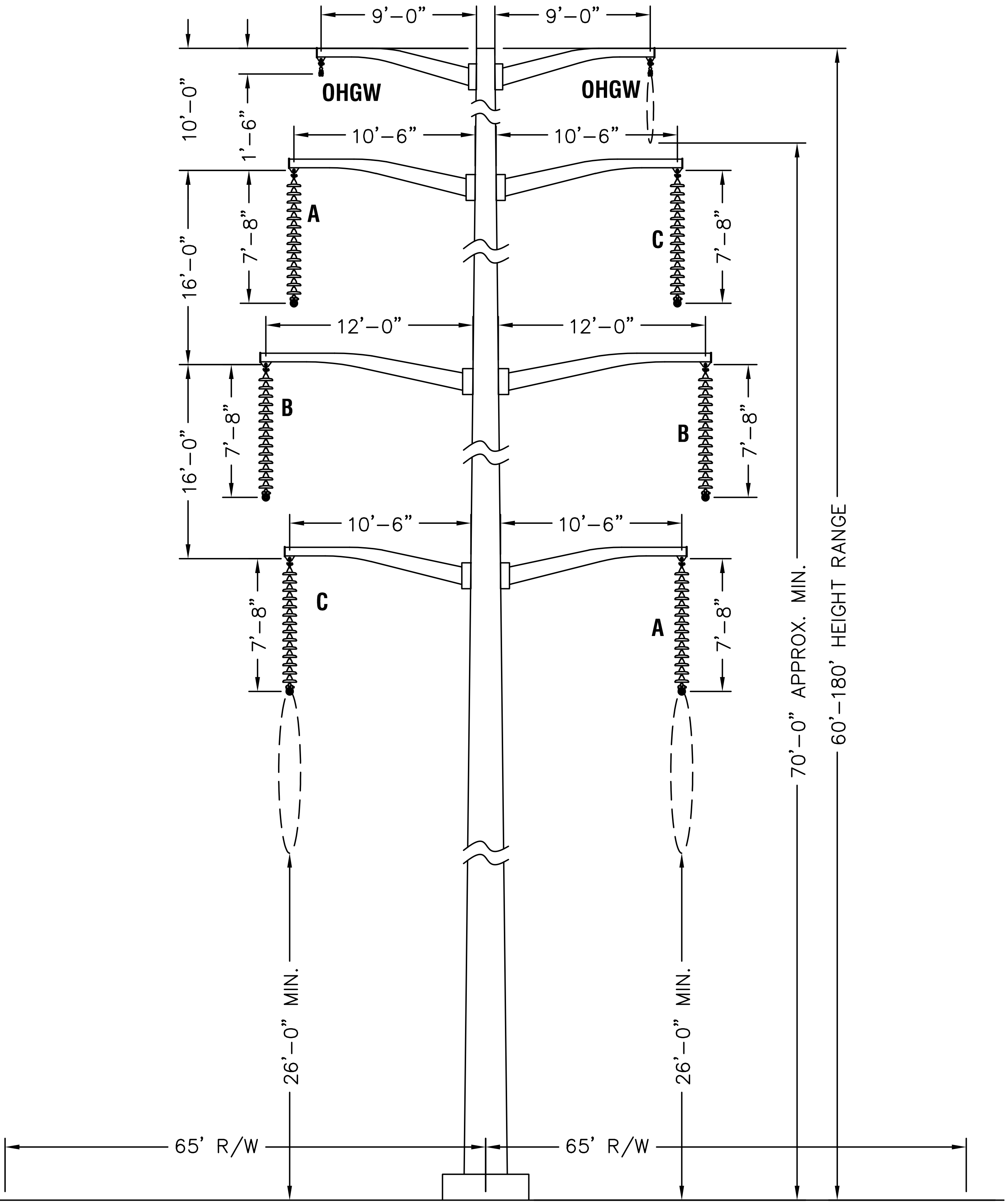
Appendix M

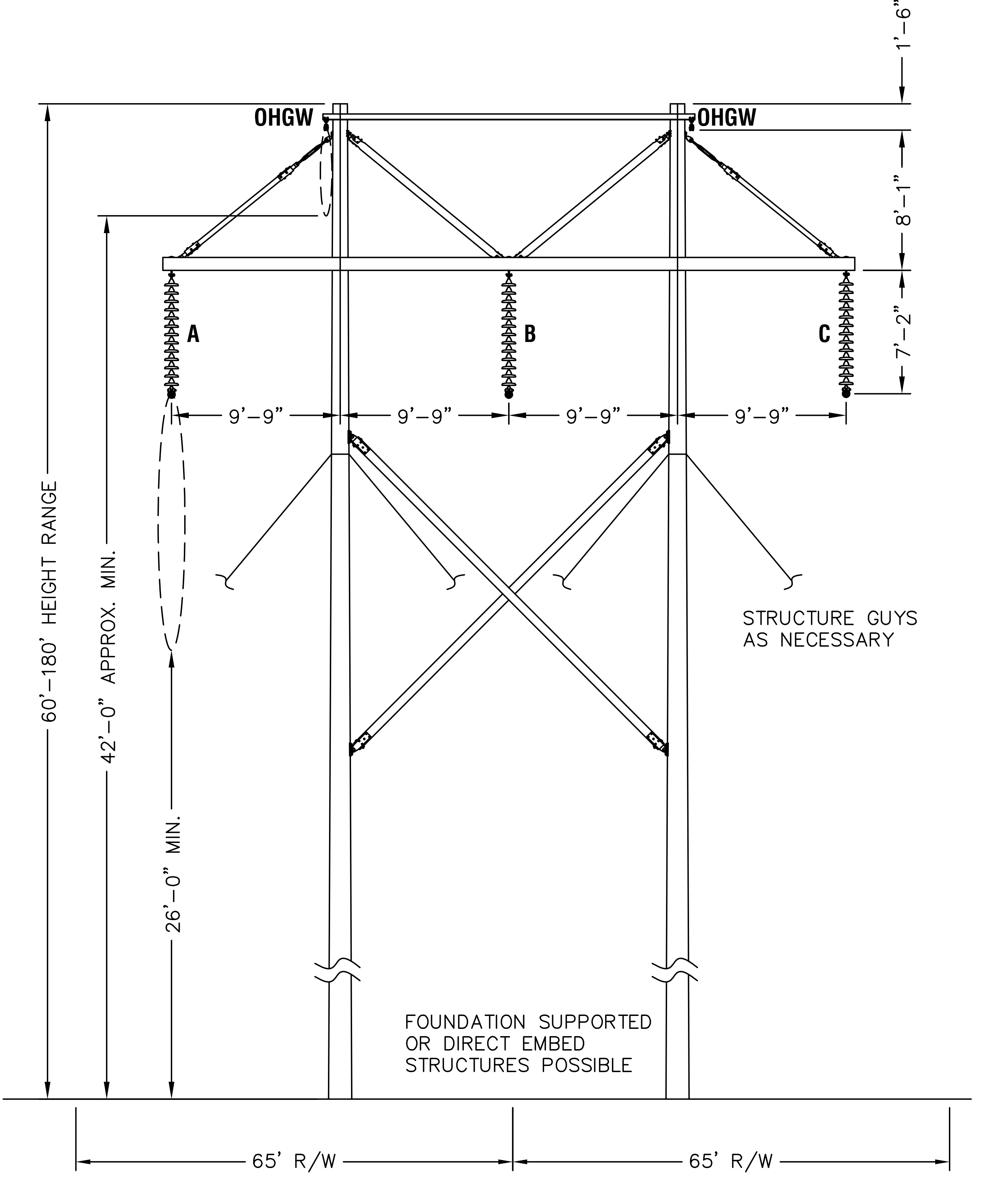
Technical Drawings of Proposed Structures



TYPICAL STRUCTURE NOTES:

1. DRAWINGS ARE CONCEPTUAL AND NOT TO SCALE.
2. GROUND CLEARANCE DIMENSIONS TO CONDUCTORS REPRESENT TYPICAL VALUES FOR NEW DESIGN TARGETS FOR COMMON GROUND CLEARANCE. DESIGN CLEARANCE VALUES WILL VARY FOR SPECIFIC LAND USES AND FEATURES. ACTUAL CLEARANCE VALUES WILL VARY.
3. TYPICAL VERTICAL DIMENSIONS FROM STRUCTURE TOP TO CONDUCTOR AND OVERHEAD GROUND WIRE POSITIONS INDICATED SHOULD BE CONSIDERED NOMINAL, BUT COULD VARY BASED ON SPECIFIC WIRES AND HARDWARE USED AND AS NECESSARY FOR STRUCTURE SPECIFIC FRAMING.
4. TYPICAL HEIGHT RANGES INDICATE THE AVERAGE EXPECTED HEIGHT OF THE MAJORITY OF STRUCTURES BASED ON SIMILAR FACILITIES. ACTUAL STRUCTURE HEIGHT IS A FUNCTION OF SPAN PROPERTIES AND TOPOGRAPHY AND MAY VARY OUTSIDE TYPICAL VALUES AS NECESSARY.
5. TYPICAL STRUCTURES PROVIDED ARE TANGENT TYPE STRUCTURES WHICH MAY NOT BE THE MOST COMMON TYPE OF STRUCTURE ON A GIVEN LINE FOR THIS PROJECT. OTHER STRUCTURE CONFIGURATIONS FOR DEADENDS, ANGLES, CROSSINGS, AND TRANSPOSITIONS WILL ALSO BE NECESSARY.

TYPICAL 230kV SINGLE POLE



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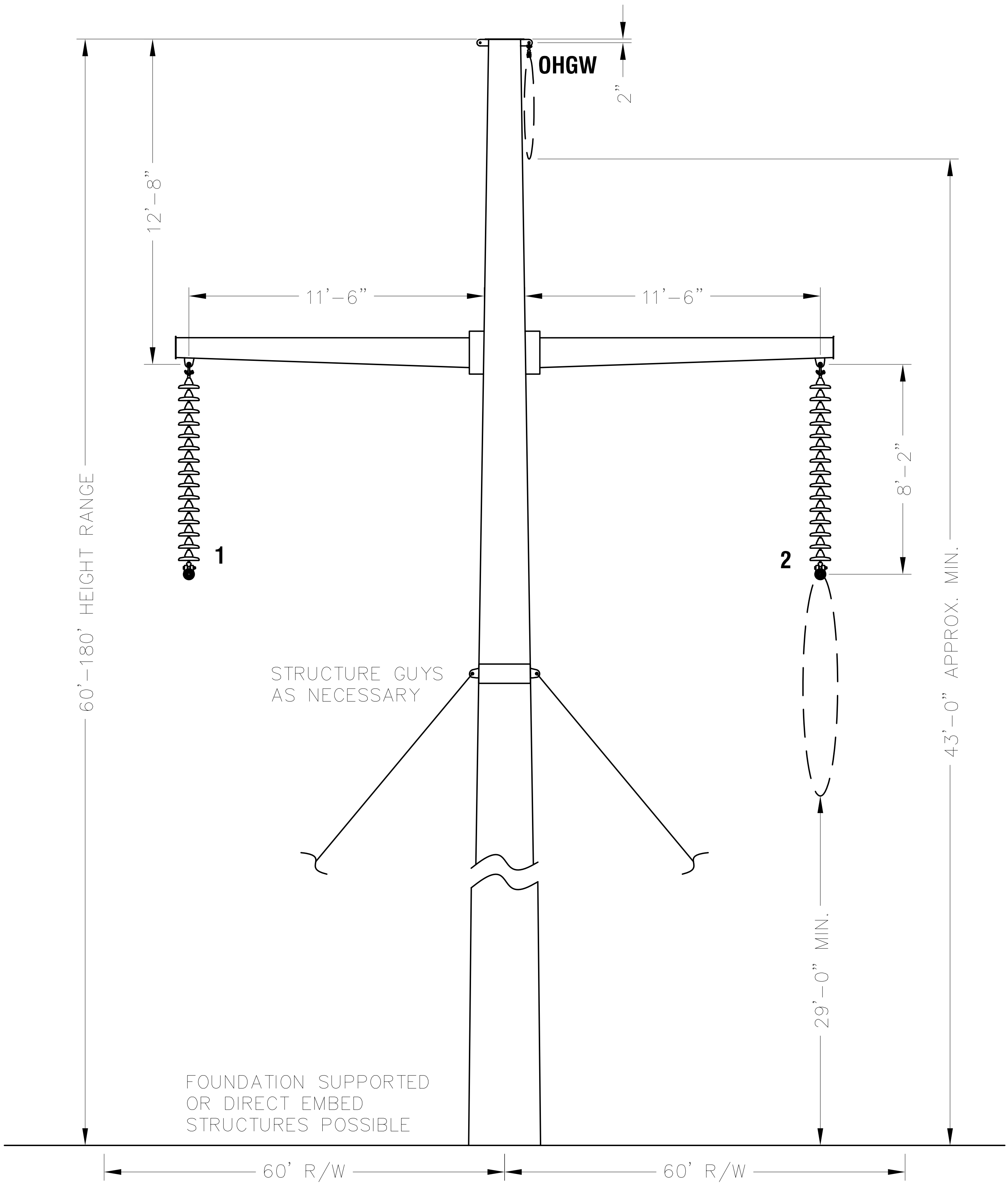
TYPICAL 230kV H–FRAME



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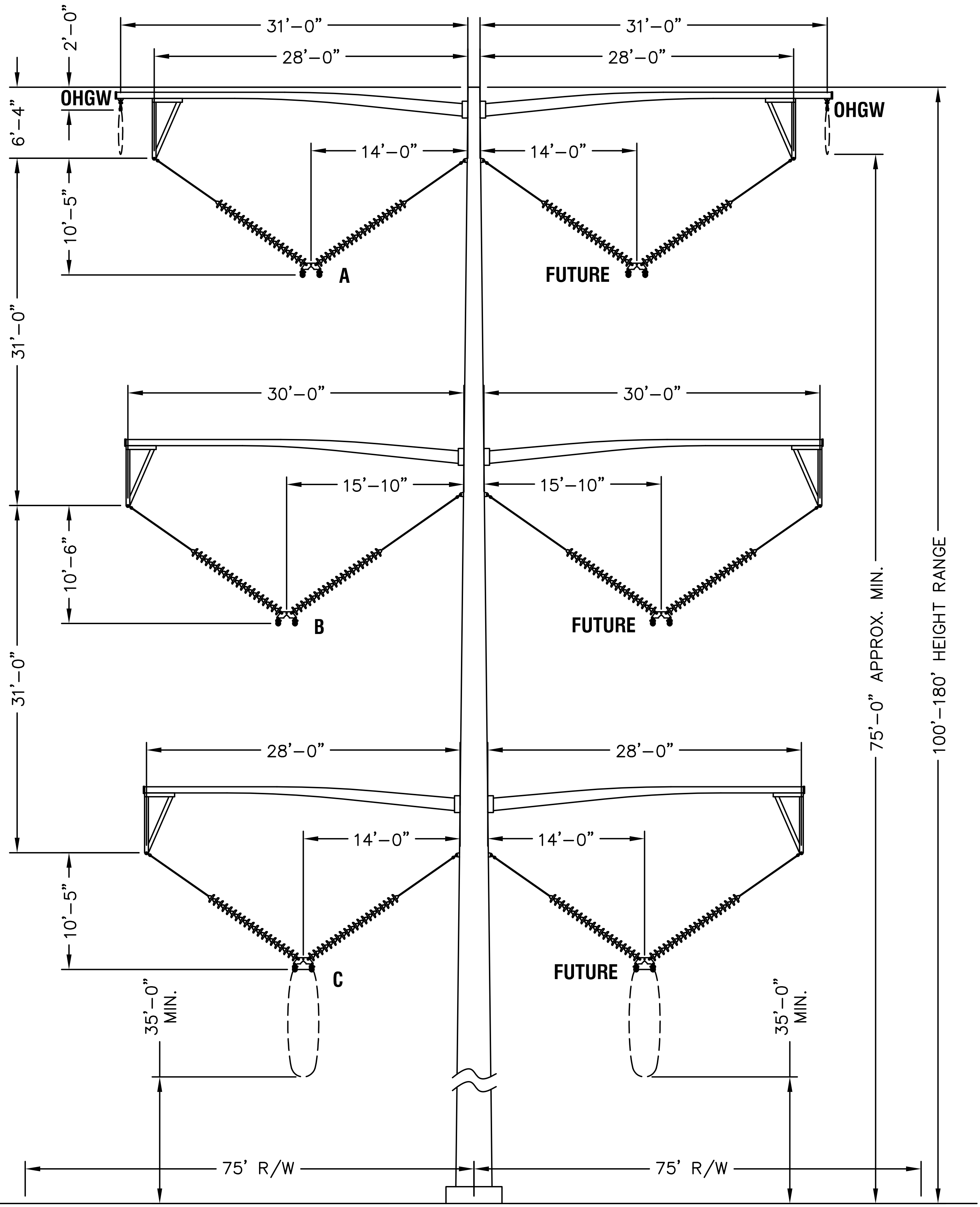
TYPICAL 250kV HVDC



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TYPICAL 345kV SINGLE POLE

Appendix N

Annual Electric Utility Forecast Report

Appendix N

Minnesota Power's July 2022 Annual Electric Utility Forecast Report

Pursuant to Minn. R. 7849.0270, subp. 1 and Minn. R. 7849.0270, subp. 2(A)-2(D), a Certificate of Need application must provide information related to peak demand and annual consumption data for an applicant's entire service territory and system. Minnesota Power requested and was granted an exemption from this rule requirement by the Minnesota Public Utilities Commission.[1] In lieu of the information required by Minn. R. 7849.0270, Minnesota Power agreed to provide substitute data in the form of forecast information from Minnesota Power's most recent Annual Electric Utility Forecast Report ("AFR").[2]

Minnesota Power filed its 2022 AFR filing with the Commission on June 28, 2022 in Docket No. E-999/PR-22-11. A copy of the 2022 AFR filing is provided in this appendix.

[1] *In re Application of Minnesota Power for a Certificate of Need for the HVDC Modernization Project*, Docket No. E015/CN-22-607, ORDER (Feb. 1, 2023).

[2] *In re Application of Minnesota Power for a Certificate of Need for the HVDC Modernization Project*, Docket No. E015/CN-22-607, Exemption Request (Nov. 30, 2022); *In re Application of Minnesota Power for a Certificate of Need for the HVDC Modernization Project*, Docket No. E015/CN-22-607, Reply Comments of Minnesota Power – Exemption Request and Notice Plan Petition (Jan. 9, 2023).

minnesota power
AN ALLETE COMPANY

30 West Superior Street
Duluth, MN 55802-2093
www.mnpower.com

June 28, 2022

VIA E-FILING
Ms. Anne Sell
Department of Commerce – Division of Energy Resources
85 7th Place East, Suite 280
St. Paul, MN 55101-2198

Re: Minnesota Power's 2022 Annual Electric Utility Forecast Report
Docket No.: E-999/PR-22-11

Dear Ms. Sell:

Enclosed please find Minnesota Power's 2022 Annual Electric Utility Forecast Report pursuant to Minn. Stat. § 216C.17, subd. 2 and Minn. Rules Chapter 7610. As an electric utility with Minnesota service areas, Minnesota Power (or the "Company") is required to submit to the Minnesota Department of Commerce – Division of Energy Resources ("Department") by July 1 of each year an annual report specifying its short- and long-term energy demand forecasts and the facilities necessary to meet the demand.

Information included in the "**ELEC_68_2021 Largest Customer List.xlsx**" and "**ELEC_68_2021 Forecast Report.xlsx**" Excel workbooks, as well as the **Methodology** document has been designated as **TRADE SECRET**.

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 Department and Minnesota Public Utilities Commission eDockets/eFiling system using Docket Number 22-11:

- ELEC_68_2021 Annual Report.xlsx
- ELEC_68_2021 Forecast Report.xlsx (**TRADE SECRET** & Public versions)
- ELEC_68_2021 Largest Customer List.xlsx (**TRADE SECRET**)
- ELEC_68_2021 Monthly Power Cost Adjustments.xlsx
- ELEC_68_2021 MN Service Area Map.pdf
- ELEC_68_2021 USDOE EIA-861.pdf
- ELEC_68_2021 Rate Schedules.pdf
- METHOD22.pdf (**TRADE SECRET** & Public versions)

Please don't hesitate to contact me if you need additional paper copies or have any questions.

Sincerely,

Benjamin Levine
Customer Insights and Forecasting Analyst Senior
Minnesota Power
218-355-3120
blevine@mnpower.com

BL:th
Attach.

cc: Leah Peterson
David Moeller
Jennifer Cady
Lori Hoyum

STATE OF MINNESOTA)
) ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA ELECTRONIC FILING

Tiana Heger of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 28th day of June, 2022, she served Minnesota Power's Annual Electric Utility Forecast Report in **Docket No. E-999/PR-22-11** on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on E-Docket's Official Service List for this Docket were served as requested.

____
Tiana Heger

Table of Contents

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's 2022 Annual Electric Utility Forecast Report	Docket No. E-999/PR-22-11

I. 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 a sound econometric methodology and data from reputable sources to produce a reasonable long-term outlook suitable for planning.

Minnesota Power (or the Company) is committed to continuous forecast process improvement, process transparency, forecast accuracy, and gaining customer insight. This 2022 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 the Company's commitment to innovate and enhance its forecast processes. Minnesota Power owes its record of forecast accuracy to a combination of close contact with customers, continuous validation of forecast model inputs, and steady improvements in statistical analytic capabilities.

Since the 2019 Annual Forecast Report (AFR), Minnesota Power has included estimated impacts of energy efficiency, distributed generation (solar), and electric vehicles in the Expected scenario outlook. This expanded approach to forecasting can then be integrated into the Company'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.

A. 2022 FORECAST RESULTS OVERVIEW

Table 1 below shows the Expected case forecast for annual energy sales and seasonal peak demand. Annual energy sales are projected to remain flat (on average) from 2021 through 2036.[1] Summer and Winter peak demands are projected to increase at average annual rates of 0.2 percent. See Figures 1 and 2 on page 4 below for graphical representations of energy and peak demand. The AFR 2022 load forecast reflects 42 megawatts (MW)[2] of system load growth by 2036.

Table 1: Expected Case Energy Sales and Seasonal System Peak Demand Outlook

Total Energy Sales			System Peak Demand					
	MWh	Y/Y Growth		Summer (MW)	Y/Y Growth		Winter (MW)	Y/Y Growth
2011	10,988,200		2011	1,746		2011	1,780	
2012	11,107,357	1.1%	2012	1,790	2.5%	2012	1,774	-0.3%
2013	10,985,809	-1.1%	2013	1,782	-0.5%	2013	1,751	-1.3%
2014	11,038,979	0.5%	2014	1,805	1.3%	2014	1,821	4.0%
2015	10,059,466	-8.9%	2015	1,597	-11.5%	2015	1,554	-14.6%
2016	9,830,787	-2.3%	2016	1,609	0.8%	2016	1,692	8.9%
2017	10,654,217	8.4%	2017	1,688	4.9%	2017	1,789	5.7%
2018	10,638,692	-0.1%	2018	1,723	2.1%	2018	1,707	-4.5%
2019	10,482,913	-1.5%	2019	1,668	-3.2%	2019	1,687	-1.2%
2020	9,230,235	-11.9%	2020	1,487	-10.8%	2020	1,646	-2.4%
2021	10,290,154	11.5%	2021	1,625	9.3%	2021	1,663	1.1%
2022	9,673,239	**-6.0%**	2022	1,592	**-2.0%**	2022	1,642	**-1.3%**
2023	9,873,355	**2.1%**	2023	1,634	**2.6%**	2023	1,641	**-0.1%**
2024	9,940,872	**0.7%**	2024	1,641	**0.4%**	2024	1,650	**0.5%**
2025	9,910,637	**-0.3%**	2025	1,640	**-0.1%**	2025	1,651	**0.1%**
2026	9,904,322	**-0.1%**	2026	1,639	**-0.1%**	2026	1,652	**0.1%**
2027	10,105,178	**2.0%**	2027	1,671	**2.0%**	2027	1,694	**2.5%**
2028	10,273,994	**1.7%**	2028	1,681	**0.6%**	2028	1,694	**0.0%**
2029	10,231,667	**-0.4%**	2029	1,680	**-0.1%**	2029	1,695	**0.0%**
2030	10,230,191	**0.0%**	2030	1,679	**-0.1%**	2030	1,695	**0.0%**
2031	10,229,080	**0.0%**	2031	1,678	**0.0%**	2031	1,697	**0.1%**
2032	10,265,530	**0.4%**	2032	1,677	**0.0%**	2032	1,699	**0.1%**
2033	10,230,380	**-0.3%**	2033	1,677	**-0.1%**	2033	1,700	**0.1%**
2034	10,231,017	**0.0%**	2034	1,675	**-0.1%**	2034	1,703	**0.1%**
2035	10,231,808	**0.0%**	2035	1,674	**-0.1%**	2035	1,705	**0.1%**
2036	10,264,096	**0.3%**	2036	1,673	**-0.1%**	2036	1,709	**0.3%**

Minnesota Power remains a Winter peaking utility and will continue to expect an approximate 20 MW difference in this seasonal profile. Figures 1 and 2 below show the projected energy sales and system peak demand, respectively for AFR 2022 compared to AFR 2021.

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[2] 42 MW = 2036 winter Peak (1,705 MW) – 2021 Winter Peak (1,663 MW).

