APPENDIX F1 – LOAD AND DISTRIBUTED ENERGY RESOURCE FORECASTING

I. LOAD FORECAST METHODOLOGY

This Appendix discusses the methodology we used in conjunction with this Resource Plan to forecast customer need, including the requirements specified in Minn. R. 7610.0320. We also note that, while this Appendix documents our load and energy demand forecasting process, we have taken additional steps with respect to the treatment of energy efficiency (EE) forecasting in this Resource Plan, to model it as a supply-side resource. Where relevant, we include explanations of these steps in order to provide transparency, and explain how this base forecast correlates to the load and energy demand forecasting discussed in Chapter 3: Minimum System Needs, and Appendix F2: Strategist Modeling Assumptions and Inputs.

The Company relies on econometric models and other statistical techniques to develop the sales forecast. The econometric models relate our historical electric sales to demographic, economic and weather variables. We develop sales forecasts for each major customer class, in each state of our service area. The individual class forecasts for each state are summed to derive a total system sales forecast.

We convert the sales forecast into energy requirements at the generator level by adding energy losses. The forecasted losses are based on forecasted loss factors, which are developed using actual historical loss factors and are held constant over the forecast period. We develop the peak demand forecast using a regression model that relates historical monthly base peak demand to energy requirements and weather. The median energy requirements forecast and normal peak-producing weather are used in the model to create the median base peak demand forecast. We provide a detailed discussion of the forecast methodology later in this Appendix.

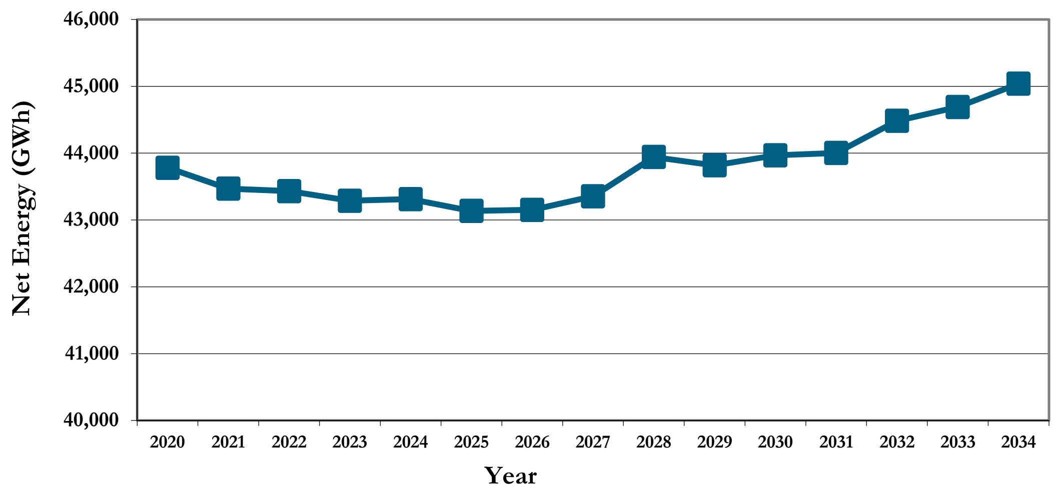
The forecasts are based on projections of economic activity for our various service areas provided by IHS Global Insight, Inc. (Global Insight). Global Insight projects continued growth in key economic indicators. For example, for the Minneapolis-St. Paul metropolitan area, households are expected to increase at an average annual rate of 0.8 percent during the 2020-2034 planning period. Real personal income is expected to increase 0.8 percent per year on average, and employment is expected to gain an average of 0.2 percent per year. Minnesota real gross state product is expected to increase at an average annual rate of 1.8 percent.

A. Energy Forecast

1. Base Forecast Methodology

The base energy forecast increases at an average annual growth rate of 0.2 percent over the 2020 – 2034 planning period, net of the 1.5 percent energy savings level approved in the Company's last Resource Plan, forecasted distributed solar, and electric vehicle charging projections. Electric energy requirements are expected to increase at an annual average of 90 gigawatt-hours (GWh), starting with 43,781 GWh in 2020 to 45,038 GWh in 2034. See Figure 1 below.

Figure 1: NSP System Total Median Net Energy (GWh)
(Includes 1.5 Percent EE Adjustment)



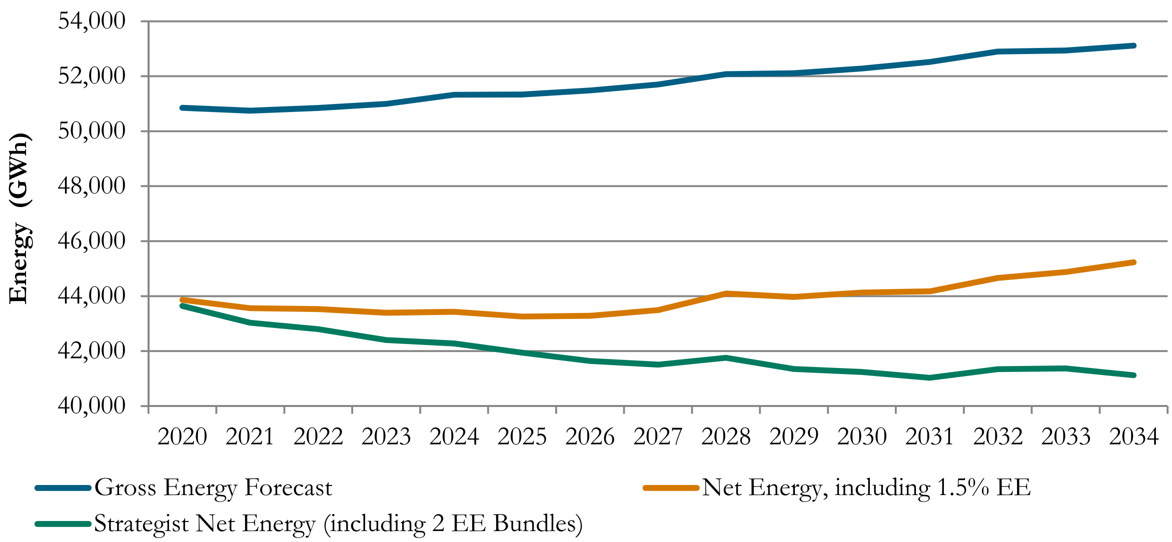
The projected 0.2 percent average annual growth in electric energy requirements is stronger than the actual growth seen over the past few years. After adjusting for unusual weather, electric energy requirements decreased at an average annual rate of *negative* 0.3 percent from 2014 to 2017.

