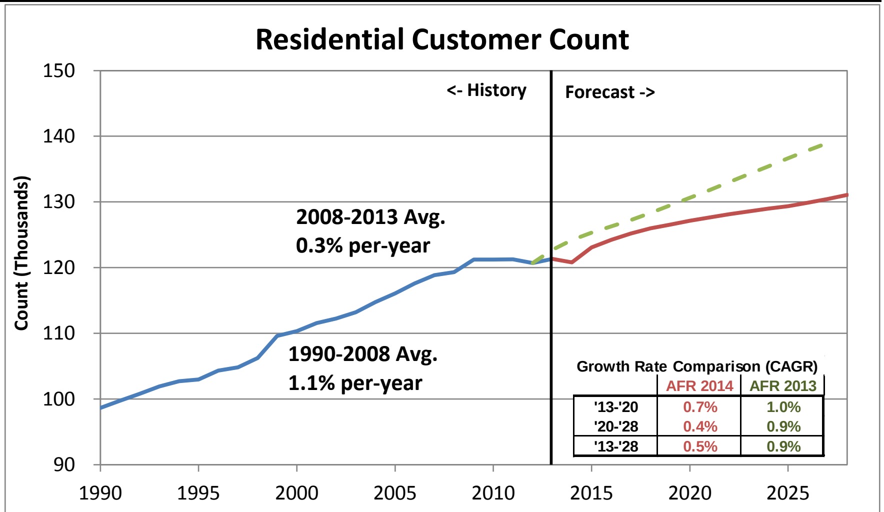
Minnesota Power did not develop a model to forecast Sales for Resale customer count. Minnesota Power currently has 17 resale customers, each of which has signed a service agreement. The loss or gain of a resale customer is therefore better accounted for by reviewing these agreements and communicating with customers. Econometric models are not appropriate for estimating future resale customer counts.

Residential Customer Count - Moderate Growth

Estimation Start/End:	7/1990 - 3/2014
Unit Modeled/Forecast:	Monthly Customer Count

	OLS Model			ARMA Test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	67,222.98	0.00%		0.00%
Trend	92.57	0.00%	2.09	0.00%
Binary_Billing_1	(2,214.61)	0.00%	1.24	0.00%
Binary_Billing_2	(3,420.87)	0.00%	1.46	0.00%
Binary_2012	(925.69)	0.00%	2.04	15.55%
Binary_2013	(2,116.80)	0.00%	2.10	14.07%
Binary_2014-2030	(2,704.59)	0.00%	1.34	12.62%
13co_Edu_Health_lead_6	0.57	0.00%	2.65	0.99%
MSA_Retail_Trade_lag_6	689.62	0.00%	2.11	9.87%

	OLS Model	
	Count	Y/Y Growth
2007	118,870	
2008	119,300	0.4%
2009	121,217	1.6%
2010	121,235	0.0%
2011	121,251	0.0%
2012	120,697	-0.5%
2013	121,314	0.5%
2014	120,818	**-0.4%**
2015	123,065	**1.9%**
2016	124,243	**1.0%**
2017	125,202	**0.8%**
2018	125,997	**0.6%**
2019	126,542	**0.4%**
2020	127,136	**0.5%**
		5 yr CAGR
2025	129,353	***0.3%***



	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	99.8%		99.9%	
AIC	11.90		11.41	
SIC	12.01		11.57	
MAPE	0.3%		0.2%	
Model F Test	15543.7	0.0%	18519.5	0.0%
Estimates Residual S.D.	377		295	
SSres	39,224,856		23,703,886	
Degrees of Freedom	276		273	
Breusch-Pegan F	3.1	0.2%	1.5	15.2%
Breusch-Pegan ChiSq	23.7	0.3%	12.0	15.2%
White's F	8.9	0.0%	2.2	11.0%
Breusch-Godfrey AIC F	74.5	0.0%	0.5	46.2%
Breusch-Godfrey AIC ChiSq	100.2	0.0%	10.6	0.1%
Breusch-Godfrey SIC F	74.5	0.0%	0.5	46.2%
Breusch-Godfrey SIC ChiSq	100.2	0.0%	10.6	0.1%
Durban-Watson	1.0		2.0	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	21.3	0.0%	15.8	0.0%
FIT^3 Ramsey's RESET F	12.9	0.0%	11.4	0.0%
FIT^4 Ramsey's RESET F	13.4	0.0%	9.8	0.0%
Out-of-Sample RMSE	709		709	
Out-of-Sample MAE	491		491	
Out-of-Sample MAPE	0.43%		0.43%	

Model Discussion

The AFR 2014 forecast of residential customer count growth moderated due to persistently low growth in the recent historical timeframe. Key economic drivers of customer growth include Employment in the Education & Health sector (13 county) and Employment in Retail Trade (Duluth MSA). This differs from last year's model which utilized Area Households (13 county) as the sole economic driver of customer count growth. Nearly all of the top models for residential customer count contained Employment in the Education and Health sector, which affirms this model's selection.

Minnesota Power's econometric interpretation of the key drivers is as follows: For each job added to the Education & Health sector, the customer count should increase by about 0.57. For each job added to the Retail Trade sector, the customer count should increase by about 0.69 (note that this variable's unit was in Thousands, so the coefficient should be divided by 1,000 to reveal the level impact on count). These impacts are in addition to a general upward trend over time. These variables are plausible and intuitive. Retail Trade employment seems to indicate the variation around the more prominent underlying growth trends indicated by Education and Health employment.

Education and Health sector accounts for 20% of the 13 county planning area employment and has been a strong driver of overall employment growth in the area. From 2000 to 2013, the 13 county area has seen total non-farm employment grow by approximately 5,000. Employment in Education and Health has grown by about 15,000; this more than makes up for substantial losses in Construction, Natural Resource Extraction, and Manufacturing. Employment in Retail Trade at the Duluth MSA level has declined about 1,500 since 2000, but its periods of growth and contraction correlate well with periods of customer growth or stagnation.

Binary variables for 2012, 2013, and 2014-2030 effectively shift the first forecast year (2014) to align with the last historical year (2013). Without these corrective binary variables, a small but growing divergence between actual and predicted customer growth in the late historical timeframe suggests the economic indicators alone would overstate customer count, and the 2014 forecast values from models without corrective binary variables confirm this. Without these binary variables, the model would project an increase of over 2,000 customers from 2013 to 2014 (a 1.5% increase). The corrective binary variables shift the forecast down to avoid improbable increases in customer counts, but do not impact the forecast trajectory; this is determined by the economic variables.

Two binary variables (Binary_Billing) 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. Last year's residential customer count model also utilized these variables.

This year's model reduced out-sample forecast error (MAPE) to 0.43% from 0.57% in last year's model and improved other key metrics such as SIC, R-Squared, and in-sample forecast error (traditional MAPE). ARMA testing of the OLS model was able to resolve heteroskedasticity and autocorrelation to confirm the significance (P-values) of the economic variables' coefficients. The very low VIF of each variable proves there is no significant multicollinearity.

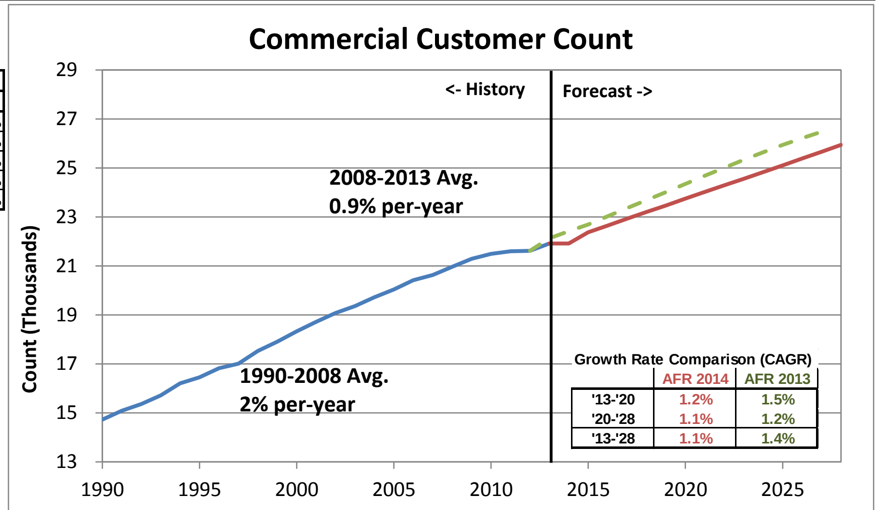
Commercial Customer Count - Moderate Growth

Estimation Start/End:	1/1991 - 3/2014
Unit Modeled/Forecast:	Monthly Customer Count

	OLS Model			ARMA Test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	(114,944)	0.00%		0.00%
Trend	27	0.00%	1.46	0.00%
Binary_Jun_2013_2030	(165)	0.01%	1.24	0.50%
13co_Edu_Health_LN_t_lead_9	3,205	0.00%	2.09	0.00%
13co_Population_LN_lag_12	15,278	0.00%	1.34	0.00%

	OLS Model	
	Count	Y/Y Growth
2007	20,630	
2008	20,969	1.6%
2009	21,287	1.5%
2010	21,491	1.0%
2011	21,603	0.5%
2012	21,614	0.1%
2013	21,915	1.4%
2014	21,921	0.0%
2015	22,376	2.1%
2016	22,644	1.2%
2017	22,928	1.3%
2018	23,205	1.2%
2019	23,469	1.1%
2020	23,749	1.2%
		5 yr CAGR
2025	25,107	*1.1%*

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	99.8%		99.8%	
AIC	9.34		9.23	
SIC	9.41		9.32	
MAPE	0.4%		0.4%	
Model F Test	30443.7	0.0%	22911.0	0.0%
Estimates Residual S.D.	106		100	
SSres	3,064,263		2,695,405	
Degrees of Freedom	274		272	
Breusch-Pegan F	1.0	38.9%	2.8	2.6%
Breusch-Pegan ChiSq	4.2	38.6%	11.0	2.6%
White's F	1.7	18.5%	4.6	1.1%
Breusch-Godfrey AIC F	5.5	0.0%	3.9	0.0%
Breusch-Godfrey AIC ChiSq	82.4	0.0%	46.8	0.0%
Breusch-Godfrey SIC F	20.1	0.0%	0.2	64.4%
Breusch-Godfrey SIC ChiSq	36.0	0.0%	0.4	52.4%
Durban-Watson	1.4		2.0	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	0.2	63.8%	-15.6	#NUM!
FIT^3 Ramsey's RESET F	5.1	0.7%	1.5	22.7%
FIT^4 Ramsey's RESET F	3.6	1.3%	2.3	7.7%
Out-of-Sample RMSE	109		109	
Out-of-Sample MAE	79		79	
Out-of-Sample MAPE	0.42%		0.42%	



Model Discussion

The AFR 2014 forecast of commercial customer count growth moderated due to persistently low growth in the recent historical timeframe. Key economic drivers of customer growth include Employment in the Education & Health sector (13 county) and Population (13 county). This differs from last year's model which utilized Area Households (13 county) as the sole economic driver of customer count growth. Nearly all of the top models for Commercial customer count contained Employment in the Education and Health sector, which affirms this model's selection.

Minnesota Power's econometric interpretation of the key drivers is as follows: For each 1% increase in Education & Health sector employment, the customer count should increase by about 32 (about 0.15%). As area Population increases by 1%, the customer count should increase by about 152 (about 0.69%). These impacts are in addition to a general upward trend over time.

A binary variable starting in June 2013 effectively shifts the first forecast year (2014) to align with the last historical year (2013). Without this corrective binary variable, a small but growing divergence between actual and predicted customer growth (beginning in June, 2013) suggests the economic indicators alone would overstate customer count, and the 2014 forecast value confirms this. Without these binary variables, the model would project an increase of 300 customers from 2013 to 2014 (a 1.4% increase). The corrective binary variables shift the forecast down to avoid improbable increases in customer counts, but do not impact the forecast trajectory; this is determined by the economic variables.

This year's model reduced out-sample forecast error (MAPE) to 0.43% from 1% last year's model and improved other key metrics such as SIC and R-Squared, and halved in-sample forecast error (traditional MAPE). The OLS model passed all tests for Heteroskedasticity. ARMA testing of the OLS model for autocorrelation confirmed the significance (P-values) of the economic variables' coefficients and solve Ramsey's RESET F tests suggest exponential transformations were unlikely to improve the model's statistical measures. The very low VIF of each variable proves there is no significant multicollinearity.

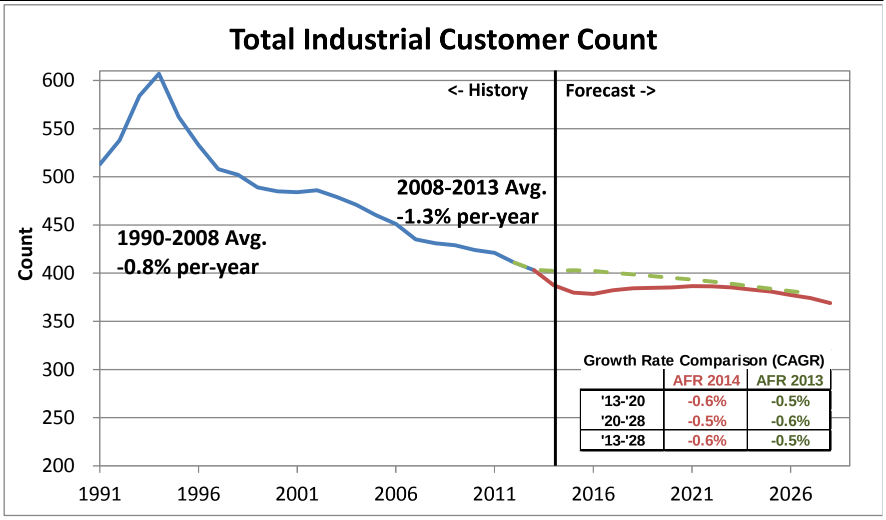
Industrial Customer Count - Moderate Growth

Estimation Start/End:	1/1991 - 3/2014
Unit Modeled/Forecast:	Monthly Customer Count

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	(3.05)	0.00%		0.11%
Trend	(0.001)	0.00%	1.59	0.00%
Binary_05_2012-2030	0.020	0.08%	1.37	75.66%
MSA_Population_t_lag_12	0.032	0.00%	1.08	0.00%
MSA_RetailTrd_t_lead_12	0.035	0.00%	1.22	0.00%

	OLS Model	
	Count	Y/Y Growth
2007	435	
2008	431	-0.9%
2009	429	-0.5%
2010	424	-1.2%
2011	421	-0.7%
2012	411	-2.4%
2013	403	-1.9%
2014	387	-3.9%
2015	380	-2.0%
2016	378	-0.3%
2017	382	1.0%
2018	384	0.5%
2019	385	0.1%
2020	385	0.1%
2025	381	*5 yr CAGR - 0.2%*

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	95.8%		99.2%	
AIC	-7.55		-9.23	
SIC	-7.48		-9.07	
MAPE	0.3%		0.1%	
Model F Test	1598.2	0.0%	3310.9	0.0%
Estimates Residual S.D.	0		0	
SSres	0		0	
Degrees of Freedom	274		267	
Breusch-Pegan F	13.0	0.0%	0.7	59.3%
Breusch-Pegan ChiSq	44.4	0.0%	2.8	58.9%
White's F	32.5	0.0%	3.6	2.9%
Breusch-Godfrey AIC F	103.7	0.0%	2.9	0.0%
Breusch-Godfrey AIC ChiSq	226.6	0.0%	57.6	0.0%
Breusch-Godfrey SIC F	654.5	0.0%	0.1	80.7%
Breusch-Godfrey SIC ChiSq	229.7	0.0%	5.7	1.7%
Durban-Watson	0.2		2.0	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	307.3	0.0%	16.4	0.0%
FIT^3 Ramsey's RESET F	183.9	0.0%	18.2	0.0%
FIT^4 Ramsey's RESET F	122.2	0.0%	12.6	0.0%
Out-of-Sample RMSE	0		0	
Out-of-Sample MAE	0		0	
Out-of-Sample MAPE	0.38%		0.38%	



Model Discussion

The AFR 2014 forecast of Industrial customer count growth is similar to last year's. Key economic drivers of customer growth include Population (Duluth MSA) and Employment in Retail Trade (Duluth MSA). This differs from last year's model which utilized Employment in Manufacturing (13 county) as the sole economic driver of customer count growth.

The selection of Employment in Retail Trade as an indicator of Industrial customer count may seem incongruent, but this variable was selected repeatedly for inclusion by Minnesota Power's model generation tool and many of the top ranked models included this as an indicator. This variable most likely serves as a proxy for general economic conditions and supplements the Population variable, which predicts the underlying growth of the series.

Minnesota Power's econometric interpretation of the key drivers is as follows: As the Duluth MSA's Population increases by 1,000, Industrial customer count should increase by 3.3% (about 13 customers). As Duluth MSA's employment in Retail Trade increases by 1,000 the customer count should increase by 3.5% (about 14 customers). These impacts are in addition to a general downward trend over time.

A binary variable starting in May of 2012 effectively shifts the first forecast year (2014) to align more closely with the last historical year (2013). This corrective shift reduced the 2013-to-2014 decrease in customer count is limited to 16 (4%) instead of 18 (4.5%). The difference in the first forecast year is not substantial but by 2020, the decrease is limited to 20 (5%) instead of 28 (7%). The corrective binary variable shifts the forecast up slightly to avoid improbable decreases in customer counts, but does not impact the forecast trajectory; this is determined by the economic variables.

This year's model utilizes a logged form of the dependent variable so comparison of statistical quality should be done using forecast errors instead of SIC or R-squared. The AFR 2014 model reduced out-sample forecast error (MAPE) to 0.38% from 1.6% in last year's model, and reduced in-sample forecast error (traditional MAPE) to 0.3% from 0.8% in last year's model.

ARMA testing of the OLS model resolved heteroscedasticity and lower-order autocorrelation to confirm the significance (P-values) of the economic variables' coefficients. Low VIF for each variable proves there is no significant multicollinearity.

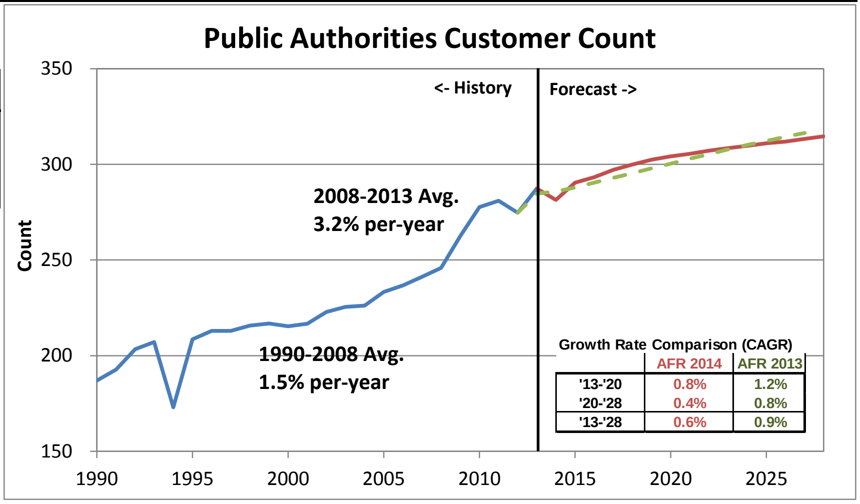
Public Authorities Customer Count - Moderate Growth

Estimation Start/End:	1/1991 - 3/2014
Unit Modeled/Forecast:	Monthly Customer Count

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	5.00	0.00%		0.00%
Trend	0.001	0.00%	2.09	0.00%
Binary_Aug_2009-2030	0.103	0.00%	2.05	0.00%
MSA_Edu_Health_lag_12	0.011	0.00%	1.03	0.00%
MSA_Empl-to-Pop_LN_diff_lead_12	1.81	0.01%	1.09	9.38%

	OLS Model	
	Count	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	287	4.6%
2014	281	-2.1%
2015	290	3.2%
2016	293	1.0%
2017	297	1.3%
2018	300	0.9%
2019	302	0.8%
2020	304	0.6%
		5 yr CAGR
2025	311	*0.4%*

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	98.1%		99.1%	
AIC	-8.22		-8.90	
SIC	-8.15		-8.76	
MAPE	0.2%		0.2%	
Model F Test	3555.3	0.0%	2910.1	0.0%
Estimates Residual S.D.	0		0	
SSres	0		0	
Degrees of Freedom	274		268	
Breusch-Pegan F	5.3	0.0%	2.3	6.0%
Breusch-Pegan ChiSq	20.2	0.0%	9.0	6.1%
White's F	6.9	0.1%	1.6	19.4%
Breusch-Godfrey AIC F	22.8	0.0%	4.7	0.0%
Breusch-Godfrey AIC ChiSq	135.9	0.0%	45.3	0.0%
Breusch-Godfrey SIC F	78.1	0.0%	5.8	0.0%
Breusch-Godfrey SIC ChiSq	149.3	0.0%	37.1	0.0%
Durban-Watson	0.6		1.9	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	2.2	13.6%	5.5	2.0%
FIT^3 Ramsey's RESET F	3.7	2.5%	3.3	3.9%
FIT^4 Ramsey's RESET F	62.1	0.0%	3.6	1.4%
Out-of-Sample RMSE	0		0	
Out-of-Sample MAE	0		0	
Out-of-Sample MAPE	0.29%		0.29%	



	AFR 2014	AFR 2013
'13-'20	0.8%	1.2%
'20-'28	0.4%	0.8%
'13-'28	0.6%	0.9%

Model Discussion

The AFR 2014 forecast of Public Authorities customer count growth is similar to last year's. Key economic drivers of customer growth include Employment in the Education & Health sector (Duluth MSA) and the Employment-to-Population ratio (Duluth MSA). The employment-to-population ratio metric is similar to an employment rate, but makes no adjustments for labor force participation. These drivers differ from last year's model which utilized Area Households (13 county) as the sole economic driver of customer count growth.

Minnesota Power's econometric interpretation of the key drivers is as follows: For every 1,000 jobs added in the Education & Health sector at the Duluth MSA level, the customer count should increase by about 1.2% (about 3 customers). A 1% increase in the Duluth MSA's month-to-month percent change in the Employment-to-Population ratio should increase customer count by about 1.8% (about 5 customers). These impacts are in addition to a general upward trend over time.

A binary variable starting in August of 2009 effectively shifts the first forecast year (2014) to align with the last historical year (2013). Without this corrective binary variable the economic indicators alone would understate customer count, The corrective binary variables shift the forecast up slightly to avoid improbable decreases in customer counts, but do not impact the forecast trajectory; this is determined by the economic variables.

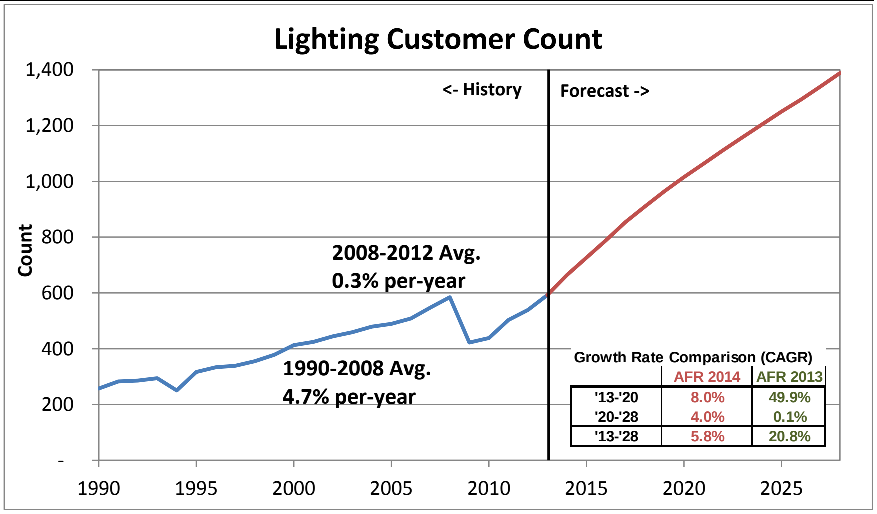
This year's model reduced out-sample forecast error to 0.3% from 2.3% in last year's model, reduced in-sample forecast error to 0.2% from 2% in last year's model, and improved other key metrics such as SIC and R-Squared.

ARMA testing of the OLS model was able to resolve heteroscedasticity. However the model was only able to resolve first, second, and third-order autocorrelation. It's possible that the P-values of the coefficients are over-estimated due to some higher-level autocorrelation. Other top model shared this characteristic. Low VIF for each variable proves there is no significant multicollinearity.

Street Lighting Customer Count - Moderate Growth

Estimation Start/End:	2/1991 - 3/2014
Unit Modeled/Forecast:	Monthly Customer Count

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	(212.28)	0.00%		5.26%
Trend	1.51	0.00%	2.06	0.00%
Binary_Jul_2009_2030	(989.05)	0.00%	278.94	0.00%
Trend_Jul_2009_2030	3.44	0.00%	279.60	0.00%
MP_13_Edu_Health_lag_12	0.012	0.00%	1.42	0.00%
MSA_Population_diff_lag_12	81.04	0.00%	1.17	0.01%



	OLS Model	
	Count	**Y/Y Growth**
2007	548	
2008	585	6.8%
2009	422	-27.8%
2010	438	3.8%
2011	503	14.8%
2012	539	7.2%
2013	592	9.8%
2014	664	**12.2%**
2015	726	**9.4%**
2016	789	**8.6%**
2017	854	**8.3%**
2018	910	**6.5%**
2019	964	**6.0%**
2020	1,015	**5.2%**
		5 yr CAGR
2025	1,250	***4.3%***

	OLS Model		ARMA Test	
Model Statistics	**Magnitude**	**P-Value**	**Magnitude**	**P-Value**
Adjusted R^2	99.1%		99.8%	
AIC	4.65		3.37	
SIC	4.72		3.56	
MAPE	1.9%		0.9%	
Model F Test	6037.9	0.0%	8589.4	0.0%
Estimates Residual S.D.	10		5	
SSres	27,751		7,330	
Degrees of Freedom	272		264	
Breusch-Pegan F	4.1	0.1%	1.8	8.7%
Breusch-Pegan ChiSq	19.6	0.2%	12.4	8.8%
White's F	8.1	0.0%	4.9	0.8%
Breusch-Godfrey AIC F	650.0	0.0%	0.0	91.6%
Breusch-Godfrey AIC ChiSq	195.7	0.0%	15.1	0.0%
Breusch-Godfrey SIC F	650.0	0.0%	0.0	91.6%
Breusch-Godfrey SIC ChiSq	195.7	0.0%	15.1	0.0%
Durban-Watson	0.3		1.9	
Durban-H	#NA	N/A	0.6	N/A
FIT^2 Ramsey's RESET F	83.2	0.0%	-44.6	#NUM!
FIT^3 Ramsey's RESET F	41.6	0.0%	13.4	0.0%
FIT^4 Ramsey's RESET F	49.6	0.0%	9.0	0.0%
Out-of-Sample RMSE	13		16	
Out-of-Sample MAE	10		10	
Out-of-Sample MAPE	2.46%		2.40%	

Model Discussion

The AFR 2014 forecast of Street Lighting customer count growth is notably different than last year's forecast. As noted in the section on Data Revisions Since Previous AFR, Minnesota Power used the an older billing practices to revise lighting customer counts in the 2009-2013 timeframe. This creates a constantly-defined series that can be accurately forecasted.

The key drivers of this year's model differ from last year's model which utilized no economic variables. Last year's model was driven by lagged-dependent variables and a binary to indicate a step change. More than half of all top models for Street Lighting customer count contained Employment in the Education and Health sector, which affirms this model's selection.

Key economic drivers of customer growth include Employment in the Education & Health sector (13 county) and Population (Duluth MSA). The Population variable is differenced to show month-to-month change in population rather than the level. As noted in the section on "Data Revisions Since Previous AFR," starting in 2009, a change in billing practices caused the street lighting customer count to increase from around 600 to nearly 6,000 in 2010. For AFR 2014, the historical count in the 2009-2013 timeframe was adjusted for consistency with pre-2009 account practices.

Minnesota Power's econometric interpretation of the key drivers is as follows: For every 1,000 jobs added in the Education & Health sector in the 13 county planning area, the customer count should increase by about 12. As the month-to-month change in Duluth MSA population increases by 1,000, street lighting customer count should increases by about 81. These impacts are in addition to a general upward trend over time.

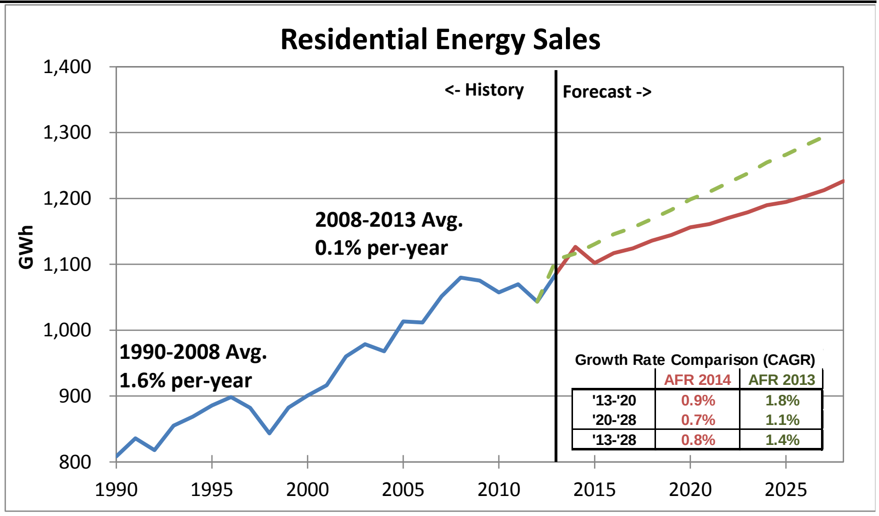
A binary variable starting in July of 2009 accounts for a step change in the historical. Although, Minnesota Power did its best to replicate the previous billing practices and construct a consistent histrionical customer count series to model, there is an obvious break in the series. This binary variable accounts for this break.

This year's model reduced out-sample forecast error (MAPE) to 2.46% (from 62% in last year's model), halved the SIC, and reduced in-sample MAPE forecast error to 1.9% from 2.2% in last year's model. ARMA testing of the OLS model was able to resolve heteroscedasticity and autocorrelation to confirm the P-values of each variables

Residential Energy Use - Moderate Growth

Estimation Start/End:	8/1990 - 3/2014
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (KWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	18.394	0.00%		0.00%
Binary_Aug	1.689	0.13%	2.51	0.11%
Trend_Jan	0.028	0.00%	3.72	0.00%
Trend_Mar	0.010	0.84%	3.92	0.99%
Trend_Jul	0.009	5.00%	5.00	8.56%
Trend_Nov	0.012	0.06%	3.21	0.22%
Trend_Dec	0.030	0.00%	4.05	0.00%
HDD_ElecHeat_Jan	1.356	0.00%	4.03	0.00%
HDD_Feb	0.202	0.00%	1.51	0.00%
HDD_ElecHeat_Mar	1.124	0.00%	4.30	0.00%
HDD_Apr	0.151	0.00%	1.49	0.00%
HDD_ElecHeat_May	0.730	0.55%	1.53	0.52%
CDD_Jul	0.493	1.12%	4.87	0.62%
CDD_CAC_Aug	1.454	1.70%	2.01	5.96%
HDD_ElecHeat_Sep	0.870	1.37%	1.49	1.02%
HDD_Oct	0.077	0.01%	1.50	0.01%
HDD_Nov	0.105	0.00%	3.63	0.00%
HDD_Dec	0.133	0.00%	4.60	0.00%
13co_WageDisb_diff_lag_5	0.005	0.08%	1.10	0.37%
13co_Gov_LN_diff_lag_6	22.431	1.53%	1.09	9.98%



	OLS Model	
	MWh	Y/Y Growth
2007	1,051,453	
2008	1,079,837	2.7%
2009	1,075,116	-0.4%
2010	1,057,476	-1.6%
2011	1,069,856	1.2%
2012	1,043,281	-2.5%
2013	1,086,481	4.1%
2014	1,126,533	**3.7%**
2015	1,101,872	**-2.2%**
2016	1,117,148	**1.4%**
2017	1,124,315	**0.6%**
2018	1,135,933	**1.0%**
2019	1,144,295	**0.7%**
2020	1,156,269	**1.0%**
		5 yr CAGR
2025	1,194,569	***0.7%***

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	89.0%		89.4%	
AIC	0.93		0.90	
SIC	1.18		1.17	
MAPE	5.1%		5.0%	
Model F Test	121.9	0.0%	120.0	0.0%
Estimates Residual S.D.	2		2	
SSres	623		602	
Degrees of Freedom	264		263	
Breusch-Pegan F	2.6	0.0%	2.5	0.1%
Breusch-Pegan ChiSq	44.7	0.1%	43.8	0.1%
White's F	9.8	0.0%	10.2	0.0%
Breusch-Godfrey AIC F	3.7	0.0%	3.0	0.1%
Breusch-Godfrey AIC ChiSq	43.3	0.0%	33.9	0.0%
Breusch-Godfrey SIC F	0.1	72.3%	1.5	21.5%
Breusch-Godfrey SIC ChiSq	0.2	63.6%	2.1	14.3%
Durban-Watson	2.0		2.1	N/A
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	1.1	28.9%	-7.9	#NUM!
FIT^3 Ramsey's RESET F	3.8	2.5%	1.9	14.5%
FIT^4 Ramsey's RESET F	2.6	5.6%	1.9	12.4%
Out-of-Sample RMSE	2		2	
Out-of-Sample MAE	1		1	
Out-of-Sample MAPE	5.61%		5.61%	

Model Discussion

The AFR 2014 forecast of residential use-per customer is similar to last year's. The graph shown above combines the output of the use-per-customer per day model with the outputs of the customer count model to show total energy sales to Residential customers. The decrease in the total energy use forecast for the residential class is primarily due to the change in the customer count projection and not a substantive change in projected use-per-customer.

This year's model found Wage Distribution in the 13 county area and Employment in the Public sector for the 13 county area to be significant indicators of per-customer use. This differs from last year's model which used only weather, appliance saturation, and seasonal trend variables to predict residential customer use.

Minnesota Power's econometric interpretation of the key drivers is as follows: As the month-to-month change in wage distribution increases by $1 Million (about 0.1% of the current level), monthly use-per-customer should increase by about 0.156 KWh (0.005 KWh x 31 days). A 1% increase in Public Sector employment will increase monthly use-per-customer by about 7 KWh (0.223 x 31 days).

When modeling residential use-per-customer, monthly/seasonal binaries and trend variables occasionally appropriated the role of weather variables due to high collinearity and the model identifying the binary as the more indicative variable. In this case, the binary variable is dropped in favor of maintaining weather a predictor because it allows for accurate after-the-fact weather normalization later by the company.

Seasonal trend variables (denoted by "Trend_month") are used to identify months where usage has shown significant trending over time. These trends suggest that monthly usage patterns are evolving independent of weather, appliance saturation, and economic conditions. Summer and winter month trending is positive and significant. Shoulder month trends were found to be either insignificant or interacted with weather to produce colliniartiy issues, and therefore excluded. These findings are consistent with last year's results.

This year's model is highly comparable to last year's in terms of statistical quality. SIC, R-Squared, in-sample forecast error (traditional MAPE), and out-sample (RMSE) are all fairly close. The OLS model passes several of the tests for Autocorrelation, but heteroscedasticity is present and ARMA testing of the OLS model was unable to resolve this. However, given that no alternative models with quality statistics and plausible growth rates could solve for heteroscedasticity, Minnesota Power considers this model the optimal choice despite the potential for bias in the P-values.

Low VIF of each variable proves there is no significant multicollinearity and the Ramsey's RESET F tests suggest that the model is properly specified and transformations of variables would not yield additional predictive power.

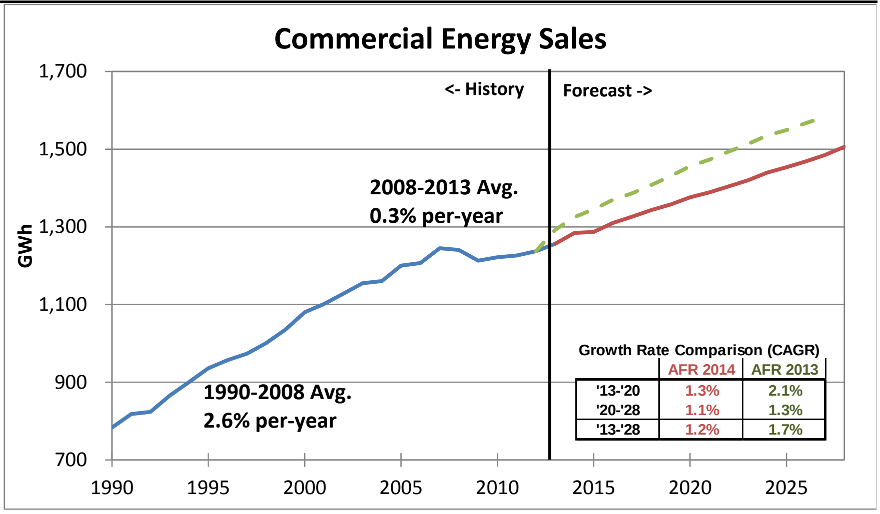
Commercial Energy Use - Moderate Growth

Estimation Start/End:	1/1991 - 3/2014
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (KWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	(145.26)	2.59%		0.00%
Trend	0.03	0.02%	1.05	0.00%
Binary_Nov	(46.14)	0.21%	49.53	0.27%
HDD_Jan	0.30	0.00%	1.16	3.17%
HDD_Feb	0.50	0.00%	1.16	0.00%
HDD_Mar	0.43	0.00%	1.16	0.92%
CDD_Jun	5.49	0.06%	1.12	1.27%
CDD_Jul	3.58	0.00%	1.13	0.00%
CDD_Aug	7.97	0.00%	1.13	0.00%
HDD_Sep	1.62	0.00%	1.14	0.32%
HDD_Nov	1.45	0.06%	49.37	0.02%
HDD_Dec	0.54	0.00%	1.16	0.00%
13co_Finance_t_lag_12	0.0035	0.24%	1.50	0.00%
13co_MFG_LN_t_lag_5	25.74	0.03%	1.49	0.00%

	OLS Model	
	MWh	Y/Y Growth
2007	1,244,930	
2008	1,240,324	-0.4%
2009	1,212,778	-2.2%
2010	1,221,754	0.7%
2011	1,226,174	0.4%
2012	1,237,386	0.9%
2013	1,256,540	1.5%
2014	1,284,024	**2.2%**
2015	1,287,245	**0.3%**
2016	1,310,008	**1.8%**
2017	1,326,212	**1.2%**
2018	1,343,242	**1.3%**
2019	1,357,620	**1.1%**
2020	1,375,938	**1.3%**
		5 yr CAGR
2025	1,453,153	***1.1%***

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	55.5%		70.5%	
AIC	4.59		4.21	
SIC	4.77		4.52	
MAPE	4.8%		3.8%	
Model F Test	27.7	0.0%	29.5	0.0%
Estimates Residual S.D.	10		8	
SSres	24,806		15,499	
Degrees of Freedom	265		251	
Breusch-Pegan F	2.3	0.8%	1.5	10.4%
Breusch-Pegan ChiSq	27.9	0.9%	22.0	10.8%
White's F	0.3	73.1%	0.2	85.9%
Breusch-Godfrey AIC F	9.1	0.0%	0.1	76.2%
Breusch-Godfrey AIC ChiSq	84.0	0.0%	4.8	2.8%
Breusch-Godfrey SIC F	32.9	0.0%	0.1	76.2%
Breusch-Godfrey SIC ChiSq	56.2	0.0%	4.8	2.8%
Durban-Watson	2.7		2.0	N/A
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	0.7	41.3%	5.1	2.5%
FIT^3 Ramsey's RESET F	2.2	11.3%	2.6	7.5%
FIT^4 Ramsey's RESET F	2.4	6.6%	2.2	9.2%
Out-of-Sample RMSE	10.0		10.2	
Out-of-Sample MAE	7.9		7.9	
Out-of-Sample MAPE	5.06%		5.10%	



Model Discussion

The AFR 2014 forecast of commercial use-per customer is a bit lower than last year's outlook. The graph shown above combines the output of the use-per-customer per day model with the outputs of the customer count model. The decrease in the total energy use forecast for the commercial class is due to a change in the customer count forecast and in the use-per-customer outlook. Employment in the Finance sector in the 13 county area and Employment in the Manufacturing sector for the 13 county area were found to be significant indicators of per-customer use.

Minnesota Power's econometric interpretation of the key drivers is as follows: For every 100 jobs added in the 13 county area Financial sector, monthly commercial use-per-customer should increase by about 11 KWh (0.0035 x 31 x 100). A 1% increase in the 13 county manufacturing sector employment should increase monthly commercial use-per-customer by about 8 KWh (0.26 x 31).

Weather's impact in shoulder months such as April or October was found to be insignificant and variables for these months were excluded from the model due to low P-value. This implies that, for the commercial class, there is a baseline of usage in these months that's largely unaffected by variations in weather. It's likely that weather does influence use in these months, but at an aggregated monthly level these impacts are indiscernible. Last year's model was very similar in its weather variable selection. These findings are consistent with last year's where shoulder month weather was also found to be insignificant

This year, commercial use-per-customer was modeled as KWh per customer whereas last year was modeled on a MWh per customer basis. This change has no material impact on the forecast. The change was made for consistency with residential energy sales which is also modeled as KWh per customer per day.

The AFR 2014 model is highly comparable to last year's in terms of statistical quality. R-Squared, in-sample forecast error (traditional MAPE), and out-sample (RMSE) are all fairly close (after accounting for the difference in the dependent variable). ARMA testing of the OLS model resolves heteroscedasticity and autocorrelation to confirm the significance of the coefficients.

Low VIF of each variable proves there is no significant multicollinearity and the Ramsey's RESET F tests suggest that the OLS model is properly specified; transformations would not improve the predictive ability of this model.

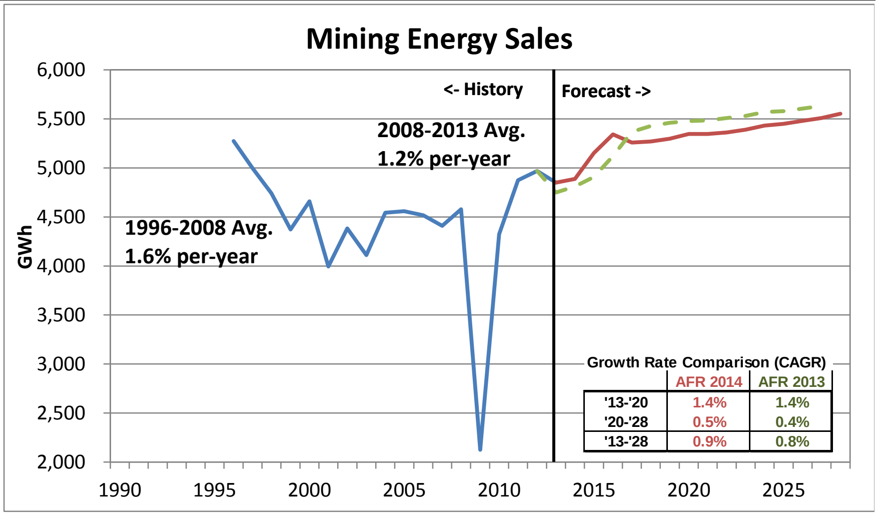
Mining and Metals Energy Use - Moderate Growth

Estimation Start/End:	1/1996 - 3/2014
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	(21,079.13)	0.00%		0.00%
Trend	(4.17)	0.00%	1.05	0.00%
IPI_Iron_LN	7,278	0.00%	49.53	0.27%

	OLS Model	
	MWh	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	4,851,094	-2.4%
2014	4,888,265	0.8%
2015	5,152,115	5.4%
2016	5,343,277	3.7%
2017	5,259,033	-1.6%
2018	5,269,835	0.2%
2019	5,298,345	0.5%
2020	5,346,458	0.9%
		5 yr CAGR
2025	5,450,764	*0.4%*

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	80.7%		90.4%	
AIC	13.54		12.84	
SIC	13.59		12.98	
MAPE	6.7%		4.2%	
Model F Test	457.9	0.0%	240.9	0.0%
Estimates Residual S.D.	866		600	
SSres	161,884,382		70,573,379	
Degrees of Freedom	216		196	
Breusch-Pegan F	35.0	0.0%	5.1	0.2%
Breusch-Pegan ChiSq	53.7	0.0%	14.5	0.2%
White's F	29.7	0.0%	7.7	0.1%
Breusch-Godfrey AIC F	58.5	0.0%	0.1	71.4%
Breusch-Godfrey AIC ChiSq	77.3	0.0%	0.8	36.9%
Breusch-Godfrey SIC F	58.5	0.0%	0.1	71.4%
Breusch-Godfrey SIC ChiSq	77.3	0.0%	0.8	36.9%
Durban-Watson	0.8		1.9	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	22.4	0.0%	-14.2	#NUM!
FIT^3 Ramsey's RESET F	18.0	0.0%	7.5	0.1%
FIT^4 Ramsey's RESET F	14.2	0.0%	5.4	0.1%
Out-of-Sample RMSE	976		735	
Out-of-Sample MAE	727		552	
Out-of-Sample MAPE	7.51%		5.44%	



Model Discussion

The outlook for Mining and Metals energy sales is a bit higher than last year's in the short-term and slightly lower in the long-term. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions. The underlying econometric forecasts are highly similar; the AFR 2014 forecast is just 0.4% higher (on average over the forecast timeframe) than AFR 2013's forecast. The change in assumptions for large customer load additions is the primary reason for the difference between this and last year's energy sales forecast.

The dependent variable being modeled differs from last year. AFR 2013's model utilized raw historical sales to Mining and Metals customers whereas the AFR 2014 is modeled on an adjusted Mining and Metals sales history which backs out recent customer load additions. This methodology is explained in the "Methodological Adjustments for the 2014 Forecast" section and specific adjustments made to the historical series are detailed in the "Data Revisions Since Previous AFR" section.

The AFR 2014 model differs from last year's in its limited use of explanatory variables. This year's model uses only the Industrial Production Index (IPI) for Iron and a trend variable, whereas last year's model incorporated some monthly binaries and a lagged dependent variable. Monthly binaries were found to be insignificant in this year's model; likely due to the exclusion of the lagged dependent variable and the use of an already seasonally-adjusted IPI series. The IPI Iron variable in the AFR 2014 model is in logged form so its econometric interpretation is as follows: for each 1% increase in the IPI for Iron, Minnesota Power's Mining and Metals customers should increase monthly use by about 2,256 (73 x 31).

The AFR 2014 model is highly comparable to last year's in terms of statistical quality. R-Squared, in-sample forecast error (traditional MAPE), and out-sample (RMSE) are all fairly close. ARMA testing of the OLS model resolves autocorrelation but could not conclusively eliminate heteroscedasticity. As a result, there is the potential that the P-values of the coefficients are bias. However, autocorrelation or heteroscedasticity cannot bias the coefficients, so the only question is whether the IPI for Iron is a significant predator of Mining and Metals customer energy use. All of this year's top mining and metals models utilized IPI for Iron and it has been in use by Minnesota Power to forecast customer use since 2009, so it's clear this variable is significant.

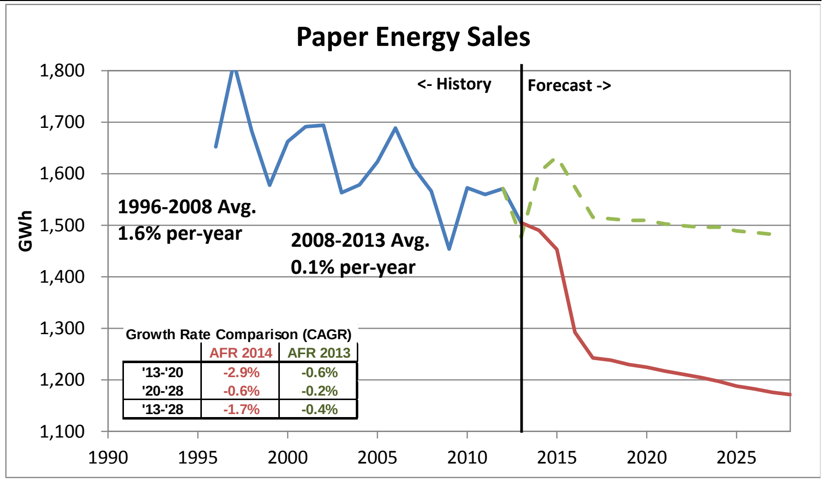
ARMA testing also suggested that the true P-value of the trend variable is 96%, which would be considered insignificant. However, the only reason this occurs in the ARMA model is because AR and MA terms have adopted the role of trend variable. Therefore, this variable is not dropped from the model due to a high ARMA tested P-value.

Paper and Wood Products Energy Use - Moderate Growth

Estimation Start/End:	1/1996 - 3/2014
Unit Modeled/Forecast:	Natural Log of Monthly Per-Day Use (MWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	5.75	0.00%		0.00%
Binary_Mar	0.05	0.08%	1.15	0.11%
Binary_Apr	0.04	0.77%	1.14	0.64%
Binary_Jun	0.07	0.00%	1.14	0.00%
Binary_Jul	0.04	0.30%	1.15	0.19%
Binary_Aug	0.09	0.00%	1.15	0.00%
Binary_Sep	0.09	0.00%	1.14	0.00%
Binary_Oct	0.09	0.00%	1.14	0.00%
Binary_Nov	0.04	1.33%	1.14	0.01%
IPI_Paper_LN	0.55	0.00%	1.29	0.00%
13co_ProductPerCap_LN_diff_lead_12	12.35	0.00%	1.27	0.05%
MSA_PerCapita_TPI_LN_diff_lead_3	3.95	0.04%	1.05	8.70%

	OLS Model	
	MWh	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	1,505,113	-4.2%
2014	1,492,657	**-0.8%**
2015	1,450,643	**-2.8%**
2016	1,287,813	**-11.2%**
2017	1,243,115	**-3.5%**
2018	1,237,921	**-0.4%**
2019	1,229,691	**-0.7%**
2020	1,224,624	**-0.4%**
2025	1,187,916	***5 yr CAGR - 0.6%***



	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	43.2%		58.1%	
AIC	-5.79		-6.09	
SIC	-5.61		-5.89	
MAPE	0.5%		0.4%	
Model F Test	16.1	0.0%	26.1	0.0%
Estimates Residual S.D.	0		0	
SSres	1		0	
Degrees of Freedom	207		205	
Breusch-Pegan F	1.7	7.3%	1.1	33.2%
Breusch-Pegan ChiSq	18.2	7.6%	12.5	32.7%
White's F	1.1	33.6%	0.6	54.5%
Breusch-Godfrey AIC F	70.9	0.0%	0.5	46.5%
Breusch-Godfrey AIC ChiSq	56.0	0.0%	2.7	9.9%
Breusch-Godfrey SIC F	70.9	0.0%	0.5	46.5%
Breusch-Godfrey SIC ChiSq	56.0	0.0%	2.7	9.9%
Durban-Watson	1.0	BAD	2.1	N/A
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	0.0	93.4%	2.0	15.7%
FIT^3 Ramsey's RESET F	1.0	37.6%	1.1	32.6%
FIT^4 Ramsey's RESET F	0.6	58.7%	0.7	52.4%
Out-of-Sample RMSE	0		0	
Out-of-Sample MAE	0		0	
Out-of-Sample MAPE	0.57%		0.57%	

Model Discussion

The AFR 2014 outlook for Paper and Wood Products energy sales is lower than last year's. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions. The underlying econometric forecast reflects a weakening of the domestic paper industry as a whole; by 2025, the AFR 2014's econometric forecast is about 3% lower than last year's. Load addition/ loss assumptions have also been updated to reflect expected changes in customer operation plans. These updates reduce expected sales in the forecast timeframe.

The dependent variable being modeled differs from last year. AFR 2013's model utilized raw historical sales to Paper and Wood customers whereas the AFR 2014 is modeled on an adjusted history which backs out the historical energy sales of customers that were recently lost. This methodology is explained in the "Methodological Adjustments for the 2014 Forecast" section and specific adjustments made to the historical series are detailed in the "Data Revisions Since Previous AFR" section.

The AFR 2014 model for Paper and Wood differs from last year's in its inclusion of regional economic variables. In past forecast models for this sector, Minnesota Power utilized the Industrial Production Index for Paper as the sole economic driver of energy sales to this customer class. The comprehensive specification search process and internally developed software enabled Minnesota Power to identify regional economic indicators that added predictive value to the forecast model.

The AFR 2014 model uses the Industrial Production Index (IPI) for Paper, Product-per-Capita (Gross Regional Product divided by Population) for the 13 county area, and Per-capita Total Personal Income for the 13 county area. Minnesota Power's econometric interpretation of the key drivers is as follows: A 1% increase in the Paper IPI should increase monthly Paper and Wood customer use by about 0.5% (about 600 MWh). A 1% increase in the rate of change in Regional Product-per-Capita and Total Personal Income per-Capita would cause a 13% and 4% (respectively) increase in monthly Paper customer usage.

This year's model utilizes a logged form of the dependent variable so comparison of statistical quality should be done using forecast errors instead of SIC or R-squared. Review of the in-sample and out-sample MAPE show this model is a vast improvement over last year in terms of forecast accuracy: in-sample MAPE decreased to 0.5% from 3.7% in last year's model, and the out-sample MAPE decreased to 0.57% from 4.3% in last year's model.

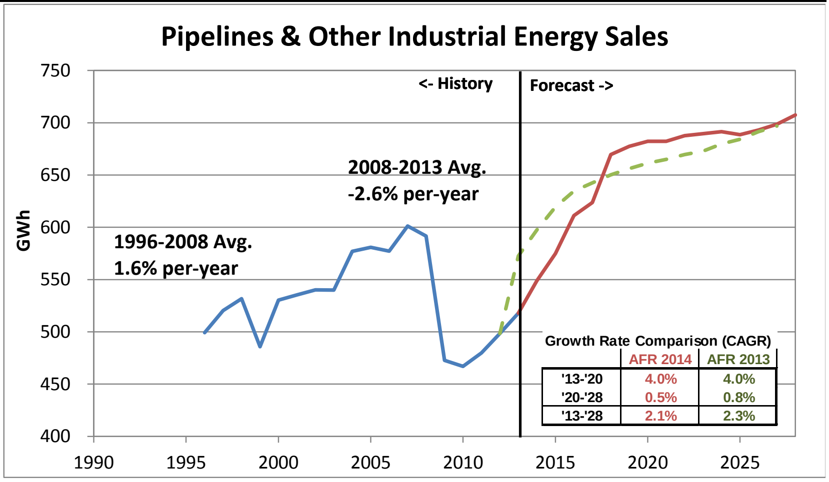
Pipelines and Other Industrial Energy Use - Moderate Growth

Estimation Start/End:	1/1996 - 3/2014
Unit Modeled/Forecast:	Natural Log of Monthly Per-Day Use (MWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	5.01	0.00%		0.00%
Trend	0.0012	0.00%	2.84	6.67%
13co_Trd_Trns_Util_lag_5	0.000045	0.00%	2.84	1.15%

	OLS Model	
	MWh	Y/Y Growth
2007	601,155	
2008	591,697	-1.6%
2009	472,749	-20.1%
2010	467,065	-1.2%
2011	479,798	2.7%
2012	498,474	3.9%
2013	517,786	3.9%
2014	548,827	6.0%
2015	574,883	4.7%
2016	611,277	6.3%
2017	623,627	2.0%
2018	669,531	7.4%
2019	677,462	1.2%
2020	682,225	0.7%
		5 yr CAGR
2025	688,571	*0.2%*

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	31.1%		53.0%	
AIC	-4.92		-5.27	
SIC	-4.88		-5.16	
MAPE	0.9%		0.7%	
Model F Test	50.2	0.0%	39.2	0.0%
Estimates Residual S.D.	0		0	
SSres	2		1	
Degrees of Freedom	216		197	
Breusch-Pegan F	2.1	12.0%	0.5	63.4%
Breusch-Pegan ChiSq	4.3	11.9%	0.9	63.1%
White's F	1.0	36.5%	1.5	23.5%
Breusch-Godfrey AIC F	20.2	0.0%	0.0	92.9%
Breusch-Godfrey AIC ChiSq	60.8	0.0%	0.7	40.5%
Breusch-Godfrey SIC F	35.8	0.0%	0.0	92.9%
Breusch-Godfrey SIC ChiSq	55.3	0.0%	0.7	40.5%
Durban-Watson	1.1		2.0	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	18.5	0.0%	0.9	33.3%
FIT^3 Ramsey's RESET F	10.9	0.0%	1.1	34.9%
FIT^4 Ramsey's RESET F	7.3	0.0%	1.1	36.4%
Out-of-Sample RMSE	0		0	
Out-of-Sample MAE	0		0	
Out-of-Sample MAPE	1.08%		0.96%	



Model Discussion

The outlook for Pipelines and Other Industrial energy sales is very comparable to last year's. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions. The underlying econometric forecast is fairly similar to last year's forecast, and differences are due to utilizing an adjusted historical sales series in modeling this year.

The dependent variable being modeled differs from the variable modeled in last year's AFR. AFR 2013's model utilized raw historical sales to Pipelines and Other Industrial Customers whereas the AFR 2014 is modeled on an adjusted history which backs out the historical energy sales of recent customer load additions and any customers that were lost in the early historical timeframe. This methodology is explained in the "Methodological Adjustments for the 2014 Forecast" section and specific adjustments made to the historical series are detailed in the "Data Revisions Since Previous AFR" section.

Load addition/ loss assumptions have been updated to reflect expected changes in customer operation plans. These updated assumptions lower the forecast in the 2014-2017 timeframe, but increase the forecast after 2017.

The AFR 2014 econometric model for Pipelines and Other Industrial is very similar to last year's model. Both utilized Employment in Trade, Transportation, and Utilities as the primary economic variable. Last year's model also utilized area population, but the 2014 AFR analysis indicated that this variable added little value to the model and was excluded. The forecast for employment in Trade, Transportation, and Utilities hasn't changed substantively since last year, and this explains the similarity in the econometric forecasts between this year and last.

Minnesota Power's econometric interpretation of the key drivers is as follows: For every 100 jobs added to the Trade, Transportation, and Utilities sector in the 13 county area, the energy sales to this customer class should increase by about 0.5%.

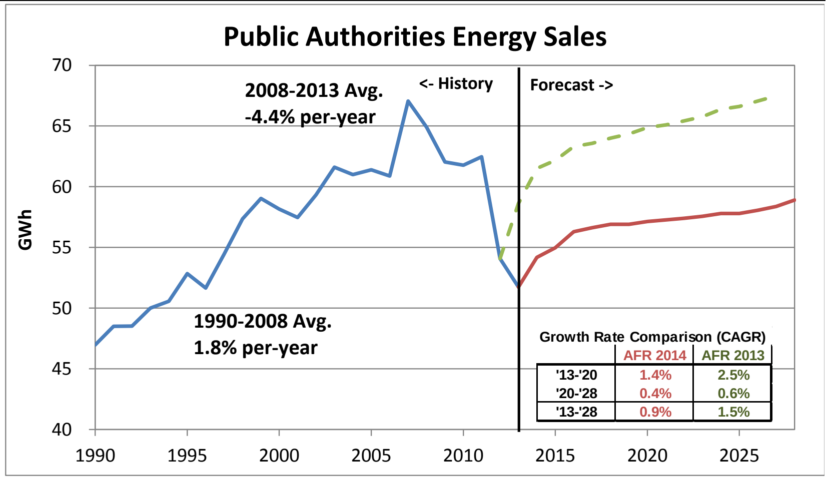
This year's model utilizes a logged form of the dependent variable so comparison of statistical quality should be done using forecast errors instead of SIC or R-squared. The in-sample and out-sample MAPE show this model is a vast improvement over last year in terms of forecast accuracy: in-sample MAPE decreased to 0.9% from 7.5% in last year's model, and the out-sample MAPE decreased to 1.1% from 14.1% in last year's model.

Tests of the OLS model show it has no significant heteroscedasticity, but suggest autocorrelation could potentially bias the P-values. ARMA testing was able to conclusively solve for autocorrelation and confirm the significance of the predictor variables.

Public Authorities Energy Use - Moderate Growth

Estimation Start/End:	7/1990 - 3/2014
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	(81.20)	4.91%		0.77%
Trend	0.19	0.00%	1.33	0.00%
Binary_04_2012-2030	(35.73)	0.00%	1.53	0.00%
Binary_Jan	41.93	0.55%	16.15	0.90%
Binary_Mar	47.34	0.18%	16.14	0.19%
Binary_May	38.02	1.18%	15.57	1.56%
Binary_Jun	45.67	0.26%	15.59	0.33%
Binary_Jul	58.03	0.01%	16.16	0.01%
Binary_Aug	54.32	0.04%	16.16	0.03%
Binary_Sep	50.85	0.08%	16.17	0.08%
Binary_Oct	45.68	0.25%	16.16	0.40%
HDD_Feb	0.97	0.14%	15.95	0.12%
HDD_Apr	1.58	0.71%	15.37	0.97%
HDD_Nov	1.23	0.36%	15.92	0.47%
HDD_Dec	1.12	0.03%	15.99	0.02%
MSA_Service_lead_5	2.04	0.00%	1.18	0.00%
13co_Con_Rsrcs_Mine_diff_lag_5	0.011	0.26%	1.06	2.84%



	OLS Model	
	MWh	Y/Y Growth
2007	67,056	
2008	64,912	-3.2%
2009	62,036	-4.4%
2010	61,768	-0.4%
2011	62,458	1.1%
2012	54,074	-13.4%
2013	51,736	-4.3%
2014	54,172	**4.7%**
2015	54,967	**1.5%**
2016	56,293	**2.4%**
2017	56,630	**0.6%**
2018	56,906	**0.5%**
2019	56,903	**0.0%**
2020	57,131	**0.4%**
		5 yr CAGR
2025	57,797	***0.2%***

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	45.8%		50.7%	
AIC	5.78		5.70	
SIC	6.00		5.97	
MAPE	8.6%		8.3%	
Model F Test	16.0	0.0%	15.2	0.0%
Estimates Residual S.D.	17		17	
SSres	81,807		71,010	
Degrees of Freedom	268		256	
Breusch-Pegan F	0.5	92.8%	0.7	82.1%
Breusch-Pegan ChiSq	8.8	92.1%	11.0	81.0%
White's F	2.5	8.8%	0.7	50.3%
Breusch-Godfrey AIC F	11.3	0.0%	0.1	81.2%
Breusch-Godfrey AIC ChiSq	32.4	0.0%	0.5	49.3%
Breusch-Godfrey SIC F	24.2	0.0%	0.1	81.2%
Breusch-Godfrey SIC ChiSq	23.7	0.0%	0.5	49.3%
Durban-Watson	2.6		2.0	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	6.6	1.1%	4.2	4.0%
FIT^3 Ramsey's RESET F	3.3	3.9%	3.1	4.8%
FIT^4 Ramsey's RESET F	2.2	8.8%	2.1	10.6%
Out-of-Sample RMSE	18		18	
Out-of-Sample MAE	14		14	
Out-of-Sample MAPE	9.17%		9.21%	

Model Discussion

The outlook for Public Authorities is down compared to last year's forecast. This is primarily due to the 2012 to 2013 reduction, and the last historical point being notably lower.

Key drivers of this year's per-day use model are Employment in Other Services sector (Duluth MSA) and Employment in the Construction, Natural Resources, and Mining sector (13 county). Last year's model used Wage Distribution in the 13 county area as the sole economic variable. Minnesota Power's econometric interpretation of the key drivers is as follows: For every 1,000 job increase in Other Services, monthly public authority usage should increase by 63 MWh (2.04 x 31). As the month-to-month change in Construction, Natural Resources, and Mining sector employment increases by 100, monthly usage will increase by 34 MWh (0.011 x 31).

This year's model and last year's model both use a binary variable to indicate the step change that occurred in 2012. This binary variable denotes municipal pumping customers switching to a general service (commercial) rate. The impact to commercial energy sales in insignificant because of the class's size, but this does noticeably affect sales to Public Authorities and must be accounted for.

Weather variables were found to be significant in only four months of the year: February, April, November, and December. This was only after excluding a binary variable for the corresponding months. If the binaries were not excluded, the model would have suggested that weather is insignificant in all months. Minnesota Power's policy regarding weather is to drop binary variables in favor of maintaining weather a predictor because it allows for accurate after-the-fact weather normalization later by the company.

Although this year's model is structurally different and utilizes different weather variables, the statistical quality is highly comparable to last year's model. SIC, R-Squared, in-sample forecast error (traditional MAPE), and out-sample (RMSE) are all fairly close.

The Variance Inflation Factors (VIF) of the binaries and weather variables in this model are fairly high. This phenomenon was noticed in last year's Public Authorities energy sales model as well. On its own, any of these variables are not correlated with any other specific variable, but it does appear that a single variable is highly correlated with all other variables in combination (which is what VIF measures).

Although the high VIF's would indicate some multicollinearity is present, Minnesota Power considers this the optimal model for this dependent variable. All other top models also had high VIFs; the only way to avoid the high VIF's was to exclude the binaries and weather variables. Excluding these variables degraded predictive power and statistical quality, and it's clear that each variable is significant, even after solving for autocorrelation and heteroscedasticity. Therefore, Minnesota Power did not exclude these binaries or weather variables despite the high VIF's.

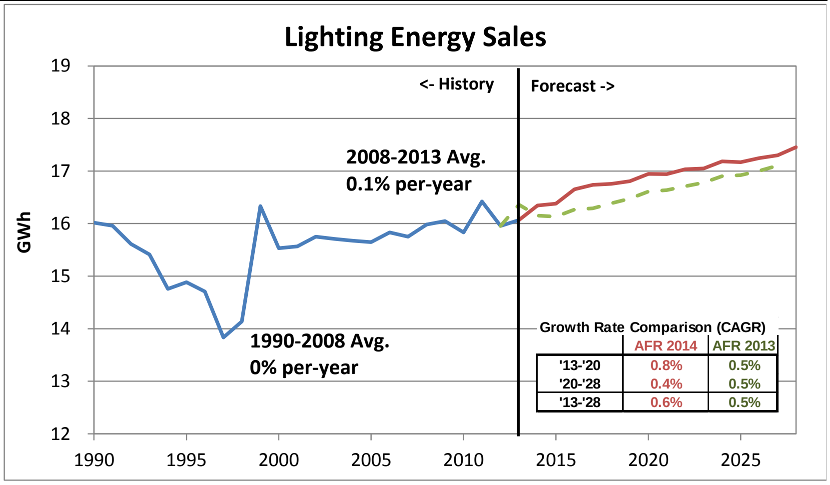
Street Lighting Energy Use - Moderate Growth

Estimation Start/End:	2/1991 - 3/2014
Unit Modeled/Forecast:	Natural Log of Monthly Per-Day Use (MWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	3.93	0.00%		0.00%
Binary_Jan	0.03	6.99%	1.83	4.19%
Binary_Feb	(0.05)	0.45%	1.87	1.14%
Binary_Mar	(0.21)	0.00%	1.87	0.00%
Binary_Apr	(0.36)	0.00%	1.84	0.00%
Binary_May	(0.50)	0.00%	1.84	0.00%
Binary_Jun	(0.62)	0.00%	1.84	0.00%
Binary_Jul	(0.59)	0.00%	1.84	0.00%
Binary_Aug	(0.46)	0.00%	1.83	0.00%
Binary_Sep	(0.29)	0.00%	1.84	0.00%
Binary_Oct	(0.17)	0.00%	1.84	0.00%
Binary_Nov	(0.06)	0.21%	1.84	0.10%
Trend	0.00	0.00%	1.19	0.00%
MSA_Pop_diff_lag_12	0.16	0.70%	1.12	9.05%
MSA_RetailTrd_diff_lag_9	0.22	0.35%	1.12	1.32%

	OLS Model	
	MWh	Y/Y Growth
2007	15,752	
2008	15,983	1.5%
2009	16,049	0.4%
2010	15,833	-1.3%
2011	16,420	3.7%
2012	15,955	-2.8%
2013	16,066	0.7%
2014	16,346	**1.7%**
2015	16,380	**0.2%**
2016	16,654	**1.7%**
2017	16,738	**0.5%**
2018	16,755	**0.1%**
2019	16,807	**0.3%**
2020	16,944	**0.8%**
		5 yr CAGR
2025	17,167	*0.3%*

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	92.2%		93.0%	
AIC	-5.42		-5.52	
SIC	-5.22		-5.30	
MAPE	1.2%		1.1%	
Model F Test	234.2	0.0%	230.8	0.0%
Estimates Residual S.D.	0		0	
SSres	1		1	
Degrees of Freedom	263		261	
Breusch-Pegan F	1.0	41.2%	1.3	23.4%
Breusch-Pegan ChiSq	14.6	40.6%	17.4	23.4%
White's F	1.3	27.7%	2.6	7.8%
Breusch-Godfrey AIC F	4.5	0.0%	2.8	0.0%
Breusch-Godfrey AIC ChiSq	64.6	0.0%	43.6	0.0%
Breusch-Godfrey SIC F	27.4	0.0%	0.0	87.3%
Breusch-Godfrey SIC ChiSq	26.3	0.0%	0.3	59.4%
Durban-Watson	1.3		1.9	
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	0.4	52.4%	-0.7	#NUM!
FIT^3 Ramsey's RESET F	0.8	45.8%	0.3	72.2%
FIT^4 Ramsey's RESET F	0.6	64.6%	0.3	86.1%
Out-of-Sample RMSE	0.1		0.1	
Out-of-Sample MAE	0.0		0.0	
Out-of-Sample MAPE	1.34%		1.34%	



Model Discussion

The outlook for energy use by Street Lighting customer is fairly comparable to last year's forecast, but the model utilizes different economic variables as drivers. Key drivers of this year's per-day use model are Population (Duluth MSA) and Employment in the Retail Trade sector (Duluth MSA). Last year's model used Total Personal Income in the 13 county area as the sole economic variable.

Minnesota Power's econometric interpretation of the key drivers is as follows: as the month-to-month change in population increases by 100, street lighting energy sales should increase by 1.6%. As the month-to-month change in retail sector employment increases by 100, street lighting energy sales should increase by 2.2%. Differenced variable appeared to be more indicative of lighting use than any other transformation, suggesting that increases in lighting are driven more by the rate of increase in population than the level of the population.

This year's model and last year's model both use binary variables to indicate the seasonal variation that's left unexplained by economic indicators. This year's model also utilizes a trend variable to account for historical trending.

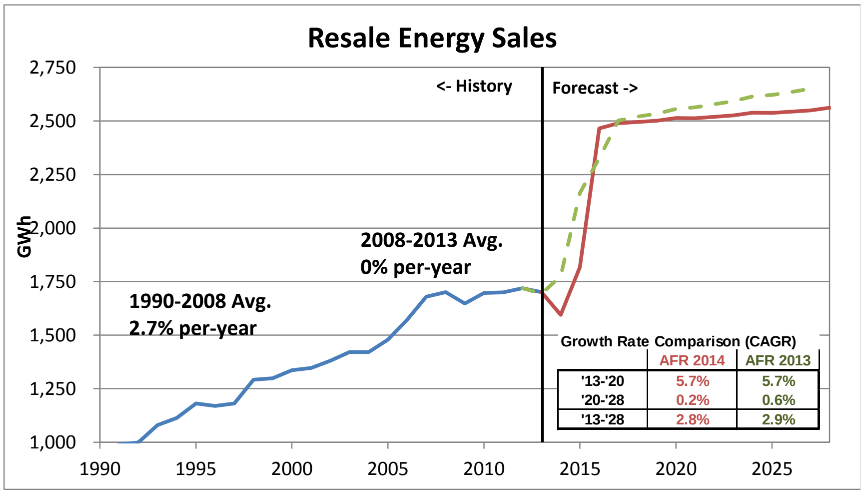
The AFR 2014 model uses a logged form of the dependent variable, so comparing the statistical quality of this year's and last year's model, which modeled the dependent variable in levels, is difficult. Some metrics such as SIC and AIC or out-sample RMSE cannot be compared. However, in sample and out-sample MAPE show this model is a vast improvement over last year in terms of forecast accuracy: in-sample MAPE decreased to 1.2% from 4% in last year's model, and the out-sample MAPE decreased to 1.3% from 4.5% in last year's model.

The OLS model passed all tests for Heteroskedasticity. ARMA testing of the OLS model solved for autocorrelation to confirm the significance (P-values) of the economic variables' coefficients. Ramsey's RESET F tests prove the current OLS specifications were sufficient; no transformations were likely to improve the model's statistical measures. The very low Variance Inflation Factors (VIF) of each variable proves there is no significant multicollinearity.

Resale Energy Use - Moderate Growth

Estimation Start/End:	1/1996 - 3/2014
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	3,736.95	0.00%		0.00%
Trend	1.30	0.06%	13.96	0.33%
Binary_Mar	386.28	0.00%	3.09	0.00%
Binary_May	(274.31)	0.00%	4.57	0.00%
Binary_Jun	204.00	1.21%	12.33	10.83%
Binary_Nov	(472.29)	0.73%	57.81	8.91%
Binary_1996-06_2006	(1,504.00)	0.00%	62.41	0.00%
Trend_1996-06_2006	3.93	0.00%	25.42	0.00%
Mar_1996-06_2006	143.01	0.44%	2.97	17.03%
Apr_1996-06_2006	365.50	0.00%	2.18	0.00%
May_1996-06_2006	555.09	0.00%	3.59	0.00%
Jun_1996-06_2006	411.43	0.00%	3.22	0.00%
Jul_1996-06_2006	504.89	0.00%	1.87	0.00%
Aug_1996-06_2006	416.84	0.00%	2.10	0.00%
Sep_1996-06_2006	407.68	0.00%	1.90	0.00%
Oct_1996-06_2006	343.94	0.00%	1.90	0.00%
Nov_1996-06_2006	232.11	0.00%	2.86	0.00%
HDD_Jan	13.74	0.00%	1.93	0.00%
HDD_Feb	14.07	0.00%	2.00	0.00%
CDD_CAC_May	1,538.33	0.02%	1.64	0.17%
HDD_Jun	(30.16)	2.74%	11.35	7.70%
CDD_CAC_Jul	191.32	0.00%	1.29	0.00%
CDD_Aug	81.14	0.00%	1.68	0.00%
HDD_Nov	21.24	0.00%	58.66	0.35%
HDD_Dec	14.05	0.00%	1.80	0.00%
MSA_Unempl_Rate_diff_lag_9	(177.69)	0.23%	1.10	1.95%
MSA_HousStart_LN_diff_lag_4	327.04	0.00%	1.61	0.77%



	OLS Model	
	MWh	Y/Y Growth
2007	1,679,267	
2008	1,701,057	1.3%
2009	1,647,759	-3.1%
2010	1,696,511	3.0%
2011	1,699,644	0.2%
2012	1,718,819	1.1%
2013	1,700,993	-1.0%
2014	1,595,159	**-6.2%**
2015	1,817,456	**13.9%**
2016	2,465,941	**35.7%**
2017	2,489,856	**1.0%**
2018	2,495,882	**0.2%**
2019	2,501,320	**0.2%**
2020	2,513,485	**6.7%**
		5 yr CAGR
2025	2,537,880	*0.2%*

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	96.8%		98.9%	
AIC	9.18		8.13	
SIC	9.60		8.62	
MAPE	1.8%		1.1%	
Model F Test	257.0	0.0%	624.6	0.0%
Estimates Residual S.D.	93		55	
SSres	1,667,166		523,890	
Degrees of Freedom	192		176	
Breusch-Pegan F	1.9	0.7%	1.3	18.7%
Breusch-Pegan ChiSq	45.1	1.1%	32.0	19.3%
White's F	4.0	2.0%	0.1	86.6%
Breusch-Godfrey AIC F	5.8	0.4%	0.0	95.7%
Breusch-Godfrey AIC ChiSq	12.7	0.2%	43.0	0.0%
Breusch-Godfrey SIC F	10.0	0.2%	0.0	95.7%
Breusch-Godfrey SIC ChiSq	11.0	0.1%	43.0	0.0%
Durban-Watson	1.5		2.0	N/A
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	4.9	2.9%	41.9	0.0%
FIT^3 Ramsey's RESET F	2.5	8.6%	28.5	0.0%
FIT^4 Ramsey's RESET F	1.9	13.1%	18.9	0.0%
Out-of-Sample RMSE	108		109	
Out-of-Sample MAE	87		89	
Out-of-Sample MAPE	2.29%		2.30%	

Model Discussion

The outlook for the Sales for Resale customer class is a bit lower than last year's. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions/reductions. Load addition assumptions have changed slightly since last year, but the underlying econometric forecasts is fairly similar after accounting for difference in modeling approach.

As described in the Changes to Database section, Minnesota Power implemented a new modeling methodology to more accurately account for recent changes in the customer class composition. Historical sales to Dahlberg were removed from the historical Resale energy sales series prior to regression since Dahlberg's contract with Minnesota Power ended on December 31st 2013. The resale customer class will be composed of MP's 16 Minnesota municipal customers and Superior Water Light and Power (SWLP) in forecast timeframe, so this is what Minnesota Power modeled and projected. This methodology is explained in the "Methodological Adjustments for the 2014 Forecast" section and specific adjustments made to the historical series are detailed in the "Data Revisions Since Previous AFR" section.

Minnesota Power's econometric interpretation of the key drivers is as follows: as the month-to-month change in the unemployment rate decreases by 0.1, monthly sales for resale should increase by 550 MWh (17.7 x 31). As the month-to-month percent change in housing starts increases by 1%, street monthly sales for resale should increase by about 100 MWh (3.25 x 31). Differenced variable appeared to be more indicative of lighting use than any other transformation, suggesting that increases in lighting are driven more by the rate of increase in population than the level of the population.

The resale model differs from last year's model in its structure and economic drivers. This year's model utilizes the Duluth MSA Unemployment Rate and annualized Housing Starts in the Duluth MSA, whereas last year's model used Employment in Financial Activities (13 county) as the sole economic driver.

Both the AFR 2014 and AFR 2013 models used monthly binaries and trend variables. Both models also account for a structural break in 2006 utilizing binary variables. Last year's model used a full set of alternate binaries to indicate the step-change, whereas this year's model leverages a single binary to serve as the shifted constant and adds to this any significant monthly binaries. This year's model also includes an additional trend variable to distinguish between growth rates in the pre and post structural break timeframe.

The model statistics show the AFR 2014 Resale model is an improvement over last year's. This year's model reduced out-sample RMSE forecast error to 2.29% (from 4.5% in last year's model), reduced SIC, and reduced in-sample MAPE forecast error to 1.8% from 4% in last year's model. ARMA testing of the OLS model was able to resolve heteroscedasticity and autocorrelation to confirm the P-values of each variables coefficient.

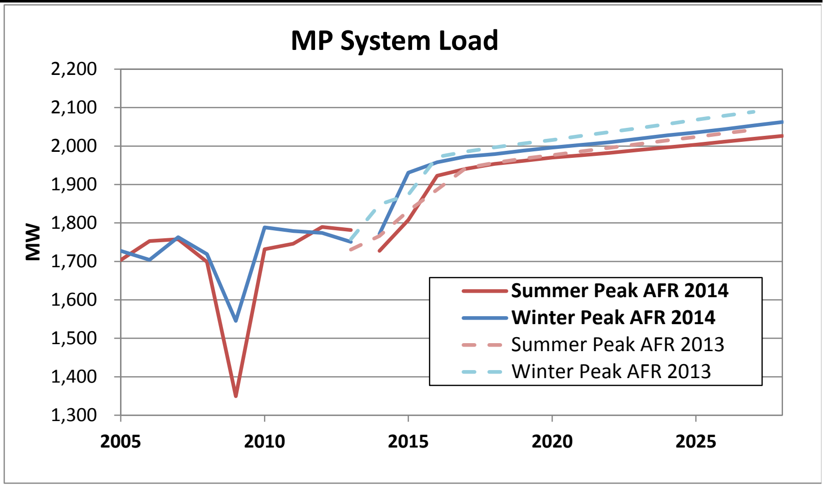
Peak Demand - Moderate Growth

Estimation Start/End:	6/1999 - 3/2014
Unit Modeled/Forecast:	Monthly Peak Demand

	OLS Model			ARMA test
Variable	Coefficient	P-Value	VIF	P-Value
CONST	337.22	0.00%		0.00%
Trend	0.34	0.00%	1.45	0.01%
Weather-normal_MWh-perday	0.04	0.00%	1.96	0.00%
Binary-LP_Coincident	(38.06)	3.05%	1.81	2.92%
Binary-Aug_1999	65.07	6.19%	1.06	4.73%
Binary-Sep_1999	102.55	0.48%	1.13	0.29%
Binary-Nov_1999	97.69	0.60%	1.08	1.53%
Binary-Apr_2000	(87.04)	1.46%	1.10	1.20%
Binary-Oct_2001	(65.13)	7.56%	1.17	21.39%
Binary-Sep_2001	(81.09)	1.84%	1.02	12.67%
Binary-Sep_2002	71.12	3.80%	1.02	0.92%
Binary-Nov_2008	129.04	0.02%	1.03	0.02%
Binary-Dec_2008	149.55	0.00%	1.05	0.00%
Temp_Low-Less_N30	(1.69)	0.00%	1.07	0.00%
Temp_Low-N30_N20	(1.83)	0.00%	1.14	0.00%
Temp_Low-N20_N10	(2.35)	0.00%	1.16	0.00%
Temp_Low-N10_Zero	(1.40)	1.27%	1.26	1.13%
Temp_Low-Zero_20	(1.41)	3.24%	1.06	4.85%
Temp_Avg-T20_30	(1.46)	0.02%	1.38	0.04%
Temp_Avg-T30_40	(1.74)	0.07%	1.08	0.23%
Temp_Avg-T40_50	(1.47)	0.00%	1.25	0.00%
Temp_High-T50_60	(0.77)	0.22%	1.26	0.25%
Temp_High-T70_80	0.20	3.12%	1.49	0.94%
Temp_High-T80_90	0.97	0.00%	1.47	0.00%
Binary-SummerPeak	30.83	0.70%	1.55	2.91%

	Peak Demand (MW)			
	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	1,732	28.3%	1,789	15.7%
2011	1,746	0.8%	1,779	-0.5%
2012	1,790	2.5%	1,774	-0.3%
2013	1,782	-0.5%	1,751	-1.3%
2014	1,727	**-3.0%**	1,772	**1.2%**
2015	1,807	**4.6%**	1,931	**9.0%**
2016	1,923	**6.4%**	1,958	**1.4%**
2017	1,941	**0.9%**	1,973	**0.8%**
2018	1,954	**0.7%**	1,979	**0.3%**
2019	1,962	**0.4%**	1,988	**0.5%**
2020	1,970	**0.4%**	1,996	**0.4%**
		5 yr CAGR		*5 yr CAGR*
2025	2,004	***0.3%***	**2,035**	***0.4%***

	OLS Model		ARMA Test	
Model Statistics	Magnitude	P-Value	Magnitude	P-Value
Adjusted R^2	90.4%		91.2%	
AIC	7.16		7.08	
SIC	7.60		7.56	
MAPE	1.7%		1.7%	
Model F Test	70.5	0.0%	71.3	0.0%
Estimates Residual S.D.	34		32	
SSres	172,477		155,002	
Degrees of Freedom	153		150	
Breusch-Pegan F	1.0	45.9%	0.6	91.4%
Breusch-Pegan ChiSq	24.3	44.4%	15.8	89.5%
White's F	1.2	29.8%	0.4	70.4%
Breusch-Godfrey AIC F	11.2	0.1%	0.0	87.7%
Breusch-Godfrey AIC ChiSq	12.2	0.0%	3.2	7.4%
Breusch-Godfrey SIC F	11.2	0.1%	0.0	87.7%
Breusch-Godfrey SIC ChiSq	12.2	0.0%	3.2	7.4%
Durban-Watson	1.5	BAD	2.0	N/A
Durban-H	#NA	N/A	#NA	N/A
FIT^2 Ramsey's RESET F	0.6	45.9%	-2.3	#NUM!
FIT^3 Ramsey's RESET F	0.7	48.7%	1.6	20.5%
FIT^4 Ramsey's RESET F	1.9	13.9%	1.1	35.6%
Out-of-Sample RMSE	42		42	
Out-of-Sample MAE	32		32	
Out-of-Sample MAPE	2.30%		2.31%	



Model Discussion

The long-run outlook for Minnesota Power's system peak is a bit lower than last year's due to a decline in the overall energy sales outlook. The short-term (2014-2015) peak demand outlook is noticeably lower due to differences in assumptions for large customer load additions/reductions, but is slightly higher than last year's for a short time in 2016; this is also due to differences in assumptions for large customer load additions/reductions.

Minnesota Power implemented a new modeling methodology to more accurately account for recent changes in the customer class composition. Historical demand was adjusted down by an average of 30 MW over the historical timeframe. This methodology is explained in the "Methodological Adjustments for the 2014 Forecast" section and specific adjustments made to the historical series are detailed in the "Data Revisions Since Previous AFR" section.

Two types of binary variables account for anomalous industrial customer behavior. The "Binary-LP_Coincident" variable denotes a historical peak when a large industrial customer was not operating at the time of the peak. The "Binary-month_year" variables denote months where the model would have realized sizable errors that could have biased the coefficients of other predictor variables.

The binary variable ("Binary-SummerPeak") notes historical summer peaks to avoid understating summer peak demand in the forecast timeframe.

Temperature variables play an important role in both this and last year's model though the definitions and structure of these variables has been improved; this is noted in the "Methodological Adjustments for the 2014 Forecast" section.

This year's model utilizes a different dependent variable than last year, so comparison of statistical quality should be done using forecast errors instead of SIC or R-squared. This year's model has an out-sample MAPE of 2.3% (compared to 2.1% in last year's model) and the in-sample increased to 1.7% from 1.3% in last year's model. The OLS model shows no signs of heteroscedasticity.

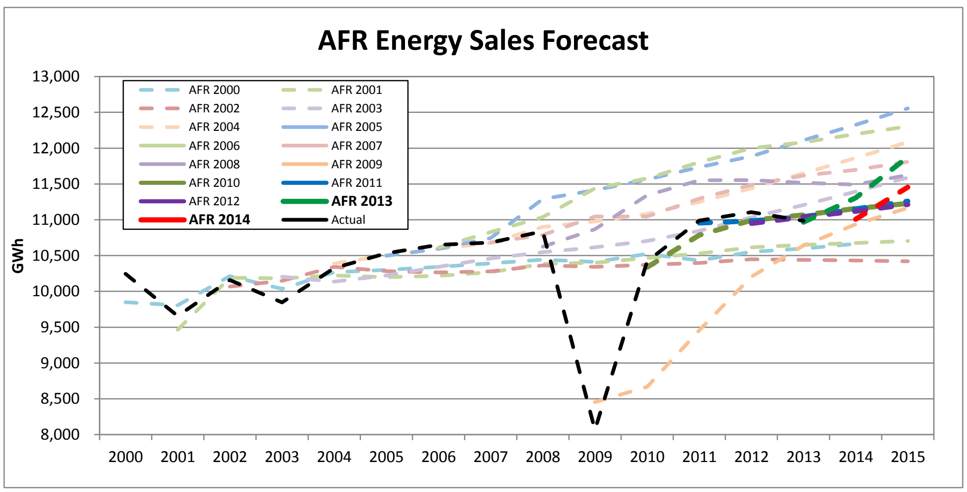
ARMA testing of the OLS model was able to resolve autocorrelation to confirm the P-values of each variable's coefficient with the exception of two "Binary-month_year" variables which only achieved an 80% and 88% level of significance. Each of these binary variables denotes a single month in the early forecast timeframe containing erratic load behavior and their exclusion from the model could bias coefficients of the temperature variables. Therefore, the decision was made to let them remain in the OLS model.

F. Confidence in Forecast & Historical Accuracy

Over the longer term, the IHS Global Insight 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. Figures 12-14 show Minnesota Power's past AFR forecast accuracy for aggregate energy use, Summer Peak, and Winter 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 -0.2 percent is the difference between the forecast produced in 2013 (AFR 2013) and the 2013 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 2012 (formulated in 2012) forecast of 2013 was 0.5 percent (54 GWh) above the actual.

Figure 12: AFR Energy Sales Forecast Accuracy

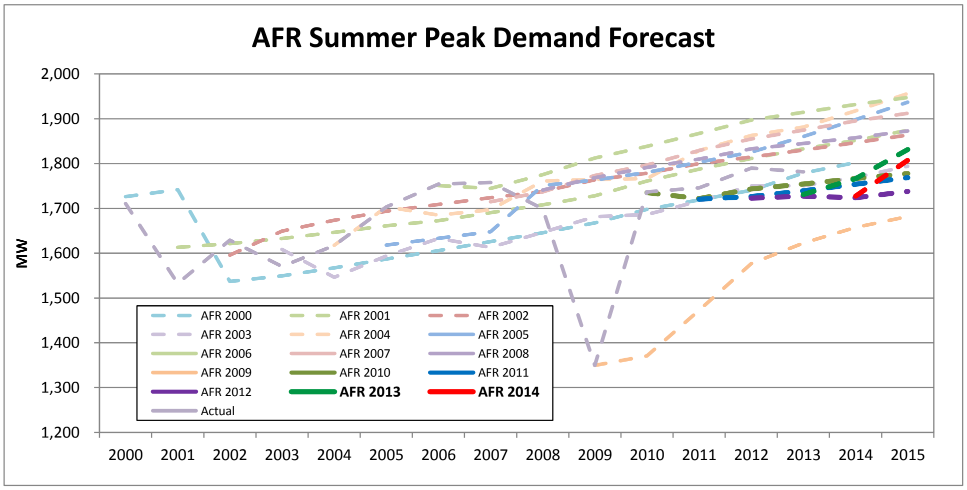


Total Energy Sales Forecast Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Average Error of AFR	Avg. Error Year-Ahead
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%	-3.5%	0.3%	1.5%
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%	-3.1%	0.2%	0.3%
AFR 2002			**-0.9%**	***3.1%***	0.2%	-2.4%	-3.6%	**-3.8%**	-4.4%	28.2%	-0.4%	-5.4%	-5.9%	-5.0%	0.0%	3.1%
AFR 2003				**3.6%**	***-1.8%***	-2.9%	-2.9%	-2.1%	**-2.7%**	31.6%	2.8%	-1.3%	-0.6%	2.0%	2.3%	1.8%
AFR 2004					**0.6%**	***-0.3%***	-0.5%	0.0%	0.6%	**36.1%**	6.4%	2.4%	3.0%	6.0%	5.4%	0.3%
AFR 2005						**-0.3%**	***-0.5%***	0.6%	4.1%	41.5%	**11.0%**	6.8%	7.0%	10.2%	8.9%	0.5%
AFR 2006							**-0.3%**	***1.4%***	1.8%	41.8%	11.1%	**7.4%**	8.0%	10.0%	10.2%	1.4%
AFR 2007								**0.0%**	***-0.5%***	37.0%	6.0%	2.8%	**3.4%**	5.7%	7.8%	0.5%
AFR 2008									**-2.0%**	***34.8%***	8.9%	5.1%	4.0%	**4.8%**	9.3%	34.8%
AFR 2009										**4.8%**	***-16.8%***	-13.9%	-8.1%	-3.1%	-7.4%	16.8%
AFR 2010											**-0.8%**	***-1.8%***	-1.0%	0.7%	-0.7%	1.8%
AFR 2011												**-0.3%**	***-1.1%***	0.5%	-0.3%	1.1%
AFR 2012													**-1.4%**	***0.5%***	-0.5%	0.5%
AFR 2013														**-0.2%**	-0.2%	

N.n%	*= Year-Ahead Foreast*	Avg Year-Ahead Error =	1.4%
N.n%	= Current Year Forecast	Avg Current Year Error =	-0.2%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	5.6%

Figure 13: AFR Summer Peak Demand Forecast Accuracy

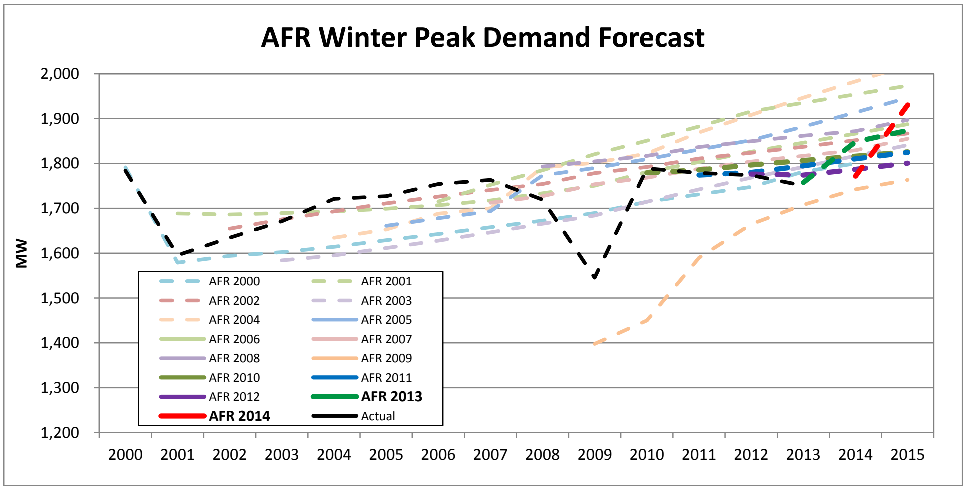


Summer System Peak Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Average Error of AFR	Avg. Error Year-Ahead
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%	-0.2%	-0.3%	13.7%
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%	2.9%	2.8%	0.5%
AFR 2002			**-2.0%**	***5.0%***	3.5%	-0.6%	-2.6%	**-1.9%**	2.3%	30.7%	2.4%	3.1%	1.4%	2.7%	3.7%	5.0%
AFR 2003				**2.4%**	***-4.4%***	-6.4%	-6.9%	-8.2%	**-3.1%**	24.6%	-2.9%	-1.7%	-2.2%	-1.7%	-1.0%	4.4%
AFR 2004					**0.0%**	***0.0%***	-3.9%	-3.5%	3.7%	**30.8%**	1.7%	4.8%	4.1%	5.6%	4.3%	0.0%
AFR 2005						**-5.0%**	***-6.9%***	-6.3%	3.1%	30.7%	**2.5%**	3.3%	2.0%	4.4%	3.1%	6.9%
AFR 2006							**-0.2%**	***-0.7%***	4.5%	34.3%	5.9%	**7.0%**	6.0%	7.5%	8.0%	0.7%
AFR 2007								**-2.4%**	***2.2%***	31.4%	3.5%	4.8%	**3.6%**	5.2%	6.9%	2.2%
AFR 2008									**2.5%**	***31.0%***	3.2%	3.7%	2.4%	**3.6%**	7.7%	31.0%
AFR 2009										**0.0%**	***-21.1%***	-15.6%	-11.9%	-8.9%	-11.5%	21.1%
AFR 2010											**-0.1%**	***-1.4%***	-2.6%	-1.5%	-1.4%	1.4%
AFR 2011												**-1.5%**	***-3.5%***	-2.4%	-2.4%	3.5%
AFR 2012													**-3.7%**	***-3.0%***	-3.4%	3.0%
AFR 2013														**-2.8%**	-2.8%	

N.n%	= *Year-Ahead Forecast*	Avg Year-Ahead Error =	0.8%
N.n%	= Current Year Forecast	Avg Current Year Error =	-0.5%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	3.4%

Figure 14: AFR Winter Peak Demand Forecast Accuracy



Winter System Peak Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Average Error of AFR	Avg. Error Year-Ahead
AFR 2000	**4.7%**	**3.0%**	-2.2%	2.0%	-0.2%	**-4.4%**	-6.4%	-5.7%	-1.6%	25.2%	-1.3%	-0.9%	-2.3%	0.0%	0.7%	3.0%
AFR 2001		**10.2%**	***3.5%***	7.6%	4.7%	-0.3%	**-2.7%**	-2.3%	2.0%	29.7%	2.6%	3.3%	2.0%	3.6%	4.9%	3.5%
AFR 2002			**1.6%**	***6.7%***	4.7%	0.4%	-1.6%	**-1.0%**	3.2%	31.8%	3.2%	3.7%	1.9%	3.1%	4.8%	6.7%
AFR 2003				**0.9%**	***-1.4%***	-5.4%	-7.2%	-6.3%	**-2.0%**	24.8%	-1.3%	-0.2%	-1.2%	0.6%	0.1%	1.4%
AFR 2004					**1.1%**	***-3.0%***	-3.8%	-3.3%	5.4%	**33.5%**	4.9%	7.1%	6.6%	9.3%	5.8%	3.0%
AFR 2005						**-2.5%**	***-4.3%***	-3.6%	4.4%	32.6%	**4.2%**	4.9%	3.5%	5.6%	5.0%	4.3%
AFR 2006							**-2.2%**	***-0.3%***	5.0%	34.9%	6.6%	**7.8%**	7.0%	8.6%	8.4%	0.3%
AFR 2007								**-2.6%**	***1.7%***	29.9%	1.8%	2.4%	**0.8%**	2.0%	5.1%	1.7%
AFR 2008									**5.5%**	***33.7%***	4.6%	5.2%	3.3%	**4.5%**	9.5%	33.7%
AFR 2009										**3.6%**	***-16.5%***	-8.9%	-7.0%	-4.1%	-6.6%	16.5%
AFR 2010											**2.4%**	***2.3%***	0.4%	1.4%	1.6%	2.3%
AFR 2011												**1.6%**	***-0.6%***	0.7%	0.6%	0.6%
AFR 2012													**-0.7%**	***-0.4%***	-0.6%	0.4%
AFR 2013														**-1.3%**	-1.3%	

N.n%	*= Year-Ahead Foreast*	Avg Year-Ahead Error =	1.9%
N.n%	= Current Year Forecast	Avg Current Year Error =	1.6%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	4.5%

2. AFR 2014 Forecast and Alternative Scenarios

A. Forecast Scenario Descriptions

Minnesota Power's developed several scenarios for system peak demand and energy forecasts. All scenarios assume some direct load additions and/or losses from specific Industrial customers, served directly by Minnesota Power or through a wholesale customer.

Moderate Growth Demand and Energy Scenario

This scenario includes changes in customer operations that are not certain, but have a 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.

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 early 2016; this is a more accelerated ramp-up than has been assumed in previous Minnesota Power forecasts, but is constant with what this customer has communicated publicly.

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

The Moderate Growth scenario results in average annual energy sales growth and average annual peak demand growth of 1.1 percent and 1.1 percent, respectively, from 2014 through 2028.

Moderate Growth with Deferred Resale Demand and Energy Scenario

This scenario is identical to the Moderate Growth scenario except it assumes a one-year deferment in the start-up of the new industrial facility in the City of Nashwauk. The facility is expected to reach full demand in early 2017 instead of early 2016 (as is assumed in the Moderate Growth scenario). Other possible additional phases of this project are not included in this scenario.

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

The Moderate Growth with Deferred resale scenario results in average annual energy sales growth and average annual peak demand growth of 1.1 percent and 1.1 percent, respectively, from 2014 through 2028.

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, expiring electric service agreements that will not be renewed, and publicly communicated schedules by prospective customers.

The largest of the adjustments to the econometric forecast accounts for the new industrial facility served by a Minnesota Power wholesale customer, the City of Nashwauk. The facility is expected to reach full demand in early 2016; this is a more accelerated ramp-up than has been assumed in previous Minnesota Power forecasts, but is constant with what this customer has communicated publicly.

This scenario is more constrained in its additions for new prospective customers and results in average annual energy sales growth and average annual peak demand growth of 0.8 percent and 0.8 percent, respectively, from 2014 through 2028.

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 1.6 percent and 1.5 percent, respectively, from 2014 through 2028. 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. This scenario includes some additions, but these are more than offset by substantial load reductions resulting in no energy or demand growth in the 2014-2028 timeframe. The results are presented in the Potential Upside table.

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 percent and 2.4 percent, respectively, from 2014 through 2028.

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

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. **Net Load/Energy Added**: are exogenous adjustments accounting for added load due to new customers or expansion by existing customers, and lost load due to closure or loss of contract. To preserve customer confidentiality, the seasonal demand and energy impacts are netted to a single value before being applied to the econometric values. Adjustments made for recent customer additions (as discussed in sections on *Methodological Improvements* and *Data Revisions Since Previous AFR*) are also included in this value.

2. **Customer Generation:** is the demand on Minnesota Power system that is met by customer owned generation. Customer generation 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 Customer Generation from the historical peak series.
    - Econometrically project a less volatile "FERC load coincident w/ Monthly Minnesota Power System peak (MW)" monthly peak series.
    - Arithmetically account for Customer Generation 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 forecast assumption for customer generation is determined by averaging the historical customer generation coincident with the monthly peak over a 12-year historical timeframe. The result is a set of 12 distinct monthly values for each month of the year. The MWh adjustment is determined similarly through averaging the most recent 12-year historical timeframe, but excluding 2009 due to its irregularly low value. These adjustments are credits that increase the estimated peaks and system energy use projection by the estimated amount.

This Customer Generation adjustment to peak and energy forecasts also accounts for expected changes in the operation or ownership of generating assets that would affect deliveries to customers.

3. **Dual Fuel**: Minnesota Power has a robust Dual Fuel program for Residential and Commercial customers. Dual Fuel impacts are accounted for in forecast in the same way as conservation. The impacts of historical interruptions are assumed to be inherent in the forecast since curtailments affected historical monthly peak demand. Post-regression adjustments for dual fuel would produce an artificially low peak demand forecast. Minnesota Power will account for dual fuel interruption as a resource and not as an adjustment to the load forecast.

C. Peak Demand and Energy Outlooks by Scenario

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					1,584	1,534	169	170	1,753	1,704	1,753	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	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	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					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,526	1,554	30	45	**1,556**	**1,599**	172	173	**1,727**	**1,772**	***1,772***	2014
2015	1,543	1,563	93	176	**1,636**	**1,739**	172	192	**1,807**	**1,931**	***1,931***	**2015**
2016	1,551	1,573	171	183	**1,722**	**1,756**	201	202	**1,923**	**1,958**	***1,958***	2016
2017	1,557	1,578	183	193	**1,740**	**1,771**	201	202	**1,941**	**1,973**	***1,973***	2017
2018	1,560	1,584	193	194	**1,753**	**1,777**	201	202	**1,954**	**1,979**	***1,979***	2018
2019	1,567	1,593	194	194	**1,761**	**1,786**	201	202	**1,962**	**1,988**	***1,988***	2019
2020	1,576	1,601	194	194	**1,769**	**1,794**	201	202	**1,970**	**1,996**	***1,996***	**2020**
2021	1,582	1,608	194	194	**1,775**	**1,801**	201	202	**1,976**	**2,003**	***2,003***	2021
2022	1,588	1,614	194	194	**1,782**	**1,808**	201	202	**1,982**	**2,010**	***2,010***	2022
2023	1,595	1,624	194	194	**1,789**	**1,817**	201	202	**1,990**	**2,019**	***2,019***	2023
2024	1,602	1,632	194	194	**1,796**	**1,826**	201	202	**1,997**	**2,028**	***2,028***	2024
2025	1,609	1,640	194	194	**1,803**	**1,834**	201	202	**2,004**	**2,035**	***2,035***	**2025**
2026	1,617	1,648	194	194	**1,810**	**1,842**	201	202	**2,011**	**2,044**	***2,044***	2026
2027	1,625	1,658	194	194	**1,818**	**1,851**	201	202	**2,019**	**2,053**	***2,053***	2027
2028	1,632	1,667	194	194	**1,826**	**1,861**	201	202	**2,027**	**2,063**	***2,063***	2028

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	Load Factor	
2000			10,243,434					
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			10,531,271	1,258,895	11,790,166	1,727	0.78	2005
2006			10,649,101	1,195,070	11,844,171	1,753	0.77	2006
2007			10,680,509	1,252,965	11,933,474	1,763	0.77	2007
2008			10,839,446	1,276,158	12,115,604	1,719	0.80	2008
2009			8,065,090	1,108,014	9,173,104	1,545	0.68	2009
2010			10,417,422	1,299,292	11,716,714	1,789	0.75	2010
2011			10,988,200	1,422,107	12,410,307	1,779	0.80	2011
2012			11,107,358	1,200,317	12,307,675	1,790	0.78	2012
2013	10,985,809		10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	10,808,480	197,504	**11,005,984**	1,251,630	**12,257,614**	***1,772***	**0.79**	2014
2015	10,819,622	635,938	**11,455,560**	1,286,450	**12,742,010**	***1,931***	**0.75**	**2015**
2016	10,906,285	1,304,421	**12,210,706**	1,422,746	**13,633,452**	***1,958***	**0.79**	2016
2017	10,926,100	1,213,426	**12,139,526**	1,462,483	**13,602,010**	***1,973***	**0.79**	2017
2018	10,939,368	1,286,636	**12,226,004**	1,462,483	**13,688,488**	***1,979***	**0.79**	2018
2019	10,987,659	1,294,783	**12,282,442**	1,462,483	**13,744,926**	***1,988***	**0.79**	2019
2020	11,074,743	1,298,331	**12,373,073**	1,466,490	**13,839,563**	***1,996***	**0.79**	**2020**
2021	11,088,873	1,294,783	**12,383,656**	1,462,483	**13,846,140**	***2,003***	**0.79**	2021
2022	11,134,063	1,294,783	**12,428,847**	1,462,483	**13,891,330**	***2,010***	**0.79**	2022
2023	11,188,371	1,294,783	**12,483,154**	1,462,483	**13,945,637**	***2,019***	**0.79**	2023
2024	11,267,085	1,298,331	**12,565,416**	1,466,490	**14,031,906**	***2,028***	**0.79**	2024
2025	11,293,034	1,294,783	**12,587,817**	1,462,483	**14,050,301**	***2,035***	**0.79**	**2025**
2026	11,351,103	1,294,783	**12,645,886**	1,462,483	**14,108,370**	***2,044***	**0.79**	2026
2027	11,411,239	1,294,783	**12,706,022**	1,462,483	**14,168,506**	***2,053***	**0.79**	2027
2028	11,503,999	1,298,331	**12,802,330**	1,466,490	**14,268,820**	***2,063***	**0.79**	2028

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	119,300	20,969	431	585	246	18	141,549
2009	121,217	21,287	429	422	262	18	143,636
2010	121,235	21,491	424	438	278	18	143,884
2011	121,251	21,603	421	503	281	18	144,077
2012	120,697	21,614	411	539	275	18	143,554
2013	**121,314**	**21,915**	**403**	**592**	**287**	**18**	**144,529**
2014	**120,818**	**21,921**	**387**	**664**	**281**	**17**	**144,089**
2015	**123,065**	**22,376**	**380**	**726**	**290**	**17**	**146,854**
2016	**124,243**	**22,644**	**378**	**789**	**293**	**17**	**148,365**
2017	**125,202**	**22,928**	**382**	**854**	**297**	**17**	**149,681**
2018	**125,997**	**23,205**	**384**	**910**	**300**	**17**	**150,813**
2019	**126,542**	**23,469**	**385**	**964**	**302**	**17**	**151,680**
2020	**127,136**	**23,749**	**385**	**1,015**	**304**	**17**	**152,606**
2021	**127,633**	**24,021**	**387**	**1,063**	**306**	**17**	**153,426**
2022	**128,132**	**24,293**	**386**	**1,112**	**307**	**17**	**154,247**
2023	**128,562**	**24,564**	**385**	**1,158**	**309**	**17**	**154,995**
2024	**128,983**	**24,833**	**383**	**1,204**	**310**	**17**	**155,729**
2025	**129,353**	**25,107**	**381**	**1,250**	**311**	**17**	**156,419**
2026	**129,873**	**25,385**	**377**	**1,294**	**312**	**17**	**157,258**
2027	**130,433**	**25,664**	**374**	**1,341**	**313**	**17**	**158,142**
2028	**131,060**	**25,946**	**369**	**1,388**	**315**	**17**	**159,094**

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	15,646	61,396	1,479,329	10,531,271
2006	1,011,699	1,206,607	6,782,975	15,831	60,882	1,571,107	10,649,101
2007	1,051,453	1,244,930	6,622,051	15,752	67,056	1,679,267	10,680,509
2008	1,079,837	1,240,324	6,737,333	15,983	64,912	1,701,057	10,839,446
2009	1,075,116	1,212,778	4,051,352	16,049	62,036	1,647,759	8,065,090
2010	1,057,476	1,221,754	6,364,080	15,833	61,768	1,696,511	10,417,422
2011	1,069,856	1,226,174	6,913,648	16,420	62,458	1,699,644	10,988,200
2012	1,043,281	1,237,386	7,037,843	15,955	54,074	1,718,819	11,107,358
2013	**1,086,481**	**1,256,540**	**6,873,992**	**16,066**	**51,736**	**1,700,993**	**10,985,809**
2014	**1,126,533**	**1,284,024**	**6,929,749**	**16,346**	**54,172**	**1,595,159**	**11,005,984**
2015	**1,101,872**	**1,287,245**	**7,177,641**	**16,380**	**54,967**	**1,817,456**	**11,455,560**
2016	**1,117,148**	**1,310,008**	**7,242,366**	**16,654**	**56,293**	**2,468,238**	**12,210,706**
2017	**1,124,315**	**1,326,212**	**7,125,775**	**16,738**	**56,630**	**2,489,856**	**12,139,526**
2018	**1,135,933**	**1,343,242**	**7,177,287**	**16,755**	**56,906**	**2,495,882**	**12,226,004**
2019	**1,144,295**	**1,357,620**	**7,205,498**	**16,807**	**56,903**	**2,501,320**	**12,282,442**
2020	**1,156,269**	**1,375,938**	**7,253,307**	**16,944**	**57,131**	**2,513,485**	**12,373,073**
2021	**1,161,158**	**1,388,599**	**7,247,011**	**16,941**	**57,266**	**2,512,682**	**12,383,656**
2022	**1,170,667**	**1,404,045**	**7,260,144**	**17,035**	**57,401**	**2,519,554**	**12,428,847**
2023	**1,179,077**	**1,419,552**	**7,283,882**	**17,051**	**57,571**	**2,526,019**	**12,483,154**
2024	**1,189,847**	**1,439,572**	**7,321,726**	**17,183**	**57,798**	**2,539,290**	**12,565,416**
2025	**1,194,569**	**1,453,153**	**7,327,251**	**17,167**	**57,797**	**2,537,880**	**12,587,817**
2026	**1,203,301**	**1,468,463**	**7,355,298**	**17,247**	**58,054**	**2,543,524**	**12,645,886**
2027	**1,212,603**	**1,484,940**	**7,383,313**	**17,298**	**58,370**	**2,549,498**	**12,706,022**
2028	**1,226,285**	**1,505,777**	**7,432,043**	**17,454**	**58,896**	**2,561,875**	**12,802,330**

ii. **Moderate Growth with Deferred Resale**

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					1,584	1,534	169	170	1,753	1,704	1,753	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	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	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					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,525	1,554	30	45	1,555	1,599	172	173	1,727	1,771	1,771	2014
2015	1,543	1,564	63	66	1,606	1,629	172	192	1,778	1,821	1,821	**2015**
2016	1,550	1,573	91	183	1,641	1,755	201	202	1,842	1,957	1,957	2016
2017	1,557	1,578	183	193	1,740	1,770	201	202	1,940	1,972	1,972	2017
2018	1,560	1,584	193	194	1,752	1,777	201	202	1,953	1,979	1,979	2018
2019	1,567	1,593	194	194	1,760	1,786	201	202	1,961	1,988	1,988	2019
2020	1,575	1,600	194	194	1,769	1,794	201	202	1,970	1,996	1,996	**2020**
2021	1,581	1,607	194	194	1,775	1,801	201	202	1,976	2,002	2,002	2021
2022	1,588	1,614	194	194	1,781	1,807	201	202	1,982	2,009	2,009	2022
2023	1,595	1,623	194	194	1,788	1,817	201	202	1,989	2,019	2,019	2023
2024	1,602	1,632	194	194	1,795	1,825	201	202	1,996	2,027	2,027	2024
2025	1,609	1,640	194	194	1,802	1,833	201	202	2,003	2,035	2,035	**2025**
2026	1,616	1,648	194	194	1,810	1,842	201	202	2,011	2,043	2,043	2026
2027	1,624	1,658	194	194	1,818	1,851	201	202	2,019	2,053	2,053	2027
2028	1,632	1,667	194	194	1,825	1,860	201	202	2,026	2,062	2,062	2028

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	1,753	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	10,985,809		10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	10,805,856	197,504	11,003,360	1,251,630	12,254,990	1,771	0.79	2014
2015	10,821,199	415,559	11,236,758	1,286,450	12,523,209	1,821	0.79	**2015**
2016	10,906,880	684,171	11,591,051	1,422,746	13,013,797	1,957	0.76	2016
2017	10,921,738	1,213,426	12,135,164	1,462,483	13,597,648	1,972	0.79	2017
2018	10,935,511	1,286,636	12,222,147	1,462,483	13,684,631	1,979	0.79	2018
2019	10,983,504	1,294,783	12,278,287	1,462,483	13,740,771	1,988	0.79	2019
2020	11,070,561	1,298,331	12,368,891	1,466,490	13,835,381	1,996	0.79	**2020**
2021	11,084,747	1,294,783	12,379,530	1,462,483	13,842,013	2,002	0.79	2021
2022	11,129,622	1,294,783	12,424,405	1,462,483	13,886,888	2,009	0.79	2022
2023	11,184,381	1,294,783	12,479,164	1,462,483	13,941,647	2,019	0.79	2023
2024	11,262,953	1,298,331	12,561,284	1,466,490	14,027,774	2,027	0.79	2024
2025	11,288,653	1,294,783	12,583,436	1,462,483	14,045,919	2,035	0.79	**2025**
2026	11,346,690	1,294,783	12,641,473	1,462,483	14,103,957	2,043	0.79	2026
2027	11,406,825	1,294,783	12,701,608	1,462,483	14,164,091	2,053	0.79	2027
2028	11,499,273	1,298,331	12,797,604	1,466,490	14,264,094	2,062	0.79	2028

iii. **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					1,584	1,534	169	170	1,753	1,704	1,753	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	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	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					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,525	1,553	30	32	1,555	1,585	172	173	1,727	1,758	1,758	2014
2015	1,543	1,564	70	122	1,613	1,686	172	177	1,784	1,862	1,862	2015
2016	1,550	1,573	110	118	1,660	1,691	176	183	1,836	1,874	1,874	2016
2017	1,557	1,578	118	118	1,675	1,696	182	183	1,856	1,879	1,879	2017
2018	1,559	1,583	118	118	1,677	1,701	182	183	1,859	1,884	1,884	2018
2019	1,567	1,592	118	118	1,685	1,710	182	183	1,867	1,893	1,893	2019
2020	1,575	1,600	118	118	1,693	1,718	182	183	1,875	1,901	1,901	2020
2021	1,581	1,607	118	118	1,699	1,725	182	183	1,881	1,908	1,908	2021
2022	1,587	1,613	118	118	1,705	1,731	182	183	1,887	1,914	1,914	2022
2023	1,594	1,623	118	118	1,712	1,741	182	183	1,894	1,924	1,924	2023
2024	1,601	1,631	118	118	1,719	1,749	182	183	1,901	1,932	1,932	2024
2025	1,608	1,639	118	118	1,726	1,757	182	183	1,908	1,940	1,940	2025
2026	1,616	1,647	118	118	1,734	1,765	182	183	1,916	1,948	1,948	2026
2027	1,623	1,657	118	118	1,741	1,775	182	183	1,923	1,958	1,958	2027
2028	1,631	1,666	118	118	1,749	1,784	182	183	1,931	1,967	1,967	2028

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	1,753	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	10,985,809		10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	10,801,397	197,504	10,998,901	1,251,630	12,250,531	1,758	0.80	2014
2015	10,811,606	475,705	11,287,311	1,251,630	12,538,941	1,862	0.77	2015
2016	10,903,391	866,765	11,770,156	1,284,222	13,054,378	1,874	0.79	2016
2017	10,920,224	857,858	11,778,082	1,324,338	13,102,420	1,879	0.80	2017
2018	10,933,261	856,396	11,789,657	1,324,338	13,113,995	1,884	0.79	2018
2019	10,980,794	856,396	11,837,190	1,324,338	13,161,528	1,893	0.79	2019
2020	11,066,720	858,742	11,925,462	1,327,967	13,253,429	1,901	0.79	2020
2021	11,080,537	856,396	11,936,933	1,324,338	13,261,271	1,908	0.79	2021
2022	11,124,600	856,396	11,980,996	1,324,338	13,305,334	1,914	0.79	2022
2023	11,178,582	856,396	12,034,978	1,324,338	13,359,316	1,924	0.79	2023
2024	11,256,408	858,742	12,115,150	1,327,967	13,443,117	1,932	0.79	2024
2025	11,281,839	856,396	12,138,235	1,324,338	13,462,573	1,940	0.79	2025
2026	11,339,586	856,396	12,195,982	1,324,338	13,520,321	1,948	0.79	2026
2027	11,399,398	856,396	12,255,794	1,324,338	13,580,133	1,958	0.79	2027
2028	11,491,551	858,742	12,350,294	1,327,967	13,678,260	1,967	0.79	2028

iv. **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					1,584	1,534	169	170	1,753	1,704	1,753	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	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	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					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,526	1,554	35	46	1,561	1,600	172	178	1,732	1,778	1,778	2014
2015	1,543	1,563	94	191	1,637	1,754	177	196	1,814	1,950	1,950	**2015**
2016	1,551	1,573	186	200	1,737	1,773	195	202	1,932	1,975	1,975	2016
2017	1,557	1,578	207	240	1,765	1,818	201	202	1,965	2,020	2,020	2017
2018	1,560	1,584	295	298	1,855	1,882	201	202	2,056	2,084	2,084	2018
2019	1,568	1,593	298	314	1,865	1,907	201	202	2,066	2,109	2,109	2019
2020	1,576	1,601	314	318	1,890	1,918	201	202	2,091	2,120	2,120	**2020**
2021	1,582	1,608	318	318	1,899	1,925	201	202	2,100	2,127	2,127	2021
2022	1,588	1,615	318	318	1,906	1,932	201	202	2,107	2,134	2,134	2022
2023	1,595	1,624	318	318	1,913	1,942	201	202	2,114	2,144	2,144	2023
2024	1,603	1,633	318	318	1,920	1,950	201	202	2,121	2,152	2,152	2024
2025	1,610	1,640	318	318	1,927	1,958	201	202	2,128	2,160	2,160	**2025**
2026	1,617	1,649	318	318	1,935	1,966	201	202	2,136	2,168	2,168	2026
2027	1,625	1,658	318	318	1,943	1,976	201	202	2,143	2,178	2,178	2027
2028	1,633	1,668	318	318	1,950	1,985	201	202	2,151	2,187	2,187	2028

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	1,753	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	10,985,809		10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	10,808,736	197,504	11,006,240	1,251,630	12,257,870	1,778	0.79	2014
2015	10,819,363	635,938	11,455,301	1,286,450	12,741,751	1,950	0.75	**2015**
2016	10,907,299	1,349,278	12,256,577	1,422,746	13,679,323	1,975	0.79	2016
2017	10,927,293	1,347,118	12,274,411	1,462,483	13,736,895	2,020	0.78	2017
2018	10,941,302	1,863,436	12,804,739	1,462,483	14,267,222	2,084	0.78	2018
2019	10,990,052	2,049,739	13,039,792	1,462,483	14,502,275	2,109	0.79	2019
2020	11,076,125	2,144,396	13,220,521	1,466,490	14,687,011	2,120	0.79	**2020**
2021	11,091,367	2,165,517	13,256,885	1,462,483	14,719,368	2,127	0.79	2021
2022	11,136,481	2,165,517	13,301,998	1,462,483	14,764,481	2,134	0.79	2022
2023	11,191,079	2,165,517	13,356,596	1,462,483	14,819,080	2,144	0.79	2023
2024	11,269,910	2,171,450	13,441,360	1,466,490	14,907,850	2,152	0.79	2024
2025	11,296,276	2,165,517	13,461,794	1,462,483	14,924,277	2,160	0.79	**2025**
2026	11,355,051	2,165,517	13,520,568	1,462,483	14,983,052	2,168	0.79	2026
2027	11,415,048	2,165,517	13,580,565	1,462,483	15,043,048	2,178	0.79	2027
2028	11,508,208	2,171,450	13,679,658	1,466,490	15,146,148	2,187	0.79	2028

V. 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					1,584	1,534	169	170	1,753	1,704	1,753	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	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	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					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,523	1,547	30	12	**1,553**	**1,559**	172	173	**1,725**	**1,732**	**1,732**	2014
2015	1,537	1,557	30	20	**1,567**	**1,577**	172	180	**1,738**	**1,758**	**1,758**	**2015**
2016	1,542	1,565	1	(16)	**1,543**	**1,549**	179	190	**1,722**	**1,739**	**1,739**	2016
2017	1,548	1,522	4	53	**1,552**	**1,575**	189	190	**1,741**	**1,765**	**1,765**	2017
2018	1,549	1,572	(21)	(18)	**1,528**	**1,554**	189	190	**1,717**	**1,744**	**1,744**	2018
2019	1,555	1,580	(18)	(24)	**1,537**	**1,556**	189	190	**1,726**	**1,746**	**1,746**	2019
2020	1,563	1,518	(24)	0	**1,539**	**1,518**	189	190	**1,728**	**1,708**	**1,728**	**2020**
2021	1,568	1,593	(96)	(96)	**1,472**	**1,497**	189	190	**1,661**	**1,687**	**1,687**	2021
2022	1,574	1,599	(96)	(96)	**1,478**	**1,503**	189	190	**1,667**	**1,693**	**1,693**	2022
2023	1,580	1,608	(96)	(96)	**1,484**	**1,512**	189	190	**1,673**	**1,702**	**1,702**	2023
2024	1,587	1,616	(96)	(96)	**1,491**	**1,520**	189	190	**1,680**	**1,710**	**1,710**	2024
2025	1,593	1,623	(96)	(96)	**1,497**	**1,527**	189	190	**1,686**	**1,716**	**1,716**	**2025**
2026	1,600	1,630	(96)	(96)	**1,504**	**1,534**	189	190	**1,693**	**1,724**	**1,724**	2026
2027	1,606	1,639	(96)	(96)	**1,510**	**1,543**	189	190	**1,699**	**1,732**	**1,732**	2027
2028	1,613	1,647	(96)	(96)	**1,517**	**1,551**	189	190	**1,706**	**1,740**	**1,740**	2028

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	1,753	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	10,985,809		10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	10,778,208	197,504	**10,975,711**	1,251,630	**12,227,342**	**1,732**	**0.81**	2014
2015	10,755,916	141,986	**10,897,901**	1,251,630	**12,149,532**	**1,758**	**0.79**	**2015**
2016	10,831,267	44,216	**10,875,483**	1,309,740	**12,185,223**	**1,739**	**0.80**	2016
2017	10,834,412	(159,504)	**10,674,908**	1,375,234	**12,050,142**	**1,765**	**0.78**	2017
2018	10,833,747	(456,854)	**10,376,893**	1,375,234	**11,752,127**	**1,744**	**0.77**	2018
2019	10,864,734	(433,876)	**10,430,858**	1,375,234	**11,806,092**	**1,746**	**0.77**	2019
2020	10,945,162	(481,005)	**10,464,157**	1,379,002	**11,843,159**	**1,728**	**0.78**	**2020**
2021	10,956,536	(1,015,802)	**9,940,734**	1,375,234	**11,315,968**	**1,687**	**0.77**	2021
2022	10,993,567	(1,015,802)	**9,977,765**	1,375,234	**11,352,999**	**1,693**	**0.77**	2022
2023	11,039,557	(1,015,802)	**10,023,755**	1,375,234	**11,398,989**	**1,702**	**0.76**	2023
2024	11,109,422	(1,018,585)	**10,090,836**	1,379,002	**11,469,838**	**1,710**	**0.76**	2024
2025	11,128,256	(1,015,802)	**10,112,454**	1,375,234	**11,487,688**	**1,716**	**0.76**	**2025**
2026	11,176,543	(1,015,802)	**10,160,741**	1,375,234	**11,535,975**	**1,724**	**0.76**	2026
2027	11,227,623	(1,015,802)	**10,211,820**	1,375,234	**11,587,054**	**1,732**	**0.76**	2027
2028	11,310,018	(1,018,585)	**10,291,433**	1,379,002	**11,670,434**	**1,740**	**0.76**	2028

vi. **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					1,584	1,534	169	170	1,753	1,704	1,753	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	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	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					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,526	1,561	35	46	**1,561**	**1,607**	172	178	**1,733**	**1,784**	**1,784**	2014
2015	1,548	1,569	94	197	**1,642**	**1,765**	177	192	**1,819**	**1,957**	**1,957**	**2015**
2016	1,557	1,580	196	254	**1,753**	**1,834**	191	192	**1,944**	**2,026**	**2,026**	2016
2017	1,565	1,586	261	299	**1,826**	**1,885**	191	145	**2,017**	**2,030**	**2,030**	2017
2018	1,569	1,593	437	449	**2,005**	**2,042**	144	112	**2,149**	**2,154**	**2,154**	2018
2019	1,577	1,604	457	523	**2,034**	**2,126**	111	112	**2,145**	**2,238**	**2,238**	2019
2020	1,587	1,613	563	691	**2,151**	**2,304**	111	112	**2,261**	**2,416**	**2,416**	**2020**
2021	1,594	1,621	691	691	**2,285**	**2,312**	111	112	**2,396**	**2,424**	**2,424**	2021
2022	1,601	1,629	691	691	**2,292**	**2,320**	111	112	**2,403**	**2,432**	**2,432**	2022
2023	1,610	1,639	691	691	**2,301**	**2,330**	111	112	**2,411**	**2,442**	**2,442**	2023
2024	1,618	1,649	691	691	**2,309**	**2,340**	111	112	**2,420**	**2,452**	**2,452**	2024
2025	1,626	1,658	691	691	**2,317**	**2,349**	111	112	**2,427**	**2,461**	**2,461**	**2025**
2026	1,634	1,667	691	691	**2,325**	**2,358**	111	112	**2,436**	**2,470**	**2,470**	2026
2027	1,643	1,678	691	691	**2,334**	**2,369**	111	112	**2,445**	**2,481**	**2,481**	2027
2028	1,652	1,689	691	691	**2,343**	**2,380**	111	112	**2,454**	**2,492**	**2,492**	2028

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	1,753	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	10,985,809		10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	10,824,555	197,504	**11,022,058**	1,251,630	**12,273,689**	**1,784**	**0.79**	2014
2015	10,870,986	635,938	**11,506,924**	1,286,450	**12,793,375**	**1,957**	**0.75**	**2015**
2016	10,969,237	1,408,435	**12,377,671**	1,393,583	**13,771,255**	**2,026**	**0.77**	2016
2017	10,999,225	1,756,413	**12,755,638**	1,389,775	**14,145,414**	**2,030**	**0.80**	2017
2018	11,024,117	2,704,174	**13,728,291**	1,048,745	**14,777,036**	**2,154**	**0.78**	2018
2019	11,088,560	3,299,983	**14,388,543**	808,111	**15,196,654**	**2,238**	**0.78**	2019
2020	11,188,824	4,122,093	**15,310,918**	810,325	**16,121,243**	**2,416**	**0.76**	**2020**
2021	11,214,503	4,973,422	**16,187,925**	808,111	**16,996,037**	**2,424**	**0.80**	2021
2022	11,270,404	4,973,422	**16,243,826**	808,111	**17,051,938**	**2,432**	**0.80**	2022
2023	11,333,762	4,973,422	**16,307,184**	808,111	**17,115,295**	**2,442**	**0.80**	2023
2024	11,423,702	4,987,048	**16,410,750**	810,325	**17,221,075**	**2,452**	**0.80**	2024
2025	11,459,373	4,973,422	**16,432,795**	808,111	**17,240,906**	**2,461**	**0.80**	**2025**
2026	11,527,964	4,973,422	**16,501,386**	808,111	**17,309,498**	**2,470**	**0.80**	2026
2027	11,599,361	4,973,422	**16,572,783**	808,111	**17,380,895**	**2,481**	**0.80**	2027
2028	11,704,344	4,987,048	**16,691,392**	810,325	**17,501,717**	**2,492**	**0.80**	2028

Sensitivities

Minnesota Power conducts tests to identify the sensitivity of the forecast to changes in weather and large customer operation. The 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 2014 forecasts:

- Trended Weather – Historical trend in weather is assumed instead of a 20 year average
- Extreme Weather – Historical extremes are assumed instead of a 20 year average
- Plug-in Electric Vehicle – Applies an estimate of the impact of PEV on the Minnesota Power system
- Customer Contract Expiration – Assumes several of Minnesota Power's largest customers do not renew their current contracts with Minnesota Power.