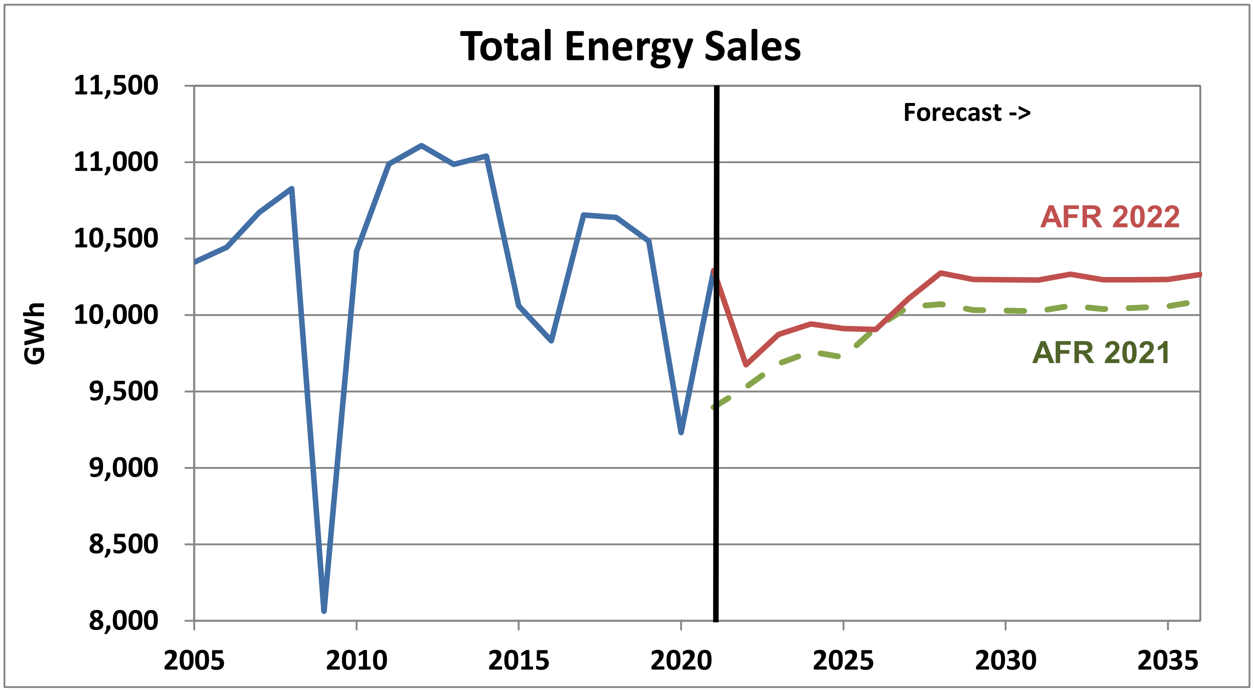

Figure 1: Expected Case Energy Sales Outlook

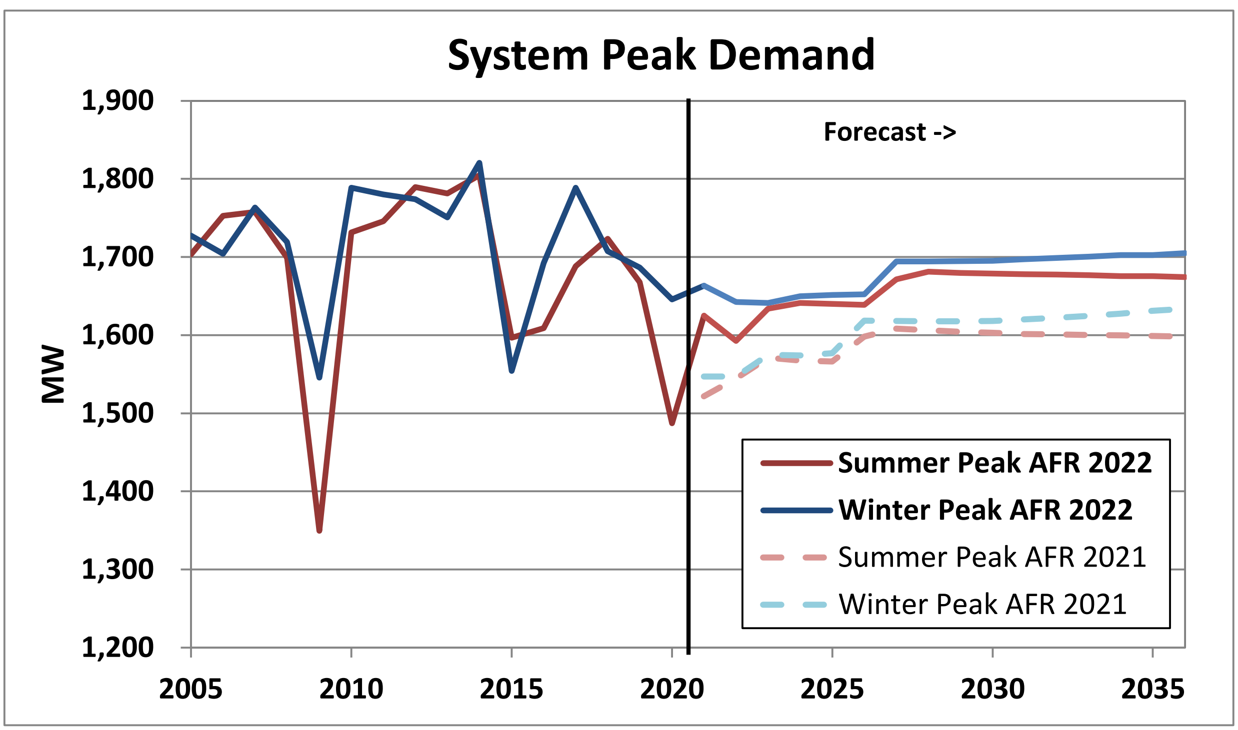

Figure 2: Expected Case Peak Demand Outlook

B. Document Structure

This report details the construction of the energy sales and demand forecast for Minnesota Power for the 2022-2036 timeframe. Each section is designed to convey the report requirements per Minn. Rules Chapter 7610, and give insight into the Company's forecasting process and results.

Section II: *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 II:

- 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 2022 to improve the forecast process and final 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 III: *Forecast Results* presents the Expected scenario forecast Minnesota Power developed for the AFR 2022 forecast. This forecast is the product of a robust econometric modeling process and careful consideration of potential industrial and resale customer load developments.

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

II. FORECASE METHODOLOGY, DATA 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) initial review and verification, and 5) internal company review and approval. The steps of the forecast process are sequential and the process is diagrammed in Figure 3 below and discussed in more detail in Section B.

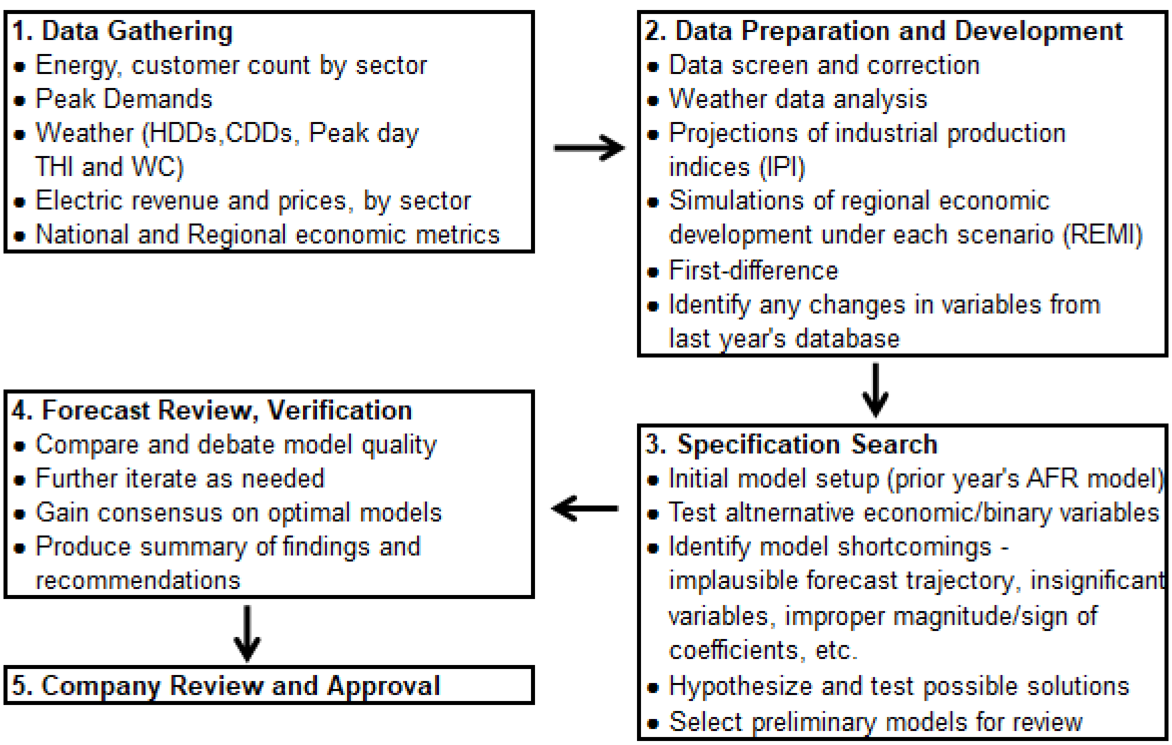

Figure 3: Minnesota Power's Forecast Process

B. Minnesota Power's Forecast Process

1. 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.
- *Regional Demographic and Economic data:*
    - *Duluth Metropolitan Statistical Area (MSA)* consists of population, households, sector-specific employment, income metrics, regional product, and other local indicators.
    - *Aggregate 13-County Minnesota Power service territory (13-Co)* consists of population, Gross Regional Product (a Regional Gross Domestic Product (GDP) metric), sector-specific employment, and income metrics.
    - *Individual 13-County Minnesota Power service territory (13-Co)* consists of sector-specific employment and income metrics for each individual County.
- *Indicators of National economic activity* such as the Industrial Production Indexes (IPI) or Macroeconomic indicators such as U.S. GDP or Unemployment.
- *Weather and related data* including heating degree days (HDD), cooling degree days (CDD), temperature, humidity, dew point, and wind speed.
- *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 as the key explanatory factors of customer count, energy sales, and peak demand.[3] For AFR 2022, Minnesota Power implemented a new model development process that leverages the knowledge gained during past AFR specification search processes. This new model development process involves iteration and gradual, targeted improvement of a regression model instead of the previous process of bulk model production, filtering, and selection of final models. The process update greatly improved forecasting efficiency (eliminated the need for bulk model production as mentioned above) while still maintaining Minnesota Power's high standards regarding statistical quality. The AFR 2022 modeling process starts with the prior year's AFR model for each dependent variable (e.g. residential customer count), and follows the steps listed below to improve this existing, proven model's predictive capability or model statistics:

   - Test the model by adding or removing variables and noting changes in statistical quality or ability to accurately predict changes in customer behavior during economic disruptions such as the Great Recession (2007-2009) or the COVID-19 Recession (2020).
   - Identify any shortcomings of this preliminary model, which may include: implausible forecast trajectory, insignificant variables, improper magnitude and/or sign of coefficients, etc. This step also highlights any general statistical issues such as: Multicollinearity, Autocorrelation, and Heteroscedasticity.
   - Form a hypothesis as to the reasons for these shortcomings and test possible solutions, including:

[3] Specific analytical techniques applied during this step are detailed in Section C.

- Create binary variables to account for any observable step-changes in the dependent variable.
- Utilize alternative forms of key economic variables such as first-differenced transformation to address issues of multicollinearity.
- Conduct a compressive search for economic or demographic variables that explain high forecast errors during a specific timeframe (e.g. during recessions).

- Repeat the process of testing and evaluation until a model has a plausible forecast, and meets Minnesota Power's existing statistical criteria as defined in the *Modeling Techniques* section of this document. At this point, the proposed, or preliminary model is ready for *Forecast Review and Verification*.

4. *Forecast Review and Verification* involves reviewing the preliminary model for each of the dependent series. During this step, analysts compare and debate the quality of each selection and its corresponding outlook. This step also inherently shares aspects of the *Specification Search* process as analysts further iterate and gradually improve upon each model. The goal is to perform an in-depth review and verification in order to reach a consensus around a final set of optimal models to put forward for *Company Review and Approval*.
5. *Company Review and Approval* involves internally vetting all forecasts to ensure that consistent use of forecast information was employed and that the forecasts are reasonable.

2. Specific Analytical Techniques

Data Transformation Schema for Economic Variables: Transformations are used to maintain consistency of definition in a variable series and identify different potential relationships between predictor variables and the dependent variable. Minnesota Power uses several data transformations in data development: constant-dollar deflating/inflating, per-day conversion, de-trending/de-seasonalizing, first difference, and exponential.

- *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 2012 as its base year in the 2020 forecast. The 2012 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 (peak demand).
- *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 potential to mistake similarity of *trend* with similarity of *variation*.
- *Exponential* – is the application of an exponent to the series; either squaring or cubing the series. This transformation of raw data was only applied to the temperature variables in the Peak Demand model so the non-linear relationship of load to temperature could be more accurately quantified.

The Company has discontinued use of natural log and first difference of natural log transformations, as well as lead/lag transformations for transparency and ease of model interpretation. The addition of these transformations to past reports was exploratory. Minnesota Power forecasters have found these transformations add minimal predictive value, but make resulting model specifications difficult to interpret and difficult to compare year-to-year changes in model inputs.

<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 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 spline interpolation procedure was conducted in Statistical Analysis System (SAS) using the "Proc Expand" command with the method specified as "Spline" and the observed as "Middle." The "Middle" specification denotes that an annual-to-monthly interpolation should assume the annual value as June, and July through May should be interpolated points. Quarterly-to-monthly interpolation should assume Quarter 1 as February, Quarter 2 as May, Quarter 3 as August, and Quarter 4 as November; all other months are interpolated points. The cubic spline interpolation function is in piecewise cubic polynomial form:[4]

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

Where: $0 \le t \le 1$

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

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

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

The cubic spline method of interpolation has been in use since the Company's AFR from 2014 and was an improvement over previously-utilized interpolation methods.

<u>*Modeling Techniques*</u> – Most of the 32 dependent count and energy variables are modeled using a trend variable to explain general, underlying growth and one or two economic/demographic variables to explain any economically-driven divergence from this trend. This approach to regression modeling reduces the potential for an independent variable to be erroneously identified as significant due to spurious, or *false,* correlation.

- <u>*Leveraging Binary Variables to Account for Recent Trends*</u> – Several of Minnesota Power's largest industrial and resale customers are in a time of significant change, and an accurate load forecast depends on properly identifying and accounting for these changes.

4 http://mathworld.wolfram.com/CubicSpline.html.

In AFR 2014, Minnesota Power began adjusting historical sales series to "back-out" recent large customer load additions to avoid double-counting customer usage in the forecast timeframe; once (partially) embedded in the econometric projection, and again through a post-regression load adjustment.

This approach is appropriate when the load addition/loss is quantifiable (e.g. a new customer, or a new customer-owned generator), but shouldn't be used when the load addition/loss cannot be accurately quantified (an existing customer's recent expansion); adjusting raw historical sales data with an estimate would just introduce additional uncertainty to the estimate.

Minnesota Power continues to adjust historical series for known/measurable recent load additions, and has supplemented this approach with the use of binaries and trend variables that account for large changes in load that cannot be precisely quantified (such as a customer expansion that is not metered separately).

The variables denote and account for a structural shift in a dependent variable (historical sales), and are then terminated at the start of the forecast timeframe to effectively "back out" this recent change so it can be accurately quantified and explicitly applied through a post-regression adjustment to the econometric series.

- *Polynomial temperature specification for peak demand* – The AFR 2022 peak demand model uses a third-degree (cubed) temperature series alongside an un-adjusted temperature series to capture the non-linear relationship of load to temperature. The two variables (cubed and un-adjusted) create a polynomial temperature specification.

  This approach was first used in AFR 2016 and was a change from prior AFRs that leveraged either a monthly interaction specification or a spline-type (temperature range) specification. These previous approaches model the effect of temperature on demand, and identify the non-continuous or non-linear relationship of load to temperature, but neither approach is the simplest solution.

  A polynomial temperature specification is continuous/not segmented, so it can always be leveraged for weather-normalization. This specification is much simpler and commonly used in demand modeling. The Company has avoided using this specification in the past, believing that the coefficients associated with the spline-segments efficiently and clearly conveyed information about load's response to weather in a specific temperature range. However, the testing of after-the-fact weather-normalization has convinced Minnesota Power Load Forecasting that a Polynomial specification is superior.

- *Modeled Peak Demand using hour-specific weather observations* – Prior to AFR 2017, the Company modeled peak demand using monthly HDD/CDD or daily high/low temperatures. Since AFR 2017, Minnesota Power has modeled peak demand as a function of the weather observations specific to the hour in which the peak occurred. The Company identified the historical peak date/times and queried an hourly weather observation dataset to identify the hourly temperature, humidity, and wind-chill coincident with the system peak. In theory, the temperature at the time of the peak should be more closely related with the load than a daily high or low temperature (for example). The Company has witnessed improved model statistics using this approach.

As a rule, all models are OLS, which are simple, transparent, explainable, and produce optimal estimates of the coefficients. All input variables' coefficients must be significant at a 90 percent confidence level (as indicated by a HAC-adjusted P-value less than 10 percent) and the Variance Inflation Factor (VIF) of each variable's coefficient must be less than five (indicating minimal multicollinearity). A constant, trend, or binary variable with a P-value greater than 10 percent or VIF greater than five may be retained if it is critical to the model structure.

- Test for multicollinearity using VIFs - 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:

  - VIF less than 3 is optimal - correlation with the remaining variables is less than 82 percent.
  - VIF of 3-5 is acceptable, but is assessed in context with other diagnostics.
  - VIF of 5-10 is generally unacceptable, but is assessed in context with other diagnostics. A VIF greater than 5 implies correlation with remaining variables is greater than 90 percent.
  - 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 economic and demographic variables in all models are well within acceptable limits or the variable serves an important function within the model and the causation of the high VIF metric (i.e. its high correlation with other variables) is understood, explainable, and unconcerning. Minnesota Power considers high VIFs on certain 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 could be if found to have high multicollinearity with other variables.

- Heteroscedasticity and Autocorrelation Consistent (HAC) - adjusts the standard errors of regression coefficients to correct t-statistics and P-values for biases resulting from autocorrelation and/or heteroscedasticity. Minnesota Power computes the HAC-adjusted P-values using a common HAC specification.[5] These HAC-adjusted P-values are used to determine inclusion/exclusion in the model. Coefficients themselves are not affected by this adjustment.

  The AFR 2022 HAC-adjustment procedure simultaneously corrects P-values for both autocorrelation and heteroscedasticity. This automated adjustment streamlines model testing and selection, and produces a more robust final forecast.

5 Developed using Andrews (1991).

Models that meet the above criteria, have plausible outputs (forecasts), and have intuitive econometric interpretations are put forward as potential final models for review during the *Forecast Review and Verification* step (AFR 2022 Forecast Process page 8).

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/or 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.

3. Treatment of Demand Side Management, Conservation Improvement Programs, Distributed Generation, and Electric Vehicles in the Forecast

Demand Side Management (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.

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, in the context of Minnesota Power conservation programs,[6] may also include process efficiency, which limits the energy input per unit of production and results in avoided energy consumption.
- *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 for economic and emergency conditions.
- *Load Shifting* - Electric demand is shifted from on-peak to off-peak hours. In 2014, Minnesota Power initiated a Time-of-Day (TOD) Rate Pilot and in 2015 extended the program.[7] Under this rate, customers pay more for usage during on-peak hours and

[6] Minnesota Power's Power of One program is made available to home and business customers. Refer to on-line conservation resources at http://www.mnpower.com/EnergyConservation for more information. However, this Company branding will be discontinued in 2022.

[7] Details of the program extension can be found under Docket Number E015/M-12-233 filed on March 25, 2018.

critical peak pricing events, and receive a discount for usage during off-peak hours. The goal of this pilot is to gauge customer interest in new rate offerings that incentivize load shifting and to further inform decisions about broader program implementation and infrastructure investment.

Accounting for Conservation in the Forecast:

Prior to AFR 2019, the effect of conservation programs were assumed implicit in the energy sales forecasts. This approach was favored since it's highly objective, involves no manipulation of the historical energy sales data prior to regression modeling, and required no exogenous adjustment for energy efficiency to be applied to the raw econometric model results. Whether this method can fully capture the recent, escalating effects of conservation on energy sales has come into question.

After thorough research, testing, review by colleagues at other Midwest utilities, and discussions with Minnesota Department of Commerce (DOC) Staff, the Company has identified a preferred approach to forecasting energy efficiency: use energy efficiency as an input variable to the regression models, referred to as "EE as RHS var" or "Energy Efficiency as a Right Hand Side Variable." The "EE as RHS var" methodology has several advantages over other common energy efficiency forecasting methodologies:

- Avoids double-counting energy efficiency impacts in the forecast timeframe.[8]
- Accounts for historical and projected conservation resulting from both Company programs and organic, customer-driven efforts.[9]
- Leverages raw sales data in regression modeling: sales data are not adjusted for conservation impacts prior to modeling.[10]

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8 The historical impact of conservation is effectively captured by the □x (coefficient x variable) series for the energy efficiency variable that spans the historical and forecast timeframes. There are no exogenous assumptions or adjustments for energy efficiency, and, in theory, no double counting.

9 Company-driven energy efficiency is used as an *indicator* of energy sales, and the regression model will assign this variable more or less weight depending on the variable's observed correlation with sales. If the observed decrease in sales is greater than the increase in the energy efficiency variable (i.e. Company-driven energy efficiency), the model is inferring some organically-driven conservation.

10 Another common method entails "adding-back" historical conservation to actual sales to reconstruct a history in which conservation effects have been removed. This series is modeled, projected, and then modified for future savings. This approach to forecasting sales with conservation impacts seems intuitive, but it involves modifying

- Doesn't require after-the-fact adjustments to econometric outputs: the energy sales forecasts already contain the effects of energy efficiency.

An "Energy Efficiency" variable explains recent trends in customer consumption that cannot be explained by economic, demographic, or weather effects. Further, this method allows the Company to quantify the volume of Conservation Improvement Programs (CIP) energy efficiency embedded in the load forecast, which will be useful in a number of applications including resource plan modeling.

Discussion of the interpretation, role/function, and justification for use of a particular energy efficiency variable within a model is documented in Section II.E "Econometric Model Documentation."

Development of the "Energy Efficiency" variable began by gathering savings data for each retail customer class, Superior Water Light and Power, and the Company's 15 municipal customers. Incremental (i.e. first year) savings data for the historical and forecast timeframe was assembled from a number of sources. Table 2 documents the derivation of energy savings assumptions for each historical and forecast period.

Table 2: Energy Efficiency Variable Data Source

			Historical	Forecast->		
	2008-2018	2019-2020	2021	2022	2023-2029	2030-2035
MP Retail						
Resale						
MN Municipal						
SWLP						

MP CIP Compliance Filing
MP Preliminary Estimate
Energy Savings Platform
Filed CIP Results (2019 and 2020) and Plan (2021 and 2022)
Historical 3-Year Average
Provided by Resale Customer
Center for Energy and Environment (CEE) - Utility Reporting Tool*
***Potential conservation estimates updated by MP in cooperation with CEE**
Extrapolated from CEE Trend

the historical series using an estimated series (historical CIP savings), which can create uncertainty in the resulting model and forecast.

Historical incremental savings data for Minnesota Power was obtained from the Company's past CIP compliance filings, Minnesota Municipal customers' historical savings information was obtained from the Minnesota "Energy Savings Platform."[11] Superior Water Light and Power provided its own historical savings information to Minnesota Power.

Forecast assumptions for Minnesota Power's residential and commercial savings in 2019 and 2020 were derived from the Company's most recent preliminary estimates of achieved 2019 savings/plan for 2020, and energy savings assumptions[12] beyond 2020, were derived primarily from the Center for Energy and Environment's (CEE) new Utility Reporting Tool.[13] In cooperation and close coordination with CEE, the Company modified CEE's estimates of "Program" potential[14] savings at the generator in two ways:

1. The Program potential savings were re-estimated using CEE's methodology and working papers, but updated using the Company's most recent outlook (AFR 2019) for energy consumption by CIP-participating customers. The outlooks for energy usage growth have decreased considerably since CEE conducted its analysis; therefore the potential for energy efficiency savings have decreased.
2. Projections of municipal customer cumulative savings (starting in 2020) were scaled to align with recent historical savings (a five-year average).[15]

11 http://mncipdata.cloudapp.net/Default.aspx

12 Resale customer assumptions for near-term (2019) incremental savings were not available in CEE's tool, so the Company assumed a five-year historical average. Superior Water Light and Power's incremental savings outlook was assumed as a five-year historical average normalized for large customer conservation projects that are unlikely to occur with any frequency and should not bias the forecast.

13 https://www.mncee.org/cmsctx/pv/emmaappleman/culture/en-US/wg/bc32b2f9-415e-43fc-885f-a6b77d7329a9/h/7c8c2cd92b01eaff3e98ba1b2941fc39e8cad43c23c520dbe32102e613a9ee03/-/cms/getdoc/5b0746d4-4ad0-49b9-9a85-7d4212b56a03/pv.aspx

14 CEE projected three levels of potential savings: Program, Economic, and Max Potential. Minnesota Power leveraged the "Program" potential savings figures in its data development since the Program metric aligned most closely with the Company's 2017 Triennial filing and past achieved savings.

15 The CEE forecast of municipal customer incremental savings for 2020 (first forecast year) were, in total, about 50% greater than the five-year historical average of incremental savings for these same municipals. The Company inferred from this that CEE's projections of Cumulative savings were inflated by a similar amount. Scaling the CEE cumulative savings estimates prevented a large step change in the final "energy efficiency" variables for each municipal customer.

For each of the retail classes and resale customers, the Company cumulated the historical and projected incremental savings[16] to produce a "cumulative energy savings" series.[17] This cumulative series is the optimal variable format/definition for modeling energy sales; Figures 4 and 5 below demonstrate why this is the case by plotting incremental and cumulative residential energy savings (at meter) since the passage of the U.S. "Energy Independence and Security Act" of 2007 and the MN "Next Generation Energy Act" of 2007.

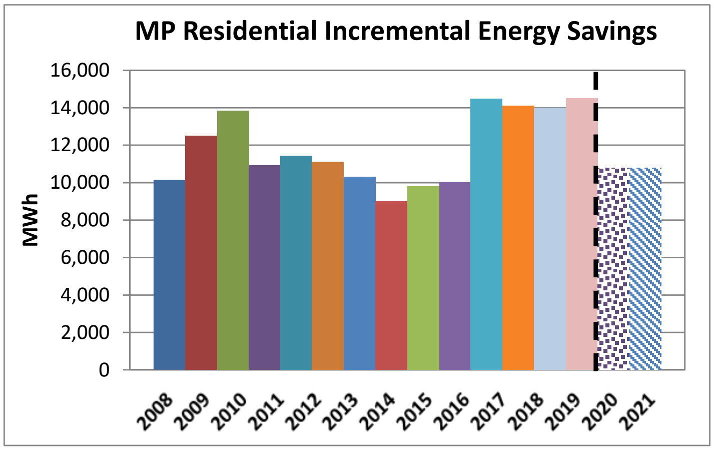

Figure 4: Residential Incremental Energy Savings

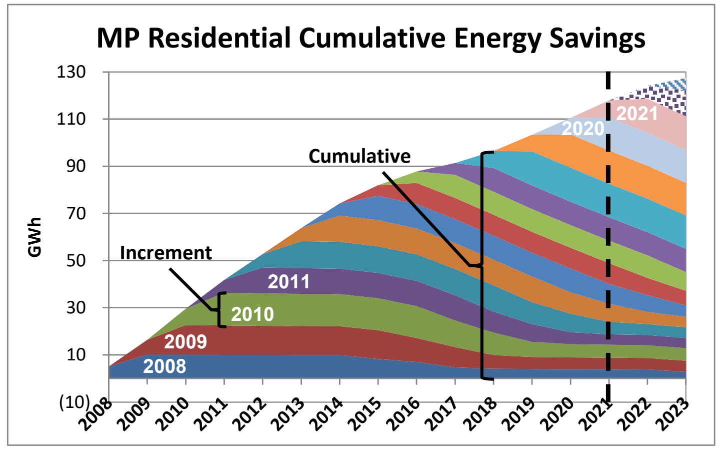

Figure 5: Residential Cumulative Energy Savings

Incremental energy savings are the "first year" or single year savings achieved via a portfolio of efficiency measures implemented in a single year. Incremental residential savings at meter are fairly constant from year-to-year, around 11,000 megawatt hours (MWh); from an econometric modeling perspective, this variable might indicate a constant shift in the level of annual sales, but it would not indicate a change in growth rate or trajectory of annual sales.