2. Modifications for Use in Strategist

As noted in Chapter 3: Minimum System Needs, we undertook additional steps to allow EE to be modeled as a supply-side resource. This required that we adjust the base energy forecast (discussed in Part 1 above) to remove the embedded EE adjustment that projects the effects of 1.5 percent energy savings to the end of the Planning Period. This resulted in an NSP System Gross Energy Requirements forecast. In a separate process, we formulated annual EE savings amounts into

"Bundles" that we made available in the Strategist model along with other supply-side resources used to model EE as a supply-side resource in Strategist. We show these adjustments in Figure 2 below.

Figure 2: Gross Energy Requirements Forecast Compared to Net Energy Requirements Forecast



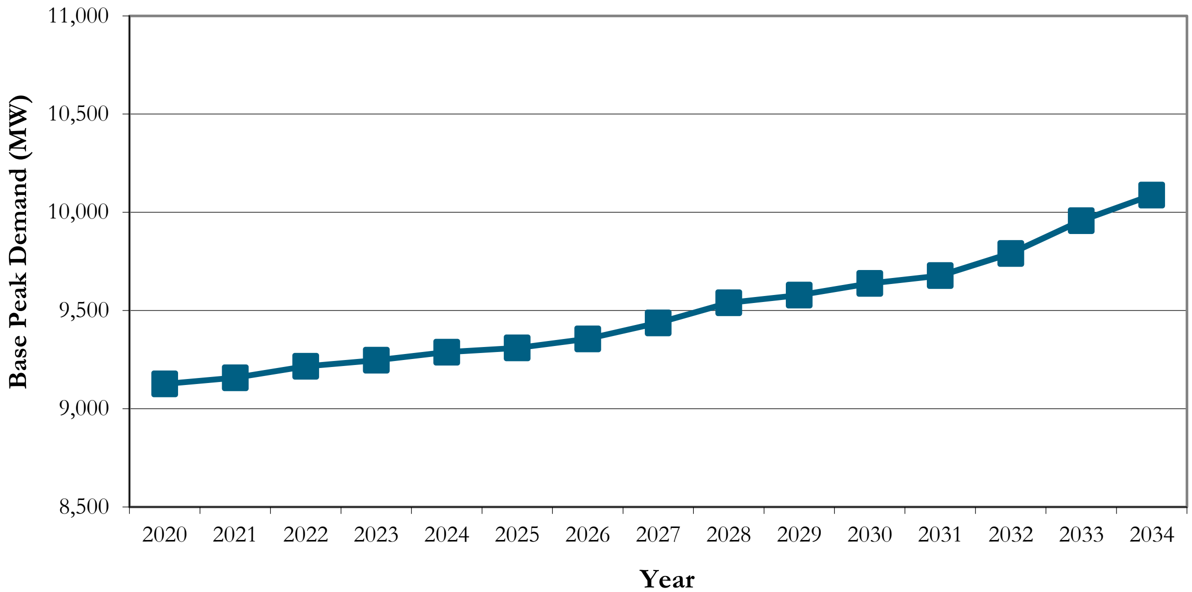
We discuss the EE Bundle modeling further in Appendix F2: Strategist Modeling and Appendix F6: Resource Options.

B. System Peak Demand Forecast

1. Base Forecast Methodology

During the 2020 – 2034 planning period, the median base peak increases at an average annual growth rate of 0.7 percent. As demonstrated in Figure 3 below, annual peak demand increases at an average of 69 MW each year, starting with 9,126 MW in 2020 to 10,087 MW in 2034.