Trended Weather

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					1,584	1,534	169	170	1,753	1,704	1,753	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	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	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					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,527	1,552	30	45	1,557	1,596	172	173	1,729	1,769	1,769	2014
2015	1,544	1,562	93	176	1,637	1,738	172	192	1,809	1,929	1,929	**2015**
2016	1,552	1,573	171	183	1,723	1,756	201	202	1,924	1,958	1,958	2016
2017	1,559	1,580	183	193	1,741	1,772	201	202	1,942	1,974	1,974	2017
2018	1,562	1,586	193	194	1,754	1,780	201	202	1,955	1,982	1,982	2018
2019	1,569	1,597	194	194	1,763	1,790	201	202	1,963	1,992	1,992	2019
2020	1,578	1,599	194	194	1,771	1,793	201	202	1,972	1,995	1,995	**2020**
2021	1,584	1,608	194	194	1,777	1,801	201	202	1,978	2,003	2,003	2021
2022	1,590	1,616	194	194	1,784	1,809	201	202	1,985	2,011	2,011	2022
2023	1,598	1,626	194	194	1,791	1,820	201	202	1,992	2,021	2,021	2023
2024	1,605	1,636	194	194	1,798	1,829	201	202	1,999	2,031	2,031	2024
2025	1,612	1,645	194	194	1,806	1,838	201	202	2,006	2,040	2,040	**2025**
2026	1,694	1,654	194	194	1,887	1,847	201	202	2,088	2,049	2,088	2026
2027	1,703	1,665	194	194	1,896	1,858	201	202	2,097	2,060	2,097	2027
2028	1,711	1,675	194	194	1,904	1,868	201	202	2,105	2,070	2,105	2028

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	Load Factor	
2000			10,243,434					
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			10,531,271	1,258,895	11,790,166	1,727	0.78	2005
2006			10,649,101	1,195,070	11,844,171	1,753	0.77	2006
2007			10,680,509	1,252,965	11,933,474	1,763	0.77	2007
2008			10,839,446	1,276,158	12,115,604	1,719	0.80	2008
2009			8,065,090	1,108,014	9,173,104	1,545	0.68	2009
2010			10,417,422	1,299,292	11,716,714	1,789	0.75	2010
2011			10,988,200	1,422,107	12,410,307	1,779	0.80	2011
2012			11,107,358	1,200,317	12,307,675	1,790	0.78	2012
2013	10,985,809		10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	10,815,714	197,504	11,013,218	1,251,630	12,264,848	1,769	0.79	2014
2015	10,829,543	635,938	11,465,481	1,286,450	12,751,931	1,929	0.75	**2015**
2016	10,919,740	1,304,421	12,224,161	1,422,746	13,646,907	1,958	0.79	2016
2017	10,937,846	1,213,426	12,151,273	1,462,483	13,613,756	1,974	0.79	2017
2018	10,952,084	1,286,636	12,238,720	1,462,483	13,701,204	1,982	0.79	2018
2019	11,001,346	1,294,783	12,296,129	1,462,483	13,758,612	1,992	0.79	2019
2020	11,092,148	1,298,331	12,390,478	1,466,490	13,856,969	1,995	0.79	**2020**
2021	11,104,555	1,294,783	12,399,338	1,462,483	13,861,822	2,003	0.79	2021
2022	11,150,747	1,294,783	12,445,530	1,462,483	13,908,013	2,011	0.79	2022
2023	11,206,047	1,294,783	12,500,831	1,462,483	13,963,314	2,021	0.79	2023
2024	11,288,558	1,298,331	12,586,889	1,466,490	14,053,379	2,031	0.79	2024
2025	11,312,714	1,294,783	12,607,497	1,462,483	14,069,981	2,040	0.79	**2025**
2026	11,371,798	1,294,783	12,666,581	1,462,483	14,129,064	2,088	0.77	2026
2027	11,432,958	1,294,783	12,727,741	1,462,483	14,190,225	2,097	0.77	2027
2028	11,529,630	1,298,331	12,827,961	1,466,490	14,294,451	2,105	0.77	2028

Extreme Weather

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					1,584	1,534	169	170	1,753	1,704	1,753	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	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	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					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014	1,603	1,573	30	50	1,633	1,622	172	170	1,805	1,792	1,805	2014
2015	1,621	1,578	93	176	1,713	1,753	172	189	1,885	1,943	1,943	**2015**
2016	1,628	1,590	171	185	1,800	1,776	201	202	2,000	1,978	2,000	2016
2017	1,635	1,594	183	193	1,818	1,786	201	199	2,018	1,985	2,018	2017
2018	1,638	1,598	193	194	1,830	1,792	201	199	2,031	1,991	2,031	2018
2019	1,645	1,603	194	194	1,839	1,796	201	201	2,039	1,997	2,039	2019
2020	1,653	1,612	194	194	1,847	1,806	201	199	2,048	2,005	2,048	**2020**
2021	1,660	1,618	194	194	1,853	1,811	201	201	2,054	2,012	2,054	2021
2022	1,666	1,623	194	194	1,859	1,817	201	202	2,060	2,019	2,060	2022
2023	1,673	1,633	194	194	1,866	1,826	201	202	2,067	2,028	2,067	2023
2024	1,680	1,642	194	194	1,874	1,835	201	202	2,074	2,037	2,074	2024
2025	1,687	1,649	194	194	1,881	1,843	201	202	2,082	2,044	2,082	**2025**
2026	1,695	1,657	194	194	1,888	1,851	201	202	2,089	2,053	2,089	2026
2027	1,702	1,667	194	194	1,896	1,861	201	202	2,097	2,062	2,097	2027
2028	1,710	1,676	194	194	1,904	1,870	201	202	2,104	2,072	2,104	2028

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	+ Customer Gen.	= System Energy Use	MP System		
						Peak	Load Factor	
2000			10,243,434					
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			10,531,271	1,258,895	11,790,166	1,727	0.78	2005
2006			10,649,101	1,195,070	11,844,171	1,753	0.77	2006
2007			10,680,509	1,252,965	11,933,474	1,763	0.77	2007
2008			10,839,446	1,276,158	12,115,604	1,719	0.80	2008
2009			8,065,090	1,108,014	9,173,104	1,545	0.68	2009
2010			10,417,422	1,299,292	11,716,714	1,789	0.75	2010
2011			10,988,200	1,422,107	12,410,307	1,779	0.80	2011
2012			11,107,358	1,200,317	12,307,675	1,790	0.78	2012
2013	10,985,809		10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	10,915,663	197,504	11,113,166	1,251,630	12,364,796	1,805	0.78	2014
2015	10,962,708	635,938	11,598,646	1,286,450	12,885,096	1,943	0.76	**2015**
2016	11,052,881	1,304,421	12,357,302	1,422,746	13,780,048	2,000	0.78	2016
2017	11,070,948	1,213,426	12,284,374	1,462,483	13,746,858	2,018	0.78	2017
2018	11,085,691	1,286,636	12,372,328	1,462,483	13,834,811	2,031	0.78	2018
2019	11,135,205	1,294,783	12,429,988	1,462,483	13,892,471	2,039	0.78	2019
2020	11,226,590	1,298,331	12,524,921	1,466,490	13,991,411	2,048	0.78	**2020**
2021	11,238,716	1,294,783	12,533,499	1,462,483	13,995,982	2,054	0.78	2021
2022	11,285,063	1,294,783	12,579,846	1,462,483	14,042,329	2,060	0.78	2022
2023	11,340,518	1,294,783	12,635,301	1,462,483	14,097,785	2,067	0.78	2023
2024	11,423,461	1,298,331	12,721,791	1,466,490	14,188,281	2,074	0.78	2024
2025	11,447,195	1,294,783	12,741,978	1,462,483	14,204,461	2,082	0.78	**2025**
2026	11,506,214	1,294,783	12,800,997	1,462,483	14,263,481	2,089	0.78	2026
2027	11,567,339	1,294,783	12,862,122	1,462,483	14,324,605	2,097	0.78	2027
2028	11,664,453	1,298,331	12,962,783	1,466,490	14,429,274	2,104	0.78	2028

Plug-in Electric Vehicle

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							1,584	1,534	169	170	1,753	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	1,369	150	176	1,350	1,545	1,545	2009
2010							1,591	1,599	140	190	1,732	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							1,645	1,589	136	162	1,782	1,751	1,750	2013
2014	1,526	1,554	0.0	0.1	35	50	1,561	1,604	172	173	1,732	1,777	1,777	2014
2015	1,543	1,563	0.0	0.1	98	181	1,641	1,744	172	192	1,812	1,936	1,936	**2015**
2016	1,551	1,573	0.1	0.2	176	188	1,727	1,761	201	202	1,928	1,963	1,963	2016
2017	1,557	1,578	0.1	0.3	188	198	1,745	1,776	201	202	1,946	1,978	1,978	2017
2018	1,560	1,584	0.1	0.4	198	199	1,758	1,783	201	202	1,959	1,985	1,985	2018
2019	1,567	1,593	0.1	0.5	199	199	1,766	1,792	201	202	1,967	1,994	1,994	2019
2020	1,576	1,601	0.2	0.6	199	199	1,774	1,800	201	202	1,975	2,002	2,002	**2020**
2021	1,582	1,608	0.2	0.8	199	199	1,780	1,807	201	202	1,981	2,009	2,009	2021
2022	1,588	1,614	0.3	0.9	199	199	1,787	1,814	201	202	1,988	2,016	2,016	2022
2023	1,595	1,624	0.3	1.2	199	199	1,794	1,823	201	202	1,995	2,025	2,025	2023
2024	1,602	1,632	0.4	1.4	199	199	1,801	1,832	201	202	2,002	2,034	2,034	2024
2025	1,609	1,640	0.4	1.7	199	199	1,808	1,840	201	202	2,009	2,042	2,042	**2025**
2026	1,617	1,648	0.5	2.0	199	199	1,816	1,849	201	202	2,017	2,051	2,051	2026
2027	1,625	1,658	0.6	2.3	199	199	1,824	1,859	201	202	2,025	2,061	2,061	2027
2028	1,632	1,667	0.7	2.7	199	199	1,831	1,868	201	202	2,032	2,070	2,070	2028

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				10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014	10,808,480	1,082	197,504	11,007,066	1,251,630	12,258,696	1,777	0.79	2014
2015	10,819,622	1,724	635,938	11,457,284	1,286,450	12,743,734	1,936	0.75	**2015**
2016	10,906,285	2,602	1,304,421	12,213,309	1,422,746	13,636,054	1,963	0.79	2016
2017	10,926,100	3,773	1,213,426	12,143,300	1,462,483	13,605,783	1,978	0.79	2017
2018	10,939,368	4,921	1,286,636	12,230,925	1,462,483	13,693,409	1,985	0.79	2018
2019	10,987,659	6,361	1,294,783	12,288,803	1,462,483	13,751,286	1,994	0.79	2019
2020	11,074,743	8,123	1,298,331	12,381,196	1,466,490	13,847,687	2,002	0.79	**2020**
2021	11,088,873	10,232	1,294,783	12,393,888	1,462,483	13,856,372	2,009	0.79	2021
2022	11,134,063	12,711	1,294,783	12,441,558	1,462,483	13,904,041	2,016	0.79	2022
2023	11,188,371	15,576	1,294,783	12,498,729	1,462,483	13,961,213	2,025	0.79	2023
2024	11,267,085	18,843	1,298,331	12,584,259	1,466,490	14,050,749	2,034	0.79	2024
2025	11,293,034	22,528	1,294,783	12,610,345	1,462,483	14,072,829	2,042	0.79	**2025**
2026	11,351,103	26,640	1,294,783	12,672,527	1,462,483	14,135,010	2,051	0.79	2026
2027	11,411,239	31,187	1,294,783	12,737,209	1,462,483	14,199,692	2,061	0.79	2027
2028	11,503,999	35,726	1,298,331	12,838,056	1,466,490	14,304,547	2,070	0.79	2028

Customer Contract Expiration

Peak Forecast (MW)

	Current Contract		+	Contract Lost		=	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							1,584	1,534		169	170		1,753	1,704	1,753	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	1,369		150	176		1,350	1,545	1,545	2009
2010							1,591	1,599		140	190		1,732	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							1,645	1,589		136	162		1,782	1,751	1,782	2013
2014	1,526	1,554		0	0		1,526	1,554		172	173		1,697	1,727	1,727	2014
2015	1,543	1,563		(17)	(17)		1,526	1,546		172	177		1,698	1,723	1,723	2015
2016	1,551	1,573		(54)	(54)		1,497	1,519		176	183		1,673	1,702	1,702	2016
2017	1,557	1,578		(59)	(82)		1,498	1,496		182	183		1,680	1,679	1,680	2017
2018	1,560	1,584		(703)	(712)		857	872		182	183		1,039	1,055	1,055	2018
2019	1,567	1,593		(712)	(719)		855	874		182	183		1,037	1,057	1,057	2019
2020	1,576	1,601		(719)	(719)		857	882		182	183		1,039	1,064	1,064	2020
2021	1,582	1,608		(719)	(719)		863	889		182	183		1,045	1,071	1,071	2021
2022	1,588	1,614		(719)	(774)		869	840		182	183		1,051	1,023	1,051	2022
2023	1,595	1,624		(774)	(774)		821	850		182	183		1,003	1,033	1,033	2023
2024	1,602	1,632		(774)	(774)		828	858		182	183		1,010	1,041	1,041	2024
2025	1,609	1,640		(774)	(774)		835	866		182	183		1,017	1,049	1,049	2025
2026	1,617	1,648		(774)	(774)		843	874		182	183		1,024	1,057	1,057	2026
2027	1,625	1,658		(774)	(774)		850	884		182	183		1,032	1,067	1,067	2027
2028	1,632	1,667		(774)	(774)		858	893		182	183		1,040	1,076	1,076	2028

Energy Sales Forecast (MWh)

	Moderate Growth	+	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	1,753	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					10,985,809		1,185,139		12,170,948	1,782	0.78	2013
2014	11,005,984		0		11,005,984		1,251,630		12,257,614	1,727	0.81	2014
2015	11,455,560		(69,066)		11,386,493		1,251,630		12,638,124	1,723	0.84	2015
2016	12,210,706		(287,702)		11,923,004		1,284,222		13,207,226	1,702	0.89	2016
2017	12,139,526		(455,510)		11,684,016		1,324,338		13,008,354	1,680	0.88	2017
2018	12,226,004		(3,183,804)		9,042,201		1,324,338		10,366,539	1,055	1.12	2018
2019	12,282,442		(5,738,150)		6,544,292		1,324,338		7,868,630	1,057	0.85	2019
2020	12,373,073		(5,810,440)		6,562,633		1,327,967		7,890,599	1,064	0.85	2020
2021	12,383,656		(5,794,565)		6,589,091		1,324,338		7,913,430	1,071	0.84	2021
2022	12,428,847		(5,794,565)		6,634,282		1,324,338		7,958,620	1,051	0.86	2022
2023	12,483,154		(6,237,821)		6,245,333		1,324,338		7,569,671	1,033	0.84	2023
2024	12,565,416		(6,256,130)		6,309,286		1,327,967		7,637,253	1,041	0.84	2024
2025	12,587,817		(6,240,239)		6,347,579		1,324,338		7,671,917	1,049	0.83	2025
2026	12,645,886		(6,240,239)		6,405,648		1,324,338		7,729,986	1,057	0.83	2026
2027	12,706,022		(6,240,239)		6,465,784		1,324,338		7,790,122	1,067	0.83	2027
2028	12,802,330		(6,257,335)		6,544,995		1,327,967		7,872,961	1,076	0.84	2028

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 the Midwest Reliability Organization, the Midcontinent Independent System Operator, 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

7610.0120 REGISTRATION

ENTITY ID#	68
REPORT YEAR	2013

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	Chairman, President, and Chief Executive Officer
David J. McMillan	Senior Vice President, External Affairs
Deborah A. Amberg	Senior Vice President, General Counsel and Secretary
Steven Q. DeVinck	Senior Vice President and Chief Financial Officer
Allan S. Rudeck, Jr.	Vice President, Strategy & Planning
Robert J. Adams	Vice President,Energy Centric Businesses and ALLETE Chief Risk Officer
Donald W. Stellmaker	Vice President, Corporate Treasurer
Timothy J. Thorp	Vice President, Investor Relations
Bonnie A. Keppers	Vice President, Human Resources
Patrick K. Mullen	Vice President, Marketing & Corporate Communications
Margaret L. Hodnik	Vice President, Regulatory & Legislative Affairs
Jeffrey J. Paulseth	Vice President, Generation
Christopher E. Fleege	Vice President, Transmission and Distribution
Bethany Owen	Vice President, Information Technology Solutions
Bradley W. Oachs	Chief Operating Officer
Steve Morris	Controller

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

FEDERAL AGENCY	FORM NUMBER	FORM TITLE	FILING CYCLE (enter an "X" in the cell) 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 Report			X
FERC	FERC-67	Steam Electric Plant, Air and Water Survey		X	
FERC	FERC-80	Licensed Projects Recreation Report			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 Projects		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/Export		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 Report		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 Securities			X
SEC	Form 5	Annual Statement of Beneficial Ownership of Securities		X	
SEC	Proxy	Definitive Proxy Statement		X	
SEC	U-3A-2	Statement by Holding Company Claiming Exemption Under		X	
		Rule U-3A-2 from the Provisions of the Public Utility			
		Holding Company Act of 1935			
SEC	Form 11-K	Annual Report for RSOP		X	
SEC	Form 15	Certification and Notification of Termination of Registration			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			RESALE ONLY
UTILITY NAME	INTERCONNECTED UTILITY	MWH PURCHASED	MWH SOLD FOR RESALE
Dahlberg Light & Power			115,816
Superior Water Light & Power			701,845
City of Aitkin			38,878
City of Biwabik			7,259
City of Brainerd			202,882
City of Buhl			8,183
City of Ely			40,422
City of Gilbert			11,671
City of Grand Rapids			177,955
City of Keewatin			6,069
City of Mountain Iron			14,803
City of Nashwauk			11,005
City of Pierz			10,754
City of Proctor			26,834
City of Randall			5,242
City of Two Harbors			29,859
City of Hibbing			162,239
City of Virginia			129,277
Other Non-Required Sales			2,278,253
Non-Associated Utilities/Other		348,045	
Municipals			
Other Cooperatives		20,173	
Square Butte Electric Power		1,254,622	
Non-Utilities		86,300	
Power Marketers		47,250	
Other Public Authorities		1,905,070	
Utility		3	
Foreign		268,564	
City of Wadena	Western Area Power Administration	72,983	72,983
City of Staples	Western Area Power Administration	23,905	23,905
Great River Energy	Great River Energy	2,545,857	2,462,598
ES&AO	Minnkota Power	1,255,445	1,255,445

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-13	$0.0103
Jul-13	$0.0110
Aug-13	$0.0098
Sep-13	$0.0098
Oct-13	$0.0106
Nov-13	$0.0122
Dec-13	$0.0121
Jan-14	$0.0112
Feb-14	$0.0128
Mar-14	$0.0139
Apr-14	$0.0118
May-14	$0.0105
Jun-14	$0.0015

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
13,897	13,897	193,320

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		46	Martin	
2	Anoka		47	Meeker	
3	Becker		48	Mille Lacs	
4	Beltrami		49	Morrison	293675
5	Benton	25329	50	Mower	
6	Big Stone		51	Murray	
7	Blue Earth		52	Nicollet	
8	Brown		53	Nobles	
9	Carlton	462260	54	Norman	
10	Carver		55	Olmstead	
11	Cass	123623	56	Otter Tail	529
12	Chippewa		57	Pennington	
13	Chisago		58	Pine	74562
14	Clay		59	Pipestone	
15	Clearwater		60	Polk	
16	Cook		61	Pope	
17	Cottonwood		62	Ramsey	
18	Crow Wing	134722	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	7206995
25	Goodhue		70	Scott	
26	Grant		71	Sherburne	
27	Hennepin		72	Sibley	
28	Houston		73	Stearns	7738
29	Hubbard	98866	74	Steele	
30	Isanti		75	Stevens	
31	Itasca	297340	76	Swift	
32	Jackson		77	Todd	205321
33	Kanabec		78	Traverse	
34	Kandiyohi		79	Wabasha	
35	Kittson		80	Wadena	97386
36	Koochiching	175843	81	Waseca	
37	Lac Qui Parle		82	Washington	
38	Lake	80627	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)	9284816
45	Marshall				
				GRAND TOTAL (Calculated)	9284816

<= (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	104,962	13,891	2,408	22,020	8	395	7,433	287	151,404
	MWH	93,138	29,681	6,544	107,176	422,039	170,543	1,872	4,263	835,256
February	No. of Customers	104,745	13,895	2,403	21,907	8	396	7,536	285	151,175
	MWH	64,815	30,944	6,475	104,617	384,876	155,608	1,575	4,445	753,354
March	No. of Customers	104,774	13,869	2,405	21,869	8	395	7,622	286	151,228
	MWH	63,385	25,689	5,986	112,689	418,241	178,460	1,477	4,407	810,334
April	No. of Customers	104,775	13,846	2,397	21,898	8	394	8,060	288	151,666
	MWH	63,527	22,243	5,867	94,990	353,641	167,441	1,222	4,241	713,172
May	No. of Customers	105,012	13,896	2,404	21,905	8	393	8,918	289	152,825
	MWH	55,005	15,677	5,217	95,218	416,509	154,783	1,186	2,899	746,493
June	No. of Customers	105,901	13,935	2,405	21,781	8	393	9,436	286	154,145
	MWH	49,131	8,578	5,538	100,630	399,285	175,244	862	4,690	743,957
July	No. of Customers	105,116	13,832	2,397	21,936	8	395	9,443	288	153,415
	MWH	74,417	5,630	5,054	104,618	423,037	178,814	822	4,246	796,638
August	No. of Customers	105,050	13,891	2,397	21,876	8	395	9,439	288	153,344
	MWH	65,704	4,869	5,323	111,749	413,133	184,303	1,125	4,710	790,916
September	No. of Customers	105,213	13,927	2,389	21,919	8	394	12,900	289	157,039
	MWH	67,604	5,359	5,782	113,337	401,128	176,142	1,269	4,623	775,244
October	No. of Customers	104,938	13,919	2,382	21,958	8	396	13,023	290	156,914
	MWH	52,815	5,937	4,815	90,803	386,830	176,799	1,451	3,807	723,256
November	No. of Customers	104,913	13,921	2,390	21,958	8	393	13,076	287	156,946
	MWH	82,835	13,635	5,012	103,246	418,679	146,010	1,466	3,987	774,870
December	No. of Customers	104,832	13,947	2,386	21,956	8	390	13,142	285	156,946
	MWH	93,239	25,077	5,934	117,468	413,603	158,848	1,738	5,419	821,326
	Total MWH	825,615	193,320	67,547	1,256,540	4,850,998	2,022,995	16,066	51,736	9,284,816

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.

	In this column report the number of farms, residences, commercial establishments, etc., and not the number of meters, where different.	This column total should equal the grand total in the worksheet labeled "ElectricityByCounty" which provides deliveries by county.	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).
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	Megawatt-hours (round to nearest MWH)	Revenue ($)
Farm	2,386	67,547	6,449,028
Nonfarm-residential	118,779	1,018,934	94,054,285
Commercial	21,956	1,256,540	103,685,175
Industrial	390	6,873,992	370,024,629
Street and highway lighting	13,142	16,066	2,118,210
All other	285	51,736	4,052,775
Entered Total	153,921	9,284,816	580,384,102
CALCULATED TOTAL	156,938	9,284,816	580,384,102

Comments	

PUBLIC DOCUMENT
TRADE SECRET DATA
HAS BEEN EXCISED

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

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

Trade Secret Data Excised

ID#	CUSTOMER NAME	ADDRESS	CITY	STATE	ZIP	MWH

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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	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	440,045	
2	USE	ST	1960	COAL	472,273	
3	USE	ST	1973	COAL	2,552,577	
4	USE	ST	1980	COAL	3,404,497	MP share
					6,869,392	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	67.125	67.125	74.98	91.65	1.39	
2	67.325	67.325	80.46	96.68	0.39	
3	357.225	357.225	82.78	92.54	3.34	
4	466.974	466.974	83.83	92.53	1.45	
	958.649	958.649	80.51	93.35	1.64	

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 ****	GAS***	QUANITY	UNITS OF MEASURE****
1	SUB	270,082	TONS	8,938	FO2	0	GAL	NG	29046	Mbtu's
2	SUB	294,417	TONS	8,944	FO2	0	GAL	NG	15991	Mbtu's
3	SUB	1,513,720	TONS	8,970	FO2	0	GAL	NG	54425	Mbtu's
4	SUB	2,453,874	TONS	9,055	FO2	0	GAL	NG	65642	Mbtu's

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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	NUMBER OF 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	241,385	
2	USE	ST	1953	COAL	230,386	
					471,771	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	48.8	48.8	57.28	88.04	1.16	
2	49.4	49.4	52.53	84.99	4.37	
	98.2	98.2	54.91	86.52	2.77	

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	179,354		8735	FO2	21	GAL	
2	SUB	170,803		8735		21		
					NG	21,016	Mbtu's	
						21,016		

NOTE: Fuels are not metered separately for these units

ALLOWABLE CODES

Cell Heading	**Code**	**Code Definition**	**Cell Heading**		**Code Definition**
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source &**	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

orced Outage Rate : Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce
(percentage)

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

perating Availability 100 - Maintenance percentage - Forced Outage percentage
(percentage)

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760
(percentage)

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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	5,155	
4	USE	ST	1951	SUB/WOOD	20,061	
					25,216	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
3	25.603	25.603	1.84	83.26	73.54	
4	32.85	32.85	8.30	88.51	0.02	
	58.5	58.5	5.07	85.89	36.78	

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	37		8,930	NG	32,311	MCF	
	WOOD	17,493		8,983				
4	SUB	37		8,930				
	WOOD	17,493		8,983				

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading		Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available X 100}}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production X 100}}{\text{Accredited Capacity Rating (MW) of the Unit X 8,760}}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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	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	42,699	
7	USE	ST	1980	WOOD/COAL	62,280	
4	USE	HC	1917	HYD	2,809	
5	USE	HC	1948	HYD	5,569	
					113,357	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
6	11.4	11.4	46.87	90.26	0.99	
7	13.0	13.0	54.69	84.49	1.81	
4	0.75	0.75	40.50	99.0	1.00	
5	1.5	1.5	41.60	76	14	
	26.7	26.7	45.92	87.4	4.5	

D. UNIT FUEL USED

				PRIMARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity				Unit of Measure ****	BTU Content (for coal only)
6	NG	36,933	MCF				
6	SUB	11,527	TONS				9,313
6	WOOD	42,393	TONS				
7	SUB	6,181	TONS				
7	WOOD	21,123	TONS				

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source &**	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate (percentage) = Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

	#7 TG	#6 TG	#5 Hydro	#4 Hydro
Total Hours Down	380	2672	2560	2123
Sched Maint	236	844	0	0
Forced Outage	144	1828	2560	2123
Maint Percentage	0.026940639	0.096347032	0	0
Forced Outage Rate	1.643835616	20.86757991	29.22374429	24.23515982
Operating factor	98.32922374	79.03607306	70.77625571	75.76484018
Capacity factor	50.456621	22.26883134	30.31018737	65.84221208

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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	98,022	
					98,022	

C. UNIT CAPABILITY DATA — CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
5	22.785	22.785	50.78%	81.11%	6.62%	
	22.785	22.785	51.46%	81.11%	6.62%	

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	22,372	tons		Gas	201,351	MCF	

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate (percentage) = Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) = 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Annual MWH of Production X 100 / Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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	NUMBER OF 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	277,704	
2	USE	ST	1953	COAL	338,381	
3	USE	ST	1954	COAL	448,349	
					1,064,434	

*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	45.18	72.39	3.51	
2	76.05	76.05	55.39	91.20	1.89	
3	83	83	71.09	91.87	4.02	
	237.75	237.75	57.22	85.15	3.14	

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	180,741	TONS	9,044	FO2	64,228	GAL	
2	SUB	220,489	TONS	9,034	FO2	30,068	GAL	
3	SUB	267,268	TONS	9,024	FO2	51,161	GAL	

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading		Code Definition
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source &**	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

orced Outage Rate :rs Unit Failed to be Available X 100
(percentage) ours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

perating Availability) - Maintenance percentage - Forced Outage percenta
(percentage)

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = Total Annual MWH of Production X 100
(percentage) Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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	NUMBER OF 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	0.0	Flood Damage
2	USE	HC	1907	HYD	0.0	Flood Damage
3	USE	HC	1907	HYD	0.0	Flood Damage
4	USE	HC	1914	HYD	0.0	Flood Damage
5	USE	HC	1918	HYD	0.0	Flood Damage
6	USE	HC	1949	HYD	0.0	Flood Damage
					0.0	

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	0.00%	0.00%	100.00%	
2	11.5	11.5	0.00%	0.00%	100.00%	
3	11.5	11.5	0.00%	0.00%	100.00%	
4	11.9	11.9	0.00%	0.00%	100.00%	
5	10.4	10.4	0.00%	0.00%	100.00%	
6	13.6	13.6	0.00%	0.00%	100.00%	
	70.4	70.4	0.00%	0.00%	0.00%	

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)

ALLOWABLE CODES

Cell Heading	**Code**	**Code Definition**	**Cell Heading**	**Code**	**Code Definition**
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source &**	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate : (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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 Station	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	32,059.3	
2	USE	HC	1925	HYD	35,691.3	
3	USE	HC	1988	HYD	19,211.6	
					86,962.2	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	3.427	3.427	61.00%	99.52%	0.31%	
2	4.013	4.013	67.91%	90.46%	9.41%	
3	3.26	3.26	36.55%	99.50%	0.07%	
	10.70	10.7	55.15%	96.49%	3.26%	

D. UNIT FUEL USED

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

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source & Fuel Type**	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

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INSTRUCTIONS: Complete one worksheet for each power plant
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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	4,929.5	
2	USE	HC	1917	HYD	3,546.9	
					8,476.4	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)
1	0.65	0.65	70.34%	99.89%	0.11%
2	0.65	0.65	50.61%	98.28%	1.72%
	1.30	1.29	60.48%	99.09%	0.92%

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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 Station	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	4542.8	
2	USE	HC	1919	HYD	5480.8	
3	USE	HC	1920	HYD	7850.8	
4	USE	HC	1979	HYD	10157.8	
5	USE	HC	1906	HYD	2133.8	
6	USE	HC	1906	HYD	2437.8	
					32603.8	

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	64.82%	99.86%	0.14%	
2	0.60	0.60	78.21%	100.00%	0.00%	
3	0.60	0.60	81.47%	99.94%	0.06%	
4	0.60	0.60	105.42%	98.64%	1.36%	
5	0.60	0.60	60.90%	95.60%	4.40%	
6	0.60	0.60	69.57%	98.57%	1.43%	
	3.60	3.60	76.73%	98.77%	1.23%	

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)

ALLOWABLE CODES

Cell Heading	**Code**	**Code Definition**	**Cell Heading**	**Code**	**Code Definition**
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source &**	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

orced Outage Rate : **(percentage)** Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

perating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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	1,454.9	
2	USE	HC	1923	HYD	2,329.4	
3	USE	HC	1923	HYD	1,351.6	
4	USE	HC	1923	HYD	1,992.1	
					7,128.0	

Unit net figues may not total station net figures

C. UNIT CAPABILITY DATA

Unit ID #	Summer (CAPACITY (MEGAWATTS))	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.02	0.02	39.13%	97.83%	2.17%	
2	0.02	0.02	64.09%	96.42%	0.00%	
3	0.02	0.02	36.18%	97.12%	0.55%	
4	0.02	0.02	53.89%	88.71%	7.67%	
	0.08	0.08	48.32%	95.02%	2.60%	

D. UNIT FUEL USED

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

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source & Fuel Type**	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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	NUMBER OF 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	3,366.8	
2	USE	HC	1913	HYD	3,068.0	
3	USE	HC	1915	HYD	1,867.7	
					8,302.5	

Unit net figures may not total the station net due to

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.4	0.4	61.60%	99.92%	0.00%	
2	0.4	0.4	55.92%	99.92%	0.00%	
3	0.4	0.4	33.07%	95.82%	4.10%	
	1.2	1.2	50.20%	98.55%	1.37%	

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading		Code Definition
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source &**	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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	NUMBER OF 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	9,413.0	
3	USE	HC	1923	HYD	12,145.0	
					21,558.0	

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

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
2	1.10	1.10	53.73%	99.90%	0.10%	
3	1.20	1.20	69.32%	100.00%	0.00%	
	2.30	2.30	61.53%	99.95%	0.05%	

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading		Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate : (percentage) $\frac{\text{Hours Unit Failed to be Available X 100}}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production X 100}}{\text{Accredited Capacity Rating (MW) of the Unit X 8,760}}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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	NUMBER OF 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	2,635.5	
2	USE	HC	1922	HYD	3,191.9	
3	USE	HC	1922	HYD	3,807.3	
					9,634.7	

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

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.3	0.3	35.10%	96.00%	0.47%	
2	0.3	0.3	43.04%	94.52%	5.48%	
3	0.3	0.3	51.82%	95.91%	0.00%	
	0.9	0.9	43.32%	95.48%	1.98%	

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading		Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT:2013

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	14312.2	online 6/28/13
					14312.2	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	11.1	11.1	14.46	37.71	8.18	
	11.1	11.1	14.46	37.71	8.18	

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading		Code Definition
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source & Fuel Type**	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available X 100}}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production X 100}}{\text{Accredited Capacity Rating (MW) of the Unit X 8,760}}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2013

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	612.1	
2	USE	HC	1921	HYD	681.0	
					1,293.1	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	
1	0.5	0.5	9.98	50.22	49.78	
2	0.5	0.5	19.43	47.75	52.25	
	1	1	14.71	48.99	51.02	

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading		Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)
Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage)
100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)
Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2013

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	Todd Simmons		
TELEPHONE	218-722-5642 x 6102		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	Use	WI	2008	Wind	55,891	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	25.0	25.0	26.5	87.7	10.9	

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

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate (percentage) = Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) = 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

Note: Per Julie Pierce Tac Ridge is to be reported as a single entity

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2013

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	Bison 1	PLANT ID	(leave this cell blank)
STREET ADDRESS	5198 30th Street		
CITY	New Salem		
		NUMBER OF UNITS	1
STATE	ND		
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	780,799	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	81.8	291.8	30.50	96.22	3.73	

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

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

INSTRUCTIONS

The individual worksheets in this spreadsheet file correspond closely to the tables in the paper forms received by the utility.
The instructions provided with the paper forms also pertain to the data to be entered in each of the worksheets in this file.
PLEASE DO NOT CHANGE THE NAME OR ORDER OF ANY OF THE WORKSHEET TABS IN THIS FILE

In general, the following scheme is used on each worksheet:

Cells shown with a light green background correspond to headings for columns, rows or individual fields.
Cells shown with a light yellow background require data to be entered by the utility.
Cells shown with a light brown background generally correspond to fields that are calculated from the data entered, or correspond to fields that are informational and not to be modified by the utility.

Each worksheet contains a section labeled Comments below the main data entry area.
You may enter any comments in that section that may be needed to explain or clarify the data being entered on the worksheet.

Please complete the required worksheets and save the completed spreadsheet file to your local computer.
Then attach the completed spreadsheet file to an e-mail message and send it to the following e-mail address:

rule7610.reports@state.mn.us

If you have any questions please contact:

Steve Loomis
MN Department of Commerce
steve.loomis@state.mn.us
(651) 539-1690

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0120 REGISTRATION

ENTITY ID#	68
REPORT YEAR	2013

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	
CONTACT TITLE	
STREET ADDRESS	
CITY	
STATE	
ZIP CODE	
TELEPHONE	
CONTACT E-MAIL	

COMMENTS

PREPARER INFORMATION	
REPARING 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	2013	No. of Cust.	2,397	118,917	21,915	9	394	592	287	144,511	144,511
		MWH	67,547	1,018,934	1,256,540	4,851,094	2,022,899	16,066	51,736	9,284,816	9,284,816
Present Year	2014	No. of Cust.	2,397	118,421	21,921	9	378	664	281	144,072	144,072
		MWH	67,547	1,058,986	1,284,024	4,888,265	2,041,484	16,346	54,172	9,410,825	9,410,825
1st Forecast Year	2015	No. of Cust.	2,397	120,668	22,376	10	370	726	290	146,837	146,837
		MWH	67,547	1,034,325	1,287,245	5,152,115	2,025,526	16,380	54,967	9,638,104	9,638,104
2nd Forecast Year	2016	No. of Cust.	2,397	121,846	22,644	11	367	789	293	148,348	148,348
		MWH	67,547	1,049,601	1,310,008	5,343,277	1,899,090	16,654	56,293	9,742,469	9,742,469
3rd Forecast Year	2017	No. of Cust.	2,397	122,805	22,928	11	371	854	297	149,664	149,664
		MWH	67,547	1,056,768	1,326,212	5,259,033	1,866,742	16,738	56,630	9,649,670	9,649,670
4th Forecast Year	2018	No. of Cust.	2,397	123,600	23,205	11	373	910	300	150,796	150,796
		MWH	67,547	1,068,386	1,343,242	5,269,835	1,907,452	16,755	56,906	9,730,122	9,730,122
5th Forecast Year	2019	No. of Cust.	2,397	124,145	23,469	11	374	964	302	151,663	151,663
		MWH	67,547	1,076,748	1,357,620	5,298,345	1,907,153	16,807	56,903	9,781,122	9,781,122
6th Forecast Year	2020	No. of Cust.	2,397	124,739	23,749	11	374	1,015	304	152,589	152,589
		MWH	67,547	1,088,722	1,375,938	5,346,458	1,906,849	16,944	57,131	9,859,589	9,859,589
7th Forecast Year	2021	No. of Cust.	2,397	125,236	24,021	11	376	1,063	306	153,409	153,409
		MWH	67,547	1,093,611	1,388,599	5,347,759	1,899,252	16,941	57,266	9,870,975	9,870,975
8th Forecast Year	2022	No. of Cust.	2,397	125,735	24,293	11	375	1,112	307	154,230	154,230
		MWH	67,547	1,103,120	1,404,045	5,361,331	1,898,813	17,035	57,401	9,909,293	9,909,293
9th Forecast Year	2023	No. of Cust.	2,397	126,165	24,564	11	374	1,158	309	154,978	154,978
		MWH	67,547	1,111,530	1,419,552	5,389,933	1,893,949	17,051	57,571	9,957,134	9,957,134
10th Forecast Year	2024	No. of Cust.	2,397	126,586	24,833	11	372	1,204	310	155,712	155,712
		MWH	67,547	1,122,300	1,439,572	5,433,098	1,888,628	17,183	57,798	10,026,126	10,026,126
11th Forecast Year	2025	No. of Cust.	2,397	126,956	25,107	11	370	1,250	311	156,402	156,402
		MWH	67,547	1,127,022	1,453,153	5,450,764	1,876,487	17,167	57,797	10,049,937	10,049,937
12th Forecast Year	2026	No. of Cust.	2,397	127,476	25,385	11	366	1,294	312	157,241	157,241
		MWH	67,547	1,135,754	1,468,463	5,480,029	1,875,269	17,247	58,054	10,102,362	10,102,362
13th Forecast Year	2027	No. of Cust.	2,397	128,036	25,664	11	363	1,341	313	158,125	158,125
		MWH	67,547	1,145,056	1,484,940	5,509,184	1,874,130	17,298	58,370	10,156,524	10,156,524
14th Forecast Year	2028	No. of Cust.	2,397	128,663	25,946	11	358	1,388	315	159,077	159,077
		MWH	67,547	1,158,738	1,505,777	5,553,365	1,878,679	17,454	58,896	10,240,455	10,240,455

* 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	2013	No. of Cust.	2,397	118,917	21,915	9	394	592	287	144,511	144,511
		MWH	67,547	1,018,934	1,256,540	4,851,094	2,022,899	16,066	51,736	9,284,816	9,284,816
Present Year	2014	No. of Cust.	2,397	118,421	21,921	9	378	664	281	144,072	144,072
		MWH	67,547	1,058,986	1,284,024	4,888,265	2,041,484	16,346	54,172	9,410,825	9,410,825
1st Forecast Year	2015	No. of Cust.	2,397	120,668	22,376	10	370	726	290	146,837	146,837
		MWH	67,547	1,034,325	1,287,245	5,152,115	2,025,526	16,380	54,967	9,638,104	9,638,104
2nd Forecast Year	2016	No. of Cust.	2,397	121,846	22,644	11	367	789	293	148,348	148,348
		MWH	67,547	1,049,601	1,310,008	5,343,277	1,899,090	16,654	56,293	9,742,469	9,742,469
3rd Forecast Year	2017	No. of Cust.	2,397	122,805	22,928	11	371	854	297	149,664	149,664
		MWH	67,547	1,056,768	1,326,212	5,259,033	1,866,742	16,738	56,630	9,649,670	9,649,670
4th Forecast Year	2018	No. of Cust.	2,397	123,600	23,205	11	373	910	300	150,796	150,796
		MWH	67,547	1,068,386	1,343,242	5,269,835	1,907,452	16,755	56,906	9,730,122	9,730,122
5th Forecast Year	2019	No. of Cust.	2,397	124,145	23,469	11	374	964	302	151,663	151,663
		MWH	67,547	1,076,748	1,357,620	5,298,345	1,907,153	16,807	56,903	9,781,122	9,781,122
6th Forecast Year	2020	No. of Cust.	2,397	124,739	23,749	11	374	1,015	304	152,589	152,589
		MWH	67,547	1,088,722	1,375,938	5,346,458	1,906,849	16,944	57,131	9,859,589	9,859,589
7th Forecast Year	2021	No. of Cust.	2,397	125,236	24,021	11	376	1,063	306	153,409	153,409
		MWH	67,547	1,093,611	1,388,599	5,347,759	1,899,252	16,941	57,266	9,870,975	9,870,975
8th Forecast Year	2022	No. of Cust.	2,397	125,735	24,293	11	375	1,112	307	154,230	154,230
		MWH	67,547	1,103,120	1,404,045	5,361,331	1,898,813	17,035	57,401	9,909,293	9,909,293
9th Forecast Year	2023	No. of Cust.	2,397	126,165	24,564	11	374	1,158	309	154,978	154,978
		MWH	67,547	1,111,530	1,419,552	5,389,933	1,893,949	17,051	57,571	9,957,134	9,957,134
10th Forecast Year	2024	No. of Cust.	2,397	126,586	24,833	11	372	1,204	310	155,712	155,712
		MWH	67,547	1,122,300	1,439,572	5,433,098	1,888,628	17,183	57,798	10,026,126	10,026,126
11th Forecast Year	2025	No. of Cust.	2,397	126,956	25,107	11	370	1,250	311	156,402	156,402
		MWH	67,547	1,127,022	1,453,153	5,450,764	1,876,487	17,167	57,797	10,049,937	10,049,937
12th Forecast Year	2026	No. of Cust.	2,397	127,476	25,385	11	366	1,294	312	157,241	157,241
		MWH	67,547	1,135,754	1,468,463	5,480,029	1,875,269	17,247	58,054	10,102,362	10,102,362
13th Forecast Year	2027	No. of Cust.	2,397	128,036	25,664	11	363	1,341	313	158,125	158,125
		MWH	67,547	1,145,056	1,484,940	5,509,184	1,874,130	17,298	58,370	10,156,524	10,156,524
14th Forecast Year	2028	No. of Cust.	2,397	128,663	25,946	11	358	1,388	315	159,077	159,077
		MWH	67,547	1,158,738	1,505,777	5,553,365	1,878,679	17,454	58,896	10,240,455	10,240,455

* 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	2013	9,284,816	-	4,013,286	3,979,246	9,555,798	305,022	4,759,658	4,576,504	0
Present Year	2014	9,410,825	-	3,415,095	3,819,839	10,520,059	704,491	4,813,027	4,630,817	0
1st Forecast Year	2015	9,638,104	-	3,689,431	4,049,145	10,731,653	733,836	4,916,919	4,796,562	0
2nd Forecast Year	2016	9,742,469	-	3,682,317	3,642,550	10,484,598	781,896	4,884,875	4,804,501	0
3rd Forecast Year	2017	9,649,670	-	3,936,031	3,578,020	10,069,150	777,491	4,905,966	4,772,031	0
4th Forecast Year	2018	9,730,122	-	4,017,191	3,538,651	10,034,594	783,011	4,934,868	4,808,120	0
5th Forecast Year	2019	9,781,122	-	4,220,574	3,537,240	9,884,402	786,614	4,991,574	4,833,888	0
6th Forecast Year	2020	9,859,589	-	3,759,756	3,424,976	10,317,216	792,407	4,990,117	4,858,949	0
7th Forecast Year	2021	9,870,975	-	3,570,102	3,434,787	10,528,734	793,075	5,009,702	4,873,787	0
8th Forecast Year	2022	9,909,293	-	3,678,758	3,191,222	10,217,717	795,961	5,030,280	4,892,247	0
9th Forecast Year	2023	9,957,134	-	3,564,543	3,238,486	10,430,506	799,428	5,083,268	4,914,793	0
10th Forecast Year	2024	10,026,126	-	3,437,655	3,210,059	10,603,211	804,682	5,085,501	4,933,832	0
11th Forecast Year	2025	10,049,937	-	3,549,770	3,083,437	10,389,712	806,107	5,110,292	4,955,612	0
12th Forecast Year	2026	10,102,362	-	3,496,958	3,066,671	10,481,889	809,813	5,138,054	4,981,628	0
13th Forecast Year	2027	10,156,524	-	3,587,010	3,068,068	10,451,235	813,653	5,196,395	5,006,633	0
14th Forecast Year	2028	10,240,455	-	3,878,121	2,978,388	10,160,529	819,807	5,200,302	5,032,940	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	2013	11.5	168.0	264.3	606.5	377.1	2.7	351.5	1781.5	1781.5

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	2013	1773.9	1754.2	1649.5	1558.4	1570.6	1618.4	1769.8	1781.5	1716.7	1557.9	1688.3	1708.6

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	2013	Summer								
		Winter								
Present Year	2014	Summer								
		Winter								
1st Forecast Year	2015	Summer								
		Winter								
2nd Forecast Year	2016	Summer								
		Winter								
3rd Forecast Year	2017	Summer								
		Winter								
4th Forecast Year	2018	Summer								
		Winter								
5th Forecast Year	2019	Summer								
		Winter								
6th Forecast Year	2020	Summer								
		Winter								
7th Forecast Year	2021	Summer								
		Winter								
8th Forecast Year	2022	Summer								
		Winter								
9th Forecast Year	2023	Summer								
		Winter								
10th Forecast Year	2024	Summer								
		Winter								
11th Forecast Year	2025	Summer								
		Winter								
12th Forecast Year	2026	Summer								
		Winter								
13th Forecast Year	2027	Summer								
		Winter								
14th Forecast Year	2028	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	2013	Summer								
		Winter								
Present Year	2014	Summer								
		Winter								
1st Forecast Year	2015	Summer								
		Winter								
2nd Forecast Year	2016	Summer								
		Winter								
3rd Forecast Year	2017	Summer								
		Winter								
4th Forecast Year	2018	Summer								
		Winter								
5th Forecast Year	2019	Summer								
		Winter								
6th Forecast Year	2020	Summer								
		Winter								
7th Forecast Year	2021	Summer								
		Winter								
8th Forecast Year	2022	Summer								
		Winter								
9th Forecast Year	2023	Summer								
		Winter								
10th Forecast Year	2024	Summer								
		Winter								
11th Forecast Year	2025	Summer								
		Winter								
12th Forecast Year	2026	Summer								
		Winter								
13th Forecast Year	2027	Summer								
		Winter								
14th Forecast Year	2028	Summer								
		Winter								

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

Capacity- External

NAME OF OTHER UTILITY =>			Laurentian Energy (LEA (Hibb&Virg)	Oliver Cty Wind (ND FPLE 1&2)	Wing River Wind (CBED)	Manitoba Hydro (MHEB)	Minnkota Power Cooperative (MPC)	Xcel Energy
Past Year	2013	Summer	13.1	13.9	0.4	50	0	0
		Winter	13.1	13.9	0.4	50	50	0
Present Year	2014	Summer	13.1	13.9	0.4	50	50	30
		Winter	13.1	13.9	0.4	50	50	30
1st Forecast Year	2015	Summer	13.1	13.9	0.4	50	50	0
		Winter	13.1	13.9	0.4	50	50	0
2nd Forecast Year	2016	Summer	13.1	13.9	0.4	50	50	0
		Winter	13.1	13.9	0.4	50	50	0
3rd Forecast Year	2017	Summer	13.1	13.9	0.4	50	50	0
		Winter	13.1	13.9	0.4	50	50	0
4th Forecast Year	2018	Summer	13.1	13.9	0.4	50	50	0
		Winter	13.1	13.9	0.4	50	50	0
5th Forecast Year	2019	Summer	13.1	13.9	0.4	50	50	0
		Winter	13.1	13.9	0.4	50	50	0
6th Forecast Year	2020	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
7th Forecast Year	2021	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
8th Forecast Year	2022	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
9th Forecast Year	2023	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
10th Forecast Year	2024	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
11th Forecast Year	2025	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
12th Forecast Year	2026	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
13th Forecast Year	2027	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0
14th Forecast Year	2028	Summer	13.1	13.9	0.4	250	0	0
		Winter	13.1	13.9	0.4	250	0	0

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>			BEPC	Minnkota Power Cooperative (MPC)
Past Year	2013	Summer	100	50
		Winter	100	0
Present Year	2014	Summer	100	0
		Winter	100	0
1st Forecast Year	2015	Summer	100	0
		Winter	100	0
2nd Forecast Year	2016	Summer	100	0
		Winter	100	0
3rd Forecast Year	2017	Summer	100	0
		Winter	100	0
4th Forecast Year	2018	Summer	100	0
		Winter	100	0
5th Forecast Year	2019	Summer	100	0
		Winter	100	0
6th Forecast Year	2020	Summer	0	0
		Winter	0	0
7th Forecast Year	2021	Summer	0	0
		Winter	0	0
8th Forecast Year	2022	Summer	0	0
		Winter	0	0
9th Forecast Year	2023	Summer	0	0
		Winter	0	0
10th Forecast Year	2024	Summer	0	0
		Winter	0	0
11th Forecast Year	2025	Summer	0	0
		Winter	0	0
12th Forecast Year	2026	Summer	0	0
		Winter	0	0
13th Forecast Year	2027	Summer	0	0
		Winter	0	0
14th Forecast Year	2028	Summer	0	0
		Winter	0	0

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item G. LOAD AND GENERATION CAPACITY (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	2013	Summer	1782		1782	1782			1782	1782	2058	77	150	1985	191	1972	13
		Winter	1751		1751	1782			1751	1782	1990	127	100	2017	187	1938	79
Present Year	2014	Summer	1727		1727	1772			1727	1772	1885	157	100	1942	185	1912	30
		Winter	1772		1772	1772			1772	1772	1885	157	100	1942	190	1961	-20
1st Forecast Year	2015	Summer	1807		1807	1931			1807	1931	1918	127	100	1945	194	2001	-56
		Winter	1931		1931	1931			1931	1931	1930	127	100	1957	208	2138	-181
2nd Forecast Year	2016	Summer	1923		1923	1958			1923	1958	1942	127	100	1969	207	2129	-160
		Winter	1958		1958	1958			1958	1958	1942	127	100	1969	211	2168	-199
3rd Forecast Year	2017	Summer	1941		1941	1973			1941	1973	1956	127	100	1983	207	2148	-165
		Winter	1973		1973	1973			1973	1973	1956	127	100	1983	211	2184	-201
4th Forecast Year	2018	Summer	1954		1954	1979			1954	1979	1956	127	100	1983	209	2162	-179
		Winter	1979		1979	1979			1979	1979	1956	127	100	1983	212	2191	-208
5th Forecast Year	2019	Summer	1962		1962	1988			1962	1988	1956	127	100	1983	210	2171	-188
		Winter	1988		1988	1988			1988	1988	1956	127	100	1983	213	2201	-218
6th Forecast Year	2020	Summer	1970		1970	1996			1970	1996	1956	277	0	2233	211	2181	53
		Winter	1996		1996	1996			1996	1996	1956	277	0	2233	214	2209	24
7th Forecast Year	2021	Summer	1976		1976	2003			1976	2003	1956	277	0	2233	211	2187	46
		Winter	2003		2003	2003			2003	2003	1956	277	0	2233	214	2217	16
8th Forecast Year	2022	Summer	1982		1982	2010			1982	2010	1936	277	0	2213	212	2195	19
		Winter	2010		2010	2010			2010	2010	2116	277	0	2393	215	2225	168
9th Forecast Year	2023	Summer	1990		1990	2019			1990	2019	2116	277	0	2393	213	2202	191
		Winter	2019		2019	2019			2019	2019	2096	277	0	2373	216	2235	137
10th Forecast Year	2024	Summer	1997		1997	2028			1997	2028	2096	277	0	2373	214	2210	162
		Winter	2028		2028	2028			2028	2028	2076	277	0	2353	217	2245	108
11th Forecast Year	2025	Summer	2004		2004	2035			2004	2035	2076	277	0	2353	214	2218	134
		Winter	2035		2035	2035			2035	2035	2056	277	0	2333	218	2253	79
12th Forecast Year	2026	Summer	2011		2011	2044			2011	2044	2056	277	0	2333	215	2227	106
		Winter	2044		2044	2044			2044	2044	2056	277	0	2333	219	2263	70
13th Forecast Year	2027	Summer	2019		2019	2053			2019	2053	2056	277	0	2333	216	2235	97
		Winter	2053		2053	2053			2053	2053	2056	277	0	2333	220	2273	59
14th Forecast Year	2028	Summer	2027		2027	2063			2027	2063	2056	277	0	2333	217	2244	89
		Winter	2063		2063	2063			2063	2063	2056	277	0	2333	221	2284	49

COMMENTS

Minnesota Power utilizes MISO's ICAP Reserve Capacity calculation and reserve margin assumption of 11.32%

Method for calculating Reserve Capacity Obligation:
[(Peak Demand - Demand Resource) x (1+11.32%)] - Peak Demand + Demand Resource = Net Reserve Capacity Obligation

Net Generating Capability values (column 9) are taken from MISO PY 2014-2015. Available Demand Resource MW is included in Net Generating Capability to balance Load and Capability.

Note: The above table reflects the most current econometric forecast and customer assumptions. Minnesota Power's MISO Peak Demand Submittal for summer of 2014 was based on a non-coincident peak of 1735 MW. The winter peak forecast was 1783 MW. 2013 peak demand values are actuals. Thus, the surplus/ deficit shown in the above table will vary from what was entered in MISO Module E in November 2013.

As shown in Minnesota Power's most recent Integrated Resource Plan, Minnesota Power is in the process of executing a bilateral bridging strategy to address the deficits identified in the 2016-2019 timeframe

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

		ADDITIONS	RETIREMENTS
Past Year	2013		
Present Year	2014		
1st Forecast Year	2015	205	70
2nd Forecast Year	2016		
3rd Forecast Year	2017		
4th Forecast Year	2018		
5th Forecast Year	2019		
6th Forecast Year	2020		
7th Forecast Year	2021		
8th Forecast Year	2022	200	
9th Forecast Year	2023		
10th Forecast Year	2024		
11th Forecast Year	2025		
12th Forecast Year	2026		
13th Forecast Year	2027		
14th Forecast Year	2028		

COMMENTS

PUBLIC DOCUMENT
TRADE SECRET DATA
HAS BEEN EXCISED

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

Trade Secret Data Excised

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	2013												
Present Year	2014												
1st Forecast Year	2015												
2nd Forecast Year	2016												
3rd Forecast Year	2017												
4th Forecast Year	2018												
5th Forecast Year	2019												
6th Forecast Year	2020												
7th Forecast Year	2021												
8th Forecast Year	2022												
9th Forecast Year	2023												
10th Forecast Year	2024												
11th Forecast Year	2025												
12th Forecast Year	2026												
13th Forecast Year	2027												
14th Forecast Year	2028												

LIST OF FUEL TYPES

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

COMMENTS

Fuel Requirements for Rapids Energy Center are not shown.

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	WING 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	ROCK CREEK (KETTLE RIVER)	11.8		795 ACSR
230 AC	904	BOSWELL	CASS LAKE***	4.65		795 ACSS
230 AC	907	SHANNON	LITTLEFORK	81.62		954 ACSR
230 AC	909	HUBBARD	AUDUBON (SHELL RIVER)	4.53		795 ACSR
230 AC	R50M	RUNNING	MORANVILLE	7.51		954 ACSR
230 AC	n/a	CASS LAKE	WILTON***	1.77		795 ACSS
250 DC	DC LINE	ARROWHEAD	SQUARE BUTTE (ND BORDER)	231.56		2839 ACSR
345 AC	n/a	MONTICELLO	QUARRY**	4.23		2-954 ACSS/TW
500 AC	601	CHISAGO (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		345 kV	2-954 bundle	ACSS/TW	AC	Quarry - Alexandria	2014	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

COMMENTS

The two 345 kV line additions listed are part of the CapX 2020 Twin Cities-Fargo 345 kV Project. The Monticello-Quarry (St. Cloud) segment of the line was energized in December 2011. Future construction includes a segment between St. Cloud and the Alexandria area and between Alexandria and the Bison Substation in the Fargo area. Minnesota Power will own 14.7% of this line under a "tenants in common" ownership model; the other owners will be Otter Tail Power Company, Missouri River Energy Services, Great River Energy, and Xcel Energy.

The Dorsey-Blackberry 500 kV line is part of the Great Northern Transmission Line Project and is required to deliver MP's 250 MW power purchase agreement (PPA) and 133 MW renewable optimization agreement (ROA) with Manitoba Hydro. Since the project is designed to facilitate up to 750 MW of incremental transfer capability in order to accomodate other Manitoba - U.S. transactions, the ownership structure for the U.S. portion of the project has not yet been determined. This line needs to be in service by 2020 to meet the requirements of MP's PPA and ROA.

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 that the utility plans to retire within the next 15 years.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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	
	8/20/13	1/21/13	<= ENTER DATES
TIME OF DAY	MW USED ON SUMMER PEAK DAY	MW USED ON WINTER PEAK DAY	
0100	1538	1623	
0200	1506	1615	
0300	1493	1601	
0400	1487	1610	
0500	1495	1600	
0600	1510	1651	
0700	1541	1684	
0800	1589	1691	
0900	1628	1718	
1000	1676	1710	
1100	1730	1717	
1200	1761	1723	
1300	1771	1695	
1400	**1782**	1682	
1500	1770	1717	
1600	1764	1735	
1700	1767	1721	
1800	1753	1718	
1900	1739	**1774**	
2000	1728	1750	
2100	1733	1765	
2200	1720	1745	
2300	1647	1674	
2400	1597	1644	

COMMENTS

APPENDIX B: DEMAND SIDE MANAGEMENT

This Appendix of the 2015 Integrated Resource Plan ("2015 Plan" or "Plan") contains information regarding Minnesota Power's planning and strategies for demand side management ("DSM"), energy efficiency and Conservation Improvement Programs ("CIP"). Minnesota Power's performance and planning outlooks for DSM, energy efficiency and CIP are broken into four parts in this Appendix:

1. Minnesota Power's Conservation Program Strategy
2. Energy Conservation Resource Alternatives and Rate Impact Study
3. Consideration of Additional Demand Response Programs
4. Order Point 12 Considerations

Part 1: Minnesota Power's Conservation Program Strategy

Minnesota Power (or "Company") is committed to providing sustainable energy-efficiency programs as is demonstrated by its recent CIP achievements. Since the Next Generation Energy Act of 2007, Minnesota Power has been refining and expanding upon its proven conservation program platform, referred to collectively and referred to herein as Power of One® or CIP, to deliver cost-effective savings and customer value. The Company remains dedicated to continuous program improvement and views ongoing CIP initiatives as part of its broader *Energy**Forward*** resource strategy; a strategy designed to provide a safe, reliable and affordable power supply while improving environmental performance. As part of the planning process for the 2015 Plan, Minnesota Power has evaluated past CIP performance, related success factors, and potential future opportunities to determine scenarios that would help meet the Company's resource planning goals, while also continuing to deliver on the State's 1.5 percent energy-savings goal for cost-effective energy efficiency.

Minnesota Power's approach to developing scenarios for energy efficiency[1] achieved through CIP, included analysis and research providing insight into historical performance, future opportunities, and the changing energy-efficiency environment. One of the key findings from the analysis was that a significant portion of the most cost-effective savings in the past has been achieved through a small number of very large, strategically planned customer projects. Given the circumstantial nature of these large-scale projects, predicting the opportunity for projects of similar magnitude in the future cannot be done with any degree of certainty. Due to the extent that recent CIP achievements have been driven by these large-scale projects, there is a high degree of risk associated with assuming historical performance is sustainable for the 2015 planning period or that savings levels can be increased from one year to the next.

The current energy-efficiency environment is rapidly evolving. The impact of potential regulatory and environmental policy changes on CIP statute and on customer behavior and

[1] According to Minn. Stat. 216B.241, "energy efficiency" means measures or programs, including energy conservation measures or programs, that target consumer behavior, equipment, processes, or devices designed to produce either an absolute decrease in consumption of electric energy or natural gas or a decrease in consumption of electric energy or natural gas on a per unit of production basis without a reduction in the quality or level of service provided to the energy consumer.

attitudes regarding energy use is still unknown. Similarly, the ongoing efforts to improve, change, or standardize the methods and assumptions used for estimating savings affirm there is some uncertainty over actual achieved and achievable savings. While the current estimation methodologies are acceptable means of measuring program performance and gauging savings impacts, long-term resource planning necessitates reducing risk and uncertainty. As such, a conservative approach to determining the best level of energy efficiency to incorporate in the resource plan is imperative.

Key factors of the costs and benefits associated with various levels of energy efficiency are not only the environmental benefits and potential overall cost savings associated with conservation, but also the actual rate impact on each individual customer class. Given the current rate structure and cost recovery mechanisms, high energy-efficiency commitments could lead to some reductions in total cost, but would likely be accompanied by rate increases for certain customer subsets. Balancing these impacts was an important consideration during the planning process.

Taking these factors into account, Minnesota Power has included additional investment in CIP as part of its short-term action plan in order to augment its already high performing energy efficiency portfolio. (See Section IV for details on energy efficiency included in the resource plan.) The Company believes that some additional savings compared to the existing CIP may be achievable and will continue its efforts to determine that level of savings along with delivery strategies. The need for low-cost, environmentally-friendly resources, balanced with the need to minimize risk and allocate costs appropriately across eligible customer segments are vital in this determination. Minnesota Power will further evaluate energy-efficiency opportunities and evolve the Power of One® platform with refined program design assumptions. Planning efforts for the 2017–2019 CIP Triennial Filing begin later this year, and more details, such as an updated Technical Resource Manual,[2] will become available for the evaluation.

The remainder of this section summarizes Minnesota Power's recent CIP achievements, discusses in more detail the factors that impact the Power of One® program design strategy, savings potential, and recommended savings goal, and introduces the scenarios modeled for the 2015 Plan.

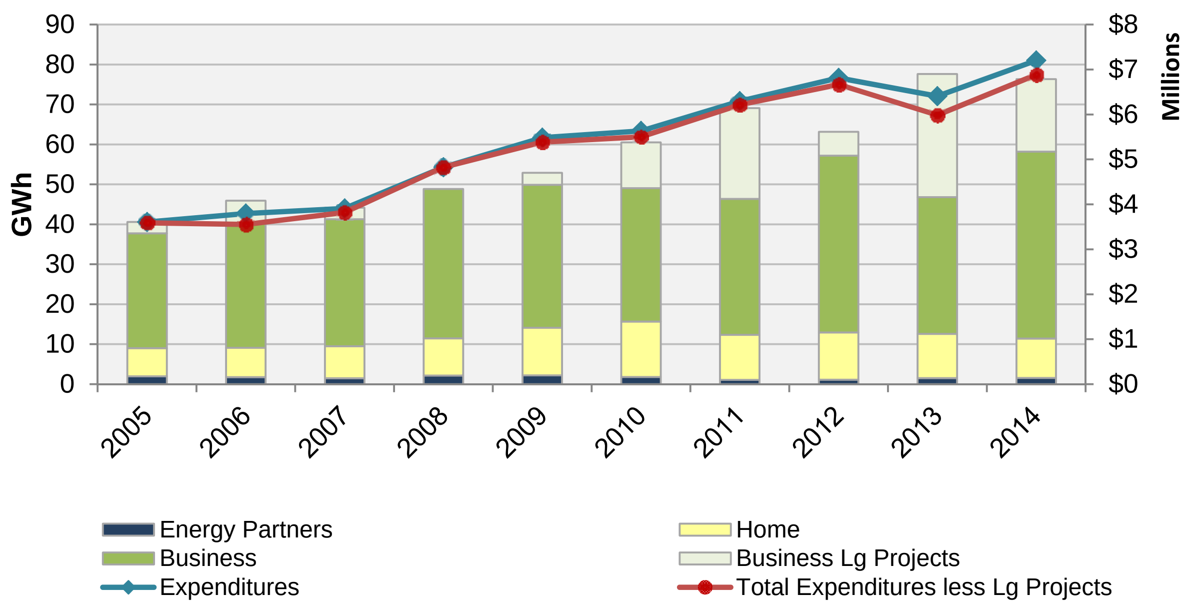
Part 2 of this Appendix presents the scenarios in more detail, summarizes the study methodology and results, and discusses industry trends and research that support Minnesota Power's energy-efficiency modeling approach and recommendations.

Minnesota Power's Recent CIP Costs and Achievements

Minnesota Power has met or exceeded the 1.5 percent savings goal since the Next Generation Energy Act of 2007 was implemented in 2010. Between 2010 and 2014, achieved first-year savings ranged from roughly 60,000 to roughly 78,000 MWh, with costs ranging between $5.6 million and $7.2 million. First-year savings averaged about $0.09 per kWh—about $0.15/kWh less than the 2013 industry average.[3]

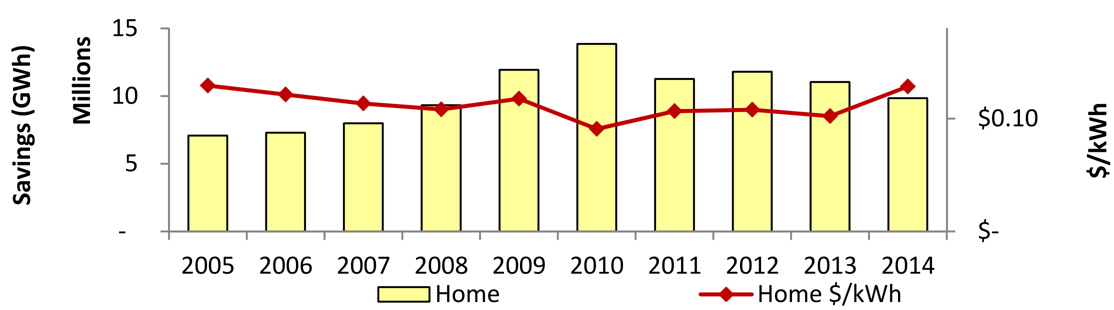
[2] The Minnesota Technical Reference Manual (TRM), developed and maintained by the Department of Commerce, consists of a set of standard methodologies and inputs for calculating the savings impacts and cost-effectiveness of energy conservation improvement programs (CIP) in Minnesota.
[3] E-Source: DSM Achievements and Expenditures 2013 Research Results.

Figure 1: Minnesota Power Historical CIP Achievements



Residential programs, referred to as "Home" and "Energy Partners" within the Company's portfolio, tend to be more expensive on average and make up just under 20 percent of annual CIP savings. Costs for these programs have increased over the past four years from about $90/MWh in 2010 to almost $130/MWh in 2014.[4] At the same time, achieved savings have decreased from about 13,800 MWh in 2010[5] to about 9,800 MWh in 2014.[6] These trends indicate that residential savings may level off for a period of time and, until new and substantially different technologies are introduced, these costs are likely to continue rising.

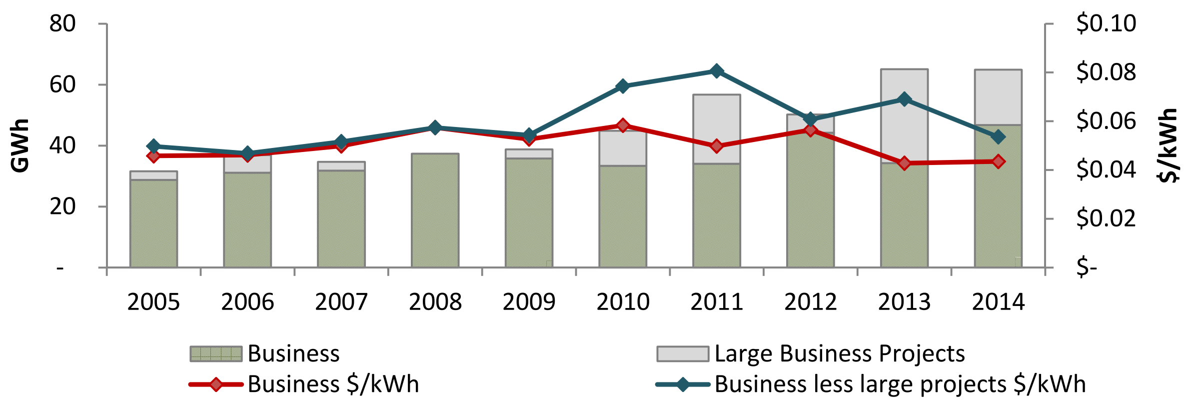
Figure 2: Residential Cost per kWh (First-year Savings)



[4] Cost per kWh calculations in this section are based on first-year energy savings and direct impact spending as filed in the respective Minnesota Power CIP Consolidated Filing. They do not include indirect program costs.
[5] Docket No. E015/CIP-08-610.02.
[6] Docket No. E015/CIP-13-409.01.

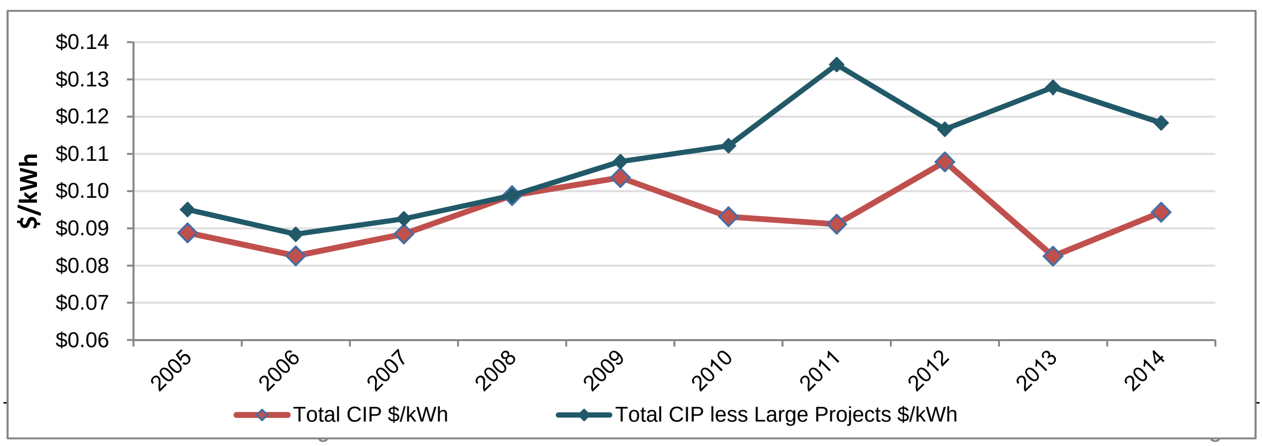
The commercial/industrial ("C/I") program or "Business" program, accounts for the majority of CIP savings (roughly 80 percent). It has shown a slight decrease in (first-year savings) costs between 2010 and 2014, going from just under $60/MWh to about $45/MWh, and averaging $50/MWh. In further contrast to the residential programs, C/I savings have increased over the same period from roughly 44,900 MWh in 2010 to about 65,000 MWh in 2013 and 2014. Notably, a small number of very large projects contributed a substantial amount of the energy savings with proportionally lower costs across several years.[7]

Figure 3: Commercial and Industrial Cost per kWh (First-year Savings)



Large project contributions over the past five years have ranged between roughly 6,000 MWh and just over 31,000 MWh, accounting for between nine percent and 40 percent of total portfolio savings. This is reflected in the large business project bars in Figure 3, and shows that large projects have played a major part in reaching the goal in recent years. An analysis of recent performance without these large projects reveals lower total achieved savings. Moreover, while the savings associated with these projects are clearly substantial, the associated costs are essentially insignificant relative to total costs, resulting in noticeably higher costs per MWh when the large projects are removed. This effect can also be seen in Figures 3 and 4. However, it should be noted that actual performance, absent these projects, is difficult to estimate as other program delivery strategies would likely have been deployed, making actual historical performance and cost figures an interesting, but not conclusive, data point.

Figure 4: Total Portfolio Cost per kWh (First-year Savings)



These large project savings contributions unduly skew results, and should be normalized to some degree for planning purposes, particularly given the limited number of eligible customers large enough to have projects of this scale or magnitude.

Because these projects have been fairly prevalent in recent years, predicting the actual cost of consistently achieving historic levels of savings without them is difficult. Although the Company believes it may be possible to cost-effectively sustain savings levels higher than the current 1.5 percent target in the future, careful consideration of future costs should be given, and incremental savings goals should be set with caution until more experience with these changing delivery conditions can provide further insight.

Evaluation of Energy Efficiency

Energy efficiency performance, goals, and costs are discussed and evaluated differently for CIP planning as compared to resource planning purposes. From a CIP perspective, energy efficiency goals are annual goals. As such, costs are typically assessed using cost of first-year savings only and goals primarily focus on first-year energy savings with less emphasis on demand savings (and even less emphasis on the timing of demand savings). In CIP planning and evaluation, lifetime (or cumulative) energy savings and demand savings are not directly considered from a goal achievement perspective, though they are reflected in the standard benefit-cost analysis tests which have a direct tie to performance. Much of the rationale for these nuances stem from the multifaceted objectives associated with CIP policy objectives, which are wide ranging in scope and designed not only to achieve aggressive energy savings, but also to provide education, assistance, and support to all eligible customers interested in energy efficiency.

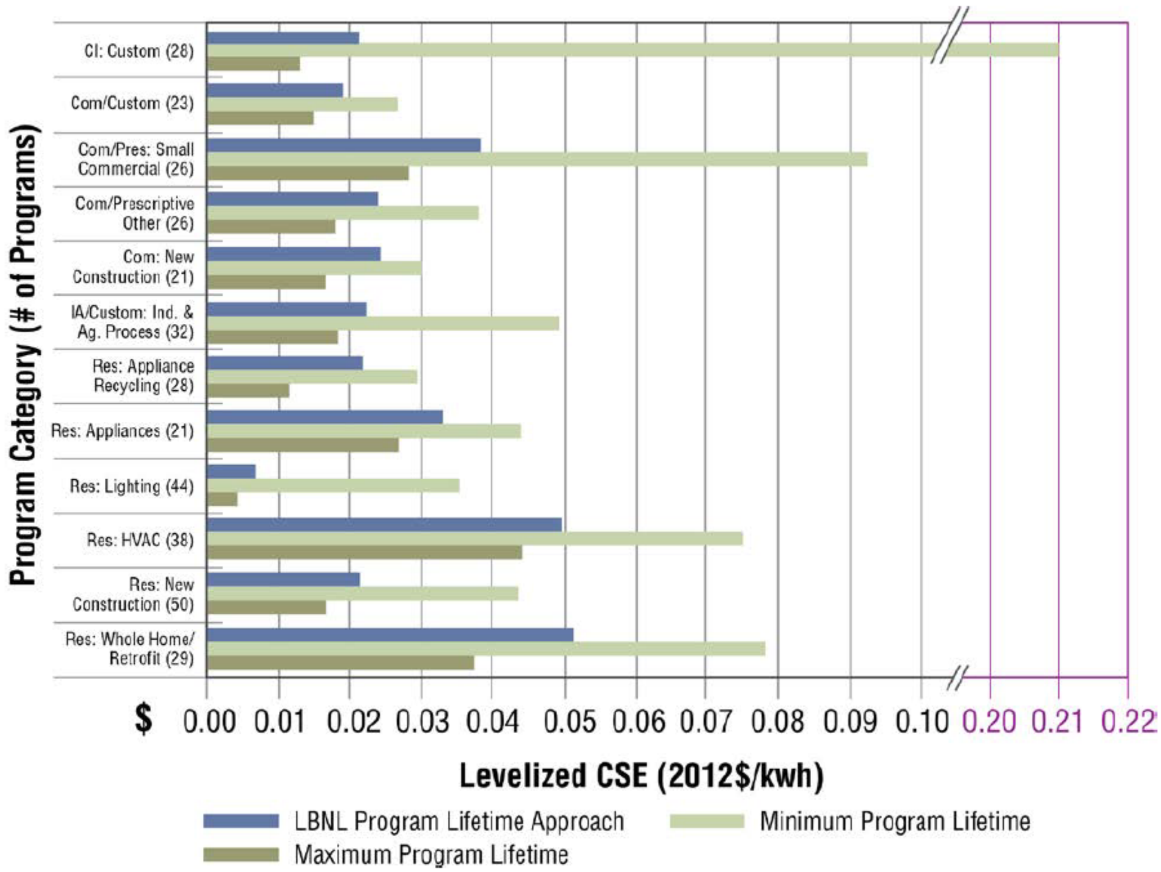
For resource planning purposes, energy-efficiency costs must account for total lifetime savings of the measures completed each program year, and will often reflect changes in the value of money between the time the measures are paid for and when the savings are realized. Additionally, demand savings (especially at peak time) are often a bigger driver than energy savings from a resource perspective. As a result of these differences, it is important to understand key factors as they affect energy efficiency from both perspectives. Further scenarios are modeled using incremental savings and costs from a base assumption. Refer to Section IV for more details specific to the Plan evaluation.

An additional complexity related to evaluating energy efficiency programs is introduced when trying to benchmark performance of programs across the nation. This is due to the fact that policy goals, measurement methodologies, maturity of programs, and savings targets (annual versus cumulative) vary from state to state. This challenge is discussed extensively in a recent technical report published by Lawrence Berkeley National Laboratory ("LBNL").[8] This report provides some further insight into utility customer-funded energy-efficiency program costs, using what the study refers to as the levelized cost of saved energy ("levelized CSE"). It's important to note that this calculation is not consistent with the methodology used in this Plan or for traditional CIP evaluation in Minnesota; however, it does provide another perspective for

[8] LBNL. 2014. The Program Administrator Cost of Energy Saved for Utility Customer-Funded Energy Efficiency Programs.

consideration when evaluating effectiveness of programs. For example, this report highlights the impact of measure lives in the overall cost evaluation of conservation programs, in addition to the impact of measures and program spending. Figure 5 was included in the report to demonstrate this effect:

Figure 5: Impact of different program average measure lifetime assumptions on the levelized CSE for electricity efficiency programs[9]



Measure lives are determined based on engineering estimates using the best available data at the time of estimate and they can vary by region, state and utility.[10] Though some of the difference can be attributed to different climate zones or customer behavior, some of the difference is more arbitrary and due to differences in regulatory rules, lack of data, or methodology.

[9] Figure 3-20 in LBNL. 2014. The Program Administrator Cost of Energy Saved for Utility Customer-Funded Energy Efficiency Programs.

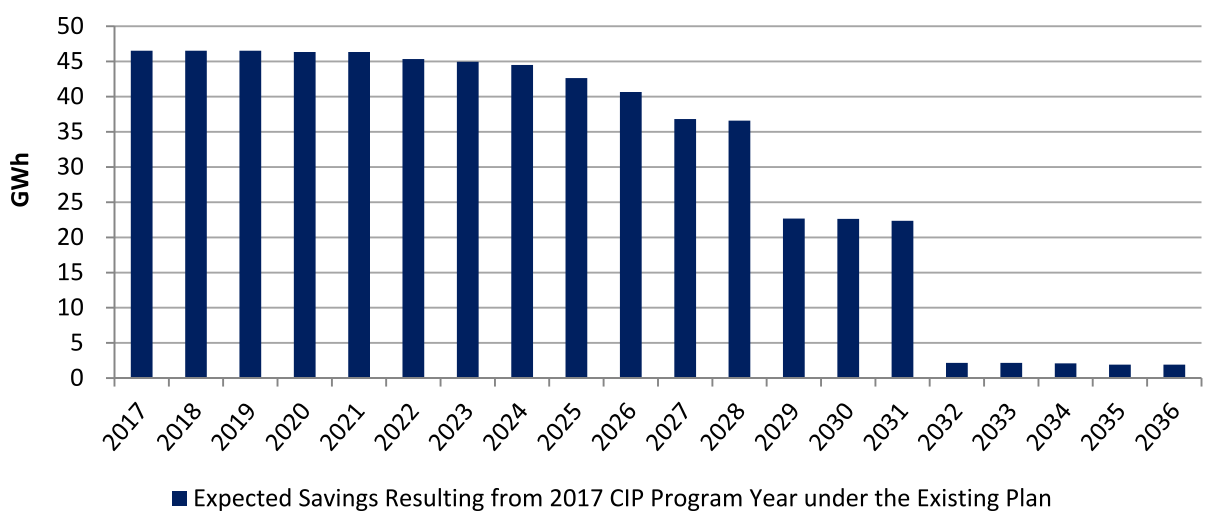
[10] The Minnesota Technical Reference Manual (TRM), developed and maintained by the Department of Commerce, consists of a set of standard methodologies and inputs for calculating the savings impacts and cost-effectiveness of energy conservation improvement programs (CIP) in Minnesota.

The effect of measure lives and lifetime savings estimates is one of the biggest factors contributing to the uncertainty and risk of using energy efficiency as a long-term resource. Changing lives of measures can have a significant impact on both the cost of energy saved when cumulative (lifetime) savings are being considered, and on actual cumulative savings realized compared to planned.

Portfolio design factors including technology mix, comprehensiveness, target markets, and new program/product introduction, in addition to regulatory or industry factors such as measurement and verification standards, accepted measure lives for different technologies, and codes and standards are all changing and evolving faster than ever in today's energy-efficiency environment. As a result of these changes and their impacts on the assumed measure lives, changes in the cost of achieving specified levels of *lifetime* savings could be substantial, frequent, and unpredictable during the resource planning period. For the purpose of estimating net benefits, these estimates work well. However, given the volatility of, and difficulty associated with accurately estimating measure lives, relying too heavily on energy efficiency in resource planning presents a risk.

For illustrative purposes, Figure 6 shows how the level of savings resulting from a single program year are expected to decrease over time given the technology mix assumed in that plan (Existing Plan). If the source (technology, sector, or customer type) of the actual savings realized from that program year differ significantly from the assumptions made in the plan, this pattern could be substantially different. Furthermore, this impact would be compounded if similar variances between the sources of realized savings and of planned savings occur in multiple years.

Figure 6: Expected Lifetime Savings for the Existing Plan



Conservation Program Strategy – Design & Delivery

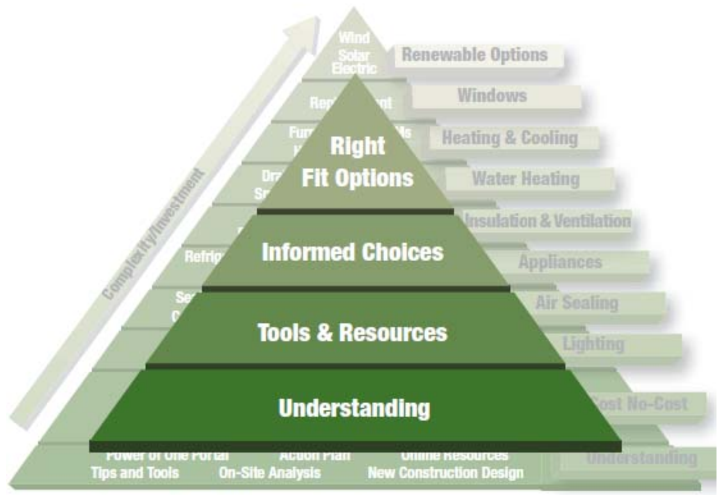
As discussed in its current CIP triennial filing,[11] Minnesota Power exercises a mindful, balanced approach in terms of traditional program design versus less established, emerging opportunities. The Company uses a combination of "direct savings" and "indirect savings" programs that complement each other and provide for a comprehensive customer experience. Power of One® Home, Power of One® Business, and Energy Partners remain the foundation programs that consistently deliver energy savings within the Power of One® conservation program portfolio. These savings are achieved typically through more established methods like rebates, incentives, and/or direct installations. While rebates certainly remain part of the equation for success in influencing customer choices, the value of Power of One® program services and resources are not solely derived from direct rebate programs. Minnesota Power provides customers with the tools and resources they need to make informed choices. These services are delivered through the Company's cross-market programs: Customer Engagement, Evaluation & Planning, Research & Development, Energy Analysis, and Customer Renewable Energy. These programs support direct savings programs and serve as a pipeline for projects that ultimately deliver on program objectives, as featured in Figure 7.

Figure 7: Program Integration

All programs within Minnesota Power's conservation program portfolio follow the Power of One® conceptual pyramid shown in Figure 8, which seeks to spur meaningful engagement through understanding, tools & resources, informed choices and right-fit options.

[11] Minnesota Power's 2014-2016 Triennial CIP Filing; Docket No. E015/CIP-13-409.

Figure 8: Minnesota Power's Conceptual Pyramid



Power of One® Home: High-level Overview

Power of One® Home is a comprehensive, portfolio-based residential sector program designed to help customers make informed choices about how they use energy in their homes. It leverages dollars, information, and infrastructure for effective program development and implementation. The success of Power of One® Home is based on connecting with the right customers through communities and one-to-one contacts.

Through the Energy Partners Program, Minnesota Power provides income-eligible customers with energy-efficient products and services to help them use energy more effectively. Program delivery is accomplished primarily through local community agencies and is built on the principles that education and collaboration are essential in empowering and engaging low-income customers. Though Energy Partners is a key component of the overall platform, due to the nature of the low-income market segment, the Energy Partners program is held at the existing plan level in all scenarios for the purposes of resource planning.

Power of One® Business Platform: High-level Overview

The Power of One® Business Program serves as the primary forum for reaching and serving business, industrial, agricultural, and public sector customers. It provides a common platform which enables the Company to encourage a broad base of customers to make effective energy choices, while providing the flexibility required for addressing the unique circumstances of various business types. Program success is best measured through the eyes of customers, and is exemplified by the growing percentage of customers who have projects that span across multiple years as opposed to "one-and-done" rebates.

When considering energy-saving opportunities, projects are reviewed with consideration toward not only energy savings, but also operating costs, effective design and technology utilization, unit output and overall productivity. By following a well-grounded model, energy conservation can become an integral part of sound investment decisions; supporting the customer's overall asset planning, informing resource considerations, and garnering buy-in from operations personnel. This model leads to identification of effective short-term projects while also providing a path toward long-term effective use of energy resources.

Through this program, both new and established, but underutilized technologies and process improvements are promoted and delivered. Other tools may include cost sharing for design assistance on a proposed new building, a compressed air study at an existing manufacturing facility, and/or monitoring facilities to identify “hot spots” to pinpoint the greatest opportunities for improvement. Power of One® Business also reinforces the importance of the commissioning process, when projects are implemented, both during initial start-up and during periodic tune-up periods.

Conservation Planning Goals

Although the primary focus of CIP strategy and planning efforts is to design and deliver an effective suite of energy-efficiency programs that comply with CIP statute and support increased customer satisfaction, this strategy also naturally and intentionally supports the Company’s resource planning goals. The State recognizes this natural relationship which is addressed in Minnesota Rules[12] by requiring an explanation of how CIP helps enable the utility to meet its long-term DSM resource planning goals. Despite the inherent relationship between CIP and resource planning, CIP is driven first and foremost by the rules and statutes set forth by the State that directly govern and guide program design, delivery, and reporting, all of which are intended to achieve a range of goals. Another distinguishing factor is that CIP energy savings are based on an annual goal using three-year weather normalized sales from a specified reference period that is held constant over the related triennial period. Annual program results are reported based on first-year savings as opposed to cumulative energy savings inclusive of prior year efforts.

CIP is intended to deliver cost-effective, environmentally-friendly energy savings that reduce overall demand for electricity, but programs also must comply with a detailed set of rules which include mandates on portfolio comprehensiveness,[13] inclusion of specific technologies and programs, a specific robust set of guidelines for cost effectiveness (based on the standard California benefit-cost tests),[14] and minimum spending requirements for low-income customers. Using these guidelines and requirements, the Company submits savings goals and program plans for approval through the triennial filing process. Once approved, the Company is obligated to work within the filed framework for the duration of the three-year CIP.

When included in the resource planning process, energy efficiency is assessed based on a much narrower subset of criteria that considers cumulative energy savings. Though it is important to incorporate CIP targets in resource planning goals, it should be viewed separately from CIP filing goals and targets. It is crucial to keep in mind that CIP activities are ultimately driven by approved and mandated CIP-specific goals, statute, and rules.

As Minnesota Power prepares the 2017–2019 Triennial plan, which will be filed on June 1, 2016, more detailed analysis will be conducted which will inform the Company’s recommended savings goals for the three-year period as well as the detailed program strategy for meeting

[12] Minnesota Rules 7690.0500, subpart. 2 (D).
[13] In the matter of Minnesota Power's 2014-2016 Triennial Filing, Docket No. E015/CIP-13-409, October 10, 2013.
[14] Minnesota Rules 7690.0500, subpart. 2 (E).

those goals. The analysis performed for this resource plan evaluation will be incorporated in triennial planning, building upon these insights and further evaluating the scenarios for reasonableness and feasibility for the 2017–2019 delivery period.

Power of One® Platform: Planning Process

The Power of One® planning strategy begins with understanding Minnesota Power's customer base, how customers use energy, what technologies or processes impact usage, and how best to deliver programs and services. As these factors change over time, the Company modifies its portfolio of programs to ensure they continue to effectively achieve savings and address the current, as well as anticipated needs, of its customers.

The overall planning approach, which creates a solid framework for implementation, combined with a delivery approach that has a strong focus on customer engagement and providing right-fit solutions, creates a flexible strategy that delivers many levels of customer benefits and achieves cost-effective savings that benefit the community and the Company.

Understanding Minnesota Power's Customer Base

Minnesota Power is unique among utilities in that more than half of its load comes from a few large industrial customers. Moreover, roughly 66 percent of the Company's load comes from 15 customers who are exempt from participating in and paying for CIP. As a result, CIP goals, funding and design focus on the remaining 3,000 GWh of the Company's total retail load.

Figure 9a: **Minnesota Power Retail Sales by Sector**

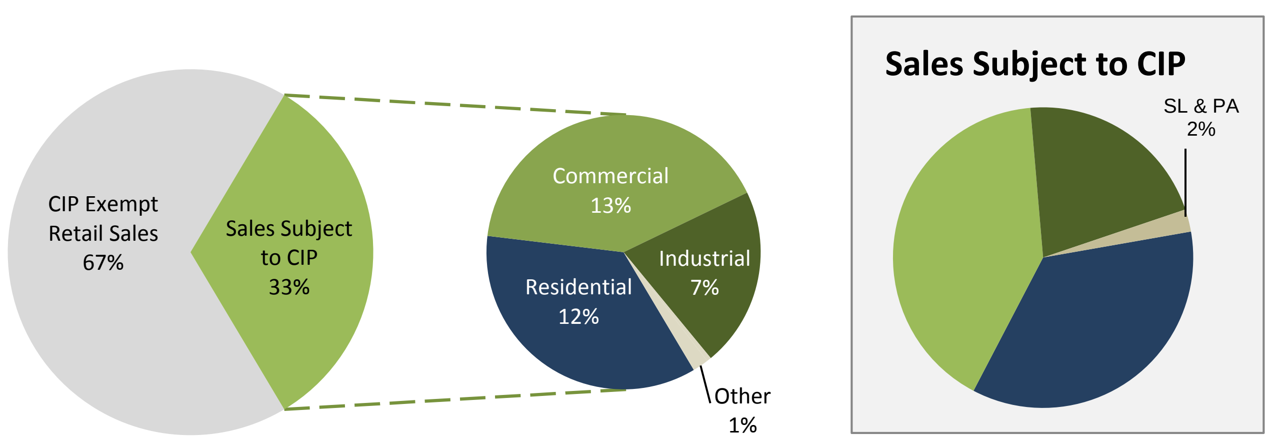
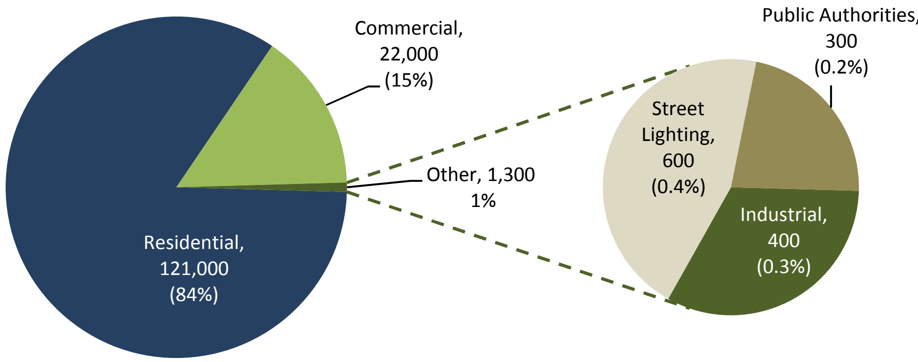


Figure 9b: Minnesota Power Customer Counts by Sector



Of the 3,000 GWh of load subject to CIP, about 35 percent come from approximately 121,000 residential customers and roughly 65 percent comes from about 23,000 commercial/industrial customers.

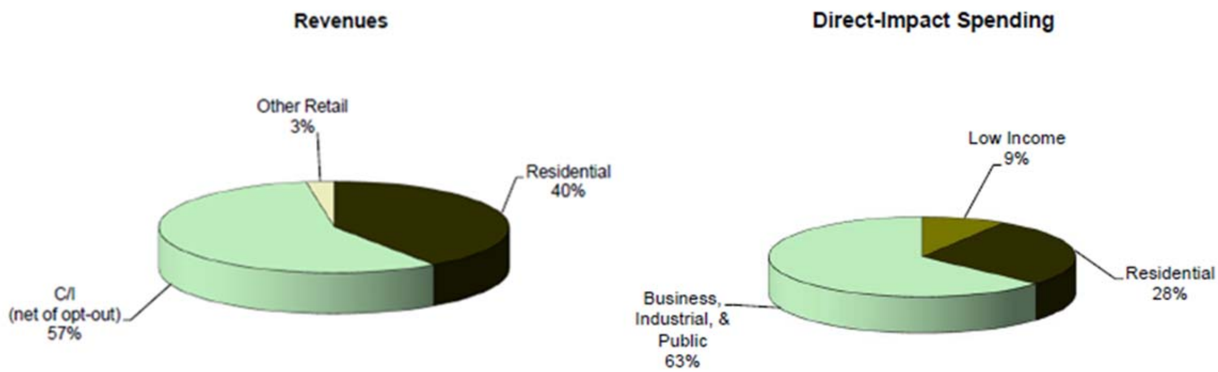
Consistent with the requirements regarding portfolio comprehensiveness,[15] Minnesota Power strives to create a balanced portfolio of conservation programs with a variety of energy efficiency measures that ensures all customers paying into CIP have the opportunity to participate while still targeting the most cost-effective savings.

During the budget planning process, historical revenue and sales contributions by customer class are factored in to help inform direct-impact spending allocation between classes. Historically, the Company's conservation plans have targeted about 20 percent of savings and budgeted roughly 35 percent of direct impact spending for residential and low income customers, and the other 80 percent of savings and 65 percent of direct impact spending for C/I customers. Similar considerations were taken into account when developing alternative savings scenarios for the resource plan.

Figure 10 depicts retail revenues by customer class (net of revenue from CIP-exempt customers) on the left and planned allocation of direct-impact spending as seen in Minnesota Power's 2014–2016 CIP Triennial Filing.[16]

[15] In the matter of Minnesota Power's 2014-2016 Triennial Filing, Docket No. E015/CIP-13-409, October 10, 2013.
[16] Minnesota Power's 2014-2016 Triennial CIP Filing; Docket No. E015/CIP-13-409.

Figure 10: Retail Revenues and CIP Direct-Impact Spending by Customer Class



Commercial and industrial program planning in particular requires a deeper understanding of customer mix, business operations, and related processes. Large commercial and industrial projects are less predictable from a program planning perspective in that they involve site and process specific custom calculations, and are largely dependent on point-in-time customer economic and business development opportunities. To provide confidence in reported savings and in acknowledgement of the complexity of these types of projects, robust measurement and verification protocol[17] are followed to ensure reasonableness of savings assumptions and related methodologies for arriving at them. Generally, these projects are far more cost-effective than smaller commercial projects. The level of detail needed to calculate these savings is not typically available at the time CIP triennial plans are being developed. Conversely, smaller commercial projects can rely more heavily on standardized prescriptive measures and participation assumptions.

In the past, Minnesota Power has been able to focus heavily on the large customized projects. In doing so, the Company has seen a high level of success due in large part to the carefully cultivated relationships the Company has developed with these participants—many of whom continue working with Minnesota Power's CIP team for several years at a time, completing numerous large-scale projects that span planning periods and program reporting years. This approach fits well with the Company's emphasis on meaningful engagement, informed choices and right fit options, but provides for potentially irregular performance across program years.

As the customer mix and opportunity shifts, Minnesota Power will need to plan for more C/I program elements that target smaller scale prescriptive projects than it has in the past in order to continue meeting savings goals. In doing so, the overall C/I program costs will likely rise and performance will become more comparable to other utility programs. As a point of reference, the industry average cost/kWh for C/I programs was $0.16 higher in 2013 than those for Minnesota Power's C/I programs.[18]

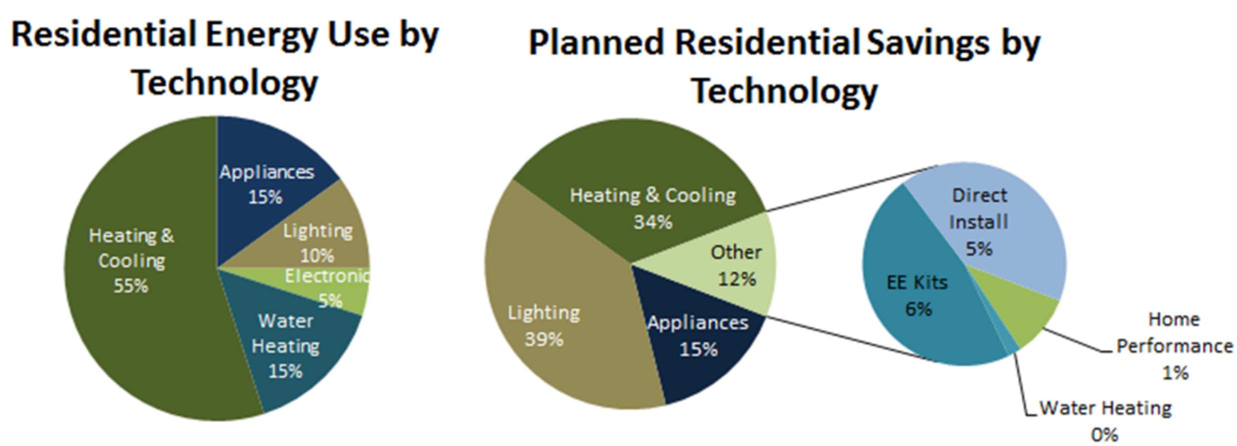
[17] Regarding Large Project Measurement and Verification Protocols, Docket No. E,G999/CIP-06-1591.
[18] E-Source: DSM Achievements and Expenditures 2013 Research Results.

Understanding Customer Use and Technology Trends

The next step in the planning process is a combination of understanding customer use and behavior and evaluating opportunities in energy-efficiency technology. For residential programs, this process is fairly straightforward and relies mainly on standardized prescriptive measures, industry best practices, codes and standards, and analysis of recent performance. For C/I programs, Minnesota Power takes a more systematic approach involving analysis of historical trends and new opportunities at the individual technology level. Prescriptive measures and best practices are not as well suited to inform these program plans. This is largely due to the fact that the majority of the Company's C/I savings come from custom projects that address specific customer needs and conditions. The Company also incorporates ongoing and extensive research and development initiatives in its conservation portfolio which provide valuable insight for future program planning across eligible customer segments.

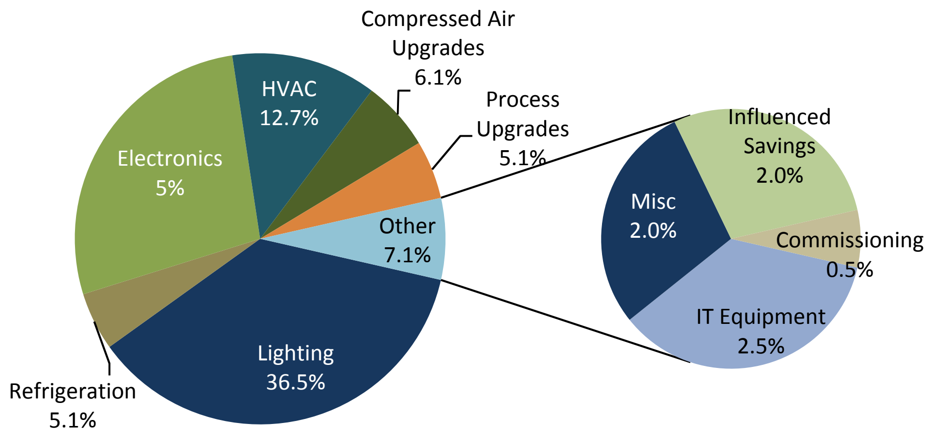
In the industry, potential studies have frequently been utilized to help inform these evaluations. Due to the cost and lack of relevance of these evaluations, Minnesota Power has chosen to instead explore similar, more cost-appropriate services that focus on the key areas of research needed to supplement the Company's internal efforts and proven program success. Figure 11a shows average contributions by technology to average residential energy use and expected/planned contributions by technology to 2016 residential energy savings. Statistics regarding average use by technology are used in conjunction with energy-efficiency technology research to understand where the best opportunities for savings are specific to Minnesota Power's customers.

Figure 11a: Residential Energy Use and Savings:



Though commercial programs are also designed to consider a mix of technologies, consumption by end use varies widely by business type. As such, a general breakdown of energy use by technology is not as meaningful. Planned C/I savings by technology for 2016 are as follows:

Figure 11b: Planned Commercial/Industrial Energy Savings by Technology



Differences between Design and Delivery

Reported program results will inevitably vary from planning assumptions. One of the biggest factors that will drive variance to plan is completing one or several large projects during the year.[19] This scenario has been exemplified in the Company's 2013 and 2014 CIP results. Given the irregular potential for large project opportunity in any given year, and some uncertainty surrounding approval and magnitude of the associated savings, it is difficult to plan for large project impacts year after year. Furthermore, allowing irregular projects of this nature to trend into the future could unintentionally create a compounding effect that would significantly overstate savings potential. A conservative approach is taken to including projects of this scale in planning assumptions in order to avoid setting unrealistic goals and budgets. Instead, these projects are reviewed and reported on a case-by-case basis in close collaboration with Department of Commerce technical staff. Consequently, historical levels of achieved savings will not necessarily be reflected in future savings projections.

Similarly, variances in economic conditions and changes in consumer behavior will have an impact on actual results as compared to planned savings. Small deviations can be addressed during delivery. For example, if the adoption rate of a technology such as light emitting diode ("LED") light bulbs is higher than anticipated, the Company may make slight modifications to planned promotions or make updated assumptions about where the savings in the affected planning period will come from. If economic conditions are negatively affecting willingness to spend on energy efficiency, more bonuses and promotions may be employed to increase participation or an increased focus on operations and maintenance as opposed to capital investments may be prudent, as was evidenced in the 2010 CIP Consolidated Filing.[20]

[19] Minnesota Power considers a large project any single project achieving energy savings of 1,000 MWh or greater.
[20] Docket No. E015/CIP-08-610.02.

Modeling Conservation for Resource Planning

Minnesota Power's 2013 Integrated Resource Plan ("2013 Plan") Order directed the Company to evaluate additional conservation scenarios for its non-CIP exempt customers and provide cost assumptions for increasing levels of conservation.[21] Based on the Company's current CIP strategy and analysis of historic performance and future opportunities, Minnesota Power provided three higher than existing[22] alternative CIP savings scenarios and developed cost projections for each. These scenarios were incorporated in the Strategist modeling process, and were further evaluated using the standard CIP benefit-cost tests. The ratepayer impact test was taken into careful consideration, and additional rate impact analysis was completed in order to assess the reasonableness of the resulting bill impacts associated with each alternative scenario. The standard CIP benefit-cost test results and the rate impact analysis are included and discussed in Part 2 of Appendix B.

High-Level Summary of Modeled Scenarios

A high-level summary of the modeled scenarios is shown in Table 1. The "Scenarios" section has two columns describing the four scenarios: The first column titled "% of Sales" represents the level of savings as a percentage of average weather normalized 2010–2012, non-CIP exempt retail sales—the baseline for the 2014–2016 Triennial plan.[23] The second column titled "Plan" represents the additional GWh the associated plan includes in terms of first-year savings as compared to the existing plan. This is the terminology that is used to refer to the scenarios throughout Appendix B.

Note the energy and demand savings shown here are first-year savings and the associated costs are estimates for the plan year 2017. Refer to Part 2 of Appendix B for more details and evaluation results.

[21] In the Matter of Minnesota Power's 2013–2027 Integrated Resource Plan, Docket No. E-015/RP-13-53, November 12, 2013.

[22] Existing plan is based on the currently approved 2014-2016 CIP Triennial, Docket No. E015/CIP-13-409.

[23] In accordance with Minnesota Rules part 7690.1200, 2010–2012, weather-normalized average retail energy sales were used to calculate the electric savings goal for Minnesota Power's 2014–2016 Triennial CIP. This equated to 3,071,179,967 kWh, net of CIP exempt customers at the time of the Triennial Filing. Savings as a percent of sales in Chart 1 were calculated using this figure. In 2014, Minnesota Power had three newly exempt customers. Adjusted weather-normalized average retail energy sales excluding these customers is 3,013,600,651 kWh.

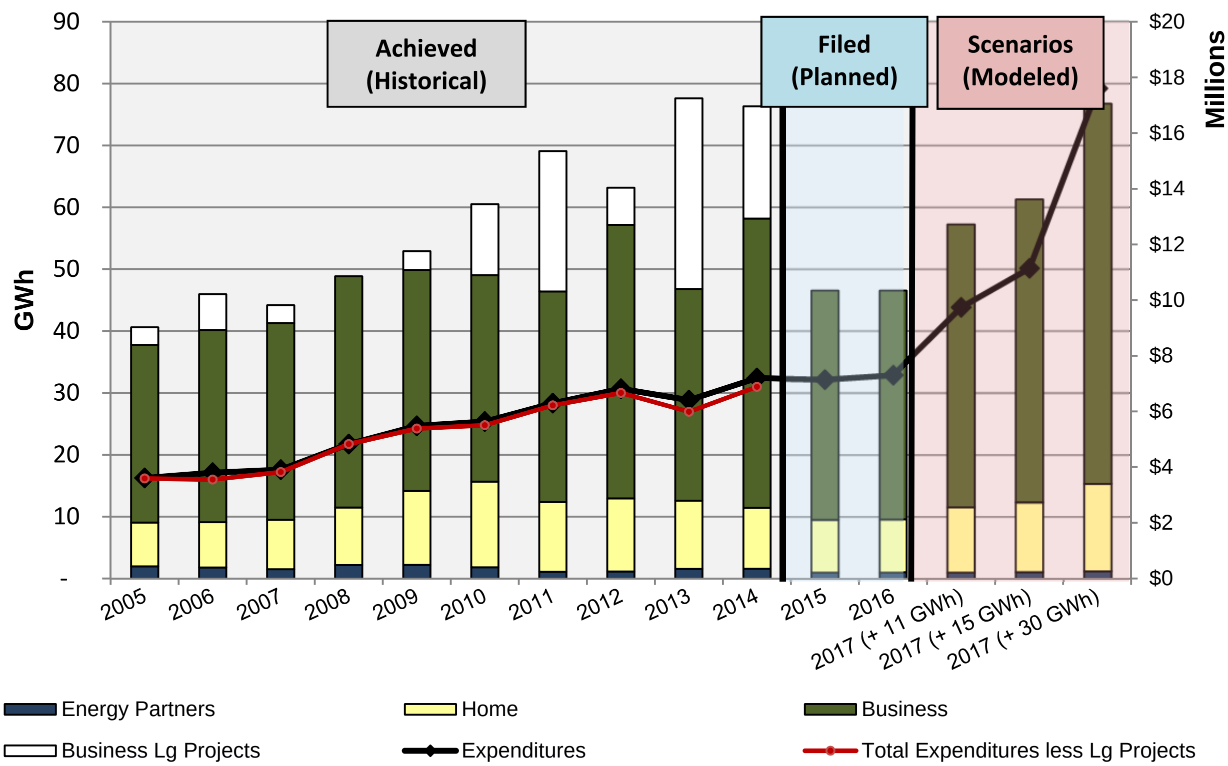
Table 1: Summary of Alternative CIP Scenarios

Scenarios		Annual Program Costs (million $)					*Annual Savings at the Generator	
*% of Sales** (rounded)*	*Plan*	*Incentives*	*Admin*	*Nonimpact*	*Total*	*Total Incremental Costs*	*Energy (GWh)*	*Summer Peak (GW)*
1.5%	Existing	$3.4	$1.2	$2.4	$7.1	$0.0	46.5	0.0071
1.87 %	+ 11 GWh	$4.8	$1.7	$3.2	$9.7	$2.7	57.3	0.0087
2.0%	+ 15 GWh	$5.6	$1.9	$3.6	$11.1	$4.1	61.2	0.0093
2.5%	+ 30 GWh	$9.4	$2.9	$5.3	$17.6	$10.5	76.5	0.0116

Developing Cost Assumptions

Figure 12 expands on the Minnesota Power Historical CIP Performance graph (Figure 1) to include planned/expected costs and savings (as filed in the current triennial) through 2016 as well as the three alternative CIP scenarios developed for resource plan modeling for the year 2017.

Figure 12: Historical, Planned, and Modeled CIP Energy Savings (First Year)



Due to the prevalence of large cost-effective projects in recent years (represented by the white bars above) and the length of the planning period, the Company has made an effort to minimize risk through more normalized assumptions. To do so, cost assumptions for the modeled scenarios were based more heavily on future expectations rather than on historic performance. As discussed previously, savings associated with unusually large projects or recently exempted CIP participants should not be included in trend analysis and savings projections. Inclusion potentially overstates the Company's ability to achieve, or understates the costs necessary to perform, especially when being considered for long-term planning purposes. Looking instead at the adjusted figures, the graph shows the projected costs for the alternative scenarios are not out of line with historical trends. Moreover, it is not unreasonable to assume increased costs for the higher savings scenarios until further insight can be attained on the ability to perform during periods with little to no opportunity for large-scale projects. These projections are both appropriate and justifiable based on the various factors that have already been discussed, among other key cost assumptions used to develop the scenarios.

Given a higher savings target, in order to minimize the risk of under-budgeting or under-performing, costs were considered and estimated for some potential strategies that would be used to supplement existing programs. One of the key areas identified for potential savings growth is the small commercial market, which historically has been one of the harder-to-reach customer segments. These programs generally rely on more prescriptive measures delivered through rebate and direct install programs that are similar in structure and cost to residential programs. As a result, cost assumptions for new activities such as rebate processing and fulfillment that would be necessary to successfully implement more robust small commercial programs were considered in higher savings scenarios. Some of these costs were estimated using the current residential costs for the same activities as a reasonable reference point.

Minnesota Power expects larger participant incentives and increased marketing efforts will be necessary to influence harder-to-reach customer segments that will be essential to meeting higher savings goals, especially as market saturation continues to increase. Thus, anticipated costs were assessed related to the need for improved accessibility to program data. More in-depth analysis will be crucial for identifying effective outreach and delivery strategies, and areas with high savings potential. Increased program modification and growth activity also necessitate more resources to manage intensified efforts related to research and new program development, additional measurement and verification needs, regulatory compliance needs, and increased program implementation. Many of these needs were indicated or discussed in the current CIP Triennial Filing, and will continue to be considered for the next planning period.

Conclusions

The source of savings in terms of customers and technologies will inevitably change as programs continue to mature and technologies evolve. As utilities strive to meet the aggressive goals set forth in statute, adaptive strategies will need to be deployed. Insights regarding customer preferences and energy consumption choices will be an integral part of future program design and delivery, not only as it applies to direct-impact programs but also as it relates to improving and introducing more effective customer engagement tools. Further, codes and standards as well as regulatory uncertainty and alignment of policy objectives with performance-based incentives are important components that will influence the ongoing success and commitment to conservation. Major changes to these policies could significantly impact the Company’s capacity to invest in new and improved programs and its ability to sustain current levels of success.

Appendix B—Demand-Side Management (DSM)
Part 2—Energy Conservation Resource Alternatives and Rate Impact Study

Presented to

Minnesota Power

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August 11, 2015

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Executive Summary

In the past, Integrated Resource Plans (IRP) relied on technical, economic and achievable potential studies to determine the demand-side management (DSM) resources available for selection. These studies require substantial market research and load research information. Some utilities use borrowed data and averages from national or regional sources. The results and applicability of such studies are somewhat limited, while still very expensive.

Integrated Resource Plans generally use the net present value of revenue requirements as the selection criteria. Consequently, the resulting plans often include an amount of DSM, especially conservation, because conservation generally reduces revenue requirements. However, conservation additions also increase rates. In today's globally competitive environment, rates are important. The rate impact on customers should be an important consideration and may be a limiting factor to the amount of conservation included in the IRP.

Minnesota Power commissioned an update of the study originally prepared for its 2004 Integrated Resource Plan to examine the rate impact of several conservation plan scenarios alongside the standard Societal, Utility and Ratepayer tests. In this report, DSM refers to energy conservation resources. The study determines the significance of conservation-induced rate impacts and provides insight helpful to determining the proper amount of conservation to be included in Minnesota Power's IRP. Although Minnesota Power commissioned this study, the views expressed are those of the author and not necessarily those of Minnesota Power. In addition, Minnesota Power edited the study document to maintain style and format consistency with the overall IRP filing.

Conclusions

- All plans are cost-effective by the Societal and Utility tests.
- All plans are not cost-effective by the Ratepayer Impact Measure Test.
- Overall plan cost-effectiveness is driven in a large part by the Commercial/Industrial Project because of this Project's large size compared to the Residential and Low Income Projects.
- Rates will increase linearly as expenditures for conservation programs increase to a differential of 0.15¢/kWh in the +11 GWh Plan, then increase to a differential of 0.54¢/kWh in the highest spending plan, compared to the Existing Plan in 2021.
- Rate impacts of larger conservation plans, such as a plan associated with the achievable potential, will have even larger rate impacts.
  - If a rate impact greater than the maximum shown in this study is acceptable, then Minnesota Power can investigate the greater levels of conservation associated with a technical/economic/achievable potential study.
  - If the maximum rate impact is unacceptable, then the conservation program size can be managed within the sensitivity parameters defined in this study, subject to the maximum acceptable rate impact. In this instance, an achievable potential study would add no further value, as the rate impact associated with it would be larger than that shown in this study.

Methodology

The study methodology defined four plans with various amounts of conservation. The plans are, in order of increasing spending and impacts:

- -16 GWh Plan
- Existing Plan (2014-16 CIP Triennial)
- +11 GWh Plan
- +15 GWh Plan
- +30 GWh Plan

The number of GWh associated with each plan refers to the differential in annual savings at the generator, compared to the Existing Plan.

Minnesota Power's approved 2014-16 CIP was used as the basis for the Existing Plan for this study. Four additional sensitivities were constructed around the Existing Plan. For purposes of the study, 2016 was not considered subject to variation as there would not be sufficient time following an Order in this proceeding to make changes, if required. The projected spending and savings for that year were assumed to be identical in all plans. Plan variation began in 2017.

Assumptions for each plan were developed by Minnesota Power's CIP group, based on implementation through the study period—2016 through 2030. The plans were each modeled and evaluated for cost-effectiveness according to the standard (Societal, Utility and Ratepayer Impact Measure) tests. The rate impact of each plan, relative to the Base Plan, was calculated for the year 2021. Plan costs, impacts and participation for all plans in the year 2016 and for each plan in the year 2017 are summarized in Table ES-1 below:

TABLE ES-1
Cost, Impact and Participation by Plan for the Years 2016 and 2017

	Annual Program Costs			*Annual Savings at Generator*	
	Direct Programs		*Nonimpact*		
Plan	*Incentives ($)*	*Admin Cost ($)*	*Total Cost ($)*	*Energy (kWh)*	*MISO Summer Peak (kW)*
All Plans - 2016	3,350,992	1,219,205	2,370,445	46,529,577	7,070
-16 GWh Plan - 2017	2,018,548	1,067,930	2,055,176	30,591,778	4,652
Existing Plan - 2017	3,418,012	1,243,589	2,417,854	46,529,577	7,070
+11 GWh Plan - 2017	4,809,780	1,723,687	3,211,156	57,253,438	8,697
+15 GWh Plan - 2017	5,570,768	1,946,120	3,626,781	61,237,888	9,301
+30 GWH Plan - 2017	9,432,408	2.853,205	5,319,279	76,538,175	11,623

Study Results

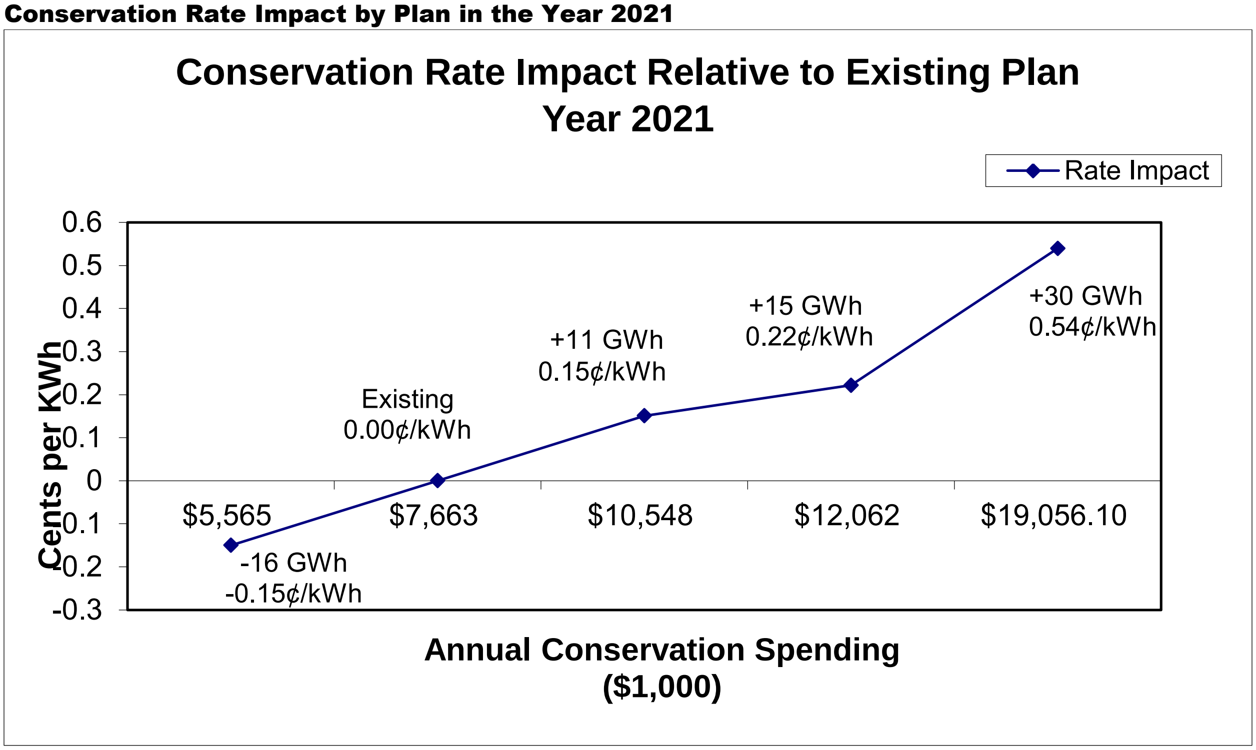
As shown in Table ES-2 below, plan energy and demand impacts in the year 2021 increase as program spending increases. Financial savings increase through the +11 GWh Plan, then decrease as incentive spending increases dramatically. Financial savings are defined as annual energy and capacity savings less program costs. The cost-effectiveness tests indicate that all plans are cost-effective according to the Societal and Utility (Revenue Requirements) perspectives, but not the Ratepayer Impact Measure (RIM) perspective.

TABLE ES-2
Plan Savings in 2021 and Cost-effectiveness by Plan

	Annual—Year 2021			*Present Value over Life*		
	Savings at Generator			*B/C Ratio*		
Plan	*Energy (kWh)*	*Summer Peak (kW)*	*Financial Savings ($)*	*Societal Test*	*Utility Test*	*RIM Test*
-16 GWh Plan	18,011,346	29,850	7,052,841	1.90	3.26	0.49
Existing Plan	277,608,373	41,922	10,039,783	2.01	3.58	0.50
+11 GWh Plan	331,165,798	50,045	10,576,048	1.97	3.24	0.49
+15 GWh Plan	351,065,046	53,063	10,332,800	1.95	3.05	0.49
+30 GWh Plan	427,478,185	64,652	8,220,065	1.89	2.44	0.49

Figure ES-1 indicates the rate impact of each plan, relative to the Base Plan, in the year 2021.

FIGURE ES-1
Conservation Rate Impact by Plan in the Year 2021



All of the plans, except the -16 GWh Plan, increase rates with respect to the Existing Plan. Larger plans than those examined in this study, such as the achievable potential, would be expected to increase rates even more. Rates increase because revenues decrease more than kWh savings.

1. Introduction

This report details the methodology and results of a sensitivity study that examines the cost-effectiveness of conservation plans from the perspective of the standard DSM cost-effectiveness tests and the nominal rate impact on Minnesota Power's customers.

The following sections include a description of the historical DSM perspective, the study methodology and assumptions used and the study results.

2. Historical DSM Perspective

Before the inception of large utility conservation programs in the mid-1980s, utility resource planning consisted primarily of developing generation expansion plans that incorporated a peak demand forecast, modified by the impacts of customer load management. The cost-effective plan was one resulting in the minimum present value of future revenue requirements over the study period. In the mid-1980s, the Electric Power Research Institute (EPRI) instituted its demand-side management (DSM) initiative, which stressed the inclusion of all types of customer-oriented programs in the strategic planning process. Although such programs included all types of customer load modifications promoted by the utility—such as load-building, load management and conservation—DSM became most closely linked with conservation. In this report, the term DSM refers to Minnesota Power's conservation projects offered through Minnesota's Conservation Improvement Program (CIP).