A cumulative savings metric represents the lasting impacts of conservation programs[18] by aggregating or *cumulating* the savings from all past conservation measures. This cumulative

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16 For municipal customer savings, the cumulative savings series was calculated by 1) cumulating all incremental savings pre-2021, and adding this to 2) CEE's projection of cumulative savings post-2021. This was computationally easier, and required fewer assumptions on the part of the Company. A similar process for retail classes that leveraged CEE's cumulative savings was not possible since the customer class-level savings needed to be scaled per the composition of past achieved savings.

17 Using internal estimates of Minnesota Power's past programs' life of measures. A Life of Measure (LoM) is the approximate time a conservation measure will reduce energy consumption. Most conservation measures have a 10-20 year life. A portfolio from any particular program year will contain measures that end earlier than others, so the overall impact of measures implemented in a program year will fade over time.

18 Figure 5 above also shows how these conservation measure impacts fade over time as, for example, households replace the aging appliances.

series grows substantially from 2008-to-present; a timeframe in which Minnesota Power's residential energy sales growth has largely stalled. From an econometric modeling perspective, a cumulative savings format/definition is indicative of a change in growth rate/trajectory of annual sales. This is precisely the phenomenon that requires explanation and quantification, and why the "cumulative" series is the optimal variable format/definition for modeling energy sales.

Note that accumulating the *annual* incremental series only produces *annual* cumulative savings series, whereas Minnesota Power's energy models are *monthly*-frequency. The Company used the same annual cumulative savings value for all 12 monthly observations of a particular year,[19] and did not attempt to estimate monthly energy savings by distributing or interpolating the annual values. Estimation of monthly savings values would have 1) involved additional assumptions on the part of Minnesota Power forecasters, and 2) potentially imparted bias to the final model through the weather coefficients. A key strength of the "Energy Efficiency as a Right Hand Side Variable" methodology is that it involves making relatively few assumptions, leveraging raw data as much as possible, and relying on the regression modeling process to objectively "solve for" unknown variables such as the seasonality of energy efficiency impacts.

The Company used a cumulative savings, annual "Energy Efficiency" variable in regression models for sales to the residential, commercial, and public authorities classes, as well as three of the Company's 16 resale customers modeled in AFR 2022. The cumulative energy sales assumptions used in regression modeling (i.e. the "Energy Efficiency" variables) and corresponding incremental savings assumptions are shown in the tables below by year. [*Note: The commercial-sector "Energy Efficiency" variable was utilized in the public authorities model since: 1) both customer groups are served by the same CIP program (Power of One Business[20] and Residential/Multifamily/Business Direct), and 2) the overall trend of conservation in public authorities is likely very similar to commercial customers*.]

[19] Note that the Company did not divide the annual values by 12. Dividing or multiplying a variable by a constant (e.g. 12) prior to regression modeling has no effect on the resulting forecast; the regression model would adjust the parameter estimates (i.e. coefficient) to maintain a least squared error function. Dividing a variable by 12 would result in a coefficient that's 12 times larger.

[20] Beginning in 2022, Minnesota Power will no longer be using "Power of One" branding.

Table 3: Cumulative Energy Sales Assumptions **Table 4: Incremental Energy Savings Assumptions**

[TRADE SECRET DATA BEGINS

[redacted]

TRADE SECRET DATA ENDS]

Accounting for Distributed Generation (DG):

Prior to AFR 2019, the Company did not make explicit, exogenous assumptions for Distributed Generation: Solar (DG Solar), but noted that "it may become possible/necessary to account for this transition in the load forecast."[21] Minnesota Power has identified a viable methodology for this transition, has projected DG Solar adoption, and has adjusted the energy sales and peak demand forecasts per this DG Solar outlook.

New DG Solar installations were projected using the exponential growth observed in recent years (since 2010) where the number of new solar installations has grown by about 40 percent

21 In Section 1.B.iv. "Treatment of Demand-Side Management (DSM), Conservation Improvement Programs (CIP), and Distributed Generation (DG)" of AFR's 2017 and 2018.

per year in both residential and commercial sectors. This outlook for the number of new installs is combined with assumptions for the sizing (kilowatt (kW) capacity) of those new installations, an expected capacity factor, and seasonal production characteristics to produce estimates of monthly energy production and peak reduction. The energy sales and peak demand forecasts are only adjusted for *new* installations (i.e. installations expected to come online in the forecast timeframe). The effects of currently installed arrays are presumed to be embedded in the forecast.

The Company projects that about 2,400 new DG Solar installations will connect to the Minnesota Power grid by 2036 (i.e. installed in years 2022-2036), generating almost 30,000 MWh per year and reducing sales by an equivalent amount. The Company adjusted the energy sales and peak demand outlook per all DG Solar adoption in the forecast timeframe (2022-2036); current DG Solar is assumed inherent in the econometric forecast.

Currently, there are nearly 600 small-scale (<40kW)[22] Distributed Generation (DG) Solar installations with a combined nameplate capacity of about 5.5 MW, reducing sales by an estimated 5,500 MWh/year (0.25 percent of combined residential and commercial sales in 2021). The Company projects that its customers will have installed about 30 MW of new small-scale solar,[23] displacing about 30,000 MWh in energy sales by 2036.

The process of forecasting DG solar generation involves two separate assumptions: 1) the rate of adoption (i.e. number of new installations each year), and 2) the average size of those new installations. When calculating both assumptions, the Company opted to segment the DG solar customer population into Residential and Commercial customers; the two classes show separate rates of historical adoption and have tended to install different sized arrays.

The adoption rate was forecasted by modeling historical adoption using annual incentive spend data and exponential trend variables (a “time trend” and square of “time trend”). The exponential trend variables describe the organic early adoption of new technologies and the Company’s solar incentive spending describes divergence from that underlying, organic trend;

22 AFR 2019 considered “Small-scale” to be <60KW. For AFR 2020 and AFR 2022, Using the <40KW more closely aligns with other major filings and current policy.

23 This is Customer installations only, and does not include Minnesota Power developments like Community Solar.

e.g. the sizable increase in incentive spending explains the spike in 2019 DG installations. The forecasts of residential and commercial DG solar are shown as the dotted lines in Figure 6 below.

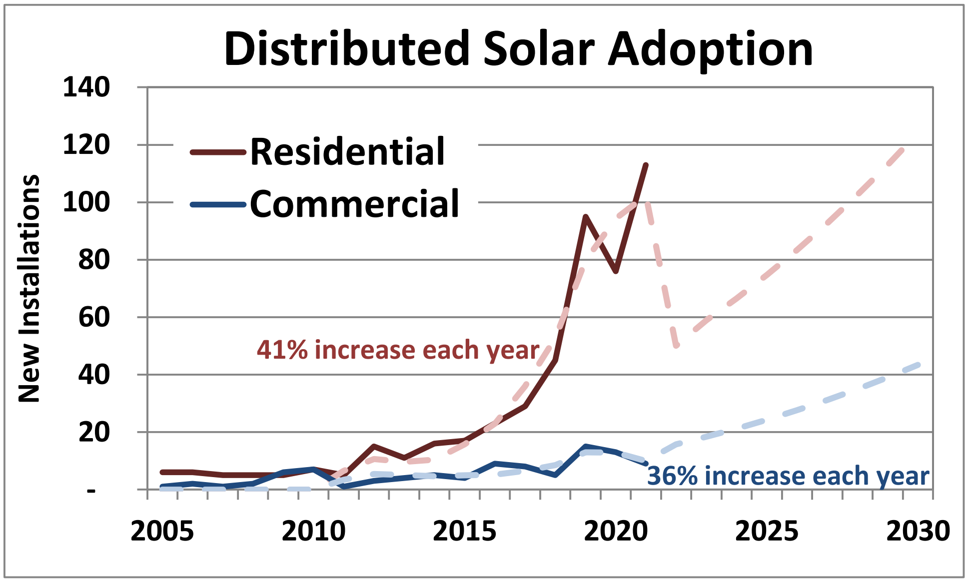

Figure 6: Residential and Commercial Distributed Solar Adoption

The average size (capacity) of new installations in the forecast timeframe is assumed as a simple historical average of installation size by class: residential customer DG solar installations have averaged a capacity of about 8.7 kW and commercial customer DG solar installations have averaged about 21.3 kW.[24]

The adoption rate series is combined with the average installation size assumption to arrive at an estimate of total kW installed per year in the forecast timeframe for both the residential and commercial classes. The "kW installed per year" series (for both commercial and residential) are transformed into cumulative series that represent the total kW installed as of a point in time, inclusive of all installations from the current and prior years.

Finally, the Company calculated the estimated impact of new DG solar on energy sales by converting the capacity series (kW) to an energy series (kWh) using an 11 percent capacity

24 Extremely large outliers were omitted. The Company recognizes that installations are often sized per the energy requirements of the customer, and if per-customer usage declines due to conservation it's likely that installation size will similarly decrease. The Company also recognizes the potential, past and present, for rouge installations (i.e. installations that are not reported to Minnesota Power); this forecast does not account for this potential.

factor[25] assumption for new distributed installations. Table 5 below shows the core assumptions of the Company's annual DG solar outlook.

Table 5: Minnesota Power Outlook for New (post-2021) Distributed Solar

Minnesota Power Outlook for NEW Distributed Solar

	New Installation Count	Cumulative Capacity (kW)	Energy Production (MWh)
2022	66	1,964	1,921
2023	77	2,872	2,821
2024	88	3,907	3,846
2025	99	5,077	5,006
2026	111	6,394	6,311
2027	124	7,869	7,772
2028	138	9,511	9,399
2029	152	11,332	11,203
2030	168	13,341	13,194
2031	184	15,550	15,382
2032	201	17,968	17,778
2033	219	20,607	20,393
2034	237	23,476	23,236
2035	257	26,587	26,318
2036	277	29,949	29,649

Identifying the impact of DG solar on the monthly peak demand outlook involves calculating the amount of solar generation that is likely during a specific month's likely peak time (i.e. historical median peak hour) using a simulated hourly solar production curve.[26] Minnesota Power typically peaks at 6 or 7 PM (well after sun-set) in winter months, so DG solar at the time of the peak is zero percent and projected winter peaks are not reduced. In summer months, Minnesota Power has historically peaked at 3 or 4 PM when DG solar is on average

25 This is the observed average capacity factor of metered solar installations on Minnesota Power's System.

26 The Company used PVSYST software to simulate eight different 10 kW systems per a Typical Meteorological Year. The eight systems varied by location within Minnesota Power's service territory, and by tilt, azimuth, and tracking ability. Each simulated profile was then weighted per the installed kW by location and array specification, and all profiles were totaled. This totalized curve was used to determine the capacity factor of DG solar for each month. Note that this curve was based on 2011 weather information and installations as this was readily available. Simulating with more current information or aggregating actual metered production data would have been time-intensive and likely would have yielded similar results with regards to the capacity factor, which was the only assumption derived from this simulated production curve.

55 percent of installed capacity (the effective load carrying capacity or "ELCC" is 0.55).[27] Summer peak forecasts are reduced by 55 percent of the projected new installed solar capacity; this equates to a 1 MW reduction in the 2022 summer peak, growing to an approximate 17 MW reduction in summer peak by 2036.

Accounting for Adoption of Electric Vehicles (EV):

Minnesota Power recognizes the potential load growth that could result from this new electric end-use and has incorporated an outlook for Electric Vehicle (EV) adoption into the residential energy sales and peak demand forecasts.

Fleet vehicles and commercial charging are not addressed in AFR 2022. Fleet EV adoption in Minnesota Power's territory is too limited to gauge the pace of organic adoption or draw meaningful parallels between local and national adoption rates. Projecting public EV charging usage will also require further study. For the sake of simplicity, and until the Company has more data on EV adoption, the Company attributes all new electric vehicle usage to the residential class. Minnesota Power will continue to gather data and refine its methods to model and incorporate new electric end-uses like EVs into the annual forecast.

The exact number of each type of EV is unknown at this time, but regional ownership is assumed to be predominantly light duty vehicles. Currently, there are 239 known electric vehicles in Minnesota Power's service territory,[28] [29] and the Company estimates there are about 550 light duty (i.e. passenger vehicles) EVs in Minnesota Power's retail service territory.[30] This equates to a 0.4 percent penetration rate for household vehicle ownership and an estimated 590 MWh of energy consumption in 2022. This level of energy consumption represents just 0.06 percent of all sales to residential customers. According to EV data posted

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27 DG solar output is less than 100 percent during the peak for several reasons, including: 1) diversity in installation arrangement and geography (every solar installation will not experience max output at the same time), 2) the likely Minnesota Power system peak timing is well after noon (12-to-1 PM would be the highest solar output hour), and 3) probabilistic variance in weather is taken into account (although its likely to be sunny and hot on the day of the system peak, that does not guarantee perfect conditions at the precise hour of the peak).

28 http://www.dot.state.mn.us/sustainability/electric-vehicle-dashboard.html.

29 Terwilliger, Hanna. Pers. Comm. "RE: 2020 EV Registration Data". April 22, 2022.

30 As of year-end 2020, based on available EV registration data, projected 2022 EV adoption, and pace of national-level vehicle sales.

on the Commission's website in February of 2020, electric vehicles in Minnesota Power's service territory accounted for about 1.4 percent of all EVs in the state, which is considerably less than Xcel Energy (70 percent of all EVs in Minnesota), but more than Otter Tail Power (about 0.5 percent). The Company is aware of the Duluth Transit Authority's seven electric transit buses.

Under the AFR 2022 expected scenario, Minnesota Power customers own about 3,250 EVs by 2030, which would represent just over 1.6 percent of regional vehicle ownership, and roughly 3 percent of homes would own at least one EV, on average. This equates to about 7,600 MWh in additional energy requirements from the residential sector and an estimated increase of 1 MW and 3.6 MW in the 2030 summer and winter peaks (respectively). By 2035, Minnesota Power customers are projected to own about 11,300 EV's and the added energy requirements from post-2020 EV adoption increases to about 28,000 MWh. This level of EV ownership would increase summer peak coincident demand by about 3.5 MW and winter peak demand by 12.75 MW.

The EV adoption rate forecast for the Minnesota Power service territory follows a projected national adoption rate, but lagged by about 6 years. To-date, the average household EV ownership rate among Minnesota Power customers trails the nation by about 6 years: in 2020 Minnesota Power customers had an approximate EV saturation of 0.2 percent whereas the national saturation rate[31] was about 1.5 percent. The National EV saturation rate was last at 0.2 percent between 2013 and 2014, so – for the purposes of forecasting – the Company assumed its customers' EV adoption would continue to lag the nation by about 6 years and would follow the national trend forecast from Bloomberg.[32] Figure 7 shows the adoption rates of Minnesota Power customers and the U.S.

[31] Inside EVs (https://insideevs.com) was used to gather actual EV sales data, and the U.S. household count was derived from the U.S. Census (https://www.census.gov/data/tables/time-series/demo/families/households.html). There are approximately 1.4 million EVs on U.S. roads and about 125 million households in the U.S., so - on average - roughly 1.15% of US households own an EV.

[32] Bloomberg's 2020 Electric Vehicle Outlook (EVO). The 2022 Electric Vehicle Outlook (EVO) was released too late in the forecast's development to be included AFR 2022, but the overall adoption rate does not differ significantly from the 2020 adoption outlook.

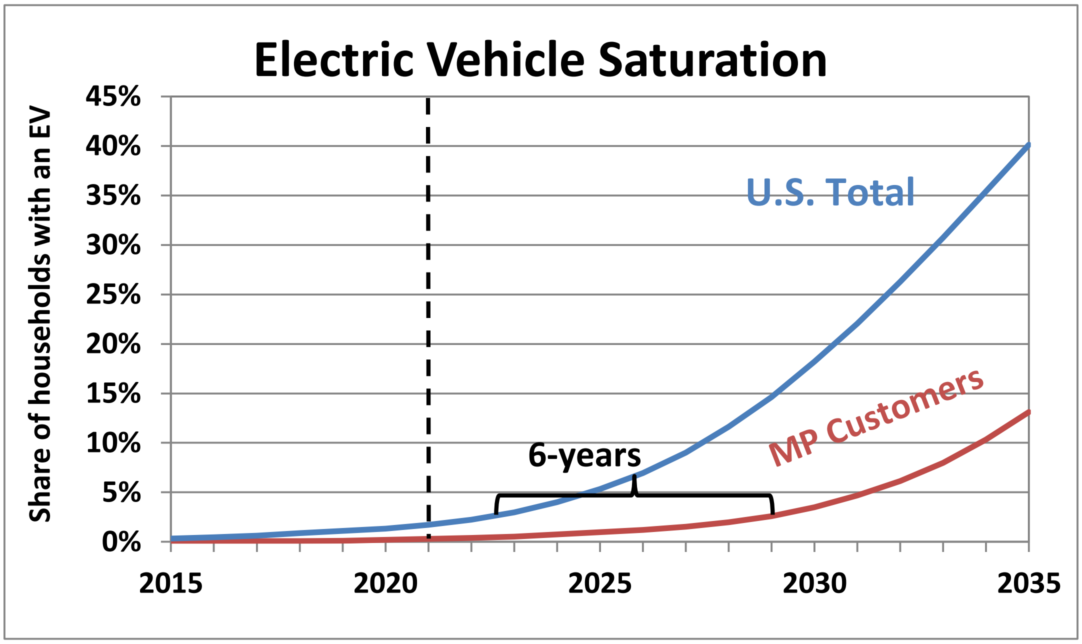

Figure 7: Minnesota Power vs. U.S. Electric Vehicle Saturation

The annual saturation rate outlook (shown in Figure 7) is then multiplied by Minnesota Power's residential customer count[33] to estimate the total number of EVs in Minnesota Power's service territory. The annual EV energy requirements forecast was calculated by multiplying the EV count and an estimate of per-unit energy requirements, which the Company assumes is about 2,520 kWh per year.[34] Table 6 shows the outlook for EVs in the Minnesota Power's service territory.

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33 Count of Standard Residential and All Electric accounts – excludes Dual Fuel and Controlled Access to avoid double counting and inflating the estimate of households served.

34 General Motors estimates the annual energy use of a Chevy Volt is 2,520 kWh – https://www.energy.gov/eere/electricvehicles/charging-home – Rough estimates of energy requirements based on regional commuting distances and 33 kWh per 100 miles (Nissan Leaf rated efficiency) produced 2,580 kWh, so the Chevy Volt estimate is likely an accurate enough assumption for long-term forecasting.

Table 6: Minnesota Power Residential Electric Vehicle Outlook

	Vehicle Count	Saturation	Energy Requirements (MWh)
2021	326	0.3%	280
2022	444	0.4%	579
2023	596	0.5%	961
2024	827	0.7%	1,543
2025	1,096	1.0%	2,221
2026	1,345	1.2%	2,849
2027	1,674	1.5%	3,679
2028	2,098	1.9%	4,747
2029	2,598	2.3%	6,007
2030	3,244	2.9%	7,634
2031	4,154	3.7%	9,927
2032	5,386	4.8%	13,032
2033	6,978	6.2%	17,044
2034	8,994	8.0%	22,125
2035	11,359	10.1%	28,084

The Company did not attempt to modify this annual energy requirement estimate (2,520 kWh) per regional commute distances or regional climate and related efficiency; both estimates would involve comparisons of national and regional characteristics that are difficult to make at this early stage of adoption. However, the Company did leverage regional temperature information to impart a seasonal (i.e. monthly) distribution to the overall annual EV energy requirements estimates.

EV energy requirements/efficiency will vary with temperature; consequently, EV efficiency will also vary by month. The Company combined regional weather information[35] with observations of the Nissan Leaf's seasonal efficiency[36] to identify this seasonal variance in energy requirements. The results suggest that EV efficiency is optimal between 60 and 70 degrees Fahrenheit which is the average daily temperature during the summer months in northeastern Minnesota.[37] During winter months, when the average daily temperature is just 15 degrees Fahrenheit, EVs will require about 40 percent more energy than during optimal conditions.

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35 The Company used a twenty-year historical average temperature by month at Duluth International Airport. This is consistent with weather assumptions used in energy and peak demand forecasting.

36 https://pubs.acs.org/doi/suppl/10.1021/es505621s/suppl_file/es505621s_si_001.pdf

37 The Company recognizes that temperature during a summer day may vary considerably, and that overall efficiency in summer months should be lower than optimal. More accurate assumptions for

Identifying the impact of EV charging on monthly peak demand requires information on charging patterns/characteristics – i.e. how/when customers will tend to charge their vehicles. A National Renewable Energy Laboratory (NREL) value assessment study of electric vehicles[38] contained modeled EV charging patterns for several customer types. For the purposes of determining EV charging load coincident with the system peak demand, Minnesota Power assumed the charging profile representative of: level 1 charging, at a single family dwelling, with *no* Time of Use (TOU) restriction or rate.

Per these profiles, approximately 12 percent of daily residential EV energy requirements are met at the most typical winter peak hour (6 PM) and about 6 percent of daily EV energy requirements are met during the likely summer peak hour (3 PM).[39]

The Company projects that by 2035, about 10 percent of Minnesota Power customers will own an EV, and Minnesota Power will be the primary service provider to about 11,400 EVs. This outlook assumes Minnesota Power customers' EV penetration and adoption continues to lag the U.S. by about 6 years. The Company attributes this lag in adoption to issues of income, population density/cost-efficiency of commercial charging station locations, and reduced efficiency in cold-weather. These factors may be overcome with technological advancement or a rapid escalation in gasoline costs, or Minnesota Power customers may "catch-up" to the rest of the country in EV adoption regardless of these limiting factors. The Company will refresh its EV forecast and methodology each year, and will publish the results along with any substantive methodological changes or key findings in the AFR.

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seasonal/temperature-related efficiency would involve more complicated assumptions for driving times and coincident temperatures. This is something the Company will investigate in the future. The Company opted for simplicity of assumption in this regard for this inaugural EV forecast.

38 https://www.nrel.gov/docs/fy17osti/66980.pdf

39 The Company recognizes that these assumptions do not capture the mid-day load potential for commercial or "at work" charging, and only accounts for home charging patterns. This is not an oversight. The Company does not currently have sufficient information to project commercial charging, but will re-evaluate in future iterations of the AFR.

4. Methodological Strengths and Weaknesses

The Company's forecast process combines econometric modeling with a sensible approach to modifying model outputs for assumed changes in large customer loads or new technology adoption. An econometric approach, utilizing regression modeling, is optimal for estimating a baseline projection with a given economic outlook and capturing the historical and projected effects of energy efficiency. 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.

The Company's econometric modeling process has two key strengths: it is 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 additions/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 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. The Company addresses this potential for error by maintaining close contact with existing and potential customers to keep current on their plans.

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.

1. AFR 2022 Forecast Database Inputs

Weather

Weather data for Duluth, Minnesota was collected for historical periods from the National Oceanic and Atmospheric Administration (NOAA) and from Weather Underground (WU).[40] Minnesota Power utilizes Monthly HDDs and CDDs 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 results 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 twenty-year historical average for each month (Jan 2001 – Dec 2020). For example, January's forecast assumption is an average of Jan-01, Jan-02, Jan-03, etc. through Jan-20.

Temperature, humidity, and wind-chill data used to model peak demand are derived from Schneider Electric. In previous forecasts, the Company has leveraged either NOAA or WU for daily or monthly-frequency values. The AFR 2022 forecast database features weather observations that are specific to the historical peak hour (i.e. the temperature, humidity, and wind-chill at the time of the peak). This closer alignment between the peak demands and the weather that induced them should produce a more accurate estimate of weather-sensitivity and a more accurate forecast of future peak demand.

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

Development of the historical weather series begins by establishing the date and time of historical monthly peaks. Weather observations for these date/times is then gathered and organized into a monthly-frequency weather series.

Calculating a twenty-year historical average of peak-time weather for use as a forecast assumption requires recorded peak dates for the timeframe prior to the establishment of the current electronic database (1998-1999). 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 twenty-year history.

A Temperature-Humidity Index (THI)[41] 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 75 degrees. A Wind-Chill (WC) index[42] was also utilized to capture the cold temperatures and, when applicable, the cooling effects of wind speed. The WC index is only applicable when temperatures drop below 40 degrees and wind speeds are greater than 3 miles per hour.

IHS Global Insight

IHS Global Insight is the singular source for all economic and demographic outlooks used in Minnesota Power's load forecast.[43] A single source for National, Metropolitan Statistical Area (MSA), and County-level outlooks ensures internal consistency of forecast assumptions.

IHS Global Insights data development process begins with producing a national-level forecast. County-level and MSA data for Northeast Minnesota is then 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.

Since 2009, Minnesota Power has utilized IHS Global Insight estimates of historical and forecast economic activity in Northeast Minnesota as key inputs to energy and customer count

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41 http://www.wpc.ncep.noaa.gov/html/heatindex_equation.shtml.
42 http://www.nws.noaa.gov/os/windchill/index.shtml.
43 With the exception of two series that are derived from REMI: Population and GRP for the 13-County Planning Region.

models. Recent years' forecast processes have featured an expansion of IHS Global Insight data use, and AFR 2022 continues this trend towards greater granularity and constancy.

AFR 2014 featured the adoption of IHS Global Insight's national-level economic indicators as inputs to Industrial Production Index (IPI) modeling process. IHS Global Insight provided access to more national-level variables than the previous source[44] and allowed Minnesota Power to expand its IPI forecast database. The data source change also maintained consistency of assumption in all areas of Minnesota Power's forecast process and among all levels of geographic granularity.