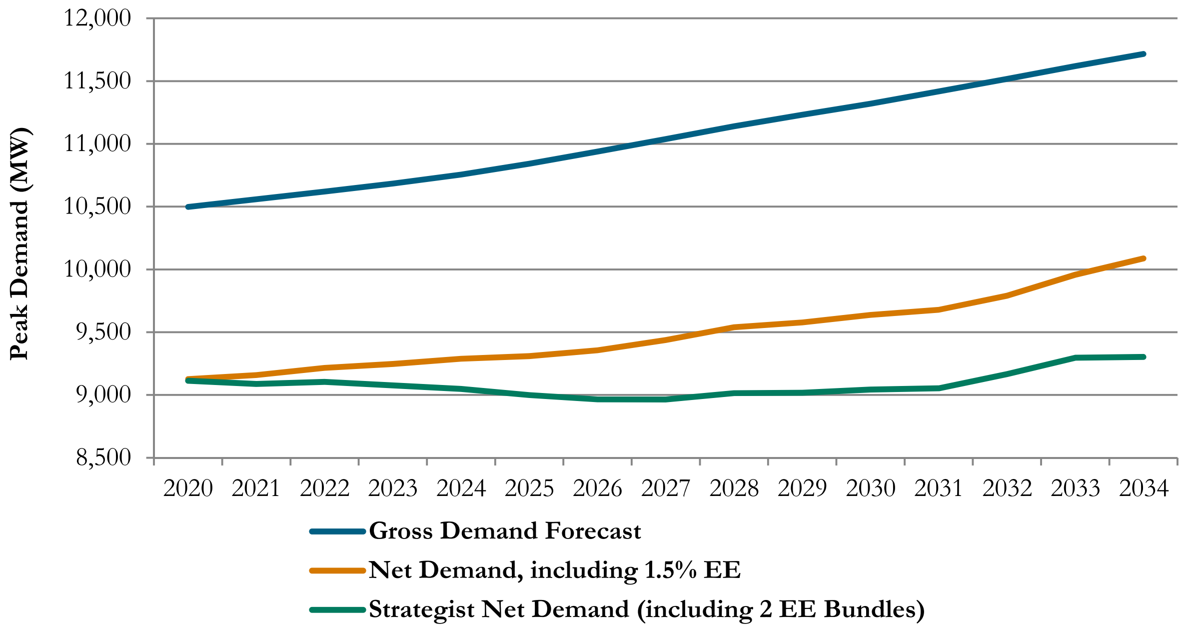
Figure 3: NSP System Median Base Summer Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)



2. *Modifications for Use in Strategist*

For modeling demand levels in Strategist, we took the same approach as noted in reference to the energy forecasts. Again here, for Strategist modeling purposes, we start with the base forecast and remove 1.5 percent EE adjustment in order to reflect gross load. This process enables us to model the system considering EE as a supply-side resource.

Figure 4: Gross Peak Demand Forecast Compared to Net Peak Demand Forecast



The balance of this Appendix discusses the energy and peak load forecasting methodologies, assumptions, analytics, adjustments, etc. to derive the System Energy Forecast presented in Part A.1 and Figure 1 above and the System Base Peak Demand Forecast presented in Part B.1 and Figure 3.

C. Key Demand and Energy Forecast Variables

Below we discuss some of the key variables that are included in the 2019 Resource Plan forecasts.

1. Demographics

Demographic projections are essential to the development of the long-range forecasts. The consumption of electricity is closely correlated with demographic statistics. The number of residential customers, weather data and economic indicators are key variables in the residential energy sales forecast. Over 99 percent of the variability in historical electric residential customer counts in our service territory can be explained through an econometric model that contains either population or households as key drivers. The forecasts for population and households are provided by Global Insight.

We forecast an average annual growth rate for total residential customers on our system of 0.6 percent, with the addition of 10,246 residential customers on average per year from 2020 through 2034.

2. *Economic Indicators*

Xcel Energy uses estimates of key economic indicators to develop electric sales forecasts. These variables include gross state product, employment and real personal income. The variables used are specific to the jurisdiction and are statistically significant in the sales models for the residential and commercial and industrial customer classes. Growth in electric energy consumption in the residential and commercial and industrial sectors closely follows trends in economic activity. Global Insight provided the economic forecasts used in our regression models.

For the planning period, the economy is expected to continue to grow, resulting in growth in electric energy consumption.

3. *Weather*

The peak demand for electric power is heavily influenced by hot and humid weather. As the temperature and humidity rise, the demand for cooling rises steeply. Our approach to forecasting peak demand includes using a weather variable that consists of the mean of an index of heat and humidity referred to as the temperature humidity index (THI). Simply stated, the THI is an accurate measure of how hot it really feels when the effects of humidity are added to the high temperature.

We have tracked the THI at the time of the system peak demand over the past 20 years. Because of the 20 years of smoothing, the weather variable does not drastically affect our median forecasts; however, it becomes a key factor in assessing the potential peak demand if and when hot and humid weather extremes are encountered. Since Xcel Energy must have adequate generating resources available during hotter than normal circumstances, planning for the extreme is important.

D. Forecast Methodology

Xcel Energy serves customers in five jurisdictions in the upper Midwest: Minnesota, North Dakota, South Dakota, Wisconsin and Michigan. We develop a forecast for each major customer class and jurisdiction using a variety of statistical techniques.

We first develop our system sales forecasts by using a set of econometric models at the jurisdictional level for the Residential and Small Commercial and Industrial sectors for all jurisdictions, the Large Commercial and Industrial sector for Minnesota, and the Minnesota Public Street and Highway Lighting and Public Authority sectors. These models relate our historical electric sales to demographic, economic and weather variables as detailed in the prior section of this document.

For the remaining customer classes, Large Commercial and Industrial, Public Street and Highway Lighting, and Public Authority in all states but Minnesota, and Interdepartmental, we use trend analysis and customer specific data. We compile our system sales by summing the individual forecasts for each sector in each jurisdiction.

Since some energy is lost, mostly in the form of heat created in transmission and distribution conductors, we use loss factors to convert the sales forecasts into energy production requirements at the generator. The forecasted loss factors are developed using actual historical loss factors and are held constant over the forecast period.