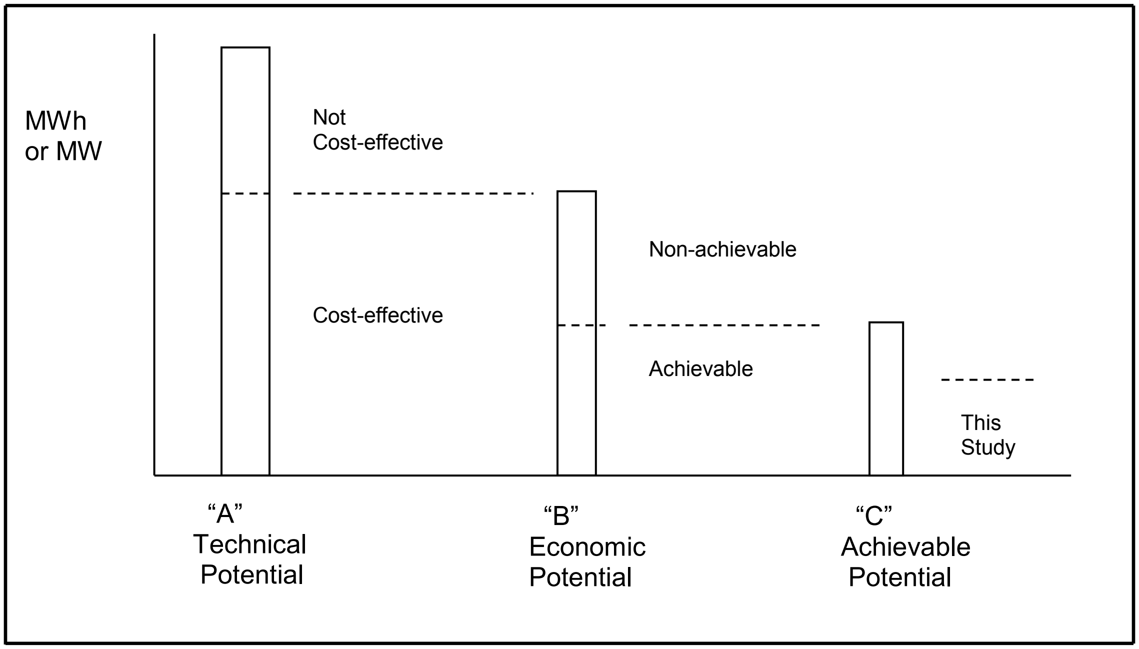
The addition of conservation to the planning process added a new level of complexity. The utility had to choose between adding new capacity resources to meet the projected growth in sales and reducing sales growth through conservation programs that were likely to reduce or delay capacity purchases or resource additions. Generation expansion planning became integrated resource planning. In addition to selecting among various supply resources, the utility now had to estimate the amount of conservation available over time, determine the amount that could be reliably expected to reduce demand and energy and select the amount to be developed.

Conservation Potential

Including conservation options in the resource plan made it necessary to first estimate the conservation available. For example, if a utility was to include efficient residential air conditioning as an option, the utility needed to determine how many megawatts (MW) and megawatthours (MWh) that option would reduce peak demand and sales. To accomplish this, the utility had to first know the age, size and efficiency of existing air conditioners as well as the efficiency assumed in the sales forecast. Then it had to determine the availability of more efficient equipment in the market and the added cost of that equipment. Only then could it determine the energy savings likely if all customers switched to the highest level of efficiency, and the cost of going to that efficiency—the technical potential.

In the past, conservation potential was determined through technical, economic and achievable potential studies. The relationship among these studies is illustrated in Figure 2.1 below.

Figure 2.1
Illustration of Technical, Economic and Achievable Potential



A technical potential study identifies the MWh and MW savings that could be obtained if all existing and future energy equipment is converted to the most efficient available equipment, bar "A." It also identifies the additional cost of implementing the most energy efficient measures. A life cycle economic screening of these measures, usually using the Societal Test to evaluate against a standard supply plan, identifies the most expensive measures as not being cost-effective. These are eliminated from further consideration (the upper segment of bar "A"). The remaining savings are known as the economic potential, shown as bar "B."

Being cost-effective does not necessarily mean that any given measure will be implemented by customers. Other factors influence the customer's decision, such as lack of awareness, individual preference, equipment availability, etc. Assessment of these factors and the influence they have on the purchase of energy equipment yield the achievable potential, bar "C." Various combinations of measures falling into the achievable category can then be developed as a conservation plan considered in the IRP. The conservation associated with the plans of this study fall within the achievable potential.

Difficulties incorporating Conservation into an IRP

Data Availability

Determining the vintage, age, efficiency and mix of the energy equipment stock and how that stock changes over time requires substantial market research and load research information. Many utilities, including Minnesota Power, do not possess the depth of information required to develop the technical potential. Development of the information is very costly, both in personnel commitment and dollars. A commonly used alternative is borrowed data and averages from national and regional sources, together with limited research. A technical potential constructed in such a manner will yield the required data, but the data's validity is limited and the study is still very costly. The development of the achievable potential involves the use of various assumptions regarding the likelihood of customers to implement measures of various cost-effectiveness. The validity of these assumptions can only be tested over time.

Selection Criteria

As do many jurisdictions, Minnesota uses the minimum net present value of revenue requirements as the selection criteria in its resource plans. While such a criteria was unquestioned in expansion planning, where sales assumptions were constant, it creates problems under the varying sales projections resulting from the introduction of conservation. Conservation measures, except for the most expensive, generally lower revenue requirements. Unlike supply resources that have an initial cost (capital) and an annual cost (fuel and O&M), conservation measures generally only have an initial utility cost (incentives to customers and program administration). The use of minimum net present value of revenue requirements tends to result in resource plans that include a large amount of utility-sponsored conservation. However, conservation reduces energy (kWh) much more than demand (kW). Since resource needs are determined more by kW than kWh, conservation generally replaces only a small amount of future generation needs. It also increases reliability risk because it is not directly controlled by the utility; customers can remove conservation or use it differently than assumed.

Because the conservation program reduces the future sales by a greater percentage than the cost, the effect is to increase rates in any given year, compared to not implementing conservation. In the regulated environment of the past, this rate impact was ignored by many utilities and regulators, either because it was felt that the impact was small or because the impact had not been quantified. The potential studies required by regulators did not examine nominal rate impacts on a year-by-year basis.

Nationally, the importance of the rate impact became evident with the emergence of deregulation. Large utility-sponsored conservation programs disappeared in many states subject to deregulation. These programs were successful in helping customers lower their electric bills, the main argument for implementing conservation, but competitors entered the market and offered those customers a lower rate than the home utility could. To compound the problem for the utility that developed the conservation, the utility rate was higher than it would have been without the conservation program. The very program that helped the utility lower customer bills also put the utility at a competitive disadvantage.

Minnesota is not in a deregulated electric market. That does not mean electric utilities do not face competition. Natural gas companies promote their product as being less expensive than electricity. Natural gas competes with electricity in many industrial, commercial and residential markets, including manufacturing processes, cooking and water heating. Promoters of customer-installed generation compete against utilities when the utility rate gets too high. This can occur even though the utility may have provided conservation to lower the customer bill. Apart from these examples, utilities, with regulatory oversight, have the overarching responsibility to provide electricity at a reasonable price to all customers. This requires examining and weighing the costs and benefits of all factors contributing to rates.

Minnesota Power Approach

To determine an appropriate conservation spending level, this study calculates the rate impact of each of four alternative conservation plans. This study provides valuable information not directly obtained in a technical potential study, and for a fraction of the cost. Any additional conservation resulting from a technical potential study can be assumed to require even greater spending than the most costly plan in this study, thus resulting in a greater rate impact.

If the maximum rate impact of the highest cost plan is acceptable, Minnesota Power can discuss cost recovery with the appropriate regulatory agency for conducting the potential studies at a future date. However, if the maximum rate impact determined by this study is at or above the acceptable limit, then the focus should be limited to the plans with spending at or below the acceptable limit. In this instance, the achievable potential study would add no further value, as the rate impact associated with it would be larger than that shown in this study.

3. Study Methodology

- Define the five Plans;
- Develop the sensitivity parameters for each plan;
- Evaluate each plan through the year 2044;
- Calculate the rate impact of each plan in a given year.

Define the Five Plans

Minnesota Power's approved 2014-16 CIP was used as the basis for the **Existing Plan** for this study. For purposes of the study, 2016 was not considered subject to variation as the year will most likely be partially over before an Order is obtained. The projected spending and savings for that year were assumed to be identical in all plans. The Existing Plan consisted of direct impact project spending of $4,570,197, energy savings of 46,530 MWh and MISO summer peak savings of 7.1 MW at the generator in 2016. The 2014-16 CIP included annual nonimpact and renewable spending of $2,370,445 in 2016. The approved spending levels and resulting participation of this Existing Plan were assumed to occur through 2030, coinciding with the study period of the IRP. The Existing Plan is approximately consistent with the savings goal of 1.5% of sales.

Four additional sensitivities were constructed around the Existing Plan. The sensitivity plans did not examine the impacts of additional measures but determined the effects of modifying incentive, administrative cost and participation assumptions, using the same set of measures. In the Existing Plan, the assumed 2016 participation was held constant through 2030. Program and participant equipment costs were permitted to escalate 2.0 percent per year after 2016 to account for inflation in all alternatives, including the Existing Plan.

The **-16 GWh Plan** represents a decrease in aggressiveness compared to the Existing Plan. Savings are approximately equal to 1% of non-exempt sales and are 16 GWh less than the Existing Plan on an annual basis. Incentives were reduced, advertising was decreased and fewer personnel were assigned to promote and administer the program. Spending was lowered to approximate the minimum spending requirement that also includes non-impact spending. In addition to costs being reduced, participation was decreased as well. 1% Plan energy savings do not meet the current minimum savings goal.

The **+11 GWh Plan** represents a moderate increase in program aggressiveness compared to the Existing Plan. Incentives were moderately increased, advertising was increased and more personnel were dedicated to administering and promoting the program. Participation increased to a level greater than in the Existing Plan. The savings associated with the +11 GWh Plan are

11 GWh greater than in the Existing Plan on an annual basis and are consistent with the Commission Order in Docket E015/RP-13-53.

The **+15 GWh Plan** represents an even greater increase in program aggressiveness compared to the Existing Plan. Incentives were moderately increased, advertising was increased and more personnel were dedicated to administering and promoting the program. Participation increased to a level greater than in the +11 GWh Plan. The savings associated with the +15 GWh Plan are 15 GWh greater than in the Existing Plan on an annual basis.

The **+30 GWh Plan** represents a substantial increase in program effort. Incentives approach full incremental cost. Advertising was further increased and even more personnel were assigned to the program. Participation increased beyond that in the +15 GWh Plan.

In the -16 GWh Plan, the +11 GWh Plan , the +15 GWh Plan and the +30 GWh Plan, the Energy Partners Low Income project was not varied in size, but was kept at the Existing Plan level. Minnesota Power is currently attempting to meet the needs of this customer class and already spends well beyond the minimum spending requirement for this sector.

Develop the Sensitivity Parameters for Each Plan

The variations in the parameters for each plan were developed by the Minnesota Power CIP group, which included those currently involved with the program. These individuals have the most realistic view of how program costs and participation would change as a result of the financial and operation changes.

Team members were provided cost, participation and savings information, on a per-measure basis, for the 2016 Existing Plan. They developed the parameters defining each plan. A spreadsheet permitted assumption changes to be made and the resulting savings and total cost impacts viewed.

First, changes were made to incentive levels. Then, assumptions were made regarding the change in advertising that would accompany the incentive changes and the number of personnel required to implement and administer the program. This yielded new administration cost. Finally, an estimate was made of the change in participation that would occur. This yielded total incentive costs and total energy and peak savings. The actual assumptions and first-year results are discussed and listed in Section 4.

Incentives for direct-install projects were not modified. That is, the measures were supplied at no cost in all plans. Program participation was affected by varying the administrative and implementation effort as well as by varying advertising. In addition, the low income expenses were not lowered beyond those in the base plan. In all plans, the Industrial exempt customers—those not funding or participating in the conservation program—remain exempt customers.

Evaluate Each Plan Through the Year 2044

Program assumptions consistent with each plan were entered into the DSManager model, the model used to evaluate the CIP projects. Since the 2014-16 CIP was developed two years ago, the avoided energy and capacity costs, as well as rate escalations and externalities were updated for this study. Each project in each plan was evaluated from the year 2017 through the year 2044, with implementation ending after 2030. Cost-effectiveness results for the Societal, Utility and Ratepayer Tests were calculated. These are detailed and discussed in Section 5.

Calculate the Rate Impact of Each Plan in a Given Year

To calculate the rate impact of the various plans, revenues and sales must be known for the year for which the rate impact was calculated. The rate impact was calculated for the year 2021, the fifth year of varied plan implementation. The 2014 kWh sales for CIP customers were provided by Minnesota Power and escalated at 0.55% per year to 2021. The average rate for 2021 was calculated by using the 2014 average rate of 7.37¢/kWh for the group of customers participating in conservation. This rate was escalated to 2021. This value multiplied by the 2020 sales equals the revenue for that year.

Changes in costs and energy savings for each plan were netted from the 2021 revenue and sales so that new rates could be calculated. These plan rates were then subtracted from the Existing Plan rate to determine the rate impact of each plan. The rate calculation assumes that all utility program costs are expensed in the year incurred and that the rate impact is borne by the customers not exempt from participating in the CIP.

4. Plan Parameters and Assumptions

Existing Plan Assumptions

The Existing Plan used the assumptions developed for Minnesota Power’s 2016 CIP Plan. Measure assumptions for the Existing Plan are listed in Table 4.1 below for the year 2016.

TABLE 4.1
Existing Plan Measure Assumptions

Year 2016	Incremental Cost ($)	Incentive ($)	Admin Cost ($)	Meter Energy Savings (kWh)	Meter Winter Peak Savings (kW)	Annual Participants
Residential			516,568			
Lighting						
CFL - Standard	2.14	1.25		34	0.0058	48,000
CFL - Specialty	5.85	3.10		41	0.0070	15,000
Torchieres	15.00	10.00		103	0.0177	35
LED - Standard	25.32	7.50		34	0.0058	6,000
LED - Specialty	26.31	10.00		52	0.0087	6,000
LED - Outdoor	36.81	10.00		103	0.0248	600
LED Indoor Fixtures	33.99	10.00		54	0.0094	1,200
LED Outdoor Fixtures	35.00	20.00		90	0.0216	55
LED Holiday Lighting	9.40	2.00		22	0.0000	3,000
Energy Star Appliances						
Clothes Washers	50.00	40.00		145	0.0239	1,300
Refrigerators	40.00	25.00		139	0.0141	1,000
Refrigerator Turn-in	150.00	150.00		915	0.0927	725
Freezer Turn-in	150.00	150.00		1,134	0.1148	150
Window A/C Turn-in	50.00	50.00		298	0.0000	50
Heating and Cooling						
Dehumidifier Replacement	20.00	10.00		436	0.0000	750
CAC Quality Install	75.00	50.00		163	0.0000	250
ASHP Quality Install	75.00	50.00		1,680	0.5090	75
Mini-split Ductless ASHP	5,300.00	500.00		11,374	3.6829	40
Std Split System ASHP	544.00	300.00		649	0.1909	15
GHP Open Loop (4 Ton)	3,972.00	400.00	150.00	30,264	9.4241	5
GHP Closed Loop (5 Ton)	14,130.00	1,000.00	300.00	24,984	7.7852	36
ECM - New Furnace	500.00	200.00		800	0.1616	800
ECM - Replacement Motor	184.00	100.00		800	0.1616	50
Home Performance Project						
Triple E - Level 1	2,537.00	1,000.00	200.00	4,703	1.4211	5
Triple E - Level 2	5,670.00	2,000.00	200.00	6,598	1.9937	10
Water Heating						
Drain Water Heat Recovery	742.00	400.00	100.00	923	0.1522	5
HP Water Heater, EF = 2.5	128.00	50.00		408	0.0673	5
Energy Efficiency Kits						
Smart Pak	15.00	15.00		490	0.0808	500
Starter Kit	12.00	12.00		179	0.0272	1,000
Direct Install Measures						
Pipe Wrap	0.40	0.40		46	0.0076	630
Showerheads	16.50	16.50		421	0.0694	200
Aerators	7.50	7.50		184	0.0303	300
Water Heater Blanket	20.00	20.00		99	0.0163	20
CFLs	4.00	4.00		34	0.0058	2,000
Shower Timer	5.50	5.50		188	0.0310	170
Refrigerator Thermometer	3.00	3.00		95	0.0096	500
Plug Load Package						
Enable Power Management	15.00	15.00		200	0.0228	160
Timer & Power Strip	20.00	20.00		90	0.0103	250

Year 2016	Incremental Cost ($)	Incentive ($)	Admin Cost ($)	Meter Energy Savings (kWh)	Meter Winter Peak Savings (kW)	Annual Participants
Commercial & Industrial			586,629			
Lighting	7,512.00	1,799.17		24,480	4.1587	500
Refrigeration	28,734.00	2,420.81		56,667	3.1868	30
Motor Upgrades	21,697.00	5,370.72		91,800	4.8770	100
HVAC	20,288.00	2,223.61		28,333	4.0780	150
Compressed Air Upgrades	8,160.00	4,054.98		68,000	8.4100	30
Process Improvements	40,390.00	11,205.39		80,952	10.0358	21
IT Equipment	17,000.00	8,447.87		141,667	21.5627	6
Miscellaneous	16,320.00	1,152.45		136,000	0.0000	5
Influenced Savings	18,410.00	0.00		68,000	0.0000	10
Commissioning	10,000.00	10,000.00		42,500	3.7730	4
Energy Partners			98,958			
Lighting						
CFL Installed by Contractor	4.00	4.00		34	0.0058	1,375
CFL Distributed to Customer	2.25	2.25		34	0.0058	370
Torchieries	20.60	43.93		103	0.0177	158
Lighting Fixtures	41.71	45.00		44	0.0076	158
Refrigerator Replacement						
18 Cubic Foot Refrigerator	710.00	755.00		577	0.0584	133
15 Cubic Foot Refrigerator	590.00	635.00		525	0.0532	37
10 Cubic Foot Refrigerator	490.00	535.00		438	0.0444	19
15 Cubic Foot Freezer	510.00	555.00		261	0.0264	5
5-9 ft Freezer	230.00	275.00		198	0.0201	5
Meter Refrigerators	0.00	0.00	5.00	0	0.0000	400
Refrigerator Turn-in	100.00	100.00		915	0.0927	189
Freezer Turn-in	100.00	100.00		1,134	0.1148	10
Water Heater						
Replacement 95EF	142.00	1,035.00		182	0.0302	50
Showerheads	16.50	16.50		421	0.0698	97
Aerators	7.50	7.50		184	0.0305	83
Pipe Wrap	0.21	0.21		46	0.0076	100
Water Heater Blanket	20.00	20.00		99	0.0164	5
Shower Timer	5.50	5.50		188	0.0312	165
Water Heater Setback	12.00	12.00		65	0.0108	5
Miscellaneous						
Dehumidifier Replacement	20.00	200.00		436	0.0000	69
Engine Block Timer	23.00	23.00		200	0.0000	14
Microwave Ovens	129.00	129.00		1,000	0.2740	14
Refrigerator Thermometer	1.00	1.00		95	0.0096	220
Plug Load - Power Strip & Tim	20.00	20.00		90	0.0103	165
Energy Expo Kits	40.00	40.00		426	0.0572	800
Delivered Fuels - Furnaces	1,254.00	2,850.00		2,807	0.9225	5

Incremental cost is the difference between the cost of a standard efficiency measure and a high-efficiency measure. It is important to this study because the incremental cost was used as the reference point for the variation in plan incentives. Existing Plan incremental costs were permitted to escalate 2.0 percent per year after 2016.

Incentive is the cash inducement for customers to install an efficient measure. Incentives can be in the form of a cash rebate or the direct installation of a measure. Existing Plan incentives escalated 2.0 percent per year after 2016.

Administrative costs are the costs incurred by Minnesota Power to implement the plan. Administrative costs were generally determined on a project basis. Payments to dealers for the sale of certain residential measures, also known as spiffs, were considered as per-measure advertising costs and were accounted for on a per-measure basis. Existing Plan administrative costs escalated 2.0 percent per year after 2016.

Energy savings are the annual kWh savings realized by the implementation of a measure. They are the savings at the customer meter and do not include system losses. The **peak savings**, also realized at the customer meter, represent the demand (kW) savings at the time of the Minnesota Power winter peak. Thus, they do not necessarily represent the maximum demand savings of the measure. Energy and savings remained constant on a per-measure basis throughout the study period for the Existing Plan and the alternative plans.

The **annual participation** represents the number of residential, low income or commercial and industrial measures installed in a year. Annual Existing Plan participation remained constant on a per-measure basis throughout the study period.

Plan Parameter Variation

The alternative plans were developed by varying the per-measure incentives, project level and per-measure administrative costs and annual participation. These parameters were not independently varied but rather varied in a manner that supported the particular plan. For instance, if per-measure incentives were increased, the amount of additional personnel and advertising (administrative cost), consistent with the desired effort, was estimated. This in turn led to an estimated change in measure participation. Variations began in the year 2017.

Incentives

Per-measure incentives were modified by determining the percentage of incremental cost of the Existing Plan incentive and by varying this percentage. Incentives in the -16 GWh Plan were decreased 15% from the Existing Plan. Incentives in the +11 GWh Plan were increased 15% above the Existing Plan for C&I programs and 25% for residential programs, with a cap at 100% of incremental cost. Incentives in the +15 GWh Plan were increased 25% for C&I programs and 40% for residential programs with a cap at 100% of incremental cost. Incentives in the+30 GWh Plan were increased 75% for C&I programs and 100% for residential programs, with a cap at 100% of incremental cost. Low Income incentives were kept constant at the Existing Plan level for all Plans. Total incentives, by measure, by Plan, for the year 2017 are provided in Appendix B – Part 2A – Table A.1.

Administrative Costs

Alternative plan administrative costs were varied by applying multipliers to the Existing Plan administrative costs. Administrative costs in the -16 GWh Plan were decreased 15% from the Existing Plan. Administrative costs in the +11 GWh Plan were increased 55% above the Existing Plan for the C&I programs and 27% for the residential programs. Administrative costs in the +15 GWh Plan were increased 80% above the Existing Plan for the C&I programs and 40% for residential programs. Administrative costs in the +30 GWH Plan were increased 175% above the Existing Plan for the C&I programs and 100% for residential programs. Low Income administrative costs were kept constant at the Existing Plan level for all Plans. Total administrative costs, by measure, by Plan, for the year 2017 are provided in Appendix B – Part 2A – Table A.2.

Nonimpact Spending

Nonimpact spending was decreased 15% from the Existing Plan for the -16 GWh Plan and was increased 33% for the +11 GWh Plan, 50% for the +15 GWh Plan and 120% for the +30 GWh Plan. Costs in each Plan were escalated 2.0% each year after 2016. Total plan costs (incentives, administrative and nonimpact), by measure, by Plan, for the year 2017 are provided in Appendix B – Part 2A – Table A.3.

Annual Participation

Alternative plan annual participation was determined by applying multipliers to the Existing Plan participation, on a per-measure basis. Participation in the -16 GWh Plan participation was decreased 35% from the Existing Plan. Participation was increased 23.55% above the Existing Plan in the +11 GWh Plan, 32.3% in the +15 GWh Plan and 65.9% in the +30 GWh Plan. The variations were applied to measures in the C&I and Residential projects. Low Income administrative costs were kept constant at the Existing Plan level for all Plans. Total participation, by measure, by Plan, for the year 2017 are provided in Appendix B – Part 2A – Table A.4.

Year 2016 – 2017 Plan Parameters

Plan costs, impacts and participation for all plans in the year 2016 and for each plan in the year 2017 are summarized in Table 4.2 below, on a total plan basis. The impacts of the Existing Plan are assumed to be embedded in Minnesota Power's load forecast.

TABLE 4.2
Cost, Impact and Participation by Plan for the Years 2016 and 2017

Plan	*Annual Program Costs*			*Annual Savings at Generator*	
	Incentives ($)	*Admin Cost ($)*	*NonImpact Cost ($)*	*Energy (kWh)*	*MISO Summer Peak (kW)*
All Plans - 2016	3,350,992	1,219,205	2,370,445	46,529,577	7,070
-16 GWh Plan - 2017	2.018,548	1,067,930	2,055,176	30,591,778	4,652
Existing Plan - 2017	3,418,012	1,243,589	2,417,854	46,529,577	7,070
+11 GWh Plan - 2017	4,809,780	1,723,687	3,211,156	57,253,438	8,697
+15 GWh Plan - 2017	5,570,768	1,946,120	3,626,781	61,237,888	9,301
+30 GWH Plan - 2017	9,432,408	2.853,205	5,319,279	76,538,175	11,623

Total energy savings at the generator, by measure, by Plan, for the year 2017 are provided in Appendix B – Part 2A – Table A.5. Total peak demand savings at the MISO summer peak, by measure, by Plan, for the year 2017 are provided in Appendix B – Part 2A – Table A.6.

5. Study Results

The plan parameters listed in Section 4 were modeled using DSManager to determine annual impacts and savings, as well as the results of the various cost-effectiveness tests (Societal, Utility and Ratepayer Impact Measure tests). The annual impacts and savings were used to calculate the rate impact in the year 2021.

Annual Impact and Dollar Savings

For each plan in the year 2021, Table 5.1 shows the annual impact savings and dollar savings on a total plan basis.

TABLE 5.1
Impact and Financial Savings by Plan in the Year 2021

Plan	*Savings at Generator*		*Financial Savings ($)*
	Energy (kWh)	*Summer MISO Peak (kW)*	
-16 GWh Plan	198,011,346	29,850	7,052,841
Existing Plan	a277,608,373	41,922	10,039,783
+11 GWh Plan	331,165,798	50,045	10,576,048
+15 GWh Plan	351,065,046	53,063	10,332,800
+ 30 GWh Plan	427,478,185	64,652	8,220,065

Energy and peak impact savings were determined at the generator (including system losses) and are cumulative over the six-year study period, taking into account a loss of savings from measures that reach end of life prior to the end of 2021. The financial savings represent the net of the energy and capacity savings, less the annual program costs.

Cost-effectiveness Test Results

Cost-effectiveness is determined by three standard tests: the Societal; Utility; and Ratepayer Impact Measure tests. The various components of each test are shown in Appendix B-Part 2-B. Results for each test are listed in Table 5.2 at the total plan level for each plan. Results at the project level are included in Appendix B–Part 2-C, Tables C.1.A through C.5.A. Project level results indicate that the total plan results are driven in a large part by the C&I project. The C&I project is substantially more cost-effective and much larger than the other projects.

Cost-effectiveness results are based on implementation through the year 2030 and consider the benefits of those measures through 2044. Tables C.1.B through C.5.B show the resulting spending and impacts associated with continuing the plans through the year 2044. These additional costs and impacts are used in the IRP modeling to account for “edge effects”. Since conservation has a finite life, the expired conservation caused by measures reaching the end of their lives is also shown in Tables C.1.B through C.4.B.

TABLE 5.2
Cost-effectiveness Test Results by Plan

	Benefits ($1,000)	*Costs ($1,000)*	*Net Benefits ($1,000)*	*B/C Ratio*
Societal Test				
-16 GWh Plan	324,580	171,009	153,572	1.90
Existing Plan	479,041	238,858	240,183	2.01
+11 GWh Plan	582,971	295,453	287,517	1.97
+15 GWh Plan	621,586	318,362	303,223	1.95
+30 GWh Plan	769,868	408,319	361,549	1.89
Utility Test				
-16 GWh Plan	161,481	49,570	111,911	3.26
Existing Plan	235,820	65,834	169,986	3.58
+11 GWh Plan	285,840	88,203	197,637	3.24
+15 GWh Plan	304,425	99,945	204,479	3.05
+30 GWh Plan	375,790	154,175	221,615	2.44
Ratepayer Impact Test				
-16 GWh Plan	161,481	330,152	(168,671)	0.49
Existing Plan	235,820	474,910	(239,090)	0.50
+11 GWh Plan	285,840	583,737	(297,897)	0.49
+15 GWh Plan	304,425	627,603	(323,178)	0.49
+30 GWh Plan	375,790	805,187	(297,897)	0.49

Societal Test

The Societal Test results indicate an increase in net benefits as the plan costs and impacts increase, while the benefit/cost ratio decreases. The Societal Test would favor an even more aggressive conservation program than that represented by the +30 GWh Plan.

Utility Test

The Utility Test results indicate an increase in net benefits as the plan costs and impacts increase, while the benefit/cost ratio decreases. Still, the +30 GWh Plan is considered cost-effective and an even more aggressive program would be favored under this test.

Ratepayer Impact Measure Test

The Ratepayer Impact Measure Test results indicate negative net benefits for all levels of conservation and an almost constant benefit/cost ratio as plan expenses increase. The Ratepayer Impact Measure Test would indicate that even low levels of conservation raise rates. The challenge with this test is determining just how much rates are increased. While a certain amount of rate increase can be tolerated, there is most likely a limit, above which is unacceptable. Neither the negative present value of net benefits nor the benefit/cost ratio less than 1.0 answers the question. An actual rate calculation is required.

Rate Impact in 2021

By subtracting the impact savings at the meter and financial savings from an estimate of sales, it is possible to calculate the rate and thus the rate impact of each conservation plan, relative to the Existing Plan. This rate impact is illustrated in the chart in Figure 5.1 below.

FIGURE 5.1
Conservation Rate Impact by Plan in the Year 2021

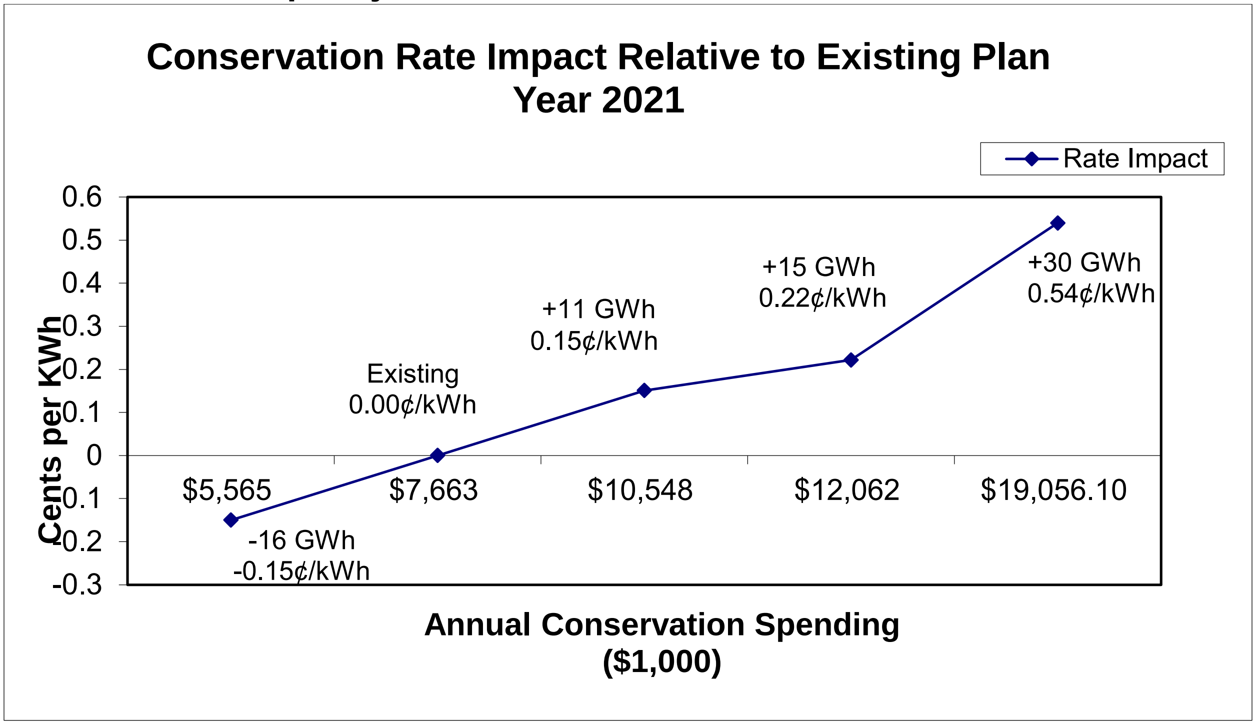


Figure 5.1 illustrates that rate impact increases linearly with conservation spending, to a differential of 0.15¢/kWh in the +11 GWh Plan, relative to the Existing Plan. This is in addition to the 0.15¢/KWh associated with the Existing Plan. The rate impact then increases to a differential of 0.22¢/kWh for the +15 GWh Plan and 0.54¢/KWh for the +30 GWh Plan, again relative to the Existing Plan. Considering that this study used simple variations of existing projects, this is not unexpected. The largest plan in terms of spending represented a direct impact spending level of greater than six percent of revenues. The +30 GWh Plan is below the spending of a plan that approaches a level of achievable potential. This study did not attempt to examine less common measures that may be examined with the achievable potential. To achieve such a level, Minnesota Power would need to promote measures of an even greater efficiency that cost more and devote even greater administrative resources to program promotion and administration. The rate impact graph could then be expected to rise at an even greater rate, beyond the +30 GWh Plan.

6. Conclusions

- All plans are cost-effective by the Societal and Utility tests.
- All plans are not cost-effective by the Ratepayer Impact Measure Test.

- Overall plan cost-effectiveness is driven in large part by the Commercial/Industrial Project because of this Project's large size compared to the Residential and Low Income Projects.
- Rates will increase linearly as expenditures for conservation programs increase to a differential of 0.15¢/kWh in the +11 GWh Plan, then increase sharply to a differential of 0.54¢/kWh in the highest spending plan, compared to the Existing Plan in 2021.
- Rate impacts of larger conservation plans, such as a plan associated with the achievable potential, will have even larger rate impacts.
- If a rate impact greater than the maximum shown in this study is acceptable, then Minnesota Power can investigate the greater levels of conservation associated with a technical/economic/achievable potential study.
- If the maximum rate impact is unacceptable, then the conservation program size can be managed within the sensitivity parameters defined in this study, subject to the maximum acceptable rate impact. In this instance, an achievable potential study would add no further value, as the rate impact associated with it would be larger than that shown in this study.

Appendix B—Part 2-A
Plan Parameters and Year 2017 Impacts

TABLE A.1
Year 2017 Incentives

Total Incentives by Measure and Plan - Page 1 of 2

Year 2017		Incentives				
		-16 GWh Plan	Existing Plan	+11 GWh Plan	+15 GWh Plan	+30 GWh Plan
		($)	($)	($)	($)	($)
Residential		**433,786**	**785,134**	**1,198,824**	**1,420,197**	**2,392,580**
Lighting		*133,533*	*241,689*	*373,258*	*447,656*	*763,038*
CFL - Standard		33,813	61,200	94,516	113,355	173,821
CFL - Specialty		26,205	47,430	73,250	87,850	148,489
Torchieres		197	357	551	661	888
LED - Standard		25,360	45,900	70,887	85,016	152,296
LED - Specialty		33,813	61,200	94,516	113,355	203,062
LED - Outdoor		3,381	6,120	9,452	11,335	20,306
LED Indoor Fixtures		6,763	12,240	18,903	22,671	40,612
LED Outdoor Fixtures		620	1,122	1,733	2,078	3,257
LED Holiday Lighting		3,381	6,120	9,452	11,335	20,306
Energy Star Appliances		*118,768*	*214,965*	*331,987*	*387,632*	*630,337*
Clothes Washers		29,305	53,040	81,914	87,715	109,992
Refrigerators		14,089	25,500	39,382	47,231	67,687
Refrigerator Turn-in		61,286	110,925	171,310	205,455	368,049
Freezer Turn-in		12,680	22,950	35,443	42,508	76,148
Window A/C Turn-in		1,409	2,550	3,938	4,723	8,461
Heating and Cooling		*141,592*	*256,275*	*395,785*	*474,673*	*833,796*
Dehumidifier Replacement		4,227	7,650	11,814	14,169	25,383
CAC Quality Install		7,044	12,750	19,691	23,616	31,728
ASHP Quality Install		2,113	3,825	5,907	7,085	9,519
Mini-split Ductless ASHP		11,271	20,400	31,505	37,785	67,687
Std Split System ASHP		2,536	4,590	7,089	8,502	13,808
GHP Open Loop (4 Ton)		1,127	2,040	3,151	3,778	6,769
GHP Closed Loop (5 Ton)		20,288	36,720	56,709	68,013	121,837
ECM - New Furnace		90,168	163,200	252,042	302,279	541,498
ECM - Replacement Motor		2,818	5,100	7,876	9,446	15,568
Home Performance Project		*14,089*	*25,500*	*39,382*	*47,231*	*84,609*
Triple E - Level 1		2,818	5,100	7,876	9,446	16,922
Triple E - Level 2		11,271	20,400	31,505	37,785	67,687
Water Heating		*1,268*	*2,295*	*3,544*	*4,251*	*7,124*
Drain Water Heat Recovery		1,127	2,040	3,151	3,778	6,278
HP Water Heater, EF = 2.5		141	255	394	472	846
Energy Efficiency Kits		*10,989*	*19,890*	*24,574*	*26,314*	*32,998*
Smart Pak		4,227	7,650	9,452	10,121	12,691
Starter Kit		6,763	12,240	15,123	16,194	20,306
Direct Install Measures		*13,547*	*24,520*	*30,294*	*32,440*	*40,678*
Pipe Wrap		143	259	320	343	430
Showerheads		1,860	3,366	4,159	4,453	5,584
Aerators		1,268	2,295	2,835	3,036	3,807
Water Heater Blanket		225	408	504	540	677
CFLs		4,508	8,160	10,082	10,796	13,537
Shower Timer		527	954	1,178	1,262	1,582
Refrigerator Thermometer		845	1,530	1,890	2,024	2,538
Plug Load Package		**4,170**	**7,548**	**9,326**	**9,986**	**12,522**
Enable Power Management		1,353	2,448	3,025	3,239	4,061
Timer & Power Strip		2,818	5,100	6,301	6,747	8,461

Total Incentives by Measure and Plan - Page 2 of 2

Year 2017		Incentives				
		-16 GWh Plan	Existing Plan	+11 GWh Plan	+15 GWh Plan	+30 GWh Plan
		($)	($)	($)	($)	($)
Energy Partners		**290,718**	**290,718**	**290,718**	**290,718**	**290,718**
Lighting		*20,791*	*20,791*	*20,791*	*20,791*	*20,791*
CFL Installed by Contractor		5,610	5,610	5,610	5,610	5,610
CFL Distributed to Customer		849	849	849	849	849
Torchieries		7,080	7,080	7,080	7,080	7,080
Lighting Fixtures		7,252	7,252	7,252	7,252	7,252
Refrigerator Replacement		*161,288*	*161,288*	*161,288*	*161,288*	*161,288*
18 Cubic Foot Refrigerator		102,423	102,423	102,423	102,423	102,423
15 Cubic Foot Refrigerator		23,965	23,965	23,965	23,965	23,965
10 Cubic Foot Refrigerator		10,368	10,368	10,368	10,368	10,368
15 Cubic Foot Freezer		2,831	2,831	2,831	2,831	2,831
5-9 ft Freezer		1,403	1,403	1,403	1,403	1,403
Meter Refrigerators		0	0	0	0	0
Refrigerator Turn-in		19,278	19,278	19,278	19,278	19,278
Freezer Turn-in		1,020	1,020	1,020	1,020	1,020
Water Heater		*56,163*	*56,163*	*56,163*	*56,163*	*56,163*
Replacement		52,785	52,785	52,785	52,785	52,785
Showerheads		1,633	1,633	1,633	1,633	1,633
Aerators		635	635	635	635	635
Pipe Wrap		21	21	21	21	21
Water Heater Blanket		102	102	102	102	102
Shower Timer		926	926	926	926	926
Water Heater Setback		61	61	61	61	61
Miscellaneous		*19,837*	*19,837*	*19,837*	*19,837*	*19,837*
Dehumidifier Replacement		14,076	14,076	14,076	14,076	14,076
Engine Block Timer		328	328	328	328	328
Microwave Ovens		1,842	1,842	1,842	1,842	1,842
Refrigerator Thermometer		224	224	224	224	224
Plug Load - Power Strip & Timer		3,366	3,366	3,366	3,366	3,366
Energy Expo Kits		*32,640*	*32,640*	*32,640*	*32,640*	*32,640*
Delivered Fuels - Furnaces		*0*	*0*	*0*	*0*	*0*
Commercial & Industrial		**1,294,043**	**2,342,160**	**3,320,238**	**3,859,852**	**6,749,110**
Lighting		*506,961*	*917,577*	*1,303,716*	*1,517,443*	*2,663,956*
Refrigeration		*40,927*	*74,077*	*105,250*	*122,505*	*215,064*
Motor Upgrades		*302,667*	*547,813*	*778,347*	*905,946*	*1,590,439*
HVAC		*187,967*	*340,212*	*483,382*	*562,626*	*987,721*
Compressed Air Upgrades		*68,555*	*124,082*	*176,299*	*205,201*	*360,242*
Process Improvements		*132,611*	*240,019*	*341,026*	*396,932*	*696,837*
IT Equipment		*28,565*	*51,701*	*73,458*	*85,500*	*150,101*
Miscellaneous		*3,247*	*5,878*	*8,351*	*9,720*	*17,064*
Influenced Savings		*0*	*0*	*0*	*0*	*0*
Commissioning		*22,542*	*40,800*	*50,408*	*53,978*	*67,687*
Total Direct Spending Plan		**2,018,548**	**3,418,012**	**4,809,780**	**5,570,768**	**9,432,408**
Non-Impact Spending		*130,050*	*153,000*	*198,900*	*229,500*	*336,600*
Total Plan with Indirects		**2,148,598**	**3,571,012**	**5,008,680**	**5,800,268**	**9,769,008**

TABLE A.2
Year 2017 Administrative Costs

Total Administrative Costs by Measure and Plan - Page 1 of 2

Year 2017		Administrative Costs -16 GWh Plan	Existing Plan	+11 GWh Plan	+15 GWh Plan	+30 GWh Plan
		($)	($)	($)	($)	($)
Residential		**456,346**	**542,250**	**693,249**	**766,092**	**1,104,733**
Lighting						
CFL - Standard						
CFL - Specialty						
Torchieres						
LED - Standard						
LED - Specialty						
LED - Outdoor						
LED Indoor Fixtures						
LED Outdoor Fixtures						
LED Holiday Lighting						
Energy Star Appliances						
Clothes Washers						
Refrigerators						
Refrigerator Turn-in						
Freezer Turn-in						
Window A/C Turn-in						
Heating and Cooling						
Dehumidifier Replacement						
CAC Quality Install						
ASHP Quality Install						
Mini-split Ductless ASHP						
Std Split System ASHP						
GHP Open Loop (4 Ton)		423	765	1,200	1,417	2,538
GHP Closed Loop (5 Ton)		6,086	11,016	17,285	20,404	36,551
ECM - New Furnace						
ECM - Replacement Motor						
Home Performance Project						
Triple E - Level 1		564	1,020	1,600	1,889	3,384
Triple E - Level 2		1,127	2,040	3,201	3,778	6,769
Water Heating						
Drain Water Heat Recovery		282	510	800	945	1,692
HP Water Heater, EF = 2.5						
Energy Efficiency Kits						
Smart Pak						
Starter Kit						
Direct Install Measures						
Pipe Wrap						
Showerheads						
Aerators						
Water Heater Blanket						
CFLs						
Shower Timer						
Refrigerator Thermometer						
Plug Load Package						
Enable Power Management						
Timer & Power Strip						

Total Administrative Costs by Measure and Plan - Page 2 of 2

		Administrative Costs				
Year 2017		-16 GWh Plan	Existing Plan	+11 GWh Plan	+15 GWh Plan	+30 GWh Plan
		($)	($)	($)	($)	($)
Energy Partners						
Lighting		**102,977**	**102,977**	**102,977**	**102,977**	**102,977**
CFL Installed by Contractor						
CFL Distributed to Customer						
Torchieries						
Lighting Fixtures						
Refrigerator Replacement						
18 Cubic Foot Refrigerator						
15 Cubic Foot Refrigerator						
10 Cubic Foot Refrigerator						
15 Cubic Foot Freezer						
5-9 ft Freezer						
Meter Refrigerators						
Refrigerator Turn-in		*2,040*	*2,040*	*2,040*	*2,040*	*2,040*
Freezer Turn-in						
Water Heater						
Replacement						
Showerheads						
Aerators						
Pipe Wrap						
Water Heater Blanket						
Shower Timer						
Water Heater Setback						
Miscellaneous						
Dehumidifier Replacement						
Engine Block Timer						
Microwave Ovens						
Refrigerator Thermometer						
Plug Load - Power Strip & Timer						
Energy Expo Kits						
Delivered Fuels - Furnaces						
Commercial & Industrial		**508,607**	**598,362**	**927,460**	**1,077,051**	**1,645,494**
Lighting						
Refrigeration						
Motor Upgrades						
HVAC						
Compressed Air Upgrades						
Process Improvements						
IT Equipment						
Miscellaneous						
Influenced Savings						
Commissioning						
Total Plan		**1,067,930**	**1,243,589**	**1,723,687**	**1,946,120**	**2,853,205**
Non-Impact Spending		*1,925,126*	*2,264,854*	*3,012,256*	*3,397,281*	*4,982,679*
Total Plan with Indirects		**2,993,056**	**3,508,443**	**4,735,943**	**5,343,401**	**7,835,883**

TABLE A.3
Year 2017 Total Costs

Total Costs by Measure and Plan - Page 1 of 2

Year 2017		Total Costs -16 GWh Plan	Existing Plan	+11 GWh Plan	+15 GWh Plan	+30 GWh Plan
		($)	($)	($)	($)	($)
Residential		**890,132**	**1,327,384**	**1,892,073**	**2,186,290**	**3,497,314**
Lighting		133,533	241,689	373,258	447,656	763,038
CFL - Standard		33,813	61,200	94,516	113,355	173,821
CFL - Specialty		26,205	47,430	73,250	87,850	148,489
Torchieres		*197*	*357*	*551*	*661*	*888*
LED - Standard		25,360	45,900	70,887	85,016	152,296
LED - Specialty		33,813	61,200	94,516	113,355	203,062
LED - Outdoor		3,381	6,120	9,452	11,335	20,306
LED Indoor Fixtures		6,763	12,240	18,903	22,671	40,612
LED Outdoor Fixtures		620	1,122	1,733	2,078	3,257
LED Holiday Lighting		*3,381*	*6,120*	*9,452*	*11,335*	*20,306*
Energy Star Appliances		118,768	214,965	331,987	387,632	630,337
Clothes Washers		29,305	53,040	81,914	87,715	109,992
Refrigerators		14,089	25,500	39,382	47,231	67,687
Refrigerator Turn-in		61,286	110,925	171,310	205,455	368,049
Freezer Turn-in		*12,680*	*22,950*	*35,443*	*42,508*	*76,148*
Window A/C Turn-in		1,409	2,550	3,938	4,723	8,461
Heating and Cooling		141,592	256,275	395,785	474,673	833,796
Dehumidifier Replacement		4,227	7,650	11,814	14,169	25,383
CAC Quality Install		7,044	12,750	19,691	23,616	31,728
ASHP Quality Install		2,113	3,825	5,907	7,085	9,519
Mini-split Ductless ASHP		11,271	20,400	31,505	37,785	67,687
Std Split System ASHP		2,536	4,590	7,089	8,502	13,808
GHP Open Loop (4 Ton)		1,550	2,805	4,351	5,195	9,307
GHP Closed Loop (5 Ton)		26,374	47,736	73,994	88,417	158,388
ECM - New Furnace		90,168	163,200	252,042	302,279	541,498
ECM - Replacement Motor		2,818	5,100	7,876	9,446	15,568
Home Performance Project		14,089	25,500	39,382	47,231	84,609
Triple E - Level 1		3,381	6,120	9,477	11,335	20,306
Triple E - Level 2		12,398	22,440	34,706	41,563	74,456
Water Heating		1,268	2,295	3,544	4,251	7,124
Drain Water Heat Recovery		*1,409*	*2,550*	*3,951*	*4,723*	*7,970*
HP Water Heater, EF = 2.5		141	255	394	472	846
Energy Efficiency Kits		10,989	19,890	24,574	26,314	32,998
Smart Pak		4,227	7,650	9,452	10,121	12,691
Starter Kit		*6,763*	*12,240*	*15,123*	*16,194*	*20,306*
Direct Install Measures		13,547	24,520	30,294	32,440	40,678
Pipe Wrap		143	259	320	343	430
Showerheads		1,860	3,366	4,159	4,453	5,584
Aerators		1,268	2,295	2,835	3,036	3,807
Water Heater Blanket		*225*	*408*	*504*	*540*	*677*
CFLs		4,508	8,160	10,082	10,796	13,537
Shower Timer		*527*	*954*	*1,178*	*1,262*	*1,582*
Refrigerator Thermometer		845	1,530	1,890	2,024	2,538
Plug Load Package		4,170	7,548	9,326	9,986	12,522
Enable Power Management		1,353	2,448	3,025	3,239	4,061
Timer & Power Strip		2,818	5,100	6,301	6,747	8,461

Total Costs by Measure and Plan - Page 2 of 2

		Total Costs				
Year 2017		-16 GWh Plan	Existing Plan	+11 GWh Plan	+15 GWh Plan	+30 GWh Plan
		($)	($)	($)	($)	($)
Energy Partners		**393,695**	**393,695**	**393,695**	**393,695**	**393,695**
Lighting		*20,791*	*20,791*	*20,791*	*20,791*	*20,791*
CFL Installed by Contractor		5,610	5,610	5,610	5,610	5,610
CFL Distributed to Customer		849	849	849	849	849
Torchieries		*7,080*	*7,080*	*7,080*	*7,080*	*7,080*
Lighting Fixtures		7,252	7,252	7,252	7,252	7,252
Refrigerator Replacement		*161,288*	*161,288*	*161,288*	*161,288*	*161,288*
18 Cubic Foot Refrigerator		102,423	102,423	102,423	102,423	102,423
15 Cubic Foot Refrigerator		*23,965*	*23,965*	*23,965*	*23,965*	*23,965*
10 Cubic Foot Refrigerator		10,368	10,368	10,368	10,368	10,368
15 Cubic Foot Freezer		2,831	2,831	2,831	2,831	2,831
5-9 ft Freezer		1,403	1,403	1,403	1,403	1,403
Meter Refrigerators		*2,040*	*2,040*	*2,040*	*2,040*	*2,040*
Refrigerator Turn-in		19,278	19,278	19,278	19,278	19,278
Freezer Turn-in		1,020	1,020	1,020	1,020	1,020
Water Heater		56,163	56,163	56,163	56,163	56,163
Replacement		52,785	52,785	52,785	52,785	52,785
Showerheads		1,633	1,633	1,633	1,633	1,633
Aerators		635	635	635	635	635
Pipe Wrap		21	21	21	21	21
Water Heater Blanket		102	102	102	102	102
Shower Timer		*926*	*926*	*926*	*926*	*926*
Water Heater Setback		61	61	61	61	61
Miscellaneous		19,837	19,837	19,837	19,837	19,837
Dehumidifier Replacement		14,076	14,076	14,076	14,076	14,076
Engine Block Timer		328	328	328	328	328
Microwave Ovens		1,842	1,842	1,842	1,842	1,842
Refrigerator Thermometer		224	224	224	224	224
Plug Load - Power Strip & Timer		*3,366*	*3,366*	*3,366*	*3,366*	*3,366*
Energy Expo Kits		32,640	32,640	32,640	32,640	32,640
Delivered Fuels - Furnaces		0	0	0	0	0
Commercial & Industrial		**1,802,651**	**2,940,521**	**4,247,698**	**4,936,903**	**8,394,604**
Lighting		*506,961*	*917,577*	*1,303,716*	*1,517,443*	*2,663,956*
Refrigeration		*40,927*	*74,077*	*105,250*	*122,505*	*215,064*
Motor Upgrades		*302,667*	*547,813*	*778,347*	*905,946*	*1,590,439*
HVAC		*187,967*	*340,212*	*483,382*	*562,626*	*987,721*
Compressed Air Upgrades		*68,555*	*124,082*	*176,299*	*205,201*	*360,242*
Process Improvements		*132,611*	*240,019*	*341,026*	*396,932*	*696,837*
IT Equipment		*28,565*	*51,701*	*73,458*	*85,500*	*150,101*
Miscellaneous		*3,247*	*5,878*	*8,351*	*9,720*	*17,064*
Influenced Savings		*0*	*0*	*0*	*0*	*0*
Commissioning		*22,542*	*40,800*	*50,408*	*53,978*	*67,687*
Total Plan		**3,086,478**	**4,661,601**	**6,533,467**	**7,516,888**	**12,285,613**
Non-Impact Spending		*2,055,176*	*2,417,854*	*3,211,156*	*3,626,781*	*5,319,279*
Total Plan with Indirects		**5,141,654**	**7,079,455**	**9,744,623**	**11,143,669**	**17,604,891**

TABLE A.4
Year 2017 Participation

Total Participants by Measure and Plan - Page 1 of 2

Year 2017		Participants -16 GWh Plan	Existing Plan	+11 GWh Plan	+15 GWh Plan	+30 GWh Plan
Residential		**59,079.1500**	**90,891.0000**	**112,295.8305**	**120,248.7930**	**150,788.1690**
Lighting		*51,928.5000*	*79,890.0000*	*98,704.0950*	*105,694.4700*	*132,537.5100*
CFL - Standard		31,200.0000	48,000.0000	59,304.0000	63,504.0000	79,632.0000
CFL - Specialty		9,750.0000	15,000.0000	18,532.5000	19,845.0000	24,885.0000
Torchieres		22.7500	35.0000	43.2425	46.3050	58.0650
LED - Standard		3,900.0000	6,000.0000	7,413.0000	7,938.0000	9,954.0000
LED - Specialty		3,900.0000	6,000.0000	7,413.0000	7,938.0000	9,954.0000
LED - Outdoor		390.0000	600.0000	741.3000	793.8000	995.4000
LED Indoor Fixtures		780.0000	1,200.0000	1,482.6000	1,587.6000	1,990.8000
LED Outdoor Fixtures		35.7500	55.0000	67.9525	72.7650	91.2450
LED Holiday Lighting		1,950.0000	3,000.0000	3,706.5000	3,969.0000	4,977.0000
Energy Star Appliances		*2,096.2500*	*3,225.0000*	*3,984.4875*	*4,266.6750*	*5,350.2750*
Clothes Washers		845.0000	1,300.0000	1,606.1500	1,719.9000	2,156.7000
Refrigerators		650.0000	1,000.0000	1,235.5000	1,323.0000	1,659.0000
Refrigerator Turn-in		471.2500	725.0000	895.7375	959.1750	1,202.7750
Freezer Turn-in		97.5000	150.0000	185.3250	198.4500	248.8500
Window A/C Turn-in		32.5000	50.0000	61.7750	66.1500	82.9500
Heating and Cooling		*1,313.6500*	*2,021.0000*	*2,496.9455*	*2,673.7830*	*3,352.8390*
Dehumidifier Replacement		487.5000	750.0000	926.6250	992.2500	1,244.2500
CAC Quality Install		162.5000	250.0000	308.8750	330.7500	414.7500
ASHP Quality Install		48.7500	75.0000	92.6625	99.2250	124.4250
Mini-split Ductless ASHP		26.0000	40.0000	49.4200	52.9200	66.3600
Std Split System ASHP		9.7500	15.0000	18.5325	19.8450	24.8850
GHP Open Loop (4 Ton)		3.2500	5.0000	6.1775	6.6150	8.2950
GHP Closed Loop (5 Ton)		23.4000	36.0000	44.4780	47.6280	59.7240
ECM - New Furnace		520.0000	800.0000	988.4000	1,058.4000	1,327.2000
ECM - Replacement Motor		32.5000	50.0000	61.7750	66.1500	82.9500
Home Performance Project		9.7500	15.0000	18.5325	19.8450	24.8850
Triple E - Level 1		3.2500	5.0000	6.1775	6.6150	8.2950
Triple E - Level 2		6.5000	10.0000	12.3550	13.2300	16.5900
Water Heating		6.5000	10.0000	12.3550	13.2300	16.5900
Drain Water Heat Recovery		3.2500	5.0000	6.1775	6.6150	8.2950
HP Water Heater, EF = 2.5		3.2500	5.0000	6.1775	6.6150	8.2950
Energy Efficiency Kits		975.0000	1,500.0000	1,853.2500	1,984.5000	2,488.5000
Smart Pak		325.0000	500.0000	617.7500	661.5000	829.5000
Starter Kit		650.0000	1,000.0000	1,235.5000	1,323.0000	1,659.0000
Direct Install Measures		*2,749.5000*	*4,230.0000*	*5,226.1650*	*5,596.2900*	*7,017.5700*
Pipe Wrap		409.5000	630.0000	778.3650	833.4900	1,045.1700
Showerheads		130.0000	200.0000	247.1000	264.6000	331.8000
Aerators		195.0000	300.0000	370.6500	396.9000	497.7000
Water Heater Blanket		13.0000	20.0000	24.7100	26.4600	33.1800
CFLs		1,300.0000	2,000.0000	2,471.0000	2,646.0000	3,318.0000
Shower Timer		110.5000	170.0000	210.0350	224.9100	282.0300
Refrigerator Thermometer		325.0000	500.0000	617.7500	661.5000	829.5000
Plug Load Package		**266.5000**	**410.0000**	**506.5550**	**542.4300**	**680.1900**
Enable Power Management		104.0000	160.0000	197.6800	211.6800	265.4400
Timer & Power Strip		162.5000	250.0000	308.8750	330.7500	414.7500

Total Participants by Measure and Plan - Page 2 of 2

Year 2017		Participants				
		-16 GWh Plan	Existing Plan	+11 GWh Plan	+15 GWh Plan	+30 GWh Plan
Energy Partners		**4,651**	**4,651**	**4,651**	**4,651**	**4,651**
Lighting		*2,061*	*2,061*	*2,061*	*2,061*	*2,061*
CFL Installed by Contractor		1,375	1,375	1,375	1,375	1,375
CFL Distributed to Customer		370	370	370	370	370
Torchieries		158	158	158	158	158
Lighting Fixtures		158	158	158	158	158
Refrigerator Replacement		*798*	*798*	*798*	*798*	*798*
18 Cubic Foot Refrigerator		133	133	133	133	133
15 Cubic Foot Refrigerator		37	37	37	37	37
10 Cubic Foot Refrigerator		19	19	19	19	19
15 Cubic Foot Freezer		5	5	5	5	5
5-9 ft Freezer		5	5	5	5	5
Meter Refrigerators		400	400	400	400	400
Refrigerator Turn-in		189	189	189	189	189
Freezer Turn-in		10	10	10	10	10
Water Heater		*505*	*505*	*505*	*505*	*505*
Replacement		50	50	50	50	50
Showerheads		97	97	97	97	97
Aerators		83	83	83	83	83
Pipe Wrap		100	100	100	100	100
Water Heater Blanket		5	5	5	5	5
Shower Timer		165	165	165	165	165
Water Heater Setback		5	5	5	5	5
Miscellaneous		*482*	*482*	*482*	*482*	*482*
Dehumidifier Replacement		69	69	69	69	69
Engine Block Timer		14	14	14	14	14
Microwave Ovens		14	14	14	14	14
Refrigerator Thermometer		220	220	220	220	220
Plug Load - Power Strip & Timer		165	165	165	165	165
Energy Expo Kits		*800*	*800*	*800*	*800*	*800*
Delivered Fuels - Furnaces		*5*	*5*	*5*	*5*	*5*
Commercial & Industrial		**556.4000**	**856.0000**	**1,057.5880**	**1,132.4880**	**1,420.1040**
Lighting		*325.0000*	*500.0000*	*617.7500*	*661.5000*	*829.5000*
Refrigeration		*19.5000*	*30.0000*	*37.0650*	*39.6900*	*49.7700*
Motor Upgrades		*65.0000*	*100.0000*	*123.5500*	*132.3000*	*165.9000*
HVAC		*97.5000*	*150.0000*	*185.3250*	*198.4500*	*248.8500*
Compressed Air Upgrades		*19.5000*	*30.0000*	*37.0650*	*39.6900*	*49.7700*
Process Improvements		*13.6500*	*21.0000*	*25.9455*	*27.7830*	*34.8390*
IT Equipment		*3.9000*	*6.0000*	*7.4130*	*7.9380*	*9.9540*
Miscellaneous		*3.2500*	*5.0000*	*6.1775*	*6.6150*	*8.2950*
Influenced Savings		*6.5000*	*10.0000*	*12.3550*	*13.2300*	*16.5900*
Commissioning		*2.6000*	*4.0000*	*4.9420*	*5.2920*	*6.6360*
Total Plan		**64,287**	**96,398**	**118,004**	**126,032**	**156,859**

TABLE A.5
Year 2017 Energy Savings

Total Energy Savings by Measure and Plan - Page 1 of 2

Year 2017	Energy (Busbar) -16 GWh Plan (kWh)	Existing Plan (kWh)	+11 GWh Plan (kWh)	+15 GWh Plan (kWh)	+30 GWh Plan (kWh)
Residential	**5,545,817**	**8,532,026**	**10,541,318**	**11,287,871**	**14,154,632**
Lighting	*2,128,895*	*3,275,222*	*4,046,537*	*4,333,119*	*5,433,594*
CFL - Standard	1,172,124	1,803,267	2,227,936	2,385,722	2,991,620
CFL - Specialty	441,701	679,540	839,572	899,031	1,127,357
Torchieres	2,589	3,983	4,921	5,270	6,608
LED - Standard	146,515	225,408	278,492	298,215	373,952
LED - Specialty	224,082	344,742	425,929	456,094	571,927
LED - Outdoor	44,386	68,285	84,367	90,342	113,286
LED Indoor Fixtures	46,540	71,600	88,462	94,727	118,785
LED Outdoor Fixtures	3,555	5,469	6,758	7,236	9,074
LED Holiday Lighting	47,402	72,926	90,100	96,481	120,985
Energy Star Appliances	*844,529*	*1,299,275*	*1,605,254*	*1,718,941*	*2,155,497*
Clothes Washers	135,383	208,282	257,332	275,557	345,539
Refrigerators	99,832	153,587	189,757	203,196	254,801
Refrigerator Turn-in	476,445	732,992	905,611	969,748	1,216,033
Freezer Turn-in	122,168	187,951	232,213	248,659	311,810
Window A/C Turn-in	10,701	16,464	20,341	21,781	27,313
Heating and Cooling	*1,931,410*	*2,971,401*	*3,671,165*	*3,931,163*	*4,929,554*
Dehumidifier Replacement	234,856	361,316	446,406	478,022	599,424
CAC Quality Install	29,267	45,026	55,630	59,570	74,699
ASHP Quality Install	90,495	139,223	172,010	184,192	230,971
Mini-split Ductless ASHP	326,758	502,705	621,092	665,079	833,987
Std Split System ASHP	6,992	10,757	13,290	14,231	17,845
GHP Open Loop (4 Ton)	108,680	167,200	206,576	221,206	277,385
GHP Closed Loop (5 Ton)	645,978	993,812	1,227,855	1,314,814	1,648,735
ECM - New Furnace	459,656	707,164	873,701	935,577	1,173,184
ECM - Replacement Motor	28,729	44,198	54,606	58,474	73,324
Home Performance Project	*64,276*	*98,887*	*122,175*	*130,827*	*164,053*
Triple E - Level 1	16,889	25,983	32,102	34,375	43,105
Triple E - Level 2	47,388	72,904	90,073	96,452	120,948
Water Heating	*4,780*	*7,353*	*9,085*	*9,729*	*12,199*
Drain Water Heat Recovery	3,315	5,099	6,300	6,746	8,460
HP Water Heater, EF = 2.5	1,465	2,254	2,785	2,982	3,740
Energy Efficiency Kits	*304,522*	*468,496*	*578,827*	*619,820*	*777,235*
Smart Pak	175,962	270,711	334,463	358,151	449,110
Starter Kit	128,560	197,785	244,363	261,669	328,125
Direct Install Measures	*267,405*	*411,392*	*508,275*	*544,272*	*682,500*
Pipe Wrap	20,814	32,021	39,562	42,364	53,123
Showerheads	60,474	93,036	114,946	123,087	154,347
Aerators	39,645	60,993	75,357	80,694	101,187
Water Heater Blanket	1,422	2,188	2,703	2,894	3,630
CFLs	48,838	75,136	92,831	99,405	124,651
Shower Timer	22,954	35,314	43,630	46,720	58,586
Refrigerator Thermometer	34,115	52,485	64,845	69,437	87,072
Plug Load Package	**39,143**	**60,219**	**74,401**	**79,670**	**99,904**
Enable Power Management	22,983	35,358	43,685	46,779	58,659
Timer & Power Strip	16,160	24,861	30,716	32,891	41,245

Total Energy Savings by Measure and Plan - Page 2 of 2

Year 2017		Energy (Busbar)				
		-16 GWh Plan	Existing Plan	+11 GWh Plan	+15 GWh Plan	+30 GWh Plan
		(kWh)	(kWh)	(kWh)	(kWh)	(kWh)
Energy Partners		**993,009**	**993,009**	**993,009**	**993,009**	**993,009**
Lighting		*91,220*	*91,220*	*91,220*	*91,220*	*91,220*
CFL Installed by Contractor		51,656	51,656	51,656	51,656	51,656
CFL Distributed to Customer		13,900	13,900	13,900	13,900	13,900
Torchieries		17,982	17,982	17,982	17,982	17,982
Lighting Fixtures		7,682	7,682	7,682	7,682	7,682
Refrigerator Replacement		*321,603*	*321,603*	*321,603*	*321,603*	*321,603*
18 Cubic Foot Refrigerator		84,794	84,794	84,794	84,794	84,794
15 Cubic Foot Refrigerator		21,464	21,464	21,464	21,464	21,464
10 Cubic Foot Refrigerator		9,195	9,195	9,195	9,195	9,195
15 Cubic Foot Freezer		1,442	1,442	1,442	1,442	1,442
5-9 ft Freezer		1,094	1,094	1,094	1,094	1,094
Meter Refrigerators		0	0	0	0	0
Refrigerator Turn-in		191,083	191,083	191,083	191,083	191,083
Freezer Turn-in		12,530	12,530	12,530	12,530	12,530
Water Heater		*112,316*	*112,316*	*112,316*	*112,316*	*112,316*
Replacement		10,055	10,055	10,055	10,055	10,055
Showerheads		45,123	45,123	45,123	45,123	45,123
Aerators		16,875	16,875	16,875	16,875	16,875
Pipe Wrap		5,083	5,083	5,083	5,083	5,083
Water Heater Blanket		547	547	547	547	547
Shower Timer		34,275	34,275	34,275	34,275	34,275
Water Heater Setback		359	359	359	359	359
Miscellaneous		*91,306*	*91,306*	*91,306*	*91,306*	*91,306*
Dehumidifier Replacement		33,241	33,241	33,241	33,241	33,241
Engine Block Timer		3,094	3,094	3,094	3,094	3,094
Microwave Ovens		15,469	15,469	15,469	15,469	15,469
Refrigerator Thermometer		23,093	23,093	23,093	23,093	23,093
Plug Load - Power Strip & Timer		16,408	16,408	16,408	16,408	16,408
Energy Expo Kits		*376,565*	*376,565*	*376,565*	*376,565*	*376,565*
Delivered Fuels - Furnaces		*0*	*0*	*0*	*0*	*0*
Commercial & Industrial		**24,052,952**	**37,004,541**	**45,719,111**	**48,957,008**	**61,390,534**
Lighting		*8,790,927*	*13,524,502*	*16,709,523*	*17,892,917*	*22,437,150*
Refrigeration		*1,220,962*	*1,878,403*	*2,320,767*	*2,485,127*	*3,116,271*
Motor Upgrades		*6,593,195*	*10,143,377*	*12,532,142*	*13,419,688*	*16,827,862*
HVAC		*3,052,405*	*4,696,008*	*5,801,918*	*6,212,818*	*7,790,677*
Compressed Air Upgrades		*1,465,154*	*2,254,084*	*2,784,920*	*2,982,153*	*3,739,525*
Process Improvements		*1,220,962*	*1,878,403*	*2,320,767*	*2,485,127*	*3,116,271*
IT Equipment		*610,481*	*939,202*	*1,160,384*	*1,242,564*	*1,558,135*
Miscellaneous		*488,385*	*751,361*	*928,307*	*994,051*	*1,246,508*
Influenced Savings		*488,385*	*751,361*	*928,307*	*994,051*	*1,246,508*
Commissioning		*122,096*	*187,840*	*232,077*	*248,513*	*311,627*
Total Plan		**30,591,778**	**46,529,577**	**57,253,438**	**61,237,888**	**76,538,175**

TABLE A.6
Year 2017 Peak Savings at MISO Summer Peak

Total kW Saving at MISO Summer Peak by Measure and Plan - Page 1 of 2

Year 2017	Peak (Busbar) -16 GWh Plan	Existing Plan	+11 GWh Plan	+15 GWh Plan	+30 GWh Plan
	(kW)	(kW)	(kW)	(kW)	(kW)
Residential	**932.5**	**1,434.6**	**1,772.4**	**1,897.9**	**2,380.0**
Lighting	*331.4*	*509.9*	*630.0*	*674.6*	*845.9*
CFL - Standard	192.0	295.3	364.9	390.7	490.0
CFL - Specialty	67.3	103.5	127.9	137.0	171.7
Torchieres	0.4	0.6	0.8	0.8	1.0
LED - Standard	24.0	36.9	45.6	48.8	61.3
LED - Specialty	41.3	63.6	78.6	84.1	105.5
LED - Outdoor	0.0	0.0	0.0	0.0	0.0
LED Indoor Fixtures	6.5	10.0	12.3	13.2	16.5
LED Outdoor Fixtures	0.0	0.0	0.0	0.0	0.0
LED Holiday Lighting	0.0	0.0	0.0	0.0	0.0
Energy Star Appliances	*122.1*	*187.9*	*232.1*	*248.6*	*311.7*
Clothes Washers	15.2	23.3	28.8	30.8	38.7
Refrigerators	13.4	20.6	25.5	27.3	34.2
Refrigerator Turn-in	63.9	98.4	121.5	130.2	163.2
Freezer Turn-in	16.4	25.2	31.2	33.4	41.9
Window A/C Turn-in	13.2	20.4	25.2	26.9	33.8
Heating and Cooling	*405.0*	*623.0*	*769.8*	*824.3*	*1,033.6*
Dehumidifier Replacement	290.4	446.8	552.0	591.1	741.2
CAC Quality Install	36.2	55.7	68.8	73.7	92.4
ASHP Quality Install	8.7	13.4	16.6	17.8	22.3
Mini-split Ductless ASHP	5.9	9.1	11.3	12.1	15.1
Std Split System ASHP	0.9	1.4	1.7	1.8	2.3
GHP Open Loop (4 Ton)	3.5	5.3	6.6	7.0	8.8
GHP Closed Loop (5 Ton)	15.5	23.9	29.6	31.6	39.7
ECM - New Furnace	41.2	63.4	78.4	83.9	105.2
ECM - Replacement Motor	2.6	4.0	4.9	5.2	6.6
Home Performance Project	*4.0*	*6.1*	*7.6*	*8.1*	*10.1*
Triple E - Level 1	1.0	1.6	2.0	2.1	2.7
Triple E - Level 2	2.9	4.5	5.6	6.0	7.5
Water Heating	*0.5*	*0.8*	*1.0*	*1.1*	*1.4*
Drain Water Heat Recovery	0.4	0.6	0.7	0.8	1.0
HP Water Heater, EF = 2.5	0.2	0.3	0.3	0.3	0.4
Energy Efficiency Kits	*36.1*	*55.6*	*68.7*	*73.5*	*92.2*
Smart Pak	19.7	30.3	37.4	40.1	50.3
Starter Kit	16.4	25.3	31.2	33.4	41.9
Direct Install Measures	*33.3*	*51.2*	*63.3*	*67.8*	*85.0*
Pipe Wrap	2.3	3.6	4.4	4.7	5.9
Showerheads	6.8	10.4	12.9	13.8	17.3
Aerators	4.4	6.8	8.4	9.0	11.3
Water Heater Blanket	0.2	0.2	0.3	0.3	0.4
CFLs	8.0	12.3	15.2	16.3	20.4
Shower Timer	2.6	4.0	4.9	5.2	6.6
Refrigerator Thermometer	4.6	7.0	8.7	9.3	11.7
Plug Load Package	**4.5**	**6.9**	**8.5**	**9.1**	**11.4**
Enable Power Management	2.6	4.0	5.0	5.3	6.7
Timer & Power Strip	1.8	2.8	3.5	3.8	4.7

Total kW Saving at MISO Summer Peak by Measure and Plan - Page 2 of 2

Year 2017	Peak (Busbar)				
	-16 GWh Plan	Existing Plan	+11 GWh Plan	+15 GWh Plan	+30 GWh Plan
	(kW)	(kW)	(kW)	(kW)	(kW)
Energy Partners	**161.6**	**161.6**	**161.6**	**161.6**	**161.6**
Lighting	*14.6*	*14.6*	*14.6*	*14.6*	*14.6*
CFL Installed by Contractor	8.5	8.5	8.5	8.5	8.5
CFL Distributed to Customer	2.3	2.3	2.3	2.3	2.3
Torchieries	2.7	2.7	2.7	2.7	2.7
Lighting Fixtures	1.1	1.1	1.1	1.1	1.1
Refrigerator Replacement	*43.2*	*43.2*	*43.2*	*43.2*	*43.2*
18 Cubic Foot Refrigerator	11.4	11.4	11.4	11.4	11.4
15 Cubic Foot Refrigerator	2.9	2.9	2.9	2.9	2.9
10 Cubic Foot Refrigerator	1.2	1.2	1.2	1.2	1.2
15 Cubic Foot Freezer	0.2	0.2	0.2	0.2	0.2
5-9 ft Freezer	0.2	0.2	0.2	0.2	0.2
Meter Refrigerators	0.0	0.0	0.0	0.0	0.0
Refrigerator Turn-in	25.7	25.7	25.7	25.7	25.7
Freezer Turn-in	1.7	1.7	1.7	1.7	1.7
Water Heater	*12.1*	*12.1*	*12.1*	*12.1*	*12.1*
Replacement	1.1	1.1	1.1	1.1	1.1
Showerheads	4.9	4.9	4.9	4.9	4.9
Aerators	1.8	1.8	1.8	1.8	1.8
Pipe Wrap	0.6	0.6	0.6	0.6	0.6
Water Heater Blanket	0.1	0.1	0.1	0.1	0.1
Shower Timer	3.7	3.7	3.7	3.7	3.7
Water Heater Setback	0.0	0.0	0.0	0.0	0.0
Miscellaneous	*47.1*	*47.1*	*47.1*	*47.1*	*47.1*
Dehumidifier Replacement	41.1	41.1	41.1	41.1	41.1
Engine Block Timer	0.0	0.0	0.0	0.0	0.0
Microwave Ovens	1.1	1.1	1.1	1.1	1.1
Refrigerator Thermometer	3.1	3.1	3.1	3.1	3.1
Plug Load - Power Strip & Timer	1.9	1.9	1.9	1.9	1.9
Energy Expo Kits	*44.6*	*44.6*	*44.6*	*44.6*	*44.6*
Delivered Fuels - Furnaces	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Commercial & Industrial	**3,558.0**	**5,473.9**	**6,763.0**	**7,242.0**	**9,081.2**
Lighting	*1,793.9*	*2,759.8*	*3,409.7*	*3,651.2*	*4,578.5*
Refrigeration	*68.7*	*105.6*	*130.5*	*139.8*	*175.3*
Motor Upgrades	*350.3*	*538.9*	*665.8*	*712.9*	*894.0*
HVAC	*439.3*	*675.9*	*835.1*	*894.2*	*1,121.3*
Compressed Air Upgrades	*181.2*	*278.8*	*344.4*	*368.8*	*462.5*
Process Improvements	*151.4*	*232.9*	*287.7*	*308.1*	*386.3*
IT Equipment	*92.9*	*143.0*	*176.6*	*189.1*	*237.2*
Miscellaneous	*234.8*	*361.2*	*446.3*	*477.9*	*599.2*
Influenced Savings	*234.8*	*361.2*	*446.3*	*477.9*	*599.2*
Commissioning	*10.8*	*16.7*	*20.6*	*22.1*	*27.7*
Total Plan	**4,652.0**	**7,070.0**	**8,697.0**	**9,301.4**	**11,622.7**

Appendix B—Part 2-B
Cost-Effectiveness Test Components

DSM Cost-Effectiveness Test Components

Societal Test

The Societal Test is the benchmark for determining project cost-effectiveness in Minnesota. This test reflects the cost-effectiveness of a project from the viewpoint of society as a whole. Positive net benefits or a benefit/cost ratio greater than 1.0 indicates cost-effectiveness according to this prospective.

Benefits	Costs
• Production Cost savings	• Incremental Participant Cost
• Generation Capacity Savings	• Administrative Costs
• Transmission Capacity Savings	• Customer O&M Costs
• Customer O&M Savings	• Measure Removal Costs, Less Salvage
• Environmental Externality Savings	

Discount Rate: Societal Rate (2.97%)

Utility Test

The Utility Test, or the Revenue Requirements Test, as it is also called, measures the change in the direct costs of the utility. A project with positive net benefits or a benefit/cost ratio greater than 1.0 will tend to lower utility costs over the long-term.

Benefits	Costs
• Production Cost savings	• Incentives
• Generation Capacity Savings	• Administrative Costs
• Transmission Capacity Savings	
• Distribution Capacity Costs	

Discount Rate: Utility Rate (8.18%)

Ratepayer Impact Measure Test

The Ratepayer Impact Measure Test (RIM) indicates the effect on long term system rates. A project with negative net benefits or a benefit/cost ratio less than 1.0 will tend to raise long term rates. A project with positive net benefits or a benefit/cost ratio greater than 1.0 will tend to lower long term rates.

Benefits	Costs
• Production Cost savings	• Incentives
• Generation Capacity Savings	• Administrative Costs
• Transmission Capacity Savings	• Lost Revenue
• Distribution Capacity Costs	

Discount Rate: Utility Rate (8.18%)

Appendix B—Part 2-C
Plan Cost-effectiveness Results by Project and Annual Plan Impacts

TABLE C.1.A
Existing Plan Cost-effectiveness Results

Project/Test Perspective	Benefits	Costs	Net Benefits	B/C Ratio
	($1000)	($1000)	($1000)	
Commercial/Industrial				
Societal Test	371,924	159,807	212,117	2.33
Utility Test	191,529	27,345	164,184	7.00
Ratepayer Impact Measure Test	191,529	347,942	(156,413)	0.55
Low Income				
Societal Test	7,050	4,112	2,938	1.71
Utility Test	3,068	3,661	(593)	0.84
Ratepayer Impact Measure Test	3,068	9,732	(6,664)	0.32
Residential				
Societal Test	100,067	44,641	55,426	2.24
Utility Test	41,223	12,344	28,879	3.34
Ratepayer Impact Measure Test	41,223	94,751	(53,528)	0.44
Total with Nonimpact Programs				
Societal Test	479,041	238,858	240,183	2.01
Utility Test	235,820	65,834	169,986	3.58
Ratepayer Impact Measure Test	235,820	474,910	(239,090)	0.50

TABLE C.1.B
Existing Plan Annual Program Costs and Impacts

	Total Plan Costs			Plan Impacts (Generator)			Cumulative DSM Expired (Generator)		
Year	Incentive	Administrative	Total	Energy	MP Winter Peak	MISO Summer Peak	Energy	Winter Peak	Summer Peak
	($)	($)	($)	(kWh)	(kW)	(kW)	(kWh)	(kW)	(kW)
2016	3,500,992	3,439,650	6,940,642	46,529,576	6,090	7,070	0	0	0
2017	3,571,012	3,508,443	7,079,455	93,059,155	12,179	14,140	0	0	0
2018	3,642,432	3,578,612	7,221,044	139,588,373	18,268	23,647	361	0	0
2019	3,715,281	3,650,184	7,365,465	185,937,066	24,332	28,258	181,247	25	22
2020	3,789,587	3,723,188	7,512,774	232,269,295	30,395	35,286	378,597	51	64
2021	3,865,378	3,797,652	7,663,030	277,608,373	36,418	41,922	1,569,098	117	498
2022	3,942,686	3,873,605	7,816,290	322,570,887	42,384	48,514	3,136,163	240	976
2023	4,021,540	3,951,077	7,972,616	367,074,850	48,278	55,059	5,161,779	435	1,501
2024	4,101,970	4,030,098	8,132,068	409,701,791	53,924	61,349	9,064,417	878	2,281
2025	4,184,010	4,110,700	8,294,710	450,355,125	59,195	67,317	14,940,662	1,696	3,383
2026	4,267,690	4,192,914	8,460,604	487,160,707	64,030	72,518	24,664,659	2,950	5,252
2027	4,353,044	4,276,772	8,629,816	523,755,471	68,822	77,696	34,599,474	4,247	7,144
2028	4,440,105	4,362,308	8,802,412	546,431,176	71,316	79,626	58,453,348	7,842	12,284
2029	4,528,907	4,449,554	8,978,461	569,069,776	73,803	81,552	82,344,327	11,444	17,428
2030	4,619,485	4,538,545	9,158,030	591,433,867	76,261	83,442	106,509,815	15,075	22,608
2031	4,711,874	4,629,316	9,341,191	593,603,907	76,822	83,659	150,869,354	20,603	29,461
2032	4,806,112	4,721,902	9,528,014	595,773,948	77,383	83,876	195,228,892	26,131	36,314
2033	4,902,234	4,816,340	9,718,575	597,875,703	77,928	84,093	239,656,716	31,675	43,167
2034	5,000,279	4,912,667	9,912,946	599,782,452	78,430	84,239	284,279,546	37,262	50,091
2035	5,100,284	5,010,921	10,111,205	601,689,202	78,931	84,385	328,902,375	42,850	57,015
2036	5,202,290	5,111,139	10,313,429	601,689,202	78,931	84,385	375,431,954	48,939	64,085
2037	5,306,336	5,213,362	10,519,698	601,689,202	78,931	84,385	421,961,533	55,028	71,155
2038	5,412,463	5,317,629	10,730,092	601,689,202	78,931	84,385	468,491,112	61,117	78,225
2039	5,520,712	5,423,982	10,944,694	601,689,202	78,931	84,385	515,020,691	67,206	85,295
2040	5,631,126	5,532,461	11,163,587	601,689,202	78,931	84,385	561,550,270	73,295	92,365
2041	5,743,749	5,643,110	11,386,859	601,689,202	78,931	84,385	608,079,849	79,384	99,435
2042	5,858,624	5,755,973	11,614,596	601,689,202	78,931	84,385	654,609,428	85,473	106,505
2043	5,975,796	5,871,092	11,846,888	601,689,202	78,931	84,385	701,139,007	91,562	113,575
2044	6,095,312	5,988,514	12,083,826	601,689,202	78,931	84,385	747,668,586	97,651	120,645

TABLE C.2.A
-16 GWh Plan Cost-effectiveness Results

Project/Test Perspective	Benefits	Costs	Net Benefits	B/C Ratio
	($1000)	($1000)	($1000)	
Commercial/Industrial				
Societal Test	250,152.00	109,413.00	140,739	2.29
Utility Test	130,359.00	17,795.00	112,564	7.33
Ratepayer Impact Measure Test	130,359.00	236,150.00	(105,791)	0.55
Low Income				
Societal Test	7,050	4,112	2,938	1.71
Utility Test	3,068	3,661	(593)	0.84
Ratepayer Impact Measure Test	3,068	9,732	(6,664)	0.32
Residential				
Societal Test	67,378.00	31,408.00	35,970	2.15
Utility Test	28,054.00	8,674.00	19,380	3.23
Ratepayer Impact Measure Test	28,054.00	64,829.00	(36,775)	0.43
Total with Nonimpact Programs				
Societal Test	324,580.00	171,009.00	153,571	1.90
Utility Test	161,481.00	49,570.00	111,911	3.26
Ratepayer Impact Measure Test	161,481.00	330,152.00	(168,671)	0.49

TABLE C.2.B
-16 GWh Annual Program Costs and Impacts

Total Plan Costs			Plan Impacts (Generator)			Cumulative DSM Expired (Generator)		
Incentive ($)	Administrative ($)	Total ($)	Energy (kWh)	MP Winter Peak (kW)	MISO Summer Peak (kW)	Energy (kWh)	Winter Peak (kW)	Winter Peak (kW)
3,500,992	3,439,650	6,940,642	46,529,576	6,090	7,070	0	0	0
2,148,598	2,993,056	5,141,654	77,121,354	10,097	11,722	0	0	0
2,191,570	3,052,917	5,244,487	107,712,773	14,104	18,260	359	0	0
2,235,401	3,113,975	5,349,377	138,123,666	18,086	21,004	181,244	25	22
2,280,109	3,176,255	5,456,364	168,561,200	22,073	25,619	335,488	45	59
2,325,712	3,239,780	5,565,492	198,011,346	26,019	29,850	1,477,120	106	480
2,372,226	3,304,576	5,676,801	227,426,596	29,923	34,173	2,653,648	209	809
2,419,670	3,370,667	5,790,338	256,383,294	33,754	38,448	4,288,728	385	1,186
2,468,064	3,438,081	5,906,144	283,623,464	37,363	42,486	7,640,336	783	1,800
2,517,425	3,506,842	6,024,267	309,475,720	40,676	46,280	12,379,858	1,477	2,658
2,567,774	3,576,979	6,144,752	332,139,059	43,678	49,416	20,308,297	2,482	4,174
2,619,129	3,648,519	6,267,648	355,910,098	46,783	52,794	27,129,036	3,384	5,448
2,671,512	3,721,489	6,393,000	365,834,975	47,606	52,932	47,795,937	6,568	9,962
2,724,942	3,795,919	6,520,860	380,582,785	49,224	54,189	63,639,905	8,957	13,357
2,779,441	3,871,837	6,651,278	395,067,293	50,816	55,410	79,747,175	11,372	16,788
2,835,029	3,949,274	6,784,303	389,413,421	50,518	54,966	115,992,825	15,677	21,884
2,891,730	4,028,259	6,919,989	390,823,948	50,883	55,107	145,174,076	19,319	26,395
2,949,565	4,108,824	7,058,389	392,166,189	51,232	55,248	174,423,613	22,977	30,906
3,008,556	4,191,001	7,199,557	393,337,324	51,542	55,318	203,844,256	26,674	35,488
3,068,727	4,274,821	7,343,548	394,576,711	51,868	55,414	233,196,647	30,355	40,044
3,130,102	4,360,317	7,490,419	393,909,349	51,693	55,362	264,455,787	34,537	44,748
3,192,704	4,447,524	7,640,227	393,909,349	51,693	55,362	295,047,565	38,544	49,400
3,256,558	4,536,474	7,793,032	393,909,349	51,693	55,362	325,639,343	42,551	54,052
3,321,689	4,627,204	7,948,893	393,909,349	51,693	55,362	356,231,121	46,558	58,704
3,388,123	4,719,748	8,107,870	393,909,349	51,693	55,362	386,822,899	50,565	63,356
3,455,885	4,814,143	8,270,028	393,909,349	51,693	55,362	417,414,677	54,572	68,008
3,525,003	4,910,426	8,435,428	393,909,349	51,693	55,362	448,006,455	58,579	72,660
3,595,503	5,008,634	8,604,137	393,909,349	51,693	55,362	478,598,233	62,586	77,312
3,667,413	5,108,807	8,776,220	393,909,349	51,693	55,362	509,190,011	66,593	81,964

TABLE C.3.A
+11 GWh Cost-effectiveness Results

Project/Test Perspective	Benefits	Costs	Net Benefits	B/C Ratio
	($1000)	($1000)	($1000)	
Commercial/Industrial				
Societal Test	453,859.00	197,054.00	256,805	2.30
Utility Test	232,688.00	38,316.00	194,372	6.07
Ratepayer Impact Measure Test	232,688.00	427,707.00	(195,019)	0.54
Low Income				
Societal Test	7,050	4,112	2,938	1.71
Utility Test	3,068	3,661	(593)	0.84
Ratepayer Impact Measure Test	3,068	9,732	(6,664)	0.32
Residential				
Societal Test	122,062.00	54,703.00	67,359	2.23
Utility Test	50,084.00	17,083.00	33,001	2.93
Ratepayer Impact Measure Test	50,084.00	117,155.00	(67,071)	0.43
Total with Nonimpact Programs				
Societal Test	582,971.00	295,453.00	287,518	1.97
Utility Test	285,840.00	88,203.00	197,637	3.24
Ratepayer Impact Measure Test	285,840.00	583,737.00	(297,897)	0.49

TABLE C.3.B
+11 GWh Annual Program Costs and Impacts

	Total Plan Costs			Plan Impacts (Generator)			Cumulative DSM Expired (Generator)		
Year	Incentive ($)	Administrative ($)	Total ($)	Energy (kWh)	MP Winter Peak (kW)	MISO Summer Peak (kW)	Energy (kWh)	Winter Peak (kW)	Winter Peak (kW)
2016	3,500,992	3,439,650	6,940,642	46,529,576	6,090	7,070	0	0	0
2017	5,008,680	4,735,943	9,744,623	103,783,017	13,580	15,767	0	0	0
2018	5,108,854	4,830,662	9,939,515	161,036,097	21,070	27,272	361	0	0
2019	5,211,031	4,927,275	10,138,306	218,108,651	28,534	33,139	181,248	26	22
2020	5,315,251	5,025,821	10,341,072	275,135,739	35,995	41,790	407,601	55	68
2021	5,421,556	5,126,337	10,547,893	331,165,798	43,415	50,045	1,630,983	125	510
2022	5,529,987	5,228,864	10,758,851	386,589,400	50,769	58,164	3,460,822	261	1,088
2023	5,640,587	5,333,441	10,974,028	441,554,450	58,050	66,235	5,749,213	470	1,714
2024	5,753,399	5,440,110	11,193,509	494,534,489	65,068	74,041	10,022,615	942	2,605
2025	5,868,467	5,548,912	11,417,379	545,146,834	71,656	81,471	16,663,711	1,844	3,872
2026	5,985,836	5,659,890	11,645,727	591,468,125	77,724	88,062	27,595,861	3,266	5,978
2027	6,105,553	5,773,088	11,878,641	636,691,424	83,651	94,451	39,626,003	4,829	8,286
2028	6,227,664	5,888,550	12,116,214	667,946,613	87,271	97,587	65,624,255	8,699	13,847
2029	6,352,217	6,006,321	12,358,538	695,894,587	90,341	99,964	94,929,722	13,119	20,167
2030	6,479,262	6,126,447	12,605,709	723,560,511	93,381	102,303	124,517,239	17,569	26,525
2031	6,608,847	6,248,976	12,857,823	730,994,927	94,520	102,965	174,336,264	23,920	34,560
2032	6,741,024	6,373,956	13,114,980	733,676,012	95,214	103,233	228,908,620	30,716	42,989
2033	6,875,844	6,501,435	13,377,279	736,288,812	95,891	103,501	283,549,261	37,529	51,418
2034	7,013,361	6,631,464	13,644,825	738,690,525	96,521	103,698	338,400,989	44,389	59,918
2035	7,153,628	6,764,093	13,917,721	741,046,313	97,140	103,879	393,298,642	51,260	68,434
2036	7,296,701	6,899,375	14,196,076	741,495,353	97,258	103,914	450,103,043	58,632	77,096
2037	7,442,635	7,037,362	14,479,997	741,495,353	97,258	103,914	507,356,484	66,122	85,793
2038	7,591,488	7,178,109	14,769,597	741,495,353	97,258	103,914	564,609,925	73,612	94,490
2039	7,743,317	7,321,672	15,064,989	741,495,353	97,258	103,914	621,863,366	81,102	103,187
2040	7,898,184	7,468,105	15,366,289	741,495,353	97,258	103,914	679,116,807	88,592	111,884
2041	8,056,147	7,617,467	15,673,615	741,495,353	97,258	103,914	736,370,248	96,082	120,581
2042	8,217,270	7,769,816	15,987,087	741,495,353	97,258	103,914	793,623,689	103,572	129,278
2043	8,381,616	7,925,213	16,306,829	741,495,353	97,258	103,914	850,877,130	111,062	137,975
2044	8,549,248	8,083,717	16,632,965	741,495,353	97,258	103,914	908,130,571	118,552	146,672

TABLE C.4.A
+15 GWh Cost-effectiveness Results

Project/Test Perspective	Benefits	Costs	Net Benefits	B/C Ratio
	($1000)	($1000)	($1000)	
Commercial/Industrial				
Societal Test	484,302.00	211,233.00	273,069	2.29
Utility Test	247,981.00	44,101.00	203,880	5.62
Ratepayer Impact Measure Test	247,981.00	459,052.00	(211,071)	0.54
Low Income				
Societal Test	7,050	4,112	2,938	1.71
Utility Test	3,068	3,661	(593)	0.84
Ratepayer Impact Measure Test	3,068	9,732	(6,664)	0.32
Residential				
Societal Test	130,234.00	58,650.00	71,584	2.22
Utility Test	53,376.00	19,553.00	33,823	2.73
Ratepayer Impact Measure Test	53,376.00	126,187.00	(72,811)	0.42
Total with Nonimpact Programs				
Societal Test	621,586.00	318,362.00	303,224	1.95
Utility Test	304,425.00	99,945.00	204,480	3.05
Ratepayer Impact Measure Test	304,425.00	627,603.00	(323,178)	0.49

TABLE C.4.B
+15 GWh Annual Program Costs and Impacts

	Total Plan Costs			Plan Impacts (Generator)			Cumulative DSM Expired (Generator)		
Year	Incentive ($)	Administrative ($)	Total ($)	Energy (kWh)	MP Winter Peak (kW)	MISO Summer Peak (kW)	Energy (kWh)	Winter Peak (kW)	Winter Peak (kW)
2016	3,500,992	3,439,650	6,940,642	46,529,576	6,090	7,070	0	0	0
2017	5,800,268	5,343,401	11,143,669	107,767,464	14,100	16,371	0	0	0
2018	5,916,273	5,450,269	11,366,542	169,004,992	22,111	28,619	360	(1)	0
2019	6,034,599	5,559,274	11,593,873	230,061,995	30,096	34,952	181,245	24	21
2020	6,155,291	5,670,460	11,825,751	291,062,754	38,075	44,207	418,374	55	67
2021	6,278,397	5,783,869	12,062,266	351,065,046	46,014	53,063	1,653,970	126	512
2022	6,403,965	5,899,546	12,303,511	410,375,461	53,884	61,749	3,581,443	266	1,127
2023	6,532,044	6,017,537	12,549,581	469,227,326	61,681	70,388	5,967,466	479	1,789
2024	6,662,685	6,137,888	12,800,573	526,054,056	69,208	78,757	10,378,624	962	2,721
2025	6,795,938	6,260,646	13,056,584	580,366,670	76,286	86,730	17,303,898	1,894	4,049
2026	6,931,857	6,385,859	13,317,716	630,223,519	82,812	93,838	28,684,937	3,378	6,242
2027	7,070,494	6,513,576	13,584,070	678,652,748	89,161	100,677	41,493,596	5,039	8,704
2028	7,211,904	6,643,848	13,855,752	713,095,642	93,198	104,261	68,288,590	9,012	14,421
2029	7,356,142	6,776,724	14,132,867	743,016,312	96,486	106,805	99,605,808	13,734	21,178
2030	7,503,265	6,912,259	14,415,524	772,652,130	99,742	109,311	131,207,878	18,488	27,973
2031	7,653,330	7,050,504	14,703,835	782,042,524	101,096	110,138	183,055,372	25,144	36,447
2032	7,806,397	7,191,514	14,997,911	784,913,488	101,839	110,425	241,422,296	32,411	45,461
2033	7,962,525	7,335,345	15,297,870	787,716,166	102,565	110,712	299,857,506	39,695	54,475
2034	8,121,775	7,482,051	15,603,827	790,301,782	103,242	110,929	358,509,778	47,028	63,559
2035	8,284,211	7,631,692	15,915,903	792,824,411	103,906	111,122	417,225,037	54,374	72,667
2036	8,449,895	7,784,326	16,234,222	793,440,291	104,068	111,170	477,847,045	62,222	81,920
2037	8,618,893	7,940,013	16,558,906	793,440,291	104,068	111,170	539,084,933	70,232	91,221
2038	8,791,271	8,098,813	16,890,084	793,440,291	104,068	111,170	600,322,821	78,242	100,522
2039	8,967,096	8,260,789	17,227,886	793,440,291	104,068	111,170	661,560,709	86,252	109,823
2040	9,146,438	8,426,005	17,572,443	793,440,291	104,068	111,170	722,798,597	94,262	119,124
2041	9,329,367	8,594,525	17,923,892	793,440,291	104,068	111,170	784,036,485	102,272	128,425
2042	9,515,954	8,766,416	18,282,370	793,440,291	104,068	111,170	845,274,373	110,282	137,726
2043	9,706,274	8,941,744	18,648,018	793,440,291	104,068	111,170	906,512,261	118,292	147,027
2044	9,900,399	9,120,579	19,020,978	793,440,291	104,068	111,170	967,750,149	126,302	156,328

TABLE C.5.A
+30 GWh Cost-effectiveness Results

Project/Test Perspective	Benefits	Costs	Net Benefits	B/C Ratio
	($1000)	($1000)	($1000)	
Commercial/Industrial				
Societal Test	601,203.00	265,604.00	335,599	2.26
Utility Test	306,704.00	73,121.00	233,583	4.19
Ratepayer Impact Measure Test	306,704.00	586,225.00	(279,521)	0.52
Low Income				
Societal Test	7,050	4,112	2,938	1.71
Utility Test	3,068	3,661	(593)	0.84
Ratepayer Impact Measure Test	3,068	9,732	(6,664)	0.32
Residential				
Societal Test	161,615.00	74,537.00	87,078	2.17
Utility Test	66,018.00	30,556.00	35,462	2.16
Ratepayer Impact Measure Test	66,018.00	162,394.00	(96,376)	0.41
Total with Nonimpact Programs				
Societal Test	769,868.00	408,319.00	361,549	1.89
Utility Test	375,790.00	154,175.00	221,615	2.44
Ratepayer Impact Measure Test	375,790.00	805,187.00	(429,397)	0.47

TABLE C.5.B

+30 GWh Annual Program Costs and Impacts

	Total Plan Costs			Plan Impacts (Generator)			Cumulative DSM Expired (Generator)		
Year	Incentive ($)	Administrative ($)	Total ($)	Energy (kWh)	MP Winter Peak (kW)	MISO Summer Peak (kW)	Energy (kWh)	Winter Peak (kW)	Summer Peak (kW)
2016	3,500,992	3,439,650	6,940,642	46,529,576	6,090	7,070	0	0	0
2017	9,769,008	7,835,883	17,604,891	123,067,750	16,099	18,693	0	0	0
2018	9,964,388	7,992,601	17,956,989	199,605,565	26,109	33,791	359	(1)	0
2019	10,163,676	8,152,453	18,316,129	275,962,855	36,092	41,916	181,243	25	23
2020	10,366,949	8,315,502	18,682,451	352,222,520	46,065	53,487	459,752	61	75
2021	10,574,288	8,481,812	19,056,100	427,478,185	55,997	64,652	1,742,261	138	533
2022	10,785,774	8,651,448	19,437,222	501,713,974	65,847	75,517	4,044,646	297	1,291
2023	11,001,490	8,824,477	19,825,967	575,491,211	75,624	86,334	6,805,583	529	2,097
2024	11,221,519	9,000,966	20,222,486	647,089,240	85,107	96,866	11,745,728	1,055	3,188
2025	11,445,950	9,180,986	20,626,936	715,610,888	94,064	106,926	19,762,254	2,107	4,751
2026	11,674,869	9,364,606	21,039,474	779,044,290	102,350	116,016	32,867,026	3,830	7,284
2027	11,908,366	9,551,898	21,460,264	839,784,294	110,319	124,583	48,665,196	5,870	10,340
2028	12,146,534	9,742,936	21,889,469	886,467,980	115,961	129,887	78,519,684	10,237	16,659
2029	12,389,464	9,937,794	22,327,259	923,963,809	120,081	133,074	117,562,029	16,126	25,095
2030	12,637,254	10,136,550	22,773,804	961,164,025	124,168	136,222	156,899,987	22,048	33,570
2031	12,889,999	10,339,281	23,229,280	978,065,374	16,348	137,684	216,536,812	139,877	43,731
2032	13,147,799	10,546,067	23,693,865	981,665,472	127,279	138,043	289,474,888	38,955	54,995
2033	13,410,755	10,756,988	24,167,743	985,197,284	128,194	138,403	362,481,250	48,049	66,258
2034	13,678,970	10,972,128	24,651,098	988,489,090	129,054	138,692	435,727,618	57,198	77,592
2035	13,952,549	11,191,570	25,144,120	991,652,387	129,886	138,935	509,102,495	66,375	88,972
2036	14,231,600	11,415,402	25,647,002	992,908,935	130,217	139,032	584,384,121	76,053	100,498
2037	14,516,232	11,643,710	26,159,942	992,908,935	130,217	139,032	660,922,295	86,062	112,121
2038	14,806,557	11,876,584	26,683,141	992,908,935	130,217	139,032	737,460,469	96,071	123,744
2039	15,102,688	12,114,116	27,216,804	992,908,935	130,217	139,032	813,998,643	106,080	135,367
2040	15,404,742	12,356,398	27,761,140	992,908,935	130,217	139,032	890,536,817	116,089	146,990
2041	15,712,836	12,603,526	28,316,362	992,908,935	130,217	139,032	967,074,991	126,098	158,613
2042	16,027,093	12,855,597	28,882,690	992,908,935	130,217	139,032	1,043,613,165	136,107	170,236
2043	16,347,635	13,112,709	29,460,344	992,908,935	130,217	139,032	1,120,151,339	146,116	181,859
2044	16,674,588	13,374,963	30,049,550	992,908,935	130,217	139,032	1,196,689,513	156,125	193,482

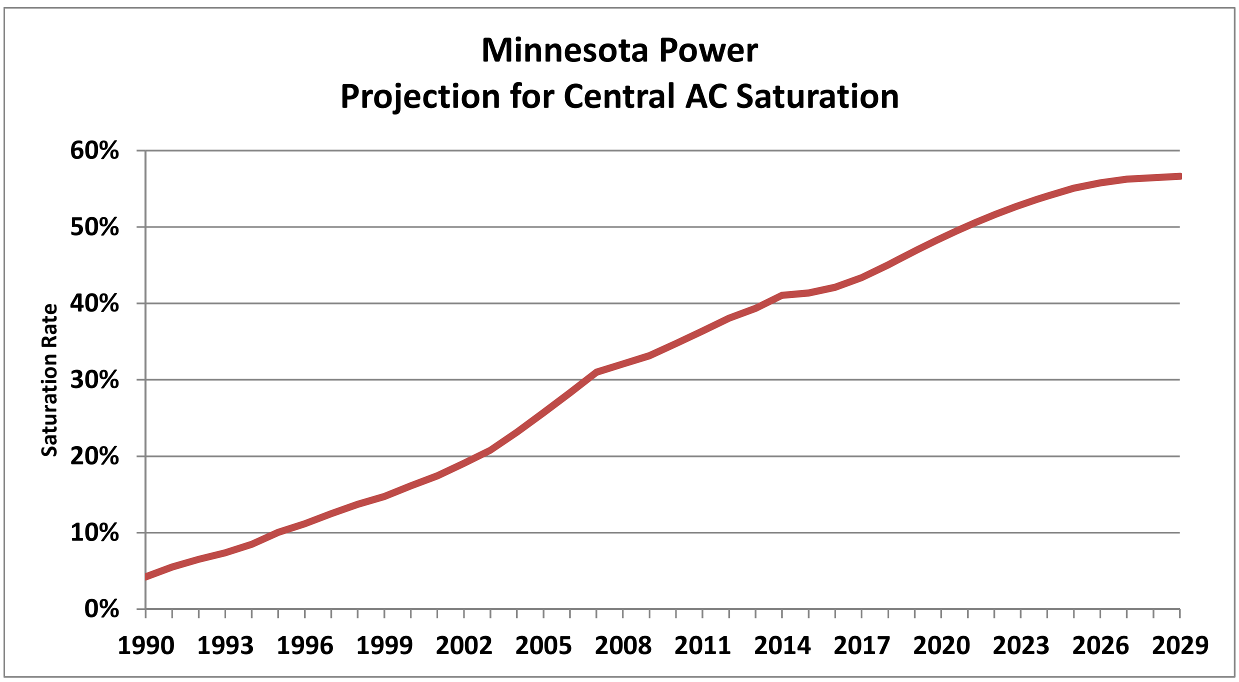
Part 3: Consideration of Additional Demand Response Programs

Minnesota Power continues to identify and implement valuable DSM programs including its conservation programs (Part 1 of this Appendix) and demand response with its existing interruptible capabilities within the large industrial customer processes and residential and commercial electric heating customers.[1] For the 2015 Plan, Minnesota Power determined it would expand its investigation of additional demand response programs through a peak shaving (or load control) programs for central air conditioning ("CAC") customers and electric hot water ("HW") customers. This section summarizes the characteristics of the two load control programs evaluated in the 2015 Plan.

CAC Demand Response Program

Residential and commercial customers with CAC are increasing in number in Minnesota Power's service territory and are projected to keep growing per load research included in its 2015 Annual Electric Utility Forecast Report ("AFR2015") and shown in Figure 1. This type of demand response program is not new; many utilities across the region employ CAC cycling programs. Minnesota Power is able to leverage the insights and understanding of how this type of program can provide optionality and benefit for the residential and small C/I customer classes.

Figure 1: Minnesota Power Projection for Central Air Conditioning

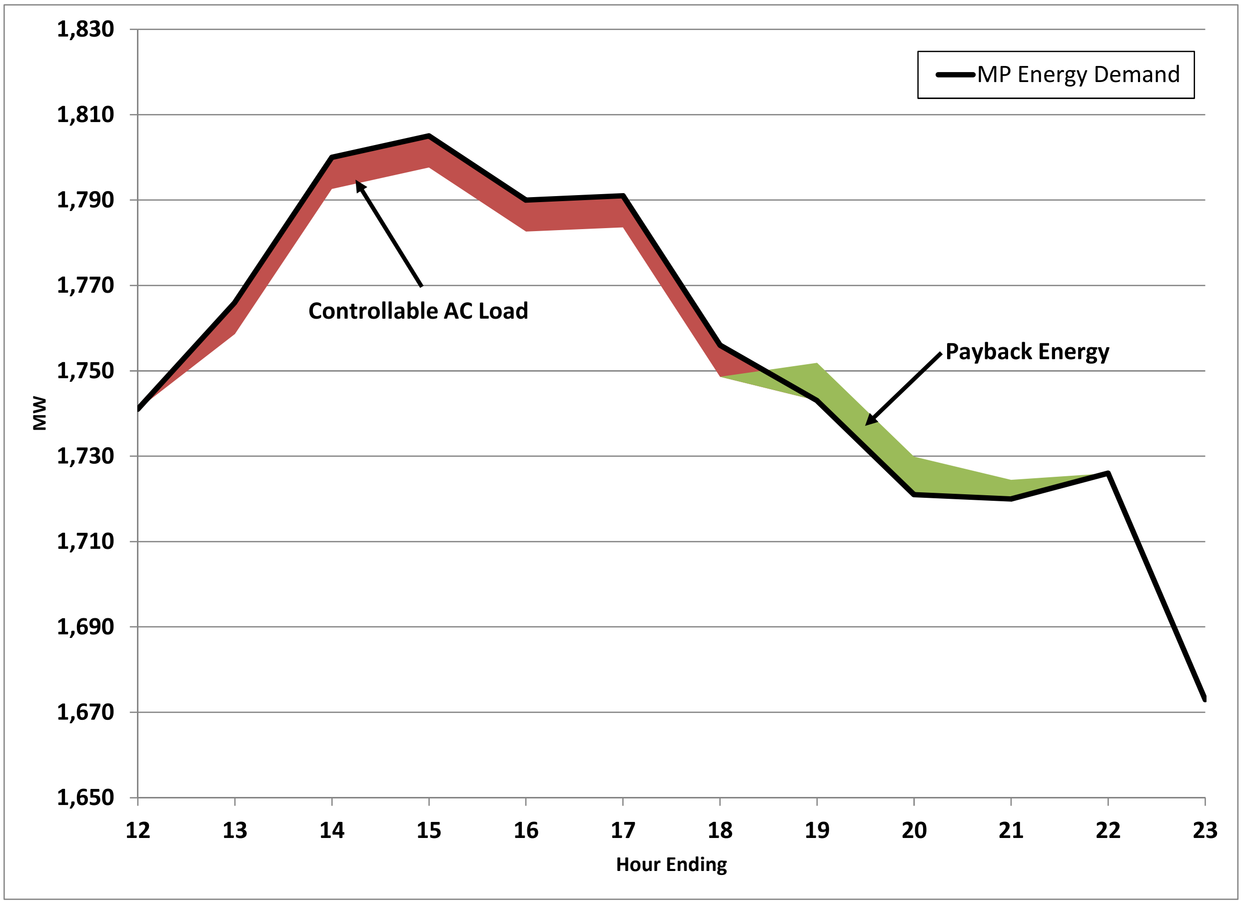


The premise of a CAC cycling program is the requirement that the end-user have a CAC unit on which a switch is installed that allows for remote cycling of the compressor on and off

[1] Minnesota Power recently provided an overview of its current demand side management programs in Docket No. E999/CI-09-1449 (Aggregators of Retail Customers).

throughout the peak hours of the day (Figure 2). Reducing energy and capacity requirements during peak summer season hours provides benefit to both the customer and the utility. Reducing peak demand can help keep rates low by allowing utilities to delay investment in capital-intensive newly constructed power plants.

Figure 2: Illustrative Example of Controllable CAC Load Available for Minnesota Power's Peak Day in Summer 2014



Minnesota Power is conducting the initial investigation of the power supply benefits of a CAC cycling program through the use of its production cost and expansion planning evaluation utilizing the Strategist software. Strategist allows Minnesota Power to evaluate new generation (or supply-side) alternatives side-by-side with load reduction (or demand side) alternatives. Minnesota Power will be able to utilize a set of assumptions to identify the benefit and cost of the CAC cycling program and determine if exploring additional program design is warranted.

Program Cost Assumptions

There are several cost categories to consider as part of a CAC cycling program including equipment, customer rate incentives, communication infrastructure, and program oversight staffing. Minnesota Power developed a set of initial assumptions based on a combination of national industry information and data more specific to Minnesota Power's region.

Equipment Cost

The equipment cost assumed in the analysis included the cost and labor of installing a switch on the participating end-user CAC unit. It was assumed that Minnesota Power would cover the entire equipment cost required (estimated to be $200 per switch). The installation labor and equipment cost of a residential or small C/I switch was based on vendor quotes and typical project scope.

Customer Rate Incentives

The customer rate incentive assumed in the analysis included a rate reduction credited to participating customers. It was assumed that Minnesota Power would provide a $40 annual incentive to each participating customer. The rate incentive was based on a comparison of incentives offered by other utilities in the Midwest region.

Communication Infrastructure

It was assumed that Minnesota Power would utilize switches with communication requirements compatible with those of its existing dual fuel heating program. The dual fuel heating program communicates remotely with customer meters similar to how cycling a compressor would work. Although a new Graphical and User interface ("GUI") is required to handle the increase in demand response functionality. For purpose of this study there was approximately $90,000 of capital and $70,000 of operations and maintenance ("O&M") per year included for the new demand response GUI system.[2] Any additional communication equipment or software required as part of the final program would increase the cost of the program to Minnesota Power relative to how it was evaluated in this study.

Staffing

It was assumed that Minnesota Power would utilize existing staff to implement and oversee the new program. If new staff is required, it would increase the cost of the program to Minnesota Power relative to how it was evaluated in this study.

Minnesota Power is currently assuming that the earliest a CAC cycling program could be implemented for customers would be the 2017 timeframe to accommodate additional design and gain regulatory approvals. As the preliminary investigation into a potential CAC cycling program continues, Minnesota Power will refine these assumptions and incorporate them into future iterations of the cost benefit evaluation.

[2] For the Strategist modeling $90,000 of capital and $70,000 of O&M for the GUI system is allocated 50/50 between the two load control programs considered in the 2015 Plan. This results in $45,000 of capital and $35,000 of annual O&M being allocated to the CAC program and HW program.

Program Operation

There are several operational assumptions associated with the evaluation of this type of demand response program including control definition (when can an interruption occur), demand reduction per customer (how many times can interruption happen), and ultimate customer participation in the program offering.

Common control assumptions that can be defined include control period and maximum control actions. The control period is generally defined as the time of day when the participant's CAC compressor would be cycled. This is typically defined during the time of day when cooling demand is expected to be greatest. A six-hour control period from 1:00 p.m. to 7:00 p.m. was assumed in this evaluation for the program. Utilities also typically define a maximum number of control events they will initiate during the year. A maximum of 15 control actions per year was used. Both the control period duration and maximum control actions per year were based on a comparison of CAC cycling program control characteristics defined by other utilities in the region.

The demand reduction per customer refers to the amount of peak demand (or kW) reduction Minnesota Power can count against its planning reserve margin ("PRM"). It was assumed Minnesota Power could count 1.9 kW of peak demand reduction per participant. The peak demand reduction was based on the value listed for customers in Minnesota in the FERC-commissioned report, *A National Assessment of Demand Response Potential* ("FERC DR Report").[3]

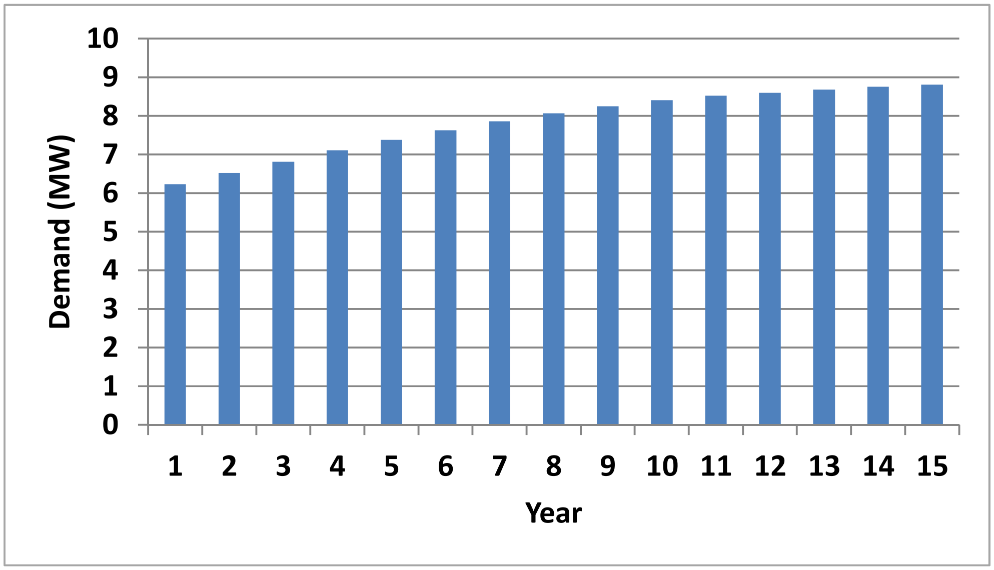
Customer participation in a CAC cycling program cannot be easily predicted; however, the pool of customers that can technically participate is more certain and for this evaluation was restricted in two ways. First, customers were restricted to only residential and small C/I customers based on the 2014 Annual Electric Utility Forecast Report ("AFR2014")[4] outlook. Second, customers were further restricted to only those residential and small C/I customers with a CAC unit based on load research. From this pool of eligible customers, it was assumed that Minnesota Power could enroll 20 percent of eligible customers in the program and then sustain a 1.3 percent growth rate over a 15-year period. The growth rate estimate was based on the growth rate for customers in Minnesota as reported in the FERC DR Report. Participating customers are assumed to be organized into at least four equal-sized control groups that could be cycled on and off every 15 minutes.

Based on the assumed customer participation rate and peak demand reduction per customer, the CAC cycling program for this evaluation amounted to a total peak reduction of approximately 8.8 MW by year 15 of the program. Figure 3 shows the total peak reduction estimated for the program over 15 years.

[3] Federal Energy Regulatory Commission Staff Report, *A National Assessment of Demand Response Potential* (June 2009), prepared by The Brattle Group, Freeman, Sullivan and Co., and Global Energy Partners, LLC.

[4] Minnesota Power recognizes that the saturation rates for CAC and HW are based on load research for AFR2015, but the customer count is based on AFR2014. At the time these load control programs were designed customer count information from AFR2015 was not available, but saturation rates were. To ensure the latest load research on saturation rates for CAC and HW were used in the evaluation the AFR2015 was utilized.

Figure 3: CAC Program Peak Reduction



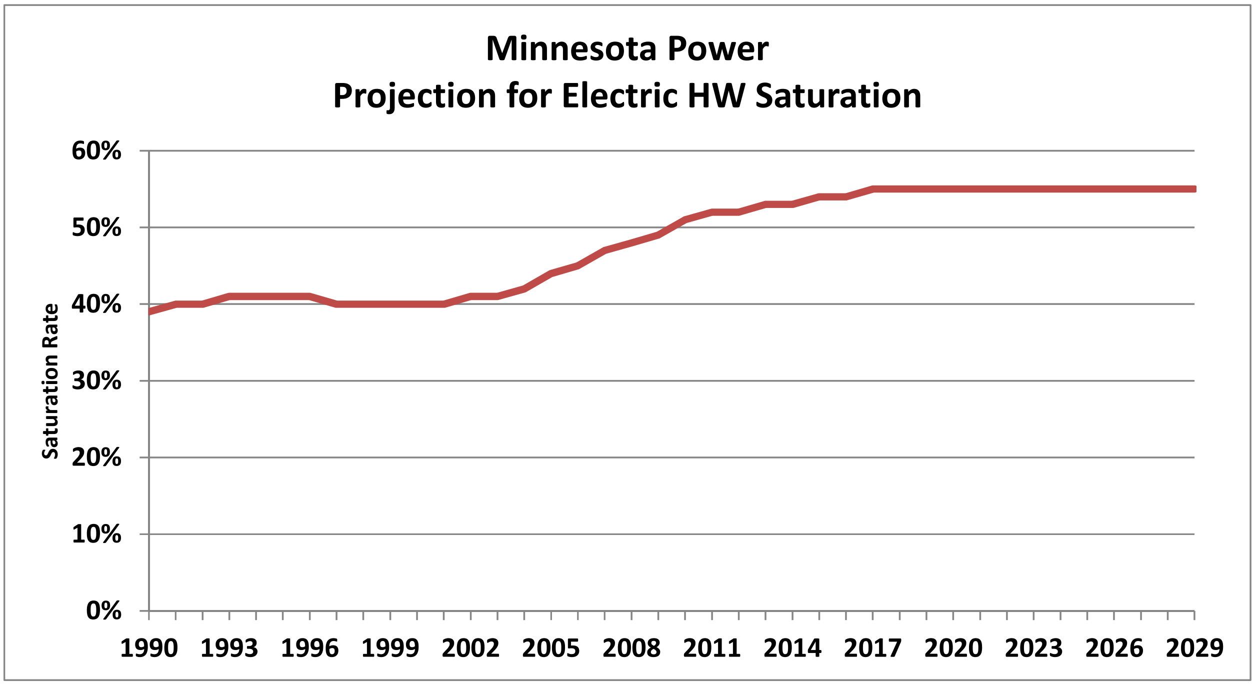
Determining a Benefit Cost

Based on the initial cost and operational parameters utilized, a present value (levelized cost) of the CAC cycling program's costs is estimated to be $1,460 per kW. Strategist was used to evaluate the cost and benefits of the CAC cycling program alongside new generation alternatives to meet future customer power requirements as described further in Section IV of this document. With more economical generation alternatives available and regional energy surpluses, the benefits of the CAC cycling program are likely to be limited in the near term for this initial evaluation. However, the assumptions utilized within this study will continue to be refined and verified as more industry data and program design specific to Minnesota Power is considered. Minnesota Power believes that as industry dynamics continue to evolve a CAC cycling program could provide benefits to system power supply and the Company will continue to monitor this accordingly, including an update of these investigations in future resource plans.

<u>Electric Hot Water Demand Response Program</u>

Residential customers with electric HW are increasing in number in Minnesota Power's service territory, but not growing nearly at the same rate as CAC customers. In fact, the saturation rate of HW is assumed to be minimal to no growth per load research included in its most recent AFR2015 and shown in Figure 4. This type of demand response program is not new; many utilities across the region employ various HW cycling programs. Minnesota Power is able to leverage the insights and understanding of how this type of program can provide rate optionality and benefit for the residential and small C/I customer classes.

Figure 4: Minnesota Power Projection for Electric Hot Water



The premise of an HW cycling program is the requirement that the end-user have an electric HW unit on which a switch is installed that allows for remote control of the thermostat connected to the heating elements, cycling on and off throughout the peak hours of the day. Reducing energy and capacity requirements during peak hours of summer and winter seasons provides benefit to both the customer and the utility. Reducing peak demand can help keep rates low by allowing utilities to delay investment in capital-intensive newly constructed power plants.

Minnesota Power is conducting the initial investigation of the power supply benefits of an HW cycling program through the use of its production cost and expansion planning evaluation utilizing the Strategist software. Strategist allows Minnesota Power to evaluate new generation (or supply-side) alternatives side-by-side with load reduction (or demand side) alternatives. Minnesota Power will be able to utilize a set of assumptions to identify the benefit and cost of the HW cycling program and determine if exploring additional program design is warranted.

Program Cost Assumptions

There are several cost categories to consider as part of an HW cycling program including equipment, customer rate incentives, communication infrastructure, and program oversight staffing. Minnesota Power developed a set of initial assumptions based on a combination of national industry information and data more specific to Minnesota Power's region.

Equipment Cost

The equipment cost assumed in the analysis included the cost and labor of installing a switch on the participating end-user electric HW unit. It was assumed that Minnesota Power would cover the entire equipment cost required (estimated to be $200 per switch). The installation labor and equipment cost of a residential switch was based on vendor quotes and typical project scope.

Customer Rate Incentives

The customer rate incentive assumed in the analysis included a rate reduction credited to participating customers. It was assumed that Minnesota Power would provide a $60 annual incentive to each participating customer. The rate incentive was based on a comparison of incentives offered by other utilities in the Midwest region.

Communication Infrastructure

It was assumed that Minnesota Power would utilize switches with communication requirements compatible with those of its existing dual fuel heating program. The dual fuel heating program communicates remotely with customer meters similar to how cycling an electric HW unit would work. Although a new GUI is required to handle the increase in demand response functionality. For purpose of this study there was approximately $90,000 of capital and $70,000 of O&M per year included for the new demand response GUI system.[5] Any additional communication equipment or software required as part of the final program would increase the cost of the program to Minnesota Power relative to how it was evaluated in this study.

Staffing

It was assumed that Minnesota Power would utilize existing staff to implement and oversee the new program. If new staff is required, it would increase the cost of the program to Minnesota Power relative to how it was evaluated in this study.

Minnesota Power is currently assuming that the earliest an HW cycling program could be implemented for customers would be the 2017 timeframe to accommodate additional design and gain regulatory approvals. As the preliminary investigation into a potential HW cycling program continues, Minnesota Power will refine these assumptions and incorporate them into future iterations of the cost benefit evaluation.

Program Operation

There are several operational assumptions associated with the evaluation of this type of demand response program including control definition (when can an interruption occur), demand reduction per customer (how many times can interruption happen), and ultimate customer participation in the program offering.

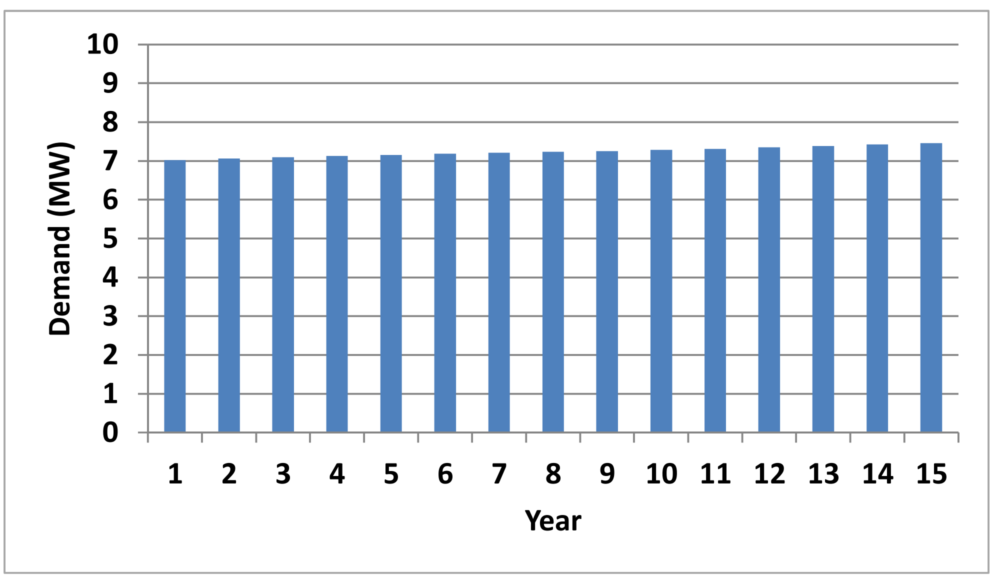
[5] For the Strategist modeling $90,000 of capital and $70,000 of O&M for the GUI system is allocated 50/50 between the two load control programs considered in the 2015 Plan. This results in $45,000 of capital and $35,000 of annual O&M being allocated to the CAC program and HW program.

Common control assumptions that can be defined include control period and maximum control actions. The control period is generally defined as the time of day when the participant's electric heating elements would be cycled. This is typically defined during the time of day when demand is expected to be greatest. A six-hour control period from 1:00 p.m. to 7:00 p.m. was assumed in this evaluation for the program. Utilities also typically define a maximum number of control events they will initiate during the year. A maximum of 365 control actions per year was used. Both the control period duration and maximum control actions per year were based on a comparison of HW cycling program control characteristics defined by other utilities in the region.