In both AFR 2015 and AFR 2016, the Company expanded the forecast database to include more geographically-granular indicators to add predictive power by more-closely aligning with the area containing Minnesota Power's customer base. AFR 2015 featured the addition of Duluth Metropolitan Statistical Area (Duluth MSA)[45] economic indicators, and the AFR 2016 database was expanded to include economic indicators for all *individual* counties in the 13-County Planning Area in addition to the 13-County Planning Area Aggregate.[46] This expanded the number of economic/demographic predictor variables from 78 (in AFR 2015 database) to 454 (in the AFR 2016 and subsequent databases).

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 the historical series used in Minnesota Power's forecast database. Thus, the historical regional employment and income data has changed from last year's database.

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.

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44 Blue Chip Economic Indicators.

45 The Duluth MSA is defined as St. Louis and Carlton counties in Minnesota, and Douglas County in Wisconsin.

46 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 Minnesota, and Douglas County Wisconsin.

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[47] 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 AFR 2022, 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.

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 GRP are not provided by IHS Global Insight 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 are 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, 2012 in this case (that is, 2012 = 100). The indexes exhibit a high degree of correlation with Minnesota Power's historical industrial energy sales and are, therefore, ideal for forecasting future energy sales to the class.

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

The historical national-level 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.[48]

Forecasts for each national-level IPI were developed from the projections of national-level economic indicators from IHS Global Insight, and are, therefore, consistent with all other AFR 2020 forecast assumptions. These macroeconomic drivers are used to model and forecast the national-level IPI series.

The historical Minnesota iron IPI was developed using actual iron ore production data from the U.S. Geological Survey website (USGS).[49] The projected Minnesota iron IPI was developed by scaling the national-level Iron IPI forecast using an assumption of the industry's composition going forward. Minnesota now comprises about 83 percent of U.S. product, so the Minnesota iron IPI equals the national-level IPI x 0.83. The entire historical and forecast Minnesota iron IPI was then indexed to 2012 for consistency with past AFRs, the other IPI series used in AFR 2022, and the U.S. Federal Reserve's current standard index year.

Note that Minnesota Power 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 2022 forecast database utilizes the seasonally adjusted historical indexes.

Energy Prices

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 the Company'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,

48 http://www.federalreserve.gov/releases/g17/revisions/Current/g17rev.pdf.
49 https://minerals.usgs.gov/minerals/pubs/commodity/iron_ore/.

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 2012 base year GDP implicit price deflator (IPD).

<u>Energy Efficiency, Distributed Solar, and Electric Vehicles</u>

Refer to section II.B.4. "Treatment of DSM, CIP, DG, and EV in the Forecast" for all data and assumption sources concerning Energy Efficiency, Distributed Solar, and Electric Vehicles.

2. Adjustments to Raw Energy Use and Customer Count Data

Minnesota Power made a limited number of adjustments to internally developed data for AFR 2022, which fall into three general categories:

1. Adjustments to raw customer count data for billing anomalies
2. Adjustments to raw sales and peak demand data for large load additions and losses
3. Adjustments to convert sales data into overall energy requirements data

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. Prior to the AFR 2014 process, Minnesota Power used both techniques, but their application was not entirely consistent. The Company's current database and modeling 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 2022 customer count and energy sales database contains 469 monthly points (about 4.2 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 BEGINS

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

TRADE SECRET DATA ENDS]

Notes on Adjustments to historical series:

- When assessing the ability of economic variables to reflect the above mentioned structural breaks, Minnesota Power identified those instances when the raw energy sales series could be modeled more accurately than the adjusted series; in these cases when the economic data explains the change, the use of the raw sales series is appropriate. When the adjusted series can be modeled more accurately than the raw series, then it is evident that the economic data cannot adequately explain the shift and the adjusted historical sales series should be utilized. However, it should be noted that it is the Company's preference to use binary variables in these instances when the relationship between variables has changed by some measurable constant. This technique utilizes the raw data series (unadjusted) as a result.

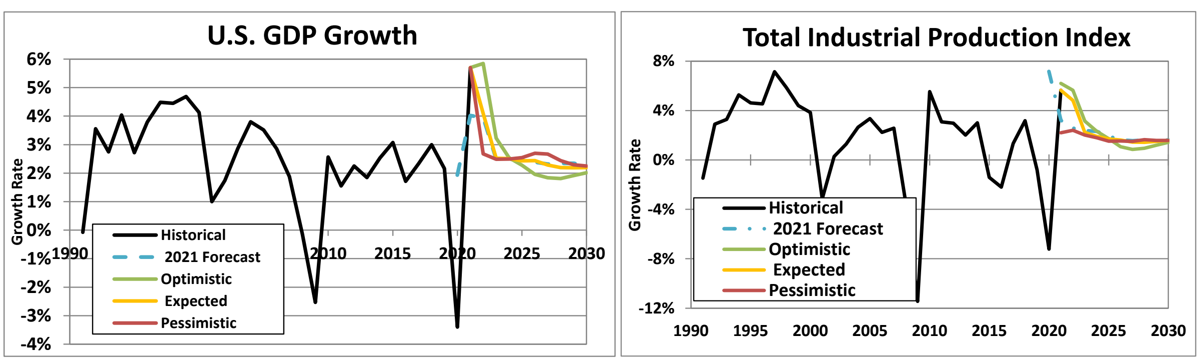
- When recent load additions or losses can be accurately quantified, they are removed from the historical sales and peak series prior to modeling and a post-regression adjustment is used to account for the load addition or loss in the forecast timeframe. When it is not possible to accurately quantify this recent change (e.g. if a customer is served by a municipal customer and their usage data is not accessible by Minnesota Power), then no adjustment is made to the historical data. 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 or the change can be modeled with a binary variable, Minnesota Power will cease the application of a specific post-regression adjustment.

D. Overview of Key Inputs/Assumptions

1. National Economic Assumptions

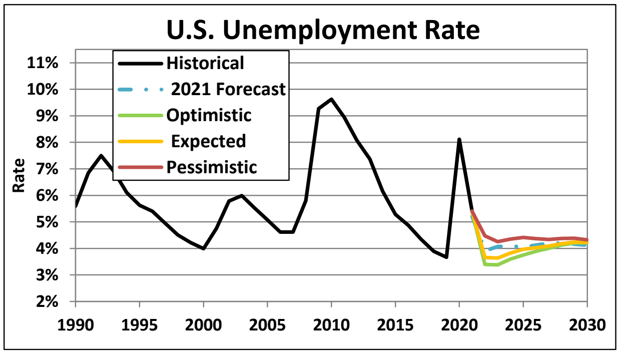
The national economic outlook is derived from IHS Global Insight and serves as the basis for Minnesota Power's regional economic model simulations. Some of the key outputs of the national economic forecast are GDP, IPI, unemployment rates, and auto sales. These variables are shown in Figures 8-11 below, for the Expected, Optimistic, and Pessimistic cases.

Figures 8 and 9: National Economic Outlook (GDP and Industrial Production)



The Expected case (yellow) macroeconomic outlook (yellow) serves as the underlying assumption for AFR 2022. In the Expected case, U.S. GDP and IPI growth average 2.6 and 2.1 percent per year from 2022-2035, respectively.

Figures 10 and 11: National Economic Outlook (Unemployment Rate and Auto Sales)



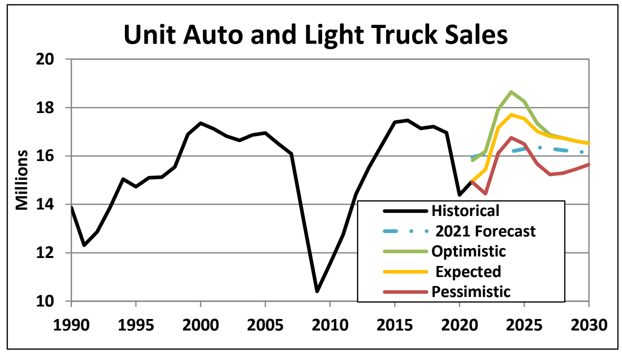
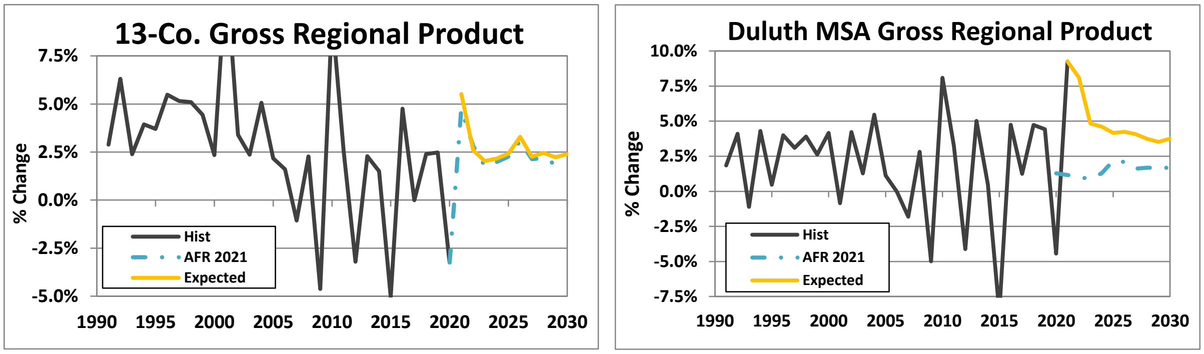


Figure 10 shows the unemployment rates in the three national outlooks all fluctuate in the first few years of the forecast timeframe before reaching long term labor market stability consistent with the assumed rate of GDP growth. Assumptions of unit auto and light truck sales in Figure 11 show a similar pattern in the forecast timeframe with moderate increases in the short-term and stabilization in the long-term.

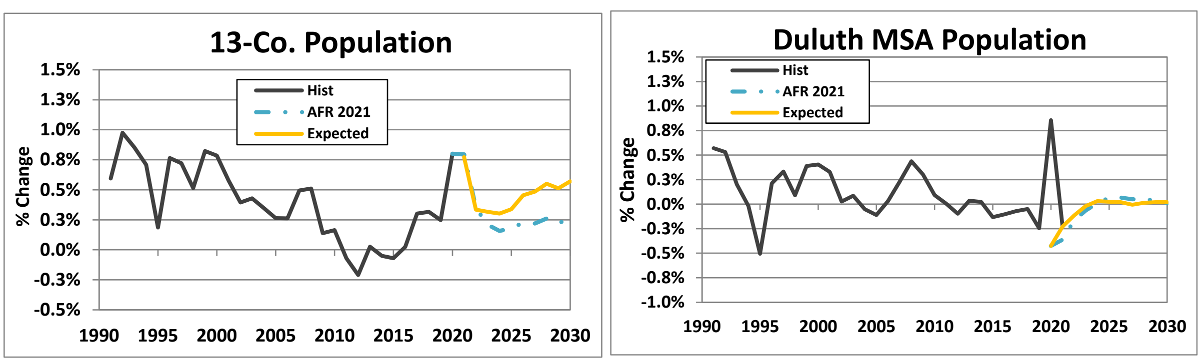
2. Regional Economic Assumptions

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 regional economic outlooks are further specified by incorporating scenario-specific inputs into REMI, as described in Section II.C. Figures 12 and 13 compare the historical and projected growth rate of both regions’ product.



Figures 12 and 13: Regional Economic Outlooks (13-County Product and Duluth MSA Product)

The 13-County Planning Area's Gross Regional Product averages 2.4 percent per-year growth in the forecast timeframe whereas the Duluth MSA product averages just 1.7 percent per-year in the forecast timeframe. Population growth rates show a similar trend: the 13-County Planning Area grows at about 0.5 percent in the forecast timeframe and the Duluth MSA area population declines at 0 percent per-year. The difference in the two regions' historical and projected growth, shown below in Figures 14 and 15, demonstrates why Minnesota Power expanded its database to include both Duluth MSA and the 13-County regional data.



Figures 14 and 15: Regional Economic Outlooks (13-County Population and Duluth MSA Population)

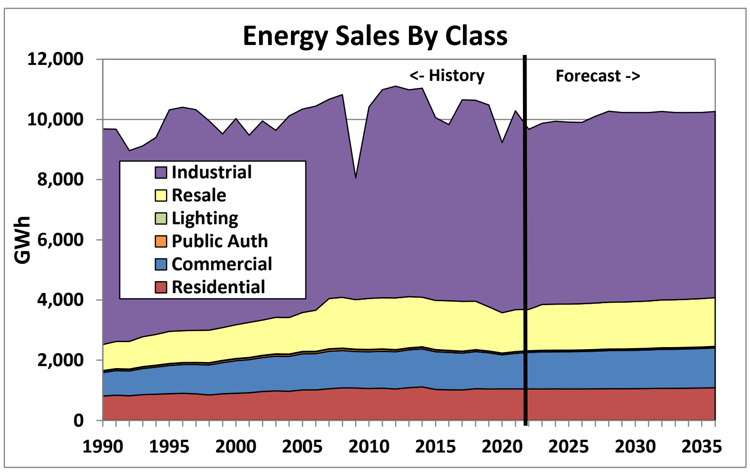
E. Econometric Model Documentation

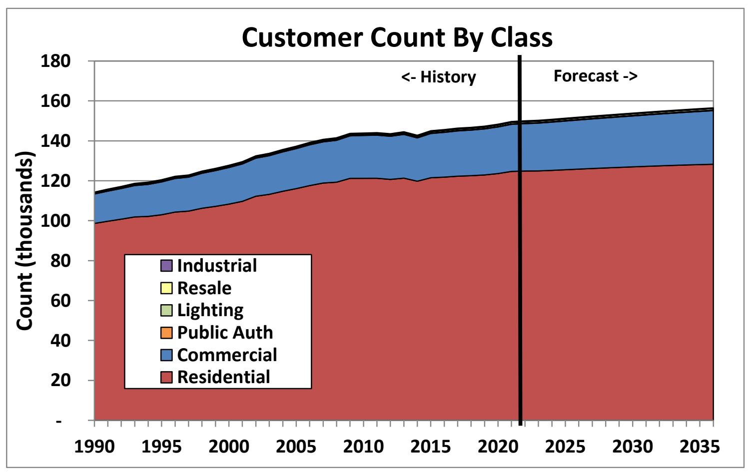
This section presents the statistical detail of all models utilized in the development of the AFR 2022 forecast. The model's structure, key diagnostic statistics, forecast results, and a discussion of the model are provided for added transparency.

Models are shown with each variable's coefficient, t-statistic, P-value, and VIF. A graph displays the historical series, growth rates for timeframes 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 the OLS model 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.

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).





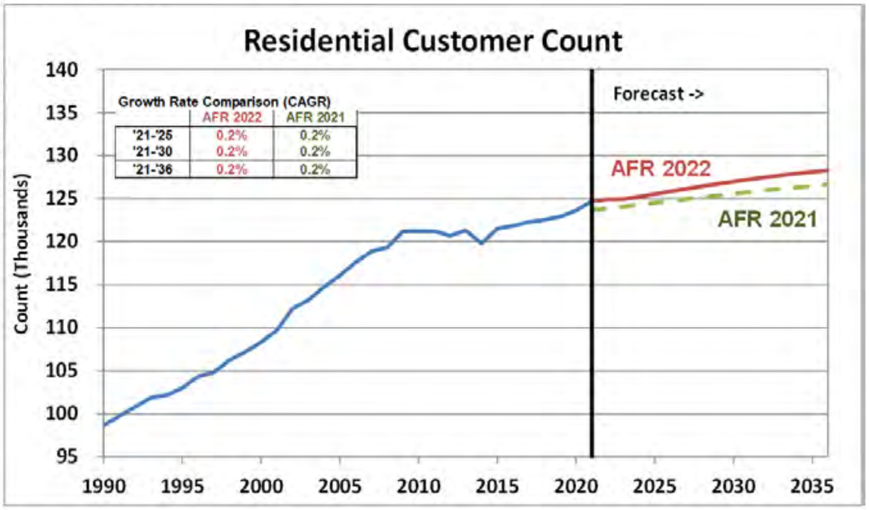
Figures 16 and 17: Projection of Energy Sales and Customer Count by Class

Minnesota Power did not develop a model to forecast Resale customer count. Minnesota Power currently has 16 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 - Expected Scenario

Estimation Start/End:	1/1990 - 12/2021
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	98,156.37	0.00%	0.00%
Bill_Res_1	(2,136.71)	0.00%	0.00%
Bill_Res_2	(2,797.47)	0.00%	0.00%
Bi_2009_2036	8,196.67	0.00%	0.00%
Trend_2009_2036	(33.25)	0.00%	0.00%
Res_C_2021_2036	1,751.23	0.00%	0.00%
MSA_HousStart_Cumulative	1.07	0.00%	0.00%



Residential Customer Count

	Count	Y/Y Growth
2011	121,251	
2012	120,697	-0.5%
2013	121,314	0.5%
2014	121,601	0.2%
2015	121,515	-0.1%
2016	121,836	0.3%
2017	122,295	0.4%
2018	122,557	0.2%
2019	122,926	0.3%
2020	123,617	0.6%
2021	124,691	0.9%
2022	124,899	**0.2%**
2023	124,940	**0.0%**
2024	125,212	**0.2%**
2025	125,528	**0.3%**
2026	125,851	**0.3%**
2027	126,152	**0.2%**
2028	126,431	**0.2%**
2029	126,706	**0.2%**
2030	126,979	**0.2%**
2031	127,235	**0.2%**
2032	127,478	**0.2%**
2033	127,707	**0.2%**
2034	127,919	**0.2%**
2035	128,111	**0.2%**
2036	128,288	**0.1%**

Model Statistics	Magnitude
Adjusted R^2	99.8%
AIC	5718
Durban-Watson	0.7
MAPE	0.27
In-Sample RMSE	410

Model Discussion

Both AFR 2022 and AFR 2021 forecasts for residential customer count had annual growth rates of 0.2%, but AFR 2022 starts from a slightly higher level.

The key economic variable driving the residential customer count projection was Duluth MSA Cumulative Housing Starts, which is a rolling accumulation of annual housing starts beginning in 1990 . This transformation converts a rate variable into a level variable, which better describes the underlying long-term trend of customer growth.

A combination of binary and trend variables ("Bi_2009_2036"" and "Trend_2009_2036") denote post-recession shifts in the relationship of MSA housing starts and residential customer count; housing starts continued, but customer counts stalled. This may be due in part to a shift towards suburban construction, where home construction continued but just outside Minnesota Power service territory. Without these corrective binary and a trend variables, the model would overestimate customer counts in recent historical years and, presumably, in the forecast timeframe.

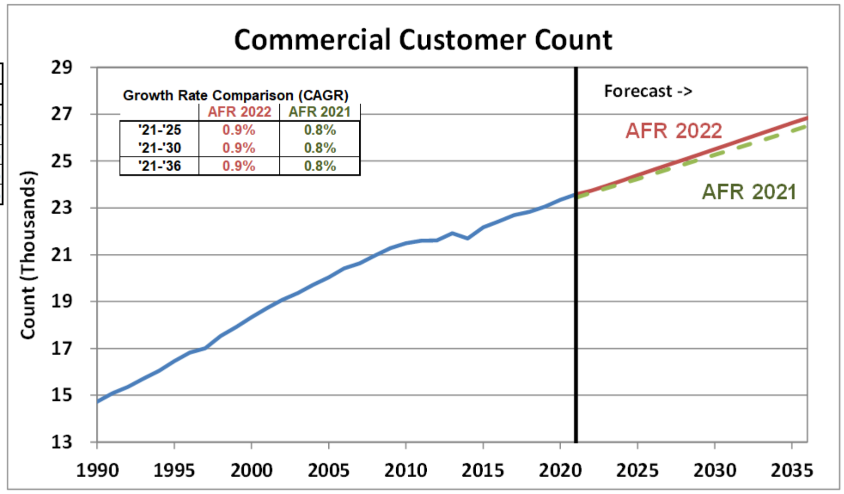
The "Res_C_2021_2036" binary variable begins in mid-2021 and denotes a realignment of the MSA housing starts metric and customer counts; the mid-pandemic increase in demand for housing appears to be driving residential development in Minnesota Power's service territory, leading to customer growth. Two binary variables (Bill_Res) account for divergence from long-term trends due to "seasonal billing" between 1994 and 2001. This accounting practice recorded customer counts from November to May as 2,000-6,000 lower than from June to October.

This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the AIC indicates a highly parsimonious model that's not over fit. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics such as the MAPE indicate model accuracy is comparable to bot the AFR 2021 (0.2%) and 2020 (0.3%) models.

Commercial Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2021
Unit Modeled/Forecast:	Monthly Customer Count

Variable	Model Specifications		
	Coefficient	P-Value	HAC-P-Value
CONST	13,682.10	0.00%	0.00%
T	27.65	0.00%	0.00%
Bi_2010_2036	2,382.84	0.00%	0.00%
Trend_2010_2036	(11.23)	0.00%	0.00%
MSA_Real_GMP	0.10	0.00%	0.00%



Commercial Customer Count

	Count	Y/Y Growth
2011	21,603	
2012	21,614	0.1%
2013	21,915	1.4%
2014	22,096	0.8%
2015	22,170	0.3%
2016	22,420	1.1%
2017	22,695	1.2%
2018	22,834	0.6%
2019	23,059	1.0%
2020	23,346	1.2%
2021	23,580	1.0%
2022	23,732	**0.6%**
2023	23,947	**0.9%**
2024	24,168	**0.9%**
2025	24,401	**1.0%**
2026	24,621	**0.9%**
2027	24,841	**0.9%**
2028	25,062	**0.9%**
2029	25,281	**0.9%**
2030	25,505	**0.9%**
2031	25,729	**0.9%**
2032	25,955	**0.9%**
2033	26,177	**0.9%**
2034	26,399	**0.8%**
2035	26,622	**0.8%**
2036	26,844	**0.8%**

Model Statistics	Magnitude
Adjusted R^2	99.8%
AIC	4700
Durban-Watson	1.1
MAPE	0.40
In-Sample RMSE	109

Model Discussion

The AFR 2022 forecast of commercial customer count is similar to the AFR 2021 outlook despite the COVID-19 recession, which did not appear to significantly impact commercial customer counts. The forecast's long-term annual growth rate increased slightly from AFR 2021 (0.8%) to 0.9%.

The key economic driver of customer growth was Duluth MSA Real Gross Metro Product (GMP). Local GMP has historically tracked well with commercial customer counts, but COVID-19 caused the two series (GMP and commercial counts) to diverge. GMP contracted sharply, following national GDP, while commercial customer counts remained steady, likely due to government supports like the Paycheck Protection Program (PPP) and Minnesota Power suspending disconnections for small business (general service) customers facing financial hardship in relation to the coronavirus pandemic. A Trend variable accounts for some of this underlying customer count growth that appears unrelated to immediate economic conditions.

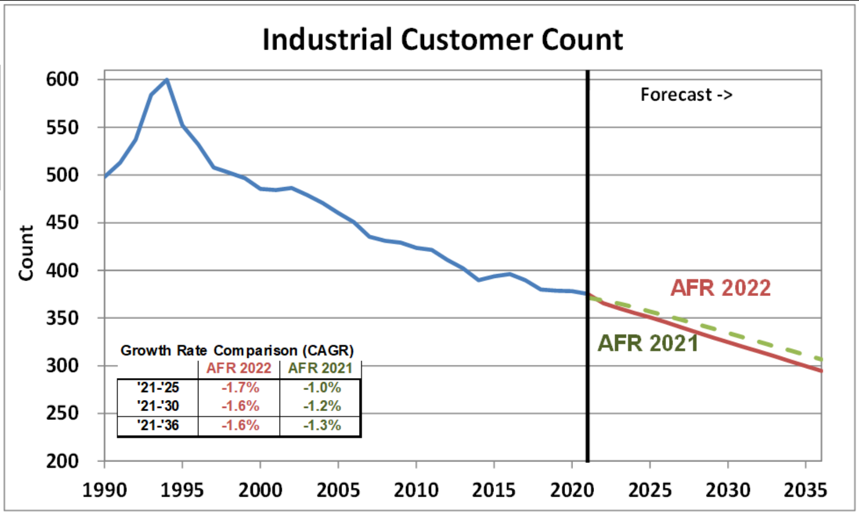
A combination of binary and trend variables ("Bi_2010_2036" and "Trend_2010_2036") denote a post-Great Recession, abrupt shift in customer count growth – customer counts grew at an average rate of 2.0% prior to 2010, and only 0.8% since. Without these corrective binary and trend variables, the model would overestimate customer counts in recent historical years and, presumably, in the forecast timeframe.

This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are very similar: MAPE is the same as the 2021 model (0.4%), and RMSE is 109 vs. 107 in the 2021 model.

Industrial Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2021
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	428.70	0.00%	0.00%
Time_Trend	(0.36)	0.00%	0.00%
Ind_1991_1997	41.93	0.00%	0.00%
MFG_13	0.005	0.00%	0.00%



Industrial Customer Count

	Count	Y/Y Growth
2011	421	
2012	411	-2.4%
2013	402	-2.2%
2014	394	-2.0%
2015	394	-0.1%
2016	396	0.6%
2017	390	-1.6%
2018	380	-2.5%
2019	379	-0.3%
2020	378	-0.2%
2021	375	-0.7%
2022	366	**-2.6%**
2023	360	**-1.5%**
2024	355	**-1.4%**
2025	351	**-1.3%**
2026	346	**-1.4%**
2027	340	**-1.6%**
2028	335	**-1.5%**
2029	330	**-1.5%**
2030	325	**-1.5%**
2031	320	**-1.5%**
2032	315	**-1.6%**
2033	310	**-1.6%**
2034	305	**-1.6%**
2035	300	**-1.7%**
2036	295	**-1.7%**

Model Statistics	Magnitude
Adjusted R^2	92.8%
AIC	3268
Durban-Watson	0.1
MAPE	2.25
In-Sample RMSE	17

Model Discussion

The AFR 2022 forecast annual growth rate for industrial customer count decreased from -1.3% to -1.6%, but the customer count projection is similar; AFR 2022 is just 11 customers lower than the AFR 2021 outlook by 2035.

The key economic driver of industrial customer count was Manufacturing sector employment (13-County). This sector was a good representation of Minnesota Power's industrial customers as it encompasses the range of business sectors in this class, including: wood products, pulp/paper/paperboard mills, food products, foundries, and petroleum refining.