We have developed a regression model to relate Xcel Energy's historical uninterrupted monthly peak demand to energy requirements and weather at the time of the peak in the winter and summer seasons. The median energy requirements forecast (50/50 forecast) and normal peak-producing weather are used in the model to create the peak demand forecast. (*Note*: Section II of this Appendix contains a comprehensive summary of the regression modeling process utilized to develop the energy and demand forecasts.)

Once the NSP System peak demand forecast is complete, a forecast is developed for the NSP System demand coincident with the Midcontinent Independent System Operator (MISO) system peak demand. The coincident demand forecast is developed using a regression model that determines the relationship between the NSP System demand coincident with the MISO peak demand and the NSP System peak demand (not coincident with the MISO peak demand). MISO only requires an annual coincident demand forecast for the next planning year. The current resource plan forecast is for the NSP System demand coincident to the MISO annual peak demand during the 2019-20 planning year (June 2019 – May 2020).

E. Forecast Adjustments

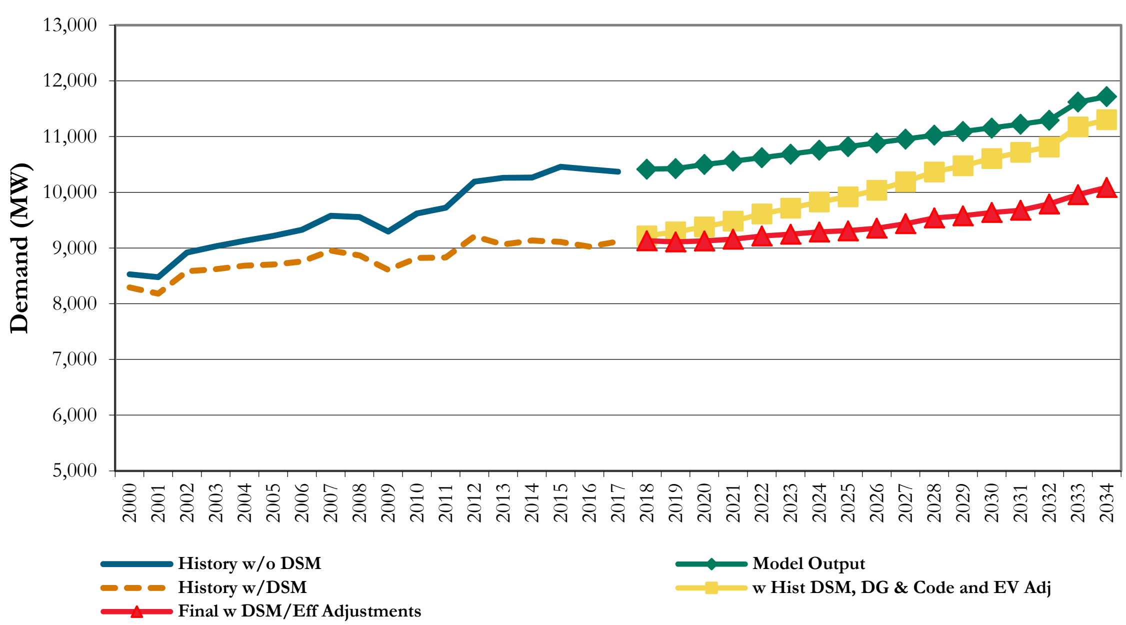
Our demand and energy forecasts are developed using a number of key forecast variables as described in this Appendix. One important adjustment to the forecasts is to take into account our conservation programs.

The EE methodology implemented for the State of Minnesota uses the same method for projecting the impacts of EE and its load management effects on the sales forecast as was used in our 2015 Resource Plan filing. There are three distinct steps to this process:

- Collect and calculate historical and current effects of EE on observed sales
- Project the forecast using observed data with the impact of EE removed (i.e. increase historical sales to show hypothetical case without EE)
- Adjust the forecast to show the impact of all planned EE in future years.
- Also adjust the forecast to account for codes and standards changes resulting in decreased sales that are in addition to Company-sponsored EE.

These EE adjustments are based on the Company's current Triennial Plan goals, which were based on the savings level approved in the resource planning process. The Commission approved an average annual energy savings level of 444 GWh for all planning years in our 2015 Resource Plan in Docket No. E002/RP-15-21.[1] Figure 5 below graphically illustrates the EE adjustment.

Figure 5: Illustration of EE Adjustment – NSP System Demand (MW)



For the State of South Dakota, the impacts from all conservation program

[1] *See* Order, Ordering Point No. 11 (January 11, 2017).

installations prior to 2018 are assumed embedded in the historical demand and energy data at a rate equal to the annual program installations from 2013 through 2017. To accurately predict future supply needs, the energy and demand forecasts must be reduced by an estimate of the incremental future conservation savings. For the base forecast, we adjust the demand and energy forecast by assuming all future annual conservation achievement equal to achievement of our 2018 goal as approved in the 2016 South Dakota DSM Status Report and 2018 DSM Plan filing (Docket No. EL17-019).

In response to the establishment of a Solar Energy Standard (SES) by the Minnesota Legislature, an increased emphasis has been placed on distributed solar generation. We developed a forecast of the expected impact on demand and energy based on new programs designed to meet goals established for the SES. We adjusted the Minnesota class-level sales forecasts and the system peak demand forecast to account for the impacts of customer-sited behind-the-meter solar installations on the NSP System. We discuss the distributed solar forecast methodology below.