The demand reduction per customer refers to the amount of peak demand (or kW) reduction Minnesota Power can count against its PRM. It was assumed Minnesota Power could count 0.5 kW of peak demand reduction per participant. Customer participation in an HW cycling program cannot be easily predicted; however, the pool of customers that can technically participate is more certain and for this evaluation was restricted in two ways. First, customers were restricted to only residential as based on the AFR2014 outlook. Second, customers were further restricted to only those residential with an electric HW unit based on load research. From this pool of eligible customers, it was assumed that Minnesota Power could enroll 20 percent of eligible customers in the program and then sustain a 1.3 percent growth rate over a 15-year period. The growth rate estimate was based on the growth rate for customers in Minnesota as reported in the FERC DR Report. Participating customers are assumed to be organized into one control group that could be cycled on and off every hour.

Based on the assumed customer participation rate and peak demand reduction per customer, the HW cycling program for this evaluation amounted to a total peak reduction of approximately 7.5 MW by year 15 of the program. Figure 5 shows the total peak reduction estimated for the program over 15 years.

Figure 5: HW Program Peak Reduction



Determining a Benefit Cost

Based on the initial cost and operational parameters utilized, a present value (levelized cost) of the HW cycling program's costs is estimated to be $1,930 per kW. Strategist was used to evaluate the cost and benefits of the HW cycling program alongside new generation alternatives to meet future customer power requirements as described further in Section IV of this document. With more economical generation alternatives available, the benefits of the HW cycling program are likely to be limited in the near term for this initial evaluation. However, the assumptions utilized within this study will continue to be refined and verified as more industry data and program design specific to Minnesota Power is considered. Minnesota Power believes that as industry dynamics continue to evolve an HW Cycling program could provide benefits to system power supply and the Company will continue to monitor this accordingly, including an update of these investigations in future resource plans.

Part 4: Order Point 12 Considerations

Minnesota Power's 2013 Integrated Resource Plan ("2013 Plan") approval,[1] identified that for its next resource plan that it would bring forward additional information regarding customer energy efficiency. Specifically, the 2013 Plan Order identified that Minnesota Power will:

a. Identify the amount of energy savings embedded in each year of its load forecast, in terms of total savings (kWh) and as a percentage of non-CIP-Exempt retail sales;

b. Identify the amount of system-wide energy savings, including aggregate data for CIP-exempt customers, embedded in each year of its load forecast;

This Appendix and the sections below will identify the estimate for the embedded energy savings it created as an approximate for what is included in its load outlook. Further, the Order requests that Minnesota Power:

a. Evaluate additional conservation scenarios for its CIP-exempt and non-CIP-exempt customers, that would achieve greater energy savings beyond those in the base case; and

b. Provide cost assumption for achieving every 0.1 percent of savings above 1.5 percent of non-CIP-exempt retail sales.

Minnesota Power administers the design and implementation of its energy efficiency programs for its non-CIP-exempt retail customers, and created several energy efficiency scenarios for the 2015 Plan. The detailed methodology and ultimate scenario levels are described in Part 1 and Part 2 of this Appendix. Further, the scenario alternatives were included into the expansion plan evaluation for new demand-side alternatives as part of Section IV and Appendix K for Minnesota Power's Preferred Plan.

The longstanding relationship and some recent examples of implementing energy savings of the CIP-exempt customers are highlighted in the sections below. The natural business drivers behind energy savings initiatives for the CIP-exempt customers are discussed, and while Minnesota Power was unable to determine forward scenarios for these dynamic customers, the energy savings activity exemplifies the current and ongoing role that energy efficiency measures have with this customer set.

Embedded Energy Savings Estimate

As part of its 2013 Plan, Minnesota Power was asked for additional insight into the energy savings in its customer sales forecast. The Company was further asked to identify the amount of system-wide energy savings, including aggregate data for CIP-Exempt customers, embedded in each year of its load forecast. Embedded conservation is not something that can be estimated with a high degree of certainty, regardless of the method used. While this study represents a good faith effort to meet the requested calculations, the results should only be considered estimates.

[1] November 12, 2013 Order - Docket No. E015/RP-13-53.

When developing its customer load forecasts each year, Minnesota Power makes no explicit assumptions for demand-side management/conservation, and does not in practice adjust its econometric load forecast for projected amounts of these items. The forecast created through the Annual Electric Utility Forecast Report ("AFR") process represents a continuation of historical trends in electric consumption and is constructed using actual historical metered electric usage. Since the impact of customer conservation is embedded in historical customer usage, it must also be embedded in the load forecast.

Per the language of the Order, Minnesota Power has identified a methodology that organizes its retail customers into two categories: non-CIP-exempt and CIP-exempt. Minnesota Power's non-CIP-exempt retail customer base is composed of residential, commercial, and all but the largest industrial customers. Minnesota Power's CIP-exempt customers are comprised of a small group of very large industrial customers that are eligible under the CIP statute to petition, and have in fact elected to petition, to "opt-out" of Minnesota Power's conservation improvement program by providing detailed information to the Minnesota Department of Commerce – Division of Energy Resources ("Department") regarding the energy efficiency and energy conservation efforts at their respective facilities.

To support a methodology to comply with the request, historical energy savings data were gathered from Minnesota Power's public filings of its energy conservation programs ("non-CIP-exempt") and from Trade Secret energy savings information provided by large industrial customers ("CIP-exempt"). The two sources provide a basis for estimation of what energy saving efforts are included in Minnesota Power's current forecast.

Minnesota Power quantified the recent historical trend of energy savings on its system using a five-year summation approach. The load forecast's embedded energy savings are estimated by totaling five-year savings achieved through both Minnesota Power programs and CIP-exempt customers.[2] The approach resulted in an embedded energy savings estimate of approximately 450 GWh annually when both customer sets are combined.

The approach presented above for embedded energy savings is fairly straightforward and based on the best data currently available. However, Minnesota Power recognizes that embedded conservation is not something that can be estimated with a high degree of certainty regardless of the method used, and will caution against placing excessive confidence in these estimates. The impacts of customer energy efficiency behavior are present in customer load outlooks and the impacts have been reducing the need for new electric sources on an ongoing basis as utilities identify supply to meet the projected customer requirements and maintain reliable electric service.

Large Customer Conservation

Minnesota Power's CIP-exempt group is comprised of those large industrial customers that have identified through State legislative designation to be considered 'Exempt" from the conservation program established in Minnesota. There are approximately 14 customers at the time of this filing that fall under the exempt classification, most of whom have submitted multiple

[2] The detail of the methodology and actual values from the two customer sets was provided as part of Minnesota Power's **Trade Secret** data submittal on July 31, 2015. The individual CIP-exempt customer data is proprietary.

reports to the Department detailing efforts to implement energy efficiency and energy conservation strategies. These energy-intensive, CIP-exempt customers are also trade-exposed because of the economic pressures they face in the global marketplace. These industries have competitors oversees that have an advantage because of other nations' favorable tax policies, trade laws, health care costs, and environmental compliance. Given the increased health care, environmental compliance, and energy costs in the United States, these customers are naturally incentivized to pursue all efficiency improvements to keep their product costs as low as possible, including any and all economically viable efficiency improvements related to energy consumption.

Minnesota Power's large power customers' energy consumption contributes to a higher than average system load factor of approximately 80 percent.[3] Due to their intensive energy needs, Minnesota Power works closely with large power customers on an ongoing basis to ensure their electric service remains reliable and new electric needs are planned for in advance. Account representatives from the Company work side by side with individual large power customers in the field to serve their current and forward looking energy needs. Minnesota Power is closely integrated with each of its large industrial customers on a daily basis. The Company interacts with regional markets for surplus and deficit electricity planning when load changes occur. The relationship between the Company and the large industrial customers allows both parties to continuously assess needs and look for opportunities to improve.

Forward looking energy efficiency scenarios for CIP-exempt customers have several estimation challenges. CIP-exempt customers' efficiency projects tend to be large and irregular, often requiring significant capital investment. The timing or feasibility of a conservation project is also subject to demand for a customer's product, which is influenced by market forces.

Minnesota Power conducts cost/benefit analysis for non-CIP-exempt customers using measure-specific cost estimates, assumptions of consumer behavior, and general assumptions of potential savings. In contrast, CIP-exempt customers' conservation is characterized by large and irregular energy saving projects, often requiring significant capital investment. There are also very few CIP-exempt customers; application of general assumptions for consumer behavior or potential savings is appropriate when applied to a large group of residential or commercial customers, but is not a viable approach to CIP-exempt conservation planning. Without gaining access to forward looking and proprietary business specific plans for each CIP-exempt customer, or making considerable assumptions that may not be well-founded, Minnesota Power cannot evaluate conservation scenarios on behalf of its CIP-exempt customers in the same way it may evaluate conservation measures for non-CIP-exempt customers.

The Company, working closely with these entities, is able to assist and optimize the energy needs and pursue energy efficiency improvements for facilities in the Company's service territory. Though specific energy efficiency reporting is no longer required under state law, large power customers continue to update and streamline their operations regularly. The Company has, and will continue to work closely with large power customers to maximize their energy efficiency. Some examples of this ongoing and recent activity of energy efficiency projects are listed below.

[3] Docket No. E015/RP-13-53.

The information below is proprietary for each customer and not able to be displayed for all stakeholders.

[TRADE SECRET DATA EXCISED]

Minnesota Power's customer outlook and forecasting process inherently includes recent trends of customer behaviors. The national and global marketplaces will continue to demand efficient production practices as these customers work to compete for the delivery of their product. Continuous refinement and implementation of best practices will be driven by their business models and support optimizing energy efficient practices in their sectors.

The Company fully anticipates continuing to work with large power customers to contribute to energy efficiency in their operations, additional energy needs, and support overall energy efficiency of the electric system in the state and region.

APPENDIX C: EXISTING POWER SUPPLY

Minnesota Power (or "Company") has a power supply portfolio that is made up of installed and Company owned assets, as well as purchases from other entities. This appendix details Minnesota Power's existing power supply in the following parts:

- Part 1 explains Minnesota Power's mission and its reliability efforts to maintain the operational integrity of its fossil-fueled and renewable resources throughout the 2015–2029 planning period. Part 1 also provides a description of each of these resources.
- Part 2 provides a summary of the Company's power sales and purchases used to meet short and long-term load and capability needs.
- Part 3 summarizes Minnesota Power's small power production, and provides updated descriptions of existing distributed generation ("DG") projects.

Part 1: Fossil, Natural Gas and Renewable

Minnesota Power's Generation Operations mission is to operate, maintain and manage its generation assets in a manner that meets customer expectations, protects people and the environment, and provides a fair return for Minnesota Power shareholders. This mission is the driving force behind maintaining the operational integrity of Minnesota Power's generation resources and is supported by a robust reliability effort. Minnesota Power's reliability efforts are comprehensive and system-wide.

Reliability Focus

Electric generating units serve a duty cycle that reflects their design and the power market demands for economic dispatch: base load, intermediate load and peak load. Preserving the usefulness of these assets requires capital investment and maintenance expenditures to sustain the unit's economic viability, availability and reliability for the duty cycle it is dispatched to serve. Minnesota Power generating units have traditionally served a base load mission due to the large component of around-the-clock industrial service in its customer base. Over time, that mission has changed slightly with the large build-out of variable wind generation now in service and planned for the future across the Midcontinent Independent System Operator ("MISO") and within the Minnesota Power system.

The combination of the variable nature of the wind coupled with low operating cost creates a potential need to back off dispatchable generation during times when wind generation is high and market demands are low. The degree of impact to base load resources depends upon how much wind energy is being generated and system demand. Currently, the impact of wind can be handled by backing down fossil-fuel units to lower loads, but as the wind fleet expands in the future there will be times when dispatchable units will need to be taken off-line to make room for wind generation whenever a dispatchable unit is already at minimum loads and system conditions dictate. Increasing the amount of on/off cycling of generating units will change the maintenance strategy as a result of the stresses created and the wear and tear of starting and stopping equipment. As noted, both operating modes require maintenance to ensure that the generating units are available to meet customer demands.

The Company continues to evolve maintenance programs to address impacts to generating unit operation, reliability, and maintenance costs inherent in operating in an increasingly volatile market. Minnesota Power continues to focus on reliability, while maintaining compliance with all pertinent regulations.

Minnesota Power's Reliability Efforts consist of the following elements:

Employee Training

Minnesota Power provides ongoing training to meet and exceed State of Minnesota boiler licensure coverage at all locations. Further, it provides specific system training when operational and maintenance criteria change as a result of policy changes, equipment replacement and/or control modifications. Through recent apprentice and training efforts, the majority of all generation job functions are shaped through State of Minnesota Department of Labor and Industry indentured apprenticeships. In addition, the Company has completed two waves of advanced reliability training, reaching 60 maintenance leaders in the organization to shape work practices, ground expectations, and enhance technical knowledge of major equipment. These lessons are focused on best practices in the industry.

To ensure safe, efficient operations and maintenance of Minnesota Power wind resources a combination of formal and on-the-job training is provided to technicians. Formal training establishes proper expectations and promotes positive work habits and practices while enhancing employee's technical knowledge of installed equipment. On-the-job training constitutes the majority of employee's development for improving needed skills for maintaining equipment safely and reliably.

Capital Investment

Minnesota Power continues to invest in base capital and asset preservation projects to maintain the integrity of major unit components, including turbine, generator, boiler, auxiliaries, electrical infrastructure, control systems and pollution control equipment consistent with specifications from original equipment manufacturers ("OEM") and best practices learned across industry.

Predictive Maintenance

Minnesota Power continuously expands the use of predictive maintenance techniques to proactively respond to equipment condition trends and changes. Condition monitoring techniques such as vibration monitoring, thermal scanning, oil tribology, precision maintenance and ultrasonics drive good equipment life cycle and business decisions. Increasing the frequency of inspections and automated condition monitoring of equipment are cornerstones of the adopted operational strategy of reliability-centered principles and behaviors.

Inspections

Routine engineering, insurance carrier and state boiler inspections are made at each generating facility. Non-destructive techniques, including dye penetration, borescope analysis, disassembly and visual inspection, along with wall thickness testing, provide important data. Coupled with maintenance trends and operating data, inspection results are used to make informed decisions.

Enhanced Monitoring

Additional continuous monitoring equipment is provided to each generating unit on a prioritized basis. Plant distributed control systems, turbine supervisory systems, instrumentation replacement, flux probes and partial discharge equipment are frequently added to improve and monitor equipment conditions.

Operating and Maintenance ("O&M") Expenditures

Prudent O&M expenditures support continued operations of the generating units. This would include, but is not limited to, periodic boiler chemical cleaning, stack cleaning and repair, rolling ash lines, turbine valve cleaning, condenser cleaning, coal nozzle replacements and boiler tube pad welding which are examples of maintenance work that is performed to sustain the unit's reliability and availability.

Internal/External Best Practices

Continued internal sharing and external scans of best operation and maintenance practices are considered and evaluated. A number of skilled employees maintain and practice in licensed disciplines. The organization has a long history of partnering with others in the utility sector (EEI, EPRI, AEIC, etc.)[1] to better understand industry trends and ideas. Optimizing coal quality/fuel blending system-wide, installing static exciters, and Mobotec for emission control are three examples of internal sharing where practices have been applied to multiple sites.

Turbine Overhauls

Major turbine overhauls are scheduled every six to ten years, with actual frequency determined by OEM recommendations, condition monitoring and operational data.

Efficiency Monitoring

A long-standing efficiency metric that remains in place for all thermal plants is heat rate. It is used to monitor the generating unit's efficiency on an on-going basis. Major maintenance such as boiler chemical cleaning and turbine overhauls maintain and can improve efficiency.

[1] Edison Electric Institute ("EEI") provides public policy leadership, critical industry data, strategic business intelligence, conferences and forums, and products and services. The Electric Power Research Institute, Inc. ("EPRI") is an independent, nonprofit organization that conducts research, development and demonstration relating to the generation, delivery and use of electricity for the benefit of the public. The Association of Edison Illuminating Companies ("AEIC"), organized in 1885, focuses its energies on finding solutions to problems of mutual concern to electric utilities, worldwide.

Renewable, Natural Gas, and Fossil Generation Resource Descriptions

Biomass Resources:

Cloquet Energy Center—22.8 MW (Accredited[2])

Cloquet Energy Center ("CEC") is a one turbine generator set located at the Sappi Fine Paper North America Mill in Cloquet, Minn. It is a pressure-reducing turbine coupled to a generator that operates between Sappi's chemical recovery boilers fueled by woodland and natural gas, and its paper machines. It was installed in 2001 and is owned by Minnesota Power and operated by Sappi Fine Paper North America. The contract specifies that after 15 years of operation, ownership of the asset will be transferred to Sappi if an extension agreement cannot be reached. If no agreement on a contract extension is reached, the asset will be transferred to Sappi on July 1, 2016. With the transfer, the generation that presently is part of Minnesota Power's generation portfolio will displace what Sappi presently purchases from Minnesota Power. The transfer will not impact Minnesota Power's net load or capability balance*.*

Hibbard Renewable Energy Center ("HREC")—62 MW (Accredited)

Hibbard Renewable Energy Center Units 3 and 4 operate as energy resources for Minnesota Power's system and are located in Duluth, Minn. HREC is capable of burning wood and wood wastes, coal and natural gas. Use of wood and wood waste fuels make much of the energy generated by HREC a qualified renewable energy product. HREC have been providing a portion of Minnesota Power's regulated services and spinning reserves since 2004. HREC is capable of and originally designed for baseload operation and supports baseload energy generation when steaming capacity is available and energy is required for customers.

In 2008, Minnesota Power came to an agreement with the City of Duluth and NewPage to purchase the Duluth Steam District #2 steam production assets (Boilers 3 and 4 and related equipment) from the City and supply steam to NewPage under a long term contract. On September 22, 2009, the Minnesota Public Utilities Commission ("Commission") issued an Order approving the purchase.[3] The assets were transferred to Minnesota Power on September 30, 2009. Since that time, capital improvements have been completed to refurbish the facility to utility standards. The boilers continue to provide steam that drives HREC3&4 turbine generators based on market conditions and also provide large quantities of steam to the adjacent Verso Paper Mill (formerly NewPage) under a contract to 2024.

The current economic life of HREC extends through 2024, as summarized in Minnesota Power's 2014 Remaining Life Depreciation Petition.[4] Based on current and planned duty cycle preservation efforts, the operational life of HREC is projected to extend through the 15-year planning period for the 2015 Integrated Resource Plan ("2015 Plan or Plan"), and the Company will seek to extend the current remaining life date in a future Depreciation Petition filing.

HREC boilers are fitted with electrostatic precipitators ("ESP"), a pollution control technology that will provide continued particulate emissions control during the operational life of

[2] Accredited values in Appendix C are based on UCAP Planning Year 2015-2016.
[3] Docket No. E015/M-08-928
[4] Docket No. E015/D-14-318

the facility. HREC has increased the percentage of biomass to more than 90 percent of fuel supply, and reduced the percentage of coal fueling for the boilers in order to comply with recent environmental regulations (maximum-achievable control technology (“MACT”) and National Ambient Air Quality Standard (“NAAQS”)). Capital improvements in recent years have focused on refurbishing the existing boilers, wood handling, and ash handling systems to manage the increased wood burn.

Plans are to continue operating HREC for renewable energy and other ancillary services, including MISO declared emergency energy needs, regulation services, spinning reserves and annual capacity accreditation, as well as steam sales to Verso Paper Mill.

Current O&M practices will continue with routine maintenance inspections performed and corrective actions implemented as needed. Capital investments are continuously reviewed and prioritized across the generating fleet, including HREC, with a goal of maintaining current capacity in a manner that maintains reliability and availability throughout the 2015–2029 resource planning period.

<u>Rapids Energy Center (“REC” or “Rapids”)—30.1 MW (Accredited)</u>

Rapids, including steam and electricity generation assets, were purchased from UPM Blandin in 2000. Assets consist of two wood-fired boilers, two natural gas-fired boilers, air compressors, two steam turbines and two small hydroelectric turbine generator sets. The REC is an efficient combined heat and power facility capable of burning wood, wood wastes, coal and natural gas. The use of wood and wood waste make the energy generated from REC a renewable energy product, which is an important part of Minnesota Power’s plans to meet its renewable energy obligations. Since its purchase of the assets, Minnesota Power has operated REC as a non-regulated business unit supplying steam and electric generation to the UPM Blandin paper mill in Grand Rapids, Minn., under the terms of an agreement between Minnesota Power and UPM Blandin.

In Minnesota Power’s 2008 rate case, the Department of Commerce – Division of Energy Resources (“Department,” then known as the Office of Energy Security) recommended that Rapids should be moved into Minnesota Power’s rate base. The Department argued that Rapids is used to serve retail load and should be included in rate base. Minnesota Power responded at the time that it would not oppose including Rapids in rate base in a future case, if allowed to recover reasonable costs, but stated that contract amendments would be necessary with UPM Blandin. The Commission delayed consideration of the inclusion of Rapids in rate base, in part due to the legal considerations of ongoing contract extension discussions between UPM Blandin and Minnesota Power. The Commission also ordered Minnesota Power to report in its next general rate case 1) full information on the status of the UPM Blandin and Minnesota Power arrangement, 2) schedules of rate base, revenues and expenses sufficient to properly review for possible inclusion in rate base, and 3) arguments supporting Minnesota Power’s position on whether Rapids should be incorporated into the rate base. These compliance requirements were included in Minnesota Power’s 2009 general rate case and there were no further comments regarding Rapids in that docket.

On September 17, 2012, Minnesota Power and UPM Blandin completed negotiations of a new electric and steam supply arrangement which makes UPM Blandin a full requirements electric customer of Minnesota Power, facilitates the transfer of REC assets into regulated operations, and allows for an investment in an optimization project at REC to increase renewable generation by approximately 56,000 MWh per year. On December 19, 2012, Minnesota Power filed petitions with the Commission to approve an amended and restated electric service agreement with UPM Blandin.[5] The agreement also included the transfer of REC assets into regulated operations that also included an additional approximately $10 million investment in an optimization project to increase renewable generation by 56,000 MWh per year.[6]

On September 25, 2013, Minnesota Power's request to transfer REC assets into regulated operations was heard before the Commission. The Department opposed the request on the basis that: 1) REC was not shown to be a least-cost method for meeting the Company's resource needs; 2) revenues and expenses associated with the proposed shift of REC into regulated operations are treated asymmetrically; 3) the Strategist cost analysis conducted by the Company showed that system costs are slightly higher with the shift into regulated operations; 4) the additional renewable energy credits produced by REC are not needed by Minnesota Power for at least ten years; and 5) the shift of REC into regulated rate base would increase ratepayers' costs and shift the burden to ratepayers for future environmental clean-up or shut down costs associated with REC. The Commission concluded that the record did not demonstrate that it is reasonable and prudent to transfer REC to Minnesota Power's regulated operations at this time and that too many fundamental questions remain unanswered.

On October 9, 2013, the Commission issued an order stating that Minnesota Power's request to approve the transfer of the assets of Rapids from non-regulated operations to regulated operations was not approved at the time, subject to further review. Minnesota Power considers REC as a valuable and diverse renewable energy source for customers, which operates in an efficient combined heat and power configuration. The Company continues to evaluate a transition of REC to regulated operations.

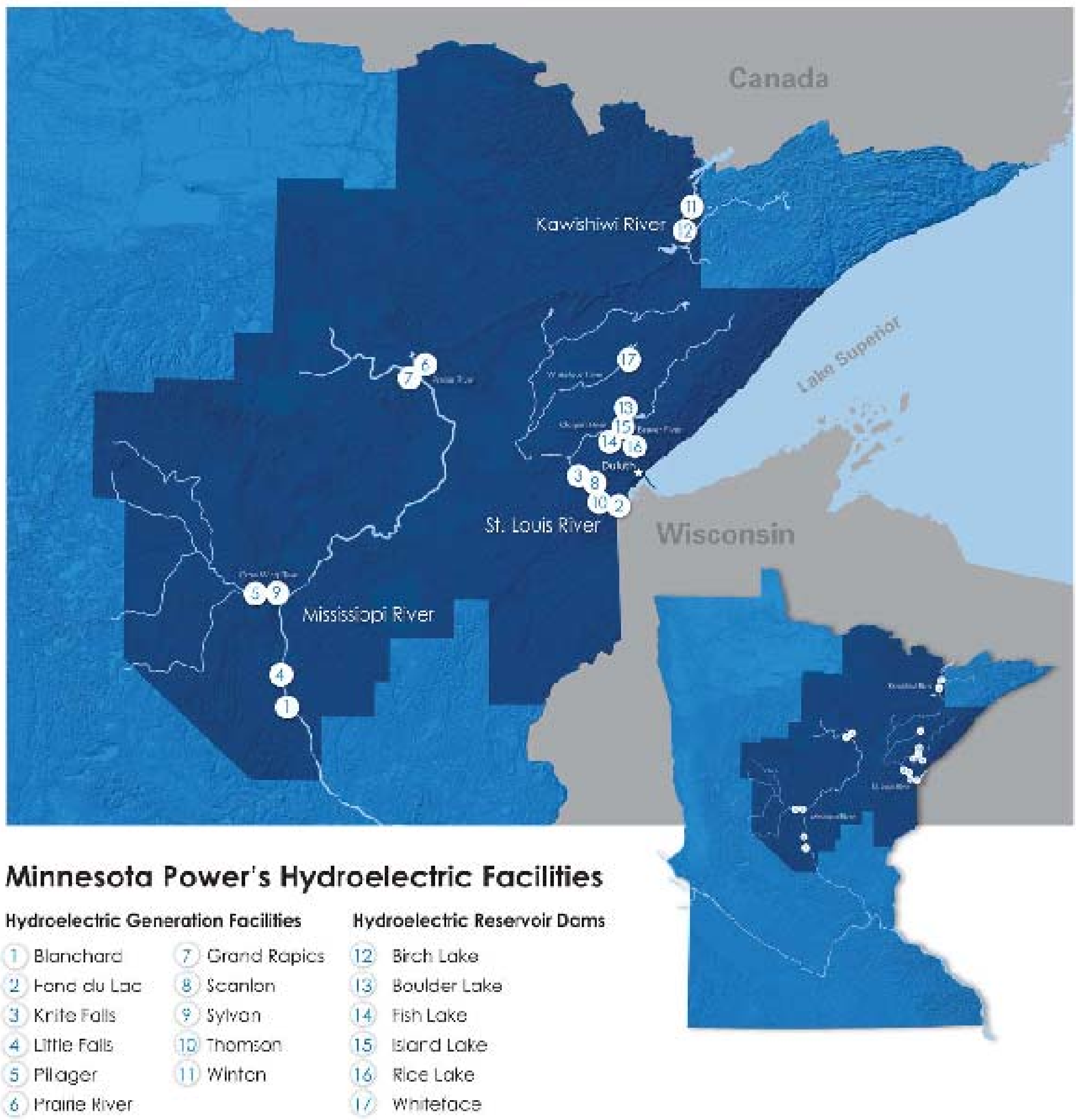
Hydro Resources:

Hydro Resources —115.6 MW (Accredited – including REC)

From its earliest days, Minnesota Power has used water to generate electricity. Today, Minnesota Power is the largest hydro energy producer in the State, with generating capability of as much as 120 MW. The Company operates 11 hydro stations on five rivers that are part of three main river systems in central and northern Minnesota – the Mississippi River, St. Louis River and Kawishiwi River. Thomson Hydroelectric Station has been generating renewable power for more than 100 years, as have the Little Falls and Sylvan stations. In addition to maintaining dams at each hydro station, Minnesota Power also maintain six headwater storage reservoirs. Minnesota Power operates its stations and reservoirs under eight federal licenses. The Federal Energy Regulatory Commission (commonly known as "FERC"), oversees dam

[5] Docket No. E015/M-12-1348.
[6] Docket No. E015/M-12-1349.

operations and safety in the United States, and FERC licenses specify operating parameters. Hydroelectric power will continue to be an important part of Minnesota Power's *Energy**Forward*** strategy, and along with investments in wind, biomass and solar energy, will help to build a cleaner and more sustainable energy future.



The facilities include[7] – Accredited (Name Plate):

- Little Falls Hydroelectric Station (Project #2532)—4.0 MW (4.7 MW)
- Blanchard Hydroelectric Station (Project #346)—12 MW (18 MW)
- Sylvan Hydroelectric Station (Project #2454)—1.3 MW (1.8 MW)
- Pillager Hydroelectric Station (Project #2663)—1.4 MW (1.8 MW)
- Prairie River Hydroelectric Station (Project #2361)—0.0 MW (1.1 MW)
- Grand Rapids Hydroelectric Energy Center (Project #2362)[8]– 0.9 MW (2.1 MW)
- St. Louis River System (Project #2360)—83.9MW (88.6 MW)
  - Knife Falls Hydroelectric Station—1.1 MW (2.4 MW)
  - Scanlon Hydroelectric Station—1.0 MW (1.6 MW)
  - Thomson Hydroelectric Station—70.2 MW (72.6 MW)
  - Fond du Lac Hydroelectric Station—11.6 MW (12.0 MW)
- Winton Hydroelectric Station (Project #469)—2.2 MW (4.0 MW)

The five facilities that have FERC licenses that expire during the 15-year planning cycle of this Plan, representing about six percent (6.5 MW) of Minnesota Power's hydroelectric capacity, are as follows:

- Little Falls Hydroelectric Station – FERC license expires 2023
- Prairie River Hydroelectric Station – FERC license expires 2023
- Grand Rapids Hydroelectric Energy Center ("REC" or "Rapids") – FERC license expires 2023
- Sylvan Hydroelectric Station – FERC license expires 2023
- Pillager Hydroelectric Station – FERC license expires 2028

Minnesota Power has identified that the useful life for these units extend beyond the planning period. Minnesota Power has completed projects and capital refurbishments at six locations identified below. These major investments have included:

- Reconstruction of Birch Lake Dam – part of Winton Hydroelectric Station, was completed in 2014; ongoing capital refurbishments to the dam and station occur on an annual basis as necessary.
- Prairie River Hydroelectric Station: Completed a full rebuild of the powerhouse and turbines in 2013; ongoing capital refurbishments to the dam and station occur on an annual basis as necessary.

[7] Project numbers refer to FERC license project number.
[8] Grand Rapids Hydroelectric Energy Center is currently a non-regulated asset.

- Rapids: In 2014, tuckpointing repairs of brick walls were completed on the powerhouse and a new roof and windows were installed. Generator overhauls were completed on Unit 4 in 2015, and are currently in progress on Unit 5. Ongoing capital refurbishments to the dam and station occur on an annual basis as necessary.
- Fond Du Lac Hydroelectric Station: Relining of the existing penstock with new steel piping was completed. This penstock rehabilitation, along with new unit overhaul electrically and mechanically was completed in 2013. Ongoing capital refurbishments to the dam and station occur on an annual basis as necessary.
- Sylvan Hydroelectric Station: Completed dam stabilization project in 2014; ongoing capital refurbishments to the dam and station occur on an annual basis as necessary.
- Thomson Hydroelectric Station: On June 19 and 20, 2012, record rainfall and flooding occurred in Duluth, Minnesota and surrounding areas. The flooding severely damaged Minnesota Power's St. Louis River hydroelectric system and particularly the Thomson facility, which was forced offline due to damage to the forebay canal and flooding at the facility. Extensive repairs at the facility included: reconstruction of the forebay canal, electrical restoration, mechanical and general civil rehabilitation, upgrades to the water conveyance system, and construction of additional spillway facilities at the main dam. The repairs[9] enabled Thomson to resume generation of low-cost renewable energy for Minnesota Power customers in November of 2014.

Minnesota Power will continue to assess the need for capital refurbishments to all hydro stations, and will re-license facilities as necessary to continue to provide value to customers. The Company will continue to assess additional efficiency projects or bolt-on additions to its hydraulic generating fleet. All hydro assets are expected to be operated throughout the 2015–2029 forecast period. The useful economic operating life of Minnesota Power's hydroelectric facilities extends beyond the planning period for all units.[10]

[9] Thomson Project for Recovery Petition Docket No. E015/M-14-577.

[10] In previous Resource Plans, the hydroelectric facilities' remaining lives have been set based on the expiration of FERC licenses. Beginning with Minnesota Power's 2014 Remaining Life Depreciation Petition (Docket No. E015/D-14-318), and going forward, all hydro facilities now reflect their projected operating lives.

Wind Resources:

Bison 1 Wind Facility ("Bison 1") — 81.8 MW (14.8 MW Accredited)

Minnesota Power's Bison 1 is located near Center, N.D. and was put into service in two phases during the time frame of 2010 through 2012, with the first phase consisting of sixteen 2.3 MW wind turbines and the second phase consisting of fifteen 3.0 MW wind turbines. The 2.3 MW turbines are geared units while the 3.0 MW turbines are new design direct-drive units without a gearbox.

Minnesota Power achieves delivery of the energy and accreditation of the capacity from this facility through its ownership of the high voltage direct current ("DC Line") between Center, N.D. and Duluth, Minn. The current economic life of Bison 1 extends through 2045 for the Phase 1 installation and through 2046 for the Phase 2 installation, as summarized in Minnesota Power's 2014 Remaining Life Depreciation Petition (Docket No. E015/D-14-318).

Bison 2 Wind Facility ("Bison 2") — 105 MW (19.0 MW Accredited)

Minnesota Power's Bison 2 is located near Center, N.D., and was put into service in 2012. The facility consists of thirty-five 3.0 MW direct-drive wind turbines. Minnesota Power achieves delivery of the energy and accreditation of the capacity from this facility through its ownership of the DC Line. The current economic life of the Bison 2 will extend through 2047, as summarized in Minnesota Power's 2014 Remaining Life Depreciation Petition (Docket No. E015/D-14-318).

Bison 3 Wind Facility ("Bison 3") — 105 MW (19.0 MW Accredited)

Minnesota Power's Bison 3 is located near Center, N.D., and was put into service in 2012. The facility consists of thirty-five 3.0 MW direct-drive wind turbines. Minnesota Power achieves delivery of the energy and accreditation of the capacity from this facility through its ownership of the DC Line. The current economic life of the Bison 3 will extend through 2047, as summarized in Minnesota Power's 2014 Remaining Life Depreciation Petition (Docket No. E015/D-14-318).

Bison 4 Wind Facility ("Bison 4") — 204.8 MW (37 MW Accredited)

Minnesota Power's Bison 4 is located near Center, N.D., and was put into service in 2014. The facility consists of 64 3.2 MW direct-drive wind turbines. Minnesota Power achieves delivery of the energy and accreditation of the capacity from this facility through its ownership of the DC Line. The current economic life of the Bison 4 will extend through 2049, as summarized in Minnesota Power's 2014 Remaining Life Depreciation Petition (Docket No. E015/D-14-318).

Taconite Ridge Energy Center — 25 MW (3.6 MW Accredited)

Taconite Ridge Energy Center consists of ten 2.5 MW wind turbines located on the Laurentian Divide in Mountain Iron, Minn., on United States Steel Corporation property. The wind facility began operation in 2008. The current economic life of Taconite Ridge Energy Center extends through 2043, as summarized in Minnesota Power's 2014 Remaining Life Depreciation Petition (Docket No. E015/D-14-318).

Natural Gas Generation Resources:

Laskin Energy Center ("Laskin" or "LEC") — 110 MW (69.5 MW Accredited[11])

LEC is located in Hoyt Lakes, Minn. and now employs 13 full-time Minnesota Power employees after the facility's transition from coal to natural gas.

Laskin has two generating units. Laskin Energy Center Units 1 and 2 ("LEC1&2") are sister boilers, similar in design and intended operation. The units are tangentially-fired steam generators and were both put into service in 1953. LEC1&2 each operate with a gross generation capability of 60 MW gross (55 MW net) with 5 MW of existing station service steam to operate auxiliary equipment.

Originally known as the Aurora Steam Station, the facility was commissioned as a coal fired facility in 1953 with a total station capability of 88 MW and was designed to serve the needs of an expanding taconite industry. LEC1&2 were uprated to the present capability in 1967 through boiler, control system, turbine, and generator upgrades.

[11] Accredited capacity for LEC after the refuel is expected to increase over time to 100MW.

In the spring of 2015 the facility was converted from coal to natural gas using the existing tangentially-fired steam generators and auxiliary equipment.[12]

Existing Emission Control Equipment

Previously, Minnesota Power completed environmental upgrades to control oxides of nitrogen ("NO_x") emissions in addition to the sulfur dioxides ("SO_2") and particulate matter ("PM") emissions historically controlled at the site. Following is a more detailed description of the equipment used for emissions control at the facility.

NOx Control

In 2006 and 2007 LEC was retrofitted with low NO_x burners ("LNB") and over-fire air for NO_x control as part of Minnesota Power's Arrowhead Regional Emissions Abatement ("AREA"), Project resulting in NO_x emissions reduction of approximately 65 percent. This technology is still being used with natural gas conversion.

SO_2, PM, and Mercury Control

LEC was initially fitted with a two-stage wet particulate scrubber in 1971 capable of both SO_2 and fly ash (PM) removal. The system utilizes a two stage horizontal spray chamber for removal of fly ash from the flue gas; some of the fly ash was recycled, increasing the alkalinity of the spray water which results in a modest reduction (30 percent) of SO_2 from the flue gas. The ash collected in this scrubber was sent to a wet ash impoundment system on site. A state-of-the-art ash pond (Cell-E) was constructed in 2000 with a four foot vertical expansion completed in July 2011. Also completed in July 2011 was a "first of its kind" Waste Water Treatment Facility for mercury removal, designed to meet and exceed Great Lakes Initiatives emission regulations. Given the conversion to natural gas the wet particulate scrubber is no longer required and has been removed from service. The mercury control technology is still being utilized until Cell E is dewatered.

These units have been well maintained through ongoing investments. The current economic life of LEC will extend through 2030, as is summarized in Minnesota Power's 2015 Remaining Life Depreciation Petition (Docket No. E015/D-15-711).

Current operation and maintenance practices will continue with routine maintenance inspections performed and corrective actions implemented as needed. Capital investments are continuously reviewed and prioritized across the generating fleet, including LEC, with a goal of maintaining current capacity in a manner that maintains reliability and availability throughout the 2015–2029 resource planning period.

[12] Docket No. E-015/GP-13-978.

Fossil Generation Resources:

Boswell Energy Center ("BEC") — Units 1, 2, 3, and 4

BEC is Minnesota Power's largest thermal facility, with a capacity of over 1,000 MW. The facility is located in Cohasset, Minn., just west of Grand Rapids. All four units are fueled by low mercury, low-sulfur Powder River Basin coal from Wyoming and Montana. BEC employs about 200 full-time Minnesota Power employees, and provided nearly half of the energy that Minnesota Power generated to meet customer requirements in 2014.

Substantial investments have been made at the facility for environmental and efficiency related improvements since 2007, with the largest investment the environmental retrofit of Unit 4, scheduled for completion in the fall of 2015.

Boswell Energy Center Units 1 and 2 ("BEC1&2") — 135 Nameplate MW (132 MW Accredited)

BEC1&2, the first two units constructed at BEC, were placed in service in 1958, and 1960, respectively. Both units are wall-fired steam generators. BEC1&2 each operate with a generation capability of 74 MW gross (69 MW net) with 5 MW of existing station service to operate auxiliary equipment.

Existing Emission Control Equipment

BEC1&2 emissions are currently controlled for NO_x and PM. BEC1&2 were originally retrofitted with LNB in 1998. Minnesota Power continued to improve the emissions reduction at BEC1&2 during the 2009-2010 timeframe with further NO_x controls by installing a selective non-catalytic reduction ("SNCR") system. BEC1&2 also deploys a fabric filter for PM control. These systems remove about 60 percent of the NO_x and 99 percent of PM and have considerable mercury co-benefit capture. Following is a more detailed description of the equipment used for emissions control at BEC1&2.

NOx Control

BEC1&2 deploys NO_x reduction technologies by utilizing the Mobotec SNCR system. This system includes a Rotamix technology and LNB with Mobotec's patented design for over-fire air called ROFA (Rotational-Opposed Fire Air). Within the Rotamix system, boiler injection ports are used to deliver urea into the boiler to chemically transform NO_x that is formed in the combustion process into harmless nitrogen gas and water vapor. This boiler gas mixing system (ROFA and Rotamix) is further increased in its effectiveness in preventing the formation of NO_x with the use of the LNB that have been in place on BEC1&2 since 1998. In combination, these NO_x controls provide, on average, approximately a 60 percent annual reduction in NO_x emissions.

LNB with over-fire air is a widely-used technology for coal-fired utility boilers aimed at minimizing the creation of NO_x in the coal combustion process. LNB/ROFA limits NO_x formation by controlling the stoichiometry and temperature profiles in each burner zone. The unique design features LNB that create a reduced oxygen level in the combustion zone that limits fuel NO_x formation, a reduced flame temperature that limits thermal NO_x formation, and/or a reduced residence time at peak temperatures which also limits thermal NO_x formation. Additionally, the installation of LNB/ROFA significantly reduces the amount of urea required for the SNCR technology.

PM Control

BEC1&2 currently utilizes fabric filters for control of PM in the combustion gases. Fabric filters are also commonly referred to as baghouses, and are widely-used technology for coal-fired utility boilers aimed at capturing particulate matter (fly ash) created in the coal combustion process. In addition to the effective PM capture, BEC1&2 have demonstrated consistent mercury co-benefit removal, significantly reducing mercury emissions due to uncombusted carbon adhering to fabric filter bags like an in-situ activated carbon system. When originally constructed, each of BEC1&2 employed a mechanical cyclone collector for PM control. These collectors were replaced by the current, more-effective fabric filter on each unit which remove PM and send the resulting hot, dry flue gas to the common exhaust stack for three of the Boswell units. The hot and dry gas that exits the fabric filter is used to reheat the cooler flue gas coming from Boswell Energy Center Unit 3 ("BEC3") as it enters a common exhaust stack. Dry flue gas is critical because moist gas is highly corrosive to the fans, ductwork, and lining within the exhaust stack. The PM collected in the fabric filter is collected and transferred pneumatically to an ash pond on site or recycled for SO_2 control on Boswell Energy Center Unit 4 ("BEC4") as a part of its venturi scrubber.

BEC1&2 operate at a high load factor, providing both base load energy and ancillary services. Ongoing investment in the units has maintained them in overall good condition. The current economic life of BEC1&2 extends through 2024, as summarized in Minnesota Power's 2014 Remaining Life Depreciation Petition (Docket No. E015/D-14-318). Current O&M practices will continue with routine maintenance inspections performed and corrective actions implemented as needed. Capital investments are continuously reviewed and prioritized across the generating fleet, including BEC1&2, with a goal of maintaining current capacity in a manner that maintains reliability and availability throughout the 2015–2029 resource planning period.

Clean Coal Solutions

In addition to the pollution control equipment and advanced controls, the Boswell Units also consume fuel amended with an additive aimed at reducing emissions of NO_x, mercury, and SO_2. This additive is proprietary technology that is applied through an agreement with Clean Coal Solutions.

Operation and maintenance practices will remain status quo with routine maintenance inspections performed and corrective actions implemented as needed. Capital investments are continuously reviewed and prioritized across the generating fleet, including BEC1&2, with a goal of maintaining current capacity in a manner that maintains reliability and availability throughout the 2015–2029 resource planning period.

BEC1&2 Natural Gas Re-fuel

As part of the 2015 Plan evaluation, refuel, retire and remission alternatives were considered for the BEC1&2 facility. These units are located outdoors, and will have operational challenges if they are not utilized as baseload generators. The following section identifies the key components of a natural gas conversion or refuel for the units.

Natural Gas Supply

BEC currently has a natural gas pipeline onsite for unit startup. The onsite pipeline is 10 inches and designed for 975 psig natural gas. The 10 inch pipeline will have adequate capacity to supply BEC1&2 combined at full load. A new onsite regulation station is required to regulate the gas to approximately 150 psig.

Required Plant Modifications

In order to convert the unit to burn 100 percent natural gas, additional equipment will be needed. The main components will include new low NO_X burners and gas igniters. The existing over fire air ("OFA") ports will be utilized to further aid in NO_X reduction. The existing distributed control systems ("DCS") is assumed to have an adequate number of input/output points for the conversion. No additional hardware has been included for the DCS, but costs have been included to reprogram the logic. Offsite and onsite natural gas piping and an on-site natural gas regulating station suitably sized for boiler operation are also required.

Auxiliary Power Requirements

A converted natural gas-fired boiler will have lower auxiliary power requirements than the existing coal-fired boiler. Auxiliary power will no longer be needed to operate the converted unit's coal handling equipment, pulverizers, particulate scrubbers, sootblowers and ash handling systems. Total auxiliary load power savings is estimated to be approximately 25 percent.

Performance

Burning natural gas will be less efficient than burning coal. Performance calculations are based on the assumption that the boiler heat input for gas firing is the same as for coal firing. The main impact on boiler efficiency is from hydrogen losses due to the higher hydrogen content of the natural gas fuel. The byproduct of combusting hydrogen is water vapor, and additional heat is needed to vaporize this water and heat it to the internal boiler temperature. This heat is lost in the flue gas rather than absorbed in the boiler's water walls to create steam.

On the other hand, natural gas is more efficient than coal when it comes to dry gas losses due to less combustion air and excess air. These calculations assume that approximately 10 percent excess air is needed for proper combustion of natural gas verses 20 percent excess air for coal. Less flue gas flow for burning natural gas equates to smaller losses for heating the flue gas.

Considering the hydrogen losses and dry gas gains, the total net boiler efficiency for gas-fired boilers is estimated to be two percentage points less than the existing coal-fired boilers. While the reduced natural gas-fired boiler efficiency reduces net plant output, the reduction in auxiliary power requirements for a gas-fired boiler increases the net plant output accordingly. Expected performances for natural gas are shown in Table 1 along with the existing plant performances.

Table 1: Gas Conversion Performance Comparison

Performance Comparison		
	PRB Coal	**Natural Gas**
Net Plant Output, kW	**69,00**	**68,700**
Net Plant Heat Rate, Btu/kWhr	**10,840**	**10,890**
Heat Input, MMBtu/hr	**748**	**748**

<u>Conclusion</u>

Converting the existing coal-fired units to be natural gas-fired will reduce the NO_X and SO_2 emissions from the boiler. It is a relatively low capital cost option that can be retrofitted with minimal equipment. Because these units are located outdoors there will be operational and availability challenges for these units as a result of their reduced utilization associated with converting these units to natural gas peaking operation, especially during the winter months.

<u>Boswell Energy Center Unit 3 — 355 Nameplate MW (346 MW Accredited)</u>

BEC3 is the third unit constructed at BEC and was placed in service in 1973. The unit is a tangentially-fired steam generator. In 2009, Minnesota Power replaced the original turbine with a more efficient design that is able to operate at 389 MW gross capability and 360 MW net output without increasing the steam flow or consuming additional fuel.

In combination with the turbine efficiency upgrade at the station, a major environmental upgrade was completed at BEC3 in 2009 to meet state and federal environmental requirements. Following the retrofit, the facility now employs LNB, over-fire air, and a selective catalytic reduction ("SCR") system for NO_x control, a spray tower absorber which is also commonly referred to as wet flue gas desulfurization ("WFGD") for SO_2 control, and an activated carbon injection system and fabric filter for mercury and PM control. The turbine upgrade completed in 2009 resulted in the additional 25 MW of unit capability, which not only offset the additional station service power required to run the new environmental control equipment, but added an additional 10 MW to the unit net capability from its historical level of 352 MW.

BEC3 operates at a high load factor, providing base load energy in the Minnesota Power system. The current economic life of BEC3 extends through 2034, as summarized in Minnesota Power's 2014 Remaining Life Depreciation Petition (Docket No. E015/D-14-318).

Existing Emission Control Equipment

As described above, BEC3 underwent a complete environmental retrofit during the period of 2007 to 2009, installing the most state-of-the-art emission control equipment available. Actual emission reductions from these investments include an 87 percent reduction in NO_x, 98 percent reduction in SO_2, 94 percent reduction in PM, and 90 percent reduction in mercury. The project was nationally recognized by industry publications such as *Power* magazine for its successful design, implementation, and level of emissions control. Following is a more detailed description of the equipment used for emissions control at BEC3.

NOx Control

BEC3 deploys new NO_x reduction technologies by utilizing a SCR system. In this system, a reactor is utilized to remove the NO_x from the flue gas with the use of ammonia as a reducing agent. The boiler flue gas enters the reactor, where ammonia, in conjunction with a specialized catalyst chemically transforms NO_x that is formed in the combustion process into nitrogen gas and water vapor. SCR is "selective" in that it predominantly affects the oxides of nitrogen.

In addition to the SCR reactor, BEC3 also utilizes special designs of both LNB and over-fire air for NO_x control similar to the other BEC units. BEC3's LNB and over-fire air technology encompass a low NO_x concentric firing system which maximizes the NO_x reduction capabilities of the existing tangential firing systems in the boiler and a separated over-fire air windbox which works with the firing system to stage and separate the air and fuel mixture properly for maximum NO_x reduction.

SO_2 Control

BEC3 currently utilizes a WFGD unit for SO_2 control. WFGD is a widely-used technology for coal-fired utility boilers aimed at removing acid gases created in the coal combustion process. WFGD eliminates SO_2, hydrochloric acid, hydrofluoric acid, and to some extent, sulfur trioxide through direct contact with the sorbent, an aqueous, finely ground limestone slurry which is sprayed into the rising flue gas in the vessel and collected at the bottom of the vessel after it has chemically transformed the acid gas into the material gypsum.

PM and Mercury Control

BEC3 currently utilizes a fabric filter for control of PM in the combustion gases. In the distinctive design of the environmental control system at BEC3, the fabric filter also helps control mercury emissions through capture of a powdered activated carbon ("PAC") sorbent which is injected into the ductwork upstream of the fabric filter to react with, and capture the mercury in the flue gas.

Clean Coal Solutions

In addition to the pollution control equipment and advanced controls, the Boswell Units also consume fuel amended with an additive aimed at reducing emissions of NO_x, mercury, and SO_2. This additive is proprietary technology that is applied through an agreement with Clean Coal Solutions.

Operation and maintenance practices will remain status quo with routine maintenance inspections performed and corrective actions implemented as needed. Capital investments are continuously reviewed and prioritized across the generating fleet, including BEC3, with a goal of maintaining current capacity in a manner that maintains reliability and availability throughout the 2015–2029 resource planning period.

Boswell Energy Center Unit 4 — 585 Nameplate MW (446 MW Minnesota Power/ 112 MW WPPI Accredited)

BEC4 was the final unit constructed at BEC and was placed in service in 1980. The unit is a tangentially-fired steam generator and has been wet-scrubbed since being placed into service. In 2010, Minnesota Power replaced the original turbine with a more efficient design that is able to operate at over 635 MW gross capability and 585 MW net capability, without increasing the steam flow or consuming additional fuel. In essence, the Company added 50 MW of zero-emission, dispatchable, capacity and energy as a result of this efficiency improvement project.

BEC4 operates at a high load factor, providing base load energy in the Minnesota Power system. WPPI Energy (formerly Wisconsin Public Power, Inc.) jointly owns BEC4 with Minnesota Power with a 20 percent ownership. The current economic life of BEC4 extends through 2035, as summarized in Minnesota Power's 2014 Remaining Life Depreciation Petition (Docket No. E015/D-14-318).

Existing Emission Control Equipment

BEC4 was originally constructed with first generation LNB and close-coupled over-fire air, and a then state-of-the-art wet spray tower absorber/particulate removal system. This system removes more than 85 percent of the SO_2 and over 97.5 percent of PM. Investments made in emission reduction technology over the past few years have resulted in continued improvements in emission reduction at BEC4. Following is a more detailed description of the equipment used for emissions control at BEC4.

NOx Control

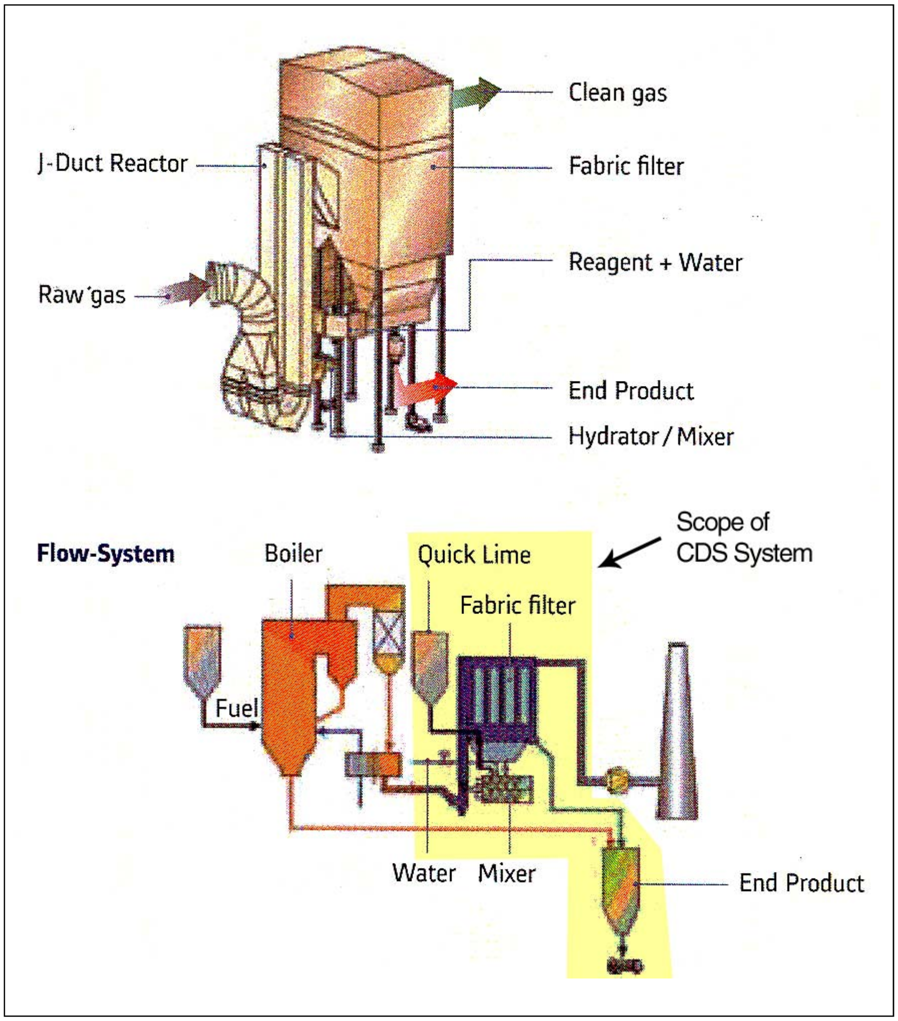
BEC4 deploys new NO_x reduction technologies by utilizing the Mobotec SNCR system. Similar to that installed on BEC1&2, this system includes a Rotamix technology, and LNB with over-fire air ("LNB/OFA"). Within the Rotamix system for BEC4, fourteen boiler injection ports are used to deliver urea into the boiler to chemically transform NO_x that is formed in the combustion process into harmless nitrogen gas and water vapor. In 2010, the Company further increased its effectiveness in preventing the formation of NO_x with the replacement of the first generation LNB with new, state-of-the-art, LNB and separated over-fire air technology. In combination, these NO_x controls provide an approximately 55 percent annual reduction in NO_x emissions. More recently, Minnesota Power has installed combustion optimization neural network systems to further optimize emission reduction performance.

SO_2, PM and Mercury Control

BEC4 is completing construction of a new Circulating Dry Scrubber (“CDS”) to replace the existing WFGD for SO_2 removal and the wet venture scrubber for PM control. This new CDS will also control mercury emissions through a PAC injection system and fabric filter for mercury capture.

A CDS is a type of semi-dry flue gas desulfurization system. In a CDS system, flue gas enters a vertical reactor tower before exiting to a fabric filter where additional emission capture and collection takes place. Flue gas enters at the base of the vertical reactor tower and flows upward through what is called a “venturi,” mixing with the fluidized bed which is comprised of a mixture of dry lime and fly ash. The intensive gas-solid mixing occurring at this point in the CDS process promotes reaction of sulfur oxides in the flue gas with the dry lime particles. Water is introduced separately above the venturi section for flue gas humidification to enhance the reactivity of the lime and physical absorption for more effective SO_2 removal. PAC is injected into the vertical reactor tower for the purpose of capturing mercury and is collected along with the PM in the fabric filter. Introducing the PAC prior to the flue gas entering the fabric filter allows for the necessary reaction time to maximize mercury removal.

Figure 1: CDS Flow Process Diagram



Powdered Activated Carbon

PAC systems are a proven power plant mercury reduction technology that are able to achieve very high removal efficiencies (i.e. 90 percent). PAC is used to remove mercury from the flue gas. The injected carbon compound adsorbs the vaporized mercury from the flue gas and combines the mercury with carbon and fly ash particulate. The particulates are then captured by a fabric filter.

Minnesota Power expects it will achieve an approximately 90 percent mercury removal at BEC4 using PAC in combination with a fabric filter and that this use of multiple emission control technologies to reduce mercury is consistent with the intent of Minn. Stat. § 216B.682, subd. 3(a) to "demonstrate that Minnesota Power has considered achieving the mercury emissions reduction required...through multiple pollutant control technology." The Fabric Filter section provides additional detail on expected mercury emission reduction.

Fabric Filter (Alstom NID Technology)

The fabric filter, also commonly referred to as a "bag house," is integral in optimizing mercury removal. When used in combination with PAC, a fabric filter is the most effective mechanism for capturing mercury. The fly ash and PAC form a cake on the filter bags. The mercury particles in the flue gas are forced to pass through the caked bags to exit the stack. This provides the necessary residence time for the PAC to contact the mercury particles. The mercury particles adhere to the fly ash and PAC matter instead of exiting the stack.

Fabric filters use fiberglass or other fabric bag materials to collect total filterable PM, fly ash and mercury-laden carbon. The unique concept of combining use of the fabric filter with a CDS system is that a portion of the fly ash is recirculated to an absorber tower to assist in SO_2 removal. As the filters continue to collect additional fly ash, a portion is sent to storage/disposal. The system operates with a controlled loading of fly ash to optimize its performance.

Byproduct Ash Handling System ("Ash System")

Conversion of BEC4 to a CDS system will change the way waste fly ash is currently managed in the existing Boswell ash disposal system. The BEC4 dry fly ash will be transported pneumatically from the BEC4 CDS to a newly constructed BEC4 fly ash silo, then transported to the ash disposal area via truck for deposition with dry coal combustion residuals ("CCRs") from Units 1, 2, and 3. Additional handling and storage capability to the Unit 1, 2, & 3 ash disposal infrastructure, which is currently designed to accommodate dry fly ash from Boswell Units 1, 2, and 3, is necessary to accommodate the increased volume of fly ash generated by the BEC4 CDS. The necessary upgrades include expansion of the bottom ash foundation base layer in the pond disposal area, larger final cover construction projects, an increased storm water sedimentation pond, access ramp and haul road improvements, and additional equipment to transport and store the additional fly ash.

Conversion to dry handling also effectively positions BEC4 to accommodate upcoming regulatory changes associated with both the CCR and Effluent Limit Guidelines of Environmental Protection Agency ("EPA") rulemakings. Additionally, the CDS system is a net consumer of water/wastewater, which will result in reduced wastewater discharge for BEC4. This water-consumptive property has obvious benefits in a regulatory future where stringent metals- or salts-based limits for wastewater discharges will otherwise require additional capital and O&M investments in the future. Additionally, internal wastewater recycling and consumption will benefit other Boswell Units, which may be able to divert wastewater streams to a retrofitted BEC4 instead of treating and discharging it.

Clean Coal Solutions

In addition to the pollution control equipment and advanced controls, the Boswell Units also consume fuel amended with an additive aimed at reducing emissions of NO_x, mercury and SO_2. This additive is proprietary technology that is applied through an agreement with Clean Coal Solutions.

Current operation and maintenance practices will continue with routine maintenance inspections performed and corrective actions implemented as needed. Capital investments are continuously reviewed and prioritized across the generating fleet, including BEC4, with a goal of maintaining current capacity in a manner that maintains reliability and availability throughout the 2015–2029 resource planning period.

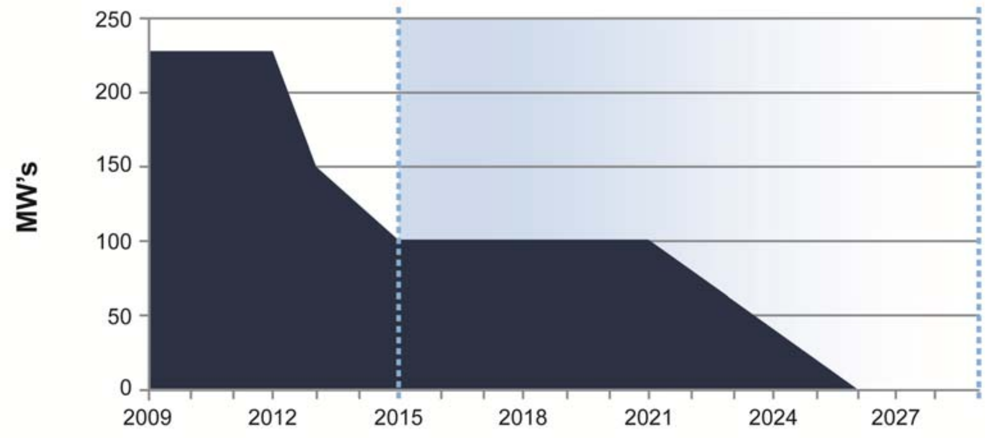
Square Butte's Milton R Young 2—455 MW Nameplate (90 MW Minnesota Power Accredited)

Milton R. Young 2 ("Young 2") lignite coal generating station in North Dakota operates as base load. Young 2 is owned by Square Butte Cooperative ("Square Butte"), managed by Minnkota Power Cooperative ("Minnkota") and provides energy sales to Minnesota Power and Minnkota. Minnesota Power's energy is transmitted via the DC Line running between the Square Butte Substation in Center, N.D. and Minnesota Power's Arrowhead Substation near Duluth, Minn. via the alternate current ("AC") transmission system. Minnkota's share is routed on its new 345KV Center, N.D. to Grand Forks, N.D. transmission line. Minnesota Power transmission system personnel have operated and maintained the DC Line since it was commissioned in May 1977. Beginning in 2006, Minnkota could exercise an option to reduce Minnesota Power's entitlement by approximately five percent annually, down to a 50 percent share. Minnkota exercised all available options and, as of January 1, 2009, both Minnkota and Minnesota Power are limited to 50 percent of Young 2 generation, or approximately 227.5 MW each.

In 2009, in a major move to accelerate Minnesota Power's strategy of reducing carbon emissions and expanding renewable wind energy development, Minnesota Power obtained Commission approval to purchase the DC Line and phase out of the long-term contract to buy coal-based electricity from Square Butte (Docket No. E015/PA-09-526).

Electricity generated at Young 2 is presently shared by Minnesota Power and Minnkota. Since 2014, Minnesota Power has been gradually reducing its 227.5 MW entitlement at Young 2, and by 2026 Minnesota Power will no longer take any of the Young 2 output for its customers. The expected gradual reduction of output taken by Minnesota Power from Young 2 is shown in Figure 1.

Figure 2: Minnesota Power's share of Young 2 Phase-out: 2015-2026



As operating agent, Minnkota is responsible for the operation and maintenance of Young 2. Minnesota Power's oversight through active participation on the operating committee ensures appropriate capital and O&M investments are being made to maintain long-term sustainability of the asset. Part of that effort includes upgrading the SO_2 and NO_x environmental controls. Enhanced SO_2 scrubbing equipment was installed in the 2010 timeframe and for NO_x, over-fire air was installed in 2007 and a SNCR system was installed in the 2010 time frame. It is anticipated that Young 2 will continue to provide base load generation to Minnesota Power through the majority of the 2015–2029 resource planning period, with the reductions as noted in the Figure 2.

<u>Taconite Harbor Energy Center ("THEC") —225 MW Summer (139 MW Accredited)</u>

THEC is located near Schroeder, Minn., on the North Shore of Lake Superior, and has a generation capability of 225 MW. THEC employs approximately 40 full-time Minnesota Power employees.

THEC was purchased from bankrupt LTV Steel Mining Co. in 2001. The three units at THEC are 75 MW tangentially-fired steam generators and were put into service in 1957, 1957, and 1967, respectively. These units each operate with a gross generation capability of 79 MW gross (75 MW net) with 4 MW of existing station service steam to operate auxiliary equipment.

Significant investments were made as the units were restarted in 2002 to improve unit availability allowing them to support Minnesota Power's retail load. The current economic life of THEC extends through 2026, as summarized in Minnesota Power's 2014 Remaining Life Depreciation Petition (Docket No. E015/D-14-318).

The THEC units again received significant investment during 2006 to 2008 as part of Minnesota Power's Arrowhead Regional Emission Abatement Plan ("AREA"). Two of the three units were fitted with the Mobotec multi-emission control technology designed to deliver a 62 percent reduction in NOx emissions, a 65 percent reduction in SO_2 emissions and up to a 90 percent reduction in mercury emissions.

Taconite Harbor Energy Center Unit 3 ("THEC3") ceased coal-fired operations in 2015 due to the Mercury and Air Toxics Standard ("MATS") regulation taking effect on April 15, 2015. The unit has been retired in place while refueling or re-missioning options are being explored. Any future operation of the unit would use an alternate fuel source other than coal or fuel oil. The THEC3 retirement reduces the available THEC generation capacity to 150MW's.

Existing Emission Control Equipment

THEC emissions are currently well controlled on two of the three units and partially controlled on the third unit. From 2006 – 2008, as a part of Minnesota Power's AREA environmental retrofit project, the company completed significant environmental upgrades on Taconite Harbor Energy Center Units 1 and 2 ("THEC1&2") to control NO_x, SO_2, PM and mercury emissions. These two units are compliant with MATS and able to generate power for customers. Original equipment for PM control is still in place at THEC3.

The AREA environmental retrofit at THEC1&2 resulted in NO_x emissions reduction of approximately 60 percent, SO_2 reductions of approximately 45 percent (from controls and new low-sulfur coal supply), and mercury reductions of up to 90 percent. Following is a more detailed description of the equipment used for emissions control at THEC.

<u>NOx Control</u>

In 2007 and 2008, THEC1&2 were retrofitted with the Mobotec Multi-pollutant control system for control of NO_x, SO_2, and mercury. NO_x is controlled through the use of the Mobotec SNCR process and ROFA technology. Similar to BEC1&2, and 4, within the Rotamix system, boiler injection ports are used to deliver urea into the boiler to chemically transform NO_x that is formed in the combustion process into harmless nitrogen gas and water vapor. This system, when combined with the ROFA boiler gas mixing system, has resulted in NO_x emissions reduction of approximately 60 percent.

<u>SO_2 Control</u>

The Mobotec Multi-pollutant control system also controls SO_2 on THEC1&2 through the injection of hydrated lime in the boiler during the combustion process. This hydrated lime chemically reacts with the SO_2 similar to the reaction in a WFGD described in the BEC3 SO_2

control section, removing the acid gases formed during the coal combustion process. The ash product created after this reaction is captured by the PM control devices detailed below.

In 2014 a Direct Sorbent Injection system ("DSI") was installed on THEC1&2 to meet the emerging Mercury Air Toxic Standards. The system injects sodium bicarbonate ("SBC") into the flue gas stream ahead of the electrostatic precipitator ("ESP") to further reduce SO_2 emissions and hydrochloride emissions. The ash product created after this reaction is captured by the PM control devices detailed below.

Mercury Control

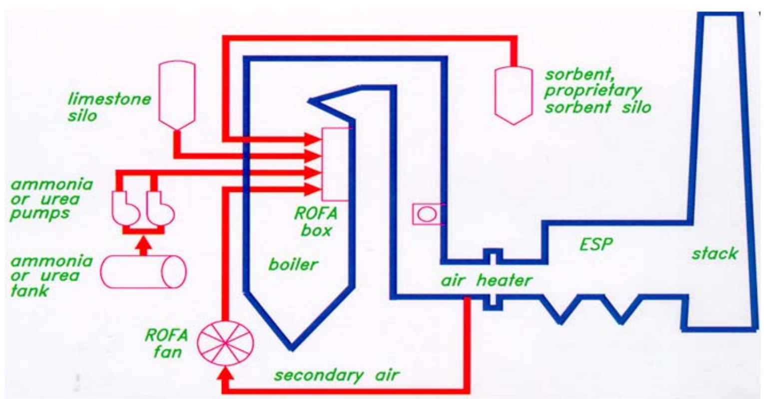
The Mobotec Multi-pollutant control system also currently controls mercury on THEC1&2 using a PAC injection system upstream of the ESP. This mercury capture sorbent is then captured by the PM control devices detailed below.

PM Control

THEC1&2 both had original hot-side ESPs used for PM control which were retrofitted during the environmental upgrades to more efficient cold-side ESPs for PM control and removal of the ash and sorbents used for SO_2 and mercury control in the system. THEC3 also utilizes an original hot-side ESP for PM control. The ash collected from THEC is sent to an ash landfill on site.

A simplified diagram of the Mobotec process and control on THEC1&2 is shown in Figure 3. The ROFA fan and urea systems are used for NO_x control. The limestone silo, along with a new SBC silo and associated injection systems are used for SO_2 control.

Figure 3: Mobotec Diagram for THEC1&2



THEC1&2 Mobotec Environmental Control System

THEC utilizes a dry-ash landfill for disposal of ash from the facility. The residual-ash generated from the coal combustion process in the boilers is deposited into a permitted landfill facility approximately three miles north of the facility.

Ongoing investment in these units has maintained them in good overall condition. The current economic life of THEC extends through 2026, as summarized in Minnesota Power's 2014 Remaining Life Depreciation Petition (Docket No. E015/D-14-318).

Minnesota Power anticipates that with current and planned preservation efforts, the operational life of THEC could extend through the 15-year planning period for this Plan. As identified in the 2015 Plan, the fuel source will need to be addressed by 2020 to address market conditions and pending Clean Power Plan ("CPP") compliance requirements.

THEC Biomass Conversion Options

Converting coal fired power plants to burning biomass brings many positive benefits including the utilization of existing power plant sites, electrical substations and generating equipment, a reduction in several air pollutants, the ability to beneficially re-use the generated ash and local economic benefits from retaining power plant jobs and adding fuel harvest and processing jobs. There are three technically proven methods to convert coal plants to burn biomass: stoker conversion, pellet conversion and advanced biomass conversion. Depending on what method is chosen, there are wide variations in capital costs, performance, fuel variety and fuel costs.

<u>Boiler Conversion for Raw Biomass</u>

The current boilers at THEC are combustion engineering tangential-fired designed for pulverized coal being fired in suspension within the boiler. In order to burn raw biomass fuel, the suspension firing system needs to be replaced with one that has the ability to burn larger sized fuel upon a grate. This conversion is the most technically challenging, and has the highest capital cost requirement. Physically this project involves removal of the lower portion of the boiler firebox and replacement with traveling or vibratory stoker grates, along with the addition of many additional supporting systems including fuel handling, over and under fired air, ash and char collection and potentially pollution control modifications.

Minnesota Power has completed this type of conversion at HREC in the 1980s. Boilers 3 and 4 at HREC provide process steam to the Verso Paper Mill in Duluth, Minn. and generate power for Minnesota Power's customers. The heat input of the boiler would be expected to decrease due to the limited cross sectional area of the boiler furnace section available for firing and boiler geometry not being optimal for heat transfer when firing high moisture biomass. The efficiency of the boiler could also decrease due to less precise control over combustion variables, increased air leakage, higher fan requirements.

A grate-fired boiler is able to burn a wide variety of solid fuels including coal, raw biomass, sludge, construction waste, municipal solid waste, pellets and advanced biomass. It does have limitations as to the quantity of finely sized particles it is able to burn such as sawdust or coal fines. The ability of this type of boiler to interchange fuels allows for substitution or the lowest fuel cost available. Additional study would be required to understand the availability and cost of wood supply in the area, and how much electric generation it would be able to sustainably support.

<u>Boiler Conversion for Pelleted Biomass</u>

Firing 100 percent pelletized fuel requires major modifications and new construction to the fuel handling and storage systems to account for the increased risk of fire and explosions related to pelletized biomass. Pelletized fuel is not able to be stored outside and would require indoor storage. There would need to be modifications to the pulverizers to perform the much different function of breaking up a fibrous pellet versus grinding the friable coal, and to control auto-ignition. The firing system would need to be modified to account for the different combustion parameters of wood fiber. Additional modifications of heat transfer surfaces may need to be modified depending on expected and required performance.

It is possible to burn lesser quantities of wood pellets without major modifications through a process known as co-firing, in which pellets are added to the coal supply or crushed and added directly to the boiler. Co-firing rates of up to 5 -10 percent are likely possible without major modifications. There are several examples of conversion utilizing pelletized fuel including the Drax Station in the United Kingdom and Ontario Power Generation's Atikokan station in Northwest Ontario.

To estimate the performance of a boiler converted to run on wood pellets, a detailed modeling will need to be performed to fully understand limitations and expected efficiencies. However, since biomass burns at different rates, contains less energy and produces flue gas with different heat transfer properties, it is likely that both the output and efficiency of the units will decrease below that of its current capabilities firing coal.

Performance modeling of the boilers and precipitators would be required to understand the NO_x and particulate emissions, but the pellet fuel would be expected to be very low in sulfur, mercury and trace metals.

Industrial wood pellets are manufactured by separating clean wood from bark, reducing the wood to a small particle size, drying and forming into a pellet. A boiler modified to burn 100 percent wood pellets will not retain its ability to fire other fuels such as coal without reversing the modifications to the pulverizer and firing systems. Wood pellets are a globally traded commodity, and much of the ship unloading system located at THEC could be utilized to accept shipments from self-unloading ships.

Boiler Conversion for Advanced Biomass

Advanced biomass utilizes production processes such as torrefaction and steam explosion seek to mimic the friable nature and hydrophobic properties that make coal a desirable power generating fuel. In theory, no modifications are required to burn advanced biomass in a pulverized coal boiler, but in practice, modifications to fuel handling are recommended to improve the safety of transfer operations. Combustion optimization is required to adjust for different fuel constituents and pollution control devices need to be carefully studied and potentially modified.

Advanced biomass processing is controlled to create a product similar to coal in terms of energy content, therefore it is anticipated that boiler capacity efficiency losses would be modest. There has been several full scale firing tests of advanced biomass that would indicate positive results, but due to the wide variety of boiler designs and fuel variation, combustion modeling or testing must be performed to verify the expected performance of an individual boiler.

There are only a few examples of generating facilities undergoing this specific type of conversion including Ontario Power Generation's Thunder Bay Generating Station. Several other facilities are undergoing pilot testing to determine the suitability of this fuel source.

Conclusion

Advanced biomass has been technologically proven at several power plants globally through pilot scale test firing, but the supply chain for advanced biomass is not as mature as industrial wood pellets, and most suppliers have not yet achieved commercial scale quantities for extended periods of time. Major questions still remain as to the long term ability of advanced pellets to survive material transfer and storage without disintegration, and whether a commercial marketplace for materials will ever be developed.

THEC Natural Gas Conversion Options

There are several conversion options for coal fired power plants that involve using alternate fuel sources, including natural gas and propane. Benefits include the utilization of existing power plant sites, electrical substations and generating equipment, as well as a reduction in several air pollutants. Re-fueling would also have local economic benefits from retaining power plant jobs and adding fuel transit and processing jobs. Four refuel options are considered below, including natural gas by pipeline, liquefied natural gas, compressed natural gas and propane. Depending on what method is chosen, there are wide variations in capital costs, performance, fuel transport options and fuel costs.

Performance

Burning natural gas will be less efficient than burning coal. The main impact on boiler efficiency is from hydrogen losses due to the higher hydrogen content of the natural gas fuel. The byproduct of combusting hydrogen is water vapor, and additional heat is needed to vaporize this water and heat it to the internal boiler temperature. This heat is lost in the flue gas rather than absorbed in the boiler's water walls to create steam.

Burning propane will be more efficient than burning coal. The propane has higher hydrogen content than coal but this is offset by the much higher heating value of about 2,500 Btu/cuft compared to natural gas at 1,000 Btu/cuft. Firing propane will most likely decrease the steam turbine heat rate, due to less reheat spray flow, since propane releases more energy in the furnace walls than the back-pass. Steam turbine heat rate is assumed to improve by approximately 0.5 percent.

Burning natural gas or propane is more efficient than coal when it comes to dry gas losses due to less combustion air and excess air. These calculations assume that approximately 10 percent excess air is needed for proper combustion of natural gas or propane verses 20 percent excess air for coal. Less flue gas flow for burning natural or propane gas equates to smaller losses for heating the flue gas.

A converted natural gas-fired or propane-fired boiler will have lower auxiliary power requirements than the existing coal-fired boiler. Auxiliary power will no longer be needed to operate the converted unit's coal handling equipment, pulverizers, ESP, sootblowers, ash handling systems, and other miscellaneous systems. Total auxiliary load power savings is estimated to be approximately 25 percent.

Fuel Storage and Supply

THEC currently has no natural gas or propane supply onsite or nearby. Northern Natural has a 16 inch pipe line approximately 27 miles from THEC. TransCanada has a large capacity pipe line approximately 100 miles south of THEC. The Northern Natural pipe line is the closest but may require upgrades to supply gas to THEC. Excluding any upgrades, extending the Northern Natural pipeline would cost approximately $25 million. Extending the TransCanada pipeline would cost approximately $85 million.

Propane or compressed natural gas would be delivered to the site by truck and stored onsite in pressure vessels. Propane and compressed natural gas would also require a vaporizer. Even though each unit is only 75 MW, a large amount of propane or compressed natural gas would have to be stored onsite. Due to the large quantity, a 90,000 gallon horizontal cylindrical tank is assumed. For 5 days of storage for two units, a total of 24 storage tanks would be necessary. In order to fill the tanks, assuming a 10,000 gallon tanker, would require approximately 44 trucks per day.

Required Plant Modifications

In order to convert the unit to burn 100 percent natural gas, additional equipment will be needed for the boiler. The main components will include new gas nozzles and gas igniters. The existing DCS is assumed to have an adequate number of input/output points for the conversion. No additional hardware has been included for the DCS, but costs have been included to reprogram the logic.

Operation and Maintenance Costs

Operating the units with natural gas will have a significant impact on the O&M costs for the facility. It is expected that the staffing can be reduced significantly as the gas-fired unit will no longer require coal and ash handling. Estimate for total staff of 25 personnel for propane operation and 31 personnel for Liquefied Natural Gas (“ LNG”) operation of THEC1&2. Staffing level could change depending on how the operations of the unit. Further, routine maintenance and variable O&M costs should be reduced. Existing equipment not required for natural gas-fired operation will no longer require maintenance. Also, major boiler maintenance will be significantly reduced due to the lack of erosion issues from burning natural gas. In addition, bottom ash and fly ash handling will no longer be necessary.

Conclusion

Converting the existing coal-fired unit to natural gas-fired will reduce the NO_X and SO_2 emissions from the boiler. Depending on the fuel supply option at the plant, capital costs can vary greatly however the higher capital cost option has the lowest fuel price. Depending on how often the unit is operated, the lower fuel cost can make up for higher capital costs very quickly. Also, there is a lot of uncertainty regarding the LNG option. Ship size and procurement and LNG source will have a large impact on capital and fuel cost. Propane will require a large amount of onsite storage and it may be difficult to find a propane company that can supply enough propane. Compressed natural gas will require a large amount of onsite storage and would require the installation of compressed natural gas processing station on either the TransCanada or Northern Natural pipelines located miles to the south of the station; however, this would be the most practical choice of these refuel options at the time of this filing.

Heat Rate and Efficiency Improvements

Maintaining and improving efficiency of the energy centers is a complex and important aspect of operating in a manner to minimize fuel consumption. Efficiency of an energy center is expressed as heat rate, which is the number of British thermal units (“BTU”) required to produce a kWh of electricity. A higher efficiency is the same as a lower heat rate. As each energy center ages, more and more effort is required to simply maintain the efficiency as the equipment wears. Considerable and continuous effort is expended in both maintaining the equipment to operate as efficiently as possible, and to leverage improving technology when it makes economic sense. Similar efforts are spent in maintaining and improving instrumentation for tracking heat rate and the ability to monitor systems as monitoring and trending technology advances. Each business unit measures the fuel burned and power produced and records the heat rate of the overall unit energy conversion cycles within the boiler and turbine. Individual systems are monitored to determine specific contributions to heat rate, requiring substantial instrumentation for this specific purpose.

Many factors impact the heat rate of each unit. These include, but are not limited to, weather conditions, load levels and fuel quality. Heat rate impact of some systems are longer-term in nature, such as turbine efficiency between stationary and rotating elements or other major equipment condition such as turbine condensers, auxiliary power utilization and large fans and motors. Maintenance of this equipment requires periodic, extended shutdowns the duration of which is dependent upon equipment condition, original manufacturer requirements and overall engineering assessments and judgment.

Larger units use a performance monitoring system that checks the operation of the energy center on a continuous basis. This system tracks operating data of all the equipment in the energy center and compares it to its expected operation. If equipment is not operating as expected, operators are alerted to the discrepancy. Sometimes this can be immediately corrected and other times it requires completely rebuilding, or even replacing, equipment. In all cases, an evaluation must balance the cost of repair against the cost of the efficiency reduction, impacts on reliability, safety and environmental considerations. This system also provides information to the energy center operations personnel to allow them to balance impacts and operate in the most efficient manner. The system is used to help determine when and where to clean the boiler, balance steam temperatures, as well as optimize boiler air flow, turbine steam flow, and balance-of-plant equipment operations. Following are representative heat rates from Minnesota Power’s thermal energy centers.

Table 2: Heat Rate (BTU/kWh) of Largest Thermal Energy Centers

Station	THEC	LEC	BEC
Net Heat Rate	11,300	12,400	10,500

Long-term Resource Operational Integrity

Minnesota Power plans to continue fleet maintenance programs to sustain the economic viability, availability and reliability of its generating units. A continuing Company priority throughout this planning period will be to carefully maintain its generation fleet to ensure productivity and efficiency in operation. A rigorous process is in place to sustain existing production across Minnesota Power's wind-water-wood-coal sources of energy conversion while maintaining an excellent environmental record and meeting more stringent environmental standards.

Minnesota Power effectively operates its units to best serve customers and the regional electric market. A comprehensive reliability-centered maintenance program including employee training, inspections, capital and operating investments, and continually employing Original Equipment Manufacturers ("OEM") requirements and industry best practices is in place to optimally meet customer electric needs.

Part 2: Wholesale Power Transactions

Part 2 of Appendix C presents summary information on power sales and purchases used to balance Minnesota Power's load and capability with particular emphasis on using power purchases to meet small to modest short-term capacity needs. Load serving entities within MISO must provide resource plans each year that show they have enough planning reserve capacity available to meet their resource adequacy requirements. This section provides information on committed transactions, a current transaction summary and a list of planned transactions.

Committed Transactions

Minnesota Power has several committed and continuing wholesale capacity transactions reflected in its load and capability. The capacity purchases and sales are characterized as energy only (participation transaction), capacity only (firm transaction), or capacity and energy (firm transaction). The term "capacity only" refers to a purchase or sale of accredited capacity according to accreditation processes defined by MISO. The term "energy only" refers to a purchase or sale of power that does not include any MISO capacity accreditation value. The term "capacity and energy" refers to a purchase or sale of power including the associated MISO accredited capacity value.

<u>Current Transaction Summary</u>

Capacity and Energy Purchases

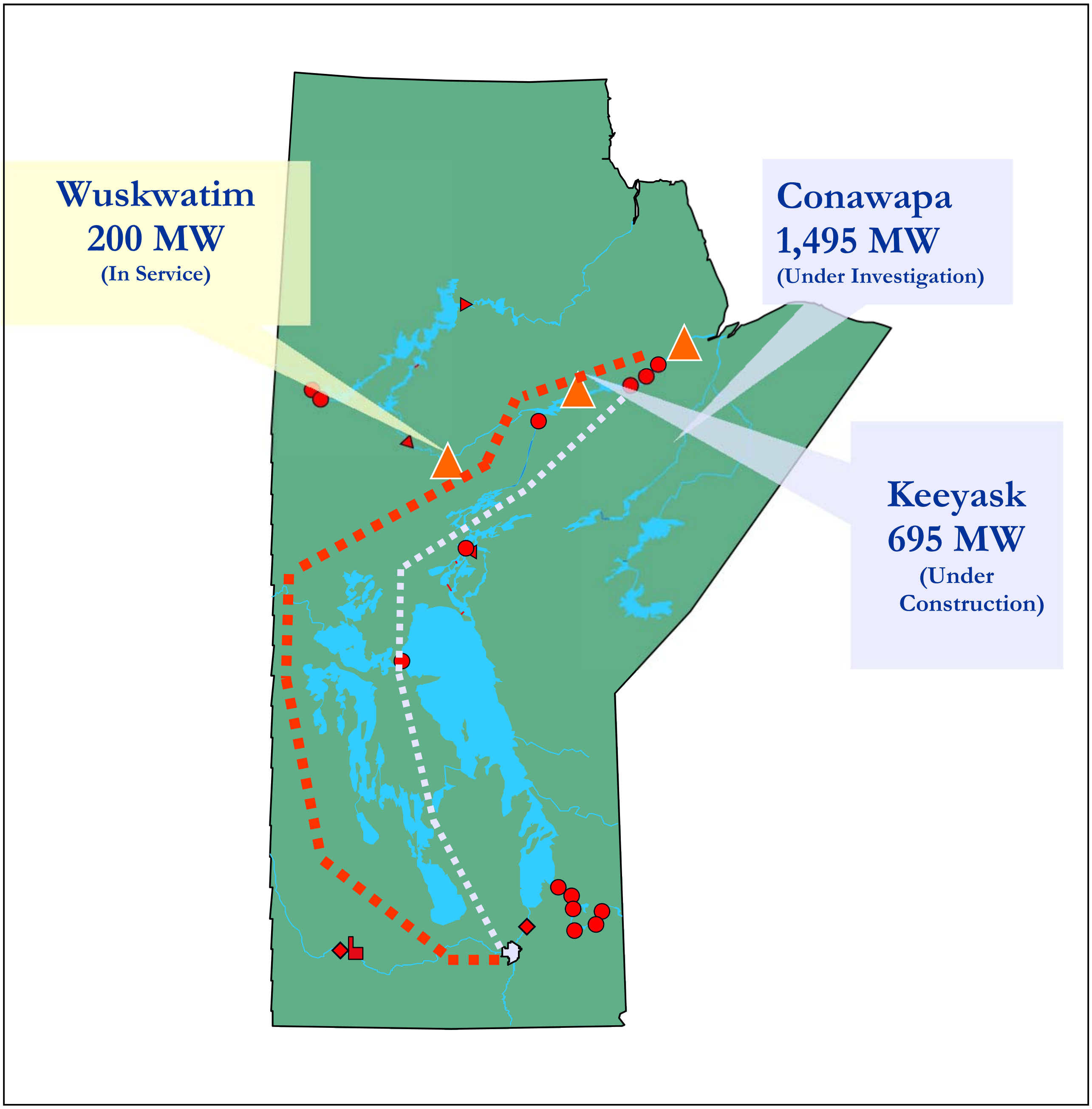
- **Manitoba Hydro-Electric Board ("MHEB")—50 MW:** In December 2013, Minnesota Power entered into an agreement with MHEB for a 50 MW purchase beginning on June 1, 2015, and continuing through May 31, 2020 (Docket No. E015/M-14-926).
- **MHEB—250 MW:** In May 2011, Minnesota Power entered into an agreement with MHEB for a 250 MW purchase beginning on June 1, 2020, and continuing through May 31, 2035 (Docket No. E015/M-11-938).

Manitoba Hydro is currently working towards approximately 900 MW of new hydroelectric expansion along their extensive river system in northern Manitoba. The hydroelectric additions, as shown in Figure 1, include the Wuskwatim (200 MW (in service)), and Keeyask (695 MW) (under construction) facilities along with a prospect for another 1500 MW that would become available if the Conawapa facility (under investigation) were to be approved.

The long-term sales will require the construction of hydroelectric facilities in northern Manitoba and the construction of the Great Northern Transmission Line, a major new transmission facility between Canada and the United States. Minnesota Power is working closely with Manitoba Hydro, MISO and associated parties on the prospective transmission needs for this project (See Appendix F).

As noted in the January 2012 press release by both Minnesota Power and Manitoba Hydro, this purchase is consistent with Minnesota Power's energy strategy for carbon minimizing resource additions and continues the strong, forward-looking and long-standing business relationship between the companies that has existed for decades.

Figure 4: Manitoba Hydro Expansion



In May 2015, the Commission unanimously approved the Great Northern Transmission Line's certificate of need.[13]

- **Minnkota Power Cooperative ("MPC")—50 MW:** In January 2014, Minnesota Power entered into an agreement with MPC for a 50 MW Firm purchase beginning January 1, 2014, and continuing through May 31, 2016.
- **MPC—50 MW:** In December 2012, Minnesota Power entered into an agreement with Minnkota Power Cooperative for a 50 MW Firm purchase beginning June 1, 2016, and continuing through May 31, 2020.
- **Florida Power & Light ("FPL")—50.6 MW**: In May 2005, Minnesota Power entered into an agreement with FPL for a 50.6 MW purchase from the Oliver County wind project beginning on December 28, 2006, and continuing through December 28, 2031.
- **FPL—48 MW:** In December 2006, Minnesota Power entered into an agreement with FPL for a 48 MW purchase from the Oliver County wind project beginning in December 31, 2007, and continuing through December 31, 2032.
- **GRE—50 MW:** In August 2014, Minnesota Power entered into an agreement with GRE for a 50 MW purchase of capacity and energy beginning on June 1, 2016, and continuing through May 31, 2020.
- **Wing River Wind ("Wing River") Community Based Energy Development ("C-BED")—2.5 MW:** In April 2007, Minnesota Power entered into a power purchase agreement with Wing River for a 2.5 MW purchase beginning in November 1, 2007, and continuing through November 1, 2027.

Capacity Only Purchases

- **Laurentian Energy Authority ("LEA")—12.5 MW:** In January 2012, Minnesota Power entered into an agreement with LEA for up to 12.5 MW capacity purchase beginning on January 1, 2012, and continuing through December 31, 2021.
- **Great River Energy ("GRE")—50 MW:** In January 2014, Minnesota Power entered into an agreement with GRE for a 50 MW capacity only purchase beginning on June 1, 2016, and continuing through May 31, 2020.
- **Xcel—50 MW:** In December 2014, Minnesota Power entered into an agreement with Xcel for a 50 MW capacity only purchase beginning on June 1, 2015, and continuing through May 31, 2016.

Capacity and Energy Sales

- **Basin Electric ("Basin")—100 MW:** In October 2009, Minnesota Power entered into an agreement with Basin for a 100 MW Firm sale beginning May 1, 2010, and continuing through April 30, 2020. Minnesota Power is relying on 100 MW of BEC capacity and associated energy to support this transaction.

[13] Docket No. E-015/CN-12-1163.

PUBLIC DOCUMENT
TRADE SECRET DATA
HAS BEEN EXCISED

Capacity Only Sales

- **Basin—50 MW:** In June 2014, Minnesota Power entered into an agreement with Basin for a 50 MW Firm capacity only sale beginning June 1, 2017, and continuing through May 31, 2019. Minnesota Power is relying on 50 MW of Basin capacity to support this transaction.

Energy Only Purchases

- **MHEB—Up to 150 MW:** In April 2010, Minnesota Power entered into an agreement with MHEB for up to 150 MW of energy purchase beginning on May 1, 2011, and continuing through April 30, 2022.
- **MHEB—Up to 133 MW:** In July 2014, Minnesota Power entered into an agreement with MHEB for up to 133 MW of energy purchase beginning on June 1, 2020, and continuing through May 31, 2040.

Energy Only Sales

- **FPL—50 MW**: In March 2014, Minnesota Power entered into an agreement with NextEra for a 50 MW purchase beginning on January 1, 2015, and continuing through December 31, 2015.
- **Alliant Energy Corporation (“AECS”)—50 MW:** In February 2015, Minnesota Power entered into an agreement with AECS for a 50 MW purchase beginning on January 1, 2016, and continuing through December 31, 2016.
- **American Electric Power (“AEP”)—50 MW:** In March 2014, Minnesota Power entered into an agreement with AEP for a 50 MW purchase beginning on January 1, 2015, and continuing through December 31, 2016.

<u>Planned Transactions</u>

Firm Purchases

[TRADE SECRET DATA EXCISED]

Part 3: Small Power Production and Distributed Generation: Projects, Studies and Demonstration Activity

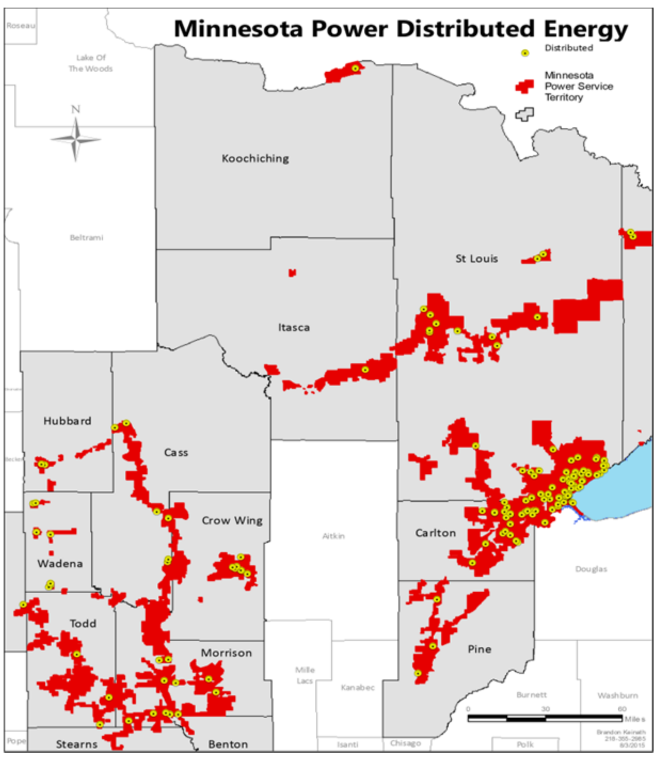
Part 3 of Appendix C summarizes Minnesota Power's small power production as reported in the most recently completed Qualifying Facilities Report in accordance with Minnesota Rules 7835.1300 - 7835.1800.[14] This section also provides updated descriptions of existing DG projects.[15]

Overview

The number of DG systems installed across Minnesota Power's service territory continues to grow each year. As DG technologies become more efficient and less costly, Minnesota Power expects to see this trend continue. The quantity and location of customer installations, including larger industrial cogeneration, has provided for both growing energy and diversity of DG on Minnesota Power's system. Although most of the installations thus far have been smaller customer projects, they are widely dispersed, as shown in Figure 5.

Additional detail on customer DG project installations and Minnesota Power's involvement in community DG and education is provided in the remainder of this section.

Figure 5: Map of Distributed Generation Projects



[14] Docket E999/PR-15-09, March 2, 2015.

[15] The majority of existing DG projects have been funded in part or in whole through Conservation Improvement Program ("CIP") dollars.

Distributed Generation and Small Power Production

For the period of January 2014 through December 2014, as reported in the March 2015 Qualifying Facilities Report,[16] Minnesota Power had a total of 147 interconnected qualifying facilities under the net energy billing rate, 15 of which were wind and 132 of which were photovoltaic systems (see Table 3). This represents a total of approximately 937 kW of customer DG installations.

Table 3: Minnesota Power Net Metering Customers

Net Metering Customers			
	Total	Wind	Photovoltaic
Total Installations	147	15	132
Total Capacity (kW)	937.3	175.2	762.1
Total Net Exports to Minnesota Power (kWh)			
	Total	Wind	Photovoltaic
TOTAL	378,422	58,988	319,434
Total Net Imports from Minnesota Power (kWh)			
	Total	Wind	Photovoltaic
TOTAL	4,635,459	107,824	4,527,635
Total Net Metered Electricity Purchased by Minnesota Power (kWh)			
	Total	Wind	Photovoltaic
TOTAL	138,365	33,129	105,236

As is referenced in Minnesota Power's Qualifying Facilities Report, installations of net metered distributed generation projects continue to be added each year. These projects receive a net energy billing rate. This rate applies to sellers with DG facilities rated at less than 1 MW. The net energy billing rate is generally paid out at the average retail rate, based on customer class.

[16] Docket E999/PR-15-09, March 2, 2015.

Customer Renewable Energy (“RE Program”)

Minnesota Power has a long-standing history of encouraging the adoption of renewable energy options. The RE Program originated from the “Renewable Energy Technology Assessment Study” performed in 2003 and is currently part of Minnesota Power’s Conservation Improvement Program.[17] Using a market-building approach to deliver small-scale renewable energy options to northern Minnesota, this program has focused on photovoltaics (“PV”), wind turbines (“WTG”), biomass and solar thermal renewable energy technologies, as well as key infrastructure aspects related to each technology through provider network development and site-based installations.

This is a multi-year, multi-phased, comprehensive program designed to impact the market for small scale (less than 40 kW) renewable energy/distributed generation (RE/DG) technologies. Minnesota Power has participated in a number of successful site-based renewable energy projects that have begun to transform the regional market. Minnesota Power has worked with a variety of stakeholders including educational institutions, manufacturers and distributors, the Department, and trade allies over the last several years in the pursuit of the shared goal of expanding the availability and customer adoption of renewable energy technologies.

Minnesota Power views renewable energy as an important and growing part of the energy landscape. Through its Conservation Improvement Program and Renewable Programs, Minnesota Power strives to equip customers with accurate and unbiased information regarding the application of renewable energy technologies. The RE Program provides customers with the tools and resources needed to make informed choices about their energy investments while continually reinforcing the objectives of the broader conservation program through which it is funded - that being “conservation first”.

Photovoltaic (Solar Electric) Projects

Also part of the RE Program is the SolarSense rebate program. In place since 2004, this program promotes the development of solar electric and solar thermal systems. It was originally designed to complement the State of Minnesota Solar Electric Rebate Program and was set up to leverage the state review process as a prequalification; thereby minimizing internal administrative costs and exemplifying effective collaboration. The SolarSense program was redesigned to include a tiered incentive when the State of Minnesota’s Solar Electric Rebate Program was discontinued indefinitely in 2011. Examples of projects in this program include:

UMD Bagley Nature Center

Minnesota Power worked with the University of Minnesota Duluth (“UMD”) to install a 5.6 kW solar PV system in the fall of 2009 at the Bagley Nature Center adjacent to the campus. This building is being used to demonstrate high performance building systems and sustainable design.

[17] Minn. Stat. §§ 216B.2411, subd. 1(a) and 216C.412, subd. 2.

Minnesota Department of Natural Resources (“DNR”) McQuade Safe Harbor

In 2009, the Minnesota DNR installed a 2 kW solar PV system at the safe harbor and boat launch on Lake Superior, just north of Duluth. Minnesota Power worked with the Minnesota DNR to develop educational signage detailing system specifications and the role of solar energy in relation to efficiency and conservation.

Cohasset Elementary School

Independent School District #318 installed a 2.88 kW solar PV system in 2009 to educate students about renewable energy. Minnesota Power worked closely with the school district to have energy efficiency education incorporated into the curriculum.

First National Bank of Chisholm

This system was installed in 2009 as a 9.84 kW solar PV system on the roof to demonstrate their commitment to green energy. It has since been expanded, exemplifying an emerging trend where systems are being installed with the intent to expand.

Fond Du Lac Ojibwe School

The school installed a 3.15 kW solar PV system on the roof of the Powwow pavilion building, used for student and tribal education, in Cloquet, Minn. The installation was completed in 2008.

Photovoltaic system at the Duluth Library

The Duluth Library installed a 2 kW rooftop PV unit to demonstrate their commitment to green energy. This project leveraged CIP research and development dollars with Rebuild Minnesota and the Legislative Commission on Minnesota Resources grants.

UMD Malosky Stadium

UMD installed a 5.8 kW fixed panel solar PV system on the top of the newly renovated Malosky Stadium in the summer of 2008. The project was completed in November of 2008 and included a training opportunity for UMD engineering students and faculty team.

St. Louis County Government Services Center (“GSC”)

Working with Minnesota Power and the University of Minnesota Duluth Natural Resources Research Institute (“NRRI”), St. Louis County purchased and installed three solar arrays in 2014, each from a different manufacturer, on the roof of the GSC in downtown Duluth. As a neutral agency, NRRI is monitoring the systems to understand the environmental, economic and performance impacts of different technologies in a northern climate. The insights gained from this project will be used as part of an ongoing effort to provide educational resources for customers about solar energy installations.

Wind Turbine Projects—Community Wind Power Project

As part of the Customer Renewable Energy Program, Minnesota Power has provided funding and assisted in the installation of several community-based wind turbine projects within its service territory.

The primary objectives of the Community Wind Power Project are to:

- Increase public awareness of the importance of efficient energy use and renewable energy technologies—specifically wind energy;
- Facilitate, through CIP funding grants, public demonstrations of grid-connected, small-scale wind power technology ($\leq$ 40kW);
- Encourage the development of real-life working examples of renewable, wind energy technology that reinforce the principles of math and science and that can be integrated into classroom discussions and other public educational opportunities.

Each of the wind projects serves as a community-wide educational resource for wind energy technology and energy conservation. Examples over the past several years have included:

Hunt Utilities Group, Pine River

The 20 kW turbine is a component of the research and education organization that promotes ecological buildings, renewable energy and sustainable living. This project was installed in 2006.

Park Rapids High School

The 20 kW turbine is part of the science, physics and environmental curriculum. This project was installed in 2007.

Minnesota Air National Guard

This project includes five building-mounted wind turbines, 1.5 kW each, installed on a cold storage building near the Duluth Airport. It was installed for demonstration and research purposes. This project entered operation in 2011. Further details about these projects and additional projects are reported in Minnesota Power's annual Conservation Improvement Program consolidated filings.

Other Small Power Project Descriptions

WLSSD Microturbine Biogas Project

The Western Lake Superior Sanitary District ("WLSSD") located in Duluth, Minn., is a municipal waste treatment facility that currently produces biogas as a function of processing wastes. This biogas can be used to produce electric energy for plant operations. This application has widespread potential for technology transfer (use of a modified microturbine to process methane gas) and the optimization of an otherwise discarded or underutilized fuel source. In 2003, two 70 kW microturbines with gas cleanup systems were installed through the joint efforts of a manufacturer, a performance contractor, WLSSD staff and board of directors and Minnesota Power. All parties contributed financial, technical and operational resources. It was one of the first installations of its kind in the world with a state-of-the-art fuel conditioning system.

Long term, Minnesota Power viewed this project as an initial step toward helping build the infrastructure and better understanding the customer motivation necessary to deliver successful DG projects. This involves determining non-energy benefits, e.g., environmental, noise, odor reduction, maintenance, etc., that influence customer decision-making, the key stakeholders required to design and implement projects, and the potential to leverage CIP dollars to package financially feasible projects.

Although the initial operating results of the unit found it to be performing better than nameplate parameters, maintenance issues were encountered. The primary issue was with the methane gas clean-up system and not with the turbine/generator. Unlike natural gas, the methane produced by the anaerobic digester contains contaminants that, if not removed, will degrade the turbine. One of the key components of the cleanup system is a cooling system that condenses the moisture and other condensable gases in the raw methane to remove the bad actors that would impact the performance of the turbine. The poor performance of this system caused major operational issues for the project and it is no longer in service. Key lessons learned from the project are:

- There is technology risk when implementing projects that have components that are new or early versions of new technology.
- Customers that deploy new technologies need to be aware that distributed generation, like any other equipment, requires resources that can detract from their primary focus. This issue is magnified if unforeseen issues arise.
- When suppliers of equipment utilize subcontractors or vendors for subsystems that they do not manufacture, the additional layer can impact responsiveness when issues occur.

Hartley Nature Center (“HNC”) Distributed Generation Project

This project, located in Duluth, Minn., was completed in 2002. Using Minnesota Power CIP funding, HNC installed an 11.5 kW roof-mounted solar PV system, a 2.5 kW PV tracker system and an eight-ton geothermal heat pump system to provide heat and power for its new facility. In addition, it has installed a real-time performance monitoring system that provides energy and environmental data in electronic format on HNC’s web site.

Rebuild Minnesota—Renewable Energy for Sustainable Communities (Lake Superior Zoo)

In 2002, a group of local stakeholders began a collaborative effort to initiate a renewable project at the Lake Superior Zoo. In 2005, a 2.9 kW solar PV system was installed on the roof of the parking pavilion used to park the zoo maintenance vehicles. The PV system provides electricity to charge the zoo’s electric vehicles.

An interactive solar electric (PV) display was located at the PV shelter, allowing visitors the opportunity to interact with a working solar panel and learn more about the relationship of solar radiation, sun angle and shading effects.

Minnesota Power Industrial Cogeneration Descriptions

Rapids Energy Center (30.1 MW)

The REC is an efficient combined heat and power facility capable of burning wood, wood wastes, coal and natural gas. The facility serves both Minnesota Power electric customers with its generation as well as the adjacent UPM/Blandin Paper Mill with process steam. This mutually supportive generation of both steam and electricity from the facility captures synergies in production and provides efficiencies in generation.

The facility supports local, industrial-scale generation of steam which is used right on site, and energy which is supplied to Minnesota Power customers. These cogeneration attributes and the industrial sized scale make it a unique application of DG at a scale in between the small customer implementation and the traditionally large utility generation installations.

Cloquet Energy Center (22.8 MW)

Minnesota Power is currently in cooperation with SAPPI Fine Paper at its paper mill in Cloquet, Minn. At this facility, high pressure steam produced in a recycle boiler is reduced in pressure by utilizing a backpressure turbine that typically generates approximately 22 MW of low cost energy for Minnesota Power customers including SAPPI. Much of the energy in the steam would not be available for beneficial use if pressure reduction was completed through a more conventional pressure reducing valve. This facility also has the benefit of generating electricity close to a major point of use, lessening strain on transmission and distribution networks.

Hibbard Renewable Energy Center (62 MW)

Minnesota Power continues to develop a second industrial scale DG project at its HREC. This project will also optimize the renewable energy generation at the facility while still providing steam to the adjacent Verso Paper Mill. The project petition was conditionally approved by the Commission in September 2009, but continued evolution and optimization of project timing has delayed implementation to a date later in Minnesota Power's planning horizon.

Renewable Energy Training Forums

In a market-building approach, Minnesota Power participates, hosts and sponsors a multitude of training opportunities to educate customers, communities and contractors about small scale renewable energy applications. Most recently, Minnesota Power has been involved in training offerings for electrical inspectors, local educators, students, utility personnel, customers and more.

In addition to ongoing training efforts throughout the year, Minnesota Power hosts the annual Energy Design Conference and Expo where renewable energy is a regularly featured topic. In its twenty-fifth (25) year, this event delivers a diverse selection of quality seminars and workshops to a variety of building, housing, and environmental professionals along with educators, students, homeowners, and others.

With the introduction of the Solar Energy Standard, Minnesota Power has further expanded its educational offerings. Refer to the recently filed Solar Energy Standard Compliance filing[18] for a detailed description of recent training efforts specific to solar energy.

[18] Docket No. E999/M-15-462, June 1, 2015.

APPENDIX D: FUTURE RESOURCE OPTIONS

Overview

This Appendix provides information regarding the supply side resource technologies that were incorporated into the planning analysis conducted in Section IV. The resource technologies were utilized in the expansion plan optimization of the Strategist production cost model, along with demand side alternatives discussed in Appendix B. The information in this Appendix was essential in defining the attributes of each supply side resource alternative. The following information is included for each resource option:

- Resource Technology Descriptions
- Technology Sensing and Application

Resource Option Listing

Through the planning process, Minnesota Power (or "Company") identified the potential resources to meet future energy and capacity needs. The options below were considered at the beginning of the planning process:

Short-term Bilateral and Market Purchases

- Market capacity purchase of 50 MW available through 2029
- Bilateral bridge purchase of 50 MW available through 2019

New Generation

- Coal-based: Super Critical Pulverized coal and Integrated Gasification Combined Cycle ("IGCC"), with carbon dioxide ("CO_2") capture and sequestration ("CCS")
- Gas-based: Combustion turbine ("CT"), Combined Cycle ("CC") and Reciprocating Engine
- Renewable-based: biomass, wind, hydroelectric and solar generation
- Nuclear: traditional and small modular
- Energy Storage: batteries and pumped hydroelectric

Resource Technology Descriptions

Short-term Purchases

<u>Market Capacity</u>

The capability to purchase up to 50 MW of bilateral capacity has been developed as a capacity resource that can be selected during the 2015–2029 period in 1 MW increments. Market energy is associated with this capacity purchase and is available to the expansion planning process by modeling a Midcontinent Independent System Operator ("MISO") market energy option. Short-term purchases of all types (peaking, intermediate or base load) are included in all plans by modeling market purchases from MISO.

Bilateral Bridge Purchase

An unidentified 50 MW bilateral purchase, referred to as a "bridge purchase" was made available as a new resource alternative in the 2015 through 2019 time period. The bilateral transaction is made available based on the market indications of available energy and capacity during this timeframe that Minnesota Power has received through its recent power contracting activity.

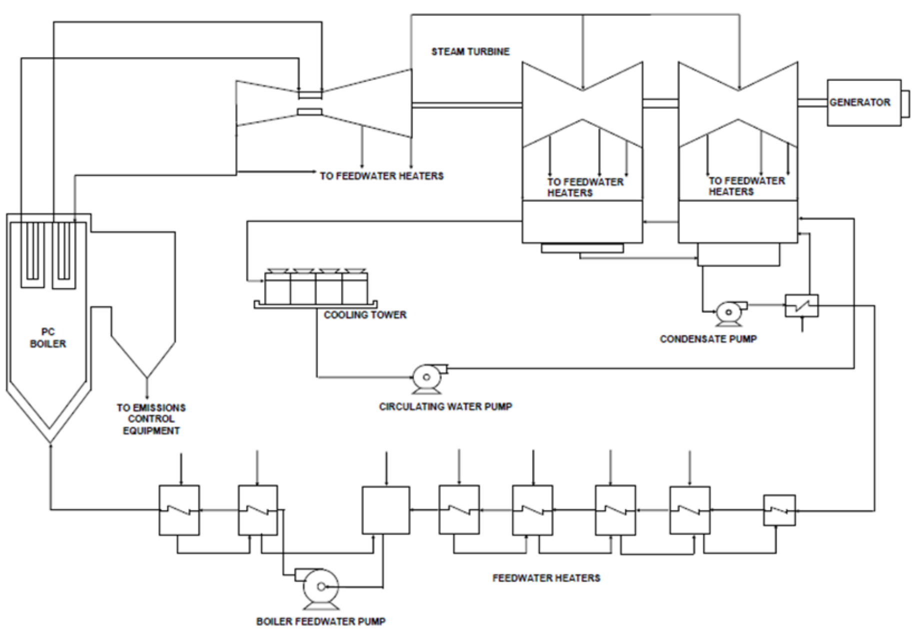
New Generation

Pulverized Coal Generation

Pulverized coal ("PC") technology is a reliable energy producer throughout the world. PC technology can be divided into two distinct designs, distinguished by the maximum operating pressure of the cycle, either subcritical or supercritical. The terms refer to the state of the water used in the steam generation process. The critical point of water is 3,208.2 psia[1] at 705.47 degrees Fahrenheit ("°F"). Subcritical power plants use pressures below this point and supercritical power plants use pressures above it. Supercritical and ultra-supercritical steam generators are generally more efficient than subcritical units of the same size resulting in fuel savings and decreased emissions. To minimize the carbon footprint of the plant, for purposes of this assessment, a supercritical design has been evaluated.

The main components of the PC unit are shown in Figure 1.

Figure 1: PC Unit Diagram



[1] PSIA is the acronym for pounds per square inch, absolute.

Coal from bunkers is fed into pulverizers, which crush it into fine particles. The primary air system transfers the fine coal particles to the steam generator burners for combustion. In the boiler, high-pressure steam is generated for the steam turbine. The expansion of the steam through the turbine provides the energy required by the generator to produce electricity. The steam turbine exhausts into a condenser. The heat load of the condenser is typically transferred to a wet cooling tower system (assumed for purposes of this study). The condensed steam is then returned to the steam generator through the condensate pumps, low-pressure feedwater heaters, deaerating heater, boiler feed pumps and high-pressure feedwater heaters.

Carbon Dioxide Capture and Sequestration

Capture

For PC technology, the capture of the CO_2 from the combustion byproducts is done on a post-combustion basis. Carbon capture technologies for pulverized coal-based generation continue to develop as more demonstration projects move forward. The coal unit in this assessment includes CCS using the advanced amine process. The advanced amine process is an enhancement on the Monoethylamine ("MEA") process that was developed over 60 years ago, and has been adapted to treat flue gas streams for CO_2 capture. Other organic chemicals belonging to the family of compounds known as "amines" are now being used to reduce cost and power consumption as compared to the traditional MEA solvent. Numerous companies are developing their own proprietary amine solvents including Fluor Corporation, Hitachi, Ltd, MHI (Mitsubishi Heavy Industries Ltd), Shell, and other companies.

The amine technology is the most developed of the large scale coal plant CCS technologies on the market. In the advanced amine process, a continuous scrubbing system is used to separate CO_2 from the flue gas stream. The system consists of two main elements: an absorber where CO_2 is removed from the flue gas and absorbed into an amine solvent, and a regenerator (or stripper), where CO_2 is released (in concentrated form) from the solvent and the original solvent is then recovered and recycled. Cooled flue gases flow vertically upwards through the absorber countercurrent to the absorbent (amine in a water solution, with some additives). The amine reacts chemically with the CO_2 in the flue gas to form a weakly bonded compound, called carbamate. The scrubbed gas is then washed and vented to the atmosphere. The CO_2-rich solution leaves the absorber and passes through a heat recovery exchanger, and is further heated in a reboiler using low-pressure steam. The carbamate formed during absorption is broken down by the application of heat, regenerating the sorbent and producing a concentrated CO_2 gas stream. The hot CO_2-lean sorbent is then returned to the opposite side of the heat exchanger where it is cooled and sent back to the absorber. Fresh reagent is added to make up for losses incurred in the process.

In North America, multiple CCS projects are under construction or being developed. SaskPower has completed their Boundary Dam 150 MW CCS project that utilizes the Shell Cansolv amine-based post combustion capture system. Boundary Dam started up in October 2014. NRG Energy, Inc. is developing a CCS system at their existing Parish facility. The 250 MW slipstream will utilize Fluor's amine based post combustion capture system. The Texan Clean Energy project is developing an IGCC unit with CCS. All three of these projects will utilize the captured CO_2 for enhanced oil recovery ("EOR").

Sequestration

Other than the mid-continent rift, no potential geological sequestration sites exist in Minnesota. It is important to note that the mid-continent rift requires extensive evaluation that will require many years of research at a high cost before it can be determined if it is a viable sequestration site. Potential EOR, coal bed methane and saline aquifer sequestration sites have been identified and characterized in North Dakota. Of the identified sequestration options, only EOR has been commercially proven. The existing commercial EOR project is able to obtain value for the CO_2 because of the value of the additional oil that is produced. The long-term "value" of CO_2 will be impacted by the amount of CO_2 that is available in the region, which is also subject to the number and size of carbon capture projects that are installed. Therefore, for the purposes of the resource assessment, a North Dakota EOR site was selected for sequestration for both plant location options. No commodity value was assigned for the CO_2.

Location

The location of a new coal generating resource for Minnesota Power would be dependent on the ability to site and permit the facility as well as the fuel, transmission, and carbon implications of the proposed location. Since both Minnesota and North Dakota siting options have been assessed historically in previous resource plans for a new Minnesota Power coal resource, the same possible locations were used as the starting point in the assessment for the 2015 Plan. Utilizing the high level coal resource location screening assessment from Appendix D of Minnesota Power's 2010 Integrated Resource Plan (Docket No. E015/RP-09-1088), the benefits and challenges when selecting either a Minnesota or North Dakota location for a new coal resource are as shown in Table 1.

Table 1: New Coal Resource Location Considerations

	Minnesota Powder River Basin Coal	North Dakota Lignite Coal	
Fuel Cost	Higher	Lower	North Dakota mine mouth plant eliminates the cost of rail.
Capital Costs	Lower	Higher	Lignite fuel characteristics require a larger boiler.
Transmission	Lower	Higher	Minnesota location will be closer to the load centers.
Sequestration Costs	Higher	Lower	North Dakota mines are adjacent to sequestration options, reducing the amount of capital for CO_2 piping and the operating costs of the compressor booster stations.
Impact on the limited northeast Minnesota Air Shed Increment	High	Low	The limited northeast Minnesota Air Shed increment is important to Minnesota Power's natural resource based customers who can't relocate their operations.

In addition to these considerations, the state of Minnesota has legislation in place regulating the addition of any new generation resource in the state which emits greenhouse gases,[2] as well as legislation regulating the import of coal-based energy,[3] affecting either a new Minnesota or North Dakota coal resource addition for Minnesota Power.

Based on consideration of the factors above, a North Dakota location was selected for consideration as a potential resource to meet future needs in the expansion plan.

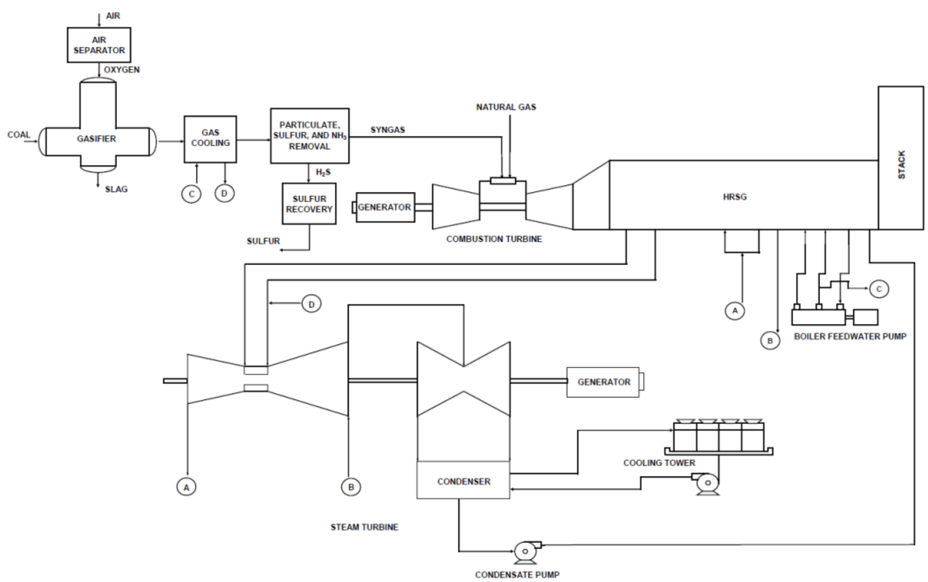
Integrated Gasification Combined Cycle Generation

Integrated Gasification Combined Cycle technology integrates a gasification block with a combined cycle power block. The gasification process produces a low calorific value synthesis gas ("syngas") from a solid fuel coal or solid waste. Pollutants are removed from the syngas prior to combustion in a CC power block consisting of syngas-fired gas turbines, heat recovery steam generators (HRSG), and a steam turbine. Gasification is a proven technology used extensively in the chemical industry for the production of chemicals, such as ammonia and methanol.

Using coal as a solid feedstock to a gasifier to produce electric power in a CC unit is not as commercially proven as solid fuel combustion for power generation; however, there are two existing IGCC facilities in the United States with long term operating experience, the Wabash River Power Station in West Terre Haute, Indiana and the Polk Power Station in Tampa, Florida.

The main components of the IGCC unit are shown in Figure 2.

Figure 2: IGCC Unit Diagram



Gasifiers designed to accept coal as a solid fuel are grouped into three categories: entrained flow, fluidized bed, and moving bed.

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[2] Minn. Stat. § 216H.03.

[3] Minn. Stat. § 216H.03, subd. 3(2), see also *North Dakota v. Heydinger*, 15 F Supp. 3d 891 (D. Minn. 2014); appeal pending North Dakota v. Heydinger, 8th Cir. May 30, 2014.

Entrained Flow

The entrained flow gasifier reactor design is based on coal conversion in suspension with the ash converted into molten slag. This design utilizes high temperatures with short residence time and will accept either liquid or solid fuel. GE Energy, ConocoPhillips (E-Gas technology), Siemens Power Generation, ThyssenKrupp Industrial Solutions (Prenflo) and Shell are some of the manufacturers of gasifiers of this design.

Fluidized Bed

Fluidized-bed reactors efficiently mix feed coal particles with coal particles already undergoing gasification. Fluidized bed gasifiers accept a wide range of solid fuels but are not suitable for liquid fuels. Gasifiers produced by KRW Energy Systems and a High Temperature Winkler design are based on this technology.

Moving Bed

In moving bed reactors, large particles of coal move slowly down through the bed while reacting with gases moving up through the bed. Moving bed gasifiers are not suitable for liquid fuels. One design with extensive experience is the Lurgi Dry Ash gasification process used both at the Dakota Gasification plant for production of synthetic natural gas (“SNG”) and the South Africa Sasol plant for production of liquid fuels.

The majority of experience that utilize coal as feedstock use the entrained flow gasification design and was assumed as the basis of this assessment. Pulverized coal with water and oxygen from an air separation unit (ASU) is fed into the gasifier at around 450 psig[4] to be partially oxidized. The raw syngas produced by the reaction in the gasifier exits at around 2,400°F and is cooled to less than 400°F in a gas cooler, which produces additional steam for both the steam turbine and gasification process. The cooled syngas is then fed into the modified combustion chamber of a gas turbine specifically designed to accept the low calorific syngas. Excess heat from the gas turbine is recovered in a HRSG. Reliability issues associated with fouling and/or tube leaks within the syngas cooler have challenged the existing IGCC installations. The syngas cooler greatly improves thermal efficiencies when compared to a quench cooler system typical of those utilized in chemical production gasifiers.

Fuel Considerations

The IGCC technology is most competitive from a performance standpoint with high rank coals. PC and IGCC performance is comparable with sub-bituminous coals subject to the viability of the IGCC to burn a high sodium coal. IGCC technology has not been demonstrated on lignite fuels and is also projected to be at a performance disadvantage relative to PC technology. Note: There is a commercial scale project currently in construction/start-up in the southeastern part of the United States utilizing low-rank lignite, the Kemper County Project.

[4] PSIG is the acronym for pounds per square inch gauge.

Carbon Dioxide Capture and Sequestration

Capture

For an IGCC technology, the capture of the CO_2 is completed prior to combustion utilizing commercially available CO_2 removal technologies, such as UOP's proprietary Selexol™ solvent. To achieve high levels of carbon capture (90 percent) from an IGCC facility, further development of the gas turbine technology to combust a high hydrogen fuel is necessary. Therefore, for the purposes of the resource assessment, the commercially available technology was chosen with the assumption that the gas turbine is capable of burning a straight hydrogen fuel.

Sequestration

See the PC technology section for a discussion of sequestration.

Natural Gas Technologies

Gas Turbine Simple Cycle Generation

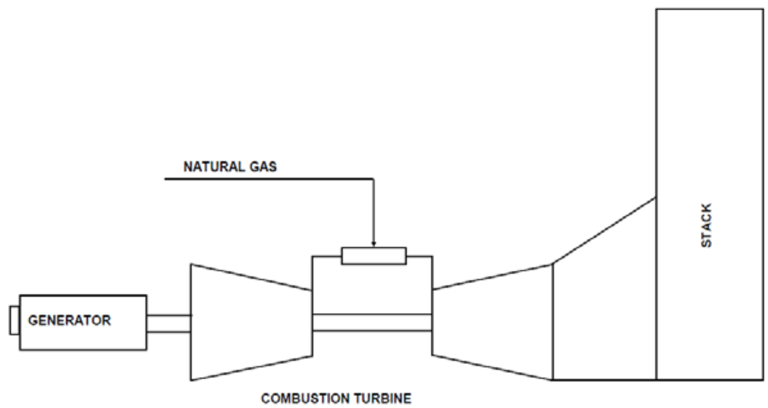
The gas turbine cycle is one of the most efficient ways to convert natural gas or fuel oil to mechanical power or electricity. A simple cycle gas turbine consists of a compressor section, combustor, and turbine section. Ambient air is compressed in the compressor. Fuel is mixed with the compressed air in the combustor section. The combustion products exit the combustor and expand through the turbine section. Typically, more than 50 percent of the turbine shaft work produced is consumed by the compressor section. The remaining shaft work is used to drive a generator. The exhaust gas exits at approximately 800–1,200°F through the exhaust stack. The simple cycle gas turbine also provides the benefit of a generation facility that can be readily converted to a larger combined cycle generation unit to quickly (within 24 months) provide additional capacity and energy to support significant load generation.

Gas turbines are broken up into two main categories, aero derivatives and frames. An aero derivative engine is based on jet engine design for airplanes so they are robust, fast starting, low maintenance and very efficient. The aero derivative uses high quality alloy materials which allow them the ability to endure much higher cycling with lower maintenance costs. Aero derivative maintenance is not affected by startups and is only based on hours of operation. Based on these characteristics, the aero derivative is typically used as a peaker or for load following that requires very high cycling. Aero derivatives are more expensive on a $/kW basis compared to a frame and the largest turbines generate approximately 100 MW. Also due to their high efficiency and subsequent low exhaust temperatures (800-1,000°F), the aero derivatives are less economical to convert to combined cycle.

The frame gas turbines are much larger and heavier than the aero derivatives. They have traditionally had longer start times, are less efficient than the aero derivatives, require more maintenance that is start and hour based, but are much larger and less expensive on a $/kW basis. The largest frame gas turbines exceed 300 MW per engine. The frame gas turbine is also very conducive to combined cycle conversion since they have much higher mass flow and exhaust temperatures (1,000-1,200°F) compared to the aero derivatives. Recently, gas turbine manufacturers have been pushing designs for faster start times, higher efficiencies, and larger engines. Frame gas turbines have become much more flexible in the past years but are still not comparable to aero derivatives.

The main components of a simple cycle gas turbine unit are shown in Figure 3.