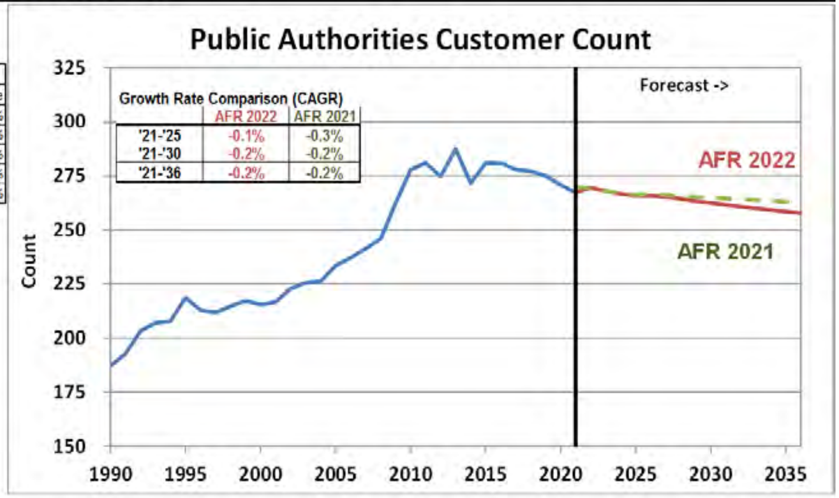
"Ind_1991_1997" is a binary variable that denotes the January-1991 through December-1997 timeframe where Industrial customer counts increased and then decreased very rapidly: a 23.7% increase from January-1991 to June-1994, followed by a 36.2% decrease from June-1994 to December-1997. These dramatic swings in customer counts were most likely due to accounting classifications of customers at the time and this binary variable effectively "backs-out" these points from consideration to avoid biasing the model.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. The MAPE has improved: 2.25% vs. 2.3% in the AFR 2021 model, and RMSE is unchanged at 17 from last year's model.

Public Authorities Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2021
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	128.35	0.00%	0.00%
BI_7_2009	38.16	0.00%	0.00%
Bi_2015_2036	100.86	0.00%	0.00%
Trend_2015_2036	(0.32)	0.00%	0.00%
GRP_13	4.68	0.00%	0.00%



Public Auth. Customer Count

	Count	Y/Y Growth
2011	281	
2012	275	-2.3%
2013	287	4.6%
2014	282	-1.9%
2015	281	-0.4%
2016	281	-0.1%
2017	278	-1.0%
2018	277	-0.3%
2019	275	-0.7%
2020	271	-1.5%
2021	267	-1.4%
2022	269	**0.8%**
2023	268	**-0.6%**
2024	267	**-0.5%**
2025	266	**-0.3%**
2026	266	**0.0%**
2027	265	**-0.3%**
2028	264	**-0.3%**
2029	263	**-0.4%**
2030	262	**-0.3%**
2031	262	**-0.3%**
2032	261	**-0.3%**
2033	260	**-0.3%**
2034	259	**-0.3%**
2035	258	**-0.3%**
2036	258	**-0.3%**

Model Statistics	Magnitude
Adjusted R^2	97.2%
AIC	2386
Durban-Watson	0.4
MAPE	1.71
In-Sample RMSE	5.4

Model Discussion

The AFR 2022 forecast annual growth rate for public authorities customer count is identical to the AFR 2021 model at -0.2%.

The key economic driver of customer growth was 13-County Gross Regional Product (GRP). GRP is a measure of general economic health that correlates with local government revenues, and presumably local government accounts with Minnesota Power. A binary variable starting in July-2009 accounts for a step-change or "systematic shift" in the historical accounting data. 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.

The combination of a binary and a trend variable for the 2015-2036 timeframe mark a shift in the level and trend of the estimate to align with recent customer growth. These variables effectively shift the first forecast year (2022) to align with the last historical year (2021). Without these corrective variables, a small but growing divergence between actual and predicted customer growth suggests the economic indicators alone would overstate customer count, and the 2022 forecast value confirms this. Without these binary and trend variables, the model would project an abrupt and unreasonably large increase in customers in 2022.

This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are comparable to the AFR 2021 model: MAPE is unchanged 1.7%, and RMSE is unchanged at 5.4.

Street Lighting Customer Count - Expected Scenario

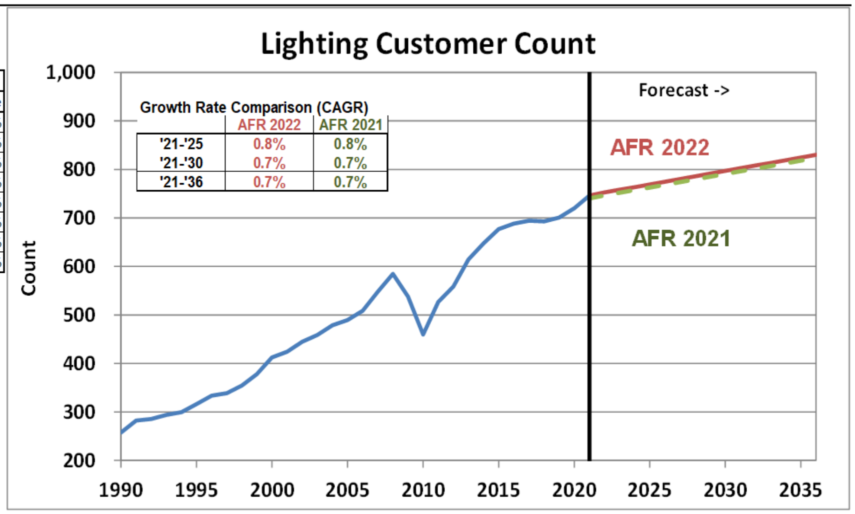
Estimation Start/End:	1/1990 - 12/2021
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	227.20	0.00%	0.00%
Time_Trend	1.47	0.00%	0.00%
Bi_2009_2014	(723.40)	0.00%	0.00%
Trend_2009_2014	2.46	0.00%	0.00%
Bi_2015_2036	310.64	0.00%	0.00%
Trend_2015_2036	(1.01)	0.00%	0.00%
Bi_2020_2036	5.57	51.54%	2.81%
Trend_2020_2036	2.20	0.50%	0.00%

Lighting Customer Count

	Count	Y/Y Growth
2011	5,335	
2012	6,414	20.2%
2013	655	-89.8%
2014	660	0.8%
2015	673	2.0%
2016	689	2.4%
2017	695	0.9%
2018	693	-0.3%
2019	701	1.1%
2020	720	2.7%
2021	746	3.7%
2022	753	**0.8%**
2023	758	**0.7%**
2024	764	**0.7%**
2025	769	**0.7%**
2026	775	**0.7%**
2027	780	**0.7%**
2028	786	**0.7%**
2029	791	**0.7%**
2030	797	**0.7%**
2031	803	**0.7%**
2032	808	**0.7%**
2033	814	**0.7%**
2034	819	**0.7%**
2035	825	**0.7%**
2036	830	**0.7%**

Model Statistics	Magnitude
Adjusted R^2	99.1%
AIC	3157
Durban-Watson	0.1
MAPE	2.66
In-Sample RMSE	15



Model Discussion

The AFR 2022 forecast annual growth rate for street lighting customer count is nearly identical to AFR 2021.

A combination of a binary and trend variable starting in July-2009 account for a step-change or “systematic shift” in the historical accounting data and extends through December-2014.

A combination of a binary variable and trend variable denoting the 2015-2036 timeframe pick up where the 2009-2014 variable left off, shifting the level and trend of the estimate to align with the updated accounting data going forward.

The combination of a binary and a trend variable for the 2020-2036 timeframe (beginning early-2020) mark a shift in the level and trend of the estimate to align with recent customer growth (this was in addition to the 2015-2036 change in forecast trajectory captured by the variables above). These variables effectively shift the first forecast year (2022) to align with the last historical year (2021). Without these corrective variables, 2022 monthly forecasted values would be understated.

This year’s model is comparable to last year’s in terms of statistical quality. The Adjusted R-Squared indicates there’s a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values (“HAC-P-Value”) suggests all variables’ coefficients’ are significant. In-sample error metrics such as MAPE and RMSE are nearly identical.

Other Industrial Remaining Customer Count - Expected Scenario

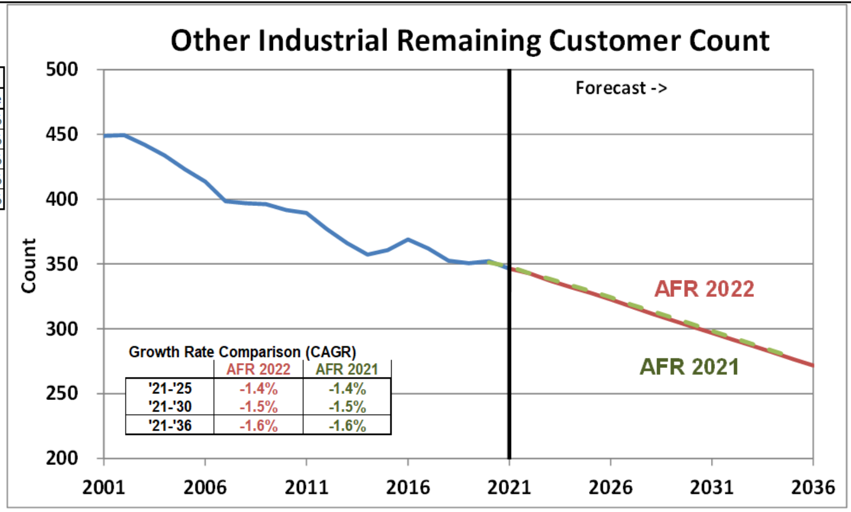
Estimation Start/End:	1/2001 - 12/2021
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	452.10	0.00%	0.00%
Time_Trend	(0.42)	0.00%	0.00%
Remaining_2019_2036	10.33	0.00%	0.01%
GRP_13_diff	24.89	0.00%	0.29%
MFG_13	0.002	0.00%	0.00%

Oth Ind Remaining Cust Count

	Count	Y/Y Growth
2011	389	
2012	377	-3.2%
2013	366	-2.9%
2014	357	-2.4%
2015	361	1.0%
2016	369	2.3%
2017	362	-1.9%
2018	353	-2.6%
2019	351	-0.5%
2020	352	0.4%
2021	346	-1.6%
2022	343	**-1.1%**
2023	337	**-1.6%**
2024	332	**-1.5%**
2025	328	**-1.4%**
2026	323	**-1.5%**
2027	317	**-1.7%**
2028	312	**-1.7%**
2029	307	**-1.7%**
2030	302	**-1.6%**
2031	297	**-1.6%**
2032	292	**-1.7%**
2033	287	**-1.7%**
2034	282	**-1.8%**
2035	277	**-1.8%**
2036	272	**-1.8%**

Model Statistics	Magnitude
Adjusted R^2	96.0%
AIC	1683
Durban-Watson	0.3
MAPE	1.35
In-Sample RMSE	6.8



Model Discussion

AFR 2022 continued the approach implemented in AFR 2021, which featured a more granular approach to forecasting the Other Industrial sector of the industrial class, and independently modeled the Pipelines, Foundries, Food Product Manufacturing, and Remaining industrial sectors individually. The "Other Industrial: Remaining" customer count includes all industrial customers not assigned to Mining, Paper, Pipelines, Foundries, or Food Product Manufacturing, and accounts for about 90% of the total industrial customer count. The Pipelines, Foundries, and Food Products sectors' customer counts have been fairly stable over time, but the "Other Industrial: Remaining" sector tends to be more acutely affected by national business cycles or regional economic conditions, and requires modeling.

Key economic drivers of customer count were 13-County Gross Regional Product (GRP) and Manufacturing sector employment (13-County). GRP is a measure of overall economic health and correlates well with the number of industrial entities doing business in Minnesota Power's service territory. Manufacturing sector employment encompasses the majority of their businesses, including: nonferrous metal production/processing, chemical manufacturing, etc.

A binary variable ("Remaining_2019_2036") begins in late-2019 and denotes a shift in the relationship between the economic variables and remaining industrial customer count not fully explained by economic variables alone. This may be due to customers in this class being better suited to handle the COVID-19 recession based on their business model. Without this corrective binary variable, the model would underestimate customer counts in recent historical years (by 2-4%) and, presumably, in the forecast timeframe.

The Adjusted R-Squared indicates there's high goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample MAPE and RMSE are nearly identical to the AFR 2021 model 1.35% and 6.8 respectively. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Residential Energy Use - Expected Scenario

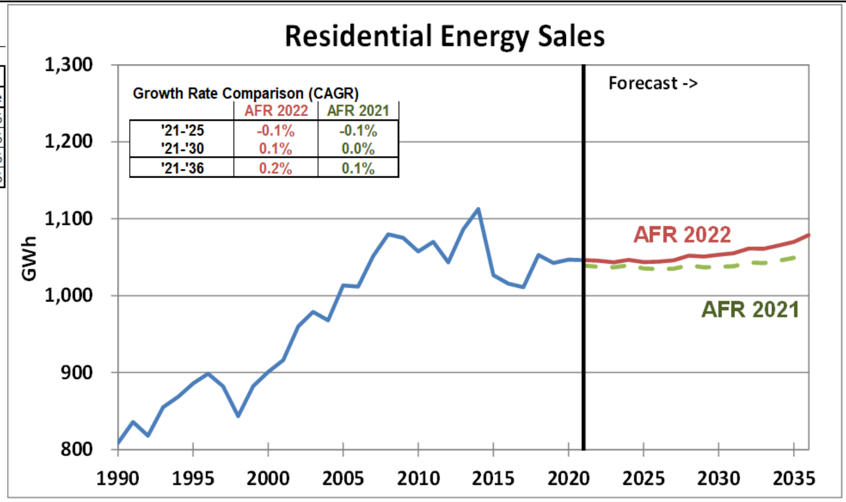
Estimation Start/End:	1/1990 - 12/2021
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	15.66	0.00%	0.00%
EE_Res	(0.0000015)	0.55%	0.49%
Dul_HDDpd	0.26	0.00%	0.00%
Dul_CDDpd	1.44	0.00%	0.00%

Residential Energy Sales

	MWh	Y/Y Growth
2011	1,069,856	
2012	1,043,281	-2.5%
2013	1,086,481	4.1%
2014	1,112,579	2.4%
2015	1,026,454	-7.7%
2016	1,015,465	-1.1%
2017	1,010,955	-0.4%
2018	1,052,800	4.1%
2019	1,042,353	-1.0%
2020	1,046,910	0.4%
2021	1,046,341	-0.1%
2022	1,044,992	-0.1%
2023	1,043,077	-0.2%
2024	1,046,600	0.3%
2025	1,043,853	-0.3%
2026	1,044,659	0.1%
2027	1,046,626	0.2%
2028	1,053,163	0.6%
2029	1,052,296	-0.1%
2030	1,055,093	0.2%
2031	1,057,715	0.2%
2032	1,064,445	0.6%
2033	1,065,005	0.0%
2034	1,069,938	0.4%
2035	1,075,484	0.4%
2036	1,085,565	0.8%

Model Statistics	Magnitude
Adjusted R^2	80.8%
AIC	1631
Durban-Watson	1.9
MAPE	6.28
In-Sample RMSE	2.0



Model Discussion

The graph above shows the final residential energy sales outlook, which combines the econometric forecast (i.e. the product of the use-per-customer per day model and the customer count model) and the projected impacts of electric vehicle and distributed solar adoption.

The AFR 2022 residential per-customer use model did not use an employment or demographic indicator variable as these variables rarely correlate well with per-customer usage and often are not intuitive or explainable. Instead, the Company uses weather and seasonal binary variables to indicate month-to-month variation in sales, a time-trend to indicate long-term underlying growth, and an Energy Efficiency variable to explain recent changes (since 2007) in the underlying trend of per-customer usage growth.

The "EE_Res" variable represents the cumulative effects of all past conservation measures on each year's sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year. The variable's construction and the Company's hypothesis regarding its effectiveness in modeling usage is documented in Section II.B.3.

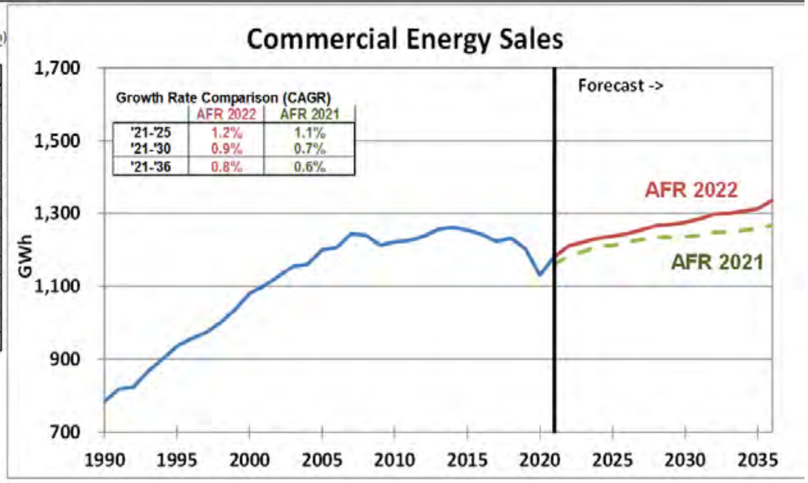
The AFR 2022 model uses simple monthly HDD and CDD (per-day) specifications. The monthly total HDD and CDD values are normalized for the number of days in a month by dividing the monthly HDD or CDD count by the number of days in the month – this results in the "per-day" series HDDpd and CDDpd. For a more detailed description of this process see Section II.C.1.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are similar but have degraded a bit, likely due to the effects of Covid19: MAPE is 6.2% vs 5.6% in the 2021 model, and RMSE is 2 vs. 1.8 in the 2021 model.

Commercial Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2021
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	47.35	0.00%	0.00%
Jan	(7.56)	0.01%	0.05%
Apr	(12.37)	0.00%	0.00%
May	(9.16)	0.00%	0.00%
Aug	11.07	0.00%	0.00%
Sep	7.56	0.02%	0.01%
Oct	(10.58)	0.00%	0.00%
Nov	(11.85)	0.00%	0.00%
Bi_2007_2036	3.08	3.50%	0.07%
EE_Com	(0.00)	0.00%	0.00%
Dul_HDDpd	0.4780	0.00%	0.00%
Dul_CDDpd	4.00	0.00%	0.00%
EmpltoPop_13	240.54	0.00%	0.00%



Commercial Energy Sales

	MWh	Y/Y Growth
2011	1,226,174	
2012	1,237,386	0.9%
2013	1,256,540	1.5%
2014	1,262,464	0.5%
2015	1,254,681	-0.6%
2016	1,243,045	-0.9%
2017	1,223,786	-1.5%
2018	1,233,117	0.8%
2019	1,202,403	-2.5%
2020	1,131,101	-5.9%
2021	1,181,246	4.4%
2022	1,214,991	**2.6%**
2023	1,232,760	**0.8%**
2024	1,233,344	**0.9%**
2025	1,237,668	**0.4%**
2026	1,244,434	**0.6%**
2027	1,255,222	**0.9%**
2028	1,266,480	**0.9%**
2029	1,269,252	**0.2%**
2030	1,275,024	**0.5%**
2031	1,284,253	**0.7%**
2032	1,297,015	**1.0%**
2033	1,299,603	**0.2%**
2034	1,305,493	**0.5%**
2035	1,311,661	**0.5%**
2036	1,323,294	**1.8%**

Model Statistics	Magnitude
Adjusted R^2	65.6%
AIC	2789
Durban-Watson	2.7
MAPE	4.57
In-Sample RMSE	9

Model Discussion

The AFR 2022 forecast of commercial energy use is higher than AFR 2021 due to a faster than anticipated rebound from the COVID-19-induced recession. Customer growth and use-per-customer are higher than estimated in AFR 2021, and - as a result - the commercial energy use forecast grows at a 0.8% per year (average) pace, compared to the AFR 2021 forecast (0.6%).

The graph above shows the final commercial energy sales outlook, which combines the econometric forecasts of use-per-customer per day and customer count, along with arithmetic adjustments for: 1) the planned installation of new generation at a specific customer's facility, and 2) the projected impacts of distributed solar adoption.

The key driver of this year's commercial energy use model was the 13-County Employment-to-Population ratio. COVID-19 resulted in a substantial loss of energy sales without any corresponding decrease in customer counts, which is unprecedented and difficult to model with the typical economic indicators. The Employment-to-Population ratio indicates the rate of employment utilization, and both correlates and explains commercial property/account energy utilization during the initial economic contraction and recovery from COVID-19.

"Bi_2007_2036" is a binary variable starting in 2007 that accounts for a step-change, or "systematic shift," in energy use for this class around the time of the 2007 Energy Act. Sales to this class have remained essentially flat since this time (aside from the COVID-19 recession of 2020).

The AFR 2022 model uses an Energy Efficiency variable as a predictor of commercial per-customer sales: the "EE_Com" variable represents the cumulative effects of all past conservation measures on each year's sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year. The variable's construction and the Company's hypothesis regarding its effectiveness in modeling usage is documented in Section II.B.3.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared of 65% indicates there's just a moderate traditional "goodness-of-fit", but this was the case in last year's model as well (Adjusted R-Squared was only 63%) and the Company does not consider the R-Squared an indicator of predictive quality. Minnesota Power leverages other objective metrics for determining model selection such as Mean Absolute Percent Error and Root Mean Square Error.

The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are similar: MAPE is 4.7% vs. 4.5% in the 2021 model, and RMSE is 9 vs. 9 in the 2021 model.

Mining and Metals Energy Use - Expected Scenario

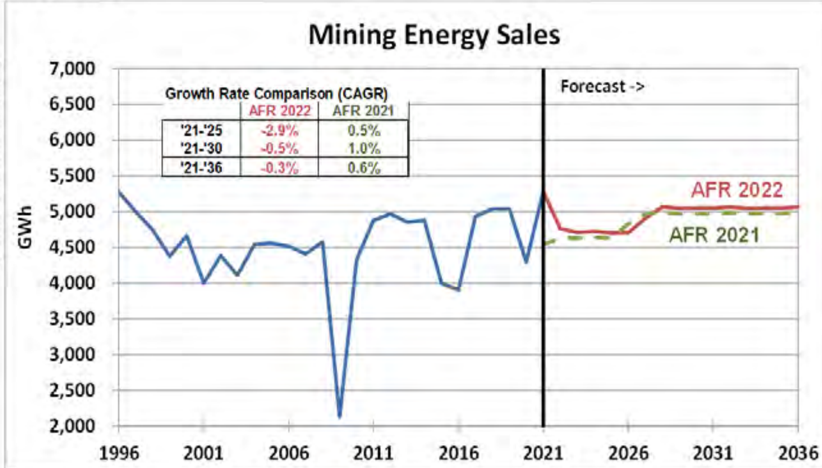
Estimation Start/End:	1/1996 - 12/2021
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC P-Value
CONST	4,434.72	0.00%	0.00%
Trend_Mine1	(30.07)	0.00%	0.00%
Bi_Mine2	(305.13)	6.00%	4.62%
Bi_Mine3	(2,220.10)	0.00%	0.00%
Bi_Mine4	(1,365.53)	0.00%	0.00%
Bi_Mine5	(848.37)	0.07%	0.47%
Bi_Mine6	176.42	4.35%	6.71%
MN_Iron_IPI	79.56	0.00%	0.00%

Mining and Metals Energy Sales

	MWh	Y/Y Growth
2011	4,874,331	
2012	4,968,517	1.9%
2013	4,851,094	-2.4%
2014	4,879,520	0.6%
2015	4,000,557	-18.0%
2016	3,906,570	-2.3%
2017	4,930,188	26.2%
2018	5,039,138	2.2%
2019	5,038,704	0.0%
2020	4,295,593	-14.7%
2021	5,280,743	22.9%
2022	4,761,677	**-9.8%**
2023	4,707,391	**-1.1%**
2024	4,723,267	**0.3%**
2025	4,701,747	**-0.5%**
2026	4,705,387	**0.1%**
2027	4,905,945	**4.3%**
2028	5,065,665	**3.3%**
2029	5,047,148	**-0.4%**
2030	5,049,375	**0.0%**
2031	5,049,171	**0.0%**
2032	5,065,260	**0.3%**
2033	5,046,332	**-0.4%**
2034	5,048,561	**0.0%**
2035	5,048,361	**0.0%**
2036	5,064,455	**0.3%**

Model Statistics	Magnitude
Adjusted R^2	88.7%
AIC	4908
Durban-Watson	1.3
MAPE	4.84
In-Sample RMSE	622



Model Discussion

The AFR 2022 outlook for mining and metals energy use is similar to the AFR 2021 projection, except for a higher level of sales long-term due to increased customer operations (post-regression adjustments). The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions.

The key economic driver of this year's mining energy use model was the Minnesota (MN) Iron IPI, which measures the real production output nationwide in the industry and is scaled to MN-only production – the process of scaling the national Iron IPI to a MN-only IPI is described in Section II.C.1.

This year's model incorporates several binary variables to control for known or suspected definitional changes in the historical mining energy sales series. These variables have been added with the goal of avoiding bias in the IPI's coefficient for these past definitional changes in the mining and metals sales series.

"Trend_Mine1" is a trend variable that denotes the timeframe from 1996-2001, when a large mining customer ended operations. The variable accounts for a possible change in relationship between Minnesota Power mining customer energy and the MN IPI, and allows for a more exact estimation of the relationship during the current paradigm.

The "Bi_Mine2" binary variable denotes and normalizes for some of the observable seasonality in mining operations.

The "Bi_Mine3" binary variable denotes the recession period from early 2009 to early 2010, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Bi_Mine4" binary variable denotes a timeframe from May-2015 to February-2017, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Bi_Mine5" binary variable denotes months between April-2020 and November-2020, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Bi_Mine6" binary variable denotes operations of four smaller metals customers in the January-2010 to September-2016 timeframe. These customers' are backed out of the historical series prior to regression modeling, but their historical production contributed to national iron IPI. This binary variable ("Bi_Mine6") explains the temporary distortion in the energy-sales-to-National-IPI relationship.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The P-values suggests all variables' coefficients' are significant. In-sample error metrics are very similar: the MAPE is the same as the 2021 model at 4.8%, and RMSE is nearly identical at 622 vs. 621 in the 2021 model.