After determining the base forecast, we develop net forecasts that include all adjustments, including future EE, distributed solar generation, electric vehicle charging, and the effects of our EE programs over time.

F. Additional Forecast Adjustments

We made additional adjustments to the energy and demand forecasts to account for expected changes in specific large customers' electricity usage. These additional adjustments include:

- Customers adding self-generation combined heat and power capabilities, which reduce energy consumption and peak demand,
- Increases or reductions in usage due to new customers in our service territory, or planned expansions or reductions of load by existing customers, and increasing use of plug-in electric vehicle charging, which we discuss in Part II.D below.

G. Forecast Variability

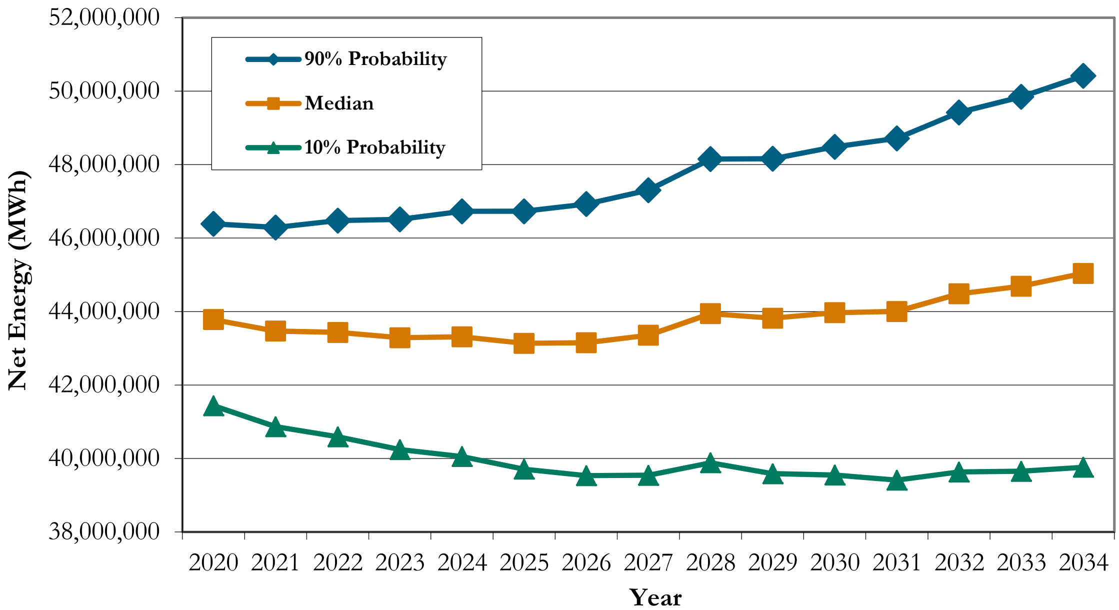
As with any forecast, our forecasts of energy requirements and peak demand depend on other forecasts of key variables. Changes in these variables will affect our forecasts. For instance, if the number of households in our service territory is lower than Global Insight has predicted, electric consumption in the residential sector will be lower. The peak demand for electric power each year is very sensitive to weather conditions and can vary considerably as the result of abnormal weather conditions.

Other forecast uncertainties include potential increases in loads due to new customers and potential losses in loads due to changes in customers' operations. For example, the potential exists for large increases in loads in the middle of the planning period due to increased mining activities in Northern Wisconsin. However, at this time there is still uncertainty around this potential increase and, therefore, we have not made an adjustment to the forecast.

Given that there is uncertainty in any long-term forecast, we supplement the median forecasts with forecasts developed using statistical techniques to reflect the potential variability in energy requirements and peak demand. These probability distributions were developed using a Monte Carlo stochastic simulation of peak demand (MW) and a simulation of energy (MWh). For example, the peak demand simulation involved taking 10,000 random draws from the weather probability distributions as well as 10,000 random draws from the 12-month sum of the energy probability distribution. The random draws produce 10,000 forecasts of peak demand and thus generate a probability distribution around the mean peak demand. We provide a more detailed description of the probability distribution methodology in Section II, and discuss summary results below.

The probability distributions developed for this forecast yielded a 90 percent probability that the net energy will be less than 50,416,762 MWh in 2034 – or alternatively, there is a 10 percent probability that the net energy will be less than 39,760,413 MWh. See Figure 6 below.

Figure 6: NSP System Total Net Energy (MWh)
(Includes 1.5 Percent EE Adjustment)



Figures 7 and 8 below show the higher and lower variations of the 2020 to 2034 long-range forecasts of base and net summer peak demand. [2]

[2] Where net summer peak demand includes adjustments form the base forecast to account for interruptible load.

Figure 7: NSP System Total Base Summer Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)