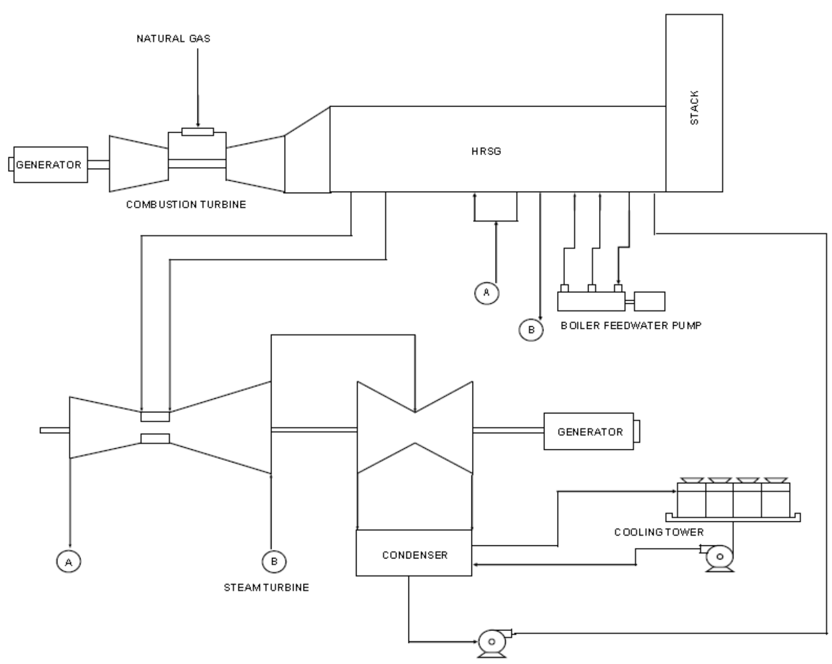
Figure 3: Simple Cycle Unit Diagram



Gas Turbine Combined Cycle Generation

The use of both the gas turbine cycle (Brayton Cycle) and the steam turbine cycle (Rankine Cycle) in a single plant is referred to as a gas turbine combined cycle. The basic principle of the CC is to fire natural gas (or fuel oil) in a gas turbine, which produces power directly via a coupled generator. The exhaust from the turbine is used to create steam in a HRSG that can drive a steam turbine generator. The main components of a combined cycle unit are shown in Figure 4.

Figure 4: Combined Cycle Unit Diagram



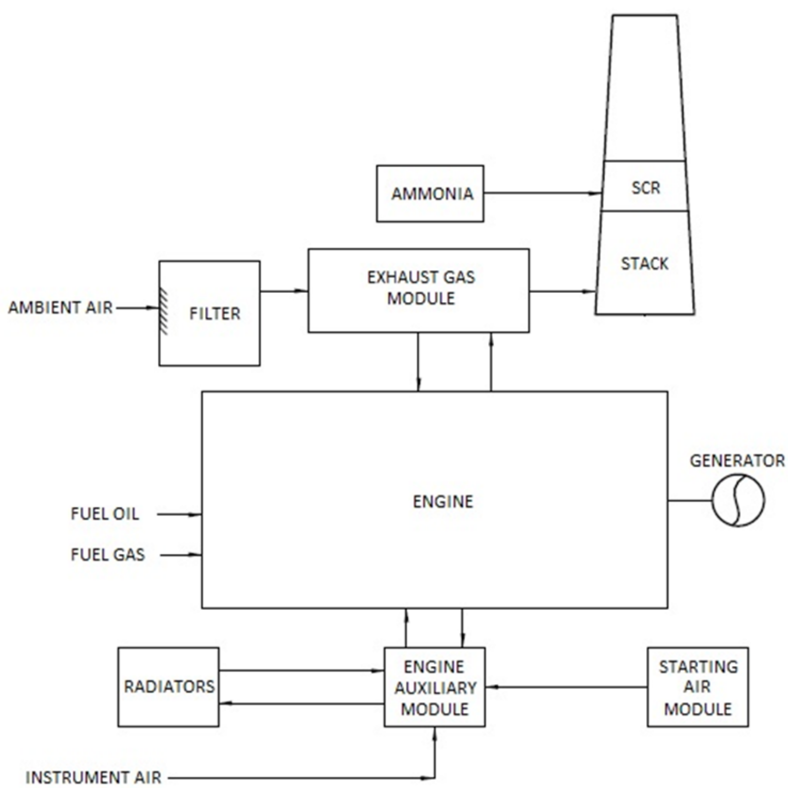
A CC facility results in high energy conversion efficiencies and low emissions (with selective catalytic reduction ("SCR") and CO_2 catalyst). The gas turbine cycle, as noted above, is one of the most efficient for converting fuel (natural gas or fuel oil) to mechanical power or electricity. Adding a steam turbine to utilize the steam produced by the HRSG increases the efficiencies to a range of 52 to 60 percent lower heating value. To increase peaking power output, additional natural gas firing (duct firing) can be performed in the HRSG, and steam can be injected into the gas turbine for power augmentation.

Gas turbine CCs can be arranged in multiple configurations. The diagram above shows a 1x1 configuration (one gas turbine/HRSG and one steam turbine). A 2x1 configuration would include two gas turbines/HRSG's feeding one steam turbine. Assuming the same gas turbines, a 2x1 plant will generate approximately twice as much power as a 1x1 plant. A 2x1 plant will also have a slightly higher efficiency.

<u>Reciprocating Engine Generation</u>

A reciprocating engine utilizes the Carnot cycle to mechanically convert fuel to energy. The reciprocating engine burns fuel in a combustion chamber which pushes a piston connected to a crankshaft which turns the generator. Most large reciprocating engines for power generation have 18 or 20 cylinders and the largest engines generate approximately 18 MW. Multiple banks of engines are typically installed to meet generation needs and result in a highly dispatchable facility. The main components of a reciprocating engine are shown in Figure 5.

Figure 5: Reciprocating Engine Diagram



A reciprocating engine's efficiency is approximately 45 percent lower heating value. It is as efficient as the most efficient simple cycle gas turbines. A reciprocating engine for power generation comes standard with an SCR and CO_2 catalyst to control oxides of nitrogen ("NO_X") and CO_2. With these controls, reciprocating engines have low emission rates but not as low as CC gas turbines.

Renewable Technologies

Biomass Generation

The term biomass refers to any fuel that can be grown, harvested and regrown. For the purposes of this estimate, untreated wood products such as mill and forest residue are assumed as fuel. Wood-fired boilers are typically a derivative of older stoker type designs, or the newer bubbling fluidized bed design, and range in size from 10 to 50 MW.

Potential alternative biomass fuels are agricultural residues such as straw from cereal production, residues from crop processing, and energy crops grown specifically for use as a fuel.

The steam cycle and main components of a biomass unit are similar to those of a PC unit shown in Figure 1, with the exception of the reheat cycle. For units of this size, the capital cost and complexity added by addition of a reheat cycle are not often economically justified.

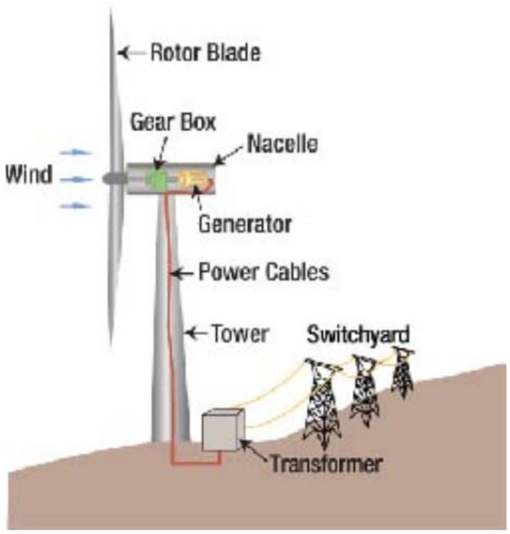
Wind Generation

Although man has captured the energy in wind for centuries, the rapid evolution of wind turbine technology has progressed in recent years resulting in wind turbine generators becoming a standard resource option on a utility scale. Key to that evolution has been the ramp up in the size of the units that has given them the economy of scale required to be competitive. Although the larger size units have been a key part of the puzzle, it is critical that the turbines are located in an area with a good wind resource to yield an effective renewable energy resource. The basics of wind are the conversion of the kinetic energy in wind to turn a shaft that turns a generator. Locations that have a high average velocity of wind over a large area of land are key to making a viable energy resource.

Minnesota Power has two logical location options available for wind: Minnesota Power service territory in northeastern Minnesota and North Dakota. Within Minnesota Power service territory, the best wind resource is located along the Laurentian Divide near the active mining areas. Although the wind in the area is only rated "good" it has the advantage of being located close to the load, which minimizes the need for transmission. Conversely, North Dakota has areas with "excellent" wind that yield a lower busbar cost, but it is located in an area that has transmission constraints.

Wind being a variable resource, available only when there is sufficient wind, in of itself cannot sustain the needs of a reliable electric system. Instead, it needs to be coupled with other dispatchable resources or energy storage to provide an effective role in the overall system that demands high levels of reliability.

Figure 6: Wind Generator Diagram

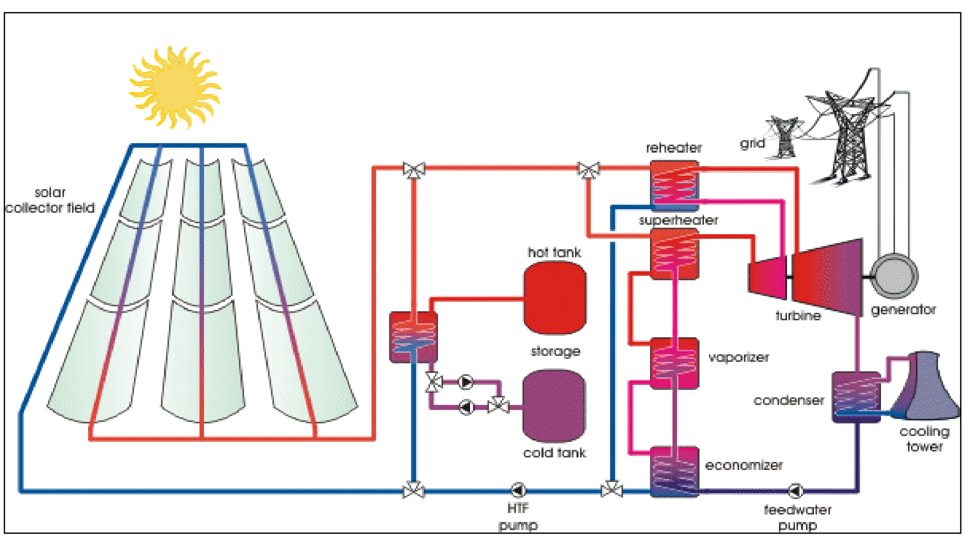


Solar Generation

Solar energy utilized for electric generation is typically classified into solar thermal and photovoltaic generation.

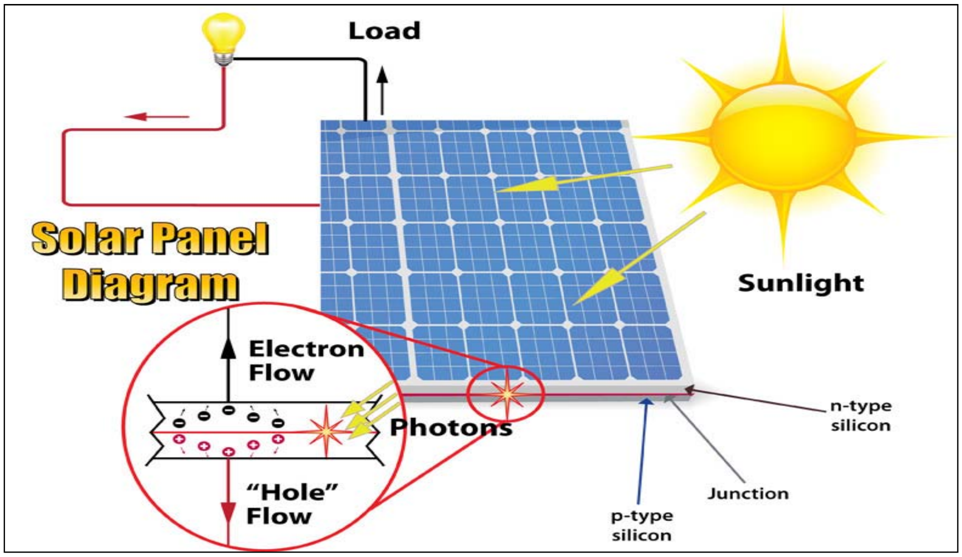
Solar thermal as shown in Figure 7 reflects the radiation in the sun's rays onto a tube or a central tower where it is captured in the form of heat and is ultimately converted into electricity with a rankine or binary cycle similar to what occurs at a conventional coal plant. Solar thermal is most economical in the desert areas of the southwest where there is limited cloud cover to diffuse the energy. The less than optimal atmospheric conditions coupled with abundant lower-cost renewable alternatives make solar thermal a non-competitive utility scale option in the upper Midwest.

Figure 7: Solar Thermal Diagram



Photovoltaic ("PV") generation directly converts the energy in sunlight into electricity when the semiconductors absorb the photons in the sunlight. There are two primary types of PV cells: crystalline silicon and thin film. Figure 8 demonstrates this technology.

Figure 8: Photovoltaic Diagram

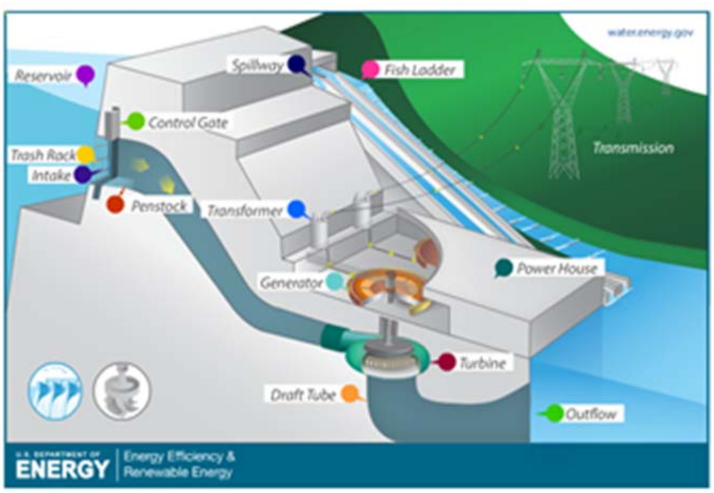


HydroElectric Generation

Hydroelectric generation, which is the conversion of energy from flowing water due to gravity into electrical power, has been utilized since the nineteenth century. In today's electricity market, it constitutes as the largest source of electricity produced from renewable resources, accounting for 7 percent of the nation's total electricity throughout the last decade.

Similar to natural gas or coal-fired power plants, most hydroelectric installations utilize a turbine to convert the energy of flowing water to produce rotating shaft work. This shaft is then coupled to a generator to produce electricity. Figure 9 displays a typical hydroelectric installation.

Figure 9: Typical Hydroelectric Plant



Hydropower installations are known to be robust and durable, often operating for several decades, making it an attractive long term power option. In addition to its longevity, its ability to adapt to changing energy demands and the relatively low cost of hydroelectricity (3 to 5 cents/kWh) makes it a competitive source of renewable electricity. Some of the key limitations for large hydroelectric plants include the requirement of a large source of water with a high amount of head (height difference between inflow and outflow), as well as the high capital costs associated with plant construction.

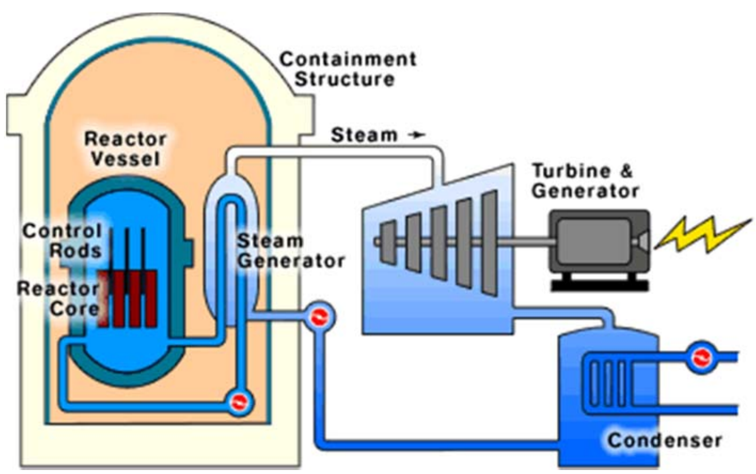
Nuclear Technologies

Nuclear Generation

Nuclear generation utilizes the energy released from the splitting of atoms to boil water that can be used in a conventional rankine steam cycle to produce electricity similar to a PC unit, but without any CO_2 emissions. Due to their difficulty to cycle, nuclear units are typically used as a baseload resource and have very large electrical output. They also have relatively high capital costs.

Many types of nuclear reactors exist, but the most common is the advanced pressurized water reactor ("APWR"). In pressurized water reactors, water is heated by the nuclear fuel but the water is kept under pressure to prevent it from boiling. Instead, the hot water is pumped from the reactor pressure vessel to a steam generator. There the heat of the water is transferred to a second, separate supply of water, which boils to produce steam. The coolant in the APWR is contained in the pressurized primary loop and does not pass through the steam turbine. This is illustrated in Figure 10.

Figure 10: Nuclear Generation Diagram

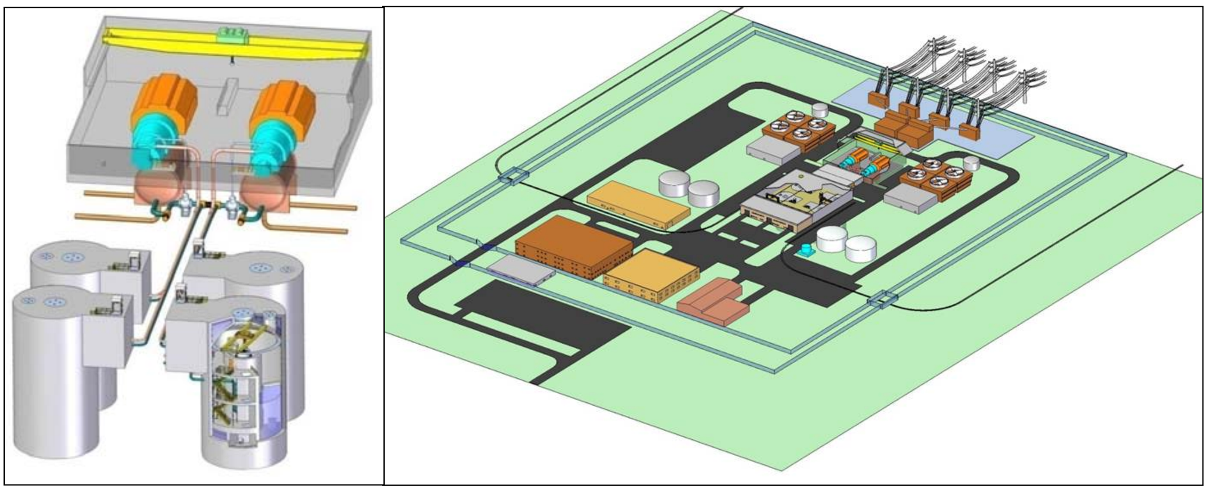


Small Modular Reactor (SMR) Generation

Manufacturers have begun designing small modular reactors ("SMR"s) with the intentions to create a smaller scale, completely modular nuclear reactor. According to these manufacturers, the benefit of these SMRs is two-fold; the smaller unit size of less than 300 MW will allow more resource generation flexibility and the modular design will reduce overall project costs. The conceptual technologies are similar to APWR reactors and the entire process and steam generation is contained in one, modular vessel. The steam generated in this vessel is then tied to a steam turbine for electric generation. Due to the design's modularity, most of the fabrication is planned to be done in the manufacturing facility before the vessel is shipped to the site. The goal is to reduce field labor and construction schedule.

Currently, SMRs are considered conceptual in design and are very developmental in nature. Several manufacturers have begun conceptual design of these modular units to target lower output and overall costs of nuclear facilities. However, there is currently no industry experience with developing this technology outside of the conceptual phase. Therefore, the information provided in this assessment for the SMR option is based on feedback and initial indications from SMR manufacturers. Figure 11 demonstrates this technology.

Figure 11: SMR Nuclear Generation Diagram

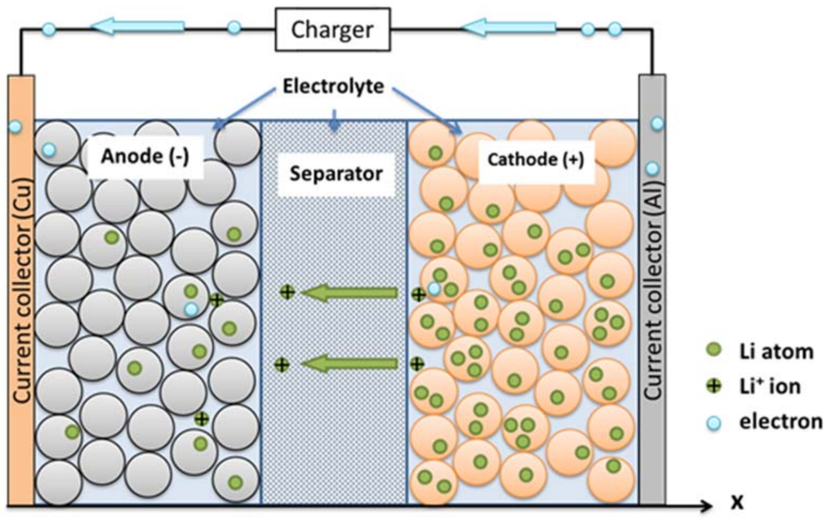


Energy Storage Technologies

Lithium Ion Battery Storage

A conventional battery contains a cathodic and an anodic electrode and an electrolyte sealed within a cell container than can be connected in series to increase overall facility storage and output. During charging, the electrolyte is ionized such that when discharged, a reduction-oxidation reaction occurs, which forces electrons to migrate from the anode to the cathode thereby generating electric current. Batteries are designated by the electrochemicals utilized within the cell, and the lithium ion type is one of the most common designs. A lithium ion battery schematic is shown in Figure 12.

Figure 12: Lithium Ion Battery Diagram



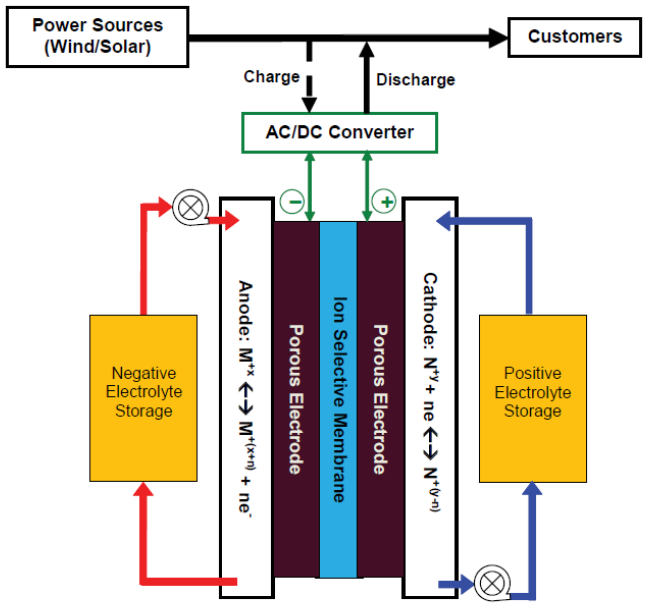
Lithium ion batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Lithium ion technology has seen a resurgence of development interest due to its high energy density, low self-discharge, and cycling tolerance, but is still developing for utility-scale applications. The life cycle is dependent on cycling (charging and discharging) and depth of charge (charged load depletion), and can range from 2,000 to 3,000 cycles at high discharge rates, up to 7,000 cycles at very low discharge rates.

Lithium ion batteries are gaining traction in several markets, including the utility and automotive industries. Continued development is anticipated to reduce production costs, but uncertainty of these developments lends to wide ranges in project costs.

Flow Battery Energy Storage

In essence, the flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge inducing chemical reaction occurs, and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system, as shown in Figure 13. Note that the cells can be stacked in series to achieve the desired voltage difference.

Figure 13: Flow Battery Diagram



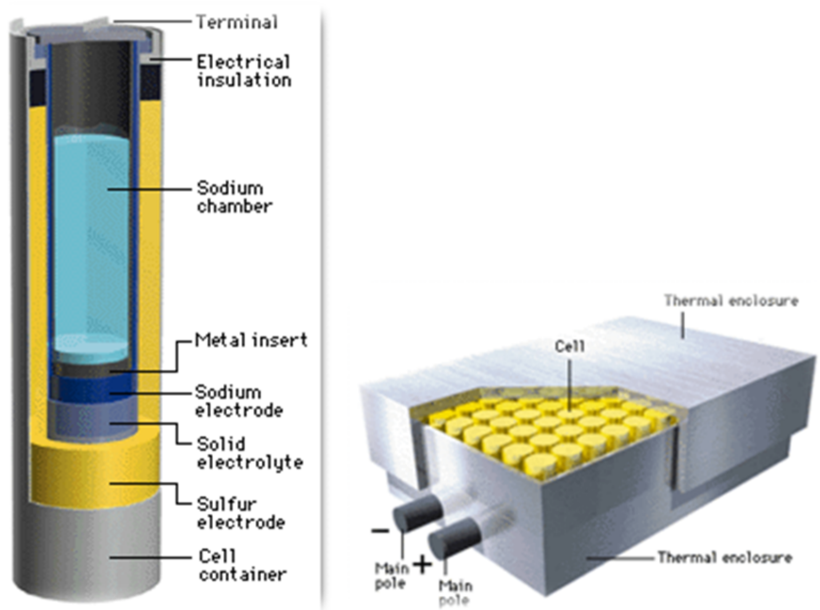
The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electro-neutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

There are three primary differences between a flow battery and the traditional battery. The electro-active materials are stored in a liquid electrolyte chemical external to the device, introduced only during charging and discharging operations. Also, energy conversion occurs as a direct result of the redox reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in a high cycling life of the flow battery. Flow batteries are better suited for larger applications due to the complexity of the electrochemical fuel delivery system. Finally, due to both aforementioned differences, flow batteries are scalable such that energy storage capacity is determined by the size of the electrolyte storage tanks, allowing the system to approach its theoretical energy density.

Sodium Sulfur Battery Energy Storage

The Sodium Sulfur ("NaS") battery is typically a hermetically sealed cell that consists of a molten sulfur electrolyte at the cathode and molten sodium electrolyte at the anode, separated by a Beta-alumina ceramic membrane and enclosed in an aluminum casing. A typical cell is shown in Figure 14.

Figure 14: Sodium Sulfur Battery Diagram



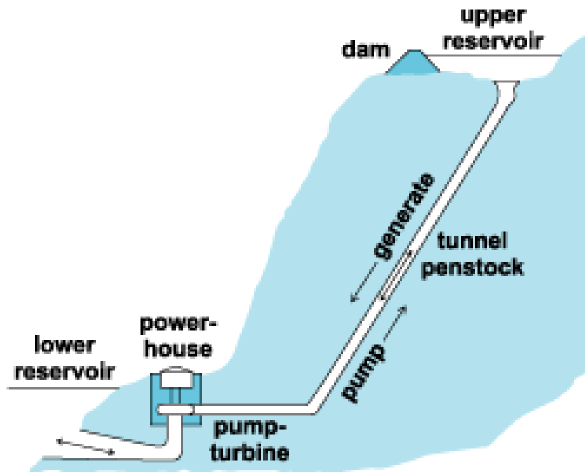
The membrane is selectively permeable only to positive sodium ions, which are created from the oxidation of sodium metal and pass through to combine with sulfur resulting in the formation of sodium polysulfides. As power is supplied to the battery in charging, the sodium ions are dissociated from the polysulfides and forced back through the membrane to re-form elemental sodium.

The melting points of sodium and sulfur are approximately 98 degrees Celsius ("^{o}C") and 113^{o}C, respectively. To maintain the electrolytes in liquid form and for optimal performance, the NaS battery systems are typically operated and stored at around 300^{o}C, which results in a higher self-discharge rate of 14-18 percent. These systems are expected to have an operable life of around 15 years and are currently one of the most developed chemical energy storage systems. Japan-based NGK Insulators, the largest NaS battery manufacturer, recently installed a 4 MW system in Presidio, Texas in 2010 following operation of systems totaling more than 160 MW since the project's inception in the 1980's.

<u>Pumped Hydro Energy Storage</u>

A pumped hydroelectric plant (pumped hydro) is a peaking energy storage power generating facility. The plant includes a lower reservoir (usually existing), a powerhouse, an upper reservoir (usually constructed with the pumped hydro project) and a means for conveying water between the upper and lower reservoirs. The powerhouse includes reversible generator/motors and pump/turbines. This is illustrated in Figure 15.

Figure 15: Pumped Hydro Diagram

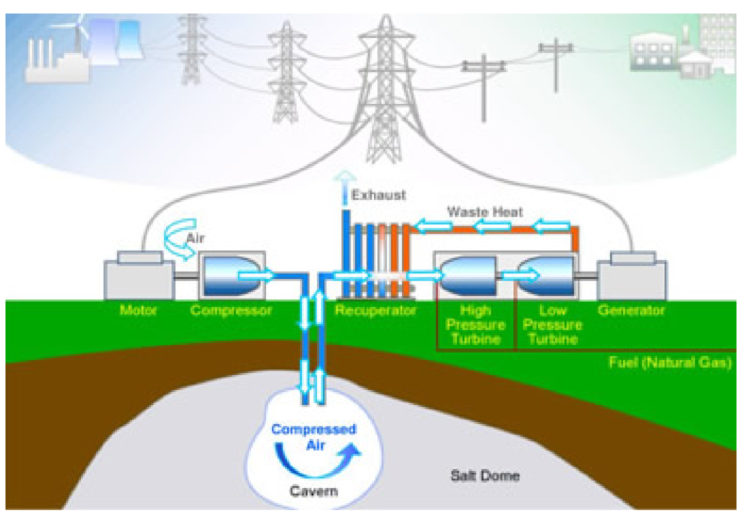


During off peak periods, when a surplus of lower costing electrical energy exists, the plant is operated in the pump mode to pump water from the lower reservoir to the upper reservoir. During peak periods, the water is released from the upper reservoir through the pump/turbines to generate electrical energy to meet the system peak demand.

Compressed Air Energy Storage

Compressed air energy storage ("CAES") offers a way of storing off-peak energy that can be dispatched during peak demand hours. CAES is a proven, utility-scale energy storage technology that has been in operation globally for over 30 years. To utilize CAES, the project needs a suitable storage site, often below ground, and availability of transmission and fuel sources. CAES facilities use off-peak electricity to compress air into an underground reservoir at approximately 850 psig. Energy is then recaptured by releasing the compressed air, heating it (typically) with natural gas firing, and generating power as the heated air travels through an expander. The process is shown in Figure 16.

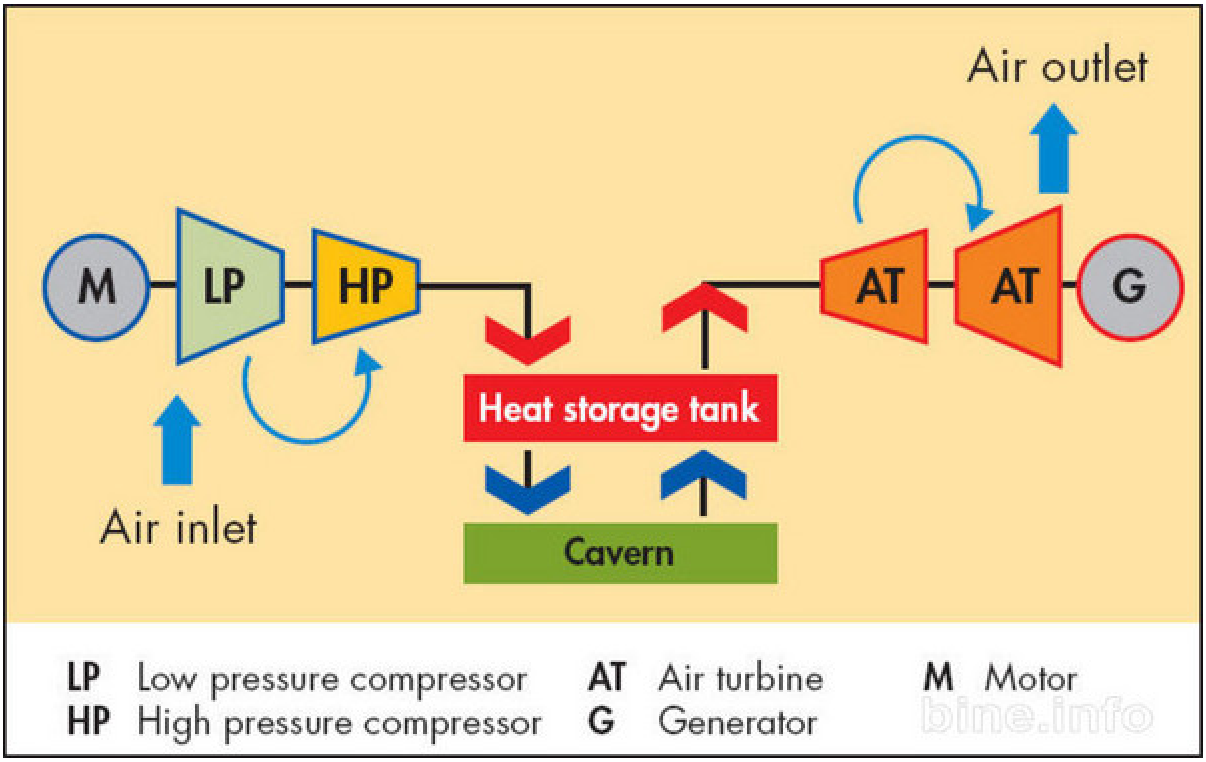
Figure 16: Compressed Air Energy Storage Diagram



This method of operation takes advantage of using less expensive, off-peak power for generation during periods of higher demand. CAES provides the ability to optimize the system for satisfying monthly or even seasonal energy needs and CAES can provide spinning reserve capacity with its rapid ramp-up capability. Energy stored off-peak and delivered on-peak can help reduce on-peak prices and is therefore beneficial to consumers.

"Second generation" CAES designs have recently been developed and are undergoing testing, but do not have commercial operating experience. These conceptual designs incorporate a separate gas turbine for additional generation capacity and use the exhaust energy as a source of preheat for the stored air before entering the expansion process. The compression-expansion portion of these designs is similar to "first generation" CAES designs. The designs differ in that a simple cycle gas turbine plant operates in parallel to the compression-expansion train and the exhaust is used in a recuperator instead of utilizing a combustor to preheat the stored air. The process is shown in Figure 17.

Figure 17: "Second Generation" Compressed Air Energy Storage Diagram



APPENDIX E: ENVIRONMENTAL POLICY AND COMPLIANCE ASSESSMENT

Part 1: Minnesota Power Contributions to Minnesota Environmental Leadership

Minnesota Power (or "Company") has a history of environmental excellence that has contributed to Minnesota's track record of environmental leadership. Strong performance has been achieved through the installation of timely, cost-effective environmental controls and new energy resources that balance its customers' needs for reliable and affordable electric energy with good environmental stewardship. The Company holds environmental stewardship as a core value and balances the environmental impacts of its activities with its obligation to customers, communities, shareholders, and future generations. Minnesota Power, as outlined in its 2015 Integrated Resource Plan ("2015 Plan" or "Plan"), is meeting its environmental objectives in advance of regulatory requirements and deadlines.

Minnesota Power environmental compliance planning measures are highlighted in Part 2 of this Appendix - Environmental Regulations Summary. Part 2 provides an overview of environmental regulations and Minnesota Power's planned measures for compliance. These measures reinforce Minnesota Power's commitment to preserving exemplary environmental performance while delivering reliable and affordable electric service to its customers. A unit-by-unit assessment is provided describing current emissions performance relative to regulations. The assessment also details planned control retrofits that ensure continued unit compliance with applicable environmental requirements. New emission control measures expand on the deployment of emissions control under the Minnesota Power Arrowhead Regional Emissions Abatement ("AREA") Plan, Minnesota Mercury Emission Reduction Act ("MERA") and the Minnesota Pollution Control Agency's ("MPCA") regional haze Northeast Minnesota Emissions Abatement Program.

Part 2 also describes how planning for required controls is separated into two cases: the Base Case that reflects environmental regulations laid out with fairly certain requirements, and an Environmental Protection Agency ("EPA") Sensitivity that reflects environmental measures with a higher level of uncertainty. The Base Case includes measures that address the Mercury and Air Toxics Standard ("MATS"), the Industrial Boiler maximum-achievable control technology ("MACT") rule, National Ambient Air Quality Standard ("NAAQS") revisions, Regional Haze requirements, 316(b) cooling water regulations, the MERA requirements for large coal-fired boilers, The EPA Sensitivity measures include consideration of potential ash handling and dewatering requirements for the EPA's Coal Combustion Residual Rule and inclusion of water treatment requirements for Effluent Limitation Guidelines ("ELG"). Separate sensitivities were evaluated that imposed a greenhouse gas regulation penalty on emissions from existing sources regulated under the Clean Air Act and per Minnesota statute requirements for resource planning.

"Cobenefits" are delivered when measures taken to address one set of regulations deliver environmental performance benefits that are targeted for reduction under a different set of regulations. Cobenefits from the combined Base Case measures are expected to satisfy the sulfur dioxides ("SO_2") and oxides of nitrogen ("NO_x") emission reductions (emissions budget) required by the Cross State Air Pollution Rule ("CSAPR"), the revised NAAQS attainment requirements in Minnesota and the MERA reduction requirements for mercury. Cobenefits from Minnesota Power measures implemented to achieve the Minnesota renewable energy standard ("RES") and conservation improvement program targets position Minneosta Power well for requirements that may be imposed under the Base Case for reducing greenhouse gas emissions (carbon dioxide or "CO_2").

Emission reduction co-benefits are a significant part of Minnesota Power's *Energy**Forward*** strategy that is shifting the resource mix serving Minnesota Power electricity customers towards a "one-third, one-third, one-third" balance of coal, natural gas and renewable energy plus conservation. The retrofit of additional emission controls on coal-fired generating units needed to satisfy environmental regulations well into the future helps assure that the one-third coal component of this strategy delivers its part for preserving reliability, protecting affordability and further improving environmental performance.

The overall cost for emission control measures described in Part 2, not including any carbon emission penalty considerations, is summarized in Table 1. The estimated $245 million cost premium under the EPA Sensitivity is associated with estimated but uncertain measures to address new water effluent guidelines and coal combustion residual management and disposal. Operation and maintenance ("O&M") costs described in Part 2 reflect the chemical feedstock costs associated with operation of retrofit environmental controls and vary unit by unit.

Table 1: Environmental Controls Planning Cost Summary

Environmental Controls Planning	Capital ($ Millions)
Base Case	$30
EPA Sensitivity *	$245

**EPA Sensitivity includes Base Case costs, excludes CO_2 penalties*

Totals reflect the environmental controls needed for all the coal fueled units at the Boswell Energy Center ("BEC"), Laskin Energy Center ("LEC") and Taconite Harbor Energy Center ("THEC") to satisfy environmental requirements. The conversion at LEC combined with the retirement of Taconite Harbor Energy Center Unit 3 ("THEC3") continue the Company's *Energy**Forward*** strategy by removing coal-fired generation from both facilities. Carbon penalty sensitivity analysis is addressed separately through the evaluation presented in Appendix K: Detailed Analysis Section.

A Minnesota carbon emission penalty applied to operational dispatch for electric generation monetizes the differences between fuel sources for emitting carbon dioxide equivalent greenhouse gases ("CO_2e"). An existing coal unit emits just over one ton of CO_2e per MWh; a natural gas unit, approximately one-half ton CO_2e per MWh; and renewable wind, hydroelectricity or biomass energy, near zero tons CO_2e per MWh. Carbon emission penalty costs as high as $34 per ton CO_2e have been required for consideration in the 2015 Plan by the Minnesota Public Utillities Commission ("Commission"). A carbon emission penalty would increase actual customer electricity costs through emissions fees (carbon penalty), resource selection bias towards lower carbon alternatives, and power market marginal dispatch price impacts.

The Minnesota carbon emission penalty will lead to higher customer costs; these costs depend on how Minnesota actions are integrated with national climate policy developments. The policy implications from imposition of a Minnesota carbon emission penalty on electric generation is further addressed in Part 3: 2015 Plan Performance and Minnesota Environmental Targets. Part 3 presents a summary of Minnesota Power emissions after implementation of the 2015 Preferred Plan, along with an assessment of policy initiatives that are shaping those measures.

Cost category analysis helps clarify how imposition of penalties, such as the carbon cost can impose higher costs on Minnesota electricity customers without achieving environmental benefits. Improvements to facilities to reduce emissions now and in the past required capital investment. These past investments and future carbon penalties both pose a cost for customers. Consequently, customers are compelled to pay twice: once to service the cost to deliver environmental performance requirements, and a second time to service the cost for emissions allowed while policy targets are being achieved.

Part 3 also presents a summary of Minnesota Power's measures that improve the environmental footprint associated with power supply for customers through the expanded use of renewable energy, conservation and efficiency improvements, and emission reductions from existing generation. In most cases, these environmentally friendly measures have been delivered in advance of national environmental requirements. These *Energy**Forward*** resource strategy measures satisfy regulatory requirements being imposed on the Company's electricity generation and will benefit customers for years to come. The Company's measures also significantly contribute to the environmental reputation that Minnesota carries nationally.

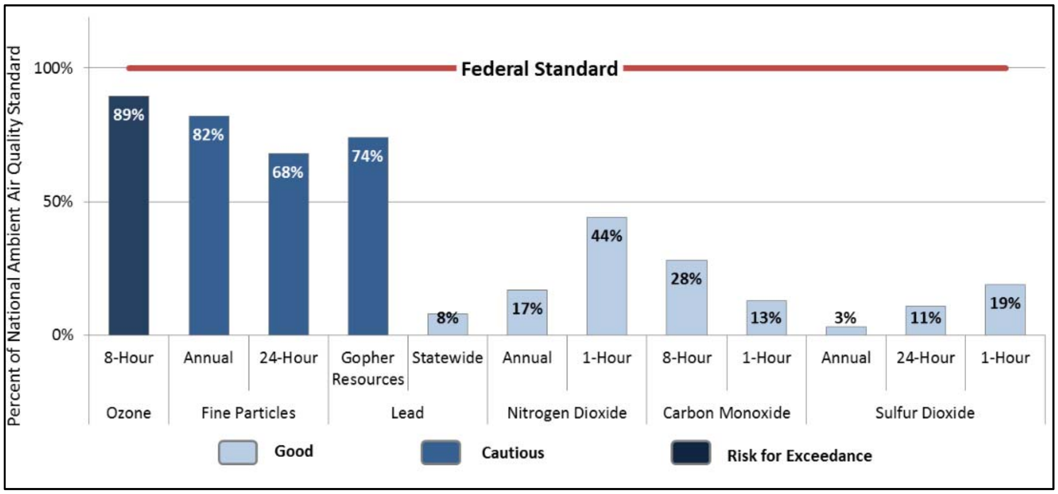
Minnesota Environmental Leadership

Both Minnesotans and their neighbors value the state's environmental quality, and there is always a desire for increased environmental improvements. There is more work in progress, but Minnesota has delivered emission reductions, environmental practices that have improved the air and water quality, and provided for the responsible use of its natural resources. With the 2015 Preferred Plan, Minnesota Power will have reduced emissions from its generation portfolio by 90 percent (Section 3).

Air quality has steadily improved over recent decades, and Minnesota anticipates meeting air quality standards even as they are made more stringent by the EPA. State policies have provided for significant reductions in local mercury emissions in advance of new national regulatory measures. Minnesota has also provided for reduced emissions loading to water bodies while expanding monitoring for environmental quality indicators. Minnesota has policies in place that provide for effective solid waste management in advance of national measures still under development.

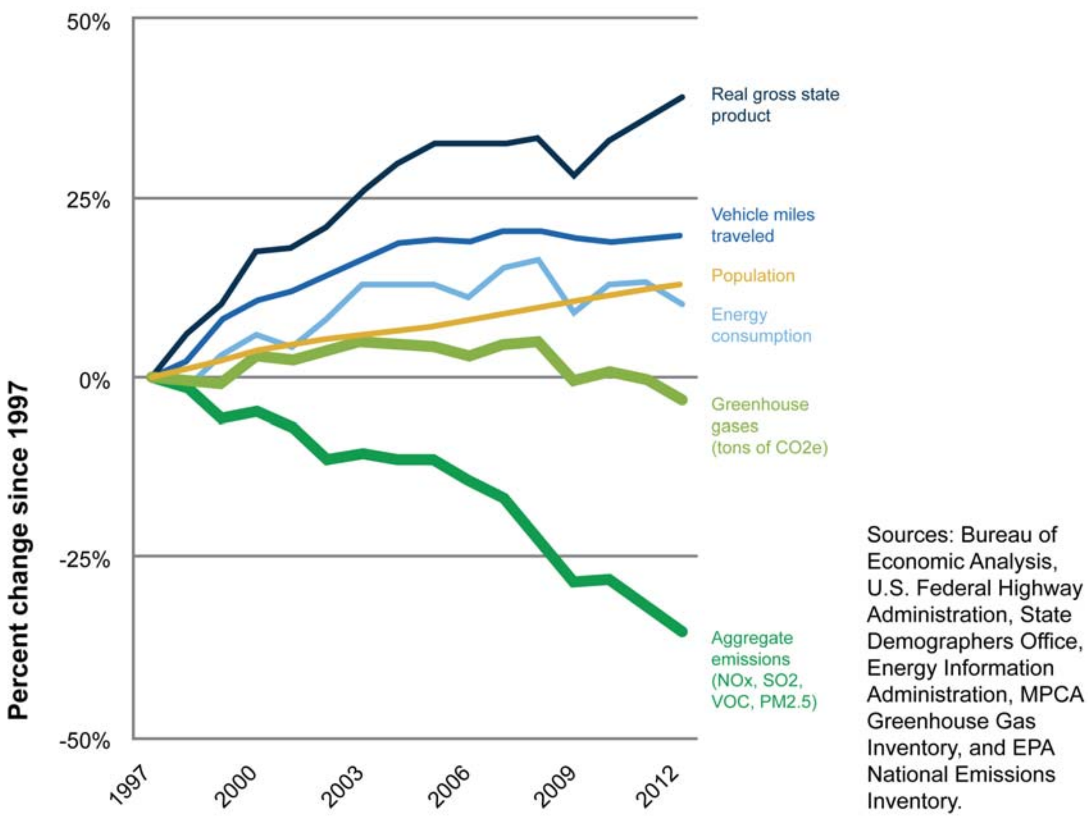
The MPCA has characterized improving air quality as shown in Figure 1.

Figure 1: Minnesota's Air Quality Compared to NAAQS (2013) [source MPCA]



A balanced approach is an important part of managing improvements to environmental quality. Potential solutions should stay rooted in sound science, enable policy makers to protect and promote Minnesota job growth, and moderate increasing energy costs that impact Minnesotans while protecting the environment. As shown in Figure 2, Minnesota has managed to grow its economy while providing for significant emission reductions.

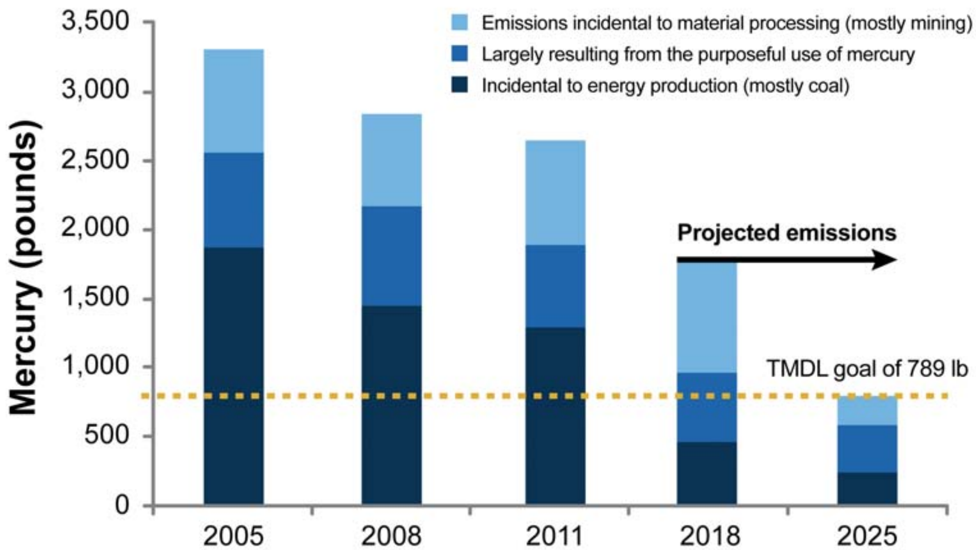
Figure 2: State Economy, Energy Use, Population, Transportation and Air Pollution



Minnesota has demonstrated leadership in this arena by providing for stakeholder process development of important environmental and energy policy initiatives, including:

- Mercury in fish improvements through the Minnesota Mercury Reduction Initiative that is on track to meeting its 85 percent mercury emission reduction goal from all Minnesota sources. MERA also requires that the largest coal-fired electric generation units in Minnesota provide for control retrofits delivering 90 percent mercury emission reductions by 2018 (see Figure 3).

Figure 3: MN Mercury Reduction Initiative TMDL[1] Goal Progress, MPCA

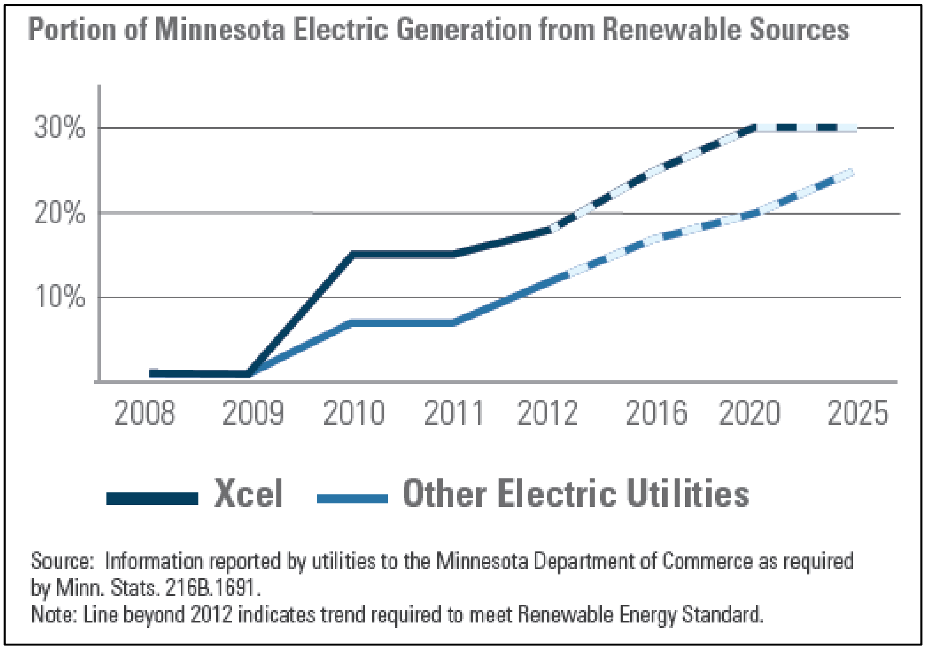


- SO_2, NO_x and volatile organic compound emission reductions through "affordable control" utility emission reduction programs like Clean Air Minnesota, the Metropolitan Emission Reduction Program and the AREA Plan. The associated local emission reductions improved Minnesota air quality in advance of Federal programs such as the Clean Air Interstate Rule and CSAPR while those programs were still an EPA "work-in-progress" for finalization.
- Visibility impairment improvement measures through the MPCA's Northeast Regional Emissions Abatement program required 20 percent to 30 percent collective reductions in targeted Minnesota SO_2 and NO_x emissions. This is in line with the Regional Haze program and Reasonable Further Progress requirements.
- Conservation and energy efficiency improvement programs have been in place for over two decades in the state, and Minnesota Power continues to meet and exceed these goals.

[1] Total maximum daily load.

- Minnesota RES requirements that stage in the expanded use of renewable energy by Minnesota utilities through 2025 (25 by 25 RES). A 12 percent renewables progress target for 2012 has already been met and Minnesota Power has already implemented renewable energy measures to meet the requirement for 25 percent of electricity generation being sourced from renewables by 2025 (see Figure 4 for Minnesota progress).

Figure 4: Portion of Minnesota Electric Generation from Renewable Resources



- Minnesota Next Generation Energy Act of 2007 ("NGEA") measures set a goal for greenhouse gas emission reductions staging a 15 percent reduction in CO_2 equivalent emissions from all sources by 2015, 30 percent by 2025 and 80 percent by 2050. The Minnesota Climate Change Advisory Group process helped frame initial options for emission reductions. Progress towards goals is being reported by the MPCA to the Legislature biannually (see Figure 5 & 6).

Figure 5: NGEA Green House Gas Emission Reduction Goals (source MPCA)

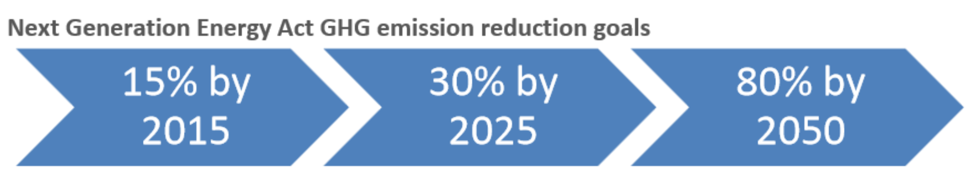
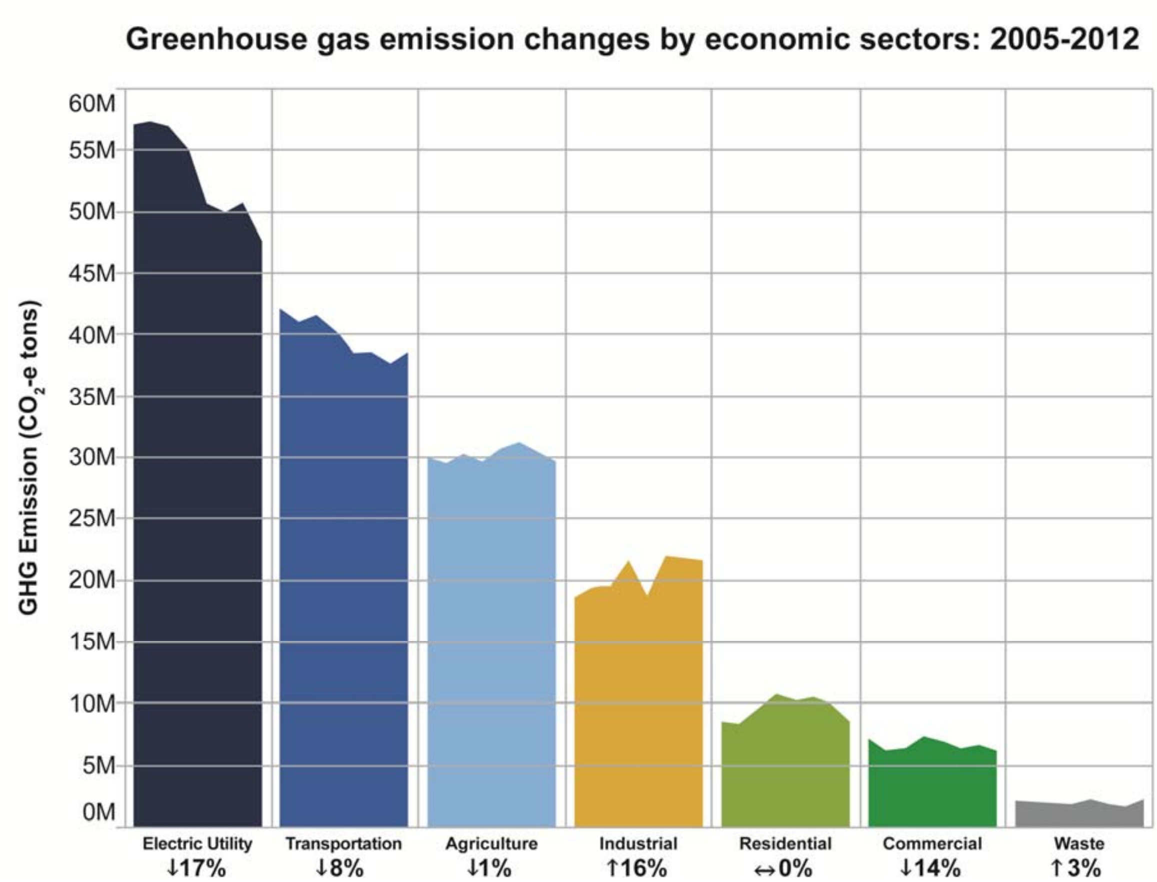


Figure 6: Greenhouse Gas Emissions from Minnesota by Economic Sector



Part 2: Environmental Regulations Summary

The landscape for environmental regulation of coal-fired power plants has changed dramatically in recent years and continues to evolve at a rapid pace. These changes could have a significant impact on Minnesota Power's operations and inject a new level of uncertainty into long-term resource planning. This section summarizes the more significant environmental regulations that have occurred or are anticipated to occur over the next several years, and estimates a potential range of impact these regulations could have on the Company.

A. Overview of Environmental Regulations

Minnesota Power closely follows state and federal rulemakings that regulate air emissions, water emissions and solid waste from coal-fired power plants. In the following sections, the Company describes pending environmental regulations relative to Minnesota Power facilities and its current assessment of their applicability. The regulations are grouped into two broad categories: 1) those that address air emissions, and, 2) those related to water discharges, water usage, and management of the ash or solid waste, which is a byproduct of coal combustion.

The regulations to be detailed in the following sections include:

<u>Air Regulations</u>

- Cross-State Air Pollution Rule ("CSAPR")
- National Ambient Air Quality Standards ("NAAQS")
- Mercury and Air Toxics Standards ("MATS") Rule
- National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters ("Boiler MACT")
- Minnesota Mercury Emissions Reduction Act ("MERA")
- Clean Air Visibility Rule ("Regional Haze")
- Clean Power Plan ("CPP")

<u>Water and Solid Waste</u>

- Coal Combustion Residuals Regulation ("CCR")
- 316(b) Rule – Standards to Protect Aquatic Ecosystems
- Water Effluent Regulation ("Effluent Limit Guidelines[2]" or "ELG")

The timeline shown in Figure 7 summarizes when these regulations are assumed to be substantially implemented based on current industry intelligence. It is important to note that some technology solutions considered in the 2015 Plan evaluation will address more than one regulatory program. Also, these regulations are expected to impact Minnesota Power primarily

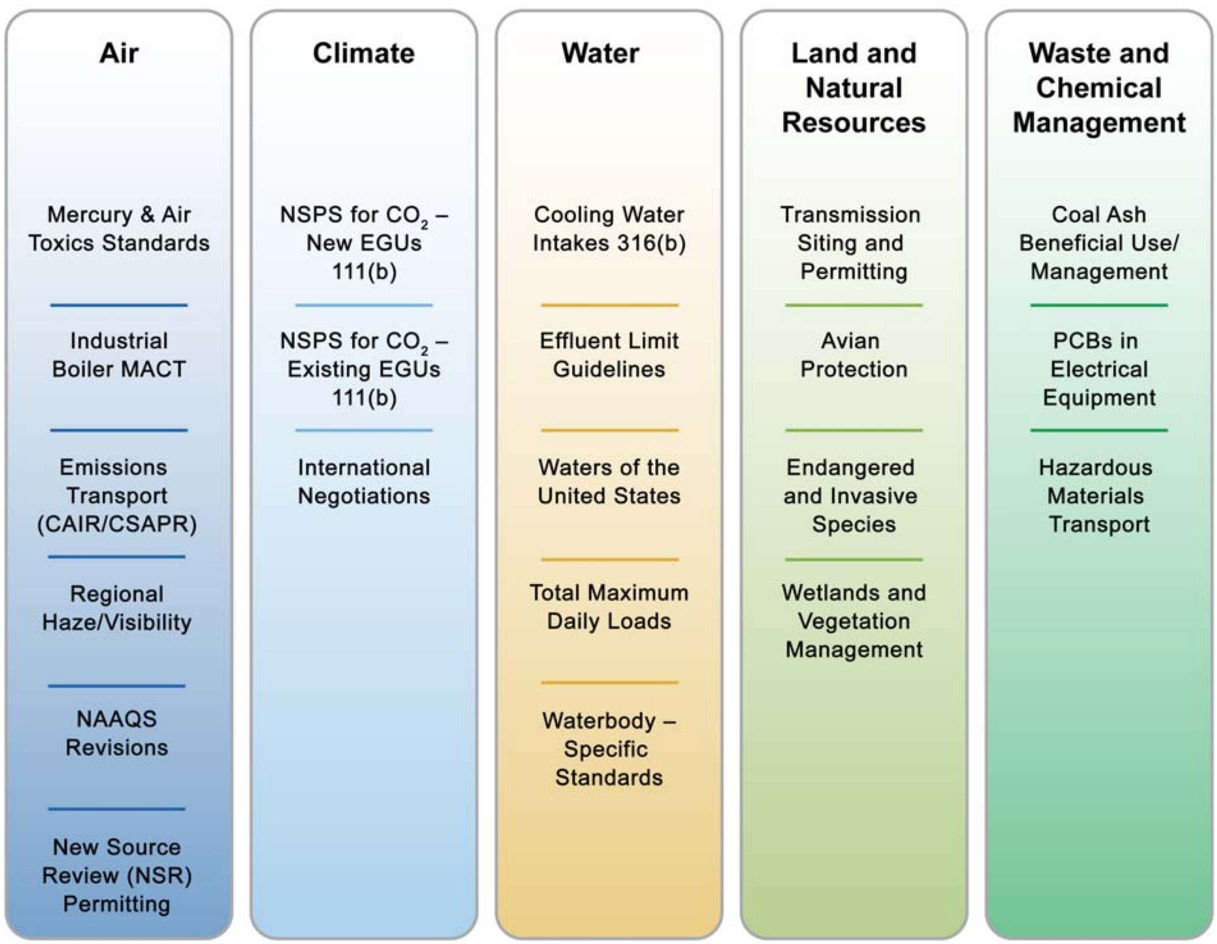
[2] Referred to as Steam Effluent in 2013 Integrated Resource Plan, hereafter referred to as Effluent Limit Guidelines in an effort to be more consistent with state guideline language.

in the 2016 to 2018 timeframe, although greenhouse gas related restrictions are not expected to affect existing units until after 2020.

Figure 7: Expected Timing for Environmental Regulations

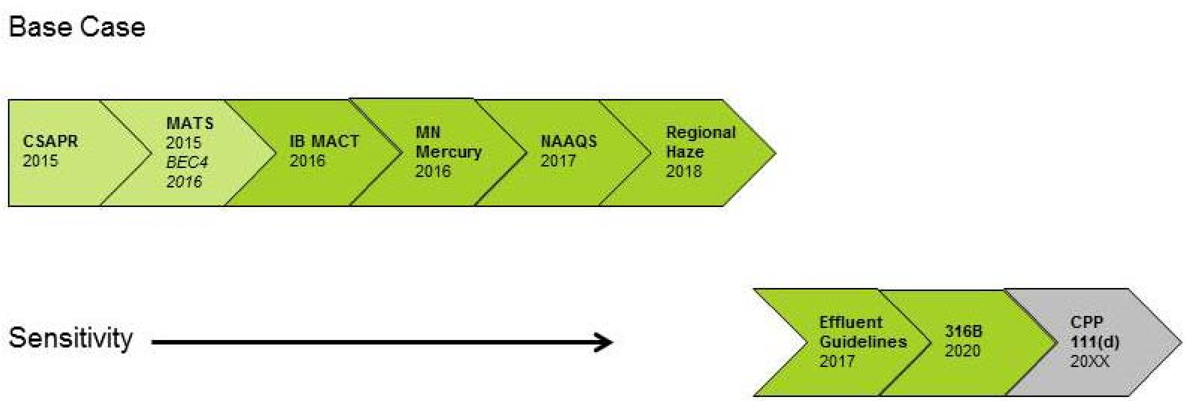
As the environmental regulations work their way through the finalization process each rule can be at different stages and have various levels of certainty associated with them. For the purposes of its forward resource planning and decision making, Minnesota Power identifies which regulations are most certain for the time period being evaluated and includes these in its Base Case outlook. For other regulations that do not have clarity on outcome or specificity on requirements, they are treated as a sensitivity in the planning process.

Figure 8: Key Federal Environmental Regulatory Challenges



For its 2015 Plan, Minnesota Power identified that all but three regulations (Effluent Limit Guidelines, Coal Combustion Residual and Greenhouse Gas) have clarity on their status and would be considered part of its Base Case outlook. In particular, Minnesota Power performed two analyses with subtitle D for the CCR rule. The Base Case includes CCR compliance costs after plant closure and the EPA sensitivity reflects the planning level estimate of pre-closure CCR activities. Figure 9 identifies how Minnesota Power categorized the regulations into the "Base Case" and "Sensitivity Analysis" categories.

Figure 9: Minnesota Power Base Case and Sensitivity for Environmental Regulations



Each of these pending regulations is explained in detail below, with a potential impact analysis on Minnesota Power's generation in the section to follow.

1. Air Emissions

Cross-State Air Pollution Rule

On July 6, 2011, the EPA finalized CSAPR, which requires 27 states, including Minnesota, to reduce power plant SO_2 and NO_x emissions that can contribute to ozone and fine particle pollution non-attainment in other states. On December 30, 2011, the D.C. Circuit stayed the rule. On October 23, 2014, the Court granted the EPA's motion to lift the stay and defer the first compliance period until January 1, 2015. CSAPR Phase 1 implementation is now 2015, with Phase 2 beginning in 2017. The CSAPR does not directly require the installation of controls. Instead, it sets a strict emission allowance budget for each state and requires facilities to surrender enough emission allowances to cover their emissions on an annual basis. Minnesota Power expects that current and planned emission reductions will comply with CSAPR.

National Ambient Air Quality Standards

NAAQS are established to protect human health ("primary standards") or public welfare ("secondary standards"). NAAQS can impact Minnesota Power in two possible ways. First, if air dispersion modeling from a state-approved protocol demonstrates that the NAAQS are being exceeded at a facility's property boundary, Minnesota Power would have to take measures to reduce emissions. Second, if a county which contains one of Minnesota Power's facilities goes into non-attainment (which means one or more sites demonstrate ambient air concentrations greater than the standard), then existing facilities may have to undertake additional control measures to reduce emissions of that pollutant. Four NAAQS have either recently been revised or are currently proposed for revision, as described below.

Ozone NAAQS

In January 2010, the EPA proposed to revise the 2008 eight-hour ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA was scheduled to decide upon the 2008 eight-hour ozone standard in July 2011, but announced that it was deferring revision of this standard until at least 2013. On November 25, 2014, the EPA proposed lowering the current standard from 75 ppb to a range of 65 to 70 parts per billion ("ppb.") This proposal also solicited comments on retaining the current standard or lowering even further to levels as low as 60 parts per million ("ppm.") Minnesota Power is not identifying any technology requirements for this standard.

Particulate Matter NAAQS

On December 14, 2012, the EPA confirmed in final rule that the current annual average fine particulate ("$PM_{2.5}$") primary standard, which has been in place since 1997, would be lowered from 15 micrograms per cubic meter to 12 micrograms per cubic meter. EPA concluded that the current 24-hour fine particulate primary standard, which would be retained and not lowered, was sufficient to provide visibility protection that is equal to, or greater than, 30 deciviews, the target level of protection the EPA set with issuance of the December 24, 2012 rule. The annual and 24-hour secondary standards were also upheld.

To implement the new lower annual standard, the EPA also revised aspects of relevant monitoring, designations, and permitting requirements. New projects and permits must comply with the new lower standard, and compliance with the NAAQS is generally demonstrated by modeling. To bridge the transition to the lower standard, the EPA finalized a grandfathering provision to ensure that projects and pending permits already underway were not unduly delayed.

On August 19, 2014, the EPA informed Minnesota of its intent to designate the entire state of Minnesota as unclassifiable/attainment. This was codified in Rule on December 28, 2014, when the administrator signed final area designations for most areas of the country including Minnesota, based on 2011 – 2013 data. According to EPA, areas designated as "unclassifiable/attainment" have monitoring data that shows they meet the standard or EPA has reviewed available data and determined they are likely to be meeting the standard and not contributing to a nearby violation.

SO_2 and Nitrogen Dioxide ("NO_2") NAAQS

During 2010, the EPA finalized new one-hour NAAQS for SO_2 and NO_2. Ambient monitoring data suggests that Minnesota will likely be in compliance with these new standards; however, the one-hour SO_2 NAAQS preamble also suggested the EPA evaluate modeling data to determine attainment. The EPA notified states that their State Implementation Plans ("SIPs") for attainment of the standard will be required to be submitted to the EPA for approval by June 2013, but could be required to include the evaluation of modeling data by 2017.

On April 12, 2012, the MPCA notified Minnesota Power that statewide SO_2 NAAQS-driven modeling had been suspended as a result of the EPA's announcement that the June 2013 SIP submittals would no longer require modeling demonstrations for states, such as Minnesota, where ambient monitors indicate compliance with the new standard. The MPCA is awaiting updated EPA guidance or rulemaking and will communicate with affected sources once the MPCA has more information on how the state will meet the EPA's SIP requirements. Currently, compliance with these new NAAQS for affected sources is expected to be required as early as 2017. In February 2013, the EPA informed the State of Minnesota that it was not yet prepared to propose designation action in Minnesota, and was therefore deffering action to designate areas in Minnesota for the 2010 1-hour SO_2 standard. However, EPA also stated that its review of the monitored air quality data from 2009-2011 showed no violations of the 2010 SO_2 standard in any areas in Minnesota.

As noted above, regional attainment with the one-hour NO_2 NAAQS is expected to be demonstrated via data from the state monitor network. In February of 2010, the EPA finalized new minimum monitoring requirements for the NO_2 monitoring network in support of the one-hour NO_2 NAAQS. In the new monitoring requirements, state and local air monitoring agencies are required to install near-road NO_2 monitoring stations at locations where peak hourly NO_2 concentrations are expected to occur within the near-road environment in large urban areas by January 1, 2013. The MPCA submitted a plan to EPA Region 5 with the process and criteria used to identify the new near-roadway monitoring site in Minnesota. They received final approval for the proposed site location along I-94 and I-35W in Minneapolis in January 2012.

A May 2011 letter from the MPCA stated that with some exceptions, the MPCA generally would not immediately require facility-based air dispersion modeling to demonstrate compliance with the 2010 one-hour NO_2, 2010 one-hour SO_2 and the 2006 24-hour $PM_{2.5}$ NAAQS. Facility modifications, permit reissuances, and State Implementation Planning analysis are examples of activities that may result in the MPCA calling for modeling, consistent with EPA requirements and the practices of EPA Region 5 states and other neighboring states. Minnesota Power will be reviewing new developments as the MPCA proceeds with expanded modeling and monitoring requirements in Minnesota.

Mercury and Air Toxics Standards Rule

Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants ("HAPs") for certain source categories. The EPA published the final MATS rule in the Federal Register on February 16, 2012, addressing such emissions from coal-fired utility units greater than 25 MW. There are currently 187 listed HAPs that the EPA is required to evaluate for establishment of MACT standards. In the final MATS rule, the EPA established categories of HAPs, including mercury, trace metals other than mercury (e.g., arsenic), acid gases (e.g., hydrochloric acid), dioxin/furans, and organics other than dioxin/furans. The EPA also established emission limits for the first three categories of HAPs, and work practice standards for the remaining categories. A particulate limit was established as a surrogate for trace metals other than mercury. Affected sources were required to be in compliance with the rule by April 2015. The 2015 Plan details how Minnesota Power chose to comply with this rule; compliance and alternative scenarios were included in the Base Case.

On June 29, 2015, the U.S. Supreme Court reversed and remanded an earlier U.S. Court of Appeals for the D.C. Circuit decision on the MATS rule in the case Michigan v. EPA. The MATS rule remains in effect until the U.S. Court of Appeals for the D.C. Circuit acts on the remand.

The Supreme Court Decision is expected to have minimal impacts on Minnesota Power generation due to ongoing emission reduction obligations under the MERA and the consent decree. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

In March 2011, the Boiler MACT final rule was published in the Federal Register. Similar to the MATS Rule, the EPA is required to evaluate HAPs emissions for establishment of MACT standards for boilers. The rule was stayed by the EPA in May 2011, to allow the EPA time to consider additional comments received. The EPA re-proposed the rule in December 2011. On January 9, 2012, the U.S. District Court for the District of Columbia ruled that the EPA stay of the Boiler MACT was unlawful, effectively reinstating the March 2011 rule and associated compliance deadlines. A final rule based on the December 2011 proposal was released by the EPA on December 21, 2012, replacing the March 2011 rule. Major sources will have to achieve compliance with the final rule by 2016. Minnesota Power has two facilities impacted by this regulation, its Rapids Energy Center and Hibbard Renewable Energy Center. Based on current understanding of the Boiler MACT rule these facilities will not require significant technology investment at this time.

Minnesota Mercury Emissions Reduction Act ("MERA")

The MERA requires Minnesota Power's two largest units (Boswell Energy Center Unit 3 ("BEC3") and Boswell Energy Center Unit 4 ("BEC4") to install mercury emission controls with the goal to achieve up to 90 percent mercury removal. BEC3 has already complied; the state law requires BEC4 to be retrofitted with mercury controls by 2018. On August 31, 2012, Minnesota Power submitted to the MPCA and Commission a plan filing[3] to request approval for a significant retrofit project at its BEC4 facility which complies with MERA. On November 5, 2013, the Commission approved this BEC4 Mercury Emission Reduction Plan.

Clean Air Visibility Rule

The federal Regional Haze Rule requires states to submit SIPs to the EPA to address regional haze visibility impairment in 156 federally-protected parks and wilderness areas. Under the first phase of the Regional Haze Rule, certain large stationary sources, put in place between 1962 and 1977, with emissions contributing to visibility impairment, are required to install emission controls, known as Best Available Retrofit Technology ("BART"). BEC3 and THEC3 are subject to BART requirements. The retrofit work completed in 2009 at BEC3 meets the BART requirements for that unit, and the June 2015 retirement of THEC3 meets BART requirements for that unit.

Clean Power Plan

On March 28, 2012, the EPA announced its proposed rule to apply CO_2 emission New Source Performance Standards ("NSPS") to new fossil fuel-fired electric generating units. The proposed NSPS apply only to new or re-powered units and were open for public comment through June 25, 2012. On August 3, 2015 the EPA released the final rules for new or re-

[3] Docket No. E015/M-12-920.

powered fossil fuel-fired electric generating units. Minnesota Power is currently monitoring the NSPS final rule as it relates to Minnesota and its potential impact to the Company.

In June 2014, the EPA announced a proposed rule under Section 111(d) of the Clean Air Act for existing power plants entitled the Clean Power Plan. In the draft CPP, the EPA proposed to set state-specific reduction goals for CO_2 emissions from the power sector. The EPA maintained such goals were achievable if a state undertook a combination of measures across its power sector that constitute the EPA's guideline for a best system of emission reduction ("BSER").

The EPA submitted its final draft of the CPP to the White House Office of Management and Budget on July 1, 2015, and the final rule was released August 3, 2015. The EPA proposed that BSER is comprised of three building blocks: 1) improved fossil fuel power plant efficiency, 2) increased reliance on low-emitting power sources by generating more electricity from existing natural gas combined cycle units, and 3) developing new renewable energy sources.

The EPA then established standard nationwide emissions rates of 1,305 pounds per MWh for coal/steam plants and 771 pounds per MWh for natural gas generators. The EPA applied those rates to each state based upon its generation mix. Minnesota was given a rate based goal of 1,213 pounds per MWh and a mass based goal of 22,678,788 short tons of CO_2. For compliance, the EPA broke the interim emissions rate into two year "step" periods of 2022-24, 2025-27 and 2028-29, with a final goal to be met in 2030 and thereafter. By September 6, 2016 states must file their final state implementation plans or they can submit initial plans and request an extension until September of 2018.

Minnesota Power is currently working with the MPCA led stakeholder working group and monitoring the CPP as it relates to the State of Minnesota and its potential impact on the Company.

Minnesota has already initiated several measures consistent with those called for under the CPP. Minnesota Power is implementing its *Energy**Forward*** strategic plan that provides for significant emission reductions (30 percent from 2005 levels by 2025) and diversifying its electricity generation mix to include more renewable and efficient natural gas energy. Minnesota Power continues to evaluate the impact of prospective greenhouse house gas regulation penalty levels on existing facilities through a series of sensitivities in its planning process (Section IV of 2015 Plan).

2. Water Issues/Ash Management

Regulation of Coal Combustion Residuals

On April 17, 2015, the EPA finalized regulations for CCR generated by the electric utility sector (40 CFR Parts 257 and 261). The final rule regulates the disposal of CCR under Subtitle D of RCRA as a non-hazardous waste. While the rule does regulate CCRs as non-hazardous, it does establish new minimum criteria for existing and new CCR landfills and impoundments, including design and operating criteria, groundwater monitoring and corrective action, closure requirements and post-closure care conditions.

The Company generates coal combustion residuals at its facilities, including fly ash, bottom ash, boiler slag, and flue gas desulphurization slurries. These byproducts are currently managed in onsite impoundments (ash ponds) or landfills. Minnesota Power continues to evaluate potential capital investments that might be required by the CCR. These potential scenarios for CCR compliance are addressed in the EPA Sensitivity of this Plan. Minnesota Power will continue to evaluate these scaenarios and variables in the 2016-2018 timeframe, and cannot reasonably estimate the cost at this time.

316(b) Rule

On May 19, 2014, the EPA finalized the cooling water intake Rule, commonly known as "316(b)," for existing power plants and manufacturing facilities with implementation through National Pollutant Discharge Elimination System ("NPDES") permits. Clean Water Act Section 316(b) requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The rule is aimed at reducing fish impingement and fish entrainment from certain cooling water systems.

Impingement refers to situations where fish are trapped against the screens located where a plant intakes water from a lake or stream. Entrainment, on the other hand, refers to situations where small fish, eggs and/or larvae are drawn in to cooling water systems. Under the final rule, affected facilities will be required to reduce fish impingement by either installing specific "fish-friendly" screens and fish return systems, with subsequent monitoring to show specified fish and shellfish mortality standards have been met, or by demonstrating that the intake velocity meets specified design criteria.

Entrainment technology determination, under the final rule, will rely on state permit writers' best professional judgment, after taking into consideration a suite of site-specific factors. For facilities withdrawing more than 125 million gallons per day, entrainment studies will be required to determine the appropriate best technology available. Technologies to meet the rule requirements will be implemented under a timeline developed during the next five-year NPDES permit cycle for affected facilities. Where required on Minnesota Power units, expected impingement technology would likely be installed in the 2020-2025 timeframe. Minnesota Power has evaluated the final rule and determined that the technology required on its facilities will likely include moderate measures such as intake netting.

Regulation of Water Effluent

On April 19, 2013, the EPA proposed new effluent limitations guidelines for the steam electric discharge category under the Clean Water Act. The final ELG rule is expected to be issued by September 15, 2015. The proposed rule solicited comments on a range of eight different regulatory options that vary in terms of number of waste streams covered, size of units controlled, and stringency of controls required. The proposed rule could requlate the following wastewater streams generated by Minnesota Power's steam generating facilities (primarily Boswell Energy Center): bottom ash transport water, Flue Gas Desulfurization ("FGD") waters, and non-chemical metal cleaning wastewater. The proposed rule indicates a compliance timeline for implementation to be as soon as possible after July 1, 2017, but no later than July 1, 2022. Legacy wastewaters generated before 2017 may not be regulated under the revised ELG but would still need to meet state water quality standards. Potential scenarios for ELG compliance are addressed in the EPA Sensitivity in this Plan, and Minnesota Power will continue to the evaluate potential capital investments necessitated by this rule. As the final ELG rule has not been issued, Minnesota Power does not have the necessary clarity to determine the specific technology requirements that may be needed at its facilities.

Additional requirements on wastewater quality may also be imposed by the MPCA during triennial reviews or by special rulemaking. For example, the State of Minnesota has an existing 10 mg/L sulfate limit based on wild rice protection, which has historically not been implemented into most Minnesota NPDES permits and which the MPCA has recently announced it intends to revise. Due to increased scrutiny of the sulfate limit in recent years, implementation of a sulfate limit on NPDES permittee that discharge to wild rice waters is possible in the 2016 - 2018 timeframe, pending the results of state-funded and independent wild rice research, “wild rice water” waterbody classifications, and state water quality rulemaking. Minnesota Power continues to monitor new developments through the Minnesota study and rulemaking process and will ensure its facilities continue to meet any applicable permit requirements.

B. Projected Impact on Minnesota Power’s Generation Facilities

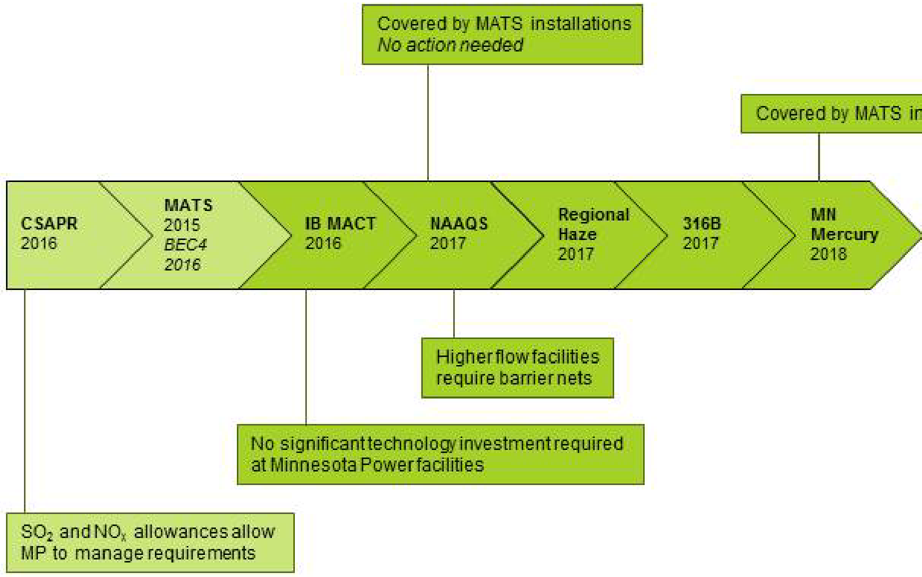
As part of its ongoing planning process, the Company has assessed the potential impact of these recently enacted and proposed rules. Since the level of stringency that will be required for the final implementation is not yet clear on all regulations being monitored, Minnesota Power identified a sensitivity approach to determine the potential impacts that the rules that currently lack clarity could have on its Boswell, Laskin, and Taconite Harbor Energy Centers.

Minnesota Power is in a better position than many utilities regarding these rules due to its significant level of voluntary reduction efforts implemented over the past decade such as the AREA Plan and BEC3 retrofit. Even so, some rules have the potential to require additional measures to be implemented with some yet unknown level of stringency, as summarized below. In general, the farther out the proposed implementation date the more uncertainty there is surrounding the regulation, making rules, such as CCR, ELG, and GHG for existing sources very uncertain.

<u>Base Case</u>

The Base Case for the 2015 Plan identified that all but three regulations (Effluent Limit Guidelines, Coal Combustion Residual (“CCR”) and Greenhouse Gas) have clarity on their status and would be considered part of its Base Case outlook. In particular, Minnesota Power performed two analyses with subtitle D for the CCR rule. The Base Case is characterized in Figure 10.

Figure 10: Minnesota Power's Base Case Assumption for Environmental Regulation



As previously mentioned, since many of the rules impact the same pollutant, the controls that may be required to meet one regulation will cover another. For example, in the Base Case it is assumed that the environmental control technologies required for the MATS rule will meet the pending NAAQS requirements. The assumptions for the Base Case make up the best known information for each rule at this time; however, information can change significantly prior to final rule implementation.

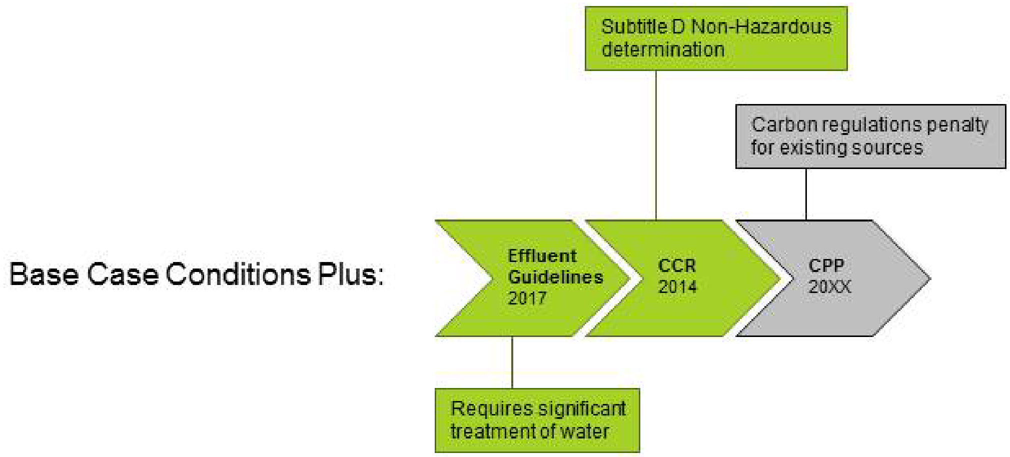
EPA Sensitivity

The EPA Sensitivity included those regulations that currently have the highest level of uncertainty. The key difference of this outlook from the Base Case is that this outlook includes all Base Case considerations plus:

- The need to dewater and close ash impoundments and construct new ash storage facilities as a result of the ELG and CCR Rule

The additions to the EPA Sensitivity are characterized in Figure 11.

Figure 11: Minnesota Power's EPA Sensitivity Assumption for Environmental Regulation



Minnesota Power Generating Unit Outlook

To identify the cost estimates for the Base Case and EPA Sensitivity, it was necessary to clarify which Minnesota Power generating units are impacted by the regulations included. Table 2 summarizes which units or set of units are impacted by each of the regulatory programs. As Table 2 illustrates, Minnesota Power's generation fleet has significant control technology in place.

Table 2: Summary of Proposed Regulatory Program Potential Impacts on Minnesota Power Facilities

Program (and Constituents)	Boswell Units 1&2	Boswell Unit 3	Boswell Unit 4	Laskin Units 1&2	Tac Harbor Units 1&2	Tac Harbor Unit 3	Hibbard Units 3&4	Rapid Units 5&6
Consent Decree				GAS REFUEL		RETIRED		
SO2	BC	☑	☑		☑			n/a
NOx	☑	☑	☑		☑			n/a
Particulate	☑	☑	☑		☑			n/a
MATS								
Mercury	☑*		☑		☑			
Acid gases	☑*		☑		☑			
Particulate	☑*		☑		☑			
Industrial Boiler MACT								
Mercury							Fuel Driven	Fuel Driven
Acid gases							Fuel Driven	Fuel Driven
Particulate							n/a	n/a
Carbon monoxide							Fuel Driven	Fuel Driven
MN MERA/Mercury Rule								
Mercury	n/a	☑	☑		☑		n/a	n/a
NAAQS								
SO2	☑*		☑	☑	☑		Fuel Driven	Fuel Driven
NOx	☑*		☑	☑	☑		☑	☑
Regional Haze								
SO2		☑						
NOx		☑						
CCR	S	S	S	S	S			
316(b)	S	n/a	n/a	☑	S		n/a	n/a
Effluent Guidelines	S	S	S	S	S		n/a	n/a

*Compliance at common stack, controls updated as needed for compliance
"BC" represents Base Case outlook, "S" represents EPA Sensitivity
☑ = Updated controls installed
n/a = Due to nature of regulation, able to comply on a facility wide basis and/or with existing controls
Shaded areas, does not apply

Minnesota Power utilized the assumptions of each outlook and the impacted generating facilities to estimate the capital investment and ongoing O&M costs that could be required for the regulation. The Base Case and EPA Sensitivity impacts are summarized by unit, or set of units, below.

<u>Boswell Energy Center Units 1 and 2 ("BEC1&2")</u>

For BEC1&2, the MATS and additional SO_2 regulations are the most critical consideration in the Base Case outlook. Compliance by these units is generally demonstrated at the common stack with BEC3. With the proactive reductions the Company made at BEC3, this facility overall has extremely well-controlled emissions. The range of cost impacts on BEC1&2 for the Base Case is represented in Table 3.

Table 3

[TRADE SECRET DATA EXCISED]

Base Case Outlook for BEC1&2

Air Emissions

As described in Appendix C, BEC1&2 currently employ low NO_x burners and Selective Non-Catalytic Reduction ("SNCR") for NO_x control, and a fabric filter for particulate matter ("PM") control. BEC1&2 utilize low sulfur, low mercury fuel from the Powder River Basin in Wyoming and Montana. In alignment with Minnesota Power's long-term action plan, the sole remaining emission control project in its thermal fleet is to control SO_2 from BEC1&2 to improve NAAQS compliance margin.

Minnesota Power entered into a consent decree ("CD") with the U.S. EPA in 2014. Pursuant to the CD, Minnesota Power agreed to retire, refuel to non-fossil fuel, or re-route the flue gas from BEC1&2 through the BEC3 scrubber by the end of 2018. With the filing of this Plan, Minnesota is proposing to re-route the BEC1&2 flue gas through the BEC3 scrubber to comply with this CD commitment and to substantially reduce the SO_2 emissions from BEC1&2.[4]

Mercury (MATS)

The MATS Rule requires coal-fired units to meet a mercury emission limit. The fabric filter, installed for the purpose of controlling emissions of particulate matter, also incidentally achieves significant mercury control co-benefits. Because of this, and the ability to do facility averaging under the proposed MATS, BEC1&2 did not require additional technology to reduce mercury under the MATS Rule in the Base Case outlook.

[4] In August 2008, Minnesota Power received a Notice of Violation ("NOV") from the EPA asserting violations of the New Source Review ('NSR") requirements of the Clean Air Act at Boswell Energy Center Units 1, 2, 3 and 4 and Laskin Energy Center Unit 2 ("LEC2"). The NOV asserted that seven projects undertaken at these coal-fired plants between the years 1981 and 2000 should have been reviewed under the NSR requirements and that the BEC4 Title V permit was violated. September 29, 2014, Minnesota Power entered into a consent decree with the United States of America and the State of Minnesota, resolving the allegations contained in the NOVs without admitting liability. Minnesota Power chose to settle, rather than litigate, the claims in the NOVs "solely to avoid the costs and uncertainties of litigation and to improve the environment" (Consent Decree, p. 2).

Acid Gases (MATS)

The MATS Rule requires Minnesota Power facilities to meet a hydrochloric acid limit (“HCl”). By controlling for HCl there are reductions in the other acid gases of concern. No acid gas control technology is assumed under the Base Case outlook. Minnesota Power burns low mercury, low sulfur, and low chlorine Powder River Basin coal, and BEC1&2 meets the HCI limit without additional controls.

Water Issues/Waste Management

CCR

At the time of the analysis for the 2015 Plan, Minnesota Power’s evaluation of the potential impacts of the coal combustion residuals rule published on April 17, 2015, was still under development. Due to the range in compliance options, and the unknown impact of the as-yet-performed landfill and impoundment evaluations on final compliance direction, inclusion of additional CCR impacts in the Base Case is not appropriate until more detail has been achieved. Therefore, these uncertainties were considered in an EPA sensitivity.

316(b)

It is expected under the Base Case outlook that BEC1&2 will need to install a barrier net at the intake structure to meet impingement requirements. Entrainment requirements (fish/eggs/larvae drawn into the cooling water systems) will be determined by the MPCA on a set of site-specific criteria, taking into account studies of entrainment levels for each facility, the cost for entrainment control technology that must include closed-cycle cooling (cooling towers), and other factors. BEC1&2 are not expected to require any additional measures beyond a barrier net to address entrainment requirements the Base Case.

EPA Sensitivity Outlook for BEC1&2

ELG

Under the EPA Sensitivity outlook, a final EPA rule setting new water discharge requirements for Steam Electric Stations will be applied to wet flue gas desulphurization (“WFGD”) streams, and fly ash contact water discharge would be banned. The WFGD standards will apply to external and internal discharges prior to co-mingling with other wastewater streams or cooling water flows. The new Effluent Limits could require significant wastewater treatment upgrades to remove mercury, selenium and arsenic for certain wastewater streams; however, wastewater from BEC1&2 consists almost entirely of the portion of sluice water used to convey bottom ash for those units. Under the proposed ELG Rule, only units over 400 MW would face potential conversion to dry bottom ash handling, so minimal impacts are anticipated for BEC1&2 in the EPA sensitivity.

CCR

Under the EPA Sensitivity, the final EPA coal ash rule results in a compliance scenario that includes significant upgrades to ash disposal facilities, including pond closures involving wastewater treatment to meet both state and federal requirments.

Boswell Energy Center Unit 3

For BEC3, the range of cost impacts on the unit for the Base Case and the EPA Sensitivity is represented graphically below. Largely, BEC3's portion of the water and coal combustion residual requirements is addressed under each outlook as BEC3 has already been retrofitted with extensive emission control equipment.

Table 4

[TRADE SECRET DATA EXCISED]

Base Case Outlook For BEC3

Air Emissions

As described in Appendix C, a major environmental upgrade was completed at BEC3 in 2009 to meet state and federal environmental requirements. Following the retrofit, the facility now employs low NO_x burners, over-fired air, and a selective catalytic reduction system for NO_x control, a WFGD system for SO_2 control, an activated carbon injection system, and a fabric filter for mercury and particulate control. These controls represent the state of the art for addressing air emission, and thus, no further air emission controls are anticipated.

Mercury (MATS)

The MATS Rule requires coal-fired units to meet a mercury emission limit. The activated carbon injection system and fabric filter was designed to capture up to 90 percent of the mercury. This system was installed to meet the expectations of the MERA. Because of significant emissions control this system affords for mercury, BEC3 did not need to do anything further to reduce mercury under the MATS regulation.

Acid Gases (MATS)

The MATS Rule requires Minnesota Power facilities to meet an HCl limit. The HCl limit is a surrogate for acid gas emissions. The WFGD system for SO_2 control is also effective at removing acid gases, including HCl. BEC3 meets the requirements of the proposed MATS without additional investment.

Particulate Matter (MATS)

The MATS Rule includes a PM limit as a surrogate for trace metals other than mercury. The fabric filter installed on BEC3 as part of the retrofit is effective at removing particulate, including associated trace metals. No additional control requirements were required.

Water Issues/Waste Management

CCR

At the time of the analysis for the 2015 Plan, Minnesota Power's evaluation of the potential impacts of the CCR Rule published on April 17, 2015, was still under development. Due to the range in compliance options, and the unknown impact of the as-yet-performed landfill and impoundment evaluations on final compliance direction, inclusion of additional CCR impacts in the Base Case are not appropriate until more detail has been received. Therefore, these uncertainties were considered in an EPA sensitivity.

316(b)

Entrainment requirements will be determined by the MPCA on a set of site-specific criteria taking into account studies of entrainment levels for each facility, the cost for entrainment control technology that must include closed-cycle cooling (cooling towers), and other factors. BEC3 is not projected to require any additional measures to address entrainment requirements under the Base Case outlook since it already has a cooling tower in place.

EPA Sensitivity

ELG

Under the EPA Sensitivity outlook, a final EPA rule setting new water discharge requirements for Steam Electric Stations will be applied to WFGD streams, and fly ash contact water discharge will be banned. The WFGD standards will apply to external and internal discharges prior to co-mingling with other wastewater streams or cooling water flows. The new Effluent Limits may require significant wastewater treatment upgrades to remove mercury, selenium and arsenic if excess water from the current closed-loop Unit 3 FGD pond needs to be discharged. Any prohibition on bottom ash water discharge is anticipated to apply only to units over 400 MW, so would not apply to BEC3.

CCR

Under the EPA Sensitivity the final EPA coal ash rule results in a compliance scenario that includes significant upgrades to the ash disposal facilities, including pond closures involving associated wastewater treatment to meet state and federal requirments. Some of the costs of these additional measures would be borne by BEC3 if the FGD impoundment, bottom ash impoundment, or dry ash cell were impacted.

Boswell Energy Center Unit 4

For BEC4, the Mercury Emission Reduction Project ("BEC4 Project") will address all of the air regulation requirements currently included in the Base Case and have overall positive impacts on future water treatment regulation as new systems require less water. The range of cost impacts on the unit based on Base Case and EPA Sensitivity analyses are represented in Table 5.

Table 5

[TRADE SECRET DATA EXCISED]

Base Case Outlook For BEC 4

Air Emissions

BEC4 is currently undergoing a major control retrofit to add a semi-dry flue gas desulfurization system, fabric filter and powder activated carbon injection system. The new multi-pollutant system will reduce mercury, particulate matter, sulfur dioxide and other hazardous air pollutants while also reducing plant waste water. Combined with BEC4's existing low NO_x burners, separated over-fire air, and SNCR technologies for NOx control, the new BEC4 retrofit project will help achieve compliance with MATS, MERA, and other enacted or pending federal and state environmental rulemakings regulating air and water emissions and solid byproducts from coal-fired power plants.

Mercury (MATS, MERA)

The MATS Rule requires coal-fired units to meet a mercury emission limit. Under MERA, Minnesota Power is installing mercury control technology on BEC4 to achieve 90 percent mercury removal Under the Base Case outlook, this emission limit and technology also complies with the MATS mercury limit. The mercury control technology was compared to other remission and retirement alternatives and found to be the best alternative.

Acid Gases (MATS)

The MATS Rule will require Minnesota Power facilities to meet a HCl limit. The HCl limit is a surrogate for acid gas emissions. The WFGD system for SO_2 control is also effective at removing acid gases, including hydrochloric acid. Under the Base Case outlook, it is anticipated that the BEC4 Project will meet the requirements of the proposed MATS without additional investment.

Water Issues/Waste Management

CCR

At the time of the analysis for the 2015 Plan, Minnesota Power's evaluation of the potential impacts of the CCR Rule published on April 17, 2015, was still under development. Due to the range in compliance options, and the unknown impact of the as-yet-performed landfill and impoundment evaluations on final compliance direction, inclusion of additional CCR impacts in the Base Case is not appropriate until more detail has been achieved. Therefore, these uncertainties were considered in an EPA sensitivity.

316(b)

Entrainment requirements will be determined by the regulator (MPCA) on a set of site-specific criteria taking into account studies of entrainment levels for each facility, the cost for entrainment control technology that must include closed-cycle cooling (cooling towers), and other factors. BEC4 is not projected to require any additional measures to address entrainment requirements under the Base Case outlook, since it already has a cooling tower in place.

EPA Sensitivity

ELG

Under the EPA Sensitivity, a final EPA rule setting new water discharge requirements for Steam Electric Stations will be applied to WFGD streams, and fly ash contact water discharge will be banned. The WFGD standards will apply to external and internal discharges prior to co-mingling with other wastewater streams or cooling water flows. The new Effluent Limits could require significant wastewater treatment upgrades including physical/chemical upgrades to remove mercury, selenium and arsenic. After the Unit 4 retrofit, BEC4 will no longer have a wet fly ash handling system or a wet FGD stream to which these restrictions would apply. The ELG may apply to legacy wastewaters from Unit 4 wet scrubbing applications if discharge is required for pond dewatering Since Unit 4 is over 400 MW, a potential ban on bottom ash water discharge would require dry handling or a closed loop system for BEC4's bottom ash.

CCR

Under the EPA Sensitivity the final EPA coal ash rule results in a compliance strategy that includes pond closures involving wastewater treatment to dewater. Some of the costs of these additional measures would be borne by BEC4.

Laskin Energy Center Units 1 and 2

For LEC, the range of cost impacts on the units based on the Base Case and EPA Sensitivity analyses are represented graphically in Table 6.

Table 6

[TRADE SECRET DATA EXCISED]

Base Case Outlook For LEC

Air Emissions

The converted LEC boilers are exempt from the MATS rule, which does not regulate natural gas – only fired boilers.

Water Issues/Waste Management

CCR

At the time of the analysis for the 2015 Plan, Minnesota Power's evaluation of the potential impacts of the CCR Rule published on April 17, 2015, was still under development. Due to the range in compliance options, inclusion of additional CCR impacts in the Base Case is not appropriate until more detail has been received. Therefore, these uncertainties were considered in an EPA sensitivity.

316(b)

LEC already has a barrier net installed at the water intake to the facility, so it will meet this requirement under the Base Case outlook. Entrainment requirements will be determined by the regulator (MPCA) on a set of site-specific criteria taking into account studies of entrainment levels for each facility, the cost for entrainment control technology that must include closed-cycle cooling (cooling towers), and other factors. LEC is not expected to require any additional measures to address entrainment requirements.

EPA Sensitivity

ELG

The conversion of LEC to gas eliminates wet and dry handling of ash and associated wastewaters.

CCR

Cessation of coal ash disposal at Laskin eliminates the need for future impoundment or landfill construction.

Taconite Harbor Energy Center Units 1 and 2

For Taconite Harbor Units 1 and 2 ("THEC1&2"), the range of cost impacts on the units based on the Base Case and EPA Sensitivity analyses are represented graphically below.

Table 7

[TRADE SECRET DATA EXCISED]

Base Case Outlook THEC

Air Emissions

As described in Appendix C, THEC1&2 underwent environmental upgrades in 2007 and 2008, respectively, as part of the AREA Project, with installation of the Mobotec multi-pollutant control system for control of NO_x and SO_2 and conversion of the hot-side ESP to a cold-side ESP for improved particulate removal. The final mercury system (activated carbon injection "ACI") is installed on these two units.

Mercury (MATS)

The MATS Rule will require coal-fired units to meet a mercury emission limit. Under the Base Case outlook, the recently installed mercury emission controls will meet MATS requirements.

Acid Gases (MATS)

The MATS Rule requires Minnesota Power facilities to meet a HCl limit. The HCl limit is a surrogate for acid gas emissions. The Base Case outlook for THEC1 & 2 includes limited sodium bicarbonate injection to ensure consistent MATS HCl compliance.

Water Issues/Waste Management

CCR

At the time of the analysis for the 2015 Plan, Minnesota Power's evaluation of the potential impacts of the CCR Rule published on April 17, 2015, was still under development. Due to the range in compliance options, and the unknown impact of the as-yet-performed landfill evaluations on final compliance direction, inclusion of additional CCR impacts in the Base Case is not appropriate until more detail has been received. Therefore, these uncertainties were considered in an EPA sensitivity.

316(b)

THEC would likely have to install a barrier net at the water intake to the facility in order to meet the impingement requirement under the Base Case outlook. Entrainment requirements will be determined by the regulator (MPCA) on a set of site-specific criteria taking into account studies of entrainment levels for each facility, the cost for entrainment control technology that must include closed-cycle cooling (cooling towers), and other factors. Under the Base Case outlook, THEC is not expected to require any additional measures to address entrainment requirements.

EPA Sensitivity

ELG

Under the draft ELG rule, there are no expected material impacts anticipated for THEC.

Part 3: 2015 Plan Performance and Minnesota Environmental Targets

Minnesota Power's generation fleet continues to evolve forward to achieve even of the higher levels of efficiency with less environmental impact. Initiatives taken by the State of Minnesota, such as those described in Part 1 of this Appendix, combined with the installation of new control technology on its coal fleet, will continue the trend of reduced emissions of all types.

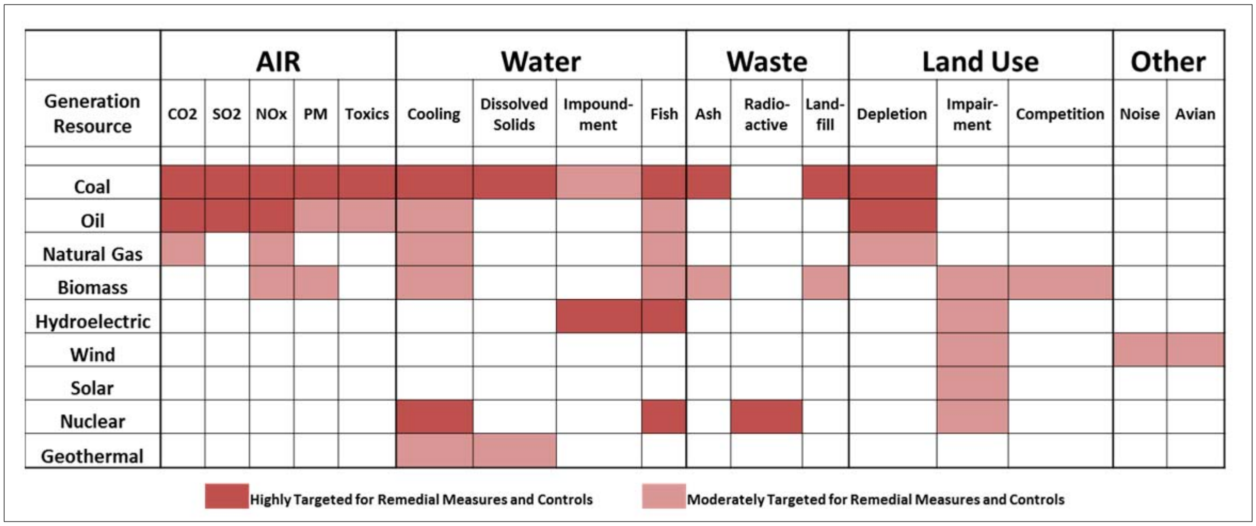
Coal units in operation will be outfitted to meet all applicable environmental standards, addressing the air, water and solid waste issues of concern. An array of newly deployed renewable energy resources, both directly owned and under contract, utilizing renewable wind, water (hydro) and wood (biomass) will help reduce or avoid the emissions of conventional, criteria pollutants like SO_2, NO_x, PM and mercury.

Contracted and purchased power will include additional hydroelectricity, efficient natural gas generation and a mix of purchased electricity from the regional wholesale market. These agreements help balance Minnesota Power's need for reliability, affordability and exemplary environmental performance. The measures taken by the Company follow the significant emissions reduction measures in place in Minnesota, that have been implemented over the last decade. Minnesota Power's *Energy**Forward*** strategy balances its planned delivery of customer electricity to one-third coal, one-third renewable energy and one-third natural gas.

Looking ahead, Minnesota Power expects the environmental footprint of electric utilities to shrink. As the MPCA has highlighted, the focus for further environmental performance improvements in the state will shift away from electric utilities to other emission source types that have emerged as significant contributors, such as the transportation sector's impact on urban air quality. Broader, multi-sector environmental issues like climate change, water use impacts and land management are emerging as key environmental issues as energy, mining, agriculture, forestry and economic policy priorities are balanced.

Minnesota Power's current and planned environmental performance measures recognize that selection amongst energy resource alternatives can significantly affect the cost, reliability and environmental performance associated with electricity supply. In addition to providing for environmental control retrofits to the Company's existing generation resources that improve their emissions profile, the 2015 Plan gave consideration to the alternative fuel types shown in Figure 12.

Figure 12: Electricity Generation Fuel Sources Carry Intrinsic Environmental Differences[5]

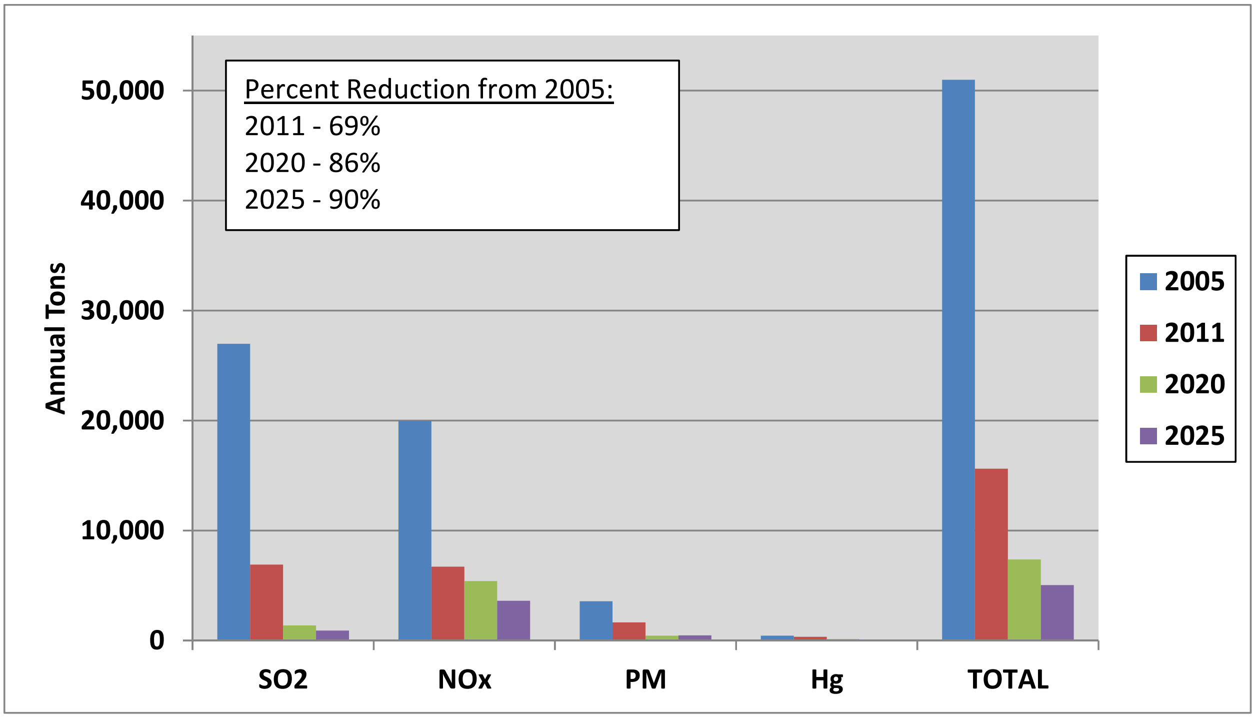


As portrayed in Figure 12, expanded use of renewable energy resources like hydroelectricity, wind, biomass and solar can deliver electric power to Minnesotans without requiring as many of the environmental control measures needed to support environmentally responsible fossil fuel (coal, oil and natural gas) generation. Minnesota also has a nuclear energy base (operated by utilities other than Minnesota Power) which avoids or reduces concerns about air emissions such as mercury, SO_2, NO_x, particulates and greenhouse gases, while exerting a need for special measures such as radioactive waste containment.

Minnesota Power's 2015 Plan provides for a balanced approach. Current and planned environmental control retrofits and unit transitions support operation with a cost optimized fuel mix for electricity generation, energy efficiency improvements and increased use of renewable energy resources. As shown in Figure 13, these measures build on the Company's record of exemplary environmental performance for the planning period.

[5] All these resources have/can receive operating permits.

Figure 13: Emission Reductions Achieved and Projected with Preferred Plan



These balanced measures reflect the combination of Minnesota policymakers' leadership and corporate environmental stewardship, delivering on the Minnesota environmental and energy policy goals through 2025 and beyond. The collective effect of the balanced measures taken by the Company meet or surpasses NGEA GHG reduction goal milestones for 2015. The Minnesota GHG reduction goals surpass measures under implementation or consideration both nationally (U.S. climate policy proposals under consideration) and internationally (Conference of Parties, Doha[6] objectives). Minnesota Power is achieving GHG reduction goal milestones through implementation of the Minnesota Legislature's desired conservation improvement, energy efficiency improvement and renewable energy deployment without special fees or burdening electricity customers with charges for CO_2e GHG emissions allowed under the NGEA reduction goals. The 2015 goal of 15 percent below 2005 GHG emission levels has been met and the Company is projecting to meet a 30 percent reduction by 2025 while implementing the 2015 Plan.

[6] The Doha Development Agenda is the second round, or conference of trade negotiations of the World Trade Organization that commenced in 2001.

Figure 14: Updated Carbon Emissions

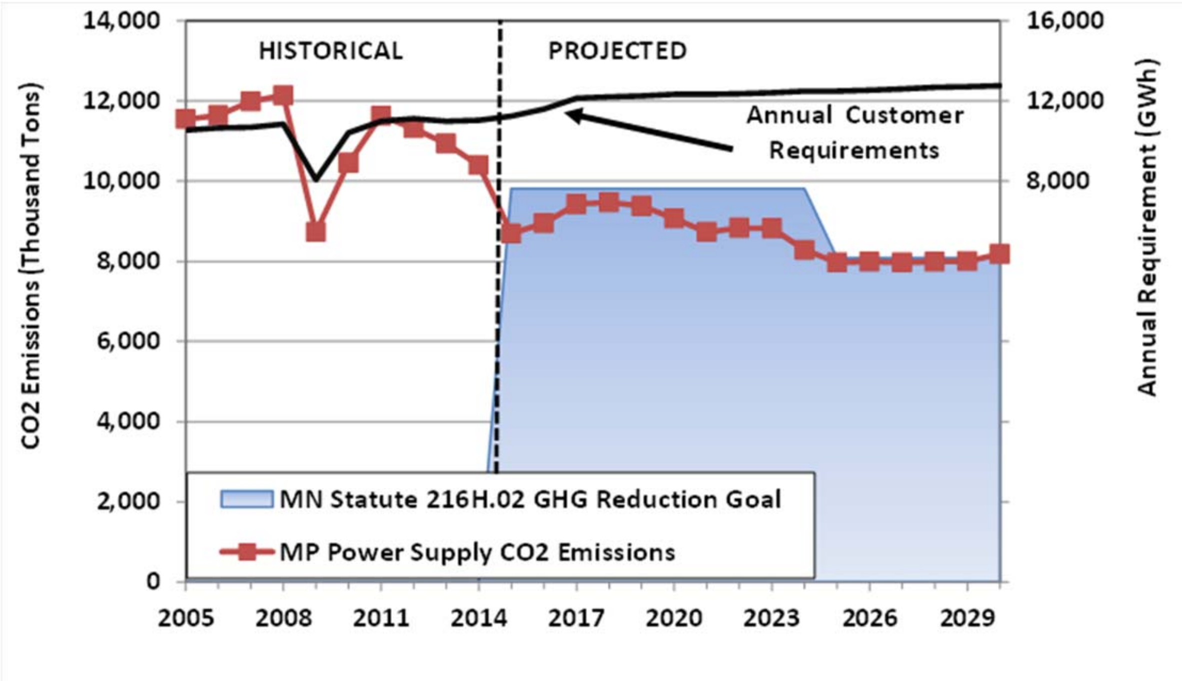
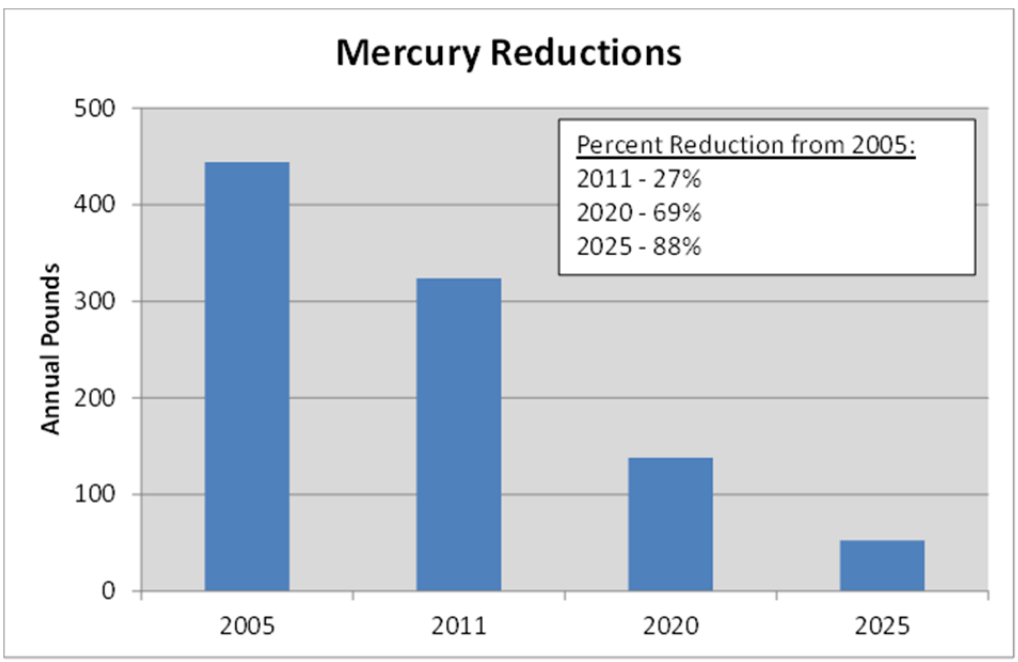


Figure 15: Minnesota Projected Mercury Reduction



Minnesota Voluntary Mercury Reduction Initiative Goal Milestones for 2025.

Pending national air toxics regulations require stringent reductions in mercury and surrogates for other air toxics (particulates and SO_2) from utility sector point sources. Minnesota established voluntary targeted reductions from all source types and instituted mandated requirements to reduce mercury from Minnesota's largest electric generation units in advance of federal requirements.

Early action under Minnesota programs has already reduced targeted emissions, as shown in Figure 14. Minnesota Power's AREA Plan combined with the control retrofits deployed on BEC3 in 2009 and BEC4 control retrofit currently in progress, plus supplemental NO_x emission reduction measures, are delivering emission reductions that comply with CSAPR, Regional Haze Rule, MATS and MERA requirements.

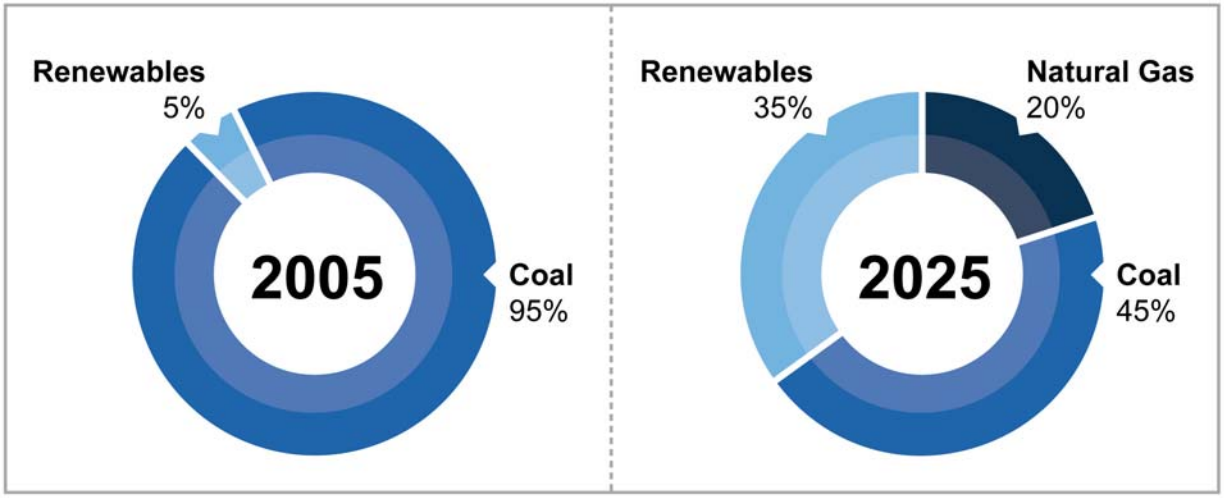
Existing Minnesota water quality requirements are expected to largely satisfy pending EPA requirements within the spectrum of stringency that the EPA has indicated is under consideration. Minnesota Power's water, wastewater and ash management measures already provide for treatment of water to meet discharge standards. While EPA's coal combustion residual requirements for impoundments and landfills may require additional action, existing operations are in full compliance with state requirements and future reductions in water discharges and increased beneficial use of ash byproducts position Minnesota Power well for increased regulation in this area.

Collectively, the array of measures implemented in Minnesota up to 2013 and through the 2015 Plan have positioned Minnesota Power to be well prepared for current and pending environmental requirements. Many of the resource actions taken to-date have resulted in significant emission reductions in Minnesota in advance of the onset of national mandates.

Minnesota Power's Changing Energy Mix

Minnesota Power is reducing its dependence on coal-based generation by balancing the resource mix the Company uses to serve its customers. The 2015 Plan reflects Minnesota Power's progress with meeting Minnesota targets while adjusting its resource mix to best meet the reliability, cost and environmental performance needs of its customers. Figure 16 shows how planned resource mix changes are delivering early reductions in greenhouse gas emissions that place Minnesota Power in a position to meet the NGEA 30 percent greenhouse gas emission reduction by 2025, in the aggregate.

Figure 16: Minnesota Power's Changing Energy Mix



Note: The 2015 Plan will move Minnesota Power toward its *Energy**Forward*** resource strategy and a supply that is made up of a third renewable, a third coal-fired, and a third natural gas and purchases over the long term.

Minnesota utilities have spent considerable resources to reduce green house gas emission's in the state. Minnesota Power is focused on delivering safe, reliable service at the lowest possible cost to customers while continuing to meet federal and state environmental requirements. To this point, Minnesota Power has brought forward it's 2015 Plan that will continue to bring the company's energy mix to one-third renewables, one-third coal, and one-third natural gas.

APPENDIX F: TRANSMISSION PLANNING ACTIVITIES

Part 1: Minnesota Biennial Transmission Projects Report Summary

Background

Every two years, Minnesota Power (or "Company") participates with the Minnesota Transmission Owners in the preparation and filing of the Minnesota Biennial Transmission Projects Report ("Biennial Report"). The Biennial Report is prepared pursuant to Minn. Stat. § 216B.2425, which requires any utility that owns or operates electric transmission facilities in the state of Minnesota to report on the status of its transmission system by November 1 of each odd numbered year. A major purpose of the Biennial Report is to provide information about all present and reasonably foreseeable transmission inadequacies that have been identified in the existing transmission system. An "inadequacy" is essentially a situation where the present transmission infrastructure is unable or unlikely to be able to perform in a consistently reliable fashion in compliance with regulatory standards in the reasonably foreseeable future. In addition to information about inadequacies and the projects proposed to address them, the Biennial Report provides information about the transmission planning process and about the utilities that own transmission lines in the state. The seventh Biennial Report (Docket No. E-999/M-13-402) was filed on November 1, 2013. This report, along with previous reports from 2001, 2003, 2005, 2007, 2009, and 2011, are publicly available on the internet.[1] The 2015 Biennial Report (Docket No. E-999/M-15-439), which will include an updated list of inadequacies and proposed projects, will be filed by November 1, 2015.

Minnesota Power's Transmission Projects

For purposes of the Biennial Report, the state of Minnesota has been divided geographically into six Transmission Planning Zones. Of these six zones, Minnesota Power is located wholly in the Northeast Zone. Table 1 provides the current status of and background information about each of the present and reasonably foreseeable future inadequacies that Minnesota Power reported in the 2013 Biennial Report. There are several inadequacies for which the need profile has changed since the 2013 Biennial Report, necessitating that the corresponding projects be cancelled. Cancelled projects have not been included in Table 1, but will be discussed in the 2015 Biennial Report. Table 2 provides information on future needs that have been identified by Minnesota Power since the filing of the 2013 Biennial Report. The projects listed in this table will be reported in the 2015 Biennial Report.

In both tables, each project is identified by its State Tracking Number as well as its MISO Midcontinent Transmission Expansion Planning ("MTEP") project number. The MTEP project numbers are utilized by the Midcontinent Independent System Operator ("MISO") to identify and track projects in the compilation of the annual MTEP Report. The table also includes the MTEP Year, which identifies the specific year of the MTEP Report in which the project was approved in its most recent Appendix. The MTEP Appendix classification indicates the status of the project

[1] http://www.minnelectrans.com.

in the regional planning process. For example "2011/A" indicates that the project was in the MISO MTEP Appendix A and approved in 2011. The MTEP Appendix definitions are as follows:

- Appendix A – Projects recommended for approval
- Appendix B – Projects still in the planning and review process

More information can be obtained on these projects by referring to the latest MTEP Report, available on the MISO website at http://www.misoenergy.org (Click on "Planning").

Table 1: Minnesota Power's Transmission Needs Identified in the 2013 Biennial Report

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2003-NE-N2	2011/A	2634	Savanna Project: 115 kV Savanna switching station and Savanna-Cromwell and Savanna-Cedar Valley 115 kV lines; St. Louis Co. Final project component expected to be completed in 2016. *Docket Nos. CN-10-973 and TL-10-1307*
2007-NE-N1	2014/B	2548	Duluth 230 kV Project: New 230/115 kV transformer & transmission line upgrade to 230 kV to increase load-serving capability in the Duluth area; St. Louis Co. Recent study indicates this project is not needed until the mid-2020 timeframe at the earliest.
2007-NE-N2	2010/A	2547	Essar Steel 230 kV Project: Transmission for Essar Steel, Grand Rapids – Nashwauk areas, Itasca Co. Phase 1 is completed. There are no current plans to construct Phase 2. *Docket No. TL-09-512*
2009-NE-N2	2013/A	3531	Deer River 230 kV Project: Construct Zemple 230/115 kV Substation to increase load-serving capability and improve reliability in Deer River and the surrounding area; Itasca Co. Anticipated in-service date 4Q 2015. Due to line length, a CoN was not required *Docket No. TL-13-68*
2011-NE-N1	2011/A	3373	9 Line Upgrade: Rebuild existing 115 kV line to higher capacity; Blackberry – Meadowlands, St. Louis Co & Itasca Co. Completed March 2015. A CoN & RPA were not required for this project.
2011-NE-N2	2015/B	7996	15 Line Upgrade: Rebuild & reconductor existing 115 kV line to higher capacity due to age & condition and system intact and post-contingent loading concerns, Fond Du Lac – Hibbard; Duluth area, St. Louis & Carlton Cos. Anticipated in-service date 2017.