Paper and Wood Products Energy Use - Expected Scenario

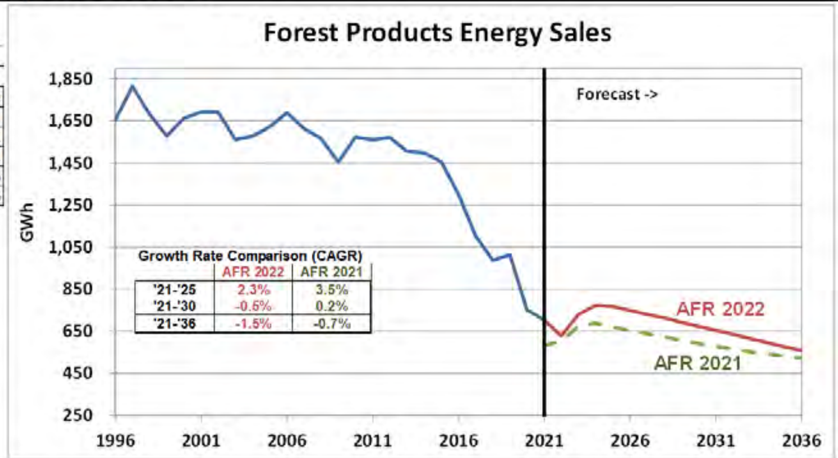
Estimation Start/End:	1/1996 - 12/2021
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	3,076.31	<.0001	<.0001
Bi_Paper1	(317.40)	0.40%	<.0001
Bi_Paper2	(559.95)	<.0001	<.0001
Bi_Paper3	(599.50)	<.0001	0.01%
Paper_IPI	9.86	<.0001	0.40%

Forest Products Energy Sales

	MWh	Y/Y Growth
2011	1,559,519	
2012	1,570,852	0.7%
2013	1,505,113	-4.2%
2014	1,498,810	-0.4%
2015	1,456,091	-2.9%
2016	1,302,920	-10.5%
2017	1,104,160	-15.3%
2018	987,208	-10.6%
2019	1,013,971	2.7%
2020	752,072	-25.8%
2021	701,549	-6.7%
2022	627,426	**-10.6%**
2023	729,476	**16.3%**
2024	774,180	**-2.4%**
2025	768,834	**-3.0%**
2026	749,692	**-2.8%**
2027	730,268	**-2.9%**
2028	713,054	**-2.6%**
2029	692,040	**-3.3%**
2030	672,723	**-3.1%**
2031	653,404	**-3.2%**
2032	635,556	**-3.1%**
2033	614,767	**-3.7%**
2034	595,449	**-3.6%**
2035	576,129	**-3.7%**
2036	558,069	**-3.6%**

Model Statistics	Magnitude
Adjusted R^2	72.7%
AIC	4622
Durban-Watson	0.3
MAPE	9.11
In-Sample RMSE	392



Model Discussion

The AFR 2022 outlook for paper and wood products energy requirements is a bit higher than the AFR 2021 projection by 2036 – about 36,000 MWh (or 7.0%) higher due to a specific new customer's load. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions.

The AFR 2022 model was driven by the Industrial Production Index (IPI) for Paper, which measures the real production output nationwide in the industry, and indicates an underlying secular decline of the North American Paper industry (and demand for paper products).

The three binary variables ("Bi_Paper1," "Bi_Paper2," and "Bi_Paper3") denote specific decreases in sales to paper customers due to transition of customer generation assets or closure of paper production capacity. Binary variables are used as this is not a situation in which pre-regression adjustments to the historical series would be appropriate. These variables terminate at the beginning of the forecast timeframe, producing an econometric forecast that's at a pre-change-in-operations level. Post-regression load adjustments are then applied to reduce the outlook in the amount of the operational changes likely demands.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's reasonable goodness-of-fit, and In-sample error metrics are a bit different: MAPE increased to 9.1% vs. 6.7% in the 2021 model, and RMSE increased to 392 vs. 296 in the 2021 model.

The AIC indicates a highly parsimonious model. HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' (except the intercept) are significant.

Other Industrial Energy Use - Expected Scenario

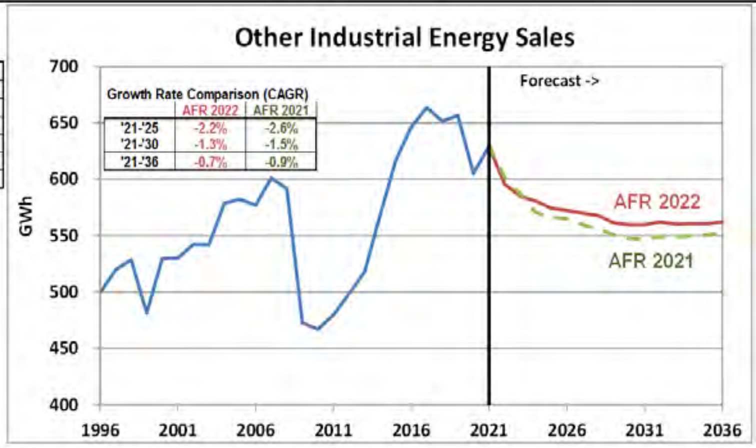
Estimation Start/End:	
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF

Other Industrial Energy Sales

	MWh	Y/Y Growth
2011	479,799	
2012	498,474	3.9%
2013	517,786	3.9%
2014	568,206	9.7%
2015	616,625	8.5%
2016	646,339	4.8%
2017	663,444	2.6%
2018	651,546	-1.8%
2019	656,590	0.8%
2020	605,277	-7.8%
2021	629,017	3.9%
2022	595,900	-5.3%
2023	585,020	-1.8%
2024	580,563	-0.8%
2025	574,380	-1.1%
2026	572,459	-0.3%
2027	570,002	-0.4%
2028	567,987	-0.4%
2029	561,360	-1.2%
2030	559,615	-0.3%
2031	559,572	0.0%
2032	562,218	0.5%
2033	560,156	-0.4%
2034	560,478	0.1%
2035	560,501	0.0%
2036	562,309	0.3%

Model Statistics	Magnitude



Model Discussion

Minnesota Power has broken out Other Industrial into four sectors: 1) Pipelines, 2) Foundries, 3) Food Products, and 4) Remaining.

Due to several Other Industrial sub-sectors containing just two or three customers, these sector-level forecasts could imply trade secret information. Minnesota Power will only show the aggregate of all sectors ("Other Industrial") in the graph above and table to the left. The sector-specific models of projected energy and the model discussions are discussed on the following pages, and are marked "TRADE SECRET" due to the limited number of customers in each sector.

[TRADE SECRET DATA BEGINS

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TRADE SECRET DATA ENDS]

Public Authorities Energy Use - Expected Scenario

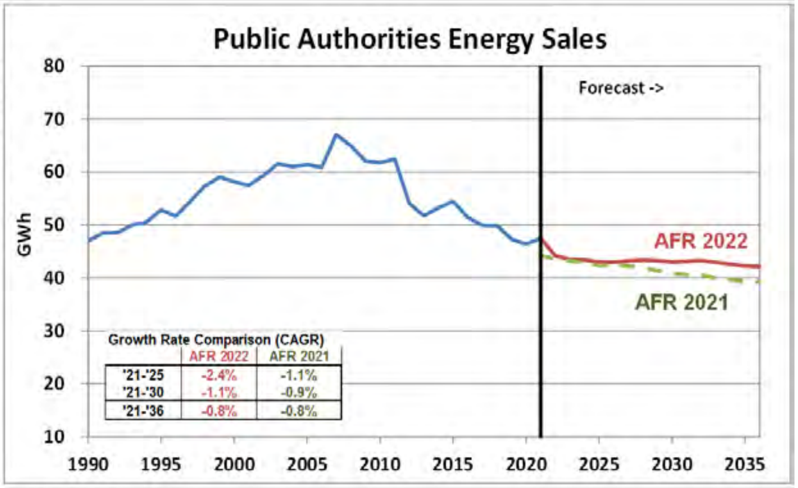
Estimation Start/End:	1/1990 - 12/2021
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	(1,301.97)	0.00%	0.00%
Bi_2021_2036	21.74	0.14%	0.09%
EE_Com	(0.00)	0.00%	0.00%
Dul_HDDpd	0.16	1.80%	1.71%
Dul_CDDpd	4.18	0.00%	0.01%
MSA_Pop	5.27	0.00%	0.00%

Public Auth. Energy Sales

	MWh	Y/Y Growth
2011	62,458	
2012	54,074	-13.4%
2013	51,736	-4.3%
2014	53,237	2.9%
2015	54,471	2.3%
2016	51,455	-5.5%
2017	49,945	-2.9%
2018	49,884	-0.1%
2019	47,302	-5.2%
2020	46,375	-2.0%
2021	47,497	2.4%
2022	44,193	-7.0%
2023	43,503	-1.6%
2024	43,400	-0.2%
2025	43,011	-0.9%
2026	42,973	-0.1%
2027	43,228	0.6%
2028	43,391	0.4%
2029	43,241	-0.3%
2030	42,998	-0.6%
2031	43,143	0.3%
2032	43,287	0.3%
2033	42,923	-0.8%
2034	42,616	-0.7%
2035	42,264	-0.8%
2036	42,108	-0.4%

Model Statistics	Magnitude
Adjusted R^2	37.1%
AIC	3401
Durban-Watson	2.1
MAPE	10.73
In-Sample RMSE	20



Growth Rate Comparison (CAGR)	AFR 2022	AFR 2021
'21-'25	-2.4%	-1.1%
'21-'30	-1.1%	-0.9%
'21-'36	-0.8%	-0.8%

Model Discussion

The key economic driver of this year's Public Authorities energy use model was Duluth MSA Population. This variable indicates the underlying growth trend, which impacts government entities' operations (affecting energy use).

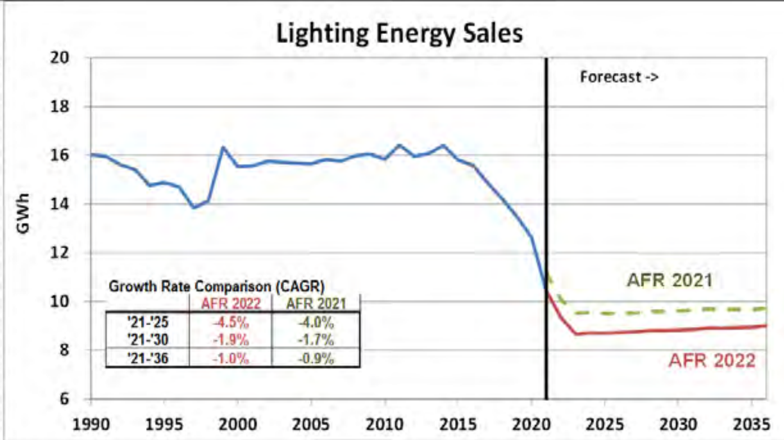
The AFR 2022 model uses an Energy Efficiency variable as a predictor of public authorities' energy sales: the "EE_Com" variable represents the cumulative effects of all past conservation measures on each year's sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year. The commercial-sector energy efficiency variable was used for the public authorities model since: 1) both customer groups are served by the same CIP program, and 2) the overall trend of conservation in public authorities is likely very similar to commercial customers. The variable's construction and the Company's hypothesis regarding its effectiveness in modeling usage is documented in Section II.B.3.

This year's model is similar to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are similar to last year's: MAPE is 10.7% vs. 10.2% in the 2021 model, and RMSE is 20.1 vs. 19.6 in the 2020 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Street Lighting Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2021
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	50.72	0.00%	0.00%
T	(0.01)	7.26%	7.76%
Jan	2.80	0.50%	0.12%
Feb	(2.10)	3.48%	0.44%
Mar	(9.49)	0.00%	0.00%
Apr	(14.31)	0.00%	0.00%
May	(20.29)	0.00%	0.00%
Jun	(23.53)	0.00%	0.00%
Jul	(23.03)	0.00%	0.00%
Aug	(19.43)	0.00%	0.00%
Sep	(11.80)	0.00%	0.00%
Oct	(8.46)	0.00%	0.00%
Nov	(2.93)	0.32%	0.00%
Bi_Light_1	(2.46)	0.32%	2.09%
Bi_Light_2	90.12	0.00%	0.00%
Trend_Light_2	(0.27)	0.00%	0.00%
NonWPI_StLou	0.002	4.66%	3.22%



Lighting Energy Sales

	MWh	Y/Y Growth
2011	16,420	
2012	15,954	-2.8%
2013	16,066	0.7%
2014	16,400	2.1%
2015	15,801	-3.7%
2016	15,588	-1.4%
2017	14,873	-4.6%
2018	14,206	-4.5%
2019	13,482	-5.1%
2020	12,617	-6.4%
2021	10,445	-17.2%
2022	9,341	**-10.6%**
2023	8,663	**-7.3%**
2024	8,706	**0.5%**
2025	8,695	**-0.1%**
2026	8,719	**0.3%**
2027	8,741	**0.3%**
2028	8,803	**0.7%**
2029	8,800	**0.0%**
2030	8,827	**0.3%**
2031	8,850	**0.3%**
2032	8,906	**0.6%**
2033	8,902	**0.0%**
2034	8,921	**0.2%**
2035	8,941	**0.2%**
2036	9,001	**0.7%**

Model Statistics	Magnitude
Adjusted R^2	85.5%
AIC	2163
Durban-Watson	1.7
MAPE	5.15
In-Sample RMSE	4

Model Discussion

The AFR 2022 lighting per-day use model utilized St. Louis County Non-Wage Personal Income as a key economic/demographic indicator.

"Bi_Light1" is a binary variable denoting the 1990-1999 timeframe and effectively shifts the level of the estimate to account for changes to the Company's accounting practices, which affected historical energy use data. The corrective binary shifts the forecast to avoid improbably changes in energy use, but does not impact the forecast trajectory; this is determined by the economic variables.

"Bi_Light2" and "Trend_Light2" are binary and trend variables denoting the 2017-2036 timeframe and effectively creates a new forecast trajectory influenced by levels starting in 2017 (this level is then held constant in the forecast timeframe after January-2023). This binary and trend combination shifts the forecast to account for Minnesota Power's LED lighting program's impact on energy use, and unlike "Bi_Light1," it does impact the forecast trajectory; in addition to the economic variables.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's high goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are similar to last year's: MAPE is 5.1% vs. 4.9% in the 2021 model, and RMSE is 4.0 vs. 4.0 in the 2021 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Resale Energy Use - Expected Scenario

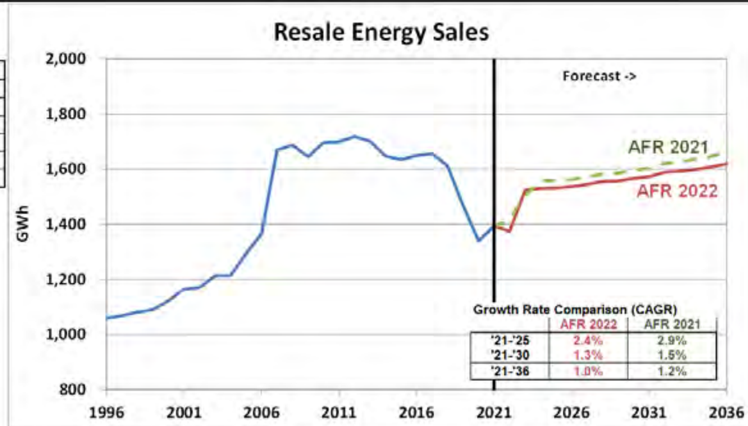
Estimation Start/End:	
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF

Resale Energy Sales

	MWh	Y/Y Growth
2008	1,587,318	
2012	1,718,819	8.3%
2010	1,585,993	3.3%
2014	1,647,763	3.9%
2015	1,634,786	-0.8%
2016	1,649,405	0.9%
2017	1,656,865	0.5%
2018	1,610,792	-2.8%
2019	1,468,108	-8.9%
2020	1,340,290	-8.7%
2021	1,393,315	4.0%
2022	1,374,718	**-1.3%**
2023	1,523,465	**11.9%**
2024	1,530,812	**1.0%**
2025	1,532,449	**0.1%**
2026	1,536,000	**2.2%**
2027	1,545,146	**0.6%**
2028	1,555,451	**0.4%**
2029	1,557,530	**0.1%**
2030	1,566,535	**0.6%**
2031	1,572,971	**0.5%**
2032	1,588,843	**1.0%**
2033	1,592,692	**0.2%**
2034	1,599,559	**0.4%**
2035	1,608,467	**0.6%**
2036	1,619,294	**0.7%**

Model Statistics	Magnitude



Model Discussion

AFR 2022 is continuing the practice of forecasting each resale customer separately, but unlike in previous years, Minnesota Power will not be providing graphs or tables that include forecast values for individual resale customers (similar to the approach mentioned above for Other Industrial).

Due to the trade secret nature of individual resale customers' forecasts, Minnesota Power will only be showing the aggregate forecast summary for total Resale energy sales in the graph above and table to the left, and withhold this information on each customers' respective page.

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System Peak Demand - Expected Scenario

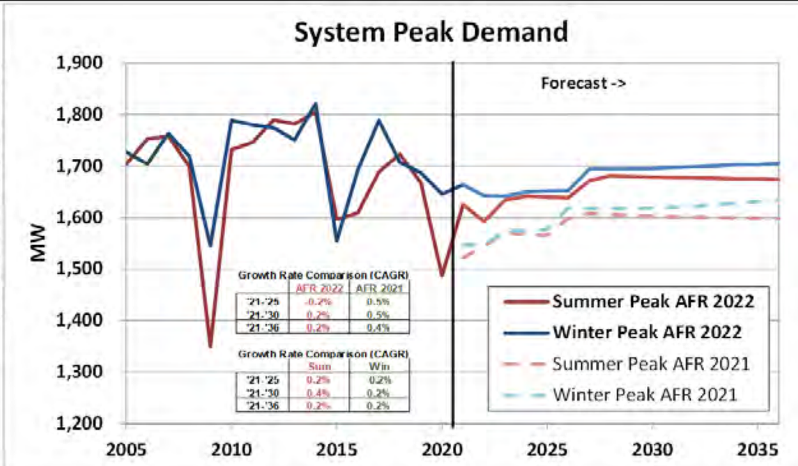
Estimation Start/End:	6/1999 - 12/2021
Unit Modeled/Forecast:	Monthly Peak Demand

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	378.52	0.00%	0.00%
WN_MWhpd	0.04	0.00%	0.00%
S	36.22	0.00%	0.12%
W	18.59	3.96%	0.49%
Bi_1999_2001	(26.74)	0.05%	0.04%
Bi_2008	108.57	0.00%	0.00%
WC_THI	(1.25)	0.00%	0.00%
WC_THI_3	0.0002	0.00%	4.05%
Jan_WN_MWhpd	(0.001)	0.94%	0.01%
Feb_WN_MWhpd	(0.001)	0.65%	0.01%
Mar_WN_MWhpd	(0.001)	0.17%	0.31%

System Peak Demand

	Summer (MW)	Y/Y Growth		Winter (MW)	Y/Y Growth
2011	1,746		2011	1,780	
2012	1,790	2.5%	2012	1,774	-0.3%
2013	1,782	-0.5%	2013	1,751	-1.3%
2014	1,805	1.3%	2014	1,821	4.0%
2015	1,597	-11.5%	2015	1,554	-14.6%
2016	1,609	0.8%	2016	1,692	8.9%
2017	1,688	4.9%	2017	1,789	5.7%
2018	1,723	2.1%	2018	1,707	-4.5%
2019	1,668	-3.2%	2019	1,687	-1.2%
2020	1,487	-10.8%	2020	1,646	-2.4%
2021	1,625	9.3%	2021	1,663	1.1%
2022	1,592	**-2.0%**	2022	1,642	**-1.3%**
2023	1,634	**2.6%**	2023	1,641	**-0.1%**
2024	1,641	**0.4%**	2024	1,650	**0.5%**
2025	1,640	**-0.1%**	2025	1,651	**0.1%**
2026	1,639	**-0.1%**	2026	1,652	**0.1%**
2027	1,671	**2.0%**	2027	1,694	**2.5%**
2028	1,681	**0.6%**	2028	1,694	**0.0%**
2029	1,680	**-0.1%**	2029	1,695	**0.0%**
2030	1,679	**-0.1%**	2030	1,695	**0.0%**
2031	1,678	**0.0%**	2031	1,697	**0.1%**
2032	1,677	**0.0%**	2032	1,699	**0.1%**
2033	1,677	**-0.1%**	2033	1,700	**0.1%**
2034	1,675	**-0.1%**	2034	1,703	**0.1%**
2035	1,674	**-0.1%**	2035	1,705	**0.1%**
2036	1,673	**-0.1%**	2036	1,709	**0.3%**

Model Statistics	Magnitude
Adjusted R^2	89.8%
AIC	2685
Durban-Watson	1.6
MAPE	1.88
In-Sample RMSE	34



Model Discussion

The long-run outlook for Minnesota Power's system peak is higher than the 2021 outlook primarily due to a projected increase in industrial energy consumption relative to AFR 2021.

Temperature variables play a critical role in peak demand modeling, and both the definition and structure of these variables are important for interpreting the results. 2022 AFR used a third-degree polynomial specification on a Wind-Chill & Temperature Humidity Index. Peak demand is modeled as a function of the weather observations specific to the hour in which the peak occurred.

The 2022 AFR peak demand model utilized two binaries to indicate the month of the system's historical summer and winter peaks, and assumed this peak in July/January (respectively) throughout the forecast timeframe. Summer peaks typically occur in either July or August, historical winter peaks have occurred in November, December, February, but are most likely in January. This broad distribution of peak occurrence dilutes the model's measured seasonality, and as a result, the peak forecast will understate both the summer and winter peak demand figures. The utilization of these peak binaries focuses the seasonal peaks – which may have occurred in August or July, or December or January - into the months of July and January. This ensures seasonal peaks are not under forecast as a result of historical diversity in the timing of those seasonal peaks.

The model also includes two binaries ("Bi_1999_2001" and "Bi_2008") denoting periods of economic downturn for Minnesota Power's large industrial customers, resulting in abnormally low usage. During (or immediately following) these periods the normal relationship of Peak-to-Energy was affected by the idling of large, high load factor customers. These binaries effectively remove these downturn periods from consideration in the regression model and allow for more accurate estimation of model coefficients under more normal economic conditions.

There is no energy efficiency variable in the peak demand model and no explicit assumption for peak demand savings. Conservation impacts are accounted for by leveraging the energy sales forecast, which includes the effects of conservations, as the key input to the peak demand regression model.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's high goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are very similar to the 2021 model: MAPE is 1.9% vs. 1.9% in the 2021 model, and RMSE is 34 vs. 34 in the 2021 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

F. Confidence in Forecast & Historical Accuracy

Minnesota Power has a strong record of accurate forecasting and consistent improvements in forecast accuracy over time. Excluding the mining downturn years (2009/2010 and 2015/2016), as well as the 2020 COVID-19 recession (including 2021), each successive AFR has reduced its current-year energy sales forecast error, on average, by about 0.05 percent over the prior year.

Tables 7-9 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 -15.7 percent is the difference between the forecast produced in 2020 (AFR 2020) and the 2020 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 2015 (formulated in 2015) forecast of 2016 was 5.9 percent (581 GWh) above the actual (due to effects of Mining downturn).

Figure 18: AFR Energy Sales Forecast Accuracy

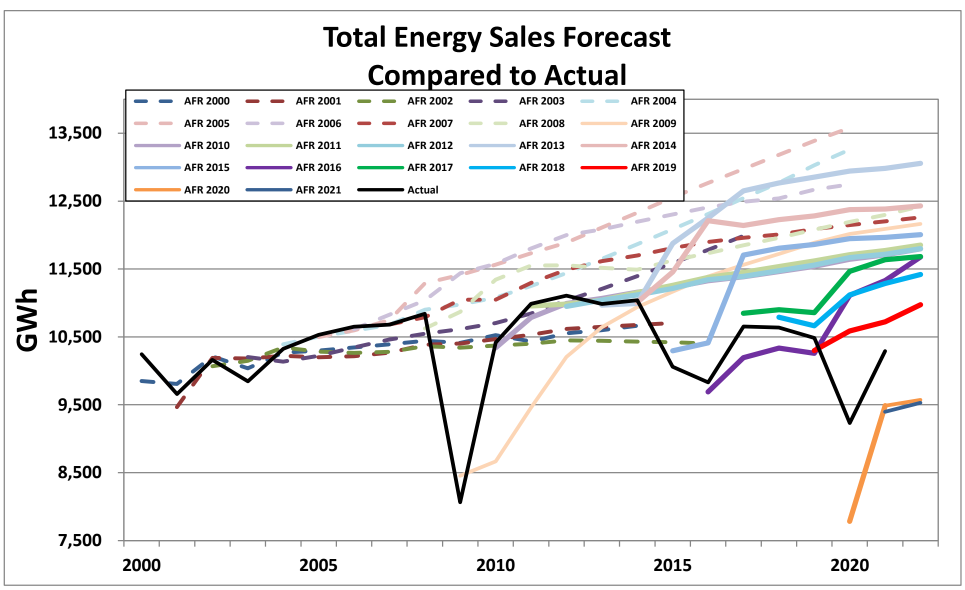


Table 7: AFR Energy Sales Forecast Accuracy

Total Energy Sales Forecast Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	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%	-3.4%								0.1%	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%	-3.3%	6.4%							0.4%	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%	-5.5%	3.6%	5.8%						0.2%	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%	3.2%	15.2%	19.8%	12.5%					5.1%	1.8%
AFR 2004					**0.6%**	***-0.3%***	-0.5%	0.0%	0.6%	**36.1%**	6.4%	2.4%	3.0%	6.0%	7.5%	20.1%	25.2%	17.7%	20.0%				9.7%	0.3%
AFR 2005						**-0.3%**	***-0.5%***	0.6%	4.1%	41.5%	**11.0%**	6.8%	7.0%	10.2%	11.7%	24.8%	29.9%	21.8%	23.9%	27.7%			14.7%	0.5%
AFR 2006							**-0.3%**	***1.4%***	1.8%	41.8%	11.1%	**7.4%**	8.0%	10.0%	10.5%	22.3%	26.2%	17.2%	17.9%	20.9%	38.1%		15.6%	1.4%
AFR 2007								**0.0%**	***-0.5%***	37.0%	6.0%	2.8%	**3.4%**	5.7%	6.0%	17.4%	21.0%	12.3%	12.9%	15.3%	31.6%	18.6%	12.6%	0.5%
AFR 2008									**-2.0%**	***34.8%***	8.9%	5.1%	4.0%	**4.8%**	4.1%	15.6%	19.3%	11.2%	12.4%	15.2%	32.1%	19.5%	13.2%	34.8%
AFR 2009										**4.8%**	***-16.8%***	-13.9%	-8.1%	-3.1%	**-0.9%**	11.0%	15.9%	8.5%	10.2%	13.4%	30.2%	17.5%	5.3%	16.8%
AFR 2010											**-0.8%**	***-1.8%***	-1.0%	0.7%	1.1%	**11.6%**	15.2%	6.9%	7.7%	10.1%	26.1%	13.8%	7.5%	1.8%
AFR 2011												**-0.3%**	***-1.1%***	0.5%	1.0%	11.9%	**15.7%**	7.5%	8.4%	10.8%	26.9%	14.4%	8.7%	1.1%
AFR 2012													**-1.4%**	***0.5%***	0.7%	11.5%	15.4%	**6.9%**	7.8%	10.2%	26.4%	13.9%	9.2%	0.5%
AFR 2013														**-0.2%**	***-0.4%***	18.1%	24.6%	18.7%	**20.0%**	22.6%	40.2%	26.2%	18.9%	0.4%
AFR 2014															**-0.3%**	***13.9%***	24.2%	13.9%	14.9%	**17.2%**	34.0%	20.3%	17.3%	13.9%
AFR 2015																**2.4%**	***5.9%***	9.9%	11.0%	13.1%	**29.4%**	16.3%	12.6%	5.9%
AFR 2016																	**-1.4%**	***-4.3%***	-2.9%	-2.2%	20.4%	**10.1%**	3.3%	4.3%
AFR 2017																		**1.8%**	***2.5%***	3.6%	24.2%	13.1%	9.0%	2.5%
AFR 2018																			**1.4%**	***1.7%***	20.4%	9.7%	8.3%	1.7%
AFR 2019																				**-1.8%**	***14.7%***	4.2%	5.7%	14.7%
AFR 2020																					**-15.7%**	***-7.8%***	-11.7%	7.8%
AFR 2021																						**-8.7%**	-8.7%	