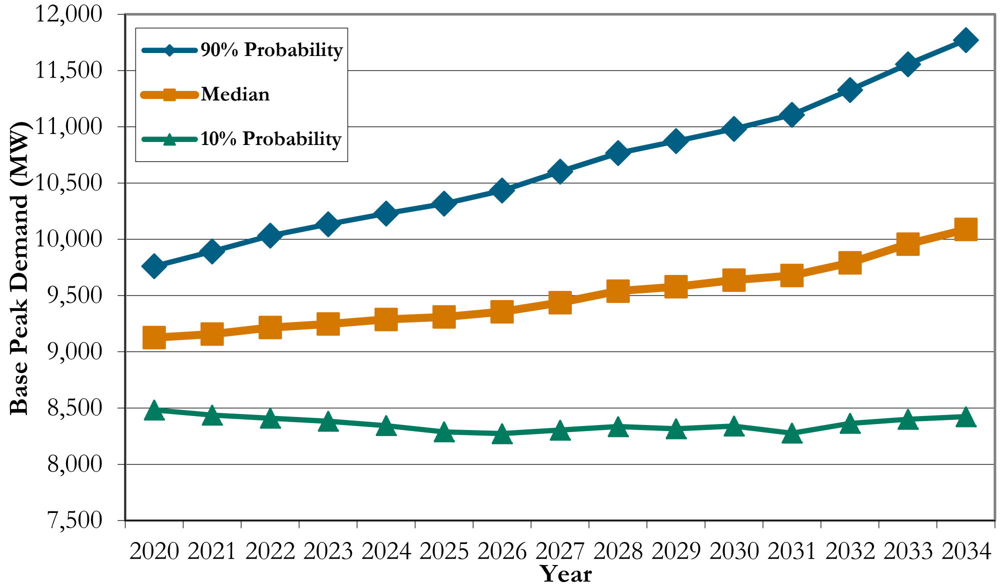
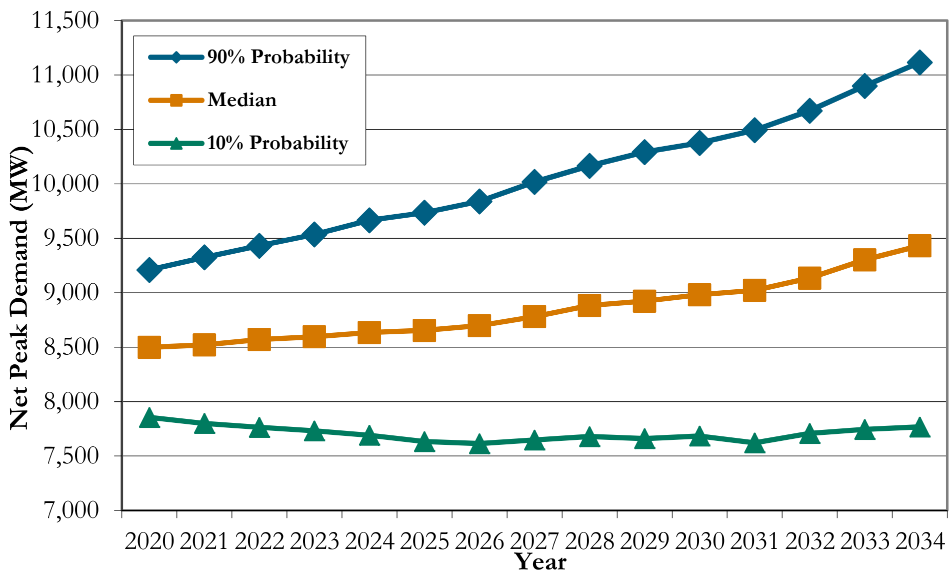


Figure 8: NSP System Total Net Summer Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)



Tables 1, 2, and 3 below provide the data underlying Figures 6, 7, and 8, respectively.

Table 1: Annual Net Energy (MWh)
(Including 1.5 Percent EE Adjustment)

Year	90% Probability	Median	10% Probability
2020	46,387,135	43,780,715	41,434,501
2021	46,289,330	43,467,677	40,864,878
2022	46,475,233	43,430,233	40,590,345
2023	46,508,251	43,287,395	40,240,549
2024	46,727,937	43,311,190	40,052,004
2025	46,728,197	43,135,149	39,706,759
2026	46,927,693	43,150,544	39,530,565
2027	47,302,668	43,354,456	39,539,672
2028	48,151,679	43,942,185	39,881,494
2029	48,158,669	43,817,294	39,583,487
2030	48,484,779	43,967,558	39,546,151
2031	48,714,578	44,001,712	39,410,068
2032	49,421,682	44,482,912	39,632,078
2033	49,845,815	44,689,679	39,649,954
2034	50,416,762	45,038,288	39,760,413
Average Annual Growth 2020 - 2034	**0.6%**	**0.2%**	**-0.3%**

Table 2: Annual Base Summer Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)

Year	90% Probability	Median	10% Probability
2020	9,761	9,126	8,483
2021	9,892	9,158	8,437
2022	10,032	9,216	8,409
2023	10,134	9,247	8,383
2024	10,229	9,288	8,344
2025	10,317	9,309	8,288
2026	10,433	9,356	8,272
2027	10,602	9,437	8,303
2028	10,766	9,539	8,334
2029	10,873	9,578	8,316
2030	10,982	9,638	8,340
2031	11,107	9,678	8,277
2032	11,327	9,791	8,364
2033	11,556	9,958	8,400
2034	11,771	10,087	8,423
Average Annual Growth 2020 - 2034	**1.4%**	**0.7%**	**-0.1%**

Table 3: Annual Net Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)

Year	90% Probability	Median	10% Probability
2020	9,210	8,498	7,855
2021	9,325	8,520	7,800
2022	9,432	8,571	7,764
2023	9,535	8,596	7,731
2024	9,666	8,635	7,691
2025	9,736	8,654	7,633
2026	9,839	8,698	7,614
2027	10,018	8,781	7,647
2028	10,166	8,883	7,679
2029	10,292	8,922	7,660
2030	10,376	8,982	7,684
2031	10,493	9,022	7,621
2032	10,671	9,135	7,708
2033	10,900	9,302	7,745
2034	11,115	9,432	7,767
Average Annual Growth 2020 - 2034	**1.3%**	**0.7%**	**-0.2%**