Table 1: Minnesota Power's Transmission Needs Identified in the 2013 Biennial Report (continued)

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2011-NE-N5	2010/A	2761	Dunka Road Substation: Construct new 138/13.8 kV substation to serve new mine; Hoyt Lakes area, St. Louis Co. Project timing is dependent on customer need. Anticipated in-service date 2017.
2011-NE-N10	2009/A	2759	Laskin Transformer: Increase 115/46 kV transformer capacity and replace end-of-life equipment at existing Laskin Substation; Hoyt Lakes area, St. Louis Co. Anticipated in-service date 2017.
2011-NE-N10	2009/A	2759	Laskin Transformer: Increase 115/46 kV transformer capacity and replace end-of-life equipment at existing Laskin Substation; Hoyt Lakes area, St. Louis Co. Anticipated in-service date 2017.
2011-NE-N12	2013/B	3756	Wrenshall Substation: Develop new 115/69 kV substation in Thomson – Cromwell 115 kV Line to improve reliability in eastern Carlton County. The project will eliminate the need for existing distribution circuits that would otherwise need to be rebuilt due to age and condition and is also a lower cost alternative; Wrenshall, Carlton Co. Anticipated in-service date 2020.
2013-NE-N1	2013/A	4039	39 Line Reconfiguration: Reconfigure Laskin – Virginia 115 kV Line, easement expiration over mine property requires removal & relocation of the line; Eveleth area, St. Louis Co. Project completed in May 2014. Due to line length, a CoN was not required *Docket No. TL-12-1123*
2013-NE-N3	2013/A	4043	Two Harbors Transformer: New 115/14 kV transformer at Two Harbors Switching Station needed due to age & condition of existing Two Harbors substation; Two Harbors, Lake Co. Project completed in March 2014
2013-NE-N5	2013/A	4040	Canisteo Project: New substation in Boswell – Nashwauk 115 kV line to serve new industrial customer; Taconite, Itasca Co. Project completed November 2014. *Docket No. TL-13-805*

Table 1: Minnesota Power's Transmission Needs Identified in the 2013 Biennial Report (continued)

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2013-NE-N7	2014/A	4044	Canosia Road Substation: New 115/14 kV substation in Arrowhead – Cloquet 115 kV line to unload feeders at existing Cloquet Substation; Esko, Carlton Co. Anticipated in-service date 2016.
2013-NE-N8	2014/A	4045	Embarrass Transformer: New 115/23 kV transformer at Embarrass Switching Station to unload Laskin – Virginia 46 kV system; Hoyt Lakes area, St. Louis Co. Anticipated in-service date 2016.
2013-NE-N11	2012/A	3843	Arrowhead 230 kV Cap Bank: New 40 MVAR capacitor bank needed for voltage support at HVDC terminal; Hermantown, St. Louis Co. Completed in 2012.
2013-NE-N12	2012/A	3842	Bison 230 kV Cap Bank: New 40 MVAR capacitor bank needed for voltage support at Bison Wind Energy Center; New Salem, North Dakota. Completed in 2012.
2013-NE-N13	2014/A	3831	Great Northern Transmission Line: U.S. portion of new Manitoba – Minnesota 500 kV tie line, including 500 kV line from border crossing to Iron Range, new Iron Range 500/230 kV Substation adjacent to existing Blackberry 230/115 kV Substation, new Warroad River midpoint series compensation station, and 230 kV modifications required to interconnect Iron Range Substation, needed to facilitate PPA's between MP & Manitoba Hydro; Roseau, Lake of the Woods, Koochiching, and Itasca Cos. Anticipated in-service date June 1, 2020.
2013-NE-N14	2013/A	4293	NERC Facility Ratings Alert Medium Priority: Derates & physical mitigation on NERC "Medium" priority lines; MP system-wide. Completed in June 2014.
2013-NE-N15	2013/A	4294	NERC Facility Ratings Alert Low Priority: Derates & physical mitigation on NERC "Low" priority lines; MP system-wide. Anticipated completion in December 2016.
2013-NE-N16	2013/B	4295	HVDC Valve Hall Replacement: Modernization of Arrowhead & Square Butte converter stations; Hermantown, St. Louis Co. & Center, North Dakota. Anticipated in-service date 2020.

Table 1: Minnesota Power's Transmission Needs Identified in the 2013 Biennial Report (continued)

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2013-NE-N17	2014/B	3856	HVDC 750 MW Upgrade: Upgrade capacity of existing HVDC line & terminals to 750 MW; Hermantown, St. Louis Co. & Center, North Dakota. Anticipated in-service date 2020.
2013-NE-N19	2014/A	4426	Hoyt Lakes Sub Modernization: Rebuid and reconfigure Hoyt Lakes Substation to serve new industrial customer; Hoyt Lakes area, St. Louis Co. Project timing is dependent on customer need. Anticipated in-service date 2017.
2013-NE-N21	2015/A 2016/A	7999 4378	Menahga Area 115 kV Project: New Hubbard – Straight River – Blueberry (Menahga) – Sebeka 115 kV Line needed to serve a new pumping station and improve load-serving capability for the 34.5 kV system between Verndale and Hubbard. MP portion of the project is the Straight River 115/34.5 kV Substation (MTEP Project #7999); Hubbard Co. Anticipated in-service date for Straight River Substation is Fall 2016. *Docket Nos. CN-14-787 and TL-14-797*

Table 2: Minnesota Power's Transmission Needs Identified Since the 2013 Biennial Report

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2015-NE-N1	2015/B	7910	5 Line Upgrade: Reconductor existing 115 kV line to increase capacity, Mud Lake – Brainerd; Brainerd Area, Crow Wing Co. Anticipated in-service date 2019
2015-NE-N2	2015/B	7913	868 Line Upgrade: Reconductor existing 115 kV line to increase capacity; Little Falls – St. Stephen Tap; Morrison, Benton, and Stearns Cos. Anticipated in-service date 2019
2015-NE-N3	2015/A	7995	Maturi 115/23 kV Transformer: Add 115/23 kV transformer at existing Maturi Substation to increase load-serving capacity between Hibbing and Virginia; St. Louis Co. Anticipated in-service date December 2015
2015-NE-N4	2015/B	7997	15th Avenue West Modernization: Rebuild & modernize existing 15th Ave West Substation due to age & condition and safety concerns; Duluth, St. Louis Co. Anticipated in-service date 2018.
2015-NE-N5	2015/A	8000	16 Line Relocation: Relocate a segment of existing 115 kV line around proposed United Taconite tailings basin expansion; St. Louis Co. Anticipated in-service date 2018. *Docket No. TL-14-977*
2015-NE-N6	2015/B 2016/A	7998 7896	Motley Area 115 kV Project: New 115 kV line and expansion of existing Dog Lake Substation needed to serve a new pumping station and improve load-serving capability for the 34.5 kV system between Baxter and Staples. MP portion of the project is the Dog Lake Substation Expansion (MTEP Project #7998); Cass, Morrison, and Todd Cos. Anticipated in-service date for Dog Lake Substation Expansion is 2017. *Docket Nos. CN-14-853 and TL-15-204*
2015-NE-N7	2016/A	9062	Maturi 115/34.5 kV Transformer Replacement: Replace existing transformer with a larger one to accommodate increased industrial customer load. Relocate existing transformer to new Straight River Substation (MTEP Project #7999); Hibbing area, St. Louis Co. Anticipated in-service date is May 2016.

Table 2: Minnesota Power's Transmission Needs Identified Since the 2013 Biennial Report (continued)

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2015-NE-N8	2016/A	9063	Hat Trick 115 kV Project: New 115/23 kV substation near Eveleth needed to accommodate removal of 23 kV feeders along Highway 53 Relocation for United Taconite mine pit expansion; Eveleth, St. Louis Co. Anticipated in-service date is 2016.
2015-NE-N9	2016/B	9064	Arrowhead 115 kV Bus Reconfiguration: Reconfigure Arrowhead Substation 115 kV bus to eliminate critical breaker failure contingency that could cause a voltage collapse; Hermantown, St. Louis Co. Anticipated in-service date 2019
2015-NE-N10	2016/A	9061	Minntac 230 kV Bus Reconfiguration: Add breakers and relocate an existing 230 kV line to reconfigure existing Minntac 230 kV substation into a 4 position ring bus in order to eliminate a breaker failure contingency that causes multiple post-contingent power flow violations in the area; Mountain Iron, St. Louis Co. Anticipated in-service date is October 2016.
2015-NE-N11	2016/A	9060	Forbes 230/115 kV Transformer Addition: Add a second 230/115 kV transformer at the existing Forbes Substation to mitigate post-contingent transformer overloads; Forbes area, St. Louis Co. Anticipated in-service date is October 2016.
2015-NE-N12	2014/B	3832	Iron Range – Arrowhead 345 kV Line: Add 500/345 kV equipment at Iron Range Substation and extend a 345 kV line from Iron Range to existing Arrowhead Substation in order to increase Manitoba – United States transfer capability; Itasca and St. Louis Cos. Project timing is dependent on Manitoba Hydro need for increased transfer capability. There are no current plans to construct this project.

Part 2: Great Northern Transmission Line

Background

Minnesota Power, in partnership with Manitoba Hydro, is planning to construct a new interconnection from southern Manitoba to northeastern Minnesota. The Great Northern Transmission Line ("GNTL") Project is the Minnesota portion of the new 500 kV interconnection between Manitoba and Minnesota. The purpose of the Great Northern Transmission Line Project is to efficiently provide Minnesota Power's customers and the Midwest region with clean, emission-free energy that will:

- Help meet the region's growing long-term energy demands
- Advance Minnesota Power's *Energy**Forward*** strategy to increase its generation diversity and renewable portfolio
- Strengthen system reliability
- Fulfill Minnesota Power's obligations under its power purchase agreements with Manitoba Hydro

The GNTL will facilitate 883 MW of incremental Manitoba – United States transfer capability, including 383 MW of hydropower and wind storage energy products to serve Minnesota Power's customers. Minnesota Power's 250 MW Power Purchase Agreement and 133 MW Renewable Energy Optimization Agreement with Manitoba Hydro both require that new transmission facilities be in place by June 1, 2020, to facilitate the transactions. The Manitoba hydropower purchases made possible by the GNTL will provide Minnesota Power and other utilities in the Upper Midwest access to a predominantly emission-free energy supply that has a unique combination of baseload supply characteristics, price certainty, and resource optimization flexibility not available in comparable alternatives for meeting customer requirements.

Project Description

The GNTL Project includes approximately 220 miles of 500 kV transmission line between a point on the Minnesota – Manitoba border northwest of Roseau, Minn., and Minnesota Power's existing Blackberry Substation near Grand Rapids, Minn. The Project also includes the development of a new substation (Iron Range 500/230 kV Substation) located on the same site as the existing Blackberry Substation as well as a 500 kV midline series capacitor bank station (Warroad River Series Compensation Station) located near Warroad, Minnesota.

Project Status

In anticipation of the GNTL Project's aggressive schedule and needing to meet a June 1, 2020, in-service date, Minnesota Power initiated a proactive public outreach program to key agency stakeholders and the public that started in August 2012 and continued through May 2015. Through this program, thousands of landowners, the public, and federal, state, and local agency stakeholders were engaged through a variety of means, including five rounds of voluntary public open house meetings held throughout the Project area.

On October 21, 2013, Minnesota Power submitted an Application for a Certificate of Need to construct the 500 kV GNTL and associated facilities to the Minnesota Public Utilities

Commission ("Commission"). Docket No. E-015/CN-12-1163. This was the first major step in the regulatory review process. Subsequently, on April 15, 2014, Minnesota Power simultaneously filed a Route Permit Application (Docket No. E-015/TL-14-21) and a Presidential Permit Application (DOE Docket No. PP-398), to the Commission and the United States Department of Energy, respectively. On May 14, 2015, the Commission granted Minnesota Power a Certificate of Need to construct the GNTL. Decisions on the Route Permit Application and Presidential Permit Application are expected in early 2016.

On September 23, 2014, Minnesota Power, Manitoba Hydro, and MISO executed a Facilities Construction Agreement ("FCA") for the GNTL Project, setting forth the ownership and financial responsibilities for the Project, among other terms. Upon approval of the FCA by the Federal Energy Regulatory Commission ("FERC") on November 25, 2014, MISO considered the Project an approved project under the MISO tariff and moved the GNTL Project to Appendix A of the MTEP14 (Midcontinent Transmission Expansion Plan 2014).

Pending the applicable regulatory approvals, Minnesota Power expects to begin construction of the GNTL Project in 2017 in order to meet the required in-service date of June 1, 2020, in order to satisfy the contractual arrangements between Minnesota Power and Manitoba Hydro.

Part 3: High Voltage Direct Current (“HVDC”) Line Modernization and Capacity Upgrades

Background

In early 2010, Minnesota Power finalized its purchase of a 465 mile, +/- 250 kV HVDC line (“DC Line”) that connects Center, N.D., and Hermantown, Minn. The line and its converter terminals at the Square Butte and Arrowhead substations were built in the 1970’s to bring electricity from the coal-fired Milton R. Young 2 (“Young 2”) generating station in Center, N.D., to Minnesota Power’s customers. Minnesota Power’s purchase of the DC Line in 2010 cleared the way for the line to be repurposed to facilitate the delivery of wind power generated in North Dakota to Minnesota Power’s customers. Since the DC Line is a critical component of Minnesota Power’s efforts to diversify its energy resources and meet the Minnesota state renewable requirements, Minnesota Power has been evaluating the need for modernization and capacity upgrades to extend the life and usefulness of the facility. Between 2010 and 2013, Minnesota Power completed a series of upgrades that increased the capacity of the DC Line by 50 MW, culminating in a November 20, 2013 release for operation at 550 MW. Additional DC Line upgrade options that have been identified by Minnesota Power are briefly described below.

HVDC Modernization

Transmission system infrastructure and equipment are essential components of delivering a reliable and safe power supply. Aging infrastructure across the U.S. has gained more attention in the recent past as many systems reach the end of their life expectancy and need to be maintained in order to keep up with electric system demands. Minnesota Power, as part of its acquisition of the DC Line, began its evaluation of the need to modernize and maintain the equipment associated with the DC Line operation. The modernization of the HVDC equipment is a prudent and necessary activity to ensure the ongoing operation of this critical piece of transmission for Minnesota Power’s customers.

Minnesota Power is evaluating a series of modernization activities for each of the major components of the HVDC system. Along with the thyristor valves, the Company can reduce the likelihood of forced outages of the 465 mile transmission line by planning replacement of transformers and smoothing reactors. Minnesota Power continues to evaluate the timing and priority for modernizing each of these components.

HVDC Capacity Upgrades

With new equipment there is opportunity to consider new designs, technology capabilities and system enhancements. Specifically with the thyristor valves, Minnesota Power has the opportunity to design a system capable for up to 750 MW while utilizing the existing building and real estate.[2] The new valves provide advantages of life extension (of at least 30 years) and the option to allow energy to flow in both west to east and east to west directions that would add a

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[2] Additional equipment upgrades would be necessary to upgrade the capacity of the DC Line to 750 MW. The converter transformers, AC filter banks and transmission line capability would need to be studied and would need to be replaced or increased in size.

new and positive dynamic to the regional transmission system. The decision to size the system for 750 MW operation will need additional study and be determined during the final design phase for the modernization activities.

Current Status

Both the HVDC Valve Hall Replacement Project and the potential HVDC 750 MW Upgrade Project are currently in the MISO MTEP Appendix B. The timing of these two projects will be identified based on Minnesota Power's reliability and economic evaluations. Minnesota Power is actively monitoring both projects and looking for opportunities to execute them while balancing system reliability needs with costs to customers and prioritization of all capital projects.

Part 4: Transmission System Analysis of Small Coal Unit Closures

Evaluating the transmission system impacts of a generating unit closure encompasses considering both local and regional reliability. Minnesota Power conducted a local transmission system impact study that evaluated the closure of Taconite Harbor Energy Center Units 1 and 2 (“THEC1&2”) in response to the Commission’s Order Point 14 from Minnesota Power’s 2013 Integrated Resource Plan (“2013 Plan”).[3] As an additional part of the evaluation conducted to develop the 2015 Integrated Resource Plan (“2015 Plan,”) Minnesota Power also conducted a local transmission system impact study that evaluated the closure of Boswell Energy Center Units 1 and 2 (“BEC1&2”). After a brief overview of the key items associated with local and regional transmission evaluation, the remainder of this section will concentrate on the conclusions derived from the local system impact studies performed by Minnesota Power.

Local Impacts

Local impacts consider the transmission and distribution system that Minnesota Power and other interconnected utilities use to serve their customers, particularly in the area surrounding the generation resource to be closed. Due to their intimate knowledge of the local transmission system, studies to determine the local impacts of a generating unit closure are typically conducted by utility transmission planners.

Key items in a local transmission system impact study include the impact of unit closures on system normal and post-contingent transmission line loadings, substation bus voltages, and transient period (dynamic) performance. Due to the unique demands of Minnesota Power’s large industrial customers, nearby unit closures can have an inordinate impact on customer operation. Therefore, a local system impact study should also focus on the particular impact of unit closures on large industrial customers located near the generation facilities being evaluated.

Regional Impacts

Regional impacts of generating unit closures on the transmission system consider transmission lines 100 kV and above owned and operated by the generation owner and neighboring utilities. Because Minnesota Power is a member of MISO, the regional transmission planner and operator for much of the Midwest, any generating unit closure on the Minnesota Power system is required to utilize the MISO Attachment Y (unit retirement) process. Section 38.2.7 of the MISO Tariff describes the process for generator retirements:

1. First, the MISO market participant owning the generation resource involved must submit an Attachment Y to MISO stating when the generation resource is to be retired. This must be done at least 26 weeks before the targeted retirement date.
2. Second, MISO will perform reliability analyses to determine if the unit may be retired without causing reliability issues on the transmission system. North American Electric

[3] Order Point 14 (2013 Plan): In its next resource plan filing, Minnesota Power shall include a full analysis of the effect of retiring or repowering Taconite Harbor 1 and 2 plants, including transmission and distribution effects.

Reliability Corporation (“NERC”) Transmission Planning (“TPL”) standards and other applicable reliability criteria are applied.

3. Third, if the unit closure does not impact reliability, the unit is allowed to shut down as scheduled. If the unit closure results in reliability criteria violations on the transmission system, the unit is placed on a System Support Resource (“SSR”) agreement per Attachment Y-1 of the MISO Tariff. The unit will then remain operational under the SSR agreement until the transmission upgrades necessary to provide adequate transmission system reliability are constructed.

The Attachment Y process ultimately results in a binding agreement between the generation owner and MISO to either close the unit or keep it online as a SSR for the reliability of the regional transmission system. MISO also offers a parallel investigative option, called the Attachment Y-2 process, by which a utility can request an information-only study of the regional reliability impacts of a particular generating unit closure without entering into a binding agreement to close the unit or keep it online.

In late 2014, Minnesota Power submitted an Attachment Y to MISO stating its plans to place Taconite Harbor Energy Center Unit 3 (“THEC3”) into suspension starting June 1, 2015. Minnesota Power worked closely with MISO through the Attachment Y study process for THEC3 and no constraints were identified, allowing THEC3 to be placed into suspension as planned. Building on the local system impact analysis discussed below, Minnesota Power intends to work with MISO to initiate an Attachment Y-2 (non-binding) study to identify the regional impacts of shutting down THEC1&2.

Local Impact Evaluation of THEC1&2 Shutdown

Minnesota Power’s transmission planners completed steady state and dynamic transmission system analyses to capture the local system impacts of the closure of THEC1&2. The transmission system performance in the Taconite Harbor Energy Center (“THEC”) unit closure scenario was compared to the performance of the existing system under several of the most limiting system conditions. The next sections will outline the analysis conducted and identify the insights gathered for the closure of THEC1&2.

The North Shore Loop

THEC is located in the North Shore Loop, an area of the Minnesota Power transmission system that historically has been extremely generation-rich and serves a notable portion of the large industrial customers in Minnesota Power’s load requirements. The North Shore Loop includes the 115 kV and 138 kV transmission system between Duluth, THEC, and the Laskin Energy Center (“LEC”), as well as the three 115 kV lines that extend from the Laskin Substation to the rest of the transmission system. Besides Minnesota Power, Great River Energy also uses the North Shore Loop transmission system to serve its member cooperative customers, mainly from Minnesota Power-owned 115 kV lines and a 69 kV line originating at the Taconite Harbor Substation and extending east toward Grand Marais.

In recent years, load and generation changes on the North Shore Loop have greatly impacted the performance of the area transmission system. Historically, much of the power generated at LEC and THEC in the North Shore Loop flowed through and out of the local transmission system due to the excess of generation compared to the amount of load in the local area. Transmission system issues caused by this disparity were mitigated by a special protection system that required running back ("Taconite Harbor Runback") or tripping ("Taconite Harbor Tripping") a unit at THEC. With the conversion of LEC to a peaking natural gas plant in 2015 and with THEC3 going into suspension on June 1, 2015, these transmission system issues were largely (though not completely) alleviated, greatly reducing Minnesota Power's reliance on the North Shore Loop special protection system. As discussed in Minnesota Power's 2013 Plan, there is a delicate balance between load and generation in the North Shore Loop transmission system. In addition to the THEC1&2 unit closure scenario Minnesota Power considered in its local system study, anticipated load growth in the Hoyt Lakes area will continue to alter the balance of load and generation in the North Shore Loop transmission system, likely leading to new transmission system issues.

Steady State Analysis

Steady state analysis focused on the performance of area 46 kV, 69 kV, 115 kV, 138 kV, and 230 kV transmission lines and substations for Category P1 (generator, transmission line, transformer, and shunt device) and P2 (bus and breaker) contingencies, as defined in NERC Standard TPL-001-4, as well as selected P6 (multiple transmission line) and P7 (double circuit transmission line) contingencies. Steady state performance was evaluated based on the relevant criteria from Minnesota Power's Facility Loading and Voltage Criteria, given in Tables 3 and 4.

Table 3: Steady State Facility Loading Criteria

Minnesota Power Steady State Facility Loading Criteria			
Facility	**Continuous Rating**	**Emergency Rating[4]**	**Seasonal Ratings Apply**
Transmission Lines	100%	110%	Yes
Transformers	100%	125%	No

Table 4: Steady State Voltage Criteria

Minnesota Power Steady State Voltage Criteria				
	Pre-Contingent		**Post-Contingent**	
Rated Voltage	**Maximum Per Unit**	**Minimum Per Unit**	**Maximum Per Unit**	**Minimum Per Unit**
230 kV	1.05	1.00	1.10	0.95
138 kV	1.05	1.00	1.10	0.95
115 kV	1.05	1.00	1.10	0.95
69 kV	1.05	0.97	1.10	0.92
46 kV	1.05	0.97	1.10	0.92

[4] Facility emergency ratings may vary on a facility-by-facility basis depending on the limiting elements.

Dynamic Analysis

Because generators have the largest single impact on the stability of the transmission system, a quality dynamic, or stability, analysis was critical for capturing the local system impacts of unit closures. Dynamic analysis focused on the response of the North Shore Loop transmission system in the first five seconds (the “transient period”) after moderate to severe disturbances on the 115 kV and 138 kV network near THEC. These disturbances included both three phase faults and stuck breaker faults with delayed line and/or bus clearing. A handful of severe faults that have appeared as limiting disturbances in broader regional studies were also included. Dynamic performance was evaluated based on the relevant criteria from Minnesota Power’s Facility Loading and Voltage Criteria, given in Table 5.

Table 5: Transient Period Voltage Criteria

Minnesota Power Transient Period Voltage Criteria		
Rated Voltage	**Maximum Per Unit**	**Minimum Per Unit**
138 kV	1.20	0.82
115 kV	1.20	0.82

Scenarios

Two scenarios, representing anticipated near-term and long-term system conditions, were studied:

- **Near-term:** In the near-term scenario, per the implementation of Minnesota Power’s 2013 Plan Near-Term Action Plan THEC 3 is shut down and LEC Units 1 and 2 are operating as peaking natural gas units. Since the purpose of the analysis is to study the reliability of the local transmission system, the peaking natural gas units at LEC were conservatively assumed to be offline in all cases. The near-term scenario is meant to represent the late 2016 timeframe, in which case it does not include anticipated mining load additions in the Hoyt Lakes area or the GNTL Project.
- **Long-term:** In the long-term scenario, the new planned operations of THEC3 and LEC were included as described for the Near-Term scenario. An additional 70 MW of new mining load was included at two substations in the Hoyt Lakes area, and the GNTL and associated incremental Manitoba – United States transfers were also included.

Analysis

Near-term

The cumulative impact of closing the two remaining units at THEC in combination with the shutdown of THEC3 and the repurposing of LEC as a peaking natural gas plant results in several concerns for the local transmission system. Without the THEC and LEC generation online, the local transmission system becomes increasingly dependent on the [TRADE SECRET DATA EXCISED] substations as the main sources of bulk power delivery to the area.

With more power flowing through these two substations, several contingencies at the the [TRADE SECRET DATA EXCISED] substations that weaken the connection between the 230 kV system and the underlying 115 kV system begin to cause localized post-contingent voltage and power flow violations. Study results indicate that the closure of THEC1&2 would require local transmission system improvements to maintain an acceptable level of reliability for Minnesota Power's customers. No stability issues were identified with the closure of THEC1&2 in the near-term scenario.

Long-term

The main change that affects the local area surrounding THEC in the long-term scenario is the addition of 70 MW of new mining load in the Hoyt Lakes area. The electrical location of this new mining load inside the North Shore Loop transmission system causes further complications with the closure of THEC1&2 in addition to those identified in the near-term scenario. Without the THEC generation online, there are several contingencies in the Hoyt Lakes area that could cause local system voltage collapse in the long-term scenario, although no transient stability issues were identified. The combination of load additions and generation reductions also causes low system intact voltages in the weakest area of the system, and intensifies and expands the post-contingent voltage and power flow violations identified in the near-term scenario. Study results indicate that the closure of THEC1&2 would require additional local transmission system improvements, beyond those identified in the near-term scenario, to maintain an acceptable level of reliability for Minnesota Power's existing and future customers in light of expected long-term load additions in the area.

<u>Conclusions</u>

Steady state and dynamic analyses of the local transmission system indicate that the cumulative impact of the closure of THEC1&2, in combination with Minnesota Power's plans to place THEC3 into suspension and repurpose LEC as a peaking natural gas plant, results in several local transmission system issues that must be remedied by implementing local transmission system upgrades. Minnesota Power estimates the cost of the local system upgrades required for the near-term THEC1&2 shutdown scenario to be approximately the [TRADE SECRET DATA EXCISED].

In the long-term THEC1&2 shutdown scenario, which includes expected load additions in the Hoyt Lakes area, the severity of the issues identified in the near-term scenario was increased and new issues were identified requiring additional local transmission system upgrades. Minnesota Power estimates the total cost of the local transmission system upgrades required for the long-term THEC1&2 shutdown scenario to be approximately the [TRADE SECRET DATA EXCISED], including the the [TRADE SECRET DATA EXCISED] identified in the analysis of the near-term THEC1&2 shutdown scenario.

Local Impact Evaluation of BEC1&2 Shutdown

To support the scenario planning of the 2015 Plan, Minnesota Power's transmission planners completed steady state and dynamic transmission system analyses to capture the local system impacts of the closure of BEC1&2. The transmission system performance in the Boswell Energy Center ("BEC") unit closure scenario was compared to the performance of the existing system under several of the most limiting system conditions. The next sections will outline the analysis conducted and identify the insights gathered for the closure of BEC1&2.

Steady State Analysis

Steady state analysis focused on the performance of area 69 kV, 115 kV, and 230 kV transmission lines and substations for Category P1 (generator, transmission line, transformer, and shunt device) and P2 (bus and breaker) contingencies, as defined in NERC Standard TPL-001-4, as well as selected P6 (multiple transmission line) and P7 (double circuit transmission line) contingencies. Steady state performance was evaluated based on the relevant criteria from Minnesota Power's Facility Loading and Voltage Criteria, given in Tables 6 and 7.

Table 6: Steady State Facility Loading Criteria

Minnesota Power Steady State Facility Loading Criteria			
Facility	**Continuous Rating**	**Emergency Rating[5]**	**Seasonal Ratings Apply**
Transmission Lines	100%	110%	Yes
Transformers	100%	125%	No

Table 7: Steady State Voltage Criteria

Minnesota Power Steady State Voltage Criteria				
	Pre-Contingent		**Post-Contingent**	
Rated Voltage	**Maximum Per Unit**	**Minimum Per Unit**	**Maximum Per Unit**	**Minimum Per Unit**
230 kV	1.05	1.00	1.10	0.95
115 kV	1.05	1.00	1.10	0.95
69 kV	1.05	0.97	1.10	0.92

[5] Facility emergency ratings may vary on a facility-by-facility basis depending on the limiting elements

Dynamic Analysis

Because generators have the largest single impact on the stability of the transmission system, a quality dynamic, or stability, analysis was critical for capturing the local system impacts of unit closures. Dynamic analysis focused on the response of the transmission system in the first five seconds (the “transient period”) after moderate to severe disturbances on the 115 kV and 230 kV network near BEC. These disturbances included both three phase faults and stuck breaker faults with delayed line and/or bus clearing. A handful of severe faults that have appeared as limiting disturbances in broader regional studies were also included. Dynamic performance was evaluated based on the relevant criteria from Minnesota Power’s Facility Loading and Voltage Criteria, given in Table 8.

Table 8: Transient Period Voltage Criteria

Minnesota Power Transient Period Voltage Criteria		
Rated Voltage	**Maximum Per Unit**	**Minimum Per Unit**
138 kV	1.20	0.82
115 kV	1.20	0.82

Scenarios

One scenario, representing anticipated near-term system conditions, was studied:

- **Near-term:** In the near-term scenario, per the implementation of Minnesota Power’s 2013 Plan near-term action plan THEC3 is shut down and LEC units 1 and 2 are operating as peaking natural gas units. Building on previous analysis, THEC1&2 were also assumed to be shut down. All transmission system mitigation identified in the near-term scenario of the Local Impact Evaluation of THEC1&2 Shutdown (discussed above) was included in the base model. Since the purpose of the analysis is to study the reliability of the local transmission system, the peaking natural gas units at LEC were conservatively assumed to be offline in all cases. The near-term scenario does not include anticipated mining load additions in the Hoyt Lakes area or the GNTL Project.

Analysis

Shutting down BEC1&2 results in several concerns for the local transmission system. Study results show that these issues are localized to western part of the Iron Range and are relatively independent of the status of THEC1&2. Without the BEC generation online, the local transmission system becomes heavily dependent on the the [TRADE SECRET DATA EXCISED] substation as the main source of bulk power delivery to the Grand Rapids area. With the the [TRADE SECRET DATA EXCISED] substation serving as the critical link between the 230 kV transmission system and the local 115 kV transmission system, several contingencies in the local area that weaken the connection between the 230 kV system and the underlying 115 kV system begin to cause localized post-contingent voltage and power flow violations. Study results indicate that the closure of BEC1&2 would require local transmission system improvements to maintain an acceptable level of reliability for Minnesota Power’s customers. With the identified transmission upgrades in place, no stability issues were identified with the closure of BEC1&2 in the near-term scenario.

Conclusions

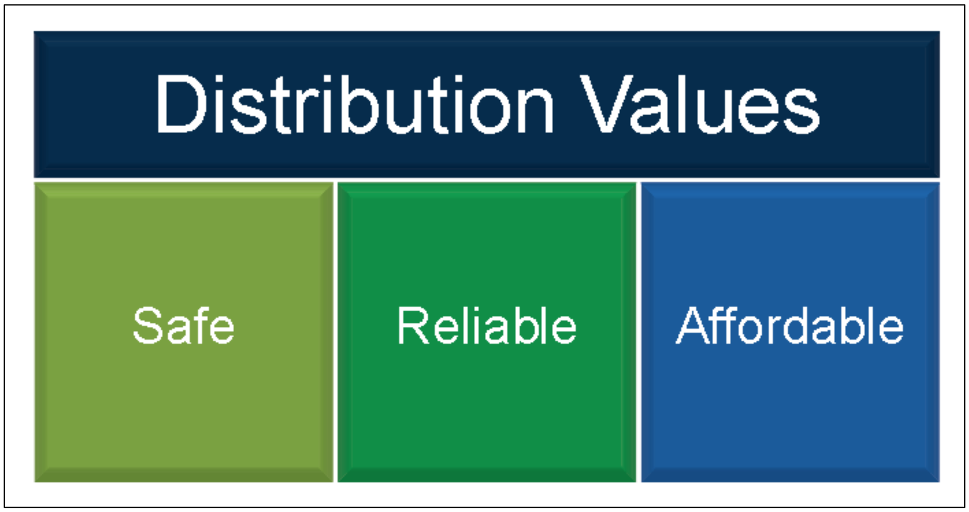
Steady state and dynamic analyses of the local transmission system indicate that the closure of BEC1&2 results in several local transmission system issues in the Grand Rapids area that must be remedied by implementing local transmission system upgrades. Minnesota Power estimates the cost of the local system upgrades required for the near-term BEC1&2 shutdown scenario to be approximately [TRADE SECRET DATA EXCISED]. Further analysis is required to identify any additional mitigation that would be required for the long-term scenario including the Great Northern Transmission Line and other planned system upgrades or load additions in the post-2020 timeframe.

APPENDIX G: DISTRIBUTION

Introduction

Minnesota Power (or “Company”) has been reliably serving its customers with low cost electricity for over one hundred years. The Company’s proactive management of its distribution system is in line with the *Energy**Forward*** resource strategy laid out in this 2015 Integrated Resource Plan (“2015 Plan” or “Plan”). The ultimate goal of the overall Plan is to provide a safe, reliable, and affordable power supply to Minnesota Power’s customers. Over the decades, Minnesota Power has worked diligently to adhere to these values even before *Energy**Forward*** was formalized as a road map for the Company’s resource strategies.

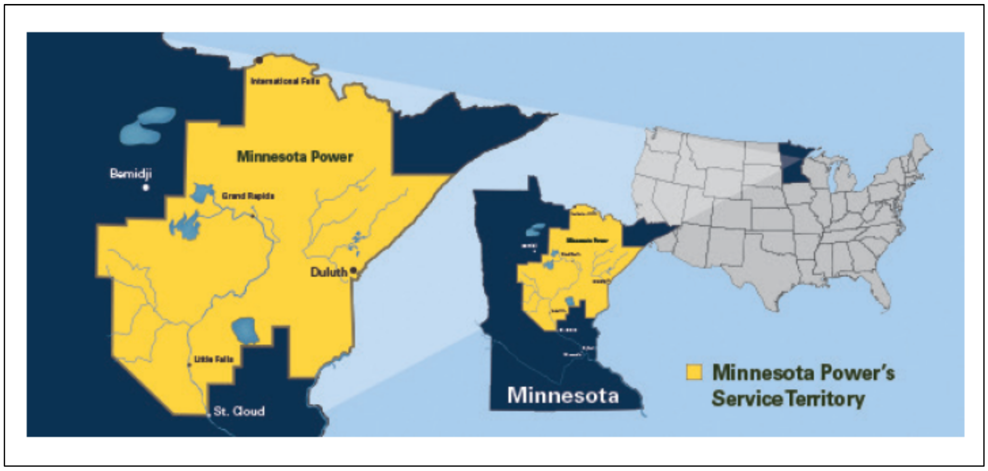
Figure 1: Minnesota Power’s Distribution Values



Minnesota Power’s distribution roots began to develop in the late 1880s when small electric utilities were sprouting up across northern Minnesota and the Nation. These early companies competed with each other to provide service to growing urban areas. The electric utilities were eager to serve the growing timber, mining and shipping businesses of the Arrowhead region in northeastern Minnesota. Even in the early years of electric utility expansion, Minnesota Power (known then as Duluth Edison Electric Company, and eventually, Minnesota Power & Light) was focused on serving industrial, commercial and residential customers with the most reliable service possible while continuing to function in a safe and efficient manner.

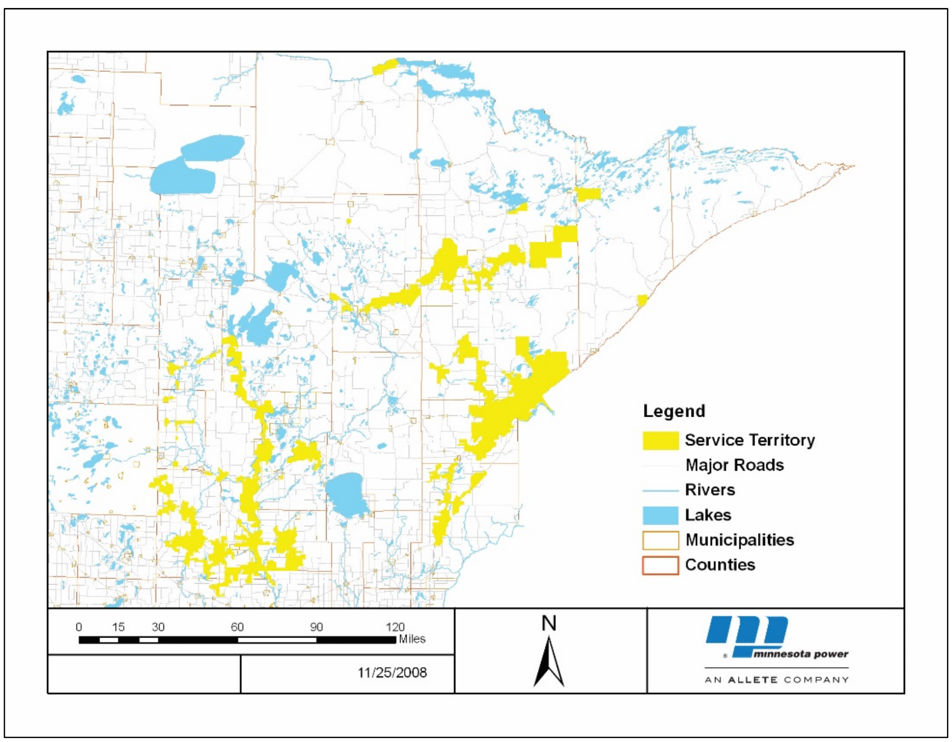
Out of these early sporadic and unregulated companies, and their eventual consolidation under the Minnesota Power & Light umbrella, originated the geographically diverse service territory Minnesota Power continues to serve today. Minnesota Power currently serves approximately 144,000 retail electric customers. These customers are scattered across a 26,000 square mile boundary in northern Minnesota.

Figure 2: Minneosta Power's Service Territory Boundary



The actual service territory of Minnesota Power does not encompass the totality of the 26,000 mile land mass. Minnesota Power's service territory is comprised of 2,422 square miles (depicted in Figure 3) within the 26,000 mile boundary. The dispersed nature of the Company's service territory, along with its varied geographic considerations, present challenges unique to the Company.

Figure 3: Minnesota Power's Service Territory Map



Strewn within the Company's sizeable service boundary are electric cooperatives and municipal utilities. While Minnesota Power does provide wholesale power to many of the municipal utilities, the Company does not necessarily provide distribution operational and maintenance support to every municipality it serves. Wholesale municipal customers own their own distribution systems and provide retail service to the customers within their boundaries. Minnesota Power serves sixteen wholesale municipal customers in Minnesota that vary in size from under 2 MW to well over 30 MW with a combined load of approximately 200 MW. Minnesota Power provides varying types of services to these customers when appropriate, depending on their needs. Services may include: engineering support, construction, maintenance, outage response, meter installation, meter service and pole inspections. Due to Minnesota Power's physical proximity to these customers, the Company can provide these services in a cost effective and timely manner.

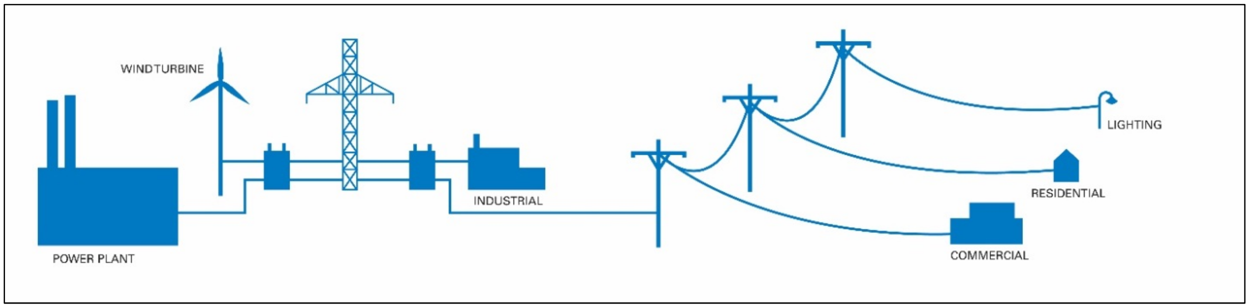
Large power customers are generally served directly from the transmission system but some of these customers do have limited interactions with the distribution system. These customers are mainly served at points located a substantial distance from the service point, such as pumping stations. While the amount of the load taken from the distribution system by these large customers is relatively small, it usually is a service which, if shut down, would have a large impact on the operation of the business.

Minnesota Power's commercial customers are served directly from the distribution system. Similar to interactions with its municipal customers, a wide range of interactions also occur with commercial customers including planning for new construction, service extensions, outage restoration, reliability and power quality concerns, system upgrades, and responding to a variety of other electric service and rate questions. These customers are a very diverse group with varying needs and expectations depending on the business (i.e., electric costs as a percentage of total operating/production costs, power quality and reliability needs, etc.). Reliability is of utmost importance to commercial customers. For many of these customers any interruption in electric service has the potential to stop business and impact their bottom line. For some customers, this may mean office workers no longer have access to computers or phones and productivity drops, where for retailers they may lose the ability to conduct business resulting in lost revenue, and for those customers with sensitive loads and technology related businesses, power quality and even momentary outages may be a significant issue.

Minnesota Power's residential customers are also served directly from the distribution system. A wide range of interfaces occur with these customers including planning for new construction, service extensions, outage restoration, system upgrades and responding to a wide variety of other electric service and rate questions. Residential customers comprise less than ten percent of the Company's total annual electric delivery and approximately fifteen percent of its revenue. While residential customers comprise a small portion of the Company's load and revenue, they are a large part of the distribution system, and an important part of Minnesota Power's business. Minnesota Power provides safe, reliable, and affordable electricity to all of it's large power, commercial and residential customers.

The Distribution System

Figure 4: The Traditional Distribution System

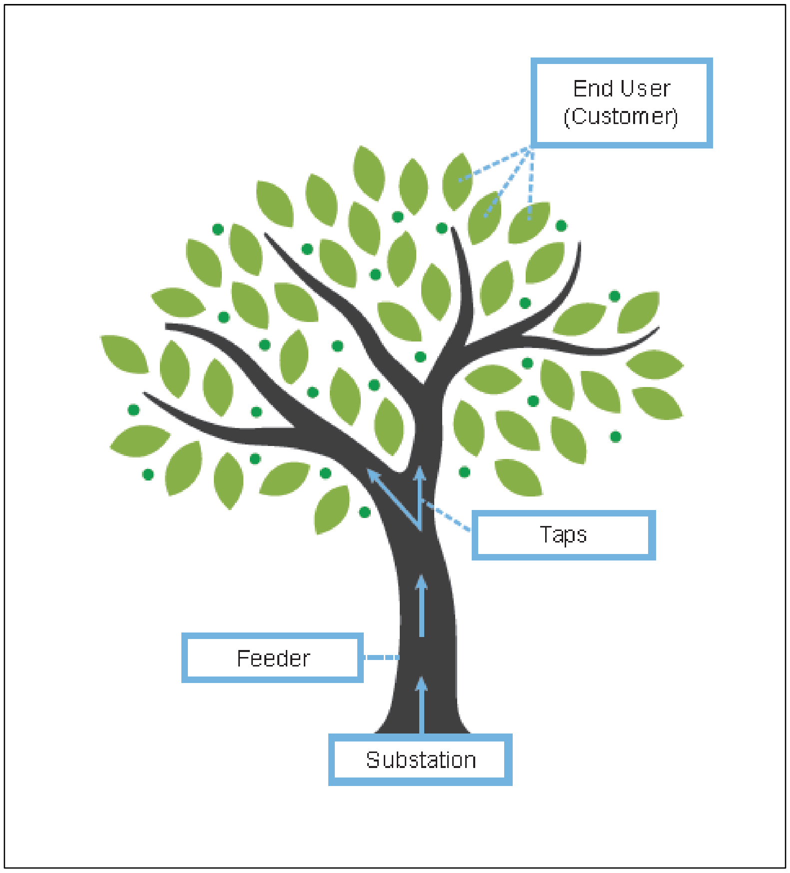


At the present time, and at the most basic level, the distribution system is the conduit for electricity to travel from the transmission system to the end customer. The distribution system begins at a substation. The substations step down the voltage from transmission level (115-34.5 kV) to distribution level voltages (34.5-4 kV). From the substation, circuits called feeders disperse into the region. The number of circuits and the proximity of substations are dictated by density of load and distance to the customer.

From the substations, the distribution system takes a character that can be likened to a tree (Figure 5). Energy exits the substation and heads towards the trunk, or feeder. The feeder extends and supports all of the load and customers on a particular circuit. From the feeder extend the large branches, or taps. These large taps carry energy toward large populations of customers or toward customers with large usage. Just like branches on a tree, many taps extend off of any given feeder. From these large three phase taps extend even smaller taps. Smaller taps reach out and carry energy to smaller populations of customers. Ultimately, when there are no longer large populations of customers to serve, or there is very small load, single phase taps are used to serve the smaller, less populated areas. The end customers are the leaves that are the final extension of the branches, or distribution system.

The “tree model” has been a mainstay of system design for more than a century. It is predicated on the idea that the proper amount of load needs to be available for each part of the system. Like leaves on a tree, many leaves are attached to each branch and each leaf is attached by a stem only big enough to support its weight. This design has historically made system construction and protection relatively straightforward. Due to these principles, the distribution system has evolved through the decades as low cost, safe, and reliable.

Figure 5: The Distribution System "Tree Model"



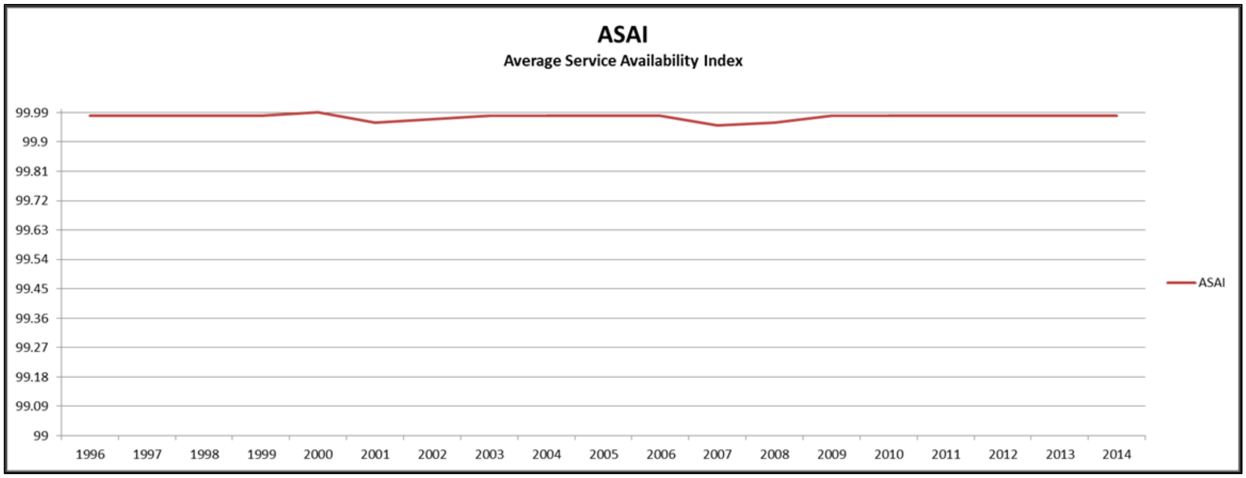
Reliability

Minnesota Power has historically met and/or exceeded annual reliability goals with very few exceptions since the Minnesota Public Utilities Commission ("Commission") instituted the Safety, Reliability, and Service Quality Report in 2004.[1] When reviewing past performance, the Company has underperformed set goals in years of unprecedented adverse weather conditions. To get a full picture of system reliability, the Average System Availability Index[2] ("ASAI") is an excellent barometer. The ASAI is a measure of the average number of minutes the system is available to customers over a year. Higher ASAI levels denote a higher level of system reliability. Minnesota Power currently has an average ASAI of 99.98 percent over the past eighteen years. System reliability can be adversely impacted by many factors and the Company takes measures to proactively mitigate any reasonably foreseeable concerns.

[1] Minnesota Power failed to meet one or more of the storm excluded SAIDI, SAIFI or CAIDI reliability goals in 2007, 2009 and 2013.

[2] ASAI is derived by taking the number of minutes in a year, (525,600 for a non-leap year) subtracting the Company's System Average Interruption Duration Index ("SAIDI") minutes for the year, and then dividing the difference by the number of minutes in the year.

Figure 6: Average Service Availability Index



Reliability Initiatives

Vegetation Management

One of the more significant factors that can impact the Company's system reliability is vegetation encroachments. A coordinated and systematic vegetation management program is a key component of Minnesota Power's distribution reliability effort. Minnesota Power has designed a vegetation management program to address each distribution line approximately every five years and transmission lines every seven years. Vegetation management benefits the system in various ways. In 2011, Minnesota Power entered into six-year contracts for vegetation management for both its transmission and distribution lines. This long term commitment maintains levels of vegetation management consistent with utility best practices while reducing costs through efficiencies realized from the vegetation management contractors having defined and committed long-term work scopes. Additionally, Minnesota Power has been working with its vegetation management contractors to transition to the use of more environmentally friendly bio-degradable chainsaw bar oil from traditional petroleum based oils.

Crew Dispatching

Communication and crew mobilization are very important elements of maintaining grid reliability and reconnecting customers in a timely and efficient manner when incidents occur on the system. In 2013 Minnesota Power installed a new system to mobilize crews for unscheduled work. The Automation of Reports and Consolidated Orders System ("ARCOS") system is programmed with the Company's callout lists. When a crew is needed, the Service Dispatcher simply lets ARCOS know what type of crew labor is required and ARCOS places automated phone calls to employees based on union callout rules. A task that formerly could take the Service Dispatcher upwards of one hour to complete is now done in several minutes by the ARCOS. The intended outcome of implementing this system is a reduction of outage durations. The Company plans to continue to utilize metrics from this system to improve both crew response and outage times in the future.

Outage Management

In late 2006, the Company installed a commercially available Outage Management System ("OMS") from General Electric called PowerOn. This system gives a real time look at the distribution system by utilizing incoming customer requests information from the field, data from Minnesota Power's Energy Management System ("EMS"), and the Geographic Information System together to provide outage intelligence. With data from these sources, the OMS uses an algorithm to predict the location of the problem. Based on that location information, the OMS predicts what customers are without power. Once the problem is confirmed in the field, actual conditions are modeled in the OMS, and the exact customers affected by the outage are identified. This method of outage detection makes identifying outages more reliant on real time data, and therefore, more efficient.

An important part of the customer face of the OMS is the Interactive Voice Response ("IVR") system, which provides an automated communication tool for customers during an outage. The IVR is a telephone system with the intelligence to read the phone number of the incoming caller. If the number the customer is calling from is in the customer information system ("CIS"), the IVR will look to the OMS to see if the caller is in an area affected by an outage. If the caller is part of a known outage, the system reports that information to the customer, and provides them with the status of the outage response. If the information is available, the system will also communicate estimated restoration time. This provides Minnesota Power the capabilities of letting each caller know what problem is affecting their area as well as giving them an estimate of the outage length. The IVR has eased congestion during periods of multiple or widespread outages. Minnesota Power is also using the IVR to communicate information to the OMS.

The Outage Center provides visitors with specific outage locations and also allows them to report outages or check the status of outages online. The Outage Center augments the IVR unit and obtains information directly from the OMS. In addition to being able to check the Outage Center on the the Company's website, customers can download the Minnesota Power Outage App to an iPhone, Android or Blackberry device to check on near-real time outage information.

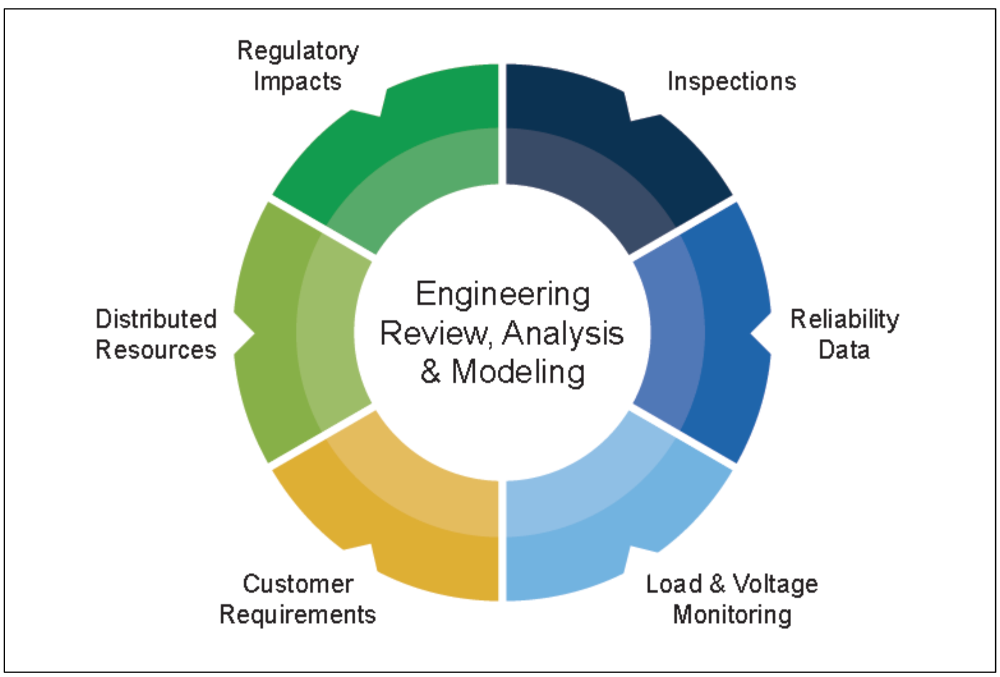
Since 2011, the OMS system has been integrated with the Company's Advanced Metering Infrastructure ("AMI") system. This integration provides real-time messages from the AMI system when the power goes out at the customer service and when the power is restored to a customer service. This information is also used in the predictive algorithms that drive the OMS outage predictions. The AMI-OMS integration also allows service dispatchers to "ping" individual customer meters to verify power restoral and service status manually. This feature is integrated into the current OMS screens utilized by the dispatchers. This capability is available on the roughly one-quarter of the Minnesota Power meter population that has the AMI system installed, so the full benefit of this technology will be realized when the majority of the meter population has been transitioned. This interface will be optimized as more meters are deployed and AMI system coverage is expanded over time. Minnesota Power expects much less need for customer-initiated communication regarding outage verification and restoration as AMI Technology is deployed. See AMI section below for more details on the use of AMI in long-term distribution planning.

Distribution Planning

Minnesota Power continues to focus on providing reliable and low cost electricity, while making prudent technology investments to enhance customer convenience and reliability. Central to this customer compact is the distribution system planning process which guides investments on the system. All system investments must be weighed by cost, number of customers served, and practicality of expected results. These complex, variable factors are further complicated by the fast moving distribution technology developments available to utilities. Recent technological developments can allow for greater visibility into system issues as well as automated responses to those issues. Recenty, Minnesota Power strategically deployed distribution technologies to gain experience with these technologies, increase reliability, and evaluate the cost-effectiveness of these system enhancements. These technological investments (detailed in the emerging trends and grid modernization sections below) come with both increased risk and uncertainty, along with a reduced equipment lifespan due to the incorporation of solid state and microprocessor based components.

Figure 7 demonstrates the core elements of Minnesota Power's distribution system planning process. The Company routinely reviews and updates its ten year distribution capital construction plan based on this process. Capital projects are selected each year based on a system which evaluates improvements in system performance, safety, compliance, capital recovery and efficiency. The investments are then prioritized based on a weighting system.

Figure 7: Distribution System Planning Components



Inspections

Ten percent of Minnesota Power's distribution poles are inspected annually. The ten-year ground line inspection cycle includes sounding, boring, and treatment of poles. Aerial line inspections are completed annually with a flyover of all 46 kV lines. Visual line inspections are also ongoing with an expected completion on a ten-year cycle. Qualified employees look for clearance violations and other line equipment problems that can be seen from the ground.

Reliability Data

Reliability data that shows the overall performance of the distribution system and performance of each feeder is reviewed annually. Relability averages and outage cause analysis for the prior five years are also reviewed annually. This information provides insights used in determining priority of distribution projects related to reliability and investments for near-term and future planning.

Load and Voltage Monitoring

Data is collected and analyzed relating to feeder and substation peak loading. Five year forecasts are generated for each distribution substation and each feeder. This data help inform to identify trends and proactively justify capacity investments. More than 100 Sensus-Telemetric line voltage and outage monitors ("TVM") are located throughout the system. Sensus Distribution Automation TVM voltage monitors measure line voltage and provide real-time notifications of steady state values, outages and under or over voltage conditions to dispatchers and select Minnesota Power employees. Alarms and profiles help identify areas that may be experiencing momentary outages or have temporary voltage drop or rise outside of the Company's normal operating limits.

Customer Requirements

Customer required projects occur when customers need additional capacity, are considering distriuted energy resources, or when extensions are required to serve new customers. This may also include commercial or industrial customer requirements for redundant or alternate services to improve reliability.

Distributed Resources

Power flow modeling is done with the Siemens PSS®SINCAL[3] software which assists in power system planning for generation, transmission, distribution and industrial grids. This tool is used to predict the behavior of the system when distributed sources are placed on a distribution feeder. This includes power flow direction, transient analysis, and fault current contributions. Planning for distributed generation ("DG") resources and working with customers on needed additions to the distribution system takes place on an ongoing basis.

[3] http://w3.siemens.com/smartgrid/global/en/products-systems-solutions/software-solutions/planning-data-management-software/planning-simulation/Pages/PSS-SINCAL.aspx

Regulatory Impacts

Investments in the distribution system are necessary to comply with regulatory requirements. Most often these projects are system relocations due to road construction which require vacating of or relocating within a road right of way.

Emerging Trends and Grid Modernization

The inherent complexity, greater optionality and shortened equipment lifespan associated with grid modernization creates challenges for grid operators. Wise investment decisions are even more imperative with the rapid developments and advancements in technology. Minnesota Power has routinely implemented new technology solutions where appropriate and feasible to assist with outage detection, response time to outages, and to respond to customer expectations regarding more timely communication and transparency of operations.

Mobile Workforce Implementation

Minnesota Power has been planning mobile workforce process enhancements for its distribution system employees, and recently selected General Electric's Field Force Automation ("FFA") to implement these enhancements. Minnesota Power anticipates improvements to work flow and elimination of paper work order control for many of its distribution system work groups. FFA will be used initially by line department employees to automate trouble restoration and update work orders in near real-time utilizing mobile platforms in the field. FFA will also be the platform on which Minnesota Power line workers, meter technicians, and credit and collections staff will be scheduled as it is phased into Minnesota Power distribution operations.

Advanced Metering Infrastructure

AMI meters' primary purpose is to communicate electrical usage values used to bill Minnesota Power's approved rates. The AMI system is also integrated with the Company's OMS to detect and verify power outages as previously outlines in the OMS section of this Appendix. The meters utilize an internal temporary power source within the meter to provide several notifications of customer outages before the power supply is depleted. When the notification is received, a dispatcher verifies the outage and dispatches a crew. Additionally, the meters stream "power on" messages when service is restored. Not all Minnesota Power customers have AMI meter technology at this time however, AMI implementation continues across the Company's service territory. Approximately 25 percent of all meters have been replaced and about $7 million has been invested in the project so far. Minnesota Power has completed approximately 70 percent of the tower-based radio infrastructure deployment and plans on leveraging and enhancing existing owned communication infrastructure for the remainder of that infrastructure as it is deployed through 2017.

As part of the Department of Energy ("DOE") Smart Grid Investment Grant ("SGIG") Consumer Behavior Study, Minnesota Power launched a Time of Use ("TOU") rate with a critical peak component in line with the requirements of the grant. Rates vary for On-peak, Off-peak, and Critical Peak Pricing periods and further detail can be found in Minnesota Power's TOU rate filing (Docket No. E015/M-12-233). Minnesota Power offered this rate to their customers in Quarter 3 of 2014 and rolled out the rate and related AMI system changes corresponding to the rate through Quarter 4 of 2014. The pilot is scheduled to continue through Quarter 4 of 2015, with analysis of the rate and rate impacts continuing into 2016. As Minnesota Power deploys its AMI system, one anticipated enhancement is the evaluation of a Meter Data Management System ("MDM") beginning in 2016 with anticipated system investment in 2017. This investment would provide much more efficient and automated validation, editing, and estimating ("VEE") functions while dealing with customer billing. Tertiary benefits of a MDM investment include load research enhancements, engineering tools, and improved data streams for customer interfaces.

Line Panel Replacements

Minnesota Power has been investing in modernizing its protection systems for many years. A critical element to these enhancements have been the replacements of relays on protection panels. Line panel replacements are budgeted on an annual basis. Line panel replacements involve replacement of traditional electromechanical relays with intelligent programmable modern protection systems. Line panel upgrades generally reduce the overall number of devices, such as electromechanical relays, due to increased functionality of the micro-processor based devices replacing the single function electromechanical devices. These upgrades also reduce the overall lifespan of the equipment due to the reduced mean time to failure ("MTTF") of solid state components within these modern devices. MTTF is the length of time a device or other product is expected to last in operation and is a way of evaluating the reliability of equipment. Line panel replacement projects are currently planned through 2020 and beyond.

Recloser and Regulator Controls

A recloser is a device installed on electrical distribution networks. Reclosers contain a circuit breaker that opens when a fault is detected on the system and has a function that automatically attempts to restore power to the affected line if the fault on that line clears prior to the subsequent attempts. Similar to the protection systems described above, modern reclosers provide many more options and forms of communication on new devices. As new equipment is installed on the distribution system and older equipment retrofitted with modern technology, these devices provide more intelligent nodes that can be leveraged for situational awareness on the distribution system.

Distribution Automation

As part of the DOE SGIG pilot project in 2010, Minnesota Power invested in fiber-optic based Distribution Automation assets to implement a Fault Location, Isolation, and Service Restoration ("FLISR") system. The fiber communications investment associated with this system provides additional benefits of communication redundancy between two critical substations in the Duluth area, along with providing situational awareness at the distribution feeder level. The cost to implement this technology is approximately $250,000 for each automated feeder. Plans to implement new automated networks in the Company's service territory are being considered and evaluated for future investment. Experience with the existing system has showed that recovery from catastrophic outages can be reduced from many hours to just minutes for the majority of customers in the areas with FLISR, however, Minnesota Power is currently evaluating the customer benefits of this reduced outage times given the cost and additional maintenance of the system.

Volt-VAR Optimization

A Volt-VAR optimization pilot was budgeted for engineering review in 2014. Intelligent capacitor controls and communications can be used to improve the dynamic voltage response of the system and improve power factor. The system becomes more efficient and losses are reduced with an improved power factor. The planned pilot may initially include one or two feeders to evaluate the performance and cost benefits of the Volt-VAR optimization.

Distributed Generation

Minnesota Power has a longstanding history of working with its customers on the implementation of innovative DG resources. From backup power supply options to the newest solar technology the Company is continuously monitoring the emerging trends of technology and its customer requirements. Minnesota Power is pursuing distributed energy resources that are consistent with its current *Energy**Forward*** resource strategy, which is designed to deliver safe and reliable service at the lowest possible cost to customers while protecting and improving the region's quality of life.

Minnesota Power has consistently worked on process improvement and optimization of the interconnection of distributed energy resources. This optimization required a change in philosophy with regard to planning, in that distribution system planners must now work to find locations where distributed energy resources can not only be accommodated, but when they can enhance system reliability and possibly improve the economic operation of the system. As DG resources are added to the system, it is very important that planners are setting the expecations for limits of systems and sizes and providing these expectations to potential DG owners. It is very important that all stakeholders are aware of the potential for disruptive levels of DG on distribution systems that may trigger significant investments for all rate payers. Minnesota Power will take a proactive approach to this planning process by monitoring and modeling these resources and communicating contstraints as part of the DG interconnection process.

The DG interconnection process is one of the more complex interactions that Minnesota Power has with customers, as it requires coordination between the customer, manufacturer, installer, inspector and the Company. Minnesota Power has dedicated Renewable Programs professionals and education tools to continually clarify and streamline the interconnection process. By enhancing customer communication efforts, Minnesota Power is helping to align customer expectations with achieved results. These efforts will aid in ensuring that DG systems continue to be installed in a safe and reliable manner.

DG Solar Overview

Minnesota Power's solar strategy takes into consideration customer outlooks, technology advancements, consumer trends and reasonable implementation costs. Utilizing each of the three pillars of focus – utility, community and customer – will enable Minnesota Power to be more flexible with its implementation plans and create a diverse approach to integrating solar energy into its power supply portfolio (see Appendix H.)

As of the end of 2014, there were 132 solar net metered customers in Minnesota Power's service territory. Current solar customers sign the uniform statewide interconnection contract with Minnesota Power. Production meters were installed for those customers receiving the *Made in Minnesota* incentives in 2014, as this annual incentive is based on actual production. Minnesota Power did not generally have production meters installed on other customers' solar generating systems prior to 2014. Going forward in 2015, as a general practice, energy generated by DG, including solar, will have a production meter installed on site. This will enable Minnesota Power to more accurately track customer-generated solar energy for billing and distribution planning.

DG: Small Scale Photo Voltaic ("PV") Systems

Small scale solar installations are located at residential customer sites and can be anywhere from 1 - 40 kW of electricity. The cost of installing solar PV systems in the U.S. has dropped by roughly 75 percent in the past decade bringing the average installed cost of a small-scale solar system to just over $4.00 watt. However, without additional incentives these systems are still cost prohibitive for most customers. Minnesota Power prioritizes the need for a safe and reliable installation for its solar DG customers. The system must not put the customer or Minnesota Power employees at risk during outage or maintenance conditions.

DG: PV Solar Gardens

A PV solar garden is a larger solar installation that is owned by a community or multiple subscribers. Typically these are connected to the distribution system and are generally larger than a single customer installation. Since it is a utility managed interconnection, operation of the system around these installations tend to be well controlled and subsequently easier to integrate.

Minnesota Power plans on filing a community solar garden pilot program for Commission considration in 2015. Minnesota Power believes that community solar gardens represent an opportunity for more customers to participate in solar, regardless of whether they own their home, have suitable rooftops or sizable upfront capital for investment. Community offerings are an important part of the Company's overall solar strategy (see Appendix H).

DG: Utility Scale Solar

Utility scale solar systems are large solar installations. They have the lowest installed cost of any other solar array due to their economies of scale (see Appendix D). Utility scale solar projects may be connected to either the distribution system or to the transmission system through a dedicated or shared substation connection, depending on the size of the solar project. An example is Minnesota Power's collaboration with Camp Ripley near Little Falls to install a utility scale solar project (also referenced in Appendix H and Section IV, and V of the Plan). Minnesota Power is joining forces with the Minnesota National Guard to build a 10 MW solar installation on the grounds of the Camp's training facility. The Camp Ripley Solar Project will be a fully integrated interconnection, requiring coordination and study as part of the distribution planning process.

DG: Microturbines (gas or propane-fired)

Microturbines are small, commercial sized combined heat and power generators that produce electricity and heat. There are currently 70 kW units at both Fond Du Lac Tribal and Community College and at the Western Lake Superior Sanitary District ("WLSSD"). WLSSD operated two turbines for nearly a year, but due to impurities in the waste gas used for their operation, they were subsequently taken out of service. A single 70 kW unit at the Fond du Lac Tribal and Community College was installed in 2006. No other microturbines are known to exist on Minnesota Power's distribution system.

Distributed Energy Resources:[4] Battery Storage

Batteries store energy for use when traditional sources of energy are not available. Examples include battery backups for personal computers and emergency lighting for public buildings. Batteries have also been used for mission critical processes such as corporate computer rooms. Normally referred to as Uninterruptible Power Supplies ("UPS"), battery backups were historically installed on large scale corporate computers to allow for an orderly shutdown of critical systems, or as a bridge to onsite backup generation. Battery banks were generally only sized to carry their emergency loads for 15 to 30 minutes as the banks were expensive to install and operate for extended operation. Not all distributed resources are generation, battery storage would be considered a distributed resource.

Over the last two years Minnesota Power has seen an increase in the installation of battery backup systems by customers who want or need battery backup for systems within their homes. Several Minnesota Power customers have installed batteries to store energy for periods of solar PV inactivity. While battery technology is not frequently seen on a home with normal electrical load, the systems have been successfully installed in remote locations and offer an option for locations where standard utility service is impractical or cost prohibitive.

DG: Micro-wind Turbines

Micro-wind turbines are small wind turbines that can be erected on residential and/or small commercial property. Since 2003, fifteen Micro-Wind Turbines have been installed on the Minnesota Power system with turbine sizes ranging from 1.8 kW – 20 kW. The total installed capacity of Micro-wind turbines on the Minnesota Power System is 175 kW.

DG: Backup Generation

Businesses throughout the region are continually evaluating their electric supply needs. As part of the alternatives considered is the implementation of reliable backup generation sources to supplement the electric needs in the rare occasions when the distribution system is not available. There are many backup generators installed throughout Minnesota Power's customer base, and typically these generators are only utilized when the customer is no longer connected to the distribution system during an outage. However, there are applications for flexible, efficient back up generators to be used to support the distribution system during normal operations. By leveraging the backup generation infrastructure for the broader needs of the power system, there can be more optimization of the electric infrastructure in the region.

[4] Because storage is not a source of generation, referring to it as DG is not entirely accurate. Standards bodies like IEEE (Institute of Electrical and Electronics Engineers) and IEC (International electrotechnical Commission) are transitioning the naming convention of the battery storage resources to Distributed Energy Resources ("DER").

Minnesota Power has included as part of its short-term action plan (see Section V) a new backup generation program option for its customers. Within the program, those customers that are looking for new backup generation to support their energy needs would have an option to work with Minnesota Power and have the generation be interconnected to the distribution system for broader use. The Company will be bringing forward this new customer option in the next several months.

Electric Vehicles

Minnesota Power has recognized the potential and has been monitoring the emerging technology surrounding electric vehicles for many years. While the adoption rate for electric vehicles is lower in northeast Minnesota than other parts of the state, the Company recognizes there is an emerging trend for a customer subset, specifically in the tourism sector, that it needs to be prepared for higher penetration of their customers who will be demanding electric vehicle accomodations. In 2010, Minnesota Power formed an Electric Vehicle Technology work group tasked with evaluating the technology, investigating market impacts, and providing recommendations for integrating electric vehicles into the Company's customer service planning. The Company has added information to its website and trained internal personnel on the emerging trends with electric vehicles.

Minnesota Power is currently working with the Minnesota Pollution Control Agency ("MPCA") and several municipalities on a proposal to install charging stations within its service territory. The project is being designed to enhance electric vehicle infrastructure in northern Minnesota. Minnesota Power plans to enter into an agreement with the MPCA to administer funding for the installation of five level 3 charging stations and two level 2 charging stations co-located with government buildings or on properties easily accessible to the public. Selected sites include: Hinckley, Duluth, Silver Bay, Ely, Virginia, Little Falls, and Crosby. These locations will facilitate travel from the southern part of Minnesota to commonly travelled corridors that lead to the northern portions of the state. The charging station proposal is pending Environmental Protection Agency ("EPA") approval and could potentially be revised following EPA review. These new charging stations will further encourage the use of electric vehicles in the Company's service territory.

In addition to the electric vehicle charging station program, Minnesota Power submitted a Petition to the Commission on February 2, 2015, requesting approval of a residential off-peak electric vehicle service tariff.[5] A 2014 Minnesota law requires Minnesota public electric utilities to file a tariff "solely for the purpose of recharging an electric vehicle."[6] The details of the tariff are provided in Table 1 on Page 16. The Company is currently working towards creating an electric vehicle rate promotion platform in conjunction with this innovative rate offering.

[5] Docket No. E015/M-15-120.
[6] Minn. Stat. § 216B.1614.

Tabel 1: Minnesota Power's EV Rate

<table>
<tr><td>Fixed Monthly Charge</td><td>$4.25</td></tr>
<tr><td>Off-Peak:</td><td></td></tr>
<tr><td>Hours</td><td>11pm to 7am</td></tr>
<tr><td>Summer Off-Peak Rate</td><td>4.332 c/kWh</td></tr>
<tr><td>Winter Off-Peak Rate</td><td>4.332 c/kWh</td></tr>
<tr><td>On-Peak:</td><td></td></tr>
<tr><td>Hours</td><td rowspan="3">On-Peak Charging Unavailable</td></tr>
<tr><td>Summer On-Peak rate</td></tr>
<tr><td>Winter On-Peak Rate</td></tr>
<tr><td>Renewable Option Premium</td><td>2.5 c/kWh</td></tr>
</table>

Minnesota Power is a propactive participant in the emerging EV market and will continue providing education, credible customer contact and insight into EV rate development.

Regulatory Outlook

On May 12, 2015, the Commission initiated an inquiry into Electric Utility Grid Modernization with a focus on distribution planning. The initiative will be launched with a series of meetings to facilitate a dialogue on Minnesota's electric distribution systems. The following topics will be covered in the initial meetings: Minnesota's electric utility distribution systems, with a discussion of the design, operations, performance, capability, and planning processes for existing distribution systems; national distribution grid modernization work and emerging best practices; and stakeholder perspectives, giving interested parties an opportunity to provide feedback on current distribution planning processes and to suggest next steps the Commission could take to improve distribution planning in the future. This activity is occurring at the same time as the e21 Initiative, which is also exploring further grid modernization.

The e21 Initiative is a stakeholder-driven collaboration that aims to develop a more customer-centric and sustainable framework for utility regulation in Minnesota. Minnesota Power is a project team member and sponsor of e21 and has been actively engaged since the Initiative's inception. The e21 includes a diverse group of stakeholders from the utility industry, government sector, business, non-profit, academia and advocacy groups. Minnesota Power fully expects to continue active participation in e21 processes.

The Company's long term plan is to enhance and create additional customer product options through integrated and coordinated distribution, transmission and power supply planning. Minnesota Power remains dedicated to providing safe, reliable and affordable electricity to all of its customers.

APPENDIX H: MINNESOTA'S RENEWABLE ENERGY

Introduction

Minnesota's Renewable Energy Standard ("RES") requires Minnesota Power (or "Company") to generate or procure sufficient electricity generated by an eligible energy technology, such that at least the following standard percentages of the Company's total Minnesota retail electric sales are generated by eligible energy technologies by the end of the year indicated:

12 percent by 2012
17 percent by 2016
20 percent by 2020
25 percent by 2025

Part 1 of Appendix H discusses the development of Minnesota Power's renewable energy mix, and the Company's efforts taken to meet the RES in 2012 and the Solar Energy Standard ("SES") in 2020. Part 2 identifies any obstacles encountered or anticipated in meeting the objectives or standards, as well as potential solutions to the perceived obstacles, are identified.

Part 1: Status of Projects and Efforts Taken

Based on its energy forecast to fulfill retail customer needs, Minnesota Power currently has sufficient eligible renewable energy resources to meet the RES through 2025. Minnesota Power's Renewable Base (pre-2006) is comprised of biomass and hydro resources as presented in Table 1 and meets approximately six percent of Minnesota Power's projected 2025 retail electric sales.

Table 1: Minnesota Power Renewable Base

Minnesota Power Renewable Base	MWh/Year
Thomson Hydro[1]	280,000
Non-Thomson Hydro	217,000
Hibbard Energy Center (biomass)	70,000
Rapids Energy Center (biomass)	110,000
Rapids Energy Center (hydro)	10,000
Cloquet Energy Center (biomass)[2]	36,000
Total Annual Projection	**723,000**

Between 2006 and 2014, Minnesota Power executed power purchase agreements ("PPA") and constructed 415.4 MW of wind facilities to increase its Minnesota-eligible renewable energy supply to approximately 19 percent of Minnesota Power's projected 2025 retail and wholesale

[1] Thomson Hydro Station returned to service in November 2014, after being inoperable due to damage sustained in the severe flooding of June 2012.
[2] Contract with Cloquet Energy Center will be ending in 2016, as will the associated Renewable Energy Credits ("RECs").

electric sales. By 2015, Minnesota Power's last approved new renewable project, a 204.8 MW wind facility, achieved commercial operation, and the renewable portion of Minnesota Power's retail energy supply increased to approximately 26 percent of its projected 2025 retail and wholesale electric sales.

Minnesota Power has implemented renewable resource additions to meet the RES of 25 percent by 2025. Figure 1 on page 6 identifes the current renewable resource portfolio that Minnesota Power will use in meeting the RES. The renewable resources include PPAs with independent power producers, a Community-Based Energy Development ("C-BED") project, and projects under Minnesota Power ownership.

As Minnesota Power's load additions continue to develop the Company will utilize resource planning activities to prioritize and finalize renewable projects in order to maintain the RES renewable requirement for 2025. Minnesota Power is not subject to any other state Renewable Portfolio Standard goal, excep the SES.

Renewable Project Development Status

Completed Projects:

Oliver 1 Wind

A 50.6 MW wind facility comprised of twenty-two 2.3 MW Siemens SWT-2.3-93 turbines located near Center, North Dakota. This facility was built by NextEra Energy Resources and began commercial operation in December 2006. Minnesota Power has a 25-year PPA with NextEra Energy Resources for all energy, capacity and renewable attributes from Oliver 1 (Docket No. E015/M-05-975).

Oliver 2 Wind

A 48 MW expansion of the original Oliver 1 Wind facility comprised of thirty-two 1.5 MW GE SLE turbines with 77 meter rotors. The facility achieved commercial operation in December of 2007. Minnesota Power has a 25-year PPA with NextEra Energy Resources for all energy, capacity and renewable attributes from Oliver 2 (Docket No. E015/M-07-216).

Wing River C-BED Wind

A 2.5 MW wind project comprised of one 2.5 MW Nordex N90 turbine located near Hewitt, Minn. This project began operation in July 2007 achieving two firsts: 1) the first C-BED project in Minnesota to begin operation; and 2) the first 2.5 MW Nordex turbine installation in the United States. Minnesota Power has a 20-year PPA with Wing River LLC for all energy, capacity and renewable attributes from the Wing River C-BED Wind Project (Docket No. E015/M-07-537).

Taconite Ridge Wind

A 25 MW wind facility comprised of ten 2.5 MW Clipper C96 Liberty turbines located on the Laurentian Divide in Mountain Iron, Minn., on US Steel property. This wind facility was built by Minnesota Power as its first wind project to own, operate and maintain for long-term use as a rate-based renewable wind generation resource. Taconite Ridge Energy Center achieved commercial operation in June 2008 (Docket No. E015/M-07-1064).

Bison 1

An 81.8 MW wind development near Center, N.D., comprised of 16 Siemens SWT-2.3-101 turbines and 15 SWT-3.0-101 turbines. This wind facility was built by Minnesota Power and Minnesota Power owns, operates, and maintains the facility for long-term use as a rate-based renewable wind generation resource. The Bison 1 wind project achieved commercial operation in two phases, the first phase in December 2010, and the second in January 2012 (Docket No. E015/M-09-285).

Manitoba Hydro

A non-firm energy supply PPA with Manitoba Hydro. The PPA assumed [TRADE SECRET DATA EXCISED] to be counted as renewable energy credits ("RECs") and covers a period from May 1, 2011 through April 30, 2022. (Docket No. E015/M-10-961).

Bison 2

A 105 MW wind project near Center, N.D., is comprised of 35 Siemens SWT-3.0-101 turbines and interconnects to the electric grid at the Square Butte Substation, which allows the wind energy to flow via Minnesota Power's existing high-voltage direct current transmission line ("DC Line") or the Alternating Current ("AC") system. The Bison 2 wind project achieved commercial operation in December 2012. Minnesota Power owns, operates, and maintains the facility for long-term use as a rate-based renewable wind generation resource (Docket No. E015/M-11-234).

Bison 3

A 105 MW wind project near Center, N.D., is comprised of 35 Siemens SWT-3.0-101 turbines and interconnects to the electric grid at the Square Butte Substation, which allows the wind energy to flow via Minnesota Power's existing DC Line or the AC system. The Bison 3 wind project achieved commercial operation in December 2012. Minnesota Power owns, operates, and maintains the facility for long-term use as a rate-based renewable wind generation resource (Docket No. E015/M-11-626).

Bison 4

A 204.8 MW wind energy facility in Oliver County in central North Dakota. The Bison 4 Wind Project ("Bison 4 Project") consist of 64 Siemens 3.2 MW SWT-3.2-113 turbines and interconnects to the electric grid at the Square Butte Substation, which allows the wind energy to flow via Minnesota Power's existing DC Line or the AC system. The project went commercially operational in December 2014. Bison 4 positioned Minnesota Power to meet its projected 2020 renewable requirement by the end of 2014 (Docket No. E015/M-13-907).

Fond du Lac Hydro

An approximate 3,000 MWh annual upgrade at the Fond du Lac hydro facility. The project utilized $815,000 in American Recovery and Reinvestment Act grant funding to re-runner the facility along with other updates. Fond du Lac was returned to service in June 2013 upon completion of the overhaul and installation of a new runner and penstock relining/recoating.

Planned Projects:

While the Company is currently positioned to completely meet the 2025 RES requirement, Minnesota Power continuously assesses a wide range of power supply resources to augment its portfolio. Renewable projects including wind, biomass, hydro and solar are part of the 2015 Integrated Resource Plan ("2015 Plan") and ongoing evaluation and consideration of power supply alternatives. Insight into the customer cost impact of the RES and SES requirements are included in Appendix I.

Since the SES was implemented in 2013, Minnesota Power has developed a robust, portfolio-based solar strategy consisting of three pillars of focus: 1) customer – maintaining relationships and providing thoughtful incentive and education programs, 2) community – enabling customer access to solar energy options and promoting community development, and 3) utility – implementing efficient resources into the customer power supply. This portfolio-based approach will position the Company for compliance with the SES in 2020. Minnesota Power reports on its progress toward meeting the SES annually, with its most current report filed on June 1, 2015.[3]

Two biomass projects that have been included in Minnesota Power's planning in the past continue to be evaluated as the Company gains additional insight from stakeholders and regional industry on the most prudent path forward.

Thomson Hydro

Thomson is a hydro facility constructed in 1905 and is located on Minnesota Power's St. Louis River hydro system near Thomson, Minn. At 71 MW Thomson is the largest hydro facility in Minnesota Power's power supply. On June 19 and 20, 2012, record rainfall and flooding occurred in Duluth, Minn. and surrounding areas. The flooding severely damaged Minnesota Power's St. Louis River Hydroelectric System and particularly the Thomson facility, which was forced offline due to damage to the forebay canal and flooding at the facility. As a result, Minnesota Power has invested $90.4 million in the facility to resume operations and provide approximately 280,000 MWh of low-cost renewable energy for customers annually. This project was approved for rate recovery by the Commission on January 29, 2015 (Docket Number E-015/M-14-577). Thomson returned to service in November 2014, and remains a key part of Minnesota Power's strategy to meet its RES requirements under Minn. Stat. § 216B.1691.

Camp Ripley 10 MW Solar Project

To embark upon its first utility scale solar opportunity, Minnesota Power identified a partner with aligned goals for a renewable energy future. The Company has partnered with the Minnesota National Guard and will install a 10 MW solar array at Camp Ripley, near Little Falls, Minn. in 2016. This unique partnership leverages Minnesota Power's energy expertise and Camp Ripley's available land to make progress in meeting both Minnesota's SES and the Department of Defense's cost savings and energy resiliency goals. In August 2014, Minnesota Power and the Minnesota National Guard entered into a multi-faceted Memorandum of Understanding, which includes an agreement to work together on conservation programs, the

[3] Docket No. E999/M-15-462.

10 MW Camp Ripley Solar Project and backup generation technology. The 10 MW Camp Ripley Solar Project will represent approximately one third of the Company's 33 MW of required solar generation to meet the SES, and will result in the largest solar project on any National Guard base in the nation.

Community Solar Program

Minnesota Power will file before the end of 2015, a community solar garden pilot program for Commission consideration. Minnesota Power believes that community solar gardens represent an opportunity for more customers to participate in solar, regardless of whether they own their own home, have suitable rooftops or sizable upfront capital for investment. As stated in the Company's SES[4] progress reports, community offerings are an important part of the Company's overall solar strategy, and Minnesota Power has conducted extensive research to develop a thoughtful program focused on its customers. The pilot program will provide customers with a streamlined customer experience, consumer protections, increased optionality and a market-based approach to the pricing structure.

Renewable Energy Credit ("REC") Outlook

Minnesota Power has taken significant steps since 2005 to develop and implement a renewable plan that incorporates substantial cost effective wind energy into its supply mix and maximizes other existing renewable resources. Current and planned projects, in addition to a sufficient bank of RECs, will enable Minnesota Power to meet the RES incremental percentage requirements, while being afforded the necessary time to evaluate market conditions and advancements in renewable energy technology (Figure 1). With a significant amount of wind energy in its energy mix, Minnesota Power is continually evaluating other renewable energy resources such as biomass, solar, and battery storage. The Company will optimize its RECs, if necessary, and update the Commission on its plans to meet the RES in Minnesota Power's next integrated resource plan.

Subsequent to the 2013 legislation to implement a Solar Energy Standard, Minnesota Power had begun tracking its status and projection of meeting the 2020 requirement. The Company's strategy is incorperated into this 2015 Plan, and Figure 2 depicts the current outlook for both utility and small scale solar energy credits ("SREC") requirements.

[4] Docket No. E999/M-15-462.

Figure 1: Minnesota Power's Renewable Resources to Fulfill 25% RES

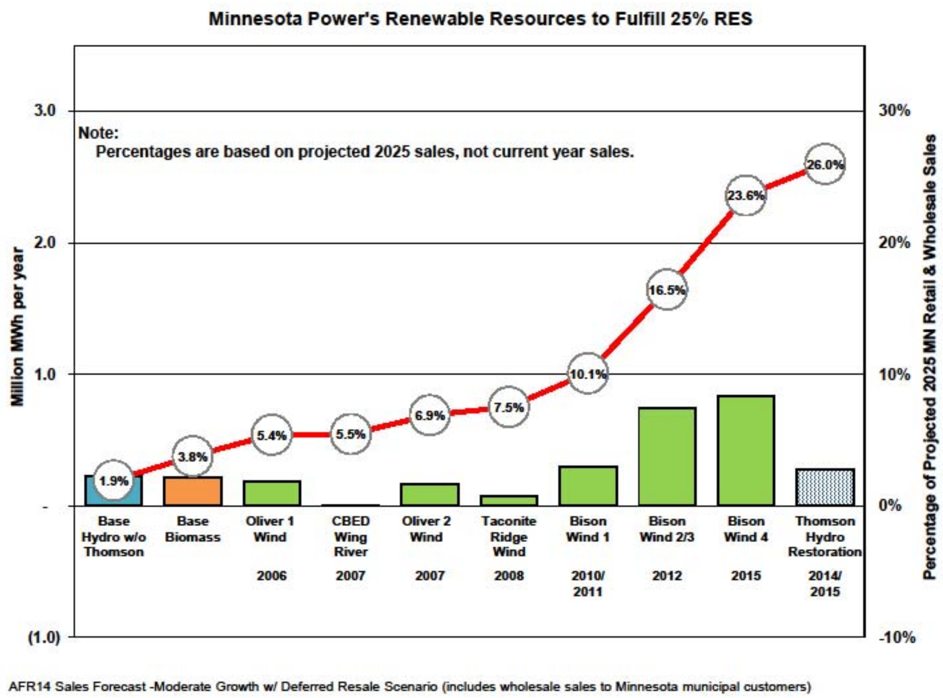
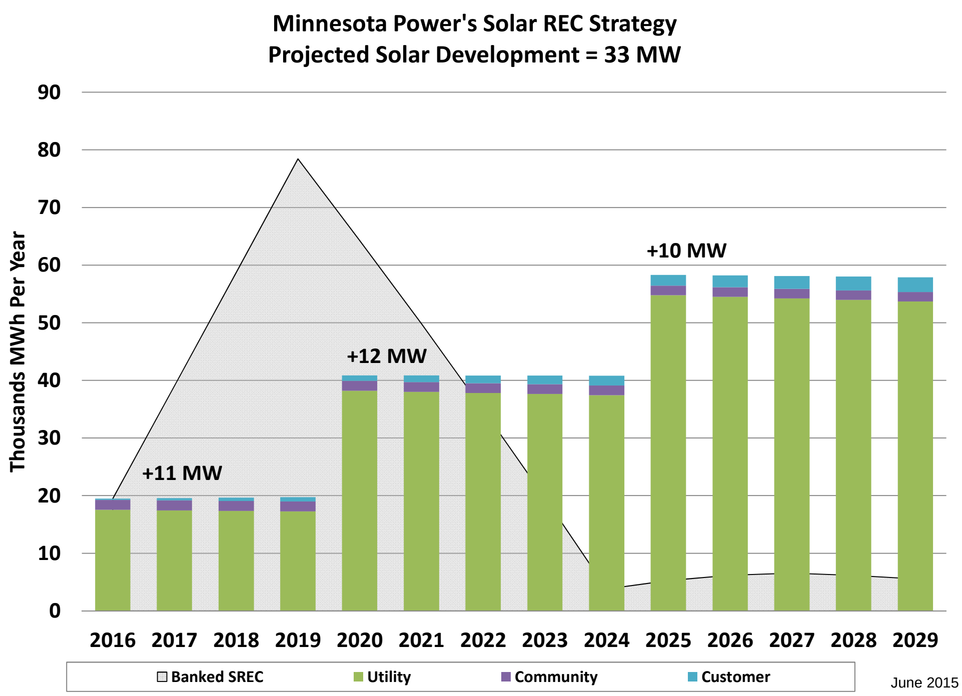


Figure 2: Minnesota Power's Solar Energy Standard Outlook



Minnesota Power's strategy to fulfill the RES and SES includes taking action to:

- Maintain existing renewable energy resources.
- Continue to implement the existing power purchase agreements for long-term wind energy.
- Maintain and operate Minnesota Power-owned wind facilities on Minnesota's Iron Range and in North Dakota.
- Implement planned projects.
- Participate in Midwest Renewable Energy Tracking System ("M-RETS"), as well as in the establishment of a program for tradable renewable energy credits and the protocols for trading credits. In lieu of generating or procuring eligible renewable energy Minnesota Power may optimize renewable energy credits allowed under the program to satisfy the renewable energy objectives and standards.[5]
- Continue to refine specific renewable plans (including the need for additional project implementation or use of renewable energy credits) during implementation due to load changes.[6]

Efforts Taken to Meet the Objective Standards

Between 2006 and 2015, Minnesota Power executed PPAs and constructed over 500 MW of wind facilities to increase its Minnesota-eligible renewable energy supply. In 2015, when approved renewable projects achieved commercial operation, the renewable portion of Minnesota Power's retail energy supply increased to approximately 25 percent of its projected 2025 retail and wholesale electric sales. The Company has exceeded current compliance with the RES and is well positioned to comply with the standard for 2025 and beyond.

Following the passage of the 2013 SES, Minnesota Power has developed a robust solar strategy consisting of the three pillars previously mentioned – customer, community and utility – and initiated work on its first utility scale solar project. While it is estimated that the Company needs approximately 33 MW of solar to meet the SES, early action on the 10 MW Camp Ripley Project and a community solar garden that will be expanded to meet customer demandwill generate solar renewable energy credits ("S-RECs") that can provide flexibility to meet this energy standard without the development of the entire 33 MW in the next four years, as depicted in Figure 2.

[5] Minnesota Power has not bought or sold any Minnesota RES RECs registered with M-RETS from September 2010 to the present.

[6] Minnesota Power will continue to monitor load additions to its system to determine the need for additional renewable projects.

Part 2: Obstacles and Potential Solutions

Minnesota Power is committed to meeting Minnesota's RES and SES requirements. There are obstacles encountered with most plans, and the key is to search for potential solutions to these obstacles. Obstacles and potential solutions encountered in the planning process include:

Hydro

Minnesota Power knows of no new large hydro project sites in Minnesota. Even if sites existed, hydro development is realistically limited to expansions at existing impoundments due to anticipated resistance to the construction of new dams. There is obtainable and expandable hydro in the Province of Manitoba, but current Minnesota law does not allow renewable generation from hydro units of 100 MW or larger to apply towards Minnesota's RES.

Minnesota Power continues to evaluate innovative hydro generation development options and determine feasibility for these projects.

Biomass

The key driver to developing new competitively priced biomass generation is having a sufficient supply of reasonably priced fuel to support the expenditure of the large scale capital that is required to build facilities. The following considerations are important in determining accessibility to reasonably priced fuel now and in the future:

- balanced forestry practices that maximize the production of biomass on a sustainable basis while maintaining the appropriate levels of diversity in the region's forests,
- a healthy fiber industry that creates the demand for round wood,
- a low cost supply of mill and forest residues for energy production,
- a healthy logging industry, and
- the potential expansion of the bioenergy industry.

Minnesota Power's biomass generation efforts are focused on existing Minnesota Power-owned sites and customer sites in order to leverage existing infrastructure to minimize capital expenditures and assure projects that are competitively priced with other renewable generation alternatives.

Wind

Wind development continues to occur primarily in areas with the best regional wind resources: southwestern Minnesota as well as North and South Dakota. Over the past few years, significant improvements in wind turbine technology (larger rotors and improved controls) and wind resource assessment (better siting and turbine layout) have enabled Minnesota Power to identify potential sites on the Iron Range in northeastern Minnesota and in North Dakota.

Minnesota Power's commitment to identifying potential sites in or near its service territory has resulted in several locations indicating good wind resources and acceptable site constructability. Concerns regarding adequate transmission and integration costs will continue for wind development in general as the penetration of wind power increases throughout the region. Minnesota Power executed a unique solution for its customers to provide transmission access to North Dakota wind resources through the purchase of the existing DC Line that runs between the Square Butte substation near Center, N.D. and Minnesota Power's Arrowhead substation near Duluth, Minn.

Solar

Minnesota Power has a long-standing history of encouraging the adoption of renewable energy options, such as grid-connected solar electric systems while ensuring affordable and reliable service to its customers. Minnesota Power currently supports retail customers in the residential and commercial segments who are interested in solar systems via the SolarSense rebate program. Available since 2004, the SolarSense rebate program helps reduce the cost of installing solar through a capacity-based incentive. A total of $150,000 in rebates through SolarSense was available in 2014 for grid-tied systems. Through programs such as the rebates mentioned, Minnesota Power has been supporting and incentivizing solar energy installations for more than a decade with over 130 customer solar systems in place on its distribution system. The Company has taken steps to enhance the customer experience by providing customers with the tools, technology and information needed to make informed decisions about their energy investments. These programs, rebates and tools will assist Minnesota Power in meeting the small scale requirement of the SES, which mandates that 10 percent of the 1.5 percent standard come from systems 20 kW or less.

There are some unique challenges associated with increased solar production and meeting the state solar mandate, including a decreasing investment tax credit and the registration of SRECs. Minnesota Power analyzes solar system costs and on an ongoing basis weighs the potential of technology improvements that may reduce cost against the solar investment tax credit, which is set to decrease from 30 percent to 10 percent at the end of 2016, in consideration of any resource additions. Additionally, the Company is developing processes for registering SRECs, particularly from small distributed generation systems and from customer solar installations receiving incentives, with the M-RETS. Registering SRECs, particularly from systems 20 kW and smaller, is necessary for Minnesota Power to meet the SES by 2020.

Community-Based Energy Development Wind Projects

The potential for the development of economical C-BED wind projects varies throughout the state as a result of the wide variation in the quality of wind resources between each region. Minnesota Power began receiving renewable energy from its first C-BED wind project in July 2007. Recent C-BED projects proposed to Minnesota Power command a significant premium over its other renewable alternatives. As a result, Minnesota Power has not added a C-BED project to its portfolio since the Wing River Wind Project in 2007, but the Company continues to evaluate additional projects.

Integration of Intermittent Resources

Although the penetration of intermittent resources such as solar and wind are presently at low enough levels that they do not significantly impact the system or market in Minnesota Power's region, planned increases in these resources to serve both local and regional needs are expected to impact its customers in the future. Minnesota Power has studied energy storage in order to prepare for future impacts of renewable resource additions. Minnesota Power continues to optomize various wind forecasting tools to maximize the accuracy of scheduling wind generation into the market.

APPENDIX I: RENEWABLE ENERGY STANDARD AND SOLAR ENERGY STANDARD COST IMPACT REPORT

Appendix I serves as Minnesota Power's Renewable Energy Cost Impact Report ("Report") to the Minnesota Public Utilities Commission ("Commission") in compliance with Minn. Stat. § 216B.1691, subd. 2e (Docket No. E999/CI-11-852). The statute is intended to provide a mechanism for determining and communicating to legislators and constituents what utility rates would be if the 2007 Minnesota Next Generation Energy Act ("NGEA") had never been implemented. This Report is intended to be in full compliance with the Commission's January 6, 2015 Order Establishing Uniform Reporting System for Estimating Rate Impact of Minn. Stat § 216B.1691 ("Order"), as well as the language and objective of the statute.

The NGEA helped to create a framework for utilities to implement expanded renewable energy portfolios. The NGEA requires Minnesota electric utilities to obtain increasing amounts of energy from eligible renewable resources according to a specified timeline. The amounts are calculated in terms of a percentage of each utility's total retail sales. During the 2011 legislative session, legislation was passed which requires utilities to report the impacts of the NGEA on customers. In 2013, the Minnesota Legislature directed the Commission to develop a uniform system for utilities to use when estimating how electric rates have been influenced by Minn. Stat. § 216B.1691. The Commission issued two notices, November 6, 2013, and April 18, 2014, respectively, seeking comments on Commission Staff's proposed general guiding principles and format for a uniform reporting system. The Commission approved the general guiding principles and format to be used by reporting utilities, including Minnesota Power, at a hearing on October 2, 2014, which was reflected in the January 6, 2015 Order.

The Order is comprehensive, but also provides some flexibility to reporting utilities due to the vast differences in demographics, structure and load. Utilities estimating the rate impact of Minn. Stat. § 216B.1691 are required to do the following:

- Report data for the period 2005 until the last reported year. (Order Point 1A.1 & 1A.2).
- Analyze costs from the year following the last reported year, and for the following 15 years. (Order Point 2A.1 & 2A.2).
- Include all facilities used to comply with the Renewable Energy Standard ("RES") and the Solar Energy Standard ("SES"), regardless of when the facilities were constructed. (Order Point 2B).
- Calculate direct costs to include payments under power purchase agreements and revenue requirements associated with utility-owned renewable energy projects. (Order Point 2C).
- Provide a narrative discussion about the impact that adding generators powered by renewable sources may have had on the utility's indirect costs, such as the cost for ancillary services and base load cycling. (Order Point 2D).
- Include transmission costs for transmission improvements created exclusively for the purpose of gaining access to electricity from renewable resources, as well as the percentage directly attributable to compliance with the RES and SES. Additionally, for

multi-purpose transmission providing access to renewable resources include a narrative estimating the costs and portion the utility would allocate to the cost of gaining access to renewable resources. (Order Point 2E.1 & 2E.2).

- Calculate savings arising from avoiding energy and capacity costs that the utility would have incurred directly in the absence of the RES and SES. (Order Point 2F.1 & 2F.2).
- Calculate savings arising from avoiding costs (past and future) that the utility would have incurred indirectly in the absence of the RES and SES to include costs of sulfur dioxides ("SO_2") and oxides of nitrogen ("NO_x") permits required under Title IV of the Federal Clean Air Act, and expected future emission compliance costs, including costs of SO_2 and NOx permits, as well as the range of compliance cost values for carbon dioxide ("CO_2") set by the Commission under Minn. Stat. § 216H.06. (Order Point 2G.1 & 2G.2).
- Report estimated annualized and estimated levelized costs. (Order Point 2H).
- Calculate separately the rate impacts of complying with the RES and the SES. (Order Point 2I.1 & 2I.2).
- Calculate the ultimate rate impact of Minn. Stat. § 216H.1691 to reflect the fact that renewable energy comprises only a fraction of a utility's total energy costs, and consequently most of a utility's energy costs are unaffected by the RES and SES. (Order Point 2J.1).
- Calculate additional modifications as are agreed upon by the Department of Commerce – Division of Energy Resources and the commentors. (Order Point 2J.2).

Minnesota Power provides historical and future rate impact information for the RES and SES as required under Minn. Stat. § 216B.1691, subd. 2e. The analysis shows that the investments the Company has made on behalf of its customers to meet the RES have been reasonable and resulted in estimated rates impacts that are competitive with alternative power supply resource options.

Methodology

For the purpose of this study, the Company calculated separate rate impacts for the RES and the SES. RES rate impact calculations were performed for two different time frames: Historic Years 2005-2014, and Future Years 2015-2029. Recognizing that the SES was adopted in 2013, and that there have been no rate impacts through the end of the historic period, SES rate impact calculations were performed for the Future Years 2015-2029.

Included in the historic and future RES rate impact calculations are estimates of transmission costs directly attributable to renewable resources. Specifically, the transmission costs are for new transmission assets required to access and transmit the renewable energy produced by the four large wind projects: Bison 1, Bison 2, Bison 3 and Bison 4 which comprise the Bison Wind Energy Center. The Bison Wind Energy Center is located in west central North Dakota, near the city of New Salem, in Oliver County. The calculation of the direct cost of renewables includes 100 percent of the revenue requirements associated with these transmission projects (see Row C in Tables 1, 2, 3, 4, 5, 6 and 7).

Historic Cost Impact for the RES (2005 – 2014)

Historic rate impacts were determined by comparing the actual direct costs associated with the Company's renewable generation each year with an estimate of the direct costs that would have been incurred had Minnesota Power acquired the same accredited generation capacity (MW) and energy (MWh) from non-renewable resources. The cost of building a new natural gas 1x1 combined cycle ("CC") unit and associated fixed operations and maintenance ("O&M") expenses were used to estimate avoided capacity costs. The energy cost from a 1x1 CC and associated variable O&M expenses were used to estimate the avoided energy cost.[1] The construction costs and generation characteristics represents a 1x1 CC typically built around 2010.

Minnesota Power's last Renewable Energy Cost Impact Report was submitted as part of Appendix G: Minnesota's Renewable Energy in its 2013 integrated resource plan.[2] The methodology used for the 2013 Report and resulting numbers were somewhat different than what is now required by the 2013 legislation and Order. For the current Report, the Company included 2013 - 2014 in its historic estimates because of its ability to use actual costs for the timeframe of 2005 – 2014; therefore, a different calculation was used for the estimated future RES costs which are based on projections.

Table 1: Historic RES Rate Impact (2005 - 2014)

		Historic (2005-2014)									
	RES Generation	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
A	Total RES Generation (PPA+Owned; GWh)	502	370	643	888	893	1,008	1,037	1,020	1,396	1,694
	Costs Associated w/ RES Generation (Revenue Requirements)										
B	Purchased Power+Owned Generation (millions)	$ 11.3	$ 12.6	$ 18.4	$ 28.3	$ 35.2	$ 49.1	$ 60.5	$ 79.8	$ 85.0	$ 107.8
C	RES Attributable Transmission (millions)	$ –	$ –	$ –	$ –	$ –	$ 1.3	$ 2.8	$ 3.6	$ 4.0	$ 6.4
D = B+C	Total Cost for RES Generation (millions)	$ 11.3	$ 12.6	$ 18.4	$ 28.3	$ 35.2	$ 50.5	$ 63.3	$ 83.3	$ 89.0	$ 114.2
E = D/A	Total Cost for RES Generation ($/MWh)	$ 22.57	$ 33.98	$ 28.55	$ 31.83	$ 39.46	$ 50.05	$ 61.08	$ 81.68	$ 63.77	$ 67.41
	Avoided Costs due to RES										
F	Avoided Energy Costs PPAs & Owned Generation (millions)	$ 30.5	$ 18.4	$ 32.2	$ 55.3	$ 28.2	$ 35.6	$ 33.6	$ 24.2	$ 43.3	$ 80.1
G	Avoided Capacity Cost PPAs & Owned Generation (millions)	$ 39.8	$ 40.0	$ 43.9	$ 45.3	$ 47.5	$ 32.6	$ 40.9	$ 47.3	$ 49.0	$ 35.2
H	Avoided Transmission Cost (millions)	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1
I	Avoided Emissions Cost PPAs & Owned Generation (millions)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (millions)	$ 70.3	$ 58.5	$ 76.2	$ 100.8	$ 75.8	$ 68.3	$ 74.6	$ 71.6	$ 92.5	$ 115.4
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 140.23	$ 158.25	$ 118.49	$ 113.55	$ 84.90	$ 67.70	$ 71.95	$ 70.21	$ 66.26	$ 68.12
L = D-J	Total RES Premium/Discount (millions)	$ (59.0)	$ (45.9)	$ (57.9)	$ (72.5)	$ (40.6)	$ (17.8)	$ (11.3)	$ 11.7	$ (3.5)	$ (1.2)
M = E-K	Total RES Premium/Discount ($/MWh)	$ (117.66)	$ (124.27)	$ (89.95)	$ (81.71)	$ (45.44)	$ (17.64)	$ (10.87)	$ 11.47	$ (2.49)	$ (0.70)
	Annualized RES Rate Impacts										
N	Minnesota Power Sales (Retail & Wholesale; GWh)	10,345	10,444	10,671	10,826	8,062	10,417	10,988	11,107	10,986	11,039
O = L/N	Rate Impact ($/MWh)	$ (5.70)	$ (4.40)	$ (5.42)	$ (6.70)	$ (5.03)	$ (1.71)	$ (1.03)	$ 1.05	$ (0.32)	$ (0.11)
P = O/10	Rate Impact (¢/kWh)	(0.57)	(0.44)	(0.54)	(0.67)	(0.50)	(0.17)	(0.10)	0.11	(0.03)	(0.01)

[1] The energy cost is based on historical natural gas prices at Ventura multiplied by the heat rate of the 1x1 CC plus variable O&M costs. The assumed heat rate for the 1x1 CC was 7,000 Btu/kWh.

[2] See Docket No. E015/RP-13-53.

Future RES Rate Impact (2015-2029)

Future RES rate impacts were calculated by comparing Minnesota Power's power supply cost projections within the Strategist software tool for two different futures: 1) a "RES" compliant future that reflects the Preferred Plan recommended in the 2015 integrated resource plan ("2015 Plan"): and 2) a "No RES" future in which all renewable generation capacity and energy contained in the "RES" future used to meet the RES are removed and replaced with non-renewable generation. The type and timing of replacement energy and capacity was based on an expansion plan using Strategist.

The "RES" future is the Preferred Plan discussed in Section IV of the 2015 Plan. Details of the power supply assumptions in the Preferred Plan are also discussed in Section IV and Appendix J. Per the Order, the RES rate impact analysis includes the required calculation of saving from avoided costs, which contains the Commission-approved CO_2 regulation penalty of $21.50/ton starting in 2019 and escalates annually at the inflation rate.

By comparing the difference between the annual power supply costs of the "RES" and "No RES" futures, one can project the cost impact of the actions the Company has taken to comply with the RES. Note that these future rate impacts reflect the cost of all the actions taken to comply with the RES and not the individual renewable projects that were built in response to the RES or already existed prior to the RES. The rate impacts will be different when calculated for incremental renewable resources.

Table 2 and Table 3 show the projected future rate impacts attributed to meeting the RES by year for 2015 - 2022 and 2023 - 2029, respectively. Table 4 shows the levelized costs and rate impacts associated with meeting the RES for the historic period (2005 - 2014) and future period (2015 - 2029).

Table 2: Future RES Rate Impact (2015 - 2022)

		Future (2015-2022)							
	RES Generation	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
A	Total RES Generation (PPA+Owned; GWh)	2,941	3,013	2,944	2,944	2,945	2,952	2,945	2,946
	Costs Associated w/ RES Generation (Revenue Requirements)								
B	Purchased Power+Owned Generation (millions)	$ 114.2	$ 106.5	$ 100.8	$ 99.3	$ 97.8	$ 100.3	$ 104.8	$ 117.4
C	RES Attributable Transmission (millions)	$ 6.7	$ 6.4	$ 6.0	$ 5.7	$ 5.5	$ 5.3	$ 5.1	$ 5.0
D = B+C	Total Cost for RES Generation (millions)	$ 120.9	$ 112.9	$ 106.9	$ 105.1	$ 103.3	$ 105.6	$ 109.9	$ 122.4
E = D/A	Total Cost for RES Generation ($/MWh)	$ 41.10	$ 37.47	$ 36.29	$ 35.68	$ 35.06	$ 35.77	$ 37.32	$ 41.53
	Avoided Costs due to RES								
F	Avoided Energy Costs PPAs & Owned Generation (millions)	$ 89.2	$ 97.4	$ 91.6	$ 99.7	$ 111.4	$ 113.7	$ 120.6	$ 121.1
G	Avoided Capacity Cost PPAs & Owned Generation (millions)	$ 30.0	$ 31.2	$ 29.8	$ 32.1	$ 31.6	$ 35.4	$ 36.2	$ 36.3
H	Avoided Transmission Cost (millions)	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4
I	Avoided Emissions Cost PPAs & Owned Generation (millions)	$ –	$ –	$ –	$ –	$ –	$ 28.4	$ 26.2	$ 27.1
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (millions)	$ 121.6	$ 131.0	$ 123.9	$ 134.1	$ 145.4	$ 173.7	$ 185.4	$ 186.8
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 41.34	$ 43.46	$ 42.07	$ 45.55	$ 49.35	$ 58.99	$ 62.95	$ 63.40
L = D-J	Total RES Premium/Discount (millions)	$ (0.7)	$ (18.1)	$ (17.0)	$ (29.1)	$ (42.1)	$ (70.5)	$ (75.5)	$ (64.4)
M = E-K	Total RES Premium/Discount ($/MWh)	$ (0.24)	$ (5.99)	$ (5.78)	$ (9.87)	$ (14.29)	$ (23.93)	$ (25.63)	$ (21.87)
	Annualized RES Rate Impacts								
N	Minnesota Power Sales (Retail & Wholesale; GWh)	11,237	11,591	12,135	12,222	12,278	12,278	12,380	12,424
O = L/N	Rate Impact ($/MWh)	$ (0.06)	$ (1.56)	$ (1.40)	$ (2.38)	$ (3.43)	$ (5.74)	$ (6.10)	$ (5.19)
P = O/10	Rate Impact (¢/kWh)	(0.01)	(0.16)	(0.14)	(0.24)	(0.34)	(0.57)	(0.61)	(0.52)

Table 3: Future RES Rate Impact (2023 - 2029)

		Future (2023-2029)						
	RES Generation	2023	2024	2025	2026	2027	2028	2029
A	Total RES Generation (PPA+Owned; GWh)	2,946	2,941	2,942	2,943	2,945	2,955	2,950
	Costs Associated w/ RES Generation (Revenue Requirements)							
B	Purchased Power+Owned Generation (millions)	$ 114.7	$ 140.8	$ 167.3	$ 161.6	$ 156.0	$ 150.5	$ 148.1
C	RES Attributable Transmission (millions)	$ 4.8	$ 4.6	$ 4.4	$ 4.3	$ 4.1	$ 4.0	$ 3.9
D = B+C	Total Cost for RES Generation (millions)	$ 149.5	$ 145.4	$ 171.7	$ 165.9	$ 160.1	$ 154.5	$ 152.0
E = D/A	Total Cost for RES Generation ($/MWh)	$ 50.74	$ 49.43	$ 58.36	$ 56.37	$ 54.37	$ 52.28	$ 51.52
	Avoided Costs due to RES							
F	Avoided Energy Costs PPAs & Owned Generation (millions)	$ 123.0	$ 109.7	$ 121.4	$ 125.8	$ 132.3	$ 138.0	$ 140.8
G	Avoided Capacity Cost PPAs & Owned Generation (millions)	$ 48.0	$ 48.2	$ 48.4	$ 48.5	$ 48.7	$ 48.9	$ 49.0
H	Avoided Transmission Cost (millions)	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4
I	Avoided Emissions Cost PPAs & Owned Generation (millions)	$ 26.7	$ 31.5	$ 30.7	$ 30.4	$ 29.6	$ 30.7	$ 30.9
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (millions)	$ 200.1	$ 191.7	$ 202.9	$ 207.2	$ 213.0	$ 219.9	$ 223.1
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 67.91	$ 65.19	$ 68.96	$ 70.41	$ 72.32	$ 74.44	$ 75.65
L = D-J	Total RES Premium/Discount (millions)	$ (50.6)	$ (46.3)	$ (31.2)	$ (41.3)	$ (52.9)	$ (65.5)	$ (71.2)
M = E-K	Total RES Premium/Discount ($/MWh)	$ (17.16)	$ (15.75)	$ (10.60)	$ (14.04)	$ (17.96)	$ (22.16)	$ (24.13)
	Annualized RES Rate Impacts							
N	Minnesota Power Sales (Retail & Wholesale; GWh)	12,479	12,561	12,583	12,641	12,702	12,798	12,827
O = L/N	Rate Impact ($/MWh)	$ (4.05)	$ (3.69)	$ (2.48)	$ (3.27)	$ (4.16)	$ (5.12)	$ (5.55)
P = O/10	Rate Impact (¢/kWh)	(0.41)	(0.37)	(0.25)	(0.33)	(0.42)	(0.51)	(0.55)

Table 4: Levelized RES Costs and Rate Impact

		Discount Rate 8.18%	
	Levelized RES Generation	Historic Period (2005-2014)	Future Period (2015-2029)
A	Total RES Generation (PPA+Owned; GWh)	867	2,952
	Levelized Costs Associated w/ RES Generation (Revenue Requirements)		
B	Purchased Power+Owned Generation (millions)	$ 42.0	$ 120.6
C	RES Attributable Transmission (millions)	$ 1.4	$ 5.3
D = B+C	Total Cost for RES Generation (millions)	$ 43.3	$ 125.9
E = D/A	Total Cost for RES Generation ($/MWh)	$ 50.00	$ 42.65
	Levelized Avoided Costs due to RES		
F	Avoided Energy Costs PPAs & Owned Generation (millions)	$ 36.2	$ 110.9
G	Avoided Capacity Cost PPAs & Owned Generation (millions)	$ 42.1	$ 37.6
H	Avoided Transmission Cost (millions)	$ 0.1	$ 2.4
I	Avoided Emissions Cost PPAs & Owned Generation (millions)	$ –	$ 17.7
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (millions)	$ 78.4	$ 168.6
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 90.47	$ 57.10
L = D-J	Levelized Total RES Premium/Discount (millions)	$ (35.1)	$ (42.7)
M = E-K	Levelized Total RES Premium/Discount ($/MWh)	$ (40.47)	$ (14.45)
	Levelized RES Rate Impacts		
N	Minnesota Power Sales (Retail & Wholesale; GWh)	10,436	12,217
O = L/N	Rate Impact ($/MWh)	$ (3.36)	$ (3.49)
P = O/10	Rate Impact (¢/kWh)	(0.34)	(0.35)

Future SES Rate Impact (2015-2029)

Future SES rate impacts were derived using a similar methodology described above for future RES rate impacts in that the comparisons of power supply cost were made for two different futures using the Strategist software tool: 1) a “SES” compliant future that reflects the Preferred Plan recommended in Section IV of the 2015 Plan, and 2) a “No SES” future in which all solar generation capacity and energy contained in the “SES” future used to meet the SES are removed and replaced with non-solar generation. The type and timing of the replacement energy and capacity was based on an expansion plan using Strategist. The difference in annual power supply cost between the two futures represents the project cost impact associated with the Company’s expected actions to comply with the SES. The “SES” future is the Preferred Plan discussed in Section IV.

It is important to note that unlike the RES, the SES applies to only a portion of Minnesota Power’s customers, and will have rate impacts only for non-exempt retail customers. Wholesale customers are excluded entirely. Consequently, the values presented for the SES rate impacts represent the impacts to non-exempt retail customers only.

Table 5 and Table 6 show the estimated future rate impacts attributed to meeting the SES by year for 2015 - 2022 and 2023 - 2029, respectively. Costs are higher in 2016 due to the revenue requirements associated with construction of Minnesota Power’s first utility scale solar project, the 10 MW Camp Ripley Solar Project,[3] and limited off-setting generation during the first year of the project. Table 7 shows the levelized costs and rate impacts associated with meeting the SES for the entire future period (2015 - 2029).

Table 5: Future SES Rate Impact (2015 - 2022)

		Future (2015-2022)							
	SES Generation	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
A	Total SES Generation (PPA+Owned; MWh)	–	1,249	19,314	19,191	19,069	40,059	39,843	39,723
	Costs Associated w/ SES Generation (Revenue Requirements)								
B	Purchased Power+Owned Generation (thousands)	$ –	$ 1,125	$ 2,404	$ 2,320	$ 2,267	$ 5,819	$ 5,572	$ 5,577
C	SES Attributable Transmission (thousands)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –
D = B+C	Total Cost for SES Generation (thousands)	$ –	$ 1,125	$ 2,404	$ 2,320	$ 2,267	$ 5,819	$ 5,572	$ 5,577
E = D/A	Total Cost for SES Generation ($/MWh)	$ –	$ 901.37	$ 124.47	$ 120.90	$ 118.90	$ 145.25	$ 139.85	$ 140.40
	Avoided Costs due to SES								
F	Avoided Energy Costs PPAs & Owned Generation (thousands)	$ –	$ 47	$ 757	$ 1,171	$ 1,039	$ 2,030	$ 1,981	$ 2,019
G	Avoided Capacity Cost PPAs & Owned Generation (thousands)	$ –	$ –	$ 1,775	$ 1,748	$ 1,717	$ 2,174	$ 2,237	$ 2,214
H	Avoided Transmission Cost (thousands)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –
I	Avoided Emissions Cost PPAs & Owned Generation (thousands)	$ –	$ –	$ –	$ –	$ 79	$ 250	$ 282	$ 293
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (thousands)	$ –	$ 47	$ 2,532	$ 2,919	$ 2,835	$ 4,455	$ 4,500	$ 4,526
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ –	$ 37.31	$ 131.11	$ 152.10	$ 148.66	$ 111.20	$ 112.95	$ 113.95
L = D-J	Total SES Premium/Discount (thousands)	$ –	$ 1,078.8	$ (128.3)	$ (598.6)	$ (567.5)	$ 1,363.9	$ 1,071.9	$ 1,050.8
M = E-K	Total SES Premium/Discount ($/MWh)	$ –	$ 864.06	$ (6.64)	$ (31.19)	$ (29.76)	$ 34.05	$ 26.90	$ 26.45
	Annualized SES Rate Impacts								
N	Minnesota Power Retail Sales (non-SES exempt; MWh)	3,076,813	3,164,274	3,470,212	3,604,487	3,636,744	3,675,273	3,692,675	3,723,822
O = L/N	Retail Rate Impact ($/MWh)	$ –	$ 0.34	$ (0.04)	$ (0.17)	$ (0.16)	$ 0.37	$ 0.29	$ 0.28
P = O/10	Retail Rate Impact (¢/kWh)	–	0.03	(0.00)	(0.02)	(0.02)	0.04	0.03	0.03

[3] See Appendix H of the 2015 Plan for information on the Camp Ripley Solar Project.

Table 6: Future SES Rate Impact (2023 - 2029)

		Future (2023-2029)						
	SES Generation	2023	2024	2025	2026	2027	2028	2029
A	Total SES Generation (PPA+Owned; MWh)	39,604	39,581	56,882	56,766	56,651	56,671	56,422
	Costs Associated w/ SES Generation (Revenue Requirements)							
B	Purchased Power+Owned Generation (thousands)	$ 5,583	$ 5,588	$ 8,557	$ 8,567	$ 7,792	$ 7,760	$ 7,699
C	SES Attributable Transmission (thousands)	$ –	$ –	$ –	$ –	$ –	$ –	$ –
D = B+C	Total Cost for SES Generation (thousands)	$ 5,583	$ 5,588	$ 8,557	$ 8,567	$ 7,792	$ 7,760	$ 7,699
E = D/A	Total Cost for SES Generation ($/MWh)	$ 140.96	$ 141.19	$ 150.43	$ 150.91	$ 137.55	$ 136.94	$ 136.46
	Avoided Costs due to SES							
F	Avoided Energy Costs PPAs & Owned Generation (thousands)	$ 2,100	$ 1,673	$ 2,834	$ 2,963	$ 3,096	$ 3,202	$ 3,200
G	Avoided Capacity Cost PPAs & Owned Generation (thousands)	$ 2,185	$ 2,162	$ 2,781	$ 2,796	$ 2,801	$ 2,830	$ 2,845
H	Avoided Transmission Cost (thousands)	$ –	$ –	$ –	$ –	$ –	$ –	$ –
I	Avoided Emissions Cost PPAs & Owned Generation (thousands)	$ 304	$ 448	$ 525	$ 501	$ 448	$ 514	$ 529
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (thousands)	$ 4,589	$ 4,283	$ 6,140	$ 6,259	$ 6,345	$ 6,547	$ 6,574
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 115.87	$ 108.21	$ 107.95	$ 110.26	$ 112.00	$ 115.52	$ 116.52
L = D-J	Total SES Premium/Discount (thousands)	$ 993.8	$ 1,305.4	$ 2,416.8	$ 2,307.6	$ 1,447.1	$ 1,213.6	$ 1,125.0
M = E-K	Total SES Premium/Discount ($/MWh)	$ 25.09	$ 32.98	$ 42.49	$ 40.65	$ 25.54	$ 21.42	$ 19.94
	Annualized SES Rate Impacts							
N	Minnesota Power Retail Sales (non-SES exempt; MWh)	3,751,547	3,787,336	3,803,179	3,833,717	3,866,999	3,913,644	3,922,658
O = L/N	Retail Rate Impact ($/MWh)	$ 0.26	$ 0.34	$ 0.64	$ 0.60	$ 0.37	$ 0.31	$ 0.29
P = O/10	Retail Rate Impact (¢/kWh)	0.03	0.03	0.06	0.06	0.04	0.03	0.03

Table 7: Levelized Costs and Rate Impact

		Discount Rate 8.18%
	Levelized SES Generation	Future Period (2015-2029)
A	Total SES Generation (PPA+Owned; MWh)	30
	Levelized Costs Associated w/ SES Generation (Revenue Requirements)	
B	Purchased Power+Owned Generation (thousands)	$ 4,239
C	SES Attributable Transmission (thousands)	$ –
D = B+C	Total Cost for SES Generation (thousands)	$ 4,239
E = D/A	Total Cost for SES Generation ($/MWh)	$ 142
	Levelized Avoided Costs due to SES	
F	Avoided Energy Costs PPAs & Owned Generation (thousands)	$ 1,534
G	Avoided Capacity Cost PPAs & Owned Generation (thousands)	$ 1,749
H	Avoided Transmission Cost (thousands)	$ –
I	Avoided Emissions Cost PPAs & Owned Generation (thousands)	$ 212
J = F+G+H+I	Total Avoided Costs PPAs & Owned Generation (thousands)	$ 3,495
K = J/A	Total Avoided Costs PPAs & Owned Generation ($/MWh)	$ 117
L = D-J	Levelized Total SES Premium/Discount (thousands)	$ 744
M = E-K	Levelized Total SES Premium/Discount ($/MWh)	$ 25
	Levelized SES Rate Impacts	
N	Minnesota Power Retail Sales (non-SES exempt; MWh)	3,585
O = L/N	Rate Impact ($/MWh)	$ 0.21
P = O/10	Rate Impact (¢/kWh)	0.02

Indirect Cost Impact – Ancillary Service and Base Load Cycling (2005 – 2029)

Minnesota Power operates its thermal fleet in the Midcontinent Independent System Operator ("MISO") regional market on a daily basis. Each unit is offered into the Day-Ahead Energy and Operating Reserve Market for the energy and ancillary services products available. MISO's region-wide optimization identifies which units will and will not be utilized for the next day's market.

Wind energy is the largest component of renewable energy in Minnesota Power's portfolio, providing over 2 million MWh each year for customers. The onset of additional wind in the Midwest has created a new operational environment for MISO to manage on a dispatch basis. Minnesota Power is monitoring the operational trends of its generating units with the additional wind in its portfolio and has not identified a significant change in operation that can be directly linked to renewable energy.

Many variables impact the regional marketplace including both supply and demand-side factors. The regional market has seen a decline in market pricing since 2008; this trend can be attributable in part to both a surplus of energy from new generation (renewable and other forms) and a decline in customer demand. A lower priced regional energy market creates more dispatch changes to the thermal unit fleet across the Midwest. Typically the generating units that are higher in cost are the first to be impacted (have reductions in energy production), and the more efficient generating facilities see less change.

Minnesota Power has seen reduced generation output due to lower market pricing in the region. The lower pricing is exacerbated during times when the wind production is high in MISO. Taconite Harbor Energy Center ("THEC") has been most impacted by the lower pricing profile and the Company is recommending it be transitioned off of coal-fired generation in 2020. Minnesota Power's other thermal generating units at Boswell Energy Center have had less operational change attributed to lower market pricing due to the competitive production costs at the facility.

The Ancillary Services Market identifies trends in a region's ability to meet its reliability requirements through the pricing and procurement of services such as regulation (balancing the system), along with spin and supplemental reserves (protecting against unexpected increases and decreases of load and generation). Typically an increase in the need for ancillary services is indicative of additional fluctuations on the power system which need to be managed. Another reason for an adjustment in procurement of these services is a change to the membership in MISO that reallocates the need for the products. MISO identifies the requirements for ancillary services on a daily basis to ensure reliability for each local balancing area.

At this time Minnesota Power has not been able to pinpoint the onset of renewables as a primary cause of increased ancillary product requirements for its customers. The MISO ancillary program started in January 2009, and Minnesota Power has only seen an increase in requirements when there was a membership change in MISO that reallocated the responsibilities for ancillary services. For example, Minnesota Power's requirement increased at the end of 2011 due to Duke Energy and First Energy departing from MISO.

In summary, Minnesota Power has seen lower energy market prices when the wind is strong in the MISO footprint in comparison to when there is less wind available. Lower pricing will pressure generating units to reduce operating levels as pricing declines. To date, THEC has seen the most operational change due to lower pricing. Minnesota Power has not identified any direct impacts to its ancillary services requirements that are due to renewable implementation as part of the RES requirements.