N.n%	= *Year-Ahead Foreast*	Avg Year-Ahead Error =	2.1%
		Avg Year-Ahead Error (No Downturns) =	-0.8%
N.n%	= Current Year Forecast	Avg Current Year Error =	-1.1%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	9.4%
		Avg 5 Year Error (No Downturns) =	3.9%

Figure 19: AFR Summer Peak Demand Forecast Accuracy

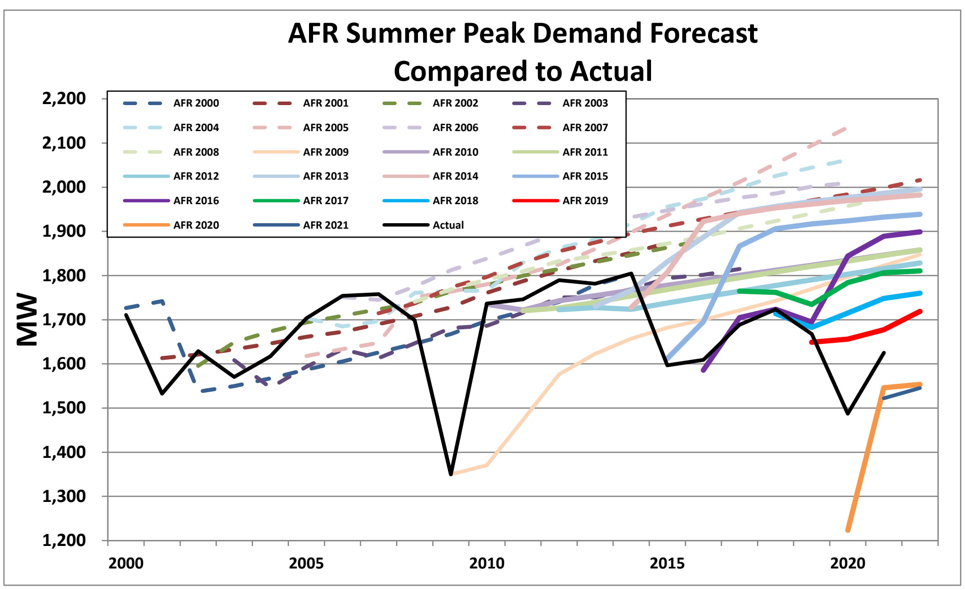


Table 8: AFR Summer Peak Demand Forecast Accuracy

Summer System Peak Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	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%	-0.1%								-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%	2.6%	17.4%							3.7%	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%	2.3%	16.7%	16.9%						5.3%	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%	-2.0%	12.4%	12.0%	7.5%					1.3%	4.4%
AFR 2004					0.0%	0.0%	-3.9%	-3.5%	3.7%	30.8%	1.7%	4.8%	4.1%	5.6%	6.3%	22.5%	22.7%	18.4%	17.5%				8.7%	0.0%
AFR 2005						-5.0%	-6.9%	-6.3%	3.1%	30.7%	2.5%	3.3%	2.0%	4.4%	5.2%	21.3%	22.8%	19.2%	19.1%	25.6%			9.4%	6.9%
AFR 2006							-0.2%	-0.7%	4.5%	34.3%	5.9%	7.0%	6.0%	7.5%	7.0%	22.0%	22.0%	17.1%	15.2%	20.0%	35.2%		13.5%	0.7%
AFR 2007								-2.4%	2.2%	31.4%	3.5%	4.8%	3.6%	5.2%	5.0%	19.8%	19.8%	15.1%	13.4%	18.1%	33.4%	23.0%	13.1%	2.2%
AFR 2008									2.5%	31.0%	3.2%	3.7%	2.4%	3.6%	2.9%	17.3%	17.4%	12.9%	11.6%	16.3%	31.6%	21.6%	12.7%	31.0%
AFR 2009										0.0%	-21.1%	-15.6%	-11.9%	-8.9%	-8.2%	5.3%	5.7%	2.0%	1.1%	6.1%	20.9%	12.2%	-1.0%	21.1%
AFR 2010											-0.1%	-1.4%	-2.6%	-1.5%	-2.1%	11.3%	11.2%	6.7%	5.1%	9.3%	23.4%	13.6%	6.1%	1.4%
AFR 2011												-1.5%	-3.5%	-2.4%	-2.8%	10.8%	10.8%	6.3%	4.9%	9.2%	23.3%	13.6%	6.2%	3.5%
AFR 2012													-3.7%	-3.0%	-4.5%	8.8%	8.9%	4.5%	3.1%	7.3%	21.2%	11.7%	5.4%	3.0%
AFR 2013														-2.8%	-2.1%	14.7%	17.3%	15.1%	13.5%	18.0%	32.9%	22.2%	14.3%	2.1%
AFR 2014															-4.3%	13.2%	19.5%	14.9%	13.3%	17.6%	32.5%	21.6%	16.1%	13.2%
AFR 2015																1.0%	5.4%	10.6%	10.6%	14.9%	29.4%	18.9%	13.0%	5.4%
AFR 2016																	-1.4%	1.0%	0.0%	1.6%	24.0%	16.2%	6.9%	1.0%
AFR 2017																		4.5%	2.2%	4.0%	20.0%	11.1%	8.4%	2.2%
AFR 2018																			-0.6%	0.9%	15.4%	7.6%	5.8%	0.9%
AFR 2019																				-1.1%	11.4%	3.2%	4.5%	11.4%
AFR 2020																					-17.7%	-4.9%	-11.3%	4.9%
AFR 2021																						-6.3%	-6.3%	

N.n%	= *Year-Ahead Foreast*	Avg Year-Ahead Error =	1.8%
		Avg Year-Ahead Error (No Downturns) =	-1.7%
N.n%	= Current Year Forecast	Avg Current Year Error =	-1.5%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	7.4%
		Avg 5 Year Error (No Downturns) =	3.0%

Figure 20: AFR Winter Peak Demand Forecast Accuracy

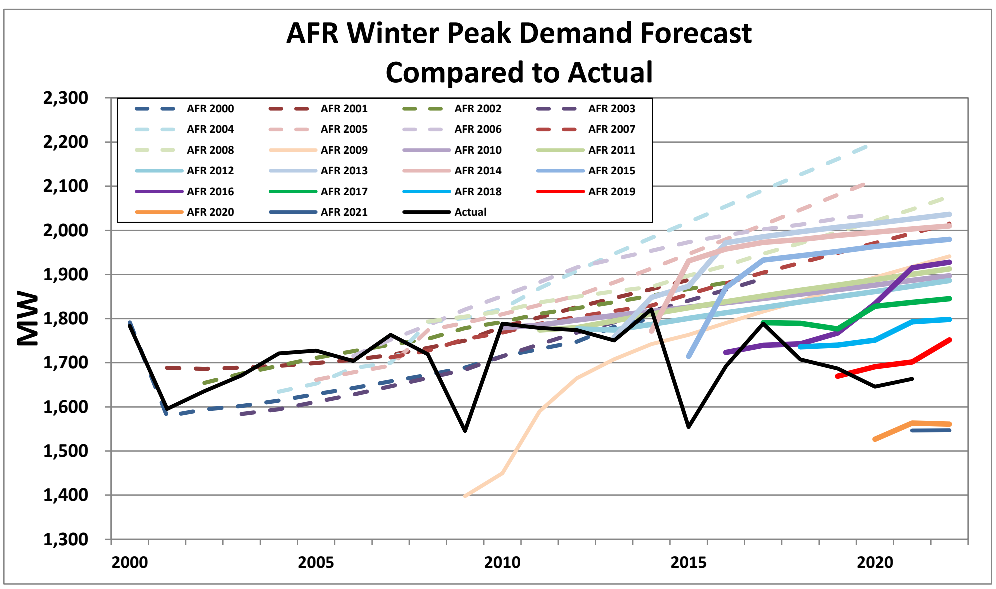


Table 9: AFR Winter Peak Demand Forecast Accuracy

Winter System Peak Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average Error of AFR	Avg. Error Year-Ahead
AFR 2000	0.4%	-1.0%	-2.6%	-4.1%	-6.2%	-5.7%	-3.6%	-6.0%	-2.7%	9.3%	-4.1%	-2.7%	-1.5%	1.8%	-1.1%								-2.0%	1.0%
AFR 2001		5.8%	3.1%	1.1%	-1.6%	-1.6%	0.2%	-2.6%	0.8%	13.3%	-0.4%	1.4%	2.9%	5.5%	2.5%	21.4%							3.4%	3.1%
AFR 2002			1.1%	0.2%	-1.6%	-0.9%	1.3%	-1.3%	2.0%	15.1%	0.2%	1.8%	2.8%	4.9%	1.7%	20.1%	11.2%						3.9%	0.2%
AFR 2003				-5.2%	-7.4%	-6.7%	-4.4%	-6.6%	-3.1%	9.0%	-4.1%	-2.1%	-0.3%	2.4%	-0.2%	18.4%	10.2%	5.7%					0.4%	7.4%
AFR 2004					-5.0%	-4.3%	-0.9%	-3.6%	4.2%	16.6%	1.9%	5.1%	7.6%	11.2%	8.9%	29.9%	21.4%	16.9%	24.5%				8.9%	4.3%
AFR 2005						-3.8%	-1.5%	-3.9%	3.2%	15.8%	1.2%	2.9%	4.4%	7.5%	5.1%	25.2%	17.0%	12.5%	19.9%	23.3%			8.6%	1.5%
AFR 2006							0.7%	-0.6%	3.8%	17.8%	3.5%	5.8%	8.0%	10.5%	7.3%	27.0%	17.5%	11.9%	17.9%	20.1%	23.7%		11.7%	0.6%
AFR 2007								-2.9%	0.5%	13.5%	-1.1%	0.5%	1.7%	3.8%	0.5%	19.4%	11.1%	6.5%	12.8%	15.5%	19.8%	19.8%	8.1%	0.5%
AFR 2008									4.3%	16.8%	1.6%	3.2%	4.2%	6.3%	2.8%	22.1%	13.5%	8.8%	15.4%	18.3%	22.8%	23.1%	11.7%	16.8%
AFR 2009										-9.6%	-18.9%	-10.6%	-6.2%	-2.4%	-4.3%	13.4%	5.8%	1.5%	7.8%	10.8%	15.1%	15.3%	1.4%	18.9%
AFR 2010											-0.5%	0.4%	1.3%	3.2%	-0.2%	17.5%	8.5%	3.2%	8.7%	10.6%	14.0%	13.4%	6.7%	0.4%
AFR 2011												-0.3%	0.3%	2.5%	-0.6%	17.4%	8.6%	3.5%	9.2%	11.2%	14.7%	14.3%	7.4%	0.3%
AFR 2012													0.1%	1.3%	-1.9%	15.8%	7.1%	2.0%	7.6%	9.6%	13.1%	12.6%	6.8%	1.3%
AFR 2013														0.4%	1.5%	20.5%	16.5%	11.0%	16.9%	19.0%	22.5%	21.8%	14.5%	1.5%
AFR 2014															-2.7%	24.2%	15.7%	10.3%	15.9%	17.9%	21.3%	20.4%	15.4%	24.2%
AFR 2015																10.3%	10.5%	8.1%	13.8%	15.8%	19.3%	18.6%	13.7%	10.5%
AFR 2016																	1.8%	-2.8%	2.1%	4.8%	11.4%	15.1%	5.4%	2.8%
AFR 2017																		0.1%	4.8%	5.3%	11.1%	10.4%	6.4%	4.8%
AFR 2018																			1.7%	3.2%	6.4%	7.8%	4.8%	3.2%
AFR 2019																				-1.0%	2.8%	2.3%	1.4%	2.8%
AFR 2020																					-7.2%	-6.0%	-6.6%	6.0%
AFR 2021																						-7.0%	-7.0%	

N.n%	= *Year-Ahead Foreast*	Avg Year-Ahead Error =	1.3%
		Avg Year-Ahead Error (No Downturns) =	-0.6%
N.n%	= Current Year Forecast	Avg Current Year Error =	-0.8%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	6.8%
		Avg 5 Year Error (No Downturns) =	3.6%

III. AFR 2022 SCENARIO FORECAST DESCRIPTIONS

A. Expected Forecast Scenario Description

The AFR 2022 Expected 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; and/or
- A timeframe for the operation and resulting power.

The Expected scenario assumes additional load from several new and existing customers. Most notably, this scenario accounts for a new industrial facility on the Iron Range; the facility is expected to reach full demand in 2024. Additionally, this scenario assumes the start-up of a new industrial facility in Duluth; the facility is expected to reach full demand in early 2023.

The scenario assumes a moderate, or “expected,” rate of national economic growth as the basis for the regional economic model.[50]

The Expected scenario results in compound annual energy sales and Summer peak demand growth of 0 percent and 0.2 percent, respectively, from 2021 through 2036.

B. Other Adjustments to Econometric Forecast

Minnesota Power’s forecast scenario 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 the Expected scenario tables. These adjustments fall into the following categories:

1. **Net Load/Energy Added**: are exogenous adjustments for load added due to Distributed Solar Generation, Electric Vehicle impacts, new customers or expansion by existing customers, and lost load due to closure or loss of contract. This adjustment includes all load added or lost on the system, regardless of how that load is met; “Net Load/Energy Added” accounts for any change in load at the system level. To preserve customer confidentiality, the seasonal demand and energy impacts are netted to a single value before being applied to the econometric values.

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.

[50] All econometric models use the “expected” rate of national economic growth per IHS Global Insight’s January 2022 release.

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 twelve-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 twelve-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. 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. Expected Scenario Peak Demand and Energy Outlooks

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	1,630	173	150	1,746	1,780	*1,780*	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					1,620	1,637	184	184	1,805	1,821	*1,821*	2014
2015					1,442	1,461	155	94	1,597	1,554	*1,597*	**2015**
2016					1,453	1,520	156	173	1,609	1,692	*1,692*	2016
2017					1,538	1,594	150	195	1,688	1,789	*1,789*	2017
2018					1,585	1,557	139	150	1,723	1,707	*1,723*	2018
2019					1,560	1,588	108	99	1,668	1,687	*1,687*	2019
2020					1,410	1,548	78	97	1,487	1,646	*1,646*	**2020**
2021					1,553	1,556	114	114	1,625	1,663	*1,663*	2021
2022	1,393	1,396	85	126	**1,479**	**1,523**	114	120	**1,592**	**1,642**	**1,642**	2022
2023	1,391	1,395	123	127	**1,514**	**1,522**	120	120	**1,634**	**1,641**	**1,641**	2023
2024	1,390	1,394	132	136	**1,522**	**1,530**	120	120	**1,641**	**1,650**	**1,650**	2024
2025	1,389	1,393	131	139	**1,520**	**1,532**	120	120	**1,640**	**1,651**	**1,651**	**2025**
2026	1,388	1,393	131	139	**1,519**	**1,533**	120	120	**1,639**	**1,652**	**1,652**	2026
2027	1,388	1,393	164	182	**1,552**	**1,575**	120	120	**1,671**	**1,694**	**1,694**	2027
2028	1,387	1,392	174	182	**1,562**	**1,575**	120	120	**1,681**	**1,694**	**1,694**	2028
2029	1,386	1,392	173	183	**1,560**	**1,575**	120	120	**1,680**	**1,695**	**1,695**	2029
2030	1,386	1,392	173	184	**1,559**	**1,575**	120	120	**1,679**	**1,695**	**1,695**	**2030**
2031	1,386	1,393	172	185	**1,558**	**1,577**	120	120	**1,678**	**1,697**	**1,697**	2031
2032	1,387	1,393	171	186	**1,558**	**1,579**	120	120	**1,677**	**1,699**	**1,699**	2032
2033	1,387	1,392	170	188	**1,557**	**1,581**	120	120	**1,677**	**1,700**	**1,700**	2033
2034	1,387	1,392	169	190	**1,556**	**1,583**	120	120	**1,675**	**1,703**	**1,703**	2034
2035	1,387	1,392	168	193	**1,555**	**1,585**	120	120	**1,674**	**1,705**	**1,705**	**2035**
2036	1,387	1,392	167	198	**1,554**	**1,590**	120	120	**1,673**	**1,709**	**1,709**	2036

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	- Customer Gen.	= System Energy Use	MP System		
						Peak	*Load Factor*	
2000			10,029,324					
2001			9,476,860					
2002			9,950,113	1,187,858	11,137,971	1,636	*0.78*	2002
2003			9,638,417	1,232,635	10,871,052	1,671	*0.74*	2003
2004			10,117,168	1,267,728	11,384,896	1,721	*0.76*	2004
2005			10,345,265	1,258,895	11,604,160	1,727	*0.77*	**2005**
2006			10,443,777	1,195,070	11,638,847	1,753	*0.76*	2006
2007			10,670,857	1,252,965	11,923,822	1,763	*0.77*	2007
2008			10,826,034	1,276,158	12,102,192	1,719	*0.80*	2008
2009			8,062,253	1,108,014	9,170,267	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	1,780	*0.80*	2011
2012			11,107,357	1,200,317	12,307,674	1,790	*0.79*	2012
2013			10,985,809	1,185,139	12,170,948	1,782	*0.78*	2013
2014			11,038,979	1,287,965	12,326,944	1,821	*0.77*	2014
2015			10,059,466	1,227,221	11,286,687	1,597	*0.81*	**2015**
2016			9,830,787	1,074,786	10,905,573	1,692	*0.74*	2016
2017			10,654,217	1,215,894	11,870,111	1,789	*0.76*	2017
2018			10,638,692	1,236,276	11,874,968	1,723	*0.79*	2018
2019			10,482,913	1,064,454	11,547,367	1,687	*0.78*	2019
2020			9,230,235	812,490	10,042,725	1,646	*0.70*	**2020**
2021			10,290,154	909,778	11,199,931	1,663	*0.77*	2021
2022	9,078,827	594,412	**9,673,239**	915,052	**10,588,291**	**1,642**	***0.74***	2022
2023	9,066,357	806,998	**9,873,355**	967,564	**10,840,919**	**1,641**	***0.75***	2023
2024	9,077,653	863,218	**9,940,872**	967,756	**10,908,628**	**1,650**	***0.75***	2024
2025	9,042,808	867,828	**9,910,637**	970,023	**10,880,660**	**1,651**	***0.75***	**2025**
2026	9,033,347	870,975	**9,904,322**	967,564	**10,871,885**	**1,652**	***0.75***	2026
2027	9,034,632	1,070,546	**10,105,178**	967,564	**11,072,742**	**1,694**	***0.75***	2027
2028	9,054,566	1,219,428	**10,273,994**	967,756	**11,241,750**	**1,694**	***0.76***	2028
2029	9,021,638	1,210,030	**10,231,667**	970,023	**11,201,690**	**1,695**	***0.75***	2029
2030	9,017,629	1,212,562	**10,230,191**	967,564	**11,197,755**	**1,695**	***0.75***	**2030**
2031	9,016,384	1,212,697	**10,229,080**	967,564	**11,196,644**	**1,697**	***0.75***	2031
2032	9,046,086	1,219,444	**10,265,530**	967,756	**11,233,286**	**1,699**	***0.75***	2032
2033	9,018,354	1,212,026	**10,230,380**	970,023	**11,200,403**	**1,700**	***0.75***	2033
2034	9,013,807	1,217,210	**10,231,017**	967,564	**11,198,581**	**1,703**	***0.75***	2034
2035	9,011,634	1,220,174	**10,231,808**	967,564	**11,199,372**	**1,705**	***0.75***	**2035**
2036	9,034,295	1,229,801	**10,264,096**	967,756	**11,231,851**	**1,709**	***0.75***	2036

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	618	262	18	143,831
2010	121,235	21,491	424	2,209	278	18	145,655
2011	121,251	21,603	421	5,335	281	18	148,909
2012	120,697	21,614	411	6,414	275	18	149,429
2013	121,314	21,915	402	655	287	18	144,591
2014	121,601	22,096	394	660	282	17	145,050
2015	121,515	22,170	394	673	281	17	145,050
2016	121,836	22,420	396	689	281	17	145,639
2017	122,295	22,695	390	695	278	17	146,370
2018	122,557	22,834	380	693	277	17	146,758
2019	122,926	23,059	379	701	275	17	147,356
2020	123,617	23,346	378	720	271	16	148,348
2021	124,691	23,580	375	746	267	16	149,676
2022	**124,899**	**23,732**	**366**	**753**	**269**	**16**	**150,035**
2023	**124,940**	**23,947**	**360**	**758**	**268**	**16**	**150,289**
2024	**125,212**	**24,168**	**355**	**764**	**267**	**16**	**150,782**
2025	**125,528**	**24,401**	**351**	**769**	**266**	**16**	**151,330**
2026	**125,851**	**24,621**	**346**	**775**	**266**	**16**	**151,875**
2027	**126,152**	**24,841**	**340**	**780**	**265**	**16**	**152,395**
2028	**126,431**	**25,062**	**335**	**786**	**264**	**16**	**152,894**
2029	**126,706**	**25,281**	**330**	**791**	**263**	**16**	**153,388**
2030	**126,979**	**25,505**	**325**	**797**	**262**	**16**	**153,884**
2031	**127,235**	**25,729**	**320**	**803**	**262**	**16**	**154,364**
2032	**127,478**	**25,955**	**315**	**808**	**261**	**16**	**154,832**
2033	**127,707**	**26,177**	**310**	**814**	**260**	**16**	**155,284**
2034	**127,919**	**26,399**	**305**	**819**	**259**	**16**	**155,717**
2035	**128,111**	**26,622**	**300**	**825**	**258**	**16**	**156,132**

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	1,293,323	10,345,265
2006	1,011,699	1,206,607	6,782,975	15,831	60,882	1,365,783	10,443,777
2007	1,051,453	1,244,930	6,622,051	15,752	67,056	1,669,615	10,670,857
2008	1,079,837	1,240,324	6,737,333	15,983	64,912	1,687,645	10,826,034
2009	1,075,116	1,212,778	4,051,352	16,049	62,036	1,644,922	8,062,253
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	1,699,643	10,988,200
2012	1,043,281	1,237,386	7,037,843	15,954	54,074	1,718,819	11,107,357
2013	1,086,481	1,256,540	6,873,993	16,066	51,736	1,700,993	10,985,809
2014	1,112,579	1,262,464	6,946,536	16,400	53,237	1,647,763	11,038,979
2015	1,026,454	1,254,681	6,073,273	15,801	54,471	1,634,786	10,059,466
2016	1,015,465	1,243,045	5,855,829	15,588	51,455	1,649,405	9,830,787
2017	1,010,955	1,223,786	6,697,793	14,873	49,945	1,656,865	10,654,217
2018	1,052,800	1,233,117	6,677,892	14,206	49,884	1,610,792	10,638,692
2019	1,042,353	1,202,403	6,709,265	13,482	47,302	1,468,108	10,482,913
2020	1,046,910	1,131,101	5,652,942	12,617	46,375	1,340,290	9,230,235
2021	1,046,341	1,181,246	6,611,310	10,445	47,497	1,393,315	10,290,154
2022	**1,044,992**	**1,214,991**	**5,985,002**	**9,341**	**44,193**	**1,374,718**	**9,673,239**
2023	**1,043,077**	**1,232,760**	**6,021,887**	**8,663**	**43,503**	**1,523,465**	**9,873,355**
2024	**1,046,600**	**1,233,344**	**6,078,011**	**8,706**	**43,400**	**1,530,812**	**9,940,872**
2025	**1,043,853**	**1,237,668**	**6,044,961**	**8,695**	**43,011**	**1,532,449**	**9,910,637**
2026	**1,044,659**	**1,244,434**	**6,027,537**	**8,719**	**42,973**	**1,536,000**	**9,904,322**
2027	**1,046,626**	**1,255,222**	**6,206,215**	**8,741**	**43,228**	**1,545,146**	**10,105,178**
2028	**1,053,163**	**1,266,480**	**6,346,706**	**8,803**	**43,391**	**1,555,451**	**10,273,994**
2029	**1,052,296**	**1,269,252**	**6,300,548**	**8,800**	**43,241**	**1,557,530**	**10,231,667**
2030	**1,055,093**	**1,275,024**	**6,281,714**	**8,827**	**42,998**	**1,566,535**	**10,230,191**
2031	**1,057,715**	**1,284,253**	**6,262,147**	**8,850**	**43,143**	**1,572,971**	**10,229,080**
2032	**1,064,445**	**1,297,015**	**6,263,034**	**8,906**	**43,287**	**1,588,843**	**10,265,530**
2033	**1,065,005**	**1,299,603**	**6,221,255**	**8,902**	**42,923**	**1,592,692**	**10,230,380**
2034	**1,069,938**	**1,305,493**	**6,204,488**	**8,921**	**42,616**	**1,599,559**	**10,231,017**
2035	**1,075,484**	**1,311,661**	**6,184,991**	**8,941**	**42,264**	**1,608,467**	**10,231,808**
2036	**1,085,565**	**1,323,294**	**6,184,834**	**9,001**	**42,108**	**1,619,294**	**10,264,096**

IV. 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 makes no assumptions regarding the expected conversion from one fuel source to another*.
- Assumptions made regarding future prices of electricity for customers and the effect that such prices would have on system demand.
  - *See Section II.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 Federal or State legislation.
  - *See Section II.B.*
- Assumptions made regarding current and future saturation levels of appliances and electric space heating.
  - *Minnesota Power makes no assumptions regarding current and future saturation levels of appliances and electric space heating*.