H. Forecast Vintage Comparison

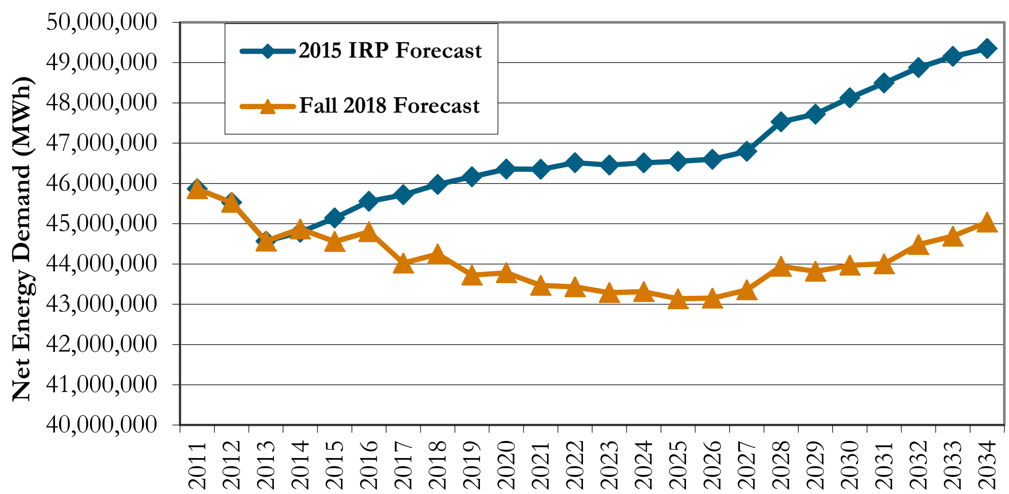
As described above, projections of energy and demand are fundamental to identifying the need for resources to meet expected customer needs. Thus, these forecasts are an important component in determining the size, type and timing of new generation resources. As a result, ensuring robust forecasts with fully analyzed assumptions and variables is a key component to supporting a Resource Plan or resource acquisition.

1. Forecast Vintage and Comparison

The review process for a Resource Plan or a resource acquisition typically takes a significant amount of time and effort to complete. During this time, forecasts can change as economic conditions, business operations, and technology changes occur. The graphs below compare the peak demand and energy of the Company's current forecast with the forecasts filed 2015 Resource Plan.

Figure 9 below indicates that the Fall 2018 energy forecast is lower than the Fall 2014 forecast provided in our 2015 Resource Plan due to lower and declining actual sales in 2015, 2016, and 2017. In particular, 2015-2017 weather normalized actual sales were lower for the NSPM residential sector and the NSPM small and large commercial and industrial sectors. In the residential sector, while the actual number of customers was slightly higher than estimated in the Fall 2014 forecast, the larger driver of the weaker-than-expected sales was lower use per customer. The NSPM small commercial and industrial sector also experienced lower-than expected use per customer. The NSPM large commercial and industrial sector was projected to grow in the Fall 2014 forecast, but actual sales declined due to customers installing combined heat and power plants and loss of other load to locations outside Xcel's service territory.

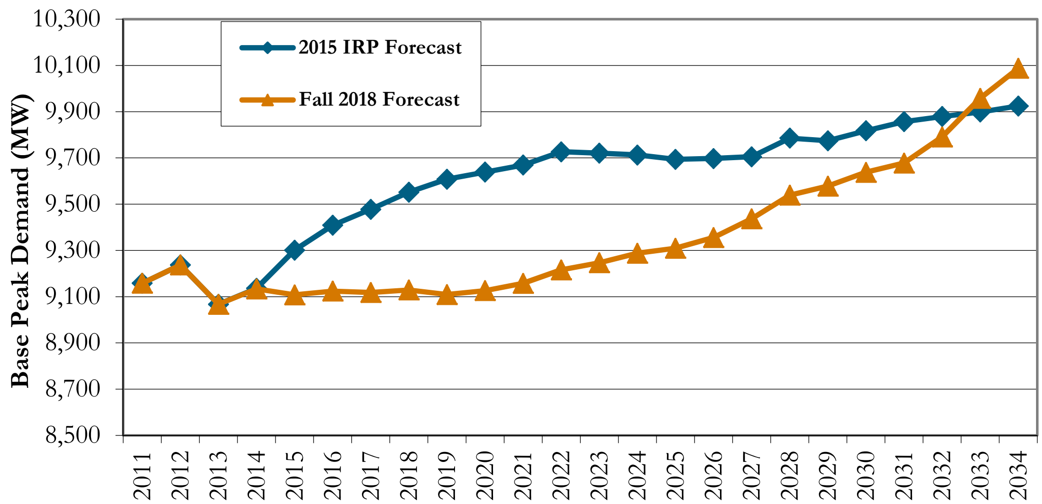
Figure 9: Net Energy Requirements (MWh) – Comparison of Current and Previous Energy Forecast
Median (50th Percentile) Forecast



In addition, the projected rate of growth of key economic indicators is lower now than when the Fall 2014 forecast was produced. For example, the average annual growth rate during the planning period for Minnesota real personal income is 1.8 percent, compared to a projected 3.6 percent in the Fall 2014 forecast. As another example, the average annual growth rate during the planning period for Minneapolis-St. Paul total employment is 0.4 percent, compared to the projected 1.1 percent in the Fall 2014 forecast.