Avoided Environmental Permitting and Emission Compliance Cost Impact

When determining the cost of a new natural gas 1x1 CC resource, the avoided costs for future emission compliance, including cost of SO_2 and NO_x permits are factored into its value. Therefore, the avoided permitting and emission related costs are accounted for in the capital cost for the new natural gas CC resources. Minnesota Power also applied the Commission-approved \$21.50/ton CO_2 regulation penalty[4] beginning in 2019.

Transmission Cost Impact (2005-2029)

Minnesota Power's renewable portfolio is comprised primarily of a combination of long-standing hydro resources and recently constructed wind resources. Transmission costs for renewable resource assets in service prior to 2005 and the RES being established were not included in the cost impact calculation. Transmission improvements associated with renewable resources added in recent years that qualify under the RES are included in the estimated costs.

Multipurpose High Voltage Direct Current Line ("DC Line")

In early 2010, Minnesota Power finalized its purchase of the 465 mile, +/- 250 kV DC Line that connects Center, N.D., and Hermantown, Minn. The DC Line was built in the 1970s to bring electricity from Milton R. Young 2 ("Young 2") lignite coal generating station in Center, N.D., to Minnesota Power's customers. Minnesota Power's purchase of the DC Line cleared the way for the DC Line to be repurposed to facilitate the delivery of wind power generated in North Dakota to Minnesota Power's customers. Between 2010 and 2013, the Company completed a series of upgrades that increased the capacity of the DC Line to 550 MW.[5]

Figure 1: Minnesota Power's DC Line Map

[4] Minn. Stat. § 216H.06.

[5] The 50 MW upgrade to the DC Line was completed in November 2013.

The purchase of the DC Line and the phase-out of Minnesota Power's long-term contract to buy coal-fired generation from Young 2 were approved by the Commission in December 2009. Up until June 2014, Minnkota Power Cooperative ("Minnkota") and Minnesota Power were each receiving 227.5 MW (50 percent shares) of electric generation from Young 2 that was delivered to customers via the DC Line. As described in Appendix C of the 2015 Plan, the Company is gradually reducing its 227.5 MW share of coal-fired generation from Young 2 and, by 2026, will no longer take any of the Young 2 output for its customers. Additionally, Minnkota began utilizing its newly constructed Center to Grand Forks 345 kV transmission line in August 2014 to transfer its share of Young 2 output.[6] These actions result in an increasing amount of capacity being available on the DC Line for the transfer of wind energy, with the full 550 MW of capacity available in 2026. Figure 2 illustrates the proportion of coal-fired generation versus wind energy being transferred via the DC Line.

Figure 2: Proportion of Coal to Wind Energy on the DC Line (2010 - 2029)

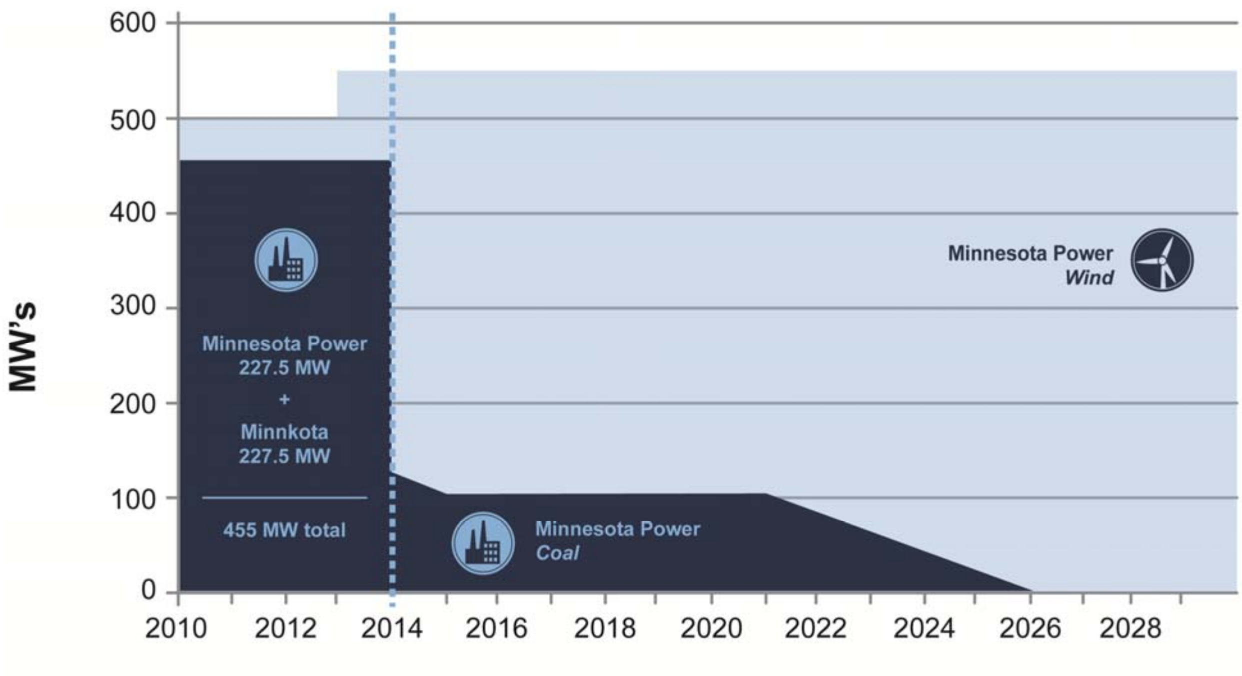


Table 8 contains the estimated DC Line cost for transferring wind power from the Bison Wind Center to Minnesota Power customers via the DC Line over the planning period. The estimated costs are based on the amount of capacity available on the DC Line to transmit wind energy multiplied by Minnesota Power's Schedule 7 rate under the MISO's Open Access Transmission and Energy and Operating Reserves Markets Tariff.[7] The ability to transfer an increasing amount of wind power via the DC Line over the planning period is reflected in Row D of Table 8.

[6] Minnkota's share of Young 2 will gradually increase to 455 MW during the period of 2014 - 2026 due to purchasing Minnesota Power's 227.5 share of Young 2 generation.
[7] MISO acts as Minnesota Power's designated agent.

Table 8: DC Line Estimate of Costs for Renewable Energy Transfer

	Minnesota Power	2015	2016	2017	2018	2019	2020	2021	2022
A	HVDC Line Cost $/MWh-YR	25,732	26,246	26,771	27,307	27,853	28,410	28,978	29,558
B	Total HVDC Capability (MW)	550	550	550	550	550	550	550	550
C	Coal Capacity on HVDC (MW)	100	100	100	100	100	100	100	80
D = B-C	Renewable Capability on HVDC (MW)	450	450	450	450	450	450	450	470
E = A*D	HVDC Cost Estimate for Renewable ($-millions)	$11.6	$11.8	$12.0	$12.3	$12.5	$12.8	$13.0	$13.9

	Minnesota Power	2023	2024	2025	2026	2027	2028	2029
A	HVDC Line Cost $/MWh-YR	30,149	30,752	31,367	31,994	32,634	33,287	33,952
B	Total HVDC Capability (MW)	550	550	550	550	550	550	550
C	Coal Capacity on HVDC (MW)	60	40	20	0	0	0	0
D = B-C	Renewable Capability on HVDC (MW)	490	510	530	550	550	550	550
E = A*D	HVDC Cost Estimate for Renewable ($-millions)	$14.8	$15.7	$16.6	$17.6	$17.9	$18.3	$18.7

Minnesota Power leveraged the existing transmission assets installed for the Bison 1 Project (Docket No. E-015/M-09-285) in 2010 and 2011 to transmit the power from the subsequent constructed Bison 2, 3 and 4 projects to the point of interconnection. The costs shown in Tables 1, 2, 3 and 4 reflect the following transmission assets:

- A new 230 kV alternating current (“AC”) transmission line, initially about 22 miles in length which was later extended 11 miles to accommodate the Bison 4 Wind project. The line is required to transmit wind generation from the substation to the point of interconnection.
- Two new substations, the Bison Substation and Tri-County Substation, that each include a 34.5 kV/230 kV transformer to enable connecting the power output to the high voltage electrical transmission network
- Modification to the existing 230 kV Square Butte Substation
- Increase in capacity of the DC Line from 500 MW to 550 MW

No new transmission assets were needed for Taconite Ridge Wind Center due to its proximity to existing transmission infrastructure; therefore, no transmission related costs for the facility were included in the calculation. The 34.5 kV collector system required to deliver the power generated by the ten turbines to the existing substation is considered a distribution asset of Taconite Ridge Wind Center. Additionally, the Company did not include transmission costs for its existing hydroelectric stations which were constructed and placed in service well before 2005 and establishment of the RES.

Ultimate Rate Impact

It was assumed for purposes of this Report that because Minnesota Power plans and constructs resources for its system as a whole, historic and future cost/rate impacts to wholesale customers are similar in magnitude to those for retail customers. With the exception of the SES (due to customer exemptions), it was assumed that wholesale and retail rate impacts due to renewables will closely track one another. As a result, the values presented for the RES rate impacts in this Report approximately represent all customer rate impacts (both retail and wholesale). The historic and future annualized RES rate impacts are shown in Rows O and P in Tables 1, 2 and 3, and the historic and future levelized rate impacts are shown in Rows O and P in Table 4. The future annualized SES rate impacts are shown in Rows O and P in Tables 5 and 6, and the future levelized rate impacts are shown in Rows O and P in Table 7. For non-exempt retail customers, the total RES and SES rate impact is the combination of the rate impact described in this Report.

In summary, the analysis shows that the investments Minnesota Power has made on behalf of its customers to meet the RES have been reasonable and resulted in estimated rates impacts that are competitive with alternative power supply resource options. Historically, costs associated with facilities to meet the RES have provided a net benefit to customers' rates compared with the cost of building a natural gas CC unit to replace the energy from qualifying renewable sources. This trend is expected to continue in future years. Costs to meet the SES are projected to increase customer rates by $0.21/MWh (levelized) during the 2015-2029 time period. The Company will continue to closely monitor developments in renewable resource technology and trends in order to ensure Minnesota Power complies with existing and future renewable energy related standards in the most cost-effective manner on behalf of its customers.

APPENDIX J: ASSUMPTIONS AND OUTLOOKS

The following section provides a summary of the key economic modeling assumptions and basis that Minnesota Power (or "Company") utilized in the Strategist Proview analysis completed for the 2015 Integrated Resource Plan ("2015 Plan" or "Plan"). This Appendix, detailing the assumptions and outlooks, is organized in the following format:

A) Base Case Economic Modeling Assumptions – a review of the base economic assumption used in the analysis for the Plan.

B) Asset Resource Alternatives – A description of the new resource alternatives considered in the Plan.

C) Assumptions Utilized in the Sensitivity Analysis

D) Long-term Planning and Wholesale Market Interaction – discussion on utilizing the wholesale market in resource planning.

E) Retirement Methodology for 2015 Plan Evaluation – A description of the retirement method utilized during the analysis within the 2015 Plan and assumptions for decommissioning of generation facilities.

A. Base Case Economic Modeling Assumptions

Study Period

The timeline of the 2015 Plan analysis is 2015 through 2029. The power supply costs shown in the Plan are the net present value of cost from 2015 through 2034 and are reported in 2015 dollars, unless noted otherwise. The reporting of power supply cost was extended past the required planning period to capture the cost of generation over a longer period of time.

The expansion planning analysis conducted with the Strategist Proview Model considered 15 years of end effects after 2034 when selecting the lowest cost plan.

Externalities, Pricing, and Wholesale Market

1. The Base Case forecasts utilized for externality values, natural gas prices, market energy prices, and market capacity prices over the study period:[1]

    a. The base forecast utilized the Metropolitan Fringe externality values from the State Externality Docket published on May 27, 2015, under Docket Nos. E999/CI-93-583 and E999/CI-00-1636. The mid-point of the externality values are utilized in the Base Case for the 2015 Plan. These value ranges are approximate representations of what is in the Strategist database.

        i. Carbon externality cost range: \$2.53/ton in 2015 to \$3.32/ton in 2029

        ii. Oxides of nitrogen ("NO_x") externality cost range: \$302/ton in 2015 to \$396/ton in 2029

[1] Values are in nominal dollars.

iii. Sulfur dioxide (“SO_2”) externality cost range: $0/ton in 2015 to $0/ton in 2029

iv. Particulate matter (“PM”) externality cost range : $3,619/ton in 2015 to $4,759/ton in 2029

v. Carbon monoxide (“CO”) externality cost range: $1.56/ton in 2015 to $2.05/ton in 2029

vi. Lead (“Pb”) externality cost range: $2,709/ton in 2015 to $3,561/ton in 2029

b. The SO_2 allowance price for Cross-State Air Pollution Rule (“CSAPR”) Group 2: $200/ton in 2015 to $68/ton in 2027.

c. Natural gas forecast assumptions utilized in the base forecast.

i. Natural Gas at Henry Hub: $3.26/MMBtu in 2015 to $5.71/MMBtu in 2029

ii. Natural gas supply prices reflect the projected spot market at Henry Hub. In addition, a regional delivery charge of [TRADE SECRET DATA EXCISED] for the fuel supply of all new gas generation alternatives is included in the petition. For natural gas at Laskin Energy Center (“LEC”), a delivery charge of [TRADE SECRET DATA EXCISED] was assumed. For natural gas refuel scenarios of existing units at Boswell Energy Center (“BEC”), a delivery charge of [TRADE SECRET DATA EXCISED] was assumed. The delivery charges were escalated at approximately 2 percent annually, on average, after 2015.

iii. The firm delivery component of intermediate natural gas resources like the combined cycle was incorporated into the fixed cost revenue requirement for the asset.

d. Delivered coal price forecast assumptions utilized in the base forecast represent the attributes of each of Minnesota Power’s facilities and include: [TRADE SECRET DATA EXCISED]

e. Delivered biomass price forecast assumptions utilized in the base forecast: [TRADE SECRET DATA EXCISED]

f. Wholesale Market Capacity (approximate): $260/MW-month in 2015 to $11,150/MW-month in 2029. Wholesale market capacity was made available up to a maximum of 50 MW for the model during all study years.

g. Wholesale Market Energy without carbon (approximate): $32/MWh in 2015 to $50/MWh in 2029.

h. Wholesale Market Energy with carbon (approximate): $32/MWh in 2015 to $59/MWh in 2029.

2. The Base Case energy market interaction structure for Minnesota Power's analysis assumed that the wholesale market was available throughout the study period. Further discussion regarding the Company's position related to the interaction with, and utilization of the wholesale energy market in long-term planning is discussed further in Part D of this Appendix. The wholesale energy market structure in the modeling represents the day-ahead interaction with the Midcontinent Independent System Operator ("MISO") regional market and helps utilities optimize power supply for customers. A sensitivity called 'Without Market' was developed that assumed the wholesale energy market was unavailable as a long-term power supply resource through the study period. This sensitivity was included to understand the impact to the planning analysis when the availability of the regional wholesale energy market is removed. A more detailed description of the structure of each market interaction is provided below.

a. <u>With Wholesale Energy Market</u> ("With Market") – A conservative approach was taken when creating the wholesale energy market that would be made available as a power supply resource during the study period. While the regional market is a valuable and useful piece of a utility's power supply, it should not be considered an 'endless' resource. To help account for the increased risk and volatility that is present when purchasing incrementally larger amounts of energy from the short term market, an increasing price adder was included based on the level of energy purchased. As the volume of energy purchased from the market increased, so did the price adder. This is referred to as a 'Tiered Energy Market' and includes the following pricing assumptions:

i. 0 to 150 MW at base forecast price

ii. 151 to 300 MW at base forecast price plus $15/MWh premium adder

iii. 301 to 600 MW at base forecast price plus $40/MWh premium adder

iv. Greater than 600 MW at emergency energy price ($250/MWh in 2015 and escalates at 2.0 percent annually)

b. <u>Without Wholesale Energy Market</u> ("No Market") – For this scenario, the Tiered Energy Market described above was removed starting in 2015. Only emergency energy (at $250/MWh) was available in 2015 and escalated at two percent annually as a wholesale energy alternative.

The No Market scenario addresses stakeholder feedback that identified long-term expansion plan modeling could be done with no energy procured from MISO. This scenario effectively cuts the utility off from the region, as if the utility is located on an island. While Minnesota Power does not envision a future without an effective and beneficial regional market, it conducts this scenario to help identify the long-term resource actions that align under both planning methodologies.

3. The estimated decommissioning cost for Minnesota Power's small coal units for the shutdown scenarios discussed in the 2015 Plan are from a study completed by Burns & McDonnell called Site Decommissioning Study 2015.[2] Decommissioning costs at each facility are assumed to be recovered and depreciated for 10 years past the shutdown date. Remaining plant balances at each facility are assumed to be recovered and depreciated according to their current schedule. This approach is included in Section E of this Appendix.

4. Carbon regulation penalty costs[3]

   Minnesota Power included a base outlook that included the base externality value for carbon dioxide ("CO_2") in its base forecast as well as a base outlook that included the base regulation penalty for CO_2 for this planning evaluation. Minnesota Power continues to consider CO_2 regulation as unlikely to come into effect in the near term. Per Minnesota state requirements, it is including an evaluation of the mid-CO_2 regulation cost as listed below. The CO_2 regulation value for the mid-CO_2 regulation penalty are from the 2014 Order Establishing 2014 and 2015 Estimate of Future Carbon Dioxide Regulation Costs, pursuant to Minn. Stat. §216H.06,in Docket No. E-999/CI-07-1199.

   a. Mid CO_2 regulation value ranging from $21.50/ton starting in 2019 to $29/ton in 2029.

<u>Minnesota Power Resources and Bilateral Power Transactions</u>

Another important component of a utility's power supply are the contracted purchases and sales conducted within the industry. These transactions optimize the power surpluses and deficits that occur due to industry load and supply changes. Also called bilateral transactions, these contracts allow the Company to work with other entities to procure energy and capacity (see Part 2 of Appendix C for a list of Minnesota Power's current bilateral transactions included in the base case).

A bilateral transaction is functionally different than the day-ahead regional energy and capacity markets represented by the MISO tariff construct. Bilateral transactions are typically forward, medium to longer-term contracts with defined pricing terms. Minnesota Power monitors the bilateral power markets to identify opportunities to contract with other entities when it is in

[2] Included in the 2015 Remaining Life Depreciation Petition (Docket No. E015/D-15-711).
[3] All carbon regulation penalty costs reflect dollars per ton.

the best interest of its customers. For this Plan the Company has the following bilateral transaction alternative made available based on its most recent industry and peer interactions:

5. An unidentified 50 MW to 150 MW bilateral purchase, referred to as a “bridge purchase” in the analysis write-up, was modeled in Strategist as a new resource alternative in the 2017 through 2020 time period. The bilateral transaction is made available based on the market indications of available energy during this timeframe that Minnesota Power has received through its recent power contracting activity.

   There were two types of bridge purchases used in the analysis:

   a. The near-term bridge purchase pricing is based on the results from a recent Request for Proposal (“RFP”) for energy and capacity in the 2016 through 2020 timeframe.
   b. The deferred bridge purchase energy pricing is based on the equivalent of purchasing energy from a natural gas combined cycle unit and was modeled as an intermediate type energy resource in the 2019 through 2020 time period.

   In the scenarios where the Minnesota Public Utilities Commission’s (“Commission”) approved carbon regulation value is modeled, the bilateral purchase had a carbon penalty added to the energy price based on the emission rate for a natural gas unit. [TRADE SECRET DATA EXCISED]

6. [TRADE SECRET DATA EXCISED]
7. The emission rates for the thermal generation units included in Strategist are modeled as tons or pounds per MMBtu of fuel consumed for energy production. The level of effluents emitted per MWh generated will vary depending on the output level of a generation facility. As a generator is dispatched to a lower output level because of economic conditions, the effluents emitted per MWh will increase due to the generator operating at a less efficient level when compared to running at full output. The effluents modeled with emission rates in Strategist are:

   a. Carbon Monoxide
   b. Carbon Dioxide
   c. Lead
   d. Mercury
   e. Nitrogen Oxide
   f. Particulate Matter 10
   g. Sulfur Dioxide

There were two approaches taken to modeling emission rates for CO_2 in the Strategist model.

a. A CO_2 rate was set-up to calculate the cost of a CO_2 regulation penalty; this is referred to as "CO_2" in the Strategist model. These CO_2 rates were applied to the generation resources that would be subject to a CO_2 regulation penalty in a CO_2 constrained scenario.

b. A CO_2 rate was set-up to calculate the externality cost of CO_2 and to measure the progress on meeting the State Green House Gas Goal (Minn. Statute § 216H.02); this is referred to as "CO_2-E" in the Strategist model. This CO_2 rate was assigned to all power supply resources, including bilateral market purchases, generation and energy sales. The accompanying CO_2 with an energy sale is removed from the power supply. The "CO_2-E" rate modeled in Strategist was pounds per MWh. *Note that the CO_2 emissions from MISO market energy purchases and sales were calculated outside of the Strategist model.*

Minnesota Power Load and General Economic Assumptions

8. Customer energy and demand requirements are based on the Moderate Growth with Deferred Resale Scenario in Minnesota Power's AFR2014. The energy and demand forecast is based on the AFR2014 econometric modeling results plus customer adjustments for increased energy sales to new customers and transmission losses.

   The transmission losses of 6 percent are added to the Annual Energies to capture the power supply requirements for serving Minnesota Power's customers.

9. Capacity accreditation values for generators are the unforced capacity ("UCAP") and are based on MISO's Planning Year 2015-2016 generation performance test results and historical XEFORd[4] per the Module E Resource Adequacy program.

10. Planning reserve margin is based on MISO's required reserve margin of 7.1 percent based on its Planning Year 2015-2016 Loss of Load Expectation Study and UCAP generating capability and projected energy demand in the MISO Region.

11. The utility discount rate is the weighted average cost of capital ("WACC") for Minnesota Power based on current capital structure and allowed return on equity. The utilized discount rate is 8.18 percent.

12. A general escalation rate of 2.0 percent was utilized, except for capital cost and operation and maintenance ("O&M") for new generation, which is escalated at 3.0 percent per year.

[4] Equivalent Forced Outage Rate Demand is a measure of the probability that a generating unit will not be available due to forced outages or forced de-ratings when there is demand on the unit to generate.

B. Asset Resource Alternatives Evaluated

The resource alternatives that were screened as possible new generation alternatives are provided below. The capital costs were based on Minnesota Power's most current planning estimates for such resources. The estimates are high level engineering projections and typically have a +/- 30 percent range of accuracy. These resource options were reduced to a smaller list for the 2015 Plan expansion planning evaluation in Strategist Proview software through a screening process that is outlined in Appendix K.

1. Partial ownership/share of 434 MW (approximate) natural gas 1x1 combined cycle facility
    a. Estimated capital build costs plus transmission upgrade costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
2. Partial ownership/share of 874 MW (approximate) natural gas 2x1 combined cycle facility
    a. Estimated capital build costs plus transmission upgrade costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
3. 221 MW (approximate) natural gas combustion turbine unit
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
4. 104 MW (approximate) natural gas aero-derivative unit
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
5. 50 MW (approximate) natural gas aero-derivative unit
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
6. 55 MW (approximate) natural gas reciprocating engines (6 x 9.1MW engines)
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
7. 25 MW (approximate) of diesel back-up generators
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
8. Partial ownership share of 510 MW (approximate) super critical pulverized coal generation asset with CO_2 capture equipment
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]

9. Partial ownership share of 1,117 MW (approximate) advanced pressurized water reactor (APWR) nuclear facility
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
10. 165 MW (approximate) nuclear small modular reactor (SMR) facility
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
11. 102 MW (approximate) wind farm located in North Dakota
    a. Estimated capital build costs for a post-2017 build date for wind in 2015 dollars is [TRADE SECRET DATA EXCISED]
12. 25 MW (approximate) wind farm located in northeast Minnesota
    a. Estimated capital build costs for a post 2017 build date in 2015 dollars is [TRADE SECRET DATA EXCISED]
13. 50 MW (approximate) biomass-fired unit
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
14. 50 MW (approximate) thin film photovoltaic ("PV") solar facility
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
    b. Solar facilities built prior to 2018 were assumed to include a 30 percent investment tax credit.
    c. Solar facilities built after 2017 were assumed to include a 10 percent investment tax credit.
15. 50 MW (approximate) crystalline silicon solar facility
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
    b. Solar facilities built prior to 2018 were assumed to include a 30 percent investment tax credit.
    c. Solar facilities built after 2017 were assumed to include a 10 percent investment tax credit.
16. 10 MW / 50 MWh (approximate) flow battery facility
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
17. 10 MW / 60 MWh (approximate) sodium sulfur battery facility
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]

18. 10 MW / 25 MWh (approximate) lithium ion battery facility
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
19. 135 MW / 1,080 MWh (approximate) compressed air energy storage facility
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
20. 200 MW / 1,600 MWh (approximate) pumped storage hydroelectric facility
    a. Estimated capital build costs in 2015 dollars is [TRADE SECRET DATA EXCISED]
21. Residential/Commercial Central Air Conditioning ("CAC") and electric hot water heater cycling ("HW") demand response program (investigative values only)
    a. The utility cost of implementing the demand response program includes equipment cost of $200 per participant plus a bill incentive of $40 per participant per year (CAC cycling program customers) or $60 per participant per year (HW cycling program customers) in 2015 dollars.
    b. The utility cost of implementing the demand response program would also include in 2015 dollars [TRADE SECRET DATA EXCISED]. The initial program cost and annual O&M were allocated 50/50 between the CAC and HW programs.
    c. The methodology utilized by Minnesota Power when modeling and developing the demand response alternative is discussed in Appendix B.

C. Assumptions Utilized in the Sensitivity Analysis

The following variables were stressed low and high in the single variable sensitivity analysis.

1. Wholesale market energy without carbon
    a. A lower sensitivity representing a decrease of 50 percent from base[TRADE SECRET DATA EXCISED]
    b. A low sensitivity representing a decrease of 25 percent from base: [TRADE SECRET DATA EXCISED]
    c. A high sensitivity representing an increase of 25 percent from base: [TRADE SECRET DATA EXCISED]
    d. A higher sensitivity representing an increase of 50 percent from base: [TRADE SECRET DATA EXCISED]

2. Wholesale market energy with carbon regulation penalty
    a. A lower sensitivity representing a decrease of 50 percent from base: [TRADE SECRET DATA EXCISED]
    b. A low sensitivity representing a decrease of 25 percent from base: [TRADE SECRET DATA EXCISED]
    c. A high sensitivity representing an increase of 25 percent from base: [TRADE SECRET DATA EXCISED]
    d. A higher sensitivity representing an increase of 50 percent from base: [TRADE SECRET DATA EXCISED]
3. Natural gas price forecast at Henry Hub
    a. A lower sensitivity representing a decrease of 50 percent from base: [TRADE SECRET DATA EXCISED]
    b. A low sensitivity representing a decrease of 25 percent from base: [TRADE SECRET DATA EXCISED]
    c. A high sensitivity representing an increase of 25 percent from base: [TRADE SECRET DATA EXCISED]
    d. A higher sensitivity representing an increase of 50 percent from base: [TRADE SECRET DATA EXCISED]
    e. The highest sensitivity representing an increase of 100 percent from base: [TRADE SECRET DATA EXCISED]
4. Carbon regulation penalty costs[5]

A base outlook was evaluated that included the base externality value for CO_2 in the base forecast. A base outlook that included the base regulation value for CO_2 was also evaluated for the 2015 Plan. Due to Minnesota state requirements, an evaluation of several levels of carbon regulation costs are included, and listed below. Though not required by the State, the Environmental Protection Agency's ("EPA") social cost of carbon and a sensitivity in which the carbon regulation penalty is delayed until 2025 are also included.

The evaluation of several carbon regulation levels provides insight into what the customer impact of potential carbon regulation prices will be. However, these costs should not directly impact long-term resource decisions until regulation has been defined and approved for implementation. The carbon regulation values for the sensitivities are from the 2014 Order

[5] All carbon regulation penalty costs reflect dollars per ton.

Establishing 2014 and 2015 Estimate of Future Carbon Dioxide Regulation Costs, pursuant to Minn. Stat. §216H.06,in Docket No. E-999/CI-07-1199.

a. A sensitivity based on the low carbon regulation value ranging from $9/ton starting in 2019 to $11/ton in 2029.

b. A sensitivity based on the high carbon regulation value ranging from $34/ton starting in 2019 to $41/ton in 2029.

The evaluation included a sensitivity based on the EPA's projected social cost of carbon using a 3 percent discount rate. The social cost of carbon was treated as an externality value in the Strategist Modeling. This sensitivity was run with the "No Market" backdrop because of a modeling constraint that did not allow a CO_2 externality value to be accurately applied to wholesale market purchases or sales.

c. The social cost of carbon values ranged from $38/ton starting in 2015 to $69/ton in 2029.

The evaluation included a sensitivity based on the Commission approved mid-carbon regulation penalty, where the start is delayed from 2019 to 2025. Given the uncertainty around the carbon reduction target mechanism and timing, the Company included a sensitivity that delayed the impact of carbon to better understand how it will impact customers.

d. The delayed mid-carbon values ranged from $21.50/ton starting in 2025 to $23/ton in 2029.

5. Externality costs

The values for SO_2, PM_{10}, CO, NO_x, Pb, and CO_2 were stressed to the low and high levels indicated in the Metropolitan Fringe from the State Externality Docket, Docket Nos. E-999/CI-93-583 and E-999/CI-00-1636.

A sensitivity was included that removed all externality values.

6. Coal fuel prices

a. The low sensitivity reduced coal prices by approximately 30 percent from base.

b. The high sensitivity increased coal prices by approximately 30 percent from base.

7. Biomass fuel prices

a. The low sensitivity reduced biomass prices by approximately 10 percent from base.

b. The high sensitivity increased biomass prices by approximately 10 percent from base.

8. Capital costs

a. The low sensitivity reduced base project costs by 30 percent from base.

b. The high sensitivity increased project costs by 30 percent from base.

9. Wind capital costs

    a. The capital cost for North Dakota-based wind farms was adjusted so that the levelized cost varied in $10/MWh increments from $35/MWh to $75/MWh.

10. Solar capital costs

    a. The capital cost for a thin film solar facility was adjusted so that the levelized cost varied in $5/MWh increments from $75/MWh to $90/MWh.

11. Incremental energy efficiency

    a. An increase of 3 GWh above base.

    b. An increase of 6 GWh above base.

    c. An increase of 9 GWh above base.

    d. An increase of 12 GWh above base.

    e. An increase of 15 GWh above base.

    f. An increase of 18 GWh above base.

    g. An increase of 21 GWh above base.

    h. An increase of 24 GWh above base.

    i. An increase of 27 GWh above base.

    j. An increase of 30 GWh above base.

12. Wind Capacity Accreditation

    a. The capacity credit of existing wind farms was reduced by 20 percent from base.

13. Planning Reserve Margin ("PRM") requirement

    a. The PRM established by MISO in their 2015 Loss of Load Expectation ("LOLE") Report was increased by 2 percent from base.

14. MISO Coincidence Factor

    a. A low sensitivity to the MISO coincidence factor of 2 percent below base, which resulted in a MISO coincident peak demand higher than base.

    b. A high sensitivity to the MISO coincidence factor of 2 percent above base, which resulted in a MISO coincident peak demand lower than base.

15. Increased Renewable Portfolio Standard ("RPS")

    a. An alternative scenario was developed which assumed the state RPS would increase to 40 percent by 2030.

16. Customer sales forecast

    a. The low sensitivity is based on the Potential Downside Scenario in the AFR2014.

b. The high sensitivity is based on the Potential Upside Scenario in the AFR2014.

c. A sensitivity based on the Current Contract Scenario in the AFR2014, which resulted in the MISO coincident peak demand and annual energy requirements being slightly lower than base.

17. Winter Peak Demand

a. The sensitivity is based on using the MISO coincident peak demand for the winter period for determining Minnesota Power's capacity requirements. The winter peak demand is based on the AFR2014 Moderate Growth with Deferred Resale Scenario.

18. Additional Environmental Regulations

a. A scenario was developed where additional environmental capital costs were added to coal generation resources for compliance with the coal ash regulation finalized on April 17, 2015, and effluent limit guideline regulation that is not finalized. The costs are based on current plans to comply with the regulations; Appendix E of this Plan provides additional details on this topic. The EPA sensitivity was labeled More Stringent.

b. Minnesota Power has included in its generating fleet outlooks the costs associated with known and finalized regulations, also shown in Appendix E.

D. Long-term Planning and Wholesale Market Interaction

This discussion is included to demonstrate why it is reasonable for the Company to assume a specific level or range of market purchases throughout the planning period within a resource plan.

It should be noted that the term "market" consists of two segments, capacity and energy. Minnesota Power recognizes that exposure to either a capacity or energy market for a majority of power supply requirements is not in the best interest of customers. However, its utilization in moderation in long-term planning can, and does, bring benefits and efficiencies to its customers.

From a long-term planning perspective, the Company limits utilization of market capacity to no more than 50 MW through the planning period. The inclusion of a small amount of market capacity brings benefit to the ratepayer by bridging short-term capacity needs. These purchases come at a lower cost than building a new resource, and bridge the Company's need until the capacity need grows to a large enough magnitude to justify a resource build. In the absence of market capacity, production cost models like Strategist would be forced to suggest that a utility build a new resource. A facility of up to hundreds of megawatt in size, depending on technology, would be recommended when a single megawatt purchase could satisfy the need. This is not prudent resource planning for capacity and can lead to an expedited overbuild of generation if the results of expansion planning models without market capacity were implemented as prescribed.

The availability of a small amount of market capacity must be present in the long-term. The foundation of resource planning, the regional reserve margin requirements, ensure that participating utilities are moving towards integrating new resources as demand rises on the power system. When demand is stagnant or falling, as the industry has seen recently, there can be generation surpluses on the system. Or as utilities build new resources that are in excess of their direct needs, due to the size of a particular generation technology, there can be temporary surpluses. The Company has utilized the bilateral market for decades to buy and sell capacity from existing generation sources on both a long and short-term basis. These transactions have benefited customers by keeping power supply additions paced with system load growth, and by allowing Minnesota Power to sell excess generation during load decline. The presence of a market capacity transaction in expansion planning outlooks identifies that a utility can optimize the timing of its next resource by reaching out to the industry marketplace, and looking for a transaction to help bridge their customers to the next resource.

Similarly, the presence of an energy market in resource planning allows for the optimization of power supply needs on a more granular level. The onset of regional markets like MISO allows day to day energy needs to be pooled together such that each utility is continuously working for the larger energy needs of the region. It is prudent planning practice to include some wholesale market interaction in base planning assumptions, as utilities transition into new generating resources and power purchase transactions for customers. When considering the integration of intermittent generation into the supply portfolio, as many utilities have embarked on with the onset of the Minnesota Renewable Energy Standard, it is appropriate to have a wholesale market available.

Energy market purchases are in the best interest of customers to plan and assist with the variability of intermittent resources. Wind, hydro, and solar all rely on the availability of other generation to “fill in the gaps” when the resource is not available. Not having the regional market available during long-term expansion planning to help with the intermittency of renewable generation would promote overbuilding of a single utility’s system and not account for existing regional support. Excluding the presence of the market would not only result in increased customer cost, but also minimize the value proposition of regional markets like MISO.

Minnesota Power has a long-term planning strategy of avoiding expansion plans which rely on more than [TRADE SECRET DATA EXCISED] percent of energy supplied for load requirements to be solely supplied from the wholesale market. The Company will procure resources, either generation assets or bilateral power purchase transactions sourced from these assets to ensure its customers are not exposed to significant wholesale market fluctuations. Market energy purchases are limited through both a capacity limit and a tiered cost structure which increases as energy purchases increase (as described in item A.2). Both regional capacity and energy prices are projected through the independent scenario forecasts that Minnesota Power subscribes to, and are updated on a biannual basis. The uncertainty of market prices and level of capacity interaction is tested through sensitivity analyses. These sensitivities illustrate potential operational and cost risks for customers, and help identify if a different resource strategy is needed. Item C.1-2 above identifies the ranges utilized. The wholesale market is included in this Plan; the regional reserve margin and bilateral support of the region will continue to be part of the Company’s power supply in the future.

E. Retirement Methodology for 2015 Plan Evaluation

This Appendix provides additional detail on Minnesota Power's existing thermal fleet and the methodology utilized in the 2015 Plan to evaluate the customer impact of the retirement of generating assets. Specifically, this section discusses the following items:

- Generation Asset Retirement background
- Generation Asset Retirement methodology

Generating Asset Retirement Background

The 2015 Plan evaluates the viability of Minnesota Power's coal-fired generating assets for continued operations into the future. The evaluation of facility retirement is driven mainly by two factors: 1) the increasing environmental regulation of coal-fired power plants across the United States, and 2) lower cost replacement options such as an efficient natural gas-fired combined cycle units. Couple these variables with the increasing pressure from low-cost natural gas supplies, and the result is that many utilities have begun evaluating alternatives available for each of their coal-fired generating assets that fall into this smaller size category.

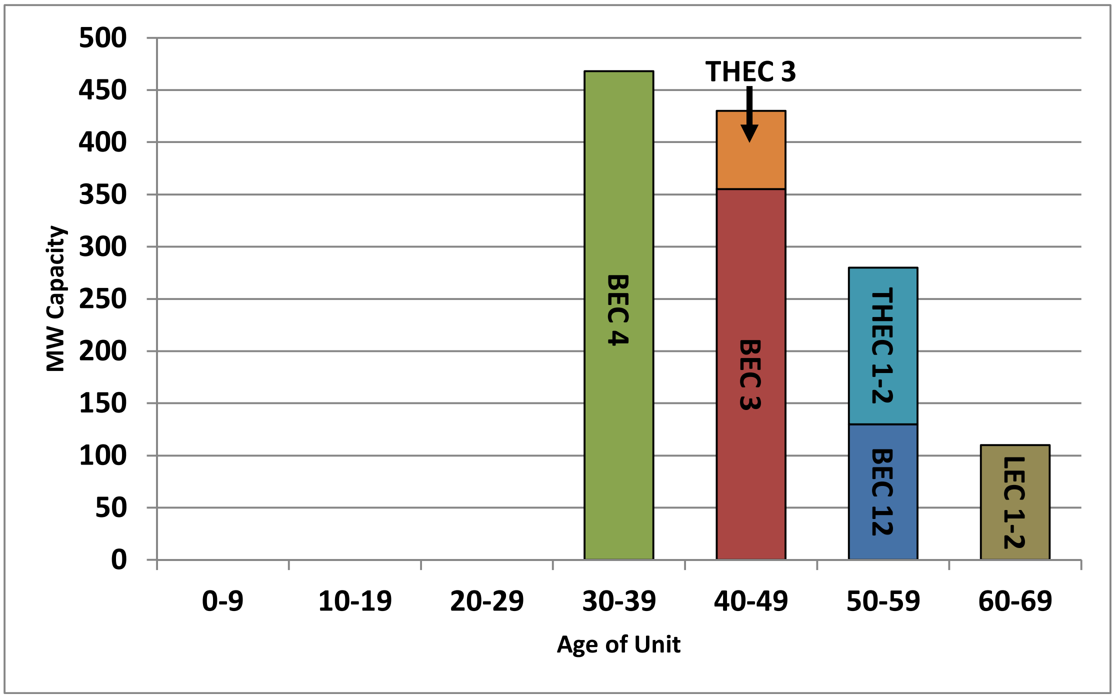
As discussed in Appendix E of this Plan, pending environmental regulations lack definition, yet promise increased environmental control requirements and pressure to reduce carbon emissions. In this highly uncertain landscape, the alternatives for existing coal-fired generating assets are limited. The realm of current considerations by U.S. utilities for the future of these generating assets largely includes:

- Continued operation with additional retrofit and environmental controls;
- Idling operations or mothballing – i.e., suspending operations for a certain period of time and allow for reassessing operations at a later date; and,
- Permanent shutdown/retirement including dismantling.

A unit retirement for existing Minnesota Power thermal facilities could occur based on a number of factors: 1) reaching the end of the useful accounting life; 2) increased environmental regulations which make the unit uneconomical to upgrade, or operate; 3) failure of a major component which makes the unit uneconomical to repair; or 4) a shift in strategy or generation requirements which change the need for the unit as a power supply resource.

A unit's age and size are both significant factors when evaluating the economic viability of the generating asset. The Company recognizes the thermal generating assets being addressed in its 2015 Plan are part of the aging fleet within the United States. Although the smallest coal-fired units are greater than 50 years old, all assets, including the largest coal-fired units, have been maintained and operated prudently. All of the Company's generating units are currently well depreciated, viable power supply resources for Minnesota Power customers. More detail on each of these generating units can be found in Appendix C.

Figure 1: Minnesota Power's Age of Fleet



Asset Retirement Methodology

Identifying the appropriate timing for any future retirement of a coal-fired asset is a complex evaluation that includes consideration of the utility's current and future power supply needs. The effects of generation asset retirement on future and long-term fleet outlook were given careful consideration for the 2015 Plan.

When evaluating a potential asset retirement, it is critical to consider the following areas: 1) the remaining value of the asset being retired, 2) the cost of physical decommissioning and restoration of the site, and 3) the replacement cost of additional generating supply. The effect of these factors on customer power supply costs must be considered in any retirement decisions. The retirement of a generating facility has an economic effect on the surrounding communities, which is also an important consideration. Areas of consideration are detailed below, along with the methodology utilized for asset retirement assessment in the 2015 Plan.

<u>1) Remaining Asset Value</u>

The remaining value of a generating asset represents the remaining financial obligation of investments made in the unit that have not yet been recovered. Minnesota Power has carefully and prudently ensured that each of its facilities remain ready and available to meet customer needs over the past several decades. This was achieved through appropriate capital investments as well as regular operations and maintenance expenditures which are further described in Appendix C. Due to this continued capital investment, upon retirement there will be a remaining asset value requiring further treatment. Depending on the magnitude, the remaining asset value can impact a decision of when to retire an asset. In the asset retirement scenarios, the remaining value of any facility was treated as a cost which was assumed to be recovered over the currently approved book life of the asset, regardless of when the retirement takes place.

2) Decommissioning Cost

When an asset is retired there is a cost associated with the decommissioning of the facility and site, as well as bringing the property back to a useable or saleable condition. The costs typically include all environmental conditions associated with lead paint, asbestos, or hazardous materials on site, and deductions for the amount of expected salvage that would be received from scrap copper and steel. For the 2015 Plan, the expenses associated with the decommissioning of a generating asset were included as part of the expense of retirement, and were assumed to be recovered over a 10-year period. The decommissioning costs used in this analysis are based on the 2015 Site Decommissioning Study completed by Burns & McDonnell.[6]

3) Replacement Power Cost

The type and timing of a generating asset retirement determines the replacement power needed. Any retirement action removes both energy and capacity from the customer power supply; this reduction is taken into the larger planning process to identify the least cost mechanism to meet expected customer requirements. Resource alternatives used to replace lost energy and capacity range from a new generating plant, a regional wholesale market purchase, and demand-side resources (such as energy efficiency and load control). Each resource alternative is compared in terms of how it fits with the rest of the existing power supply to meet customer load requirements. Section IV of this Plan outlines the Company's planning process in more detail, including the process for defining an expansion plan to meet customer requirements.

Community Impact

The most difficult area to estimate when considering a future generating asset retirement is the associated effect of the retirement on the surrounding communities it serves. Impacts to the community would include: loss of work for suppliers and service providers, loss of facility employees spending and living in the communities, and community property taxes. An additional effect would be the indirect support received from having a facility in the community, such as volunteer work performed by employees and/or their families.

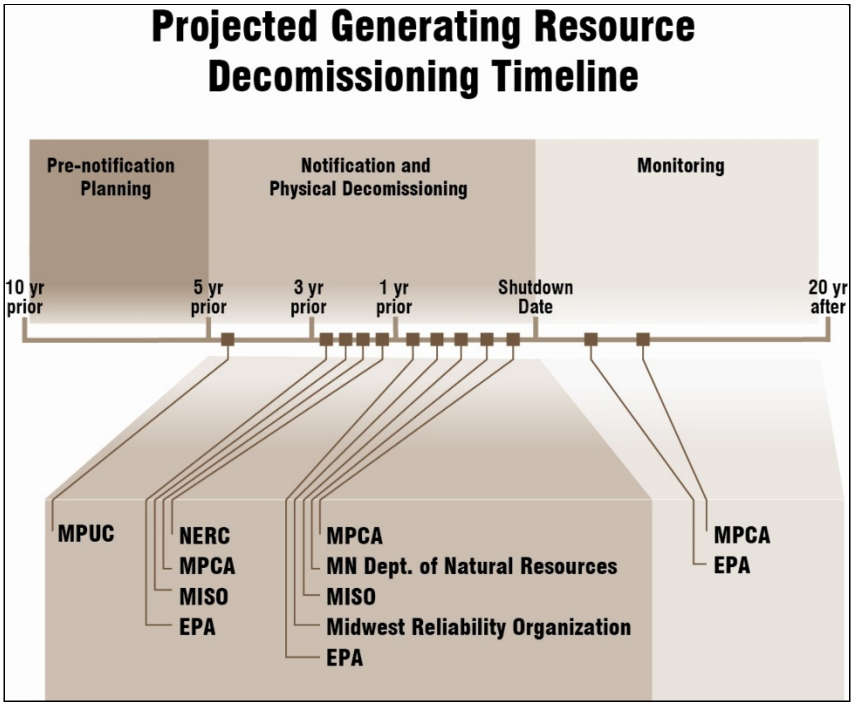
Minnesota Power recognizes that the impact of retiring one of its facilities would be substantial to northeastern Minnesota. Dialogue with officials, representatives, and residents of effected cities and communities through interactive forums such as the Community Advisory Panels are important as future resource decisions are made. The Company conducted a socioeconomic evaluation of unit closure for Boswell Energy Center Units 1 and 2, and Taconite Harbor Energy Center Units 1 and 2; the findings of the study are detailed in Appendix M of this Plan.

[6] Included in the 2015 Remaining Life Depreciation Petition (Docket No.E015/D-15-711).

Pre-notification Requirements

The process for removing a generating unit from the interconnected power system is complex. Each shutdown has the potential to have far reaching impacts on the physical side of the power system, as well as financial repercussions to customers' electric service. To gain insight into the requirements of shutting down a generating asset, a preliminary timeline was established to better understand the entities involved and requirements for implementing an actual unit shutdown. The graphic below identifies the key entities involved in the shutdown process with a high-level listing of the timing requirements needed to vet a facility shutdown. This timeline can change on a case by case basis and can be delayed based on increases in volumes of shutdown requests to each entity. A three to five year timeframe has been identified as reasonable for generator shutdown to allow for necessary coordination with the associated processes of each entity.

Figure 2: Projected Decommissioning Timeline



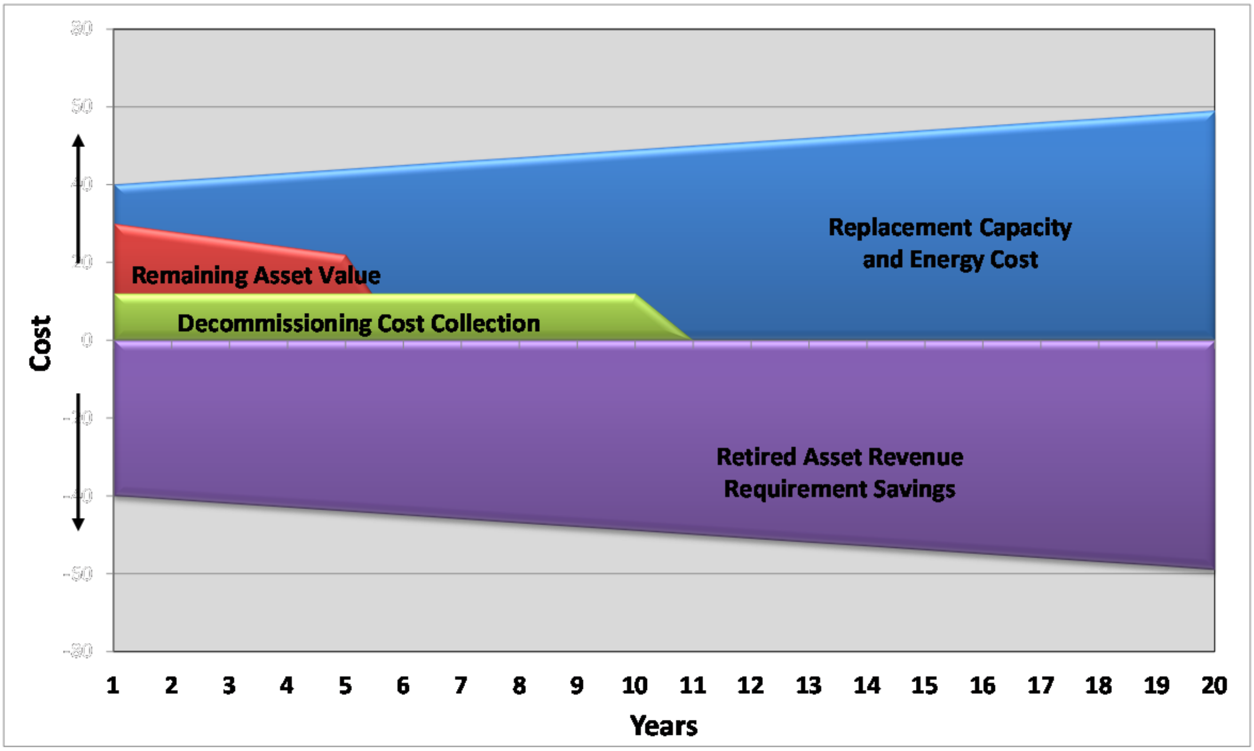
MPUC: Minnesota Public Utilities Commission
MPCA: Minnesota Pollution Control Agency
MISO: Midcontinent Independent System Operator
EPA: Environmental Protection Agency

Minnesota Power's Methodology for Asset Retirement

Minnesota Power assumed in its base case that its coal fleet continued to operate at an investment level required for continued long-term operations through the end of each asset's currently approved book life. For each coal-fired generating asset being evaluated, a matrix of remaining asset values were calculated that identified what the decommissioning costs would be if the unit was retired in a particular year.

Strategist was utilized to evaluate if asset retirement would be economically plausible or if it showed a benefit for customers. The Strategist process took into consideration all aspects of the retirement including 1) remaining asset value and decommissioning cost, 2) replacement capacity and energy cost, and 3) retired asset revenue requirement savings for customers. The graphic below demonstrates a hypothetical retirement in which all three components work together to come up with the ultimate value equation for the customer by netting both the costs and benefits. Note the graphical representation is not to scale and is for demonstration purposes only; each shutdown scenario would look different.

Figure 3: Sample Retirement Diagram



The Strategist simulations are not robust enough to dictate the ultimate retirement planning decision for a generating asset; they can however be a useful planning tool. Minnesota Power will take the outcome of the retirement analysis conducted within the 2015 Plan and carefully monitor the drivers that determine the viability of an asset retirement.

APPENDIX K: DETAILED ANALYSIS SECTION

This Appendix contains the support and approach for the analysis discussed in Section IV of Minnesota Power's 2015 Integrated Resource Plan ("2015 Plan" or "Plan"). This appendix is broken into six sections:

1. Screening of Power Generation Alternatives
2. Additional Analysis further supporting Minnesota Power's Preferred Plan
3. Impact to Expansion Plans with different load forecast scenarios
4. Impact to Expansion Plans when 50 and 75 percent of all New Energy Needs Met with Conservation and Renewable Energy Resources
5. Cost assumptions for Achieving 0.1 Percent of Savings Above 1.5 Percent of non-Conservation Improvement Programs ("CIP")-exempt Retail Sales (2013 Integrated Resource Plan ("2013 Plan") Order Point 12.d)
6. Midcontinent Independent System Operator ("MISO") Coincident vs. Non-Coincident Peak Demand Modeling

1. Screening of Power Generation Alternatives

This section explains how Minnesota Power (or "Company") screened generation alternatives to be included in the expansion plan modeling using the Strategist Proview model. This was a necessary first step due to limitations in the number of alternatives the Strategist Proview model can evaluate simultaneously in an expansion plan evaluation. For the 2015 Plan, Minnesota Power considered a number of new and emerging generation resources in addition to mature technologies.

Consistent with the Company's power supply principles and *Energy**Forward*** plan, only carbon-minimizing resources that could further diversify the fuel supply mix were considered as viable power generation alternatives. These supply side and demand side resource options include renewable resources, energy efficiency, energy storage technologies, mature natural gas-fired technologies, nuclear, and the developing carbon dioxide ("CO_2") sequestration technology combined with a mature coal-fired technology.

The power supply alternatives Minnesota Power considered represent a diverse range of generation technologies including traditional baseload, intermediate and peaking options, as well as renewable generation and energy storage. In order to compare technologies with similar operational characteristics through an initial screening process, the alternatives were organized into three primary generation categories – Baseload/Intermediate, Peaking and Renewable/Storage.

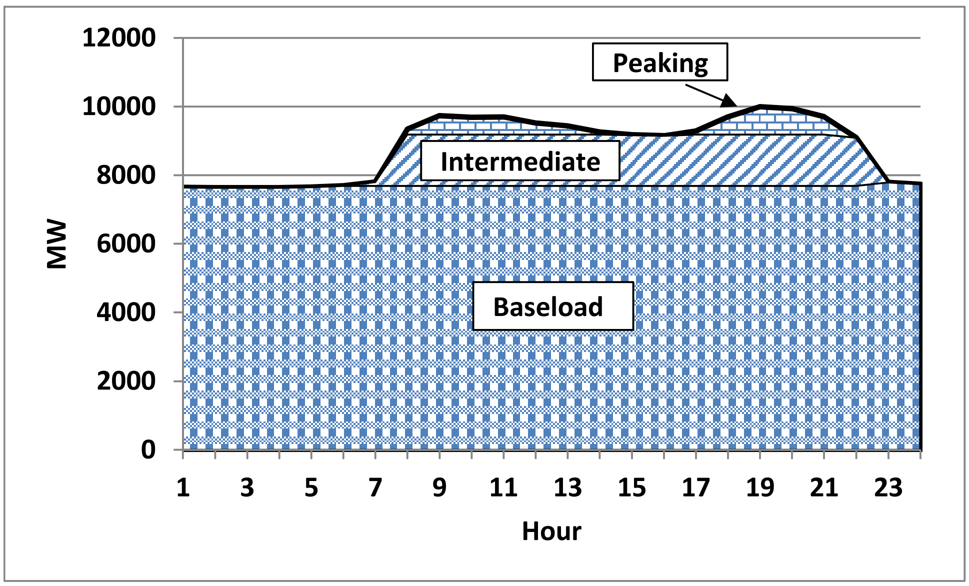
Typically, a baseload generation resource is used to supply energy to customer load that is constant or also referred to as base load. Because a constant supply of generation is needed, energy production with a low variable cost is a general trademark of a baseload generation resource, such as coal or nuclear generation. A baseload generation resource produces electricity seven days a week, 24 hours a day, to meet the base requirement. In Figure 1, the "Baseload" area of the graph represents the energy served by baseload generation.

As load requirements increase throughout a typical day, intermediate generation resources are relied upon to supply the next step up in load requirements. In addition to energy production cost with moderate variable cost, operational flexibility is another important characteristic of an intermediate generation resource such as combined cycle ("CC"). The typical operation for an intermediate generation resource is to produce energy over the course of 10 to 16 peak energy demand hours during the day and produce no energy overnight, as shown in Figure 1. With the recent trend in low natural gas prices, intermediate generation has operated more like a baseload type resource for short periods of time in some areas of the country.

During peak load hours when all baseload and intermediate generating capacity are already producing energy for customers, peaking generation resources are used to fulfill the remaining power supply requirements. Peaking generation, such as a combustion turbine or aero derivative, is typically characterized by very flexible operations with high variable cost. The typical operation for a peaking generation resource is to produce energy for short periods of time ranging from 1 to 4 hours, as shown in Figure 1. Solar generation can also offset a portion of the peaking energy requirements, providing a carbon free resource to meet peak demand.

Figure 1 shows a load curve for a typical day and how different types of generation technology could be dispatched to meet the load requirements.

Figure 1: Representative load generation curve



Renewable generation is another important category of resource alternatives. Renewable technologies, as described in Appendix D, can vary in their capabilities, however, they are largely intermittent and cannot be called upon when needed, except for biomass and storage. Renewable and storage generation technologies were screened as one category because most of the generation is at defined output levels due to intermittency or limitations to the technology.

The following list contains the set of resource technologies that were considered in the initial screening process.

New Thermal Generation

- Nuclear (Baseload Generation):
    - Advanced Pressurized Water Reactor (“APWR”)
    - Small Modular Reactor (“SMR”)
- Coal-fired with carbon capture (Baseload Generation):
    - Supercritical Pulverized Coal (“SCPC”)

Natural gas-fired

- Peaking
    - Simple Cycle Gas Turbine – Combustion Turbine (“SC GT”)
    - Simple Cycle Aero Derivative (“SC Aero”)
    - Simple Cycle Reciprocating Internal Combustion Engine (“RICE”)
- Intermediate
    - Combined Cycle Gas Turbine (“CCGT”)

Renewable Generation

Minnesota Power has been committed to the development of renewable resources in order to meet the Renewable Energy Standard (“RES”) requirements in accordance with Minnesota Statute § 216B.1691. Since the filing of the 2010 Integrated Resource Plan, Minnesota Power has installed nearly 525 MW of wind generation in North Dakota (Bison wind projects 1 through 4). Minnesota Power considered the following renewable resources in the initial screening process.

Dispatchable generation

- Biomass

Intermittent generation

- Wind located in northeastern Minnesota
- Wind located in North Dakota
- Thin Film Photovoltaic Solar
- Crystalline Silicon Solar

Energy Storage

- Pumped Storage Hydroelectricity
- Compressed Air Energy Storage
- Flow Battery
- Sodium Sulfur Battery
- Lithium Ion Battery

Demand-Side Management and Conservation (beyond current forecasts levels)

Minnesota Power remains a state leader in the successful implementation of its conservation programs, and exceeding the 1.5 percent requirement established by Minnesota's Next Generation Energy Act of 2007. All historic and current conservation impacts that meet the 1.5 percent energy savings requirement are being reflected in Minnesota Power's 2014 Annual Electric Utility Forecast Report ("AFR2014") and associated energy and demand forecasts. In addition to the conservation programs assumed in the load forecast, incremental efficiency above the 1.5 percent requirement and peak shaving or demand response alternatives were also considered in Minnesota Power's 2015 Plan.

- Incremental Energy Efficiency
- Central Air Conditioning ("CAC") Cycling Peak Shave Program
- Electric Hot Water Heater ("HW") Cycling Peak Shave Program
- Customer-Owned Backup Generator Program

The economic feasibility of demand-side management ("DSM") alternatives cannot be compared on the same $/MWh basis as new generation alternatives for a screening assessment. The incremental conservation and peak shave programs were evaluated against supply-side options in later expansion planning analysis with the Strategist model.

Screening Analysis Results

The screening analysis was done by developing and comparing a levelized busbar cost of each resource over a 20 year period. The levelized busbar approach is a simple and effective method to screen generation alternatives for consideration in expansion planning by removing the higher cost alternatives. The levelized busbar cost for each power generation alternative included estimated capital, transmission, operation and maintenance (fixed and variable), and fuel costs. Busbar costs for resources were compared with and without a carbon emission penalty cost at the base regulation level of $21.50 per ton starting in 2019. As previously discussed, the alternatives were organized into three primary categories for screening purposes – Baseload/Intermediate, Peaking and Renewable/Storage. All of the alternatives were then grouped based on those primary categories with the purpose of selecting the most cost-competitive resources for further evaluation in the expansion plan process. Figures 2 – 7 show the $/MWh levelized busbar cost comparison with and without a carbon penalty organized by category. Tables 1 – 3 show the alternative net plant cost in 2016$/kW. The busbar cost is shown over a range of assumed capacity factors for each resource alternative assuming an 8.18 percent discount rate and a 2016 in-service date.

Figure 2: Baseload/Intermediate Alternatives 20-year Levelized Busbar Cost with Carbon Penalty

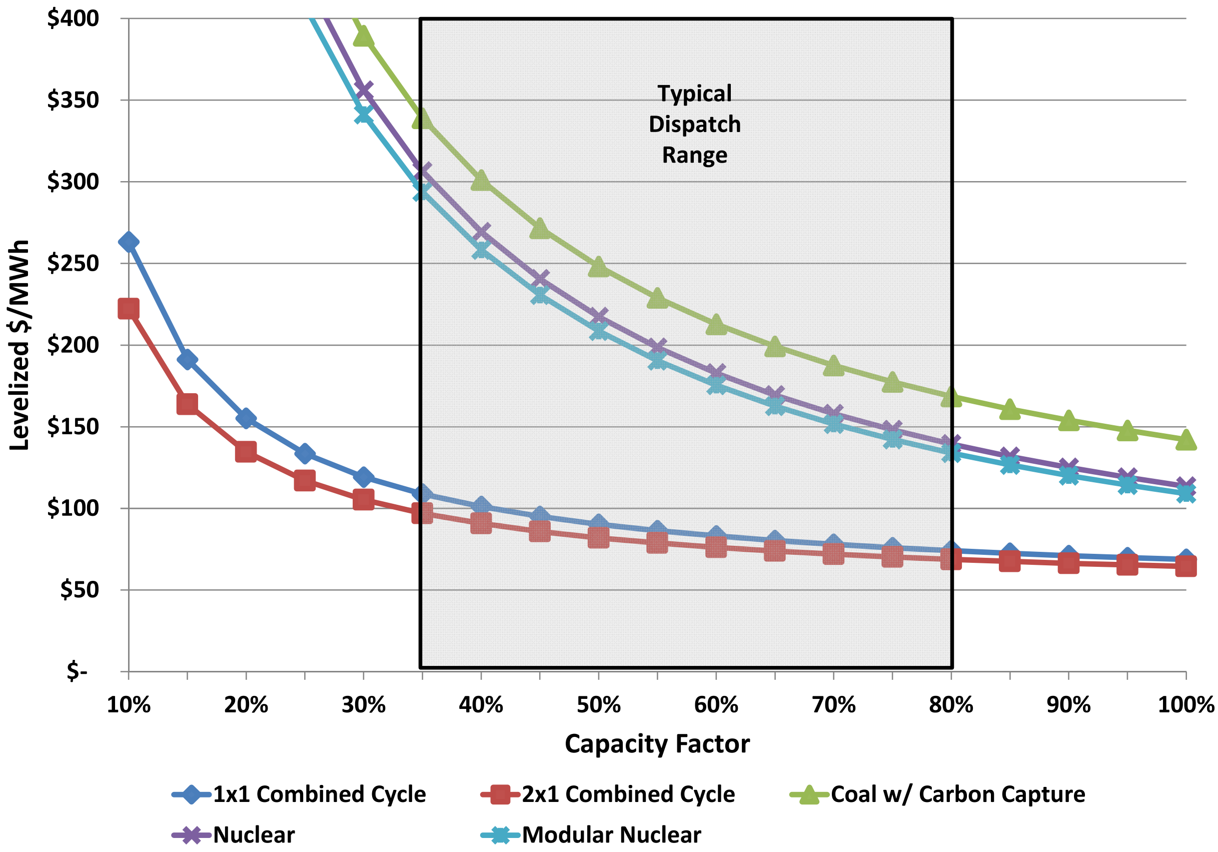


Figure 3: Baseload/Intermediate Alternatives 20-year Levelized Busbar Cost No Carbon Penalty

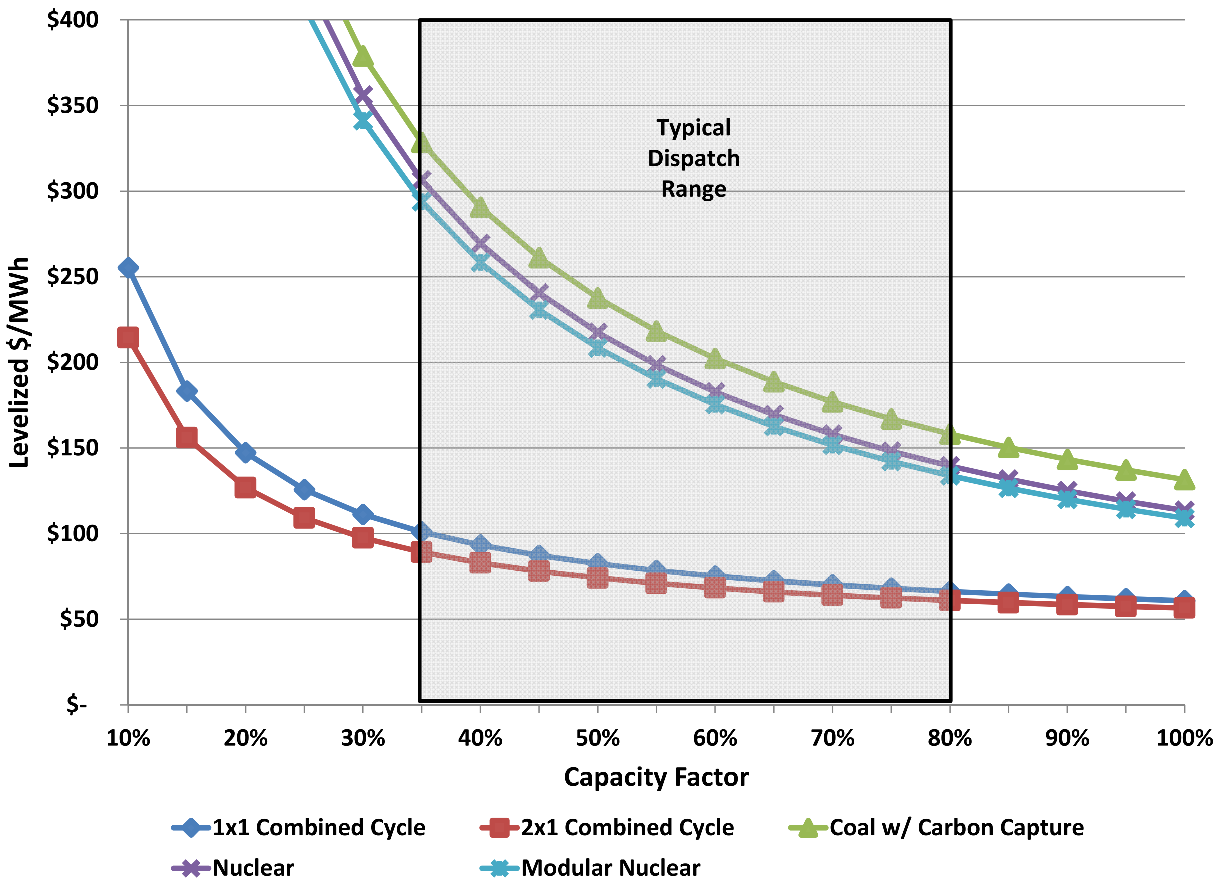


Table 1: Baseload/Intermediate Alternatives Net Plant Cost, 2016$/kW

[TRADE SECRET DATA EXCISED]

With or without a carbon penalty considered, the 2x1 CC represented the lowest levelized busbar cost across all capacity factors for the intermediate generation resource alternatives. Additionally, coal and nuclear generation face some development risk at both the state and the national levels due to waste storage and greenhouse gas emissions. Based on the screening results of the baseload/intermediate alternatives, the 2x1 CC alternative was carried forward for further analysis within the Strategist Proview expansion model.

Figure 4: Peaking Alternative 20-year Levelized Busbar Cost with Carbon Penalty

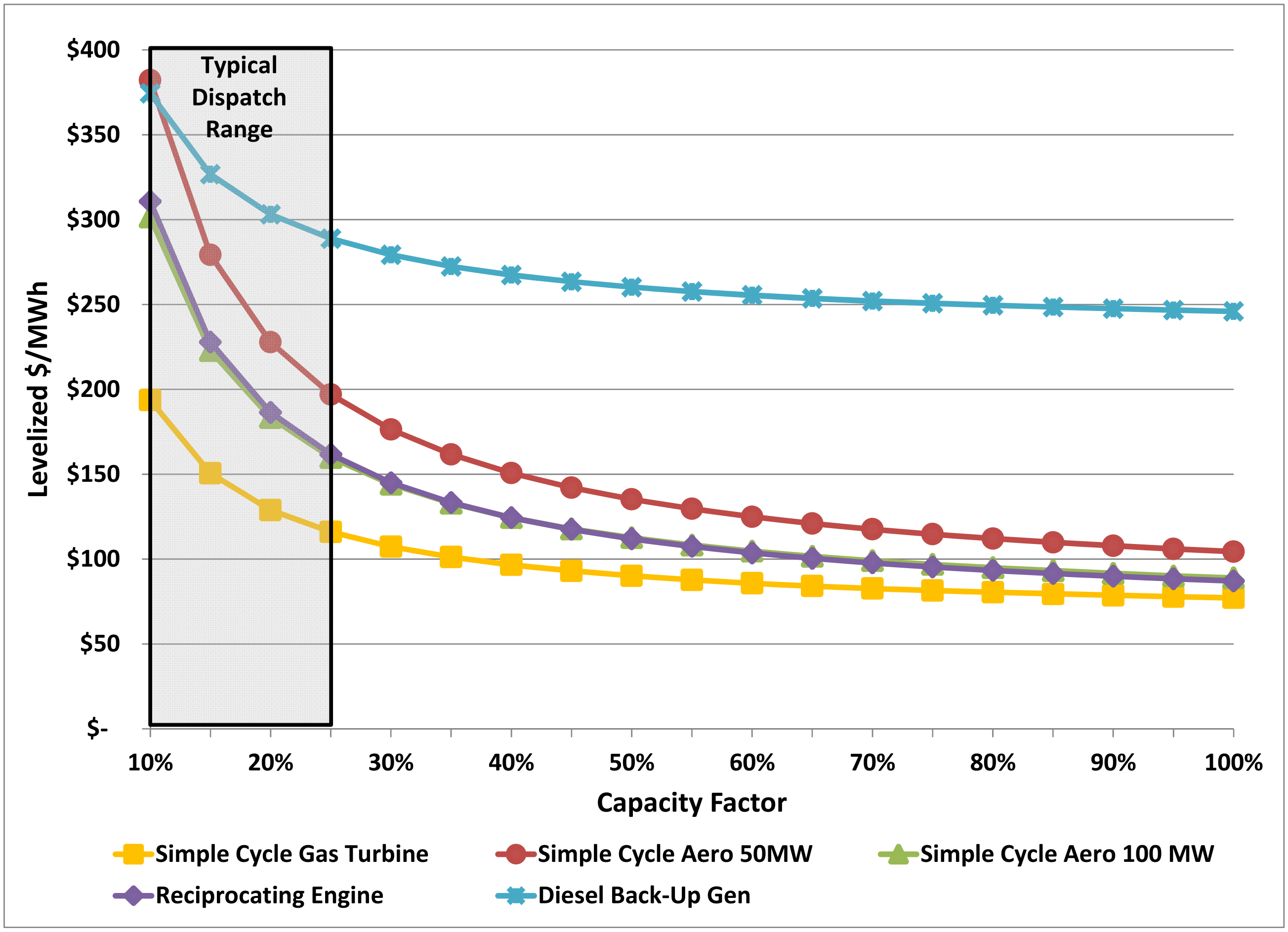


Figure 5: Peaking Alternative 20-year Levelized Busbar Cost No Carbon Penalty

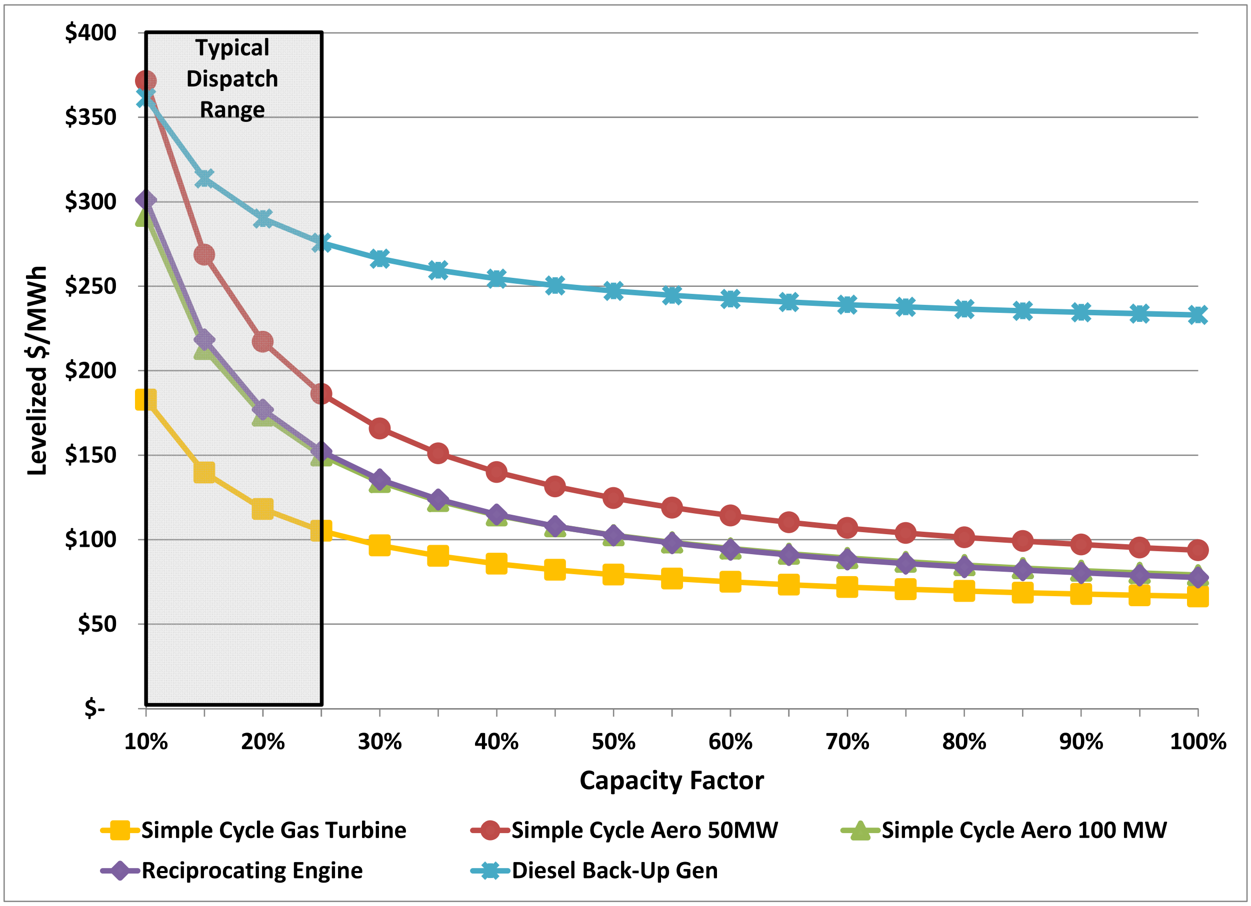


Table 2: Peaking Alternative Net Plant Cost, 2016$/kW

[TRADE SECRET DATA EXCISED]

For peaking resources, the SC GT, also referred to as a combustion turbine, represented the lowest levelized busbar cost across all capacity factors with or without a carbon penalty. The reciprocating engine and the 100 MW SC Aero options had the next lowest levelized busbar costs. The project size of the reciprocating engines is smaller and represented a more flexible resource option for expansion planning purposes by meeting smaller capacity requirements that would not be cost effective to meet with a larger alternative. The diesel backup generator had the highest busbar cost, but had the second to lowest capital cost on a $/kW basis. This represents a high variable cost with a low fixed cost alternative at a small incremental capacity. Based on the screening results of the peaking alternatives, the combustion turbine, reciprocating engines, and the diesel backup generators were carried forward for further analysis within the Strategist Proview expansion model. Additionally, the CAC and HW cycling programs were carried forward for further analysis in Strategist.

Figure 6: Renewable/Storage Options 20-year Levelized Busbar Cost with Carbon Penalty

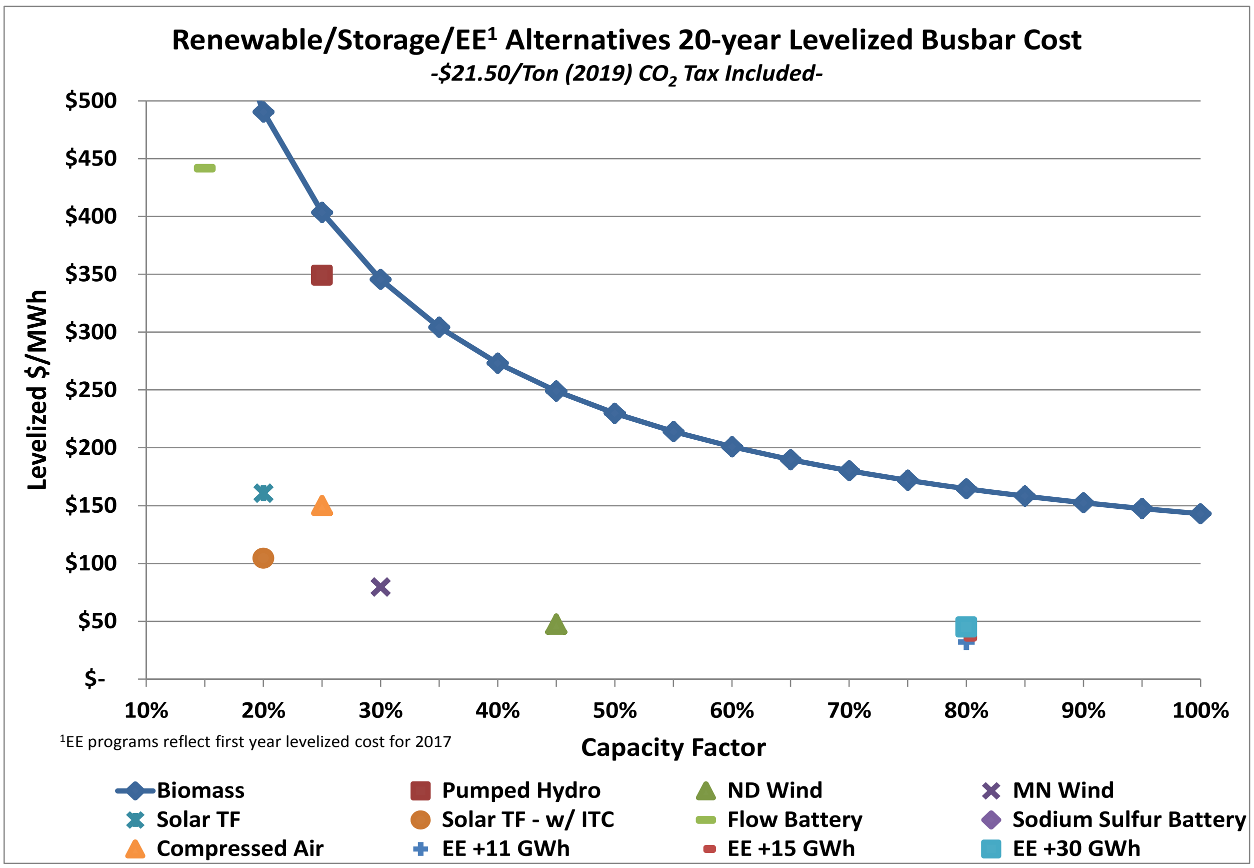


Figure 7: Renewable/Storage Options 20-year Levelized Busbar Cost No Carbon Penalty

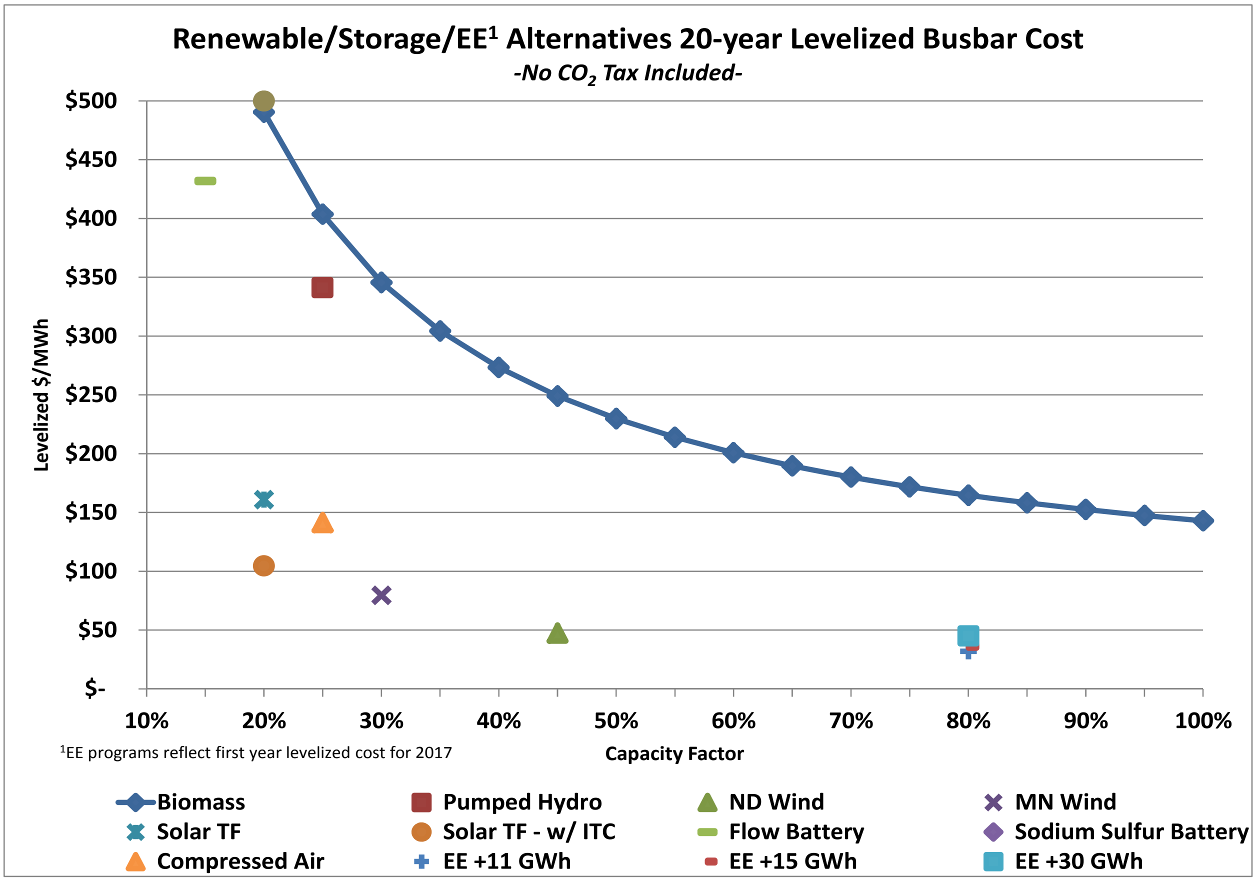


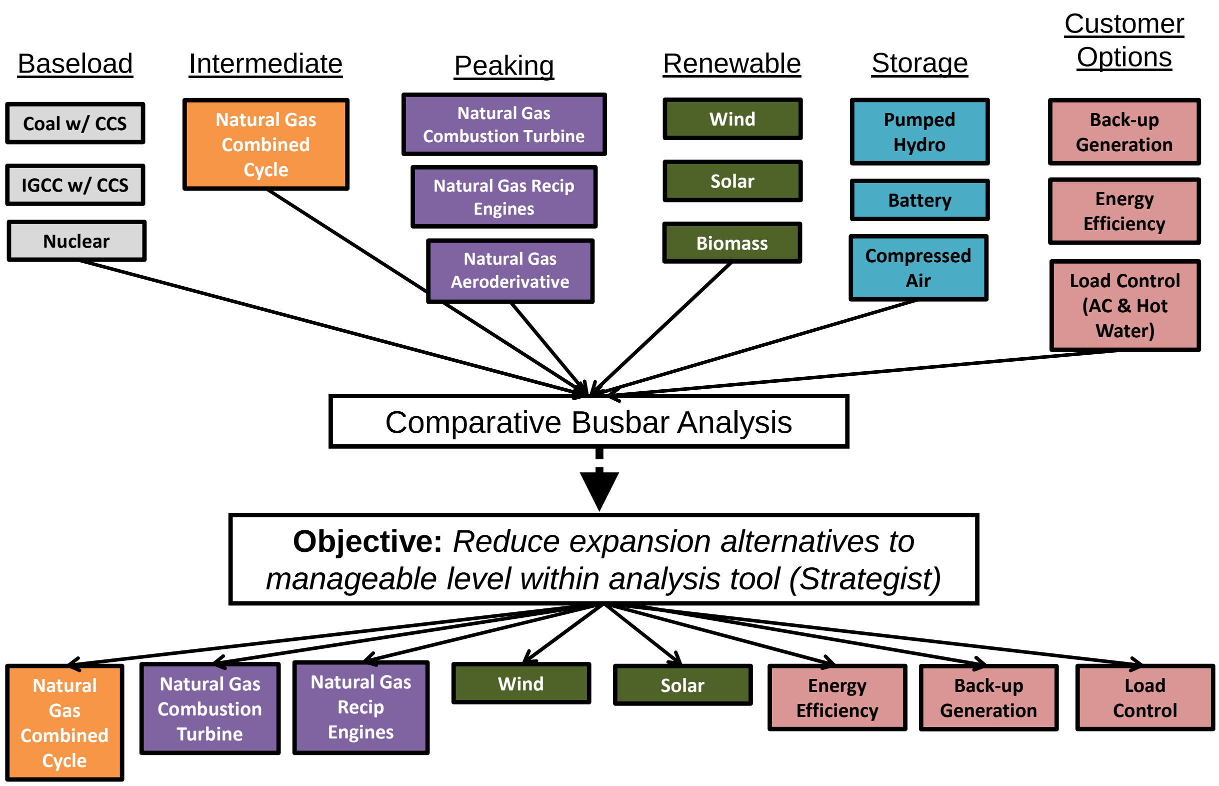
Table 3: Renewable/Storage Options Net Plant Cost, 2016$/kW

[TRADE SECRET DATA EXCISED]

With the exception of the biomass alternative, the renewable and energy storage options represent an intermittent source of power supply. Therefore, the levelized busbar costs are shown as representative capacity factors based on expected hourly production curves or round trip cycle efficiency assumptions. The North Dakota Wind alternative represented the lowest levelized busbar cost by a large margin at an approximate 40 percent capacity factor. The energy efficiency alternatives for an additional 11, 15, or 30 GWh can also be seen as cost effective demand side alternatives. These were shown for informational purposes in Figures 6 and 7. Based on screening results of the renewable/storage alternatives, the North Dakota Wind, Solar Thin Film, and Energy Efficiency options were carried forward for further analysis within the Strategist Proview dispatch model.

The levelized busbar cost is a simple and effective methodology for screening potential resource alternatives to be considered in greater detail within the Strategist Proview dispatch model. However, the screening analysis does not show the interaction of long term capacity requirements, utility load factor, and existing resource mix that also factor into the expansion plan analysis. Therefore, this screening depicted in Figure 8 is only the first step to determining Minnesota Power's Preferred Expansion Plan for its 2015 Plan.

Figure 8: Narrowing of Resource Alternatives Modeled in Strategist



With the resource alternatives reduced to a manageable level for the Strategist Proview model, the focus of this section will transition to the 2015 Plan modeling results that supports the Company's Preferred Plan.

2. Additional Analysis that Further Supports Minnesota Power's Preferred Plan

The intent of this section is to provide further support for Minnesota Power's Preferred Plan by providing additional insight into the results from the Steps 2 through 4 discussed in Section IV of the 2015 Plan. To help manage the large amount of data gathered for the study, this section is organized as follows:

- Additional results for the Detailed Coal Analysis (Step 2)
- Resource expansion plan results from the Detailed Resource Analysis (Step 3)
- Sensitivity analysis (Step 4)
- Impact to expansion plans with different load forecast scenarios
- Impact to expansion plans with 50 percent and 75 percent Renewable Requirement for replacement energy and new customer demand

Additional Results for the Detailed Coal Analysis (Step 2)

This section of the Appendix provides additional detail and insight into specific areas of the analysis used to support Minnesota Power's Preferred Plan for small coal units. This section looks at the results after Step 2 – Detailed Coal Analysis is complete and where the Preferred Plan for the small coal units is considered. Below is a list of the areas discussed in this section for the Company's Preferred Plan for small coal units.

a. Emission performance – shows the change in emission rates with the Preferred Plan for small coal units

b. Shutdown & Remission Considerations – discuss insights from the shutdown analysis for the small coal units

a. <u>Emission Performance of Minnesota Power's Preferred Plan for Small Coal Units</u>

This section looks at the change in emission rates with Minnesota Power's Preferred Plan for small coal units described in Section IV. The focus will be on the emission reductions at Boswell Energy Center ("BEC") and Taconite Harbor Energy Center ("THEC") as these are the two facilities with changes in emissions as part of the Preferred Plan for small coal units. The discussion on emission changes at BEC will focus only on the small coal units at the facility Units 1 and 2 ("BEC1&2"). There is no discussion on the re-fuel decision at Laskin Energy Center ("LEC") which was recommended as part of Minnesota Power's 2013 Plan and for which the transition to burning natural gas was completed in late 2015.

The Preferred Plan for small coal units has BEC1&2 re-routing its emissions through Unit 3's scrubber in 2019. A benefit to this action is a significant reduction in sulfur dioxides ("SO_2") and carbon monoxide. The impact to the BEC1&2 emission rates are shown in Table 4 after the re-route project. With the re-route project at BEC1&2, the Company is projecting an average reduction in SO_2 emission rates of 95 percent.

Table 4: Change in BEC1&2 Emission Rates

	"As Is" (lb/MMBtu)	Unit 3 Re-route (lb/MMBtu)	Percent Change
Sulfur Dioxide ("SO_2")	0.56	0.03	-95%

At Taconite Harbor Energy Center Units 1 and 2 ("THEC1&2"), the Preferred Plan for small coal units includes ceasing coal-fired operations by 2020 with the associated avoided annual emissions shown in Table 5. Additionally, the Preferred Plan pursues economic idling of THEC1&2 by 2017. The low cost of replacement power from the wholesale market is driving the decision to expedite moving away from coal at THEC1&2 and idling by 2017; however, it was determined that THEC1&2 retaining operational characteristics during the idling period is an important consideration in retaining operational flexibility and provide system reliability to the region.

Table 5: Avoided Annual Emissions from Coal-Fired Operations at THEC1&2

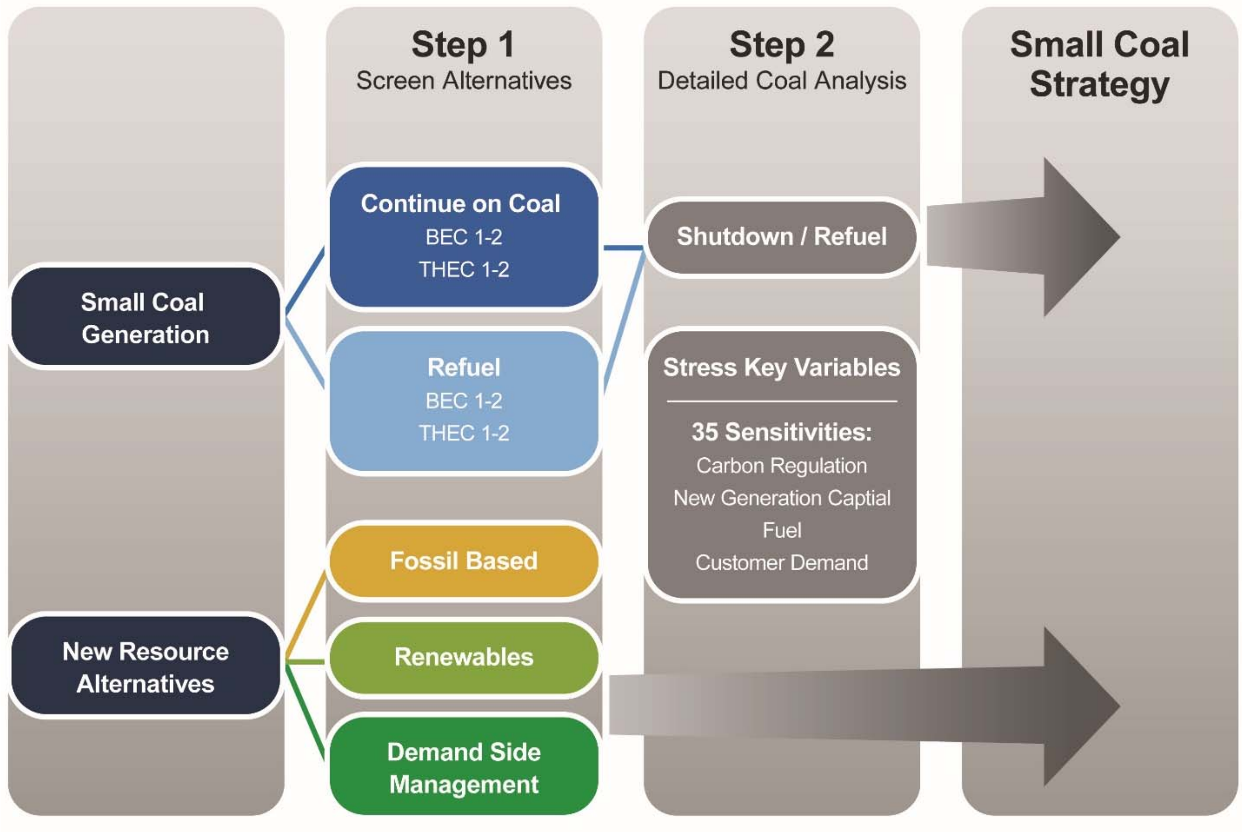
	Annual Emission Reduction[1] (Tons)
Particulate Matter ("PM_{10}")	149
Oxides of Nitrogen ("NO_x")	655
SO_2	1,657
CO_2	977,658
Mercury (Pounds)	22

b. <u>Shutdown Decisions with Preferred Plan for Small Coal Units</u>

This section summarizes results from Minnesota Power's analysis of the Preferred Plan for the small coal units with THEC1&2 idled and BEC1&2 continuing to operate through the end of their accounting life in 2024 (Step 2 shown in Figure 9).

[1] The avoided emissions shown in the Table 5 do not take into consideration the emission from replacement energy.

Figure 9: Plan Development Process – Steps 1 and 2



Minnesota Power used the Strategist Proview model to compare the continued operations options for the remainder of the small coal fleet identified in Step 1 with a shutdown prior to the accounting end of life.[2] The Strategist Proview software compared the cost of continuing to operate the small coal units to new generation alternatives under two futures, with and without carbon regulation. The carbon regulation scenario had a carbon penalty of $21.50 per ton starting in 2019.

The new generation alternatives that were considered as replacement alternatives in the shutdown analysis are based on the results from the Minnesota Power screening analysis described above, short term market purchases, wind and natural gas-fired generation. Figure 10 shows the results from the Strategist Proview evaluation of various small coal operation alternatives as tested under more than 30 sensitivities stressing carbon regulation, fuel, new generation capital expense, and others. Figure 11 shows the results under these sensitivities with a base carbon regulation penalty of $21.50 per ton starting in 2019.

[2] The accounting end of life for the remaining small coal units is 2026 for THEC1&2 and 2024 for BEC1&2. Included as a base assumption is the shutdown of these at their end of accounting life and their energy and capacity would be replaced.

Figure 10: Step 2 Detailed Coal Analysis Expansion Plan

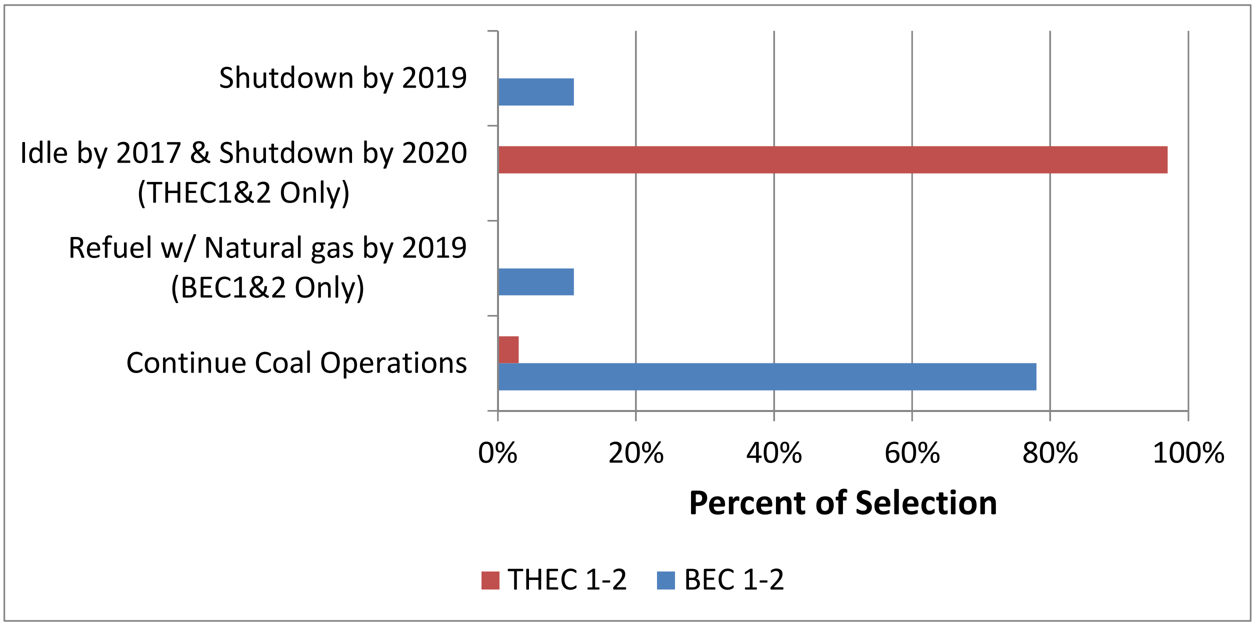
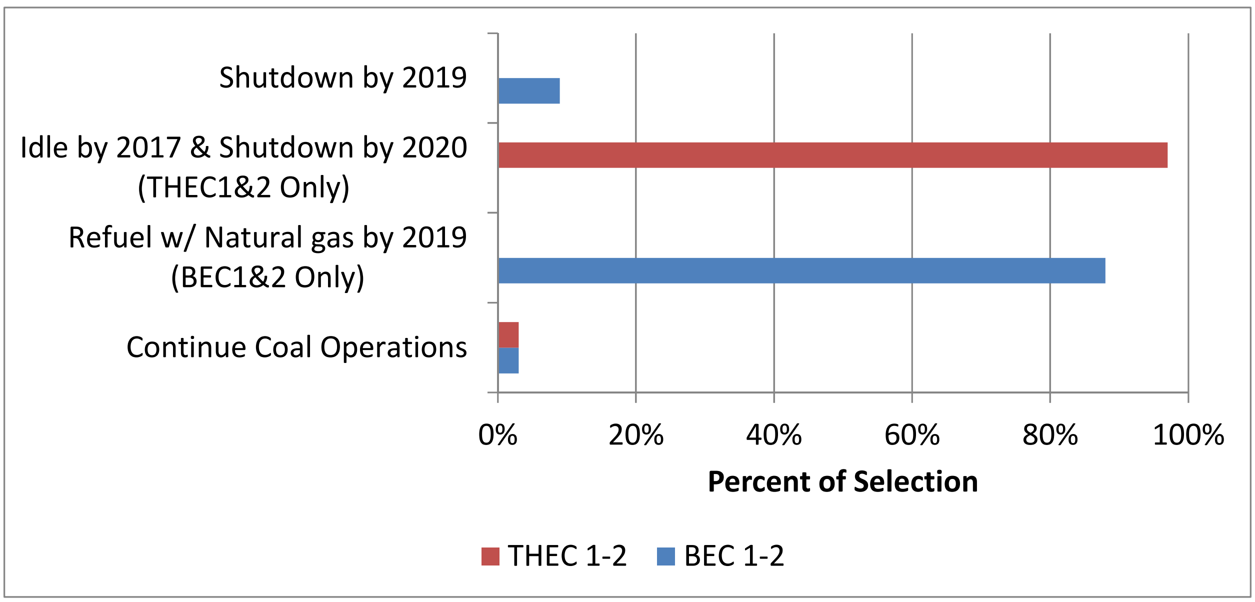


Figure 11: Step 2 Detailed Coal Analysis Expansion Plan with Carbon Penalty



The results from Step 1 and Step 2, as described further in Section IV, helped the Company develop its Preferred Coal Plan and included the following decisions:

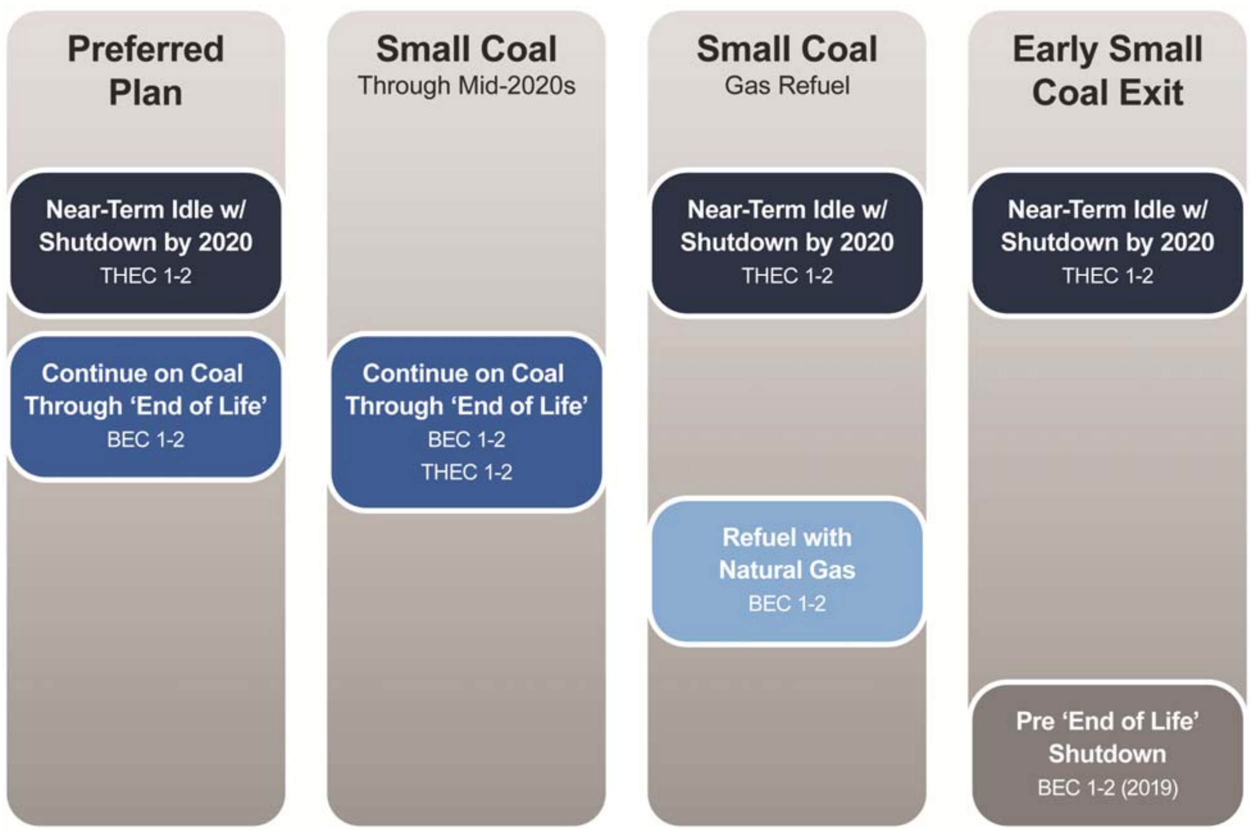
- BEC1&2: Re-route emissions through Boswell Energy Center Unit 3 ("BEC3") scrubber by 2019 and continue operations on coal.
- THEC1&2: Economically idle by 2017 and replace power with wholesale market purchases and cease coal operation by 2020.

Under base assumptions, the small coal unit actions above deliver reasonable solutions for continuing Minnesota Power's *Energy**Forward*** strategy of diversifying its energy supply. With consideration of a carbon regulation penalty starting in 2019, the low cost solution includes a refuel of BEC1&2 to natural gas by 2019. Should carbon regulation materialize in the short term, the Company's Preferred Plan for small coal retains the capital flexibility to consider shutdown or future alternatives.

Resource Expansion Plan Results

After the small coal decisions were identified in Step 2 for the development of a Preferred Plan, an expansion plan was developed for the Preferred Plan and three alternative swim lanes. The alternative swim lanes were developed with stakeholder input taken into consideration. A summary of the small coal strategy decisions under each of the swim lanes developed is shown in Figure 12.

Figure 12: Preferred Plan and Alternative Swim Lanes for Minnesota Power Small Coal Generation



The Strategist Proview model was used to develop the lowest cost expansion plan that filled in the projected capacity and energy requirements in the Preferred Plan and alternative swim lanes. The lowest cost expansion plan was based on power supply cost from the expansion planning period 2015 through 2034 plus the 15-year end effect period. The results of the expansion plan were combined with the Preferred Plan for the small coal units to finalize Minnesota Power's Preferred Plan for the 2015 Plan and comparative alternative swim lanes.

Minnesota Power continues to only consider low carbon emitting alternatives and renewable generation as viable future resource alternatives, such as natural gas-fired generation, solar and wind generation along with demand-side options such as energy efficiency and load control programs. These resource alternatives selected to be available in the expansion model are based on the results from the screening analysis discussed earlier in this Appendix. Along with new resource alternatives, a 50 MW market capacity purchase was considered for each year of the plan and an additional 50 MW bilateral bridge purchase was made available each year from 2016 through 2021. These purchases serve two purposes in the modeling: 1) reflect the capacity available for purchase in the market and 2) delay new resource additions until the energy and capacity requirement is large enough to justify a new resource addition – this is a benefit realized by Minnesota Power customers when utilizing the MISO market for energy and capacity.[3]

The resource alternatives below are included in the Strategist Proview model for the expansion plan analysis:

- 200 MW share of a natural gas-fired 2x1 combined cycle ("200 MW CC")
- 198 MW natural gas-fired combustion turbine ("198 MW CT")
- 55 MW natural gas-fired reciprocating internal combustion engine ("55 MW Reciprocating Eng")
- 150 MW bilateral bridge purchase ("150 MW Bridge")
- 50 MW request for proposal ("RFP") baseload purchase ("50 MW RFP")
- 102 MW wind farm located in North Dakota ("102 MW N.D. Wind")
- 50 MW Solar
- Backup generation program ("DG Backup P1" & "DG Backup P2")
- CAC load control ("CAC DSM")
- HW load control ("Water Heater DSM")
- Energy efficiency

Figure 13 shows the resulting expansion plan resource selections for the Preferred Plan swim lane assuming no carbon regulation penalty. Figure 14 shows the resulting expansion plans assuming a carbon regulation penalty of $21.50/ton starting in 2019.

[3] Refer to Appendix J for an explanation on why Minnesota Power considers market purchases in the resource planning analysis.

Figure 13: Step 3 Detailed Resource Analysis Preferred Plan Expansion Plan

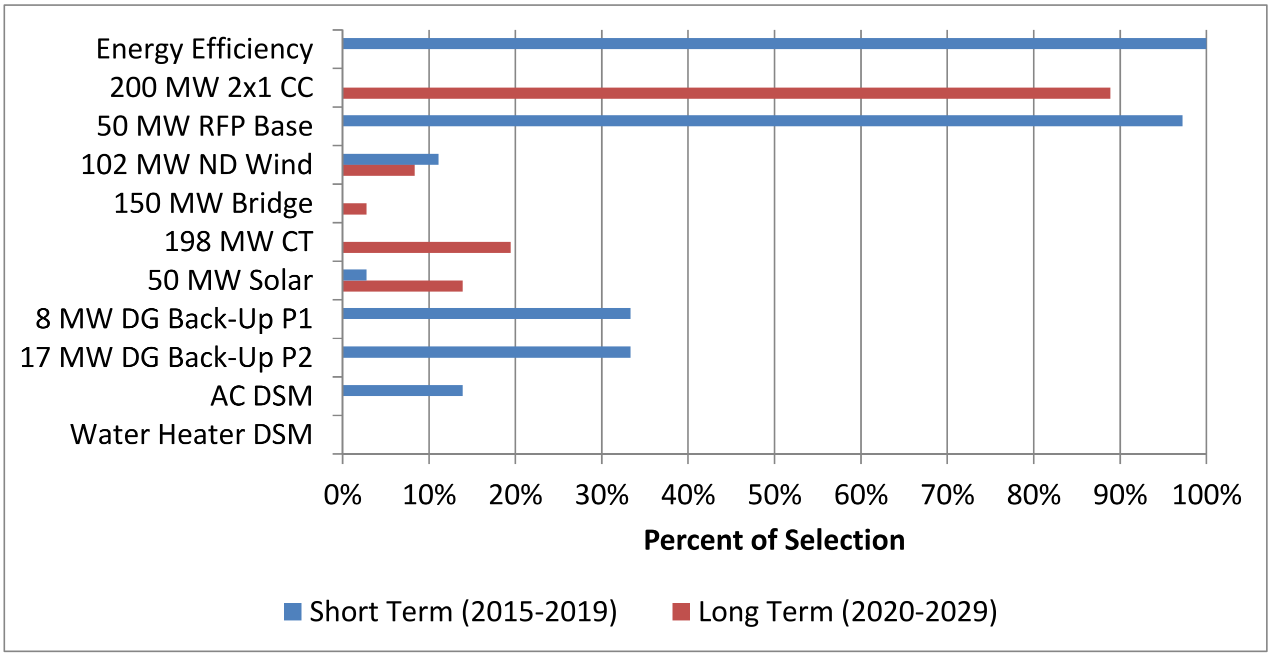


Figure 14: Step 3 Detailed Resource Analysis Preferred Plan Expansion Plan with Carbon Penalty

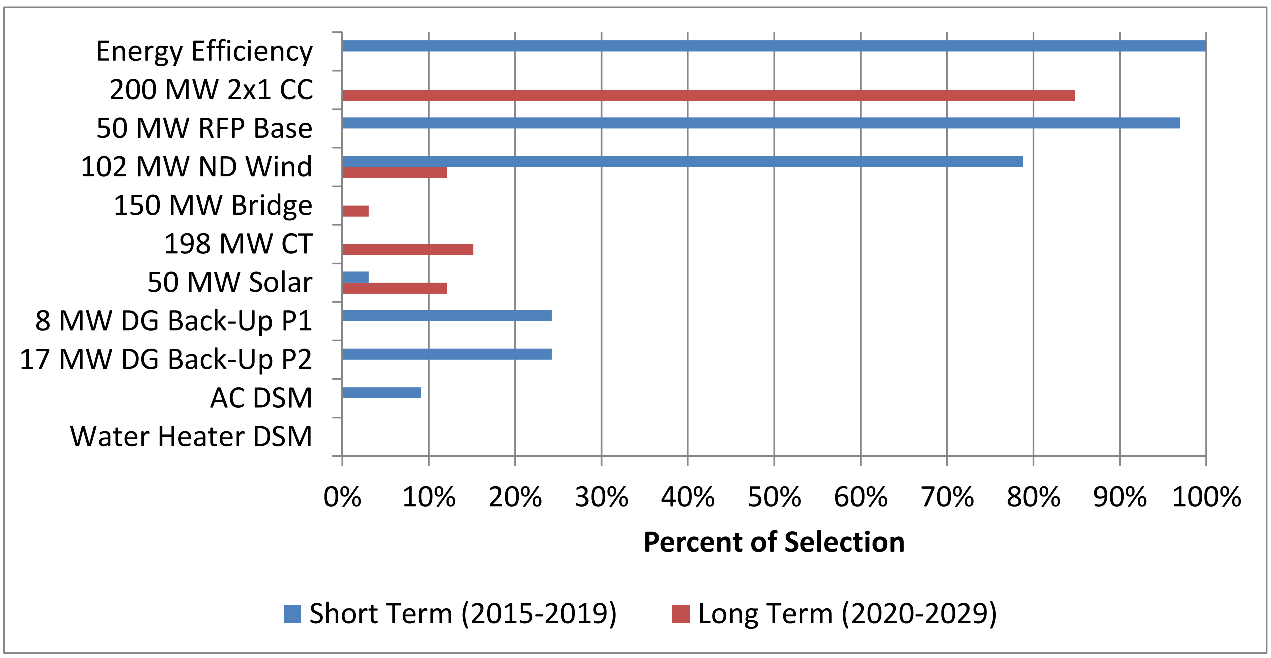


Figure 15 shows the resulting expansion plans for the Small Coal Through Mid-2020s alternative swim lane assuming no carbon regulation penalty. Figure 16 shows the resulting expansion plans assuming a carbon regulation penalty of $21.50/ton starting in 2019.

Figure 15: Step 3 Detailed Resource Analysis Small Coal Through Mid-2020s Expansion Plan

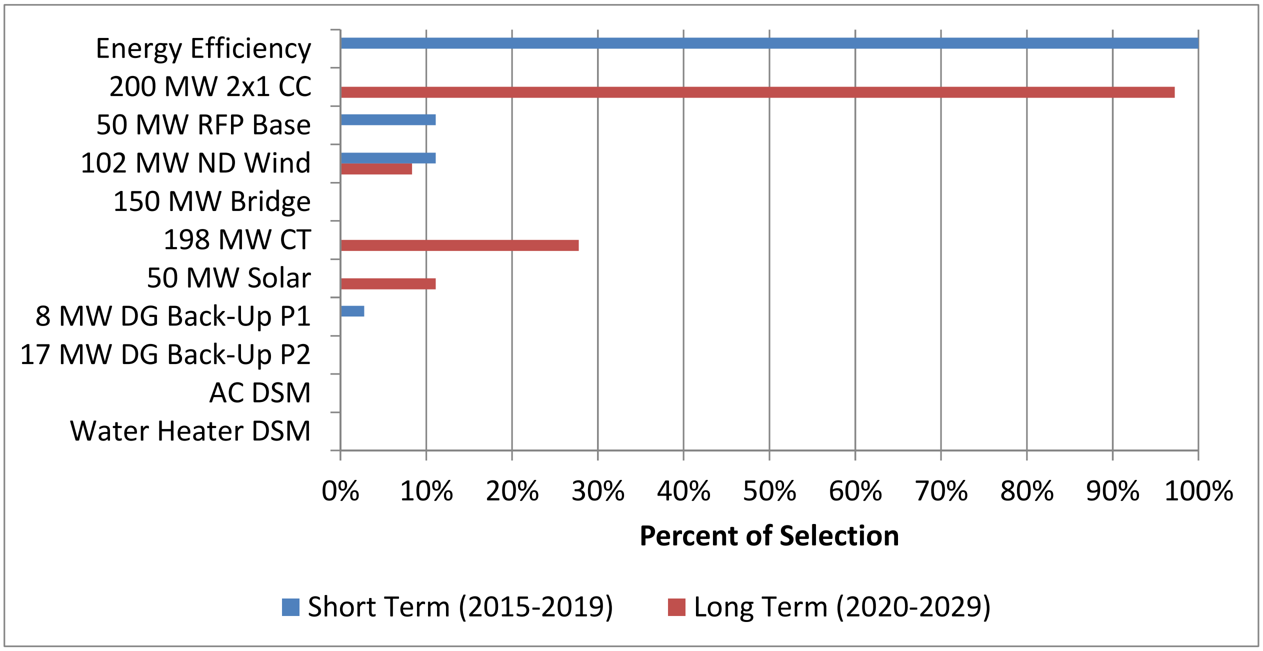


Figure 16: Step 3 Detailed Resource Analysis Small Coal Through Mid-2020s Expansion Plan with Carbon Penalty

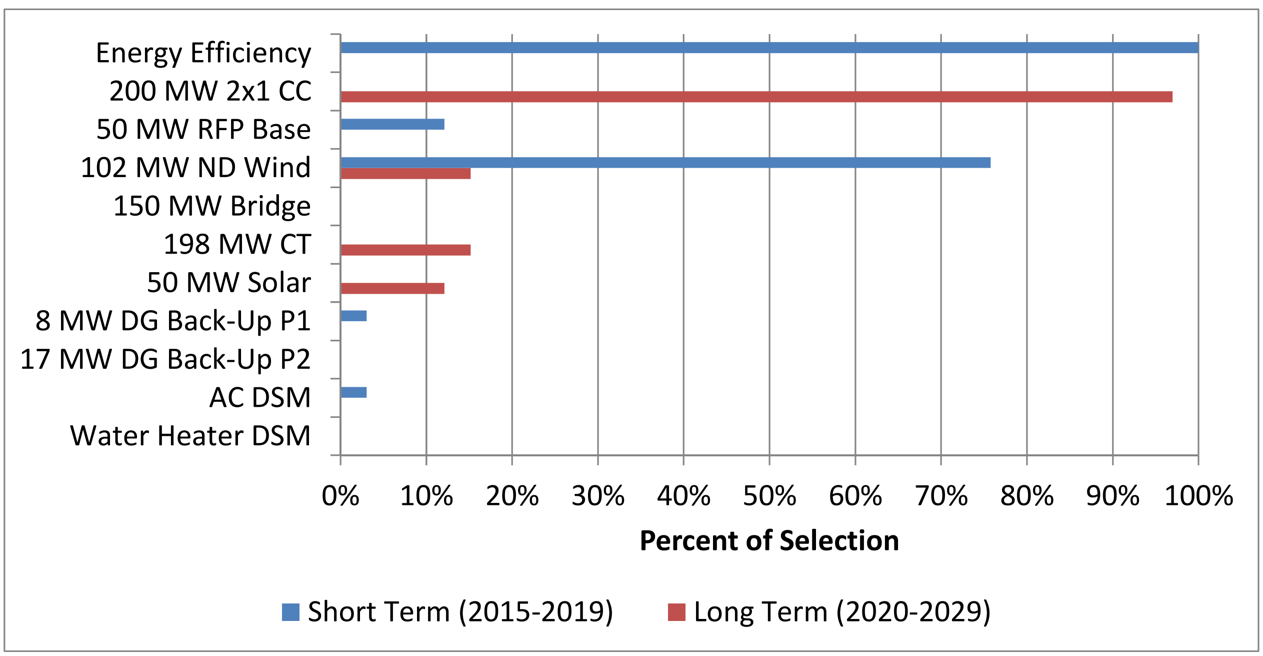


Figure 17 shows the resulting expansion plans for the Small Coal Gas Refuel alternative swim lane assuming no carbon regulation penalty. Figure 18 shows the resulting expansion plans assuming a carbon regulation penalty of $21.50/ton starting in 2019.

Figure 17: Step 3 Detailed Resource Analysis Small Coal Gas Refuel Expansion Plan

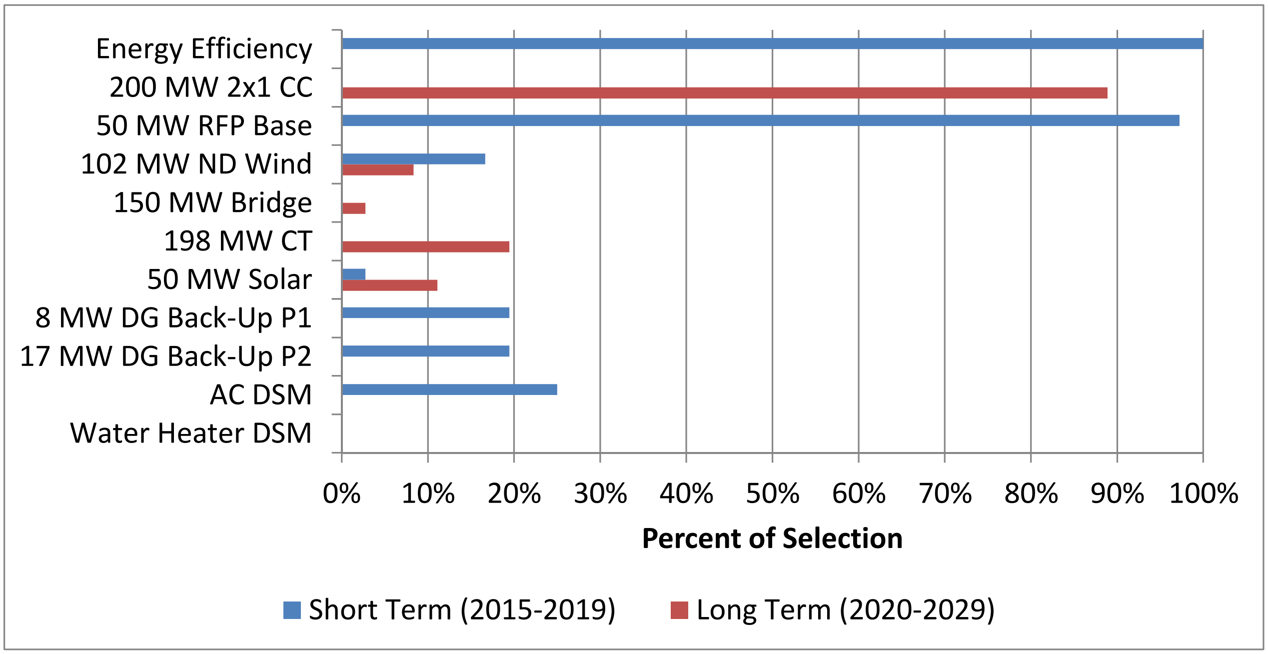


Figure 18: Step 3 Detailed Resource Analysis Small Coal Gas Refuel Expansion Plan with Carbon Penalty

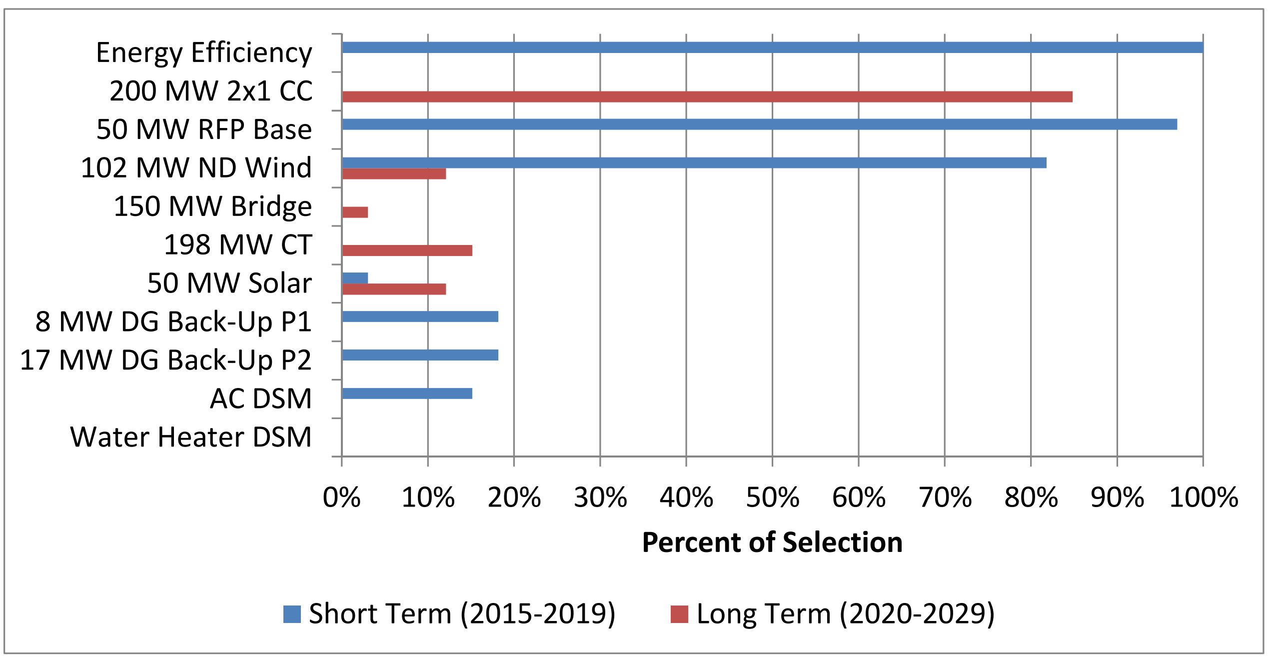


Figure 19 shows the resulting expansion plans for the Early Small Coal Exit alternative swim lane assuming no carbon regulation penalty. Figure 20 shows the resulting expansion plans assuming a carbon regulation penalty of $21.50/ton starting in 2019.