B. Coordination of Forecasts with Other Systems

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

C. Compliance with 7610.0320 Forecast Documentation

Statute or Rule	***Requirement***	***Reference Section***
7610.0320, Subp. 1(A)	The overall methodological framework that is used.	Section II.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 II.B, II.E
7610.0320, Subp. 1(C)	The manner in which these specific techniques are related in producing the forecast.	Section II.B
7610.0320, Subp. 1(D)	The purpose of the technique, typical computations specifying variables and data, and the results of appropriate statistical tests.	Section II.E
7610.0320, Subp. 1(E)	Forecast confidence levels or ranges of accuracy for annual peak demand and annual electrical consumption.	Section II.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 II.B, II.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 II.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 II.C
7610.0320, Subp. 3	Discussion of essential assumptions.	Sections II.D, II.E
7610.0320, Subp. 4	Subject of assumption.	Section IV
7610.0320, Subp. 5(A)	Description of the extent to which the utility coordinates its load forecasts with those of other systems.	Section IV
7610.0320, Subp. 5(B)	Description of the manner in which such forecasts are coordinated.	Section IV

Appendix O

Summaries of 2021 Conservation Improvement Program and Integrated Resource Plan Filings

APPENDIX O

APPLICANT'S DEMAND-SIDE MANAGEMENT AND CONSERVATION

Pursuant to Minn. R. 7849.0290, a Certificate of Need application must provide information related to an applicant's energy conservation and efficiency programs and a quantification of the impact of these conservation and efficiency programs on forecast data. Minnesota Power requested and was granted an exemption from this rule requirement by the Minnesota Public Utilities Commission. In lieu of the information required by Minn. R. 7849.0290, Minnesota Power agreed to provide a summary of the conservation and demand-side management information that was provided as part of Minnesota Power's Integrated Resource Plan and Conservation and Improvement Plan ("CIP") filings.

Minnesota Power filed its 2022 CIP Consolidated Filing with the Commission on April 3, 2023 in Docket No. E015/M-23-135. A copy of the "Summary" section and the "2022 CIP Status Report" section of this filing is provided in this appendix.

Minnesota Power filed its 2021 Integrated Resource Plan ("2021 IRP") with the Commission on February 1, 2021 in Docket No. E015/RP-21-33. Appendix B of the 2021 IRP filing contained information regarding Minnesota Power's planning and strategies for demand-side management, Energy Efficiency, and CIP. A copy of Appendix B of the 2021 IRP filing is provided in this appendix.

Additional information regarding Minnesota Power's conservation and demand-side management programs can be found on Minnesota Power's website at: https://www.mnpower.com/ProgramsRebates/PO1 .

2022 Consolidated Filing

Conservation Improvement Program

UNDERSTANDING

TOOLS AND RESOURCES

INFORMED CHOICES

RIGHT FIT OPTIONS

minnesota power

AN ALLETE COMPANY

April 3, 2023

Docket No. E-015/M-23-135 | E-015/CIP-20-476.02

minnesota power
AN ALLETE COMPANY

30 West Superior Street
Duluth, MN 55802-2093
www.mnpower.com

April 3, 2023

Mr. Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Deputy Commissioner Michelle Gransee
Minnesota Department of Commerce
85 Seventh Place East, Suite 500
St. Paul, MN 55101-2198

Re: **2022 Conservation Improvement Program Consolidated Filing**
Docket Nos. E015/M-23-135, E015/CIP-20-476.02

Dear Mr. Seuffert and Ms. Gransee:

Attached please find via eFiling Minnesota Power's 2022 Conservation Improvement Program ("CIP") Consolidated Filing. This submittal includes a CIP Tracker Activity Report, a Financial Incentives Report, a Proposed Conservation Program Adjustment Factor, 2022 CIP Project Evaluations and a compliance with Department of Commerce ("DOC") orders section. Minnesota Power is filing this information pursuant to Minn. Stat. §§ 216B.241, 216B.16, subd, 6c, 216B.2401, and 216B.2411 and in compliance with Minnesota Public Utilities Commission ("MPUC") and DOC rules and orders relating to annual filings associated with Company-sponsored conservation program activities, including Minn. Rule 7690.0550.

Minnesota Power requests that the MPUC review the filed material and approve Minnesota Power's 2022 CIP Tracker Activity, Financial Incentives, proposed Conservation Program Adjustment ("CPA") factor, and a variance of Minn. Rules 7820.3500 and 7825.2600 to permit Minnesota Power to continue to combine the CPA factor with the Fuel Clause Adjustment on customer bills and/or combine the CPA factor with other currently applicable cost recovery riders on bills as the Minnesota Policy Adjustment when final rates in the Company's latest rate case are effective. Further, Minnesota Power requests that the DOC review and approve the evaluations of the various CIP projects included herein and the compliance with prior DOC orders. Minnesota Power has electronically filed this document and copies of this Cover Letter along with the Summary of Filing have been served on the parties on the attached service list.

If you have any questions regarding this filing, please contact me at (218) 355-3602 or avang@mnpower.com.

Sincerely,

Analeisha Vang
Senior Public Policy Advisor

AMV:th
Attach.

Summary

Minnesota Power

2022 Conservation Improvement Program ("CIP") Consolidated Filing

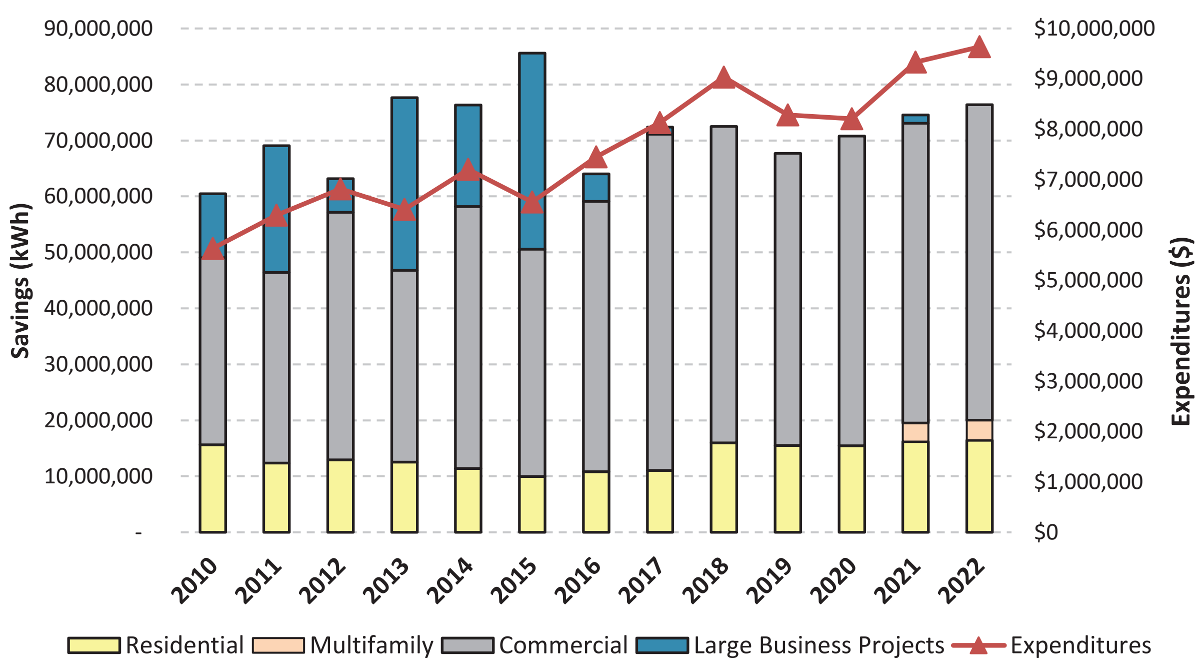
EXECUTIVE SUMMARY

Minnesota Power (or, "the Company") is pleased to report its 2022 energy conservation program results:

- Minnesota Power achieved energy savings of **2.9%** of gross annual retail energy sales,[1] well above the 1.5% energy-savings goal set in the 2021-2023 Triennial Order, and the 1.75% goal in the 2021 Energy Conservation and Optimization Act.[2]
- The Company achieved energy savings totaling **76,400,068 kilowatt hours ("kWh")**, which is **115%** of the approved energy-savings goal for the year. The Company also achieved demand savings of **8,195 kilowatts ("kW")**, which is **82%** of the approved demand-savings goal. The proposed energy-savings target for 2022 was well above the state 1.5% energy-savings goal for CIP.
- Expenditures totaled **$9,635,730**, which was **90%** of the approved budget for 2022.

The figure below illustrates historical and recent kWh energy-savings achievements, along with CIP expenditures. While Minnesota Power continues to have a successful track record of exceeding the state energy savings goal, the cost of delivering on these goals continues to increase. The Company anticipates the trend of increasing costs will continue as inflation impacts the cost of both products and labor and more cost-effective measures reach market saturation. Cost-effectiveness is also being impacted by lower avoided costs. While Minnesota Power's CIP portfolio continues to be cost-effective overall, higher cost programs – especially those serving income-qualified customers – are becoming increasingly less cost-effective.

Minnesota Power's 2005–2022 CIP Achievements



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[1] In accordance with Minnesota Rules part 7690.1200, weather-normalized average retail energy sales were used to calculate the electric savings goal for Minnesota Power's 2021–2023 Triennial Plan.

[2]While the Energy Conservation and Optimization Act (ECO Act) passed in 2021 with a higher savings goal, the energy savings goal for the 2022 Consolidated is based on the November 24, 2020 Order in Docket No. [illegible] 20-476.

Minnesota Power's 2022 CIP Expenditures and Energy Savings

2022	*Expenditures*	*Energy Savings (kWh) at busbar*
Direct Savings Programs:		
Residential		
Energy Partners (Low Income)	$488,578	1,203,774
Home Efficiency (Residential)	$2,054,644	15,214,197
Multifamily		
Multifamily Direct Install	$156,743	351,955
Custom Multifamily Efficiency	$267,636	3,251,017
Commercial		
Prescriptive Business Efficiency	$59,247	1,013,699
Custom Business Efficiency (Business/Commercial/Industrial/Agricultural)	$4,474,126	55,365,426
Indirect Savings Programs:		
Customer Engagement	$640,290	
Energy Analysis	$700,495	
Research & Development	$148,909	
Evaluation & Program Development	$467,870	
Regulatory Charges	$177,191	
Total	**$9,635,730**	**76,400,068**

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's 2022 Conservation Improvement Program Consolidated Filing	Reporting on CIP Tracker Account Activity, Financial Incentives Report, Proposed CPA Factors and 2022 Project Evaluations Docket No. E-015/M-23-135 E-015/CIP-20-476.02

SUMMARY OF FILING

Minnesota Power (or, "the Company") hereby files with the Minnesota Public Utilities Commission ("MPUC" or "Commission") and the Department of Commerce, Division of Energy Resources ("Department") its annual Conservation Improvement Program ("CIP") Consolidated Filing in compliance with Minn. Stat. § 216B.241. Minnesota Power requests approval of the following:

- Recovery of the 2022 CIP Tracker Account activity year-end balance of $1,321,045.
- A revised Conservation Program Adjustment ("CPA"), to be first implemented without proration on July 1, 2023, of $0.000306/kilowatt hour ("kWh").
- A variance of Minn. Rules 7820.3500 and 7825.2600 to permit the continued combination of the Conservation Program Adjustment with the Fuel and Purchased Power Clause Adjustment on customer bills, until final rates from Minnesota Power's latest rate case are implemented.[3]
- A variance of Minn. Rules 7820.3500 and 7825.2600 to permit the combination of the Conservation Program Adjustment with other currently applicable cost recovery riders (Rider for Transmission Cost Recovery, Rider for Renewable Resources, and Rider for Solar Energy Adjustment), on bills as the Minnesota Policy Adjustment when final rates are effective as detailed in the February 28, 2023 Order in Minnesota Power's latest rate case.[4]

Minnesota Power submits its Conservation Improvement Program Consolidated Filing via eFiling with the Department of Commerce, Division of Energy Resources to comply with annual CIP project evaluation filing requirements.

[3] *Minnesota Power's 2021 Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E015/GR-21-335.
[4] From the docket above, see the February 28, 2023 Order at Order Point 43 and the September 1, 2022 ALJ's Findings of Fact, Conclusions of Law, and Recommendations at pp. 129-31.

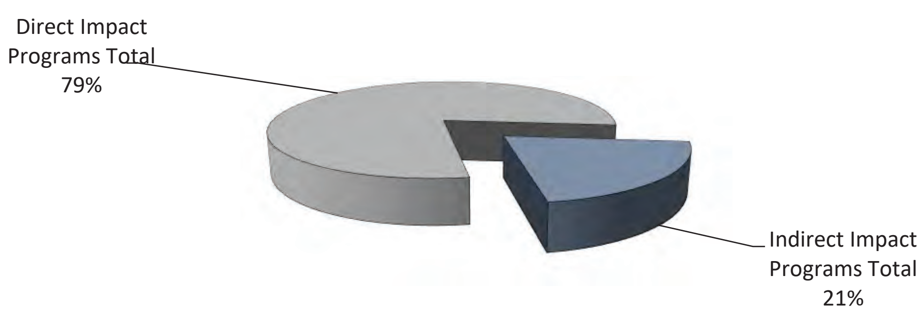
Status Report

Status Report

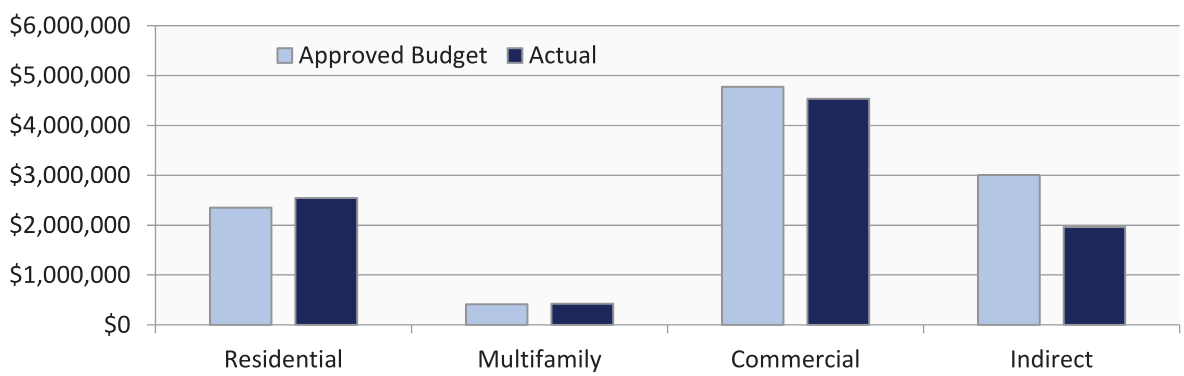
2022 CIP Status Report

Minnesota Power's energy conservation strategy provides a wide variety of program offerings to best serve its diverse customer mix. Each customer is unique in both their motivations for pursuing energy efficiency opportunities and their ability to engage in different offerings. With this knowledge, Minnesota Power provides a combination of traditional programs and innovative delivery strategies designed to address the needs and barriers of each customer segment including residential, multifamily and business. Minnesota Power's CIP portfolio includes a combination of "direct savings" and "indirect savings" programs that complement each other and provide for a balanced and meaningful customer experience.

2022 Program Spending By Direct and Indirect Savings Programs

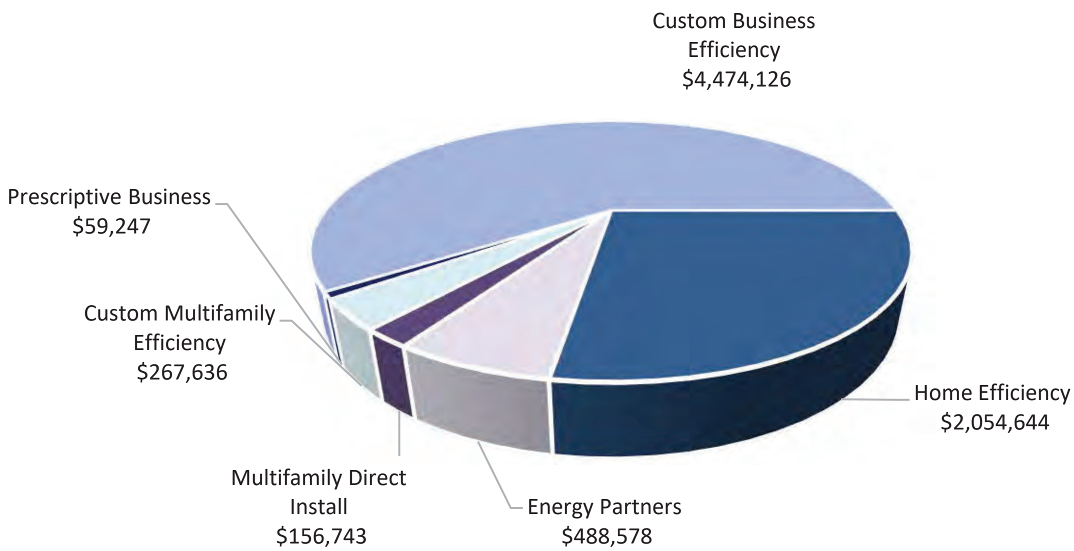


2022 Approved Budgets & Actual Spending Per Segment

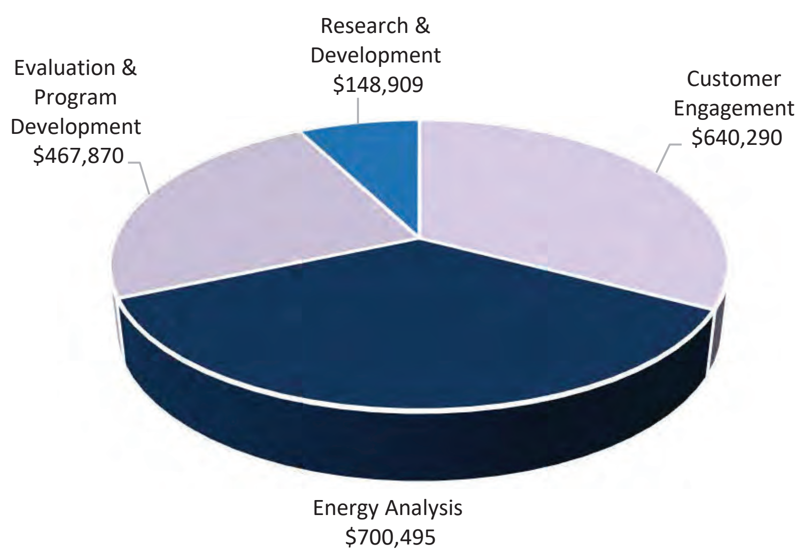


Investing in a range of programs is essential to keep Minnesota Power's program portfolio strong well into the future. Minnesota Power added three new programs to its CIP portfolio in the 2021-2023 Triennial Plan to better serve all customer segments. See the figures below for a breakdown of spending by program.

2022 Direct Savings Program Spending Breakdown

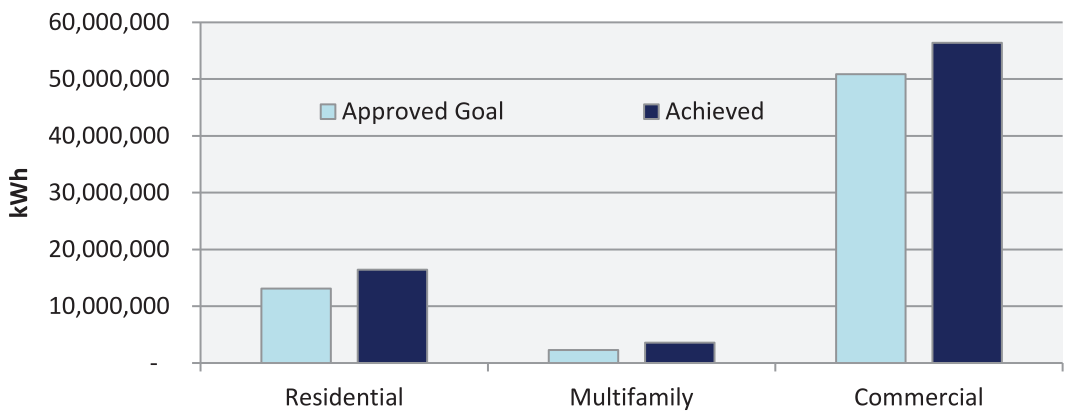


2022 Indirect Savings Program Spending Breakdown



Minnesota Power met or exceeded the energy savings goal in each segment of its CIP portfolio, as shown in the chart below. Two programs within those segments, Multifamily Direct Installation and Energy Partners, did not achieve the approved energy savings goal for various reasons as described in detail in the specific program descriptions. Minnesota Power continues to work with customers, stakeholders and delivery partners to identify opportunities to refine these offerings going forward.

2022 Approved Savings Goals & Achievements per Segment



For further context regarding Minnesota Power's energy conservation programs and the impact they have on customers, see the Successes section of this filing. These case studies highlight people, businesses and communities taking ownership of their energy usage and demonstrate how Minnesota Power connects with customers through conservation.

Looking Forward

There are many factors influencing the energy efficiency environment in Minnesota, including rising delivery costs, evolving state and federal policy, and changes in cost effectiveness. Minnesota Power has worked closely with customers, contractors, stakeholders, and regulators to ensure that programs are flexible and responsive to the evolving industry and has taken steps to modify programs as needed. However, additional actions will be required to ensure Minnesota Power's CIP portfolio continues to meet customer needs and encourages equitable access to customer programs as the environment continues to evolve.

Program delivery costs have increased significantly in recent years. The combination of inflation, supply chain disruptions, and economic uncertainty have impacted customers' ability to make capital improvements to their homes and businesses. Additionally, attracting and retaining talent in northern Minnesota has continued to create challenges for customers, delivery partners, and the Company. Encouraging customers to make energy-efficient investments has required higher incentives, more costly equipment and more resources than have historically been required.

In addition, the Company anticipates that recent federal and state policy changes will have a significant impact on Minnesota Power's CIP portfolio in the coming years. Initial guidance related to the ECO Act passed by the Minnesota legislature in 2021 was provided on March 15, 2022 as the result of a significant Department-led stakeholder working group.[17] This guidance will enable utilities to begin exploring new types of offerings including efficient fuel switching and load management activities. As utilities and stakeholders begin to utilize this guidance, further discussion and additional guidance will likely be needed. Meanwhile, the passage of the Inflation Reduction Act ("IRA") has introduced a significant amount of federal funding that will be available in the form of both rebates and tax credits on the purchase of energy efficient equipment and services. It will be critical for utilities and the Department of Commerce to coordinate on the design and implementation of these programs to ensure that customers are able to maximize the benefits of both CIP and IRA programs. While effective coordination and implementation of these funds could help address the rising costs of utility conservation programs, there is significant uncertainty around actual impacts.

Meanwhile, as the result of a robust series of Department-led working group efforts which included utilities, stakeholders, and industry experts, significant changes to the CIP/ECO evaluation framework and calculations have been proposed. Changes include the addition of a new primary screening test referred to as the Minnesota Cost Test ("MCT"), a test designed to reflect the State's energy policy goals and objectives, inclusion of new utility system and non-utility system impacts within the tests, and potential standardization of various existing impacts that historically have been utility specific. These changes, along with rising delivery costs and the new IRA programs described above, will make it difficult to predict the overall cost-effectiveness of CIP portfolios going forward. Flexibility to update and modify programs and portfolios will be more critical than ever going into the next Triennial.

Minnesota Power will continue to work with customers, stakeholders and regulators to ensure that programs are well-positioned to address challenges and opportunities associated with the rapidly evolving energy efficiency and optimization landscape into the future. Minnesota Power remains committed to providing sustainable, inclusive, and cost-effective energy-efficiency programs, with ongoing program development and increased efforts to raise program awareness and participation.

[17] Docket No. E,G999/CIP-21-837

Minnesota Power's 2022 CIP Expenditures & Achievements

2022	*Expenditures*				*Energy Savings (kWh @ Busbar)*				*Demand Savings (kW @ Busbar)*				*Participation*			
Direct Impact Programs	*Filed Budget*	*Approved Budget*	*Actual*	*Percent of Approved*	*Filed Goal*	*Approved Goal*	*Achieved*	*Percent to Goal*	*Filed Goal*	*Approved Goal*	*Achieved*	*Percent to Goal*	*Filed Goal*	*Approved Goal*	*Achieved*	*Percent to Goal*
Home Efficiency	$ 1,985,398	$ 1,985,398	$ 2,054,644	103%	11,847,171	11,847,171	15,214,197	128%	1,309	1,309	1,735.3	133%	225,559	225,559	309,430	137%
Energy Partners	$ 366,961	$ 366,961	$ 488,578	133%	1,246,050	1,246,050	1,203,774	97%	132	132	133.4	101%	14,126	14,126	12,735	90%
Multifamily Direct Install*	$ 247,228	$ 106,131	$ 156,743	148%	1,025,640	401,482	351,955	88%	112	43	39.9	92%	12,294	3,868	2,904	75%
Custom Multifamily Efficiency*	$ 140,588	$ 307,643	$ 267,636	87%	1,092,769	1,912,346	3,251,017	170%	184	350	628.4	179%	45	68	82	121%
Prescriptive Business Efficiency*	$ 123,323	$ 119,422	$ 59,247	50%	1,102,604	603,964	1,013,699	168%	123	88	173.4	198%	1,178	1,015	6,059	597%
Custom Business Efficiency	$ 4,651,797	$ 4,651,797	$ 4,474,126	96%	50,267,374	50,267,374	55,365,426	110%	8,101	8,101	5,484.9	68%	1,365	1,365	1,437	105%
Direct Impact Programs Total	**$ 7,515,295**	**$ 7,537,352**	**$ 7,500,974**	**100%**	**66,581,608**	**66,278,387**	**76,400,067.6**	**115%**	**9,962.1**	**10,023.0**	**8,195.2**	**82%**	**254,567**	**246,001**	**332,647**	**135%**
Indirect Impact Programs																
Customer Engagement	$ 864,900	$ 864,900	$ 640,290	74%									100,750	100,750	103,470	103%
Energy Analysis	$ 1,018,077	$ 1,018,077	$ 700,495	69%									6,145	6,145	5,771	94%
Evaluation & Program Development	$ 731,472	$ 731,472	$ 467,870	64%												
Research & Development	$ 384,600	$ 384,600	$ 148,909	39%												
Indirect Impact Programs Total	**$ 2,999,049**	**$ 2,999,049**	**$ 1,957,564**	**65%**	**-**	**-**	**-**						**106,895**	**106,895**	**109,241**	**102%**
Regulatory Charges	$ 200,000	$ 200,000	$ 177,191	89%												
Total	**$ 10,714,344**	**$ 10,736,401**	**$ 9,635,730**	**90%**	**66,581,608**	**66,278,387**	**76,400,068**	**115%**	**9,962.1**	**10,023.0**	**8,195.2**	**82%**	**361,462**	**352,896**	**441,888**	**125%**

*Approved budgets and goals for these programs reflect program modifications as filed and approved in Docket No. E015/CIP-20-476.