Figure 19: Step 3 Detailed Resource Analysis Early Small Coal Exit Expansion Plan

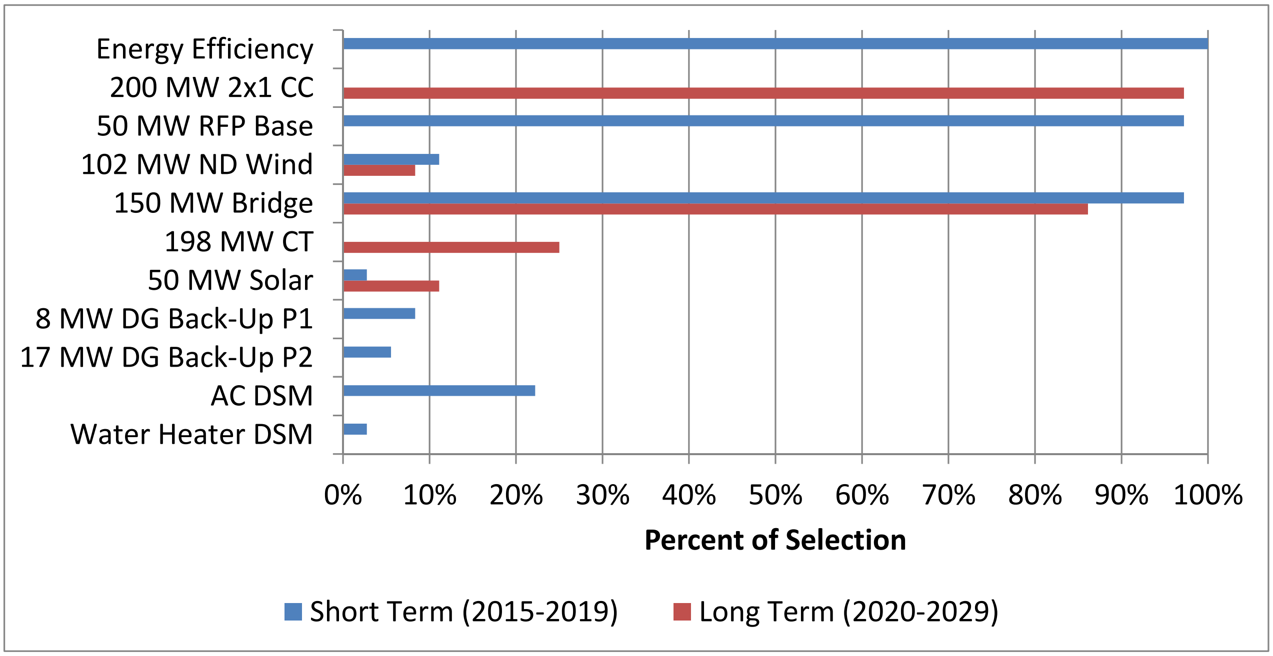
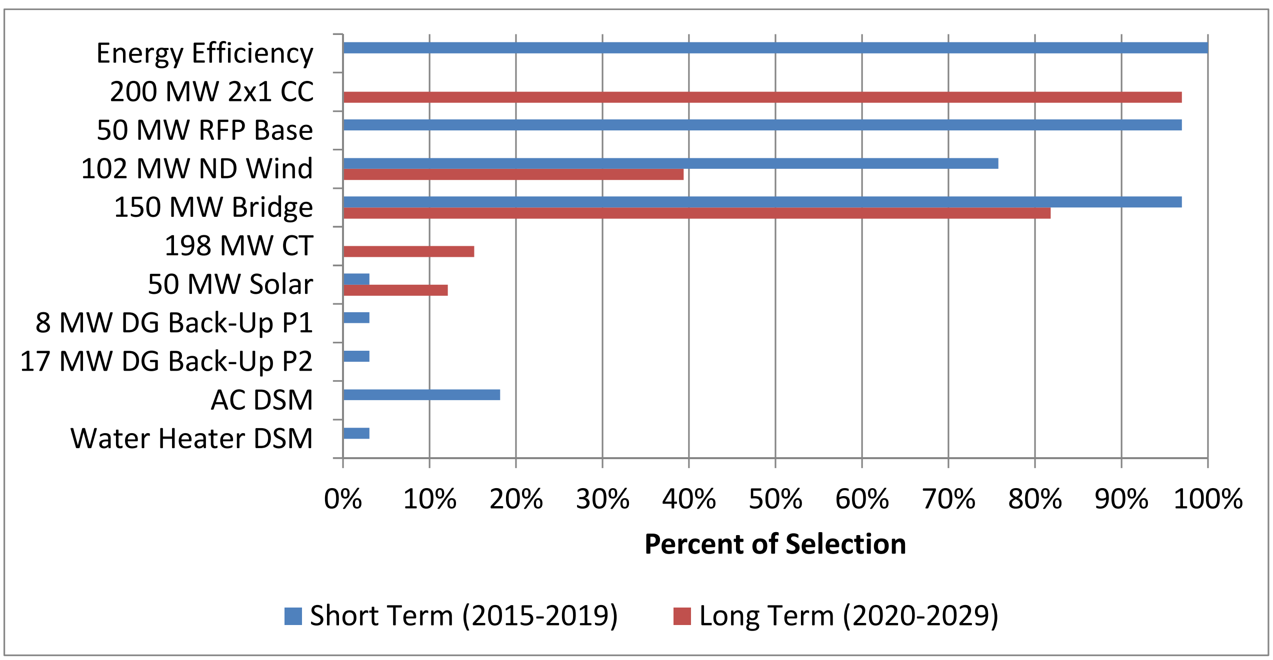


Figure 20: Step 3 Detailed Resource Analysis Early Small Coal Exit Expansion Plan with Carbon Penalty



The expansion plan resource selections under the various base and sensitivity assumptions were reviewed in order to develop a resource plan for each of the developed swim lanes. A summary of the resulting expansion plans is shown in Table 6.

Table 6: Step 3 Swim Lane Expansion Plan Summary

	Preferred Plan	Small Coal Through Mid-2020s	Small Coal Gas Refuel	Early Small Coal Exit
Short-Term (2015-2019) Actions				
Small Coal Shutdown/Refuel:				
THEC1&2 Idle by 2017	X		X	X
THEC1&2 Shutdown by 2019				
BEC1&2 Shutdown by 2019				X
BEC1&2 Gas Refuel by 2019			X	
Resource Additions:				
Combustion Turbine				
2x1 Combine Cycle (share)				
Reciprocating Engine				
Solar				
Wind				
Bilateral Bridge Transactions	X		X	X
DSM Additions:				
Backup Generation Program	X			
CAC Load Control			X	
HW Load Control				
Energy Efficiency	X	X	X	X
Long-Term (2020-2029) Actions				
Resource Additions:				
Combustion Turbine				
2x1 CC (share)	X	X	X	X
Reciprocating Engine				
Solar				
Wind				
Bilateral Bridge Transaction				X
DSM Additions:				
Backup Generation Program				
CAC Load Control				
HW Load Control				
Energy Efficiency				
Strategist Power Supply Cost 2015-2034 net present value (“NPV:”)	**$7.54 B**	**$7.58 B**	**$7.56 B**	**$7.56 B**

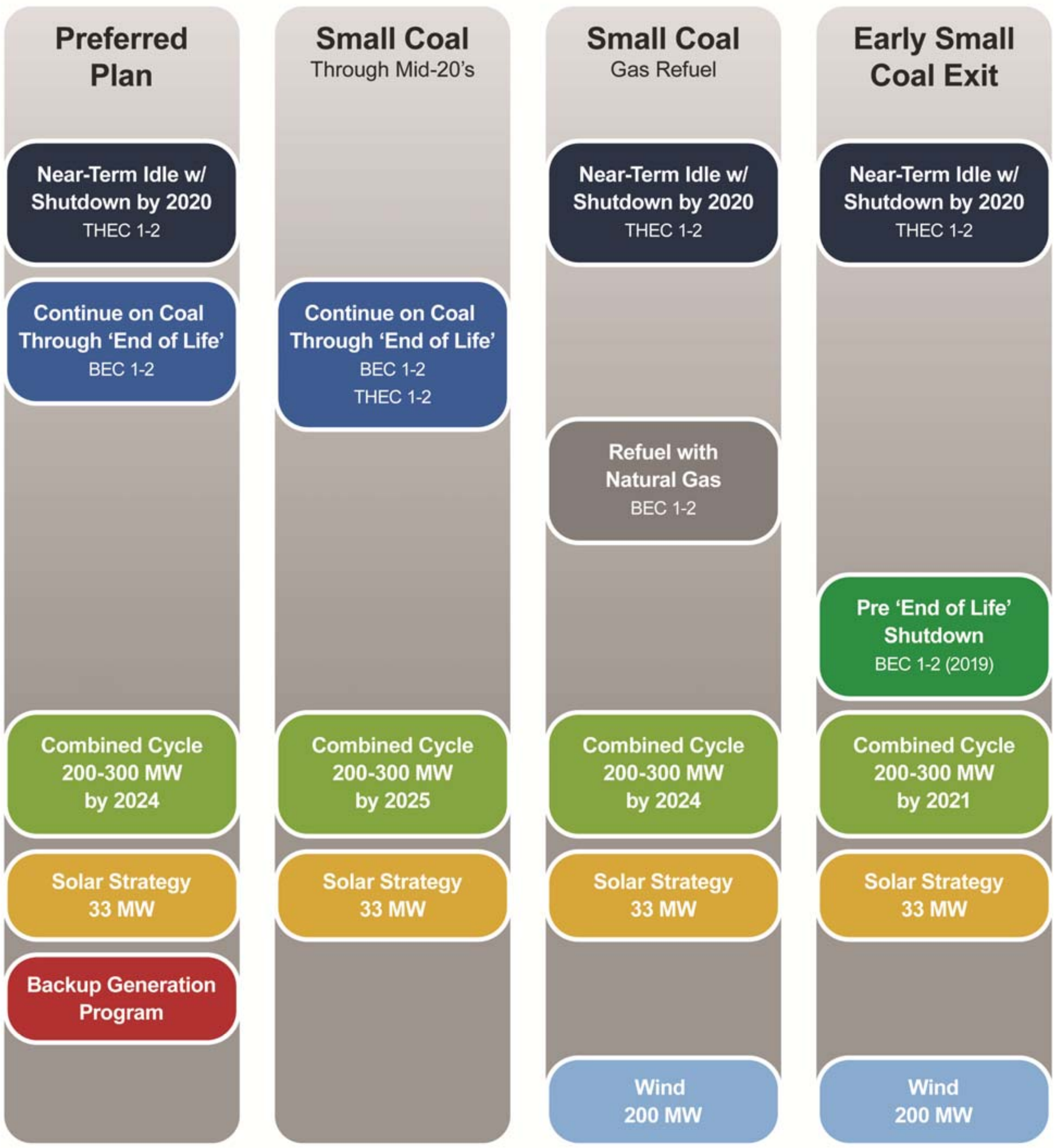
Table 7 shows the resulting expansion plans developed with the inclusion of a carbon regulation penalty starting in 2019.

Table 7: Step 3 Swim Lane Expansion Plan Summary with Carbon Penalty

	Preferred Plan	Small Coal Through Mid-2020s	Small Coal Gas Refuel	Early Small Coal Exit
Short-Term (2015-2019) Actions				
Small Coal Shutdown/Refuel:				
THEC1&2 Idle by 2017	X		X	X
THEC1&2 Shutdown by 2019				
BEC1&2 Shutdown by 2019				X
BEC1&2 Gas Refuel by 2019			X	
Resource Additions:				
Combustion Turbine				
2x1 Combine Cycle (share)				
Reciprocating Engine				
Solar				
Wind	X	X	X	X
Bilateral Bridge Transactions	X		X	X
DSM Additions:				
Backup Generation Program				
CAC Load Control				
HW Load Control				
Energy Efficiency	X	X	X	X
Long-Term (2020-2029) Actions				
Resource Additions:				
Combustion Turbine				
2x1 Combine Cycle (share)	X	X	X	X
Reciprocating Engine				
Solar				
Wind				X
Bilateral Bridge Transaction				X
DSM Additions:				
Backup Generation Program				
CAC Load Control				
HW Load Control				
Energy Efficiency				
Strategist Power Supply Cost 2015-2034 NPV:	**$8.58 B**	**$8.65 B**	**$8.55 B**	**$8.57 B**

The results from Step 3 helped Minnesota Power develop its resource plan for the Preferred Plan and alternative swim lanes. A summary of the new resource additions that build upon small coal options for the Preferred Plan and alternative swim lanes is shown in Figure 21.

Figure 21: Preferred Plan and Alternative Swim Lane Resource Additions

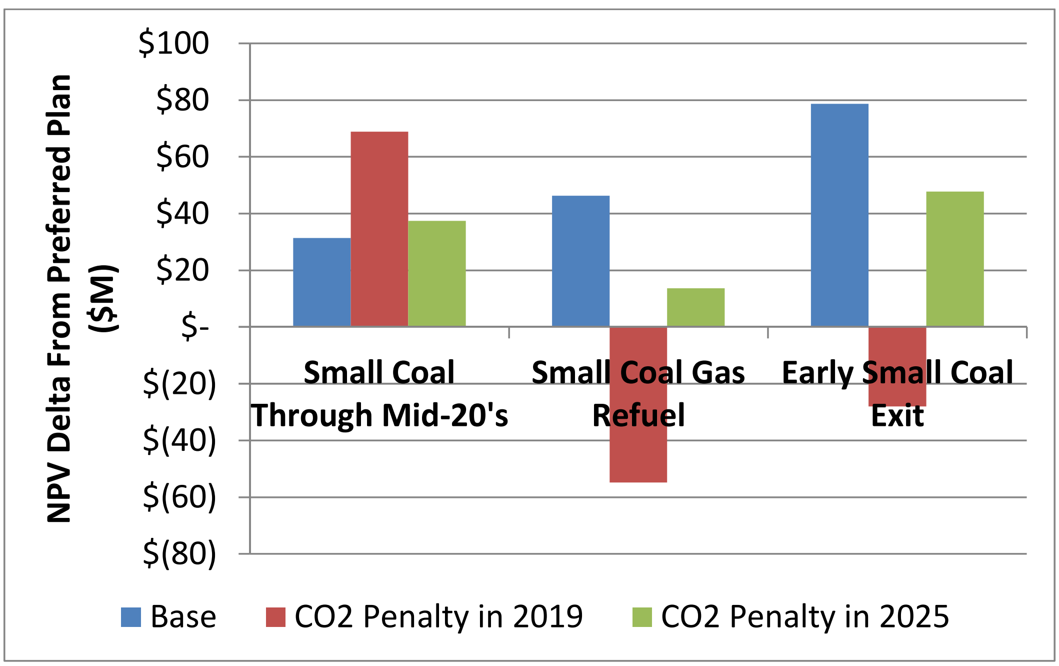


Short-term actions common to all other alternative swim lanes include the pursuit of increased incremental energy efficiency. Long-term actions common to all other alternative swim lanes include the pursuit of 200 to 300 MW share of CC generation. There were no further actions for the Small Coal Through Mid-2020s swim lane. The Small Coal Gas Refuel and Early Small Coal Exit both include the pursuit of bilateral base load purchases from the RFP responses and additional wind generation. The Early Small Coal Exit swim lane also included a long-term action of pursuing a longer term bilateral bridge purchase to maintain planning reserve margins. Table 8 shows the resulting swim lane costs and Figure 22 demonstrates the change in power supply cost from the Preferred Plan to alternative swim lanes where a positive change in power supply cost shows the alternative swim lane is higher cost than the Preferred Plan.

Table 8: Step 4 Swim Lane Final Expansion Plan Summary NPVs

	Preferred Plan	Small Coal Through Mid-2020s	Small Coal Gas Refuel	Early Small Coal Exit
Strategist Power Supply Cost 2015-2034 NPV:	$7.54 B	$7.57 B	$7.59 B	$7.62 B
NPV Delta from Preferred Plan	-	$31 M	$46 M	$79 M
Strategist Power Supply Cost with Carbon Penalty 2015-2034 NPV	$8.59 B	$8.66 B	$8.54 B	$8.56 B
NPV Delta from Preferred Plan	-	$69 M	($55 M)	($28 M)
Strategist Power Supply Cost with Delayed Carbon Penalty 2015-2034 NPV	$7.99 B	$8.02 B	$8.00 B	$8.03 B
NPV Delta from Preferred Plan	-	$37 M	$14 M	$48 M

Figure 22: Comparison of NPV Deltas from Preferred Plan



The Preferred Plan represents the portfolio with the lowest power supply cost without the inclusion of a carbon regulation penalty starting in 2019 and retains the flexibility to move to a lower cost portfolio should a carbon regulation penalty come to pass starting in 2019. As shown in the sensitivity with a delayed carbon regulation penalty (starting in 2025), the Preferred Plan remains the portfolio with the lowest power supply cost. Carbon regulation at the Federal level is currently proposed to start no earlier than 2020. Of the alternative swim lanes, the analysis shows higher cost for Minnesota Power customers when BEC1&2 and THEC1&2 are shut down early and replaced with new natural gas-fired generation without the inclusion of a carbon regulation penalty. The Small Coal Through Mid-2020s Plan consistently shows a higher power supply cost relative to the Preferred Plan for Minnesota Power's customers, showing the benefit of transitioning some of the small coal fleet to a more diverse power supply mix and taking advantage of current wholesale energy market conditions. The Small Coal Gas Refuel Plan is a more expensive power supply cost option for Minnesota Power's customers assuming no carbon regulation penalty starting in 2019. The Preferred Plan, Small Coal Through Mid-2020s and Small Coal Gas Refuel plans show that continued reliance on the Company's existing facilities to bridge their power supply transition to more natural gas in the mid-2020s rather than early shutdown of small coal facilities present a lower power supply cost outcome for Minnesota Power's customers. The Preferred Plan is a flexible and economical approach to reducing emissions, diversifying the fuel mix with natural gas generation, and keeping customer cost reasonable.

The following are some of the observations from Step 3 and 4 regarding new resource decisions organized around each swim lane and decisions common to all swim lanes.

<u>Observations Common to All/Most Swim Lanes:</u>

- As shown in Table 6 and 7, a share of a CC facility is added in the long-term action plan, reflecting the need for additional baseload/intermediate generation.
- With the exception of the Small Coal Through Mid-2020s Plan, all swim lanes utilize 150 MW of short term bilateral baseload purchase to idle and expedite an end to coal-fired operations at THEC1&2 by 2020, reflecting the current low cost of wholesale capacity and energy in the MISO region.
- Energy efficiency programs beyond the current 1.5 percent goal show the potential to reduce overall power supply cost, although the timing and equitable distribution of benefits to all Minnesota Power customer's needs to be monitored.

<u>Observations for Preferred Plan:</u>

- The Preferred Plan combines short term bilateral baseload capacity and energy purchases along with continued small coal-fired operations at BEC1&2 to balance transitioning a portion of Minnesota Power's energy supply mix to lower carbon intensity natural gas fuel and minimizing customer cost.
- The Preferred Plan offers the lowest power supply cost without a carbon penalty starting in 2020 and maintains the flexibility to shift to a lower carbon energy mix in the future should carbon penalties materialize by 2019.

- The Preferred Plan offers the lowest power supply cost when the carbon penalty is delayed until 2025.

Observations for Small Coal Through Mid-2020s Plan:

- The 2015 NPV of the plan costs is $7,572 million and *$31 million higher* in cost than the Preferred Plan without a carbon regulation penalty. The 2015 NPV of plan costs is *$69 million higher* in cost than the Preferred Plan with a carbon regulation penalty starting in 2019.
- The small coal retirements impact the timing of the need to add new generation resources. Maintaining operations of the existing small coal generation fleet delays need for a new generation resource until 2025, the latest installation of a new resource in any swim lane.

Observations for Small Coal Gas Refuel Plan:

- The 2015 NPV of the plan costs is $7,587 million and *$46 million higher* in cost than the Preferred Plan without a carbon regulation penalty. The 2015 NPV of plan costs is $55 million lower in cost than the Preferred Plan with a carbon regulation penalty starting in 2019.
- Maintaining operations at BEC1&2 rather than early shutdown delays the need for new generation to mid-2020s rather than early 2020s and provides a smaller spread in potential power supply costs relative to the Preferred Plan.
- Adding 200 MW of additional wind generation helps hedge against the cost of a carbon regulation penalty, resulting in this swim lane being the lowest cost plan when considering a $21.50 per ton carbon regulation penalty starting in 2019.

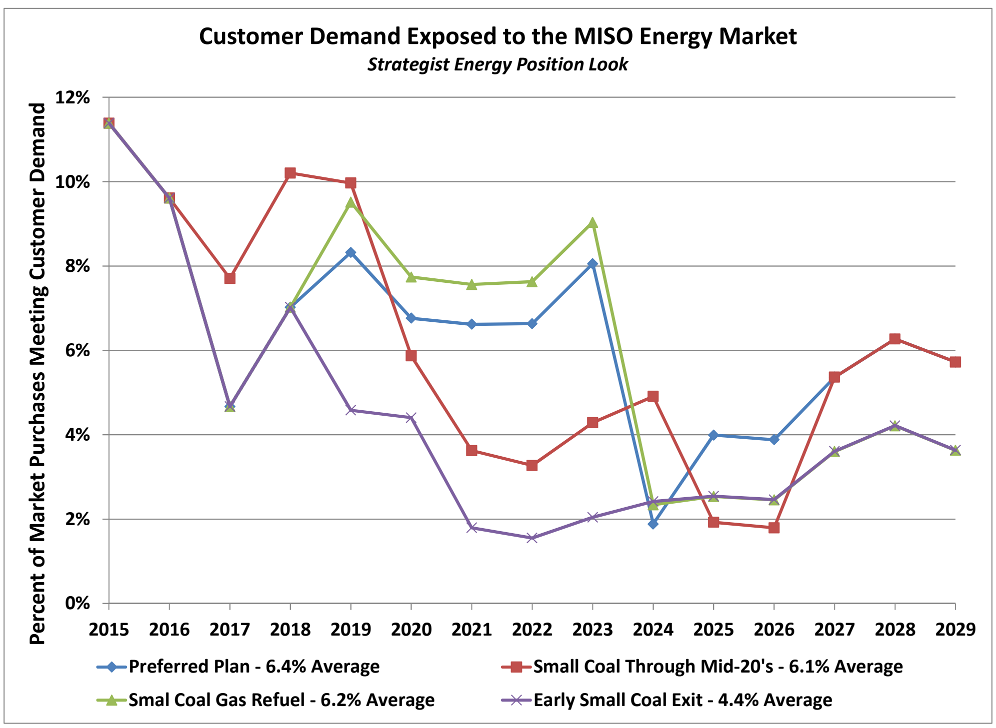
Observations for Early Small Coal Exit Plan:

- The 2015 NPV of the plan costs is $7,639 million and *$79 million higher* in cost than the Preferred Plan without a carbon regulation penalty. The 2015 NPV of plan costs is only $28 million lower in cost than the Preferred Plan with a carbon regulation penalty starting in 2019.
- Approximately 300 MW of coal-fired generation is shutdown by 2019, which is replaced by 300 MW of bilateral baseload purchases. The bilateral purchases allow Minnesota Power to maintain sufficient planning reserve margin while delaying investment in a new combined cycle resource until 2021.
- If bilateral baseload purchases are not available at the capacity and prices assumed, it could have adverse cost impacts to Minnesota Power's customers in the short term.

The following figures demonstrate how the different power supply characteristics such as wholesale market exposure and annual power supply cost differ between the Preferred Plan and alternative swim lanes.

Figure 23 shows the percentage of customer demand exposed to the wholesale energy market across the different swim lanes.[4] Other than the Early Small Coal Exit swim lane with an average market exposure of 4.4 percent over the study period, the remaining swim lanes have an average market exposure closer to 6 percent. The Early Small Coal Exit has the greatest amount of energy added to the power supply with the small coal unit energy being replaced with bilateral purchases that have a 100 percent capacity factor where the small coal unit capacity factor is closer to 70 percent, resulting in more energy being available for the power supply. Also, the Early Small Coal Exit includes 205 MW of additional wind in 2019 which offsets market exposure, although not at the level expected. By 2025 the Preferred Plan and Early Small Coal Exit have the same power supply mix other than the 205 MW or 800,000 MWh of wind in the latter swim lane. Although the difference in market exposure is only 200,000 MWh, this shows only 25 percent of the new wind generation is actually meeting new energy requirements, and the rest of the energy is displacing either coal or natural gas-fired generation. When considering additional wind in the power supply it's important to consider that it's not being built to meet new energy requirements, but added to displace existing generation that is required to maintain resource adequacy in the power supply. With the Company's power supply mix including over 600 MW of wind generation, adding more wind is showing diminishing benefits for the customers.

Figure 23: Customer Demand Exposed to the MISO Energy Market



[4] The exposure to the wholesale market is based on an economic dispatch in the Strategist model where the MISO energy market is removed, effectively dispatching the energy resources as if they are located on an island with no access to generation resources outside Minnesota Power's power supply.

The power supply cost comparison between the Preferred Plan and the alternative swim lanes is generally very close; all plans are within one percent of each other under base assumptions. Figures 24 and 25 show a comparison of annual power supply costs between the Preferred Plan and the alternative swim lanes with base assumptions and the CO_2 regulation penalty assumption. With base assumptions, the annual power supply costs are relatively close, except for the Early Small Coal Exit swim lane where in the 2019 to 2023 time frame the power supply costs are approximately $34 million higher each year when compared to the Preferred Plan. The Preferred Plan keeps costs lower in the 2019 to 2023 period as Minnesota Power transitions its power supply away from small coal to less carbon intense resources such as the 383 MW Manitoba Hydro power purchase and new natural gas generation.

Figure 24: Comparison of Annual Power Supply Cost with Base Assumptions

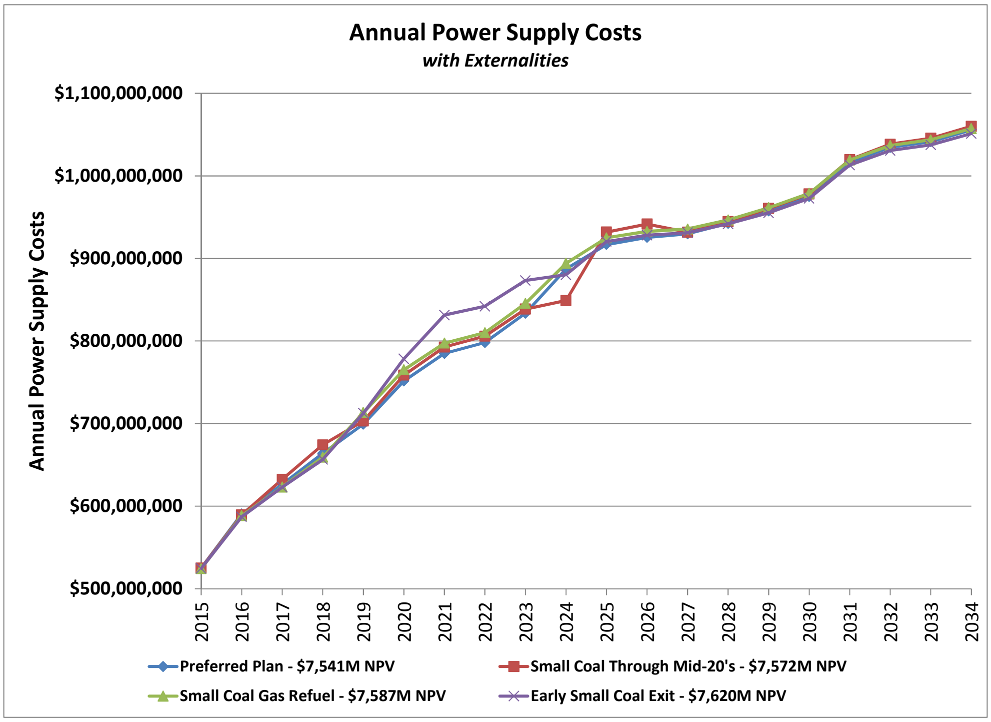
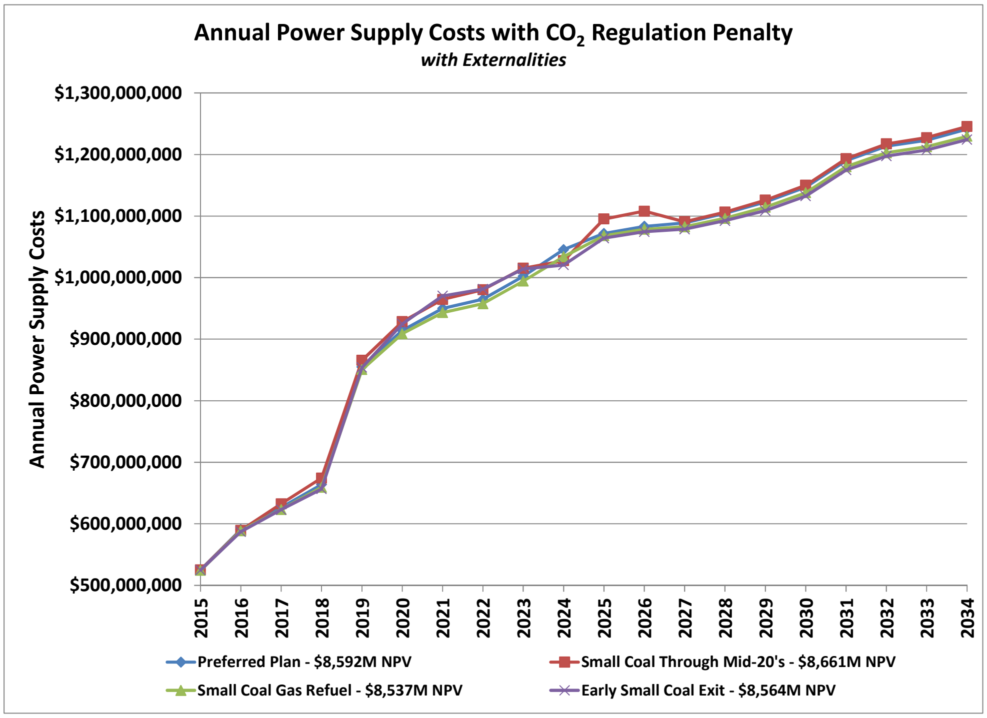
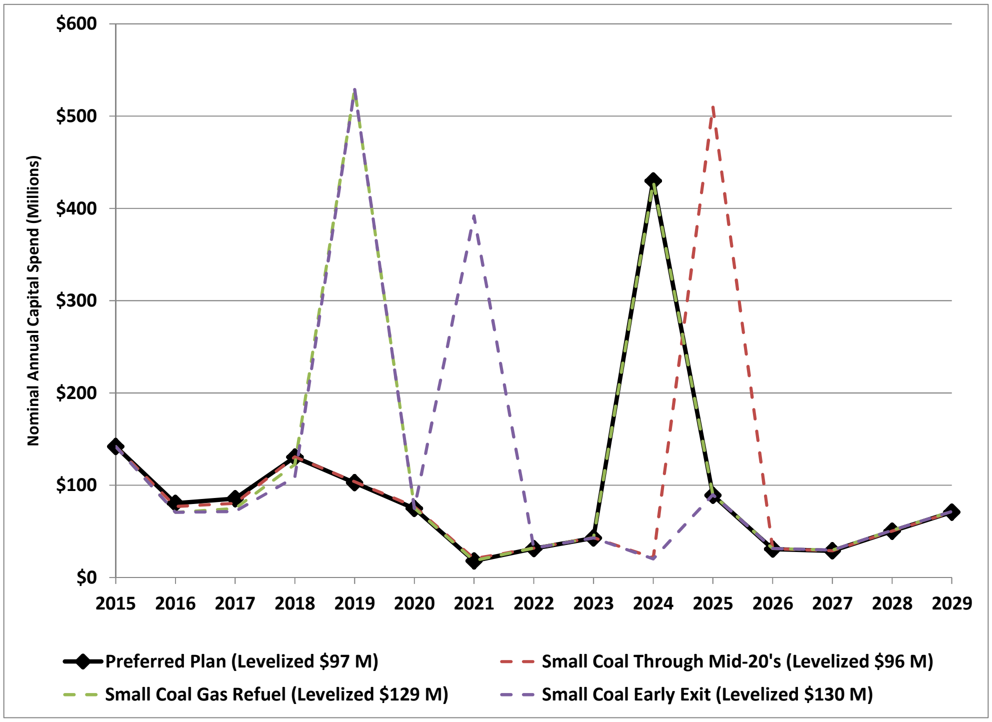


Figure 25: Comparison of Annual Power Supply Cost with CO_2 Regulation Penalty



Minnesota Power's preferred plan demonstrates a reasonable outlook for annual capital spend in both the short-term and long-term action plan, with the lowest capital spend in the short-term action plan. The Preferred Plan's levelized capital outlook of $97 million per year is nearly the lowest cost when compared to the alternative swim lanes (Figure 26) – a third less in capital spend than the Small Coal Gas Refuel and Small Coal Early Exit alternative swim lanes. The most significant difference in the capital spend outlooks between the Preferred Plan and the two highest alternative swim lanes, Small Coal Gas Refuel and Small Coal Early Exit, is the early capital spend for an additional 205 MW of new wind generation in the latter swim lanes. Otherwise, the other significant difference is the timing of when the 300 MW natural gas resource is included in the power supply.

Figure 26: Comparison of Projected Capital Spend for the Preferred Plan and Alternative Swim Lanes



Minnesota Power's Preferred Plan demonstrates a more balanced resource approach in comparison to the other alternatives, providing the low cost power supply under the majority of the sensitivities considered. The Preferred Plan represents a diverse generation portfolio that allows flexibility for Minnesota Power to take advantage of changing fuel cost or carbon regulation trends in the future, while delivering an environmentally responsible power supply that considerably reduces emissions. A near term carbon regulation penalty at $21.50 per ton or higher would favor a decision to refuel BEC1&2 to natural gas in 2019 relative to the Preferred Plan which is unlikely in the near term outlook. Should carbon regulation materialize in the future, the BEC1&2 re-route solution has no additional environmental capital requirements which keeps the consideration of closure costs lower. This provides the Company more flexibility when determining future options for this facility. Taking action in the short term to protect against the chance of a mid to high carbon regulation penalty would implement a less flexible plan for customers and unnecessarily increase cost in the near term. The expansion planning and sensitivity evaluation shows with base assumptions and with most stressed variables, the low cost plan for Minnesota Power customers is the Preferred Plan.

3. Impact to Expansion Plan with Different Load Forecast Scenarios

This section of the Appendix considers the impact to the detailed coal analysis (Step 2) and detailed resource analysis (Step 3) for the Preferred Plan when the customer energy and demand forecast is stressed up and down for various reasons. Considered as part of the load forecast scenarios is the potential for industrial customer growth higher or lower than what is assumed in the base forecast along with a winter peak demand outlook. New to the 2015 Plan analysis is the impact Minnesota Power's most recent load forecast has on the 2015 analysis.

With 2015 Annual Electric Utility Forecast Report ("AFR2015") energy and demand forecast published near the end of the analysis work for the 2015 Plan, time only allowed a small number of model runs with the new forecast to understand how it would impact the Preferred Plan decisions. As the tables on the following pages demonstrate, there were minimal changes to the detailed coal analysis and detailed resource analysis with the implementation of the AFR2015 forecast. Minnesota Power's next significant resource decisions and Preferred Plan were unaffected by the AFR2015 data. The load sensitivities used in the load scenario analysis were:

- Potential Downside Scenario (AFR2014): A low economic and industrial outlook that contemplates a reduction in Minnesota Power's electricity sales due to contracting industry.
- Potential Upside Scenario (AFR2014): A moderate industrial expansion outlook that increases industrial demand in northeast Minnesota beyond Minnesota Power's base case.
- Current Contract Scenario (AFR2014): A minimal industrial expansion outlook that decreases industrial demand in northeast Minnesota below Minnesota Power's base case.
- Winter Peak Demand Scenario (AFR2014): A peak demand based on Minnesota Power's peak demand coincident with MISO's peak demand.
- AFR2015 Base Case: The expected outlook referred to as the Moderate Growth Scenario.

A more detailed description of the AFR2014 load scenarios (i-iii above) is included in Appendix A.

Detailed Coal Analysis with Load Sensitivities

The options evaluated in the detailed coal analysis were revaluated under the different load sensitivities described above. The detailed coal analysis determined if a small coal generation facility should be shutdown prior to the accounting end of life, rather than move forward with the cost effective option(s) identified in Step 1. The results from the load sensitivity analysis were compared to the Preferred Plan for the small coal units identified in Step 2 to understand how the plan might change if a different load outlook was realized. Tables 9 and 10 below show the impact the load sensitivities have on the detailed coal analysis with base case assumptions and the $21.50 per ton carbon regulation penalty assumption. The figures demonstrate the robustness of Minnesota Power's recommendation for the small coal units with the majority of the load sensitivities showing no change. The only deviations from the Preferred Plan were:

- The "Potential Upside Scenario" results show the lowest cost plan is continuing to operate THEC1&2 and BEC1&2 on coal through their end of life.
- The "Potential Downside Scenario" and "Current Contract Scenario" results show the lowest cost plan is to shutdown BEC1&2 by 2019, which is prior to their current end of life.

Table 9: Results from the "Detailed Coal Analysis" with Base Case Assumptions and Load Sensitivity Scenarios

	Base	Potential Downside Scenario	Potential Upside Scenario	Current Contract Scenario	Winter Peak Demand Scenario	AFR2015 Base Case Outlook
THEC 1-2 Options						
Continue Coal Operations			X			
Idle by 2017	X	X		X	X	X
Shutdown by 2019						
BEC 1-2 Options						
Continue Coal Operations	X		X		X	X
Refuel w/ Natural gas by 2019						
Shutdown by 2019		X		X		

Table 10: Results from the "Detailed Coal Analysis" with \$21.50 per ton CO_2 Regulation Penalty Assumption and Load Sensitivity Scenarios

	Base	Potential Downside Scenario	Potential Upside Scenario	Current Contract Scenario	Winter Peak Demand Scenario	AFR2015 Base Case Outlook
THEC 1-2 Options						
Continue Coal Operations			X			
Idle by 2017	X	X		X	X	X
Shutdown by 2019						
BEC 1-2 Options						
Continue Coal Operations						
Refuel w/ Natural gas by 2019	X		X		X	X
Shutdown by 2019		X		X		

Detailed Resource Analysis for Preferred Plan with Load Sensitivities

The new supply-side and demand-side resource alternatives evaluated in the detailed coal analysis for the Preferred Plan were revaluated under the different load sensitivities described previously. The Strategist Proview module was used to determine the lowest cost expansion plan with the varying load sensitivities. A summary of the resulting expansion plans for the preferred small coal strategy is shown in Table 11 and 12.

To ensure enough capacity to maintain the required planning reserve margin in the near term, several bilateral bridge purchase options were used to bridge from 2015 to 2020 until all new resource alternatives were available starting in 2021 in the Strategist software. There are several observations to note from the expansion plans under the load scenario analyses. The following are observations regarding changes from Minnesota Power's Preferred Plan that includes the Moderate Growth with Deferred Resale scenario.

Observed Changes under the Downside Potential Scenario:

- No additional generation alternatives, wind or natural gas, are added over the fifteen year period. THEC1&2 idle, increase energy efficiency and the solar strategy are the only changes to Minnesota Power's current generation fleet. There is no need for additional generation beyond what is in the base case to meet customer requirements.

Observed Changes under Upside Potential Scenario:

- The need for additional natural gas, customer sited generation and renewable energy is expedited; with a 50 MW solar farm added in 2017, customer sited generation added 2016 through 2019, and 400 MW combined cycle added 2021 to 2025 time period.
- Additional bilateral transactions in lieu of a solar farm in the near term would likely allow Minnesota Power to bridge to a larger more efficient natural gas resource in the 2021 to 2025 timeframe (as is included in the short and long-term action plans for the 2015 Plan).

Observed Changes under Current Contract Scenario:

- The need for significant additional natural gas resources is delayed to 2025 and only one block of a 200 MW share of a combined cycle is required to meet customer requirements in the long-term action plan.

Observed Changes under Winter Peak Demand Scenario:

- There were no material changes to the resource decisions in the Preferred Plan.

Observed Changes under AFR2015 Base Case Scenario:

There were no material changes to the resource decisions in the Preferred Plan.

Table 11: Change to Preferred Plan's Expansion Plan with Base Assumptions and Load Sensitivity Scenarios

	Base	Potential Downside Scenario	Potential Upside Scenario	Current Contract Scenario	Winter Peak Demand Scenario	AFR2015 Base Case Outlook
Short-Term (2015-2019) Actions						
Small Coal Shutdown/Refuel:						
THEC1&2 Idle by 2017	X	X	X	X	X	X
THEC1&2 Shutdown by 2019						
BEC1&2 Shutdown by 2019						
BEC1&2 Gas Refuel by 2019						
Resource Additions:						
Combustion Turbine						
2x1 Combine Cycle (share)						
Reciprocating Engine						
Solar			X			
Wind						
Bilateral Bridge Transactions	X		X	X	X	X
DSM Additions:						
Backup Generation Program	X		X			
CAC Load Control						
HW Load Control						
Energy Efficiency	X	X	X	X	X	X
Long-Term (2020-2029) Actions						
Resource Additions:						
Combustion Turbine						
2x1 Combine Cycle (share)	X		X	X	X	X
Reciprocating Engine						
Solar						
Wind						
Bilateral Bridge Transaction			X			
DSM Additions:						
Backup Generation Program						
CAC Load Control						
HW Load Control						
Energy Efficiency						
Strategist Power Supply Cost 2015-2034 NPV:	**$7.54 B**	**$6.54 B**	**$8.04 B**	**$7.32 B**	**$7.56 B**	**$7.25 B**

Table 12: Change to Preferred Plan's Expansion Plan with Base Assumptions and Load Sensitivity Scenarios

	Base	Potential Downside Scenario	Potential Upside Scenario	Current Contract Scenario	Winter Peak Demand Scenario	AFR2015 Base Case Outlook
Short-Term (2015-2019) Actions						
Small Coal Shutdown/Refuel:						
THEC1&2 Idle by 2017	X	X	X	X	X	X
THEC1&2 Shutdown by 2019						
BEC1&2 Shutdown by 2019						
BEC1&2 Gas Refuel by 2019						
Resource Additions:						
Combustion Turbine						
2x1 Combine Cycle (share)						
Reciprocating Engine						
Solar			X			
Wind	X		X	X	X	X
Bilateral Bridge Transactions	X		X	X	X	X
DSM Additions:						
Backup Generation Program			X			
CAC Load Control		X				
HW Load Control						
Energy Efficiency	X	X	X	X	X	X
Long-Term (2020-2029) Actions						
Resource Additions:						
Combustion Turbine						
2x1 Combine Cycle (share)	X		X	X	X	X
Reciprocating Engine						
Solar						
Wind			X			
Bilateral Bridge Transaction			X			
DSM Additions:						
Backup Generation Program						
CAC Load Control						
HW Load Control						
Energy Efficiency						
Strategist Power Supply Cost 2015-2034 NPV:	**$8.58 B**	**$7.40 B**	**$9.13 B**	**$8.32 B**	**$8.59 B**	**$8.25 B**

4. Impact to Expansion Plan with 50 and 75 Percent Renewable Requirement for New Energy Requirements

This section describes the process and shows the results for the least cost expansion plan for meeting 50 and 75 percent of all new energy needs through a combination of conservation and renewable energy resources (“50 and 75 Percent Renewable Scenario”). These expansion plans were developed to comply with Minn. Stat. §216B.2422, subd. 2 (shown below):

As a part of its resource filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resource.

This section first explains how Minnesota Power setup the Strategist model to determine a new expansion plan where 50 and 75 percent of energy requirements are met with a combination of conservation and renewable energy sources. The section concludes with showing the results of these expansion plans.

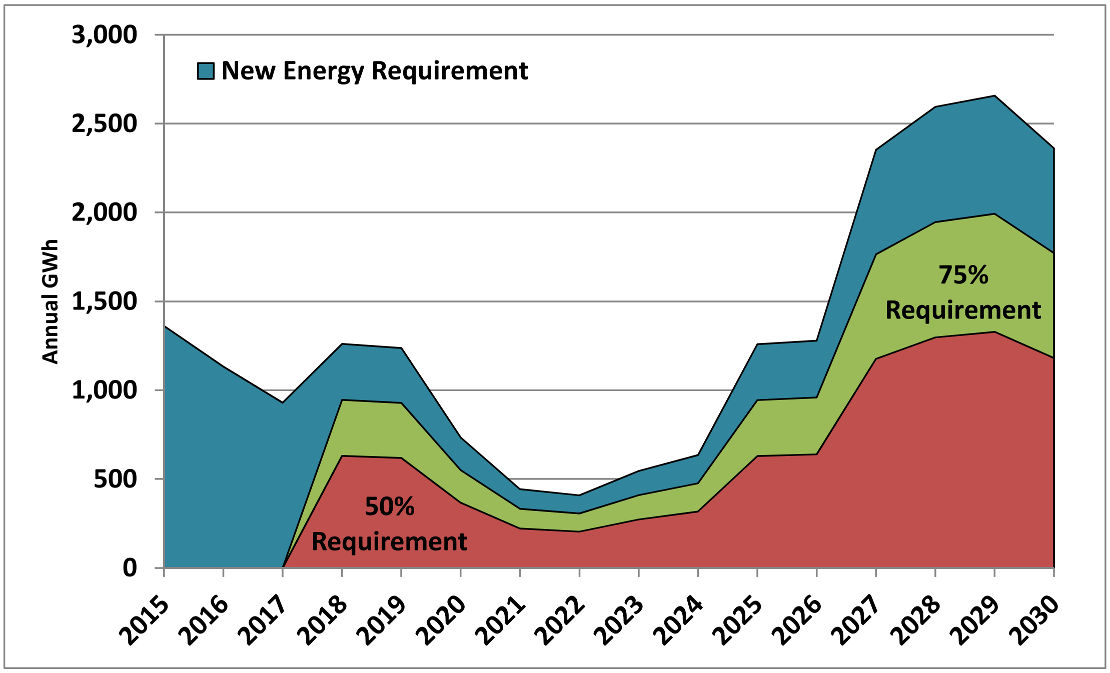
Strategist Set-up for 50 and 75 Percent Renewable for New Energy Needs

Before setting up the Strategist model to run the expansion plans with the 50 and 75 percent renewable scenario, Minnesota Power first identified the quantity of new energy that needs to be met with 50 and 75 percent renewable energy resources and conservation (see Figure 27). The new energy requirements are based on the generation set-up for the Base Case in Strategist, which is also the “Small Coal Through Mid-2020s” swim lane prior to any new resources being added to the Power Supply.[5] Using the Strategist model an economic dispatch was run with no energy market available, the resulting energy shortfall was defined as the ‘new energy requirements’. A constraint was set-up in the Strategist Model that required 50 and 75 percent of the ‘new energy requirements’ being met with renewable resources.[6] Minnesota Power assumed the 50 and 75 percent renewable and conservation constraint started in 2018, the first year new renewable resources could reasonably be put into service. The final step was developing new expansion plans where the Strategist model was required to add enough renewable generation to meet the energy requirements identified in Figure 27. Another modification made to the Strategist model was the size of the new wind alternative was increased from 102 MW to 205 MW to ensure enough renewable resources were available to be selected for these scenarios.

[5] To comply with Minn. Stat. §216B.2422, subd. 2 Minnesota Power re-ran the Step 3-Detailed Resource Analysis for the “Small Coal Through Mid-2020s” swim lane with the 50 and 75 percent renewable constraint. Only the expansion plans with base case assumptions and the $21.50 per ton CO_2 regulation penalty were evaluated for both the 50 and 75 percent renewable constraint.

[6] Note that given the “Small Coal Through Mid-2020s” already included an increase in energy efficiency spending and the associated energy savings, these Strategist model did not consider additional energy efficiency as a renewable option.

Figure 27: New Energy Requirements met with 50 and 75 Percent Renewable Energy and Conservation



The results of the expansion plan analysis showed that wind was the preferred renewable resource when 50 and 75 percent of new energy requirements must be met by a renewable resource (Table 13). For the short-term action plan approximately 205 MW of wind was added to the power supply that already has more than 600 MW of wind generation. For the long-term action plan an additional 205 MW to 410 MW of wind was added along with new natural gas-fired generation. One insight gained from this analysis, is as more wind generation is added to the power supply the preferred natural gas resource can switch from an efficient CC to a more inefficient combustion turbine. At higher penetration of wind generation the additional capital required to achieve greater efficiency with gas-fired generation is not economical because the capacity factor of the natural gas resource doesn't warrant it - the capacity factor of the gas generation resource decreases to allow the wind generation onto the power supply.

Table 13: Impact the 50 and 75 Percent Renewable and Conservation Requirement for New Energy Requirement has on Expansion Plan Selections

	50% Requirement	75% Requirement	50% Requirement w/ $21.50 per ton CO2 Regulation Penalty	75% Requirement w/ $21.50 per ton CO2 Regulation Penalty
Short-Term (2015-2019) Actions				
Small Coal Shutdown/Refuel:				
THEC1&2 Idle by 2017				
THEC1&2 Shutdown by 2019				
BEC1&2 Shutdown by 2019				
BEC1&2 Gas Refuel by 2019				
Resource Additions:				
Combustion Turbine				
2x1 Combine Cycle (share)				
Reciprocating Engine				
Solar				
Wind (205 MW)	X	X	X	X
Bilateral Bridge Transactions				
DSM Additions:				
Backup Generation Program				
CAC Load Control				
HW Load Control				
Energy Efficiency	X	X	X	X
Long-Term (2020-2029) Actions				
Resource Additions:				
Combustion Turbine	X	X		X
2x1 Combine Cycle (share)	X		X	X
Reciprocating Engine				
Solar		X		
Wind (205 MW)	X	X	X	X
Bilateral Bridge Transaction				
DSM Additions:				
Backup Generation Program				
CAC Load Control				
HW Load Control				
Energy Efficiency				
Strategist Power Supply Cost 2015-2034 NPV:	**$7.67 B**	**$7.68 B**	**$8.67 B**	**$8.70 B**

The power supply cost for the 50 and 75 percent renewable scenario are higher by approximately $10 million to $161 million than the swim lanes identified in Section 4. With the Preferred Plan projecting an energy mix growing to 35 percent renewable energy by 2025, Minnesota Power is already meeting new energy needs with renewable energy resources. The 400 MW to 600 MW of wind generation added to the power supply in these scenarios assumes no additional transmission projects are required to facilitate this addition. Adding wind at these levels could results in new transmission projects to maintain reliability of the system which would result in higher power supply cost than shown in Table 13. Minnesota Power has committed since 2005 to add only carbon-minimizing resources to its generation fleet including over 1,000 MW of renewable generation by 2025. As load continues to grow, Minnesota Power has kept to this strategy and is continually reducing the carbon intensity of its power supply. The Preferred Plan with over 1000 MW of renewable generation and expanded energy conservation demonstrates Minnesota Power continues to meet a significant share of their new energy requirements with renewable generation and conservation.

5. Order Point 12.d: Cost to Achieve Incremental Increases in Energy Efficiency

This section will demonstrate how Minnesota Power complied with Order Point 12.d from the 2013 Plan. The Order point stated:

> *Provide cost assumptions for achieving energy 0.1 percent of savings above 1.5 percent of non-CIP-exempt retail sales.*

To comply with the Order, Minnesota Power calculated the cost to achieve increments of 0.1 percent of energy savings above the 1.5 percent baseline for non-CIP-exempt customers. Then, included the costs and associated 0.1 percent of incremental energy savings as part of the sensitivity analysis included in the Comparative Swim Lane Analysis. The sensitivity analysis performed with Strategist included incremental energy savings ranging from 0.1 percent to 1 percent in 0.1 percent increments and the associated incremental program cost. Note that in the Strategist modeling and other sections of the 2015 Plan Minnesota Power refers to the different levels of incremental energy savings as GWh saved, not incremental percentage of energy saved. Table 14 cross references the incremental percentage of energy savings above the baseline with the associated incremental GWh of energy saved. The incremental first year cost from the baseline for each level of incremental energy savings considered in the 2015 plan is also shown in Table 14.

Table 14: Incremental Levels of Energy Savings Modeled in the 2015 Plan

Percentage of Incremental Energy Savings Above Base Line	Total Energy Saving (*Includes Base Line Savings*)	GWh of Incremental Energy Savings Each Year	First Year Incremental Program Cost ($000)
0.10%	1.60%	3	$511
0.20%	1.70%	6	$1,199
0.30%	1.80%	9	$2,034
0.37%	1.87%	11	$2,665
0.40%	1.90%	12	$2,988
0.50%	2.00%	15	$4,064
0.60%	2.10%	18	$5,206
0.70%	2.20%	21	$6,438
0.80%	2.30%	24	$7,725
0.90%	2.40%	27	$9,057
1.00%	2.50%	30	$10,525

To understand how varying levels of energy efficiency impact power supply cost Minnesota Power modeled as a sensitivity in the Comparative Swim Lane analysis the varying levels of 0.1 percent of incremental energy savings and the associated program cost shown in Table 14. For the Preferred Plan and the alternative swim lanes the assumed increase spending for energy efficiency programs and associated savings was removed from the power supply and replaced with the incremental energy savings sensitivity.[7] Table 15 and 16 shows the change in power supply cost from the base assumptions when the level of energy efficiency is increased for the evaluated scenarios.

Table 15: Change in Power Supply Cost from Base Assumptions when Incremental Energy Savings is Added (No CO_2 Regulation Penalty)

	Change in Power Supply Cost ($millions)			
Sensitivities	**Preferred Plan**	**Small Coal Through Mid- 20's**	**Small Coal Gas Refuel**	**Early Small Coal Exit**
Incremental EE +3GW	$3.8	$2.8	$3.7	$1.7
Incremental EE +6GW	$0.8	$0.5	$1.0	($0.3)
Incremental EE +9GW	($0.3)	($0.4)	($0.2)	($0.7)
Incremental EE +12GW	$0.0	$0.1	$0.0	$0.3
Incremental EE +15GW	$1.5	$1.9	$1.5	$2.5
Incremental EE +18GW	$3.5	$4.2	$3.6	$5.3
Incremental EE +21GW	$6.4	$7.6	$6.6	$9.1
Incremental EE +24GW	$9.7	$11.7	$10.1	$13.2
Incremental EE +27GW	$13.8	$16.3	$14.2	$18.3
Incremental EE +30GW	$19.3	$22.1	$19.8	$24.6

[7] The Preferred Plan and alternative swim lanes included 11 GWh of additional energy savings from the base line energy savings.

Table 16: Change in Power Supply Cost from Base Assumptions when Incremental Energy Savings is Added (Included $21.50 per ton CO_2 Regulation Penalty)

	Change in Power Supply Cost ($millions)			
Sensitivities	Preferred Plan	Small Coal Through Mid-2020s	Small Coal Gas Refuel	Early Small Coal Exit
Incremental EE +3GW	$9.9	$9.2	$9.7	$7.8
Incremental EE +6GW	$4.7	$4.5	$4.8	$3.4
Incremental EE +9GW	$1.3	$1.2	$1.3	$0.8
Incremental EE +12GW	($0.8)	($0.7)	($0.8)	($0.5)
Incremental EE +15GW	($1.6)	($1.4)	($1.5)	($0.5)
Incremental EE +18GW	($2.0)	($1.6)	($1.8)	($0.1)
Incremental EE +21GW	($1.4)	($0.8)	($1.2)	$1.3
Incremental EE +24GW	($0.5)	$0.7	($0.1)	$3.1
Incremental EE +27GW	$1.2	$2.7	$1.7	$5.7
Incremental EE +30GW	$4.2	$6.0	$4.8	$9.6

6. MISO Coincident vs. Non-Coincident Peak Demand Modeling

In the 2015 Plan analysis, Minnesota Power used the summer peak demand forecast coincident with MISO's peak ("MISO coincident peak") for determining the capacity requirements. The MISO coincident peak is where Minnesota Power demand is projected to be at the time MISO's entire system peaks in the summer period. Traditionally, Minnesota Power has planned its capacity requirements for its own system peak, which occurs in the winter. To meet the requirements of MISO's Resource Adequacy program that Minnesota Power participates in, the company demonstrates and plans for meeting resource adequacy requirements for future years based on capacity requirements for MISO coincident peak in the summer period.

With the start of MISO's Resource Adequacy Program back in 2010, meeting the summer peak demand requirements became the focus for the region.[8] With this change Minnesota Power started to plan its resource needs around its summer demand. Although, the company continues to monitor what it's capacity requirements would be if in the future resource adequacy is measured for summer and winter peak demand. As the MISO Resource Adequacy program evolved so did its requirements. Per MISO Resource Adequacy rule changes starting in Planning Year 2013-2014, MISO Load Serving Entities ("LSE") started to show resource adequacy based on its MISO coincident peak. Prior to this rule change Minnesota Power demonstrated resource adequacy based on its summer system peak. The difference between Minnesota Power's system peak demand and its MISO coincident peak demand is referred to as the diversity factor – the percent difference between the two peak demands.[9] Prior to the MISO coincident peak, the benefit of the diversity factor of the individual LSE's was socialized

[8] MISO's system peak demand occurs during the summer period.

[9] An example of the diversity factor calculation: 1750MW MISO Coincident Peak/1800MW Minnesota Power System Peak - 1 = 3% Diversity Factor or the MISO Coincident Peak is approximately 3% lower than the system peak.

across its system. With the change to the MISO coincident peak each individual LSE received the benefit of their system's diversity factor. Given that Minnesota Power's control area is in the northwestern half of the MISO footprint, which historically has customer demand peaking later than the MISO system, this resource adequacy change provides benefit to Minnesota Power customers in that it requires less capacity resources to meet customer needs and still maintain system reliability. This is one of the significant benefits customers receive being a member of a reserve sharing pool such as MISO which balances energy and capacity requirements over a larger region.

In the 2015 Plan analysis Minnesota Power considered still planning or at a minimum to have a sensitivity that showed the capacity resources required for meeting a system peak demand. To achieve this Minnesota Power would need the MISO system diversity factor, which would replace Minnesota Power's own diversity factor that is currently used to calculate its capacity requirements. Prior to switching to a MISO coincident peak the MISO Loss of Load Expectation ("LOLE") report showed the diversity factor for the MISO system. The last study to show the diversity factor was the 2012 report. With the addition of Entergy in 2014 to the MISO footprint and the age of the study, the 2012 LOLE report is no longer a good source for the peak demand diversity factor in MISO. Minnesota Power decided not to include a system peak demand outlook in the 2015 Plan given there was not an accurate source for the system diversity factor that reflects MISO as it exist today.

APPENDIX L: COST IMPACT ANALYSIS BY CUSTOMER CLASS

Introduction

Order Point 5.f. of the Public Utilities Commission's ("Commission") May 6, 2011, Order Accepting Resource Plan and Requiring Compliance Filings in Minnesota Power's 2010-2024 Integrated Resource Plan ("Plan")[1] required Minnesota Power (or "Company") to include a "cost impact analysis by customer class" in its next resource plan. The Company complied with this order point in its 2013 Integrated Resource Plan. This Appendix is included to comply with that requirement for the 2015 Integrated Resource Plan ("2015 Plan"). For purposes of this analysis, the terms "cost impact" and "rate impact" are assumed to have the same meaning. It should be noted that these are estimated impacts and thus may not correspond with actual rates that the Commission sets for various rate classes in the future. In addition, numerous simplifying assumptions have been made in both the calculation methodology and the input variables, and these assumptions naturally cause imprecision in the estimates. Long-term resource planning is inherently uncertain and therefore causes additional uncertainty in the resulting rate impacts. Thus, the numbers estimated here should be used as guideposts on rate impact rather than viewed or used as ultimately determinative calculations on customer power costs.

This Appendix provides detail on the estimated rate impacts of the 2015 Plan. Specifically, this Appendix discusses the following items:

A. Calculation of 2015 Plan Power Supply Costs
B. Calculation of 2015 Base Rates
C. Calculation of Rate Impacts
D. Rate Impacts of Other 2015 Plan Alternative Cases

A. Calculation of 2015 Plan Power Supply Costs

The estimated rate impacts are based on the revenue requirement outputs from the 2015 Plan long-term planning model for the five-year action plan time period. These outputs are referred to as the "IRP Power Supply Costs." The first step in estimating the rate impacts by customer class is to calculate the annual incremental power supply cost of the 2015 Plan Preferred Plan for the years 2015 to 2019, compared to the 2015 Plan Base Case power supply costs.[2] The 2015 Base Case power supply costs are subtracted from the annual power supply cost of the Preferred Plan for 2015 to 2019 to determine the incremental power supply cost relative to 2015. The estimated rate impacts by class will therefore be calculated relative to the 2015 Base Rates which will be discussed in the next section.

The incremental 2015 Plan power supply costs are separated into three buckets: power supply costs, solar costs and energy efficiency costs. The power supply costs are allocated to jurisdiction and class as described below. The solar costs are divided by the projected non-exempt energy usage by class to obtain the solar cost rates by class. The energy efficiency cost are divided by the projected energy usage by class that is subject to the Conservation Program Adjustment ("CPA") charge to obtain the energy efficiency rates by class.

[1] Docket E-015/RP-09-1088.
[2] The 2015 Plan Preferred Plan, 2015 Plan Base Case, and other Alternative Cases are described in Appendix K.

After the incremental power supply costs of the Preferred Plan for 2015 to 2019 are determined, these costs are allocated to the Minnesota jurisdiction and to customer class based on projected revenue requirement allocators for 2016 to 2019. The allocators are based on the total revenue requirements allocated to the Minnesota jurisdiction and to each retail class in Minnesota Power's last retail rate case.[3] The annual allocators for the 2015 Plan are projected assuming perfect annual rate making that follows the fully allocated class cost-of-service study. In other words, the 2010 rate case relationships between jurisdictional and class revenue requirements and jurisdictional and class energy at the meter are assumed to remain constant, thus allowing those relationships (ratios) to be used to project the allocators using the forecasted energy by jurisdiction and class from Minnesota Power's 2014 Annual Electric Utility Forecast Report (see Appendix A). The 2015 Plan incremental power supply costs are then divided by the projected energy usage by class to obtain the 2015 Plan incremental power supply cost rates by class.

In developing the rate impacts, one adjustment to the 2015 Plan incremental power supply costs was made. The 2015 Plan incremental power supply costs includes the revenue requirements associated with the Great Northern Transmission Line, but does not include the other projected revenue requirements for Minnesota Power's Transmission Cost Recovery ("TCR") Rider projects. The Company therefore made an adjustment to include these costs in the rate impacts. These revenue requirements were projected based on Minnesota Power's 2016 budget and the project details from Minnesota Power's TCR Rider. After the total Company TCR Adjustment was determined, these costs were allocated to the Minnesota retail jurisdiction and to customer class based on projected Power Supply Production ("D-02") Transmission allocators for 2016 to 2019. The costs were then divided by the projected energy usage by class to obtain the the TCR adjustment rates.

The 2015 Plan incremental power supply costs rates, the solar cost rates, energy efficiency rates and the TCR Adjustment rates are added by class to obtain the total adjusted 2015 Plan incremental power supply cost rates by class.

B. Calculation of 2015 Base Rates

As mentioned above, the estimated rate impacts by class are calculated relative to Minnesota Power's 2015 Base Rates. The starting point to estimate the 2015 Base Rates is the 2010 base rates by class from Minnesota Power's last rate case. The estimated average rates customers will pay in 2015 for Minnesota Power's Renewable Resources Rider, TCR Rider, and the Boswell 4 Environmental Rider are added to estimate a "rider" rate to add to the 2010 base rates. Lastly, the estimated Fuel and Purchased Energy ("FPE") Adjustment and the estimated 2015 average CPA rate are added to arrive at the estimated 2015 Base Rates.[4] The 2015 FPE Adjustment is estimated by comparing the total average cost of fuel and purchased energy ($19.76 per MWh) that was included in Minnesota Power's last rate case[5] to the 2015 budgeted costs.

[3] Docket E-015/GR-09-1151.

[4] CPA factor is not applied to Large Power customers that have obtained exemptions from CIP charges.

[5] Note that the $19.76 per MWh average cost of fuel and purchased energy includes $10.18 per MWh in base energy rates plus the 2010 test year average FPE Adjustment of $9.58 per MWh.

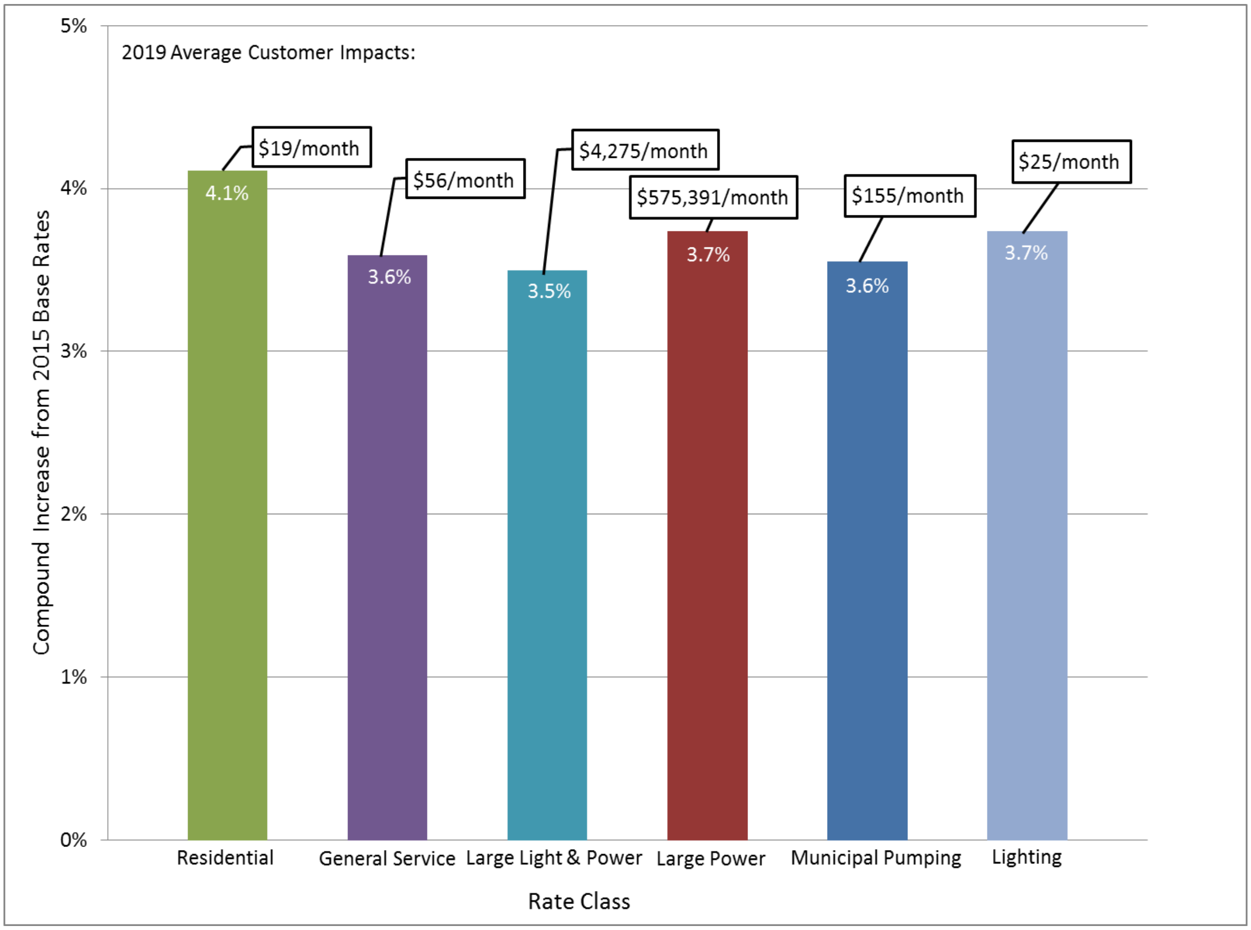
C. Calculation of Rate Impacts

The Preferred Plan incremental power supply cost rates by class from 2015 to 2019 are divided by the estimated 2015 Base Rates to determine the estimated percent increase in rates. The Preferred Plan incremental power supply cost rates by class from 2015 to 2019 are then multiplied by the projected average monthly billing units by class to estimate the average dollar per month increase by class. As shown in Table 1 and Figure 1, the Preferred Plan incremental power supply costs in 2019 would be expected to increase the average residential rate by about 4.1 percent on a compounded annual basis through 2019. That is equivalent to an increase of $18.69 per month above the 2015 estimated Base Rate. The impact to the average large power rate would be an increase of about 3.7 percent on a compounded annual basis through 2019. That is equivalent to an increase of 1.2 cents per kWh above the 2015 estimated Base Rate.

Table 1: Estimated Average Rate Impacts of Preferred Plan Relative to 2015 Projected Base Rates

Rate Class Impacts \1	2015	2016	2017	2018	2019	Compounded Annual Increase
Residential (average rate, cents/kWh)	10.238	10.238	10.238	10.238	10.238	-
Increase (cents/kWh)	0.023	1.075	1.461	1.858	2.283	-
Increase (%)	0.22%	10.50%	14.27%	18.15%	22.30%	4.11%
Average Impact ($ / month)	$0.19	$8.75	$11.89	$15.17	$18.69	-
General Service (average rate, cents/kWh)	10.233	10.233	10.233	10.233	10.233	-
Increase (cents/kWh)	0.018	0.953	1.285	1.617	1.975	-
Increase (%)	0.18%	9.31%	12.56%	15.80%	19.30%	3.59%
Average Impact ($ / month)	$0.51	$26.99	$36.33	$45.81	$55.91	-
Large Light & Power (average rate, cents/kWh)	8.327	8.327	8.327	8.327	8.327	-
Increase (cents/kWh)	0.014	0.790	1.050	1.289	1.562	-
Increase (%)	0.17%	9.48%	12.61%	15.47%	18.76%	3.50%
Average Impact ($ / month)	$36	$2,146	$2,810	$3,527	$4,275	-
Large Power (average rate, cents/kWh)	5.995	5.995	5.995	5.995	5.995	-
Increase (cents/kWh)	0.010	0.666	0.834	0.998	1.207	-
Increase (%)	0.17%	11.11%	13.91%	16.65%	20.13%	3.74%
Average Impact ($ / month)	$5,297	$353,522	$395,722	$474,334	$575,391	-
Municipal Pumping (average rate, cents/kWh)	9.396	9.396	9.396	9.396	9.396	-
Increase (cents/kWh)	0.043	0.887	1.178	1.466	1.792	-
Increase (%)	0.46%	9.44%	12.53%	15.60%	19.07%	3.55%
Average Impact ($ / month)	$3.73	$77.97	$102.97	$127.49	$154.52	-
Lighting (average rate, cents/kWh)	15.916	15.916	15.916	15.916	15.916	-
Increase (cents/kWh)	0.014	1.438	1.974	2.580	3.203	-
Increase (%)	0.09%	9.04%	12.41%	16.21%	20.12%	3.74%
Average Impact ($ / month)	$0.11	$11.60	$15.74	$20.31	$24.90	-
Average Weighted Increase (cents/kWh)	0.013	0.756	0.980	1.199	1.457	-
Avg Weighted Increase (%)	0.18%	10.53%	13.64%	16.69%	20.28%	3.76%
Notes: 1/ Average current rates are 2015 estimates. These estimates are based on 2010 base rates from Minnesota Power's last rate case (E-015/GR-09-1151) with 2015 estimated cost recovery rider rates and estimated 2015 FPE and CPA factor added. CPA factor is not applied to Large Power Class.						

Figure 1: Estimated 2019 Rate Impact by Class of Preferred Plan Relative to Projected 2015 Base Rates



D. Rate Impact of Other Alternative Cases

The rate impacts for each of the Alternative Plans are in the following tables:

A. Table 2 – Summary of 2019 Rate Impacts by Case
B. Table 3 – Small Coal Through Mid-2020s
C. Table 4 – Small Coal Gas Refuel
D. Table 5 – Early Small Coal Exit

Table 2: Summary of 2019 Rate Impacts by Case Relative to 2015 Projected Base Rates

Rate Class Impacts \1	Preferred Plan	Small Coal Through Mid-2020s	Small Coal Gas Refuel	Early Small Coal Exit
Residential (average rate, cents/kWh)	10.238	10.238	10.238	10.238
Increase (cents/kWh)	2.283	2.327	2.529	2.473
Increase (%)	22.30%	22.73%	24.70%	24.15%
Average Impact ($ / month)	$18.69	$19.06	$20.71	$20.25
Compounded Annual Increase (%)	4.11%	4.18%	4.51%	4.42%
General Service (average rate, cents/kWh)	10.233	10.233	10.233	10.233
Increase (cents/kWh)	1.975	2.013	2.188	2.139
Increase (%)	19.30%	19.67%	21.38%	20.90%
Average Impact ($ / month)	$55.91	$57.00	$61.94	$60.56
Compounded Annual Increase (%)	3.59%	3.66%	3.95%	3.87%
Large Light & Power (average rate, cents/kWh)	8.327	8.327	8.327	8.327
Increase (cents/kWh)	1.562	1.593	1.731	1.692
Increase (%)	18.76%	19.13%	20.79%	20.32%
Average Impact ($ / month)	$4,275	$4,358	$4,736	$4,631
Compounded Annual Increase (%)	3.50%	3.56%	3.85%	3.77%
Large Power (average rate, cents/kWh)	5.995	5.995	5.995	5.995
Increase (cents/kWh)	1.207	1.228	1.325	1.298
Increase (%)	20.13%	20.49%	22.10%	21.65%
Average Impact ($ / month)	$575,391	$585,532	$631,602	$618,731
Compounded Annual Increase (%)	3.74%	3.80%	4.07%	4.00%
Municipal Pumping (average rate, cents/kWh)	9.396	9.396	9.396	9.396
Increase (cents/kWh)	1.792	1.827	1.985	1.941
Increase (%)	19.07%	19.44%	21.13%	20.65%
Average Impact ($ / month)	$154.52	$157.53	$171.19	$167.38
Compounded Annual Increase (%)	3.55%	3.62%	3.91%	3.83%
Lighting (average rate, cents/kWh)	15.916	15.916	15.916	15.916
Increase (cents/kWh)	3.203	3.266	3.549	3.470
Increase (%)	20.12%	20.52%	22.30%	21.80%
Average Impact ($ / month)	$24.90	$25.38	$27.59	$26.97
Compounded Annual Increase (%)	3.74%	3.80%	4.11%	4.02%
Notes: 1/ Average current rates are 2015 estimates. These estimates are based on 2010 base rates from Minnesota Power's last rate case (E-015/GR-09-1151) with 2015 estimated cost recovery rider rates and estimated 2015 FPE and CPA factor added. CPA factor is not applied to Large Power class.				

Table 3: Estimated Avg. Rate Impacts of Small Coal Through Mid-2020s Relative to 2015 Projected Base Rates

Rate Class Impacts \1	2015	2016	2017	2018	2019	Compounded Annual Increase
Residential (average rate, cents/kWh)	10.238	10.238	10.238	10.238	10.238	-
Increase (cents/kWh)	0.023	1.059	1.550	2.002	2.327	-
Increase (%)	0.22%	10.35%	15.13%	19.55%	22.73%	4.18%
Average Impact ($ / month)	$0.19	$8.62	$12.61	$16.35	$19.06	-
General Service (average rate, cents/kWh)	10.233	10.233	10.233	10.233	10.233	-
Increase (cents/kWh)	0.018	0.940	1.361	1.741	2.013	-
Increase (%)	0.18%	9.18%	13.30%	17.01%	19.67%	3.66%
Average Impact ($ / month)	$0.51	$26.61	$38.49	$49.33	$57.00	-
Large Light & Power (average rate, cents/kWh)	8.327	8.327	8.327	8.327	8.327	-
Increase (cents/kWh)	0.014	0.779	1.111	1.387	1.593	-
Increase (%)	0.17%	9.36%	13.34%	16.65%	19.13%	3.56%
Average Impact ($ / month)	$36	$2,117	$2,972	$3,795	$4,358	-
Large Power (average rate, cents/kWh)	5.995	5.995	5.995	5.995	5.995	-
Increase (cents/kWh)	0.010	0.658	0.876	1.067	1.228	-
Increase (%)	0.17%	10.98%	14.61%	17.80%	20.49%	3.80%
Average Impact ($ / month)	$5,297	$349,597	$415,765	$506,998	$585,532	-
Municipal Pumping (average rate, cents/kWh)	9.396	9.396	9.396	9.396	9.396	-
Increase (cents/kWh)	0.043	0.875	1.247	1.578	1.827	-
Increase (%)	0.46%	9.31%	13.27%	16.79%	19.44%	3.62%
Average Impact ($ / month)	$3.73	$76.89	$109.00	$137.26	$157.53	-
Lighting (average rate, cents/kWh)	15.916	15.916	15.916	15.916	15.916	-
Increase (cents/kWh)	0.014	1.416	2.098	2.781	3.266	-
Increase (%)	0.09%	8.90%	13.18%	17.48%	20.52%	3.80%
Average Impact ($ / month)	$0.11	$11.42	$16.72	$21.90	$25.38	-
Notes: 1/ Average current rates are 2015 estimates. These estimates are based on 2010 base rates from Minnesota Power's last rate case (E-015/GR-09-1151) with 2015 estimated cost recovery rider rates and estimated 2015 FPE and CPA factor added. CPA factor is not applied to Large Power Class.						

Table 4: Estimated Average Rate Impacts of Small Coal Gas Refuel Relative to 2015 Projected Base Rates

Rate Class Impacts \1	2015	2016	2017	2018	2019	Compounded Annual Increase
Residential (average rate, cents/kWh)	10.238	10.238	10.238	10.238	10.238	-
Increase (cents/kWh)	0.011	1.048	1.416	1.795	2.529	-
Increase (%)	0.10%	10.23%	13.83%	17.54%	24.70%	4.51%
Average Impact ($ / month)	$0.09	$8.53	$11.53	$14.66	$20.71	-
General Service (average rate, cents/kWh)	10.233	10.233	10.233	10.233	10.233	-
Increase (cents/kWh)	0.008	0.930	1.246	1.562	2.188	-
Increase (%)	0.08%	9.09%	12.17%	15.26%	21.38%	3.95%
Average Impact ($ / month)	$0.23	$26.33	$35.23	$44.27	$61.94	-
Large Light & Power (average rate, cents/kWh)	8.327	8.327	8.327	8.327	8.327	-
Increase (cents/kWh)	0.006	0.771	1.019	1.246	1.731	-
Increase (%)	0.08%	9.26%	12.24%	14.96%	20.79%	3.85%
Average Impact ($ / month)	$17	$2,096	$2,728	$3,409	$4,736	-
Large Power (average rate, cents/kWh)	5.995	5.995	5.995	5.995	5.995	-
Increase (cents/kWh)	0.005	0.653	0.812	0.968	1.325	-
Increase (%)	0.08%	10.89%	13.55%	16.15%	22.10%	4.07%
Average Impact ($ / month)	$2,449	$346,685	$385,469	$460,035	$631,602	-
Municipal Pumping (average rate, cents/kWh)	9.396	9.396	9.396	9.396	9.396	-
Increase (cents/kWh)	0.020	0.866	1.142	1.417	1.985	-
Increase (%)	0.21%	9.22%	12.16%	15.08%	21.13%	3.91%
Average Impact ($ / month)	$1.73	$76.09	$99.89	$123.21	$171.19	-
Lighting (average rate, cents/kWh)	15.916	15.916	15.916	15.916	15.916	-
Increase (cents/kWh)	0.006	1.400	1.911	2.492	3.549	-
Increase (%)	0.04%	8.80%	12.01%	15.66%	22.30%	4.11%
Average Impact ($ / month)	$0.05	$11.29	$15.23	$19.62	$27.59	-

Notes: 1/ Average current rates are 2015 estimates. These estimates are based on 2010 base rates from Minnesota Power's last rate case (E-015/GR-09-1151) with 2015 estimated cost recovery rider rates and estimated 2015 FPE and CPA factor added. CPA factor is not applied to Large Power Class.

Table 5: Estimated Average Rate Impacts of Early Small Coal Exit Relative to 2015 Projected Base Rates

Rate Class Impacts \1	2015	2016	2017	2018	2019	Compounded Annual Increase
Residential (average rate, cents/kWh)	10.238	10.238	10.238	10.238	10.238	-
Increase (cents/kWh)	0.016	1.028	1.414	1.758	2.473	-
Increase (%)	0.16%	10.04%	13.81%	17.17%	24.15%	4.42%
Average Impact ($ / month)	$0.13	$8.37	$11.51	$14.36	$20.25	-
General Service (average rate, cents/kWh)	10.233	10.233	10.233	10.233	10.233	-
Increase (cents/kWh)	0.013	0.912	1.244	1.530	2.139	-
Increase (%)	0.12%	8.92%	12.16%	14.95%	20.90%	3.87%
Average Impact ($ / month)	$0.35	$25.84	$35.17	$43.36	$60.56	-
Large Light & Power (average rate, cents/kWh)	8.327	8.327	8.327	8.327	8.327	-
Increase (cents/kWh)	0.010	0.758	1.018	1.220	1.692	-
Increase (%)	0.12%	9.10%	12.22%	14.65%	20.32%	3.77%
Average Impact ($ / month)	$25	$2,059	$2,724	$3,339	$4,631	-
Large Power (average rate, cents/kWh)	5.995	5.995	5.995	5.995	5.995	-
Increase (cents/kWh)	0.007	0.643	0.811	0.950	1.298	-
Increase (%)	0.12%	10.73%	13.53%	15.85%	21.65%	4.00%
Average Impact ($ / month)	$3,697	$341,608	$384,949	$451,584	$618,731	-
Municipal Pumping (average rate, cents/kWh)	9.396	9.396	9.396	9.396	9.396	-
Increase (cents/kWh)	0.030	0.850	1.141	1.388	1.941	-
Increase (%)	0.32%	9.05%	12.14%	14.77%	20.65%	3.83%
Average Impact ($ / month)	$2.60	$74.70	$99.73	$120.69	$167.38	-
Lighting (average rate, cents/kWh)	15.916	15.916	15.916	15.916	15.916	-
Increase (cents/kWh)	0.010	1.372	1.908	2.440	3.470	-
Increase (%)	0.06%	8.62%	11.99%	15.33%	21.80%	4.02%
Average Impact ($ / month)	$0.08	$11.07	$15.21	$19.21	$26.97	-
Notes: 1/ Average current rates are 2015 estimates. These estimates are based on 2010 base rates from Minnesota Power's last rate case (E-015/GR-09-1151) with 2015 estimated cost recovery rider rates and estimated 2015 FPE and CPA factor added. CPA factor is not applied to Large Power Class.						

APPENDIX M: 2015 SOCIOECONOMIC IMPACT ANALYSIS

Small Coal Facilities – Discussion of Assumptions, Method, and Results

Background

As part of its 2015 Integrated Resource Plan ("2015 Plan or Plan"), Minnesota Power (or "Company") considered both power supply resource additions and retirements when making resource decisions for the planning period of 2015-2029. Minnesota Rules 7843.0400, Subp. 3(A) identifies that the socioeconomic impacts of power supply resource decisions be included as part of the overall evaluation and subsequent short and long-term action plans included in this resource plan.

For its 2015 Plan, the Company considered the potential and timing for additional small coal transition, including alternatives for shutdown of the Taconite Harbor Energy Center Units 1 and 2 ("THEC1&2") and Boswell Energy Center Units 1 and 2 ("BEC1&2"). These alternatives are being included, along with other supply and demand side resources, to identify the recommended short-term and long-term action plans contained in Sections V and VI of this Plan.

The purpose of this study is to analyze the potential regional economic impacts of the retirement and decommissioning of the small coal units located at Taconite Harbor Energy Center ("THEC") in Schroeder, Minn. and Boswell Energy Centers ("BEC") located in Cohasset, Minn. This study considered multiple scenarios for its remaining small coal facilities, as shown in Figure 1. For THEC, two distinct retirement paths were considered; a retirement in 2016, and a retirement in 2020. Based on the 2015 Plan evaluation, the study considered a single retirement path for BEC1&2 in 2019.

Figure 1: Small Coal Scenario Comparison Timeline

	2016	2017	2018	2019	2020	2021	2022	2023	2024
THEC - Scenario 1	Plant Close	Decommissioning		Post Decommission					
THEC - Scenario 2					Plant Close	Decommissioning		Post Decommission	
BEC - Scenario 3				Plant Close	Decommissioning		Post Decommission		

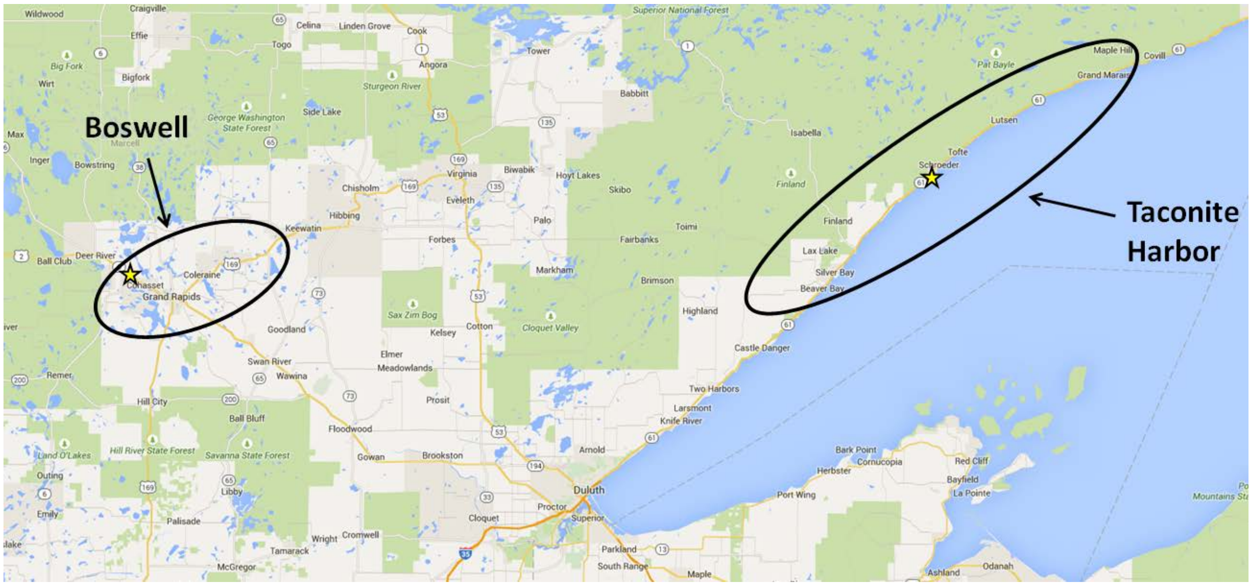
Description of Terms

Several concepts are important in understanding the study results. The following geographic distinctions and modeling concepts are mentioned throughout this document and defined below:

Region refers to the Minnesota Power planning region of 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).

Sub-Region refers to a small area in the immediate vicinity of the small coal facility examined. In the case of THEC, the sub-region is comprised of Schroeder, Tofte, Silver Bay, Beaver Bay, Lutsen, and Grand Marais. In the case of BEC, the sub-region is comprised of Grand Rapids, Cohasset, Coleraine, Bovey, Blackberry Township, and LaPrairie. The sub-regions are circled in Figure 2; plant locations are indicated by yellow stars.

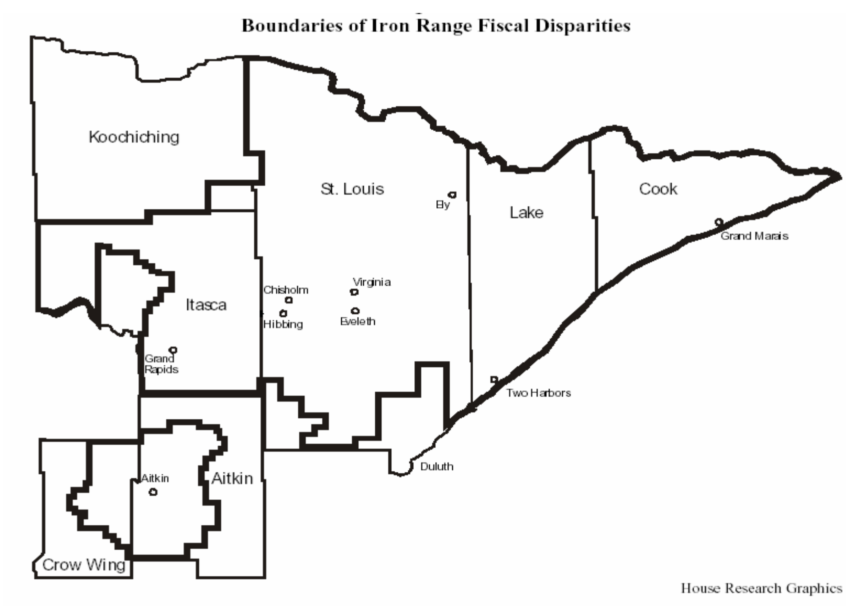
Figure 2: Sub-Region Identification



Baseline refers to the level of a particular variable being studied (e.g. employment, population, etc.) in a "status-quo", no plant retirement scenario. The impacts quantified in this study are differences from this baseline, or the difference in the variable being studied (e.g. employment, population, etc.) caused by plant retirement.

Fiscal Disparity refers to a tax-base sharing program among local government entities on the Iron Range of Minnesota. A portion of each government's Commercial/Industrial property tax base is pooled and then allocated based on local per capita tax base relative to the entire region. Figure 3 outlines the area included in the Iron Range fiscal disparity program.

Figure 3: Northeast Minnesota Fiscal Disparity Region



Summary of Results

Three different socioeconomic scenarios were evaluated to inform Minnesota Power's long-term resource planning decisions. Tables 1a and 1b display the key economic impacts caused by plant closure under each scenario at both the Sub-Regional and Regional levels. Note that this study assumes normal end-of-asset life would occur in 2026 for THEC1&2 and in 2024 for BEC1&2, as included in Section IV of this Plan. Therefore, this study's Cumulative and Net Present Value ("NPV") figures only include values within this timeframe (i.e. no loss of value due to facility closure was assessed beyond the assumed normal end-of-asset life).

It is evident from the study results that both the THEC1&2 and BEC1&2 facilities provide significant support to the local and regional economy. The annual impact of facility closure is shown by year in the tables below, with the percent impact of the respective geographic region (either Sub-Region or Region) shown in parenthesis. Key insights include:

- The 2020 closure option for THEC1&2 and BEC1&2 would impact the region by $144 million and $210 million, respectively. These estimations highlight the value of finding other refueling and/or remission opportunities for these facilities to protect the regional economy once the facilities can no longer economically utilize coal as a fuel source.
- The average employment impact of a THEC1&2 closure in 2020 is similar to a BEC1&2 closure in the same time period.
- THEC1&2 – an estimated 182 jobs are lost regionally, about 76 of those are estimated to be lost in the surrounding sub-region.
- BEC1&2– 143 jobs lost regionally, about 75 of those are lost in the sub-region.
- Overall population impacts are projected to be limited. Migration from either sub-region due to plant closure is not expected to exceed 2 percent of the population.
- Tax impacts: THEC vs. BEC.
- The estimated sub-regional revenue loss due to a THEC1&2 closure is mitigated by existing property tax exemptions.
- At the regional level, the estimated tax revenue loss due to either plant closure in 2020 ($18 million to $24 million) are close in magnitude as this is influenced more by employment and population.
- The 2020 closure of THEC1&2, identified in the Company's Preferred Plan (see Section IV) protects up to $130 million of Regional Product and $15 million of local government tax revenue compared to the earlier retirement option.

Table 1a: Sub-Regional Impacts by Scenario

	THEC - 2016 Closure				THEC - 2020 Closure				BEC - 2019 Closure			
Year	**GRP**	**Tax**	**Empl.**	**Pop.**	**GRP**	**Tax**	**Empl.**	**Pop.**	**GRP**	**Tax**	**Empl.**	**Pop.**
2020	-$5,240 0.9%	-$99 0.2%	-93 1.9%	-54 1.1%	-$2,839 0.5%	-$44 0.1%	-67 1.4%	-8 0.2%	-$4,664 0.3%	-$196 0.1%	-89 0.5%	-24 0.1%
2021	-$5,256 0.9%	-$101 0.2%	-44 1.0%	-63 1.2%	-$4,639 0.8%	-$85 0.2%	-88 1.8%	-22 0.4%	-$4,872 0.3%	-$323 0.2%	-96 0.5%	-38 0.1%
2022	-$5,275 0.9%	-$102 0.2%	-47 1.0%	-70 1.3%	-$4,687 0.8%	-$95 0.2%	-93 1.8%	-35 0.6%	-$5,339 0.3%	-$465 0.3%	-101 0.5%	-51 0.2%
2023	-$5,295 0.9%	-$104 0.2%	-49 1.0%	-77 1.5%	-$5,305 0.9%	-$103 0.2%	-97 1.9%	-46 0.9%	-$5,365 0.3%	-$470 0.3%	-100 0.5%	-62 0.3%
2024	-$5,317 0.9%	-$105 0.2%	-51 1.1%	-82 1.5%	-$5,330 0.9%	-$105 0.2%	-96 1.9%	-56 1.1%	-$5,390 0.3%	-$474 0.3%	-47 0.5%	-71 0.3%
2025	-$5,339 0.9%	-$107 0.2%	-52 1.1%	-88 1.7%	-$5,352 0.8%	-$107 0.2%	-46 1.0%	-65 1.2%				
2026	-$5,367 0.8%	-$108 0.2%	-54 1.1%	-92 1.8%	-$5,380 0.8%	-$108 0.2%	-48 1.0%	-72 1.4%				
Cumulative	-$54,130	-$1,030			-$33,532	-$648			-$28,291	-$2,031		
Net Present Value	-$50,337	-$957			-$30,871	-$596			-$26,219	-$1,879		

Note that Gross Regional Product ("GRP"), Local Tax and NPV are in thousands (2014$); Employment and Population figures are from a baseline, not cumulative.

Table 1b: Regional Impacts by Scenario

	THEC - 2016 Closure				THEC - 2020 Closure				BEC - 2019 Closure			
Year	**GRP**	**Tax**	**Empl.**	**Pop.**	**GRP**	**Tax**	**Empl.**	**Pop.**	**GRP**	**Tax**	**Empl.**	**Pop.**
2020	-$34 0.1%	-$4 0.2%	-200 0.1%	-170 0.0%	-$18 0.1%	-$2 0.1%	-110 0.0%	-29 0.0%	-$26 0.1%	-$3 0.1%	-121 0.0%	-49 0.0%
2021	-$34 0.1%	-$4 0.2%	-200 0.1%	-198 0.0%	-$32 0.1%	-$4 0.2%	-164 0.0%	-69 0.0%	-$27 0.1%	-$3 0.1%	-135 0.0%	-78 0.0%
2022	-$35 0.1%	-$4 0.2%	-199 0.1%	-222 0.0%	-$33 0.1%	-$4 0.2%	-173 0.1%	-103 0.0%	-$29 0.1%	-$4 0.1%	-162 0.1%	-108 0.0%
2023	-$35 0.1%	-$4 0.2%	-198 0.1%	-243 0.0%	-$35 0.1%	-$4 0.2%	-206 0.1%	-142 0.0%	-$29 0.1%	-$4 0.1%	-164 0.1%	-135 0.0%
2024	-$35 0.1%	-$4 0.2%	-197 0.1%	-261 0.0%	-$36 0.1%	-$4 0.2%	-208 0.1%	-174 0.0%	-$30 0.1%	-$4 0.1%	-165 0.1%	-158 0.0%
2025	-$35 0.1%	-$4 0.2%	-196 0.1%	-278 0.0%	-$36 0.1%	-$4 0.2%	-207 0.1%	-204 0.0%				
2026	-$36 0.1%	-$4 0.2%	-196 0.1%	-292 0.1%	-$37 0.1%	-$4 0.2%	-206 0.1%	-229 0.0%				
Cumulative	-$357	-$41			-$228	-$26			-$156	-$19		
Net Present Value	-$332	-$38			-$210	-$24			-$144	-$18		

Note that GRP, Local Tax, and NPV are in millions (2014$); Employment and Population figures are from a baseline, not cumulative.

Modeling Software

Minnesota Power simulated economic impacts using Regional Economic Models, Inc. ("REMI") software. This model assumes the region's economy progresses normally in a "status-quo" manner unless an impact is induced via adjusting specific variables (e.g. employment or government revenues). All economic impacts are simulated "in a vacuum," i.e. plant closure is estimated to affect the region in the same way regardless of other developments or large projects in the region that may mitigate the negative impacts of closure.

This study differs from the study included in the 2013 Integrated Resource Plan ("2013 Plan")[1] in its use of modeling software. The 2013 Plan study conducted an input-output analysis utilizing the IMPLAN (IMpact analysis for PLANning) model that estimates impacts on a specific study area to predict the effect of changes in one industry on the region's economy including its consumers, government, and suppliers. Key differences between the 2015 Plan study and the 2013 Plan study include:

1) Enhanced granularity – The 2015 Plan Study identifies socioeconomic impacts at the sub-regional level; i.e. the communities within a few miles of the power plants.
2) Improved compatibility with Minnesota Power Service Territory – the 2013 Plan Socioeconomic Study only included three counties: St. Louis, Lake, and Cook. The 2015 Plan Study defines the "Region" as the 13 county area that overlaps with Minnesota Power's service territory.
3) Expanded scope of the study to include several new economic indicators – local taxes, school enrollment, and net present value.
4) Incorporated a more extensive and detailed set of input variables for greater specificity in the outputs/impact estimates.
5) REMI has an inter-temporal capability, meaning it can capture the lasting impacts of a short-lived economic shock (such as a temporary lay-off/furlough); IMPLAN cannot identify lasting impacts because each year is simulated separately

Scenario Definitions

<u>Scenario 1: Shutting down and decommissioning Taconite Harbor Energy Center - 2016 Closure</u>

This scenario has three phases of economic effects: 1) Plant Shutdown, 2) Decommissioning, and 3) Post-Decommission.

1) The first phase, "Plant Shutdown," begins in 2016 at THEC. It involves the immediate impacts of plant closure; namely: employment reductions and cessation of payments to local vendors and utilities.

[1] Docket No. E015/RP-13-53.

Although there are 42 employees at THEC, the utility sector employment variable is only reduced by 22 in this first year to capture the potential impact of severance payments. Based on THEC's current workforce, potential severance payments represent the equivalent of roughly 20 full-time employees for one full year. This is also a conservative approach, as Minnesota Power will work to place affected employees in other positions within the Company.

Investments induced by the change in employment are input directly using detailed historical payment data from each plant. This is done to prevent the model from attempting to approximate the change in industry demand, sales, consumption, etc. This approach allows Minnesota Power to use quality estimates (payments to vendors) and avoid double-counting employment/investment impacts.

A three-year historical average (2012-2014) of actual payments is used as the assumed reduction from baseline for both variables. The detailed historical records allow the Company to distinguish between payments to businesses in the 'Sub-Region' and businesses throughout the wider Minnesota Power Region to calculate payment impacts at both geographical levels.

2) The second phase, "Decommissioning," begins in 2017. This phase consists of plant deconstruction (construction employment) and reduced property tax payments to local governments.

Deconstruction of THEC is estimated to require 19 full-time construction laborers (annualized) per-year over the two year decommissioning timeframe.[2] The regional simulation uses construction employment as the direct input variable with the assumption that many of these workers reside within the Minnesota Power region. The sub-regional simulation assumes that this labor is imported to the local area and so there is no adjustment to construction employment. Instead, inputs consist of the estimated impact of the 19 construction workers on local businesses (namely: hotels and restaurants) utilizing the General Services Administration's per-diem allowances for lodging and meals.

As the plant is deconstructed, the property value and corresponding property tax payments to local government are reduced. This study assumes a linear decommission schedule to calculate the reduction in government revenue: the property's value is reduced by half after the first year and fully reduced after the second year. Actual (historical) tax rates are applied to the year-end plant value to determine the government revenue reduction for the upcoming year; hence the lag in the revenue impact. This study makes the distinction between payments to local government authorities (city, school board) and regional authorities (county, fiscal disparity region) to simulate the impacts at the sub-regional and the Minnesota Power regional levels.

3) The third phase, "Post-Decommission," is a static timeframe (beginning in 2019); there are no new impacts simulated in this timeframe; the temporary stimulus from decommissioning activities (i.e. construction employment) has ended. Government revenue, vendor and utility payments, and plant employment are all held at their below-baseline levels to simulate the continued impacts of the shocks.

[2] Values taken from Burns & McDonnell's Site Decommissioning Study used in Minnesota Power's 2013 Plan filing as the 2015 Plan Study was not complete at the time of this simulation.

Scenario 2: Shutting down and decommissioning Taconite Harbor Energy Center - 2020 Closure

This scenario has three phases of economic effects: 1) Plant Shutdown, 2) Decommissioning, and 3) Post-Decommission.

The same assumptions used in Scenario 1 are simply shifted out four years. This puts “Plant Shutdown” in 2020, “Decommissioning” in 2021, and “Post-Decommission” in 2023.

Scenario 3: Shutting down and decommissioning Boswell Energy Center Units 1 and 2 – 2019 Closure

This scenario has three phases of economic effects: 1) Plant Shutdown, 2) Decommissioning, and 3) Post-Decommission.

1) The first phase, “Plant Shutdown,” begins in 2019 at BEC1&2. It involves the immediate impacts of plant closure; namely: employment reductions and cessation of payments to local vendors and utilities.

Although there are 35 employees at BEC1&2, the utility sector employment variable is only reduced by 19 in this first year to capture the potential impact of severance payments. Based on Boswell’s current workforce, potential severance payments represent the equivalent of roughly 16 full-time employees for one full year. This is also a conservative approach, as Minnesota Power will work to place affected employees in other positions within the Company.

The investment induced by the change in employment is nullified to prevent the model from attempting to approximate the change in industry demand, sales, consumption, etc. These are input directly using detailed historical payment data from each plant. This approach allows Minnesota Power to use quality estimates (payments to vendors) and avoid double-counting employment/investment impacts.

The assumed reduction in payments to local vendors and utilities are introduced to the model as a reduction in “Investment Spending” and “Industry Sales – Utilities” (respectively). For simplicity, payments to vendors are aggregated into a single variable (Investment Spending) instead of making small, industry-specific adjustments.

A three-year historical average (2012-2014) of actual payments is used as the assumed reduction from baseline for both variables. The detailed historical records allow Minnesota Power to distinguish between payments to businesses in the ‘Sub-Region’ and businesses throughout the wider Minnesota Power Region to calculate payment impacts at both geographical levels.

2) The second phase, “Decommissioning,” begins in 2020. This phase consists of plant deconstruction (construction employment) and reduced property tax payments to local governments.

Deconstruction of BEC1&2 is estimated to require 10 full-time construction laborers (annualized) per-year over the two year decommissioning timeframe. The regional simulation uses construction employment as the direct input variable with the assumption that many of these workers reside within the Minnesota Power region. The sub-regional simulation assumes that this labor is imported to the local area and so there is no adjustment to construction employment. Instead, inputs consist of the estimated impact of the 10 construction workers on local businesses (namely: hotels and restaurants) utilizing the General Services Administration's per-diem allowances for lodging and meals.

As the plant is deconstructed, the property value and corresponding property tax payments to local government are reduced. This study assumes a linear decommission schedule to calculate the reduction in government revenue: the property's value is reduced by half after the first year and fully reduced after the second year. Actual (historical) tax rates are applied to the year-end plant value to determine the government revenue reduction for the upcoming year; hence the lag in the revenue impact. This study makes the distinction between payments to local government authorities (city, school board) and regional authorities (county, fiscal disparity region) to simulate the impacts at the sub-regional and the Minnesota Power regional levels.

Due to the fact that only two of the four units at Boswell would be decommissioned as part of this study, Minnesota Power had to get at tax and property value figures by unit. Tax information was straight-forward and was available from the Company's Accounting Department. Property Value numbers were calculated based on the percent of taxable structures that Units 1 and 2 represented over the past five years (also based off of information provided by the Accounting Department).This allowed Minnesota Power to reasonably estimate the impacts of closing only Units 1 and 2.

3) The third phase, "Post-Decommission," is a static timeframe (beginning in 2022); there are no new impacts simulated in this timeframe; the temporary stimulus from decommissioning activates (i.e. construction employment) has ended. Government revenue, vendor and utility payments, and plant employment are all held at their below-baseline levels to simulate the continued impacts of the shocks.

Full Results

Complete results for both Sub-Regional and Regional can be found below listed by scenario. Please note that column dollar references change depending on the variable being discussed. For example, Gross Regional Product at the Sub-Regional level is displayed in thousands, while the same variable at the Minnesota Power Regional level is in millions. Also note that the following tables include two additional impact metrics vs. the summary tables 1a and 1b: Annual Migration and School Enrollment.

Scenario 1 – Complete Results

THEC - 2016 Closure **Sub-Regional Impacts**

Year	GRP	Tax	Empl.	Pop.	Annual Migration	School Enroll.
2020	-$5,240 0.9%	-$99 0.2%	-93 1.9%	-54 1.1%	-10 0.2%	-11 1.7%
2021	-$5,256 0.9%	-$101 0.2%	-44 1.0%	-63 1.2%	-9 0.2%	-13 1.8%
2022	-$5,275 0.9%	-$102 0.2%	-47 1.0%	-70 1.3%	-7 0.2%	-14 2.1%
2023	-$5,295 0.9%	-$104 0.2%	-49 1.0%	-77 1.5%	-6 0.1%	-16 2.4%
2024	-$5,317 0.9%	-$105 0.2%	-51 1.1%	-82 1.5%	-6 0.2%	-17 2.4%
2025	-$5,339 0.9%	-$107 0.2%	-52 1.1%	-88 1.7%	-5 0.1%	-18 2.8%
2026	-$5,367 0.8%	-$108 0.2%	-54 1.1%	-92 1.8%	-4 0.1%	-19 2.9%
Cumulative	-$54,130	-$1,030			-92	

Note that GRP and Local Tax are in thousands (2014$); all figures (except GRP, Local Tax, & Annual Migration) are from a baseline, not cumulative.

THEC - 2016 Closure **Regional Impacts**

Year	GRP	Tax	Empl.	Pop.	Annual Migration	School Enroll.
2020	-$34 0.1%	-$4 0.2%	-200 0.1%	-170 0.0%	-29 0.0%	-34 0.0%
2021	-$34 0.1%	-$4 0.2%	-200 0.1%	-198 0.0%	-24 0.0%	-40 0.0%
2022	-$35 0.1%	-$4 0.2%	-199 0.1%	-222 0.0%	-20 0.0%	-46 0.0%
2023	-$35 0.1%	-$4 0.2%	-198 0.1%	-243 0.0%	-16 0.0%	-52 0.1%
2024	-$35 0.1%	-$4 0.2%	-197 0.1%	-261 0.0%	-13 0.0%	-57 0.1%
2025	-$35 0.1%	-$4 0.2%	-196 0.1%	-278 0.0%	-11 0.0%	-61 0.1%
2026	-$36 0.1%	-$4 0.2%	-196 0.1%	-292 0.1%	-9 0.0%	-66 0.1%
Cumulative	-$357	-$41			-254	

Note that GRP and Local Tax are in millions (2014$); all figures (except GRP, Local Tax, & Annual Migration) are from a baseline, not cumulative.

Scenario 2 – Complete Results

THEC - 2020 Closure **Sub-Regional Impacts**

Year	GRP	Tax	Empl.	Pop.	Annual Migration	School Enroll.
2020	-$2,839 0.5%	-$44 0.1%	-67 1.4%	-8 0.2%	-8 0.2%	-2 0.3%
2021	-$4,639 0.8%	-$85 0.2%	-88 1.8%	-22 0.4%	-14 0.2%	-5 0.6%
2022	-$4,687 0.8%	-$95 0.2%	-93 1.8%	-35 0.6%	-12 0.2%	-7 1.0%
2023	-$5,305 0.9%	-$103 0.2%	-97 1.9%	-46 0.9%	-11 0.2%	-9 1.4%
2024	-$5,330 0.9%	-$105 0.2%	-96 1.9%	-56 1.1%	-10 0.2%	-11 1.7%
2025	-$5,352 0.8%	-$107 0.2%	-46 1.0%	-65 1.2%	-9 0.2%	-13 2.0%
2026	-$5,380 0.8%	-$108 0.2%	-48 1.0%	-72 1.4%	-7 0.1%	-15 2.3%
Cumulative	-$33,532	-$648			-72	

Note that GRP and Local Tax are in thousands (2014$); all figures (except GRP, Local Tax, & Annual Migration) are from a baseline, not cumulative.

THEC - 2020 Closure **Regional Impacts**

Year	GRP	Tax	Empl.	Pop.	Annual Migration	School Enroll.
2020	-$18 0.1%	-$2 0.1%	-110 0.0%	-29 0.0%	-29 0.0%	-6 0.0%
2021	-$32 0.1%	-$4 0.2%	-164 0.0%	-69 0.0%	-38 0.0%	-14 0.0%
2022	-$33 0.1%	-$4 0.2%	-173 0.1%	-103 0.0%	-33 0.0%	-21 0.0%
2023	-$35 0.1%	-$4 0.2%	-206 0.1%	-142 0.0%	-35 0.0%	-28 0.0%
2024	-$36 0.1%	-$4 0.2%	-208 0.1%	-174 0.0%	-30 0.0%	-35 0.0%
2025	-$36 0.1%	-$4 0.2%	-207 0.1%	-204 0.0%	-25 0.0%	-42 0.0%
2026	-$37 0.1%	-$4 0.2%	-206 0.1%	-229 0.0%	-21 0.0%	-48 0.0%
Cumulative	-$228	-$26			-211	

Note that GRP and Local Tax are in millions (2014$); all figures (except GRP, Local Tax, & Annual Migration) are from a baseline, not cumulative.

Scenario 3 – Complete Results

BEC - 2019 Closure **Sub-Regional Impacts**

Year	GRP	Tax	Empl.	Pop.	Annual Migration	School Enroll.
2020	-$4,664 0.3%	-$196 0.1%	-89 0.5%	-24 0.1%	-15 0.1%	-5 0.1%
2021	-$4,872 0.3%	-$323 0.2%	-96 0.5%	-38 0.1%	-14 0.1%	-8 0.1%
2022	-$5,339 0.3%	-$465 0.3%	-101 0.5%	-51 0.2%	-13 0.1%	-10 0.2%
2023	-$5,365 0.3%	-$470 0.3%	-100 0.5%	-62 0.3%	-11 0.1%	-12 0.2%
2024	-$5,390 0.3%	-$474 0.3%	-47 0.5%	-71 0.3%	-10 0.1%	-14 0.2%
2025						
2026						
Cumulative	-$28,291	-$2,031			-71	

Note that GRP and Local Tax are in thousands (2014$); all figures (except GRP, Local Tax, & Annual Migration) are from a baseline, not cumulative.

BEC - 2019 Closure

Regional Impacts

Year	GRP	Tax	Empl.	Pop.	Annual Migration	School Enroll.
2020	-$26 0.1%	-$3 0.1%	-121 0.0%	-49 0.0%	-29 0.0%	-10 0.0%
2021	-$27 0.1%	-$3 0.1%	-135 0.0%	-78 0.0%	-27 0.0%	-16 0.0%
2022	-$29 0.1%	-$4 0.1%	-162 0.1%	-108 0.0%	-29 0.0%	-22 0.0%
2023	-$29 0.1%	-$4 0.1%	-164 0.1%	-135 0.0%	-24 0.0%	-27 0.0%
2024	-$30 0.1%	-$4 0.1%	-165 0.1%	-158 0.0%	-20 0.0%	-32 0.0%
2025						
2026						
Cumulative	-$156	-$19			-148	

Note that GRP and Local Tax are in millions (2014$); all figures (except GRP, Local Tax, & Annual Migration) are from a baseline, not cumulative.

Methodology and Conclusions

The 2015 Plan Socioeconomic Analysis was a venture into modeling highly-localized economic impacts. Identifying the estimated economic impact of plant retirement on sub-regions can add significant value and insight for the communities located in close proximity to the facilities examined.

The process of sub-regional modeling involves detailed examination of both city and county demographics surrounding each facility and careful consideration of how plant closure would affect the immediate community. The REMI software was not specifically designed to model such a small geographic area and Minnesota Power had to interpret or adjust the raw REMI model outputs for consistency with local demographics. This necessitates some subjectivity on the part of the analyst, which could be viewed as a weakness of this approach, but every effort was made to maintain the study's internal consistency. The incorporation of the sub-regional results strengthened this analysis, and the impacts are able to be assessed at a more granular level than other impact studies used in the past – internally or through third party consultants.

As these results indicate, the closure of a small coal generation facility in Minnesota Power's service territory has substantial socioeconomic impacts on the host communities and surrounding area. The analyses provided insights that are informative to the resource planning process as well as to policymakers, state regulators, and community leaders. Study results will help inform response efforts, working with local community leaders and elected officials to identify new re-use and development opportunities.

APPENDIX N: MINNESOTA POWER PLAN CROSS REFERENCE INDEX

Appendix N provides a cross reference of filing requirements contained in Minnesota Statues and Rules applicable to the filing and content of resource plans and the plan sections and/or appendices that contain information to fulfill a requirement. In addition, this section identifies those items the Commission included in its Order dated November 12, 2013, in Docket No. E015/RP-13-53*.* The Table contains a listing of each Order point and its requirement, and references the appropriate sections and/or appendices within this filing to locate the information.

Statute or Rule	Requirement	Reference Section
7843.0300, Subp. 3	Completeness of filing. The resource plan filing must contain the information required by part 7843.0400, unless an exemption has been granted under subpart 4.	Refer to contents of resource plan filing points listed below.
7843.0300, Subp. 5	Copies of filings. Submit 15 copies of the plan to the Commission, and to the Minnesota Department of Commerce, the Residential and Small Business Utilities Division of the Office of the Attorney General, the Minnesota Environmental Quality Board and member agencies, and other interested persons or parties who request copies.	See Service List inside front cover. This requirement is met via e-Filing with the Minnesota Public Utilities Commission and Department of Commerce.
7843.0400, Subp. 1	Advance forecasts. Include a copy of the latest Advance Forecast Report for the DOC and MEQB.	Appendix A
7843.0400, Subp. 3(A)	Supporting information. Include a list of resource options considered. Utility must include an evaluation of the option's availability, reliability, cost, socioeconomic effects, and environmental effects.	Section IV, Appendix B Appendix D, Appendix J and Appendix M
7843.0400, Subp. 3(B)	Supporting information. Description of the process and analytical techniques used in developing the plan.	Section IV, Appendix J and Appendix K
7843.0400, Subp. 3(C)	Supporting information. Include a five-year action plan, with a schedule of key activities and regulatory filings.	Sections II and V
7843.0400, Subp. 3(D)	Supporting information. Include a narrative and quantitative discussion of why the plan would be in the public interest, considering the factors listed in part 7843.0500, subp. 3.	Section IV, Appendix I and Appendix L

Statute or Rule	Requirement	Reference Section
7843.0400, Subp. 4	Nontechnical summary. Include a non-technical summary not to exceed 25 pages in length that describes the utility's resource needs, the resource plan created to meet those needs, the process and analytical techniques used, activities required over the next five years to implement, and the likely effect of plan implementation on electric rates and bills.	Section II
216B.2422, Subd. 2	Resource plan filing and approval. Include least-cost plan for meeting 50 percent and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources.	Section IV and Appendix K
216B.2422, Subd. 2a	Historical data and advance forecast. Each utility required to file a resource plan under this section shall include in the filing all applicable annual information required by section 216C.17, subdivision 2, and the rules adopted under that section. To the extent that a utility complies with this subdivision, it is not required to file annual advance forecasts with the department under section 216C.17, subdivision 2.	Appendix A
216B.2422, Subd. 3(a)	Environmental costs. A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.	Section IV and Appendix I
216B.2422, Subd. 4	Preference for renewable energy facility. The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest.	Not Applicable
216B.2422, Subd. 6	Consolidation of resource planning and certificate of need. Utility should state if it intends to site or construct a large energy facility.	Not Applicable

Statute or Rule	Requirement	Reference Section
216B.1691, Subd. 2(e)	Rate impact of standard compliance; report. The utility must submit as part of each integrated resource plan or plan modification filed under section 215B.2422 a report containing an estimation of the rate impact of activities necessary to comply with this section.	Section II, Section IV and Appendix I
216B.1691, Subd. 3	Utility plans filed with commission. Report on efforts toward meeting renewable energy objective/renewable energy standard.	Appendix H
216B.1612, Subd. 5(b)	Priority for C-BED projects. Consider Community-Based Energy Development projects.	Appendix H
216B.2426	Opportunities for distributed generation. The commission shall ensure that opportunities for the installation of distributed generation, as that term is defined in section 216B.169, subdivision 1, paragraph (c), are considered in any proceeding under section 216B.2422, 216B.2425, or 216B.243.	Appendices B, Appendix C, Appendix G and Section IV

Nov. 12, 2013 Order Point	Requirement	Reference Section
11.	The Commission approves energy savings goal of 1.87 percent of Minnesota Power's retail sales by its next resource plan filing.	Appendix B
12.a.	Identify the amount of energy savings embedded in each year of its load forecast, in terms of total savings (kWh) and as a percentage of non-CIP-exempt retail sales.	Appendix B and Appendix K
12.b.	Identify the amount of system-wide energy savings, including aggregate data for CIP-exempt customers, embedded in each year of its load forecast.	Appendix B and Appendix K
12.c.	Evaluate additional conservation scenarios for its CIP-exempt and non-CIP-exempt customers, that would achieve greater energy savings beyond those in the base case.	Appendix B and Appendix K
13.	In its next resource plan filing, Minnesota Power shall include the midpoint of the Commission's approved CO_2 range in its base case assumptions.	Section IV, Appendix J and Appendix K
14.	In its next resource plan filing, Minnesota Power shall include a full analysis of the effects of retiring or repowering the Taconite 1 and 2 plants, including transmission and distribution effects.	Section IV, Appendix F and Appendix K
15.	In its next resource plan filing, Minnesota Power shall provide a summary of its compliance with new statutory measures and how the legislative changes impact its resource plan.	Section II

APPENDIX O: LIST OF ACRONYMS, TERMS AND DESCRIPTION

ACRONYM	DEFINITION
2013 Plan	Minnesota Power's 2013 Integrated Resource Plan
2015 Plan	Minnesota Power's 2015 Integrated Resource Plan
AC	Alternate Current
ACI	Activated Carbon Injection
AEIC	Association of Edison Illuminating Companies
AFR	Annual Electric Utility Forecast Report
AFR2014	2014 Annual Electric Utility Forecast Report
AFR2015	2015 Annual Electric Utility Forecast Report
AMI	Advanced Metering Infrastructure
APWR	Advanced Pressurized Water Reactor
ARCOS	Automation of Reports and Consolidation Orders System
AREA	Arrowhead Regional Emissions Abatement
ARRA	American Recovery and Reinvestment Act
ASAI	Average System Availability Index
ASHPs	Air Source Heat Pumps
ASU	Air Separation Unit
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Base Case	Foundation for Minnesota Power's 2015 Resource Plan
BEC	Boswell Energy Center
BEC1&2	Boswell Energy Center Units 1 & 2
BEC3	Boswell Energy Center 3
BEC4	Boswell Energy Center 4
BEC4 Project	BEC4 Environmental Retrofit Project
BES	Bulk Electric System
Biennial Report	Minnesota Biennial Transmission Projects Report
Bison	Bison Wind Energy Center
Bison 1	Bison 1 Wind Facility
Bison 2	Bison 2 Wind Facility
Bison 3	Bison 3 Wind Facility
Bison 4	Bison 4 Wind Facility
Boiler MACT	Maximum-Achievable Control Technology
Brayton Cycle	Gas Turbine Cycle
BSER	Best System of Emission Reduction
BTA	Bets Technology Available
BTU	British Thermal Units
C&I or C/I	Small Commercial and Industrial Customer Classes
CAC	Central Air Conditioning

ACRONYM	DEFINITION
CAES	Compressed Air Energy Storage
CAIDI	Customer Average Interruption Duration Index
C-BED	Community-Based Energy Development
CBSP	Consumer Behavior Study Plan
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals Regulation
CCS	Capture and Sequestration
CD	Consent Decree
CDS	Circulating Dry Scrubber
CEC	Cloquet Energy Center
CID	Certified Interruptible Demand
CIP	Conservation Improvement Program
CIS	Customer Information System
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent Greenhouse Gases
Commission	Minnesota Public Utilities Commission
Company	Minnesota Power
CPA	Conservation Program Adjustment
CPP	Clean Power Plan
CPV	Concentrated PV
CSAPR	State Air Pollution Rule
CSE	Cost of Saved Energy
CT	Combustion Turbine
D-02	Power Supply Production Transmission Allocators for 2016 to 2019
DC	Direct Current
DC Line	High Voltage Direct Current Transmission Line connecting Center, N.D. and Hermantown, Minn.
DCS	Distributed Control Systems
Department	Department of Commerce – Division of Energy Resources
DG	Distributed Generation
DOE	U.S. Department of Energy
D-Prime	End of a current ash storage facilities useful file
DSM	Demand Side Management
EAD/CDS	Enhanced All-Dry
ECMs	Electronically Commutated Motors
EDC	Energy Design Conference and Expo
EEI	Edison Electric Institute
EIS	Environmental Impact Statement
ELG	Effluent Limitation Guidelines
EMS	Emergency Management System

ACRONYM	DEFINITION
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EQB	Environmental Quality Board
ESP	Electrostatic Precipitator
FCA	Facilities Construction Agreement
FERC	Federal Energy Regulatory Commission
FFA	General Electric's Field Force Automation
FGD	Flue Gas Desulfurization
FLISR	Fault Location, Isolation and Service Restoration System
FPE	Fuel and Purchased Energy
FPL	Florida Power and Light
GE	General Electric
GHG	Greenhouse Gas Regulation
GNTL	Great Northern Transmission Line
GRE	Great River Energy Cooperative
GRP	Gross Regional Product
GSHPs	Ground Source Heat Pumps
HAP	Hazardous Air Pollutant
HCI	Hydrochloric Acid
HPSA	Hitachi Power Systems America
HREC	Hibbard Renewable Energy Center
HRSG	Heat Recovery Steam Generator
HVDC	High Voltage Direct Current
HW	Hot Water Heater
IEE&C	Integrated Energy Education and Communications
IGCC	Integrated Gasification Combined Cycle
Iron Range	A range of low hills containing iron-ore in northeastern Minnesota. It extends 110 miles from Babbitt (northeast) to Grand Rapids (southwest)
IVR	Interactive Voice Response System
Keetac	Keewatin Taconite
Kv	Kilovolt
L&C	Load and Capability
Laskin	Laskin Energy Center
LBNL	Lawrence Berkeley National Laboratory
LEA	Laurentian Energy Authority
LEC	Laskin Energy Center
LEC1&2	Laskin Energy Center, Units 1 and 2
LED	Light Emitting Diode
LL&P	Large Light & Power

ACRONYM	DEFINITION
LLP Schedule	Minnesota Power’s Large Light and Power Service Schedule
LNB/OFA	LNB with Over Fire Air
LNG	Liquefied Natural Gas
LOLE	MISO Loss of Load expectation Report
LP	Low Pressure Turbines
Magnetation Process™	Magnetation Mineral Reclamation process
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Rule
MDG	Million Gallons Per Day
MDM	Meter Data Management System
MEA	Monoethylamine Process
MERA	Minnesota Mercury Emission Reduction Act of 2006
MERP	Minnesota Metro Emissions Reduction Project
MHEB	Manitoba Hydro-Electric Board
Minnkota	Minnkota Power Cooperative
MISO	Midcontinent Independent System Operator
MPCA	Minnesota Pollution Control Agency
M-RETS	Midwest Renewable Energy Tracking
MTEP	Midcontinent Transmission Expansion Planning
MTEP14	Midcontinent Transmission Expansion Plan 2014
MTTF	Mean Time to Failure
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standard
NaS	Sodium Sulfur
NERC	North American Electric Reliability Corporation
NGEA	Minnesota Next Generation Energy Act of 2007
NO_x	Oxides of Nitrogen
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NRRI	University of Minnesota Natural Resources Research Institute
NSPS	New Source Performance Standards
O&M	Operating and Maintenance
OEM	Original Equipment Manufacturers
OFA	Over Fire Air
OMS	Outage Management System
OPG	Ontario Power Generation, Inc.
PAC	Powdered Activated Carbon
Pb	Lead
PC	Pulverized Coal

ACRONYM	DEFINITION
PJFF	Pulse Jet Fabric Filter
Plan	Minnesota Power’s 2015 Integrated Resource Plan
Plant 1	Magnetation Plant South of Keewatin
Plant 2	Magnetation Plant near Taconite, Minnesota
Plant 3	Magnetation Plant South of Chisholm, Minnesota
PM	Particulate Matter
PM control	Fabric Filter for Particulate Matter
$PM_{2.5}$	Average Fine Particulate
PPA	Power Purchase Agreement
PRB	Powder River Basin
Preferred Plan	Minnesota Power’s Preferred Resource Plan
Primary Standards	NAAQS to protect human health
PRM	Planning Reserve Margin
PSC	Permanent split Capacitor
PV	Photovoltaics
R&D	Research and Development
Rankine Cycle	Steam Turbine Cycle
Rapids	Rapids Energy Center
RCRA	Resource Conservation and Recovery Act
RE Program	Community-focused Small Scale Renewable Energy Program
RE/DG	Renewable Energy/Distributed Generation Technologies
REC or Rapids	Rapids Energy Center
RECs	Renewable Energy Credits
Regional Haze	Clean Air Visibility Rule
RES	Renewable Energy Standard
RFP	Request for Proposals
RICE	Simple Cycle Reciprocating Internal Combustion Engine
ROFA	Mobotec Rotating Opposed Fired Air
RPS	Renewable Portfolio Standard
RRR Adjustment	Minnesota Power’s Renewable Resources Rider
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SC Aero	Simple Cycle Aero Derivative
SC GT	Simple Cycle Gas Turbine – Combustion Turbine
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
Secondary Standards	NAAQS to protect public welfare
SES	Solar Energy Standard
SGIG	Smart Grid Investment Grant
SIP	State Implementation Plan
SMR	Small Modular Reactor

ACRONYM	DEFINITION
SNCR	Selective Non-Catalytic Reduction
SNG	Synthetic Natural Gas
SO_2	Sulfur Dioxides
Square Butte	Square Butte Cooperative
S-RECs	Solar Renewable Energy Credits
SSR	System Support Resource
Steam Effluent/ELG	Water Effluent Regulation
SWLP	Superior Water Light & Power
Tailoring Rule	Greenhouse Gas Tailoring rule
TCR	Transmission Cost Recovery Rider
TCR Adjustment	Transmission Cost Recovery Adjustment
THEC	Taconite Harbor Energy Center
THEC1&2	Taconite Harbor Energy Center Units 1 and 2
THEC3	Taconite Harbor Energy Center Unit 3
TOD	Time-of-Day Rate with Critical Peak Pricing Pilot
TOU	Time of Use Rate with Critical Peak Component
TPL	Transmission Planning
TVM	Telemetric Line Voltage and Outage Monitors
UCAP	Unforced Capacity
UMD	University of Minnesota, Duluth
UPS	Uninterruptible Power Supplies
USS	United States Steel
VEE	Validation, Editing and Estimating
WACC	Weighted Average Cost of Capital
WFGD	Wet Flue Gas Desulphurization
WLSSD	Western Lake Superior Sanitary District
WPPI	Wisconsin Public Power, Inc.
WTG	Wind Turbines
Young 2	Square Butte's Milton R. Young 2 lignite coal generating station