Figure 10 below shows a comparison of the base peak demand forecast to the Fall 2014 forecast. Similar to the energy forecast, the current demand forecast is lower than the Fall 2014 forecast underlying the 2015 Resource Plan for most of the planning period. While actual sales from 2011 to 2017 have trended downward, the NSP system peak demand has remained fairly flat, but well below the Fall 2014 forecast. The current forecast calls for peak demand to increase and surpass the Fall 2014 forecast as energy gains turn positive in the outer years of the planning period.

Figure 10: Base Peak Demand (MW) – Comparison of Current and Previous Demand Forecast
Median (50th Percentile) Forecast



II. OVERALL METHODOLOGICAL FRAMEWORK

In this Section, we outline the technical details regarding our forecast, consistent with the requirements of Minn. R. 7610.0320.

Xcel Energy prepares its forecast by major customer class and jurisdiction, using a variety of statistical and econometric techniques. The NSP System serves five jurisdictions: Minnesota, North Dakota and South Dakota are served by Northern States Power Company, a Minnesota corporation (NSPM); Wisconsin and Michigan are served by Northern States Power Company, a Wisconsin corporation (NSPW). The overall methodological framework is "model oriented." The NSPM and NSPW Systems operate as an integrated NSP System. The forecast is referred to as the 2018v2.1 Forecast (August 2018).

A. Specific Analytical Techniques

1. *Econometric Analysis*

Xcel Energy uses econometric analysis to develop jurisdictional MWh sales forecasts at the customer meter for the following sectors:

a) Residential without Space Heating;
b) Residential with Space Heating;

c) Small Commercial and Industrial;
d) Large Commercial and Industrial (Minnesota);
e) Public Street and Highway Lighting (Minnesota);
f) Other Sales to Public Authorities (Minnesota).

Xcel Energy also uses econometric analysis to develop the total system MW peak demand forecast.

2. *Trend Analysis*

Trend analysis is used for the "Other" sectors, which include Public Street and Highway Lighting (all states except Minnesota), Other Sales to Public Authorities (Michigan, North Dakota and Wisconsin), Interdepartmental sales (Michigan, Minnesota and Wisconsin), and Large Commercial and Industrial (Michigan, North Dakota, South Dakota, and Wisconsin).

3. *Loss Factor Methodology*

Loss factors by jurisdiction are used to convert the sales forecasts into system energy requirements (at the generator).

4. *Judgment*

Whenever possible, Xcel Energy uses quantitative models to structure its judgment in the forecasting process. However, judgment is inherent to the development of any forecast. The sales forecasts are estimates of MWh levels measured at the customer meter. They do not include line or other losses. The various jurisdictional class forecasts are summed to yield the total system sales forecast. Native energy requirements are measured at the generator and include line and other losses. Xcel Energy creates native energy requirements based on the sales forecasts.

A system loss factor for each jurisdiction, developed based on average historical losses, is applied to the jurisdictional sales forecast to calculate total losses. The sum of the jurisdictional MWh sales and losses equals native energy requirements. The native energy requirements, along with peak producing weather and binary variables, are then used as independent variables within an econometric model to forecast MW peak demand for the NSP System.

B. Models Used

1. Residential Econometric Models

Sales to the residential sectors represent 29.7 percent of total NSP System electric retail sales in 2018. Residential sales are divided into with space heating and without space heating customer classes for each jurisdiction. Regression models using historical data are developed for each residential sector. A variety of independent variables is used in the models, including:

- Number of customers;
- Real Personal Income for respective jurisdiction;
- Employment for the respective jurisdiction;
- Gross State Product for respective jurisdiction;
- Actual heating and temperature humidity index (THI) degree days;
- Number of monthly billing days.

2. Small Commercial and Industrial Econometric Models

The small commercial and industrial sector represents 43.7 percent of NSP System electric retail sales in 2018. The models are regressions using historical data. The models include a combination of variables, including the following:

- Number of small commercial and industrial customers;
- Gross State or Metro Product for respective jurisdiction;
- Employment for respective jurisdiction;
- Real Personal Income for respective jurisdiction;
- Actual heating and temperature humidity index (THI) degree days;

3. Large Commercial and Industrial Econometric Models

Sales to the large commercial and industrial sector represent 26.0 percent of NSP System electric retail sales in 2018. The models are regressions using historical data and a combination of variables, including the following:

- Industrial Production for respective jurisdiction;
- Number of monthly billing days;
- Indicator variables such as CI reclassification.

4. Others

Sales to the "Others" sector represent 0.6 percent of NSP System electric retail sales in 2018. This sector includes Public Street and Highway Lighting (PSHL), Sales to Public Authorities (OSPA) and Interdepartmental (IDS) sales. Because this class represents a very small portion of the total sales, trend analysis is used and very little growth is forecast. Exceptions to this are the Minnesota Street Lighting and Other Public Authority classes. Minnesota Street Lighting sales are based on population in the Minneapolis-St. Paul MSA. Minnesota Other Public Authority sales are based on the Minnesota Other Public Authority customer forecast.

5. *Peak Demand Model*

An econometric model is developed to forecast base peak demand for the entire planning period. The model includes a combination of variables, including the following:

- Weather normalized native energy requirements
- Peak producing weather by month
- Binary variables

C. Methodology Strengths and Weaknesses

The strength of the process Xcel Energy uses for this forecast is the richness of the information obtained during the analysis. Xcel Energy's econometric forecasting models are based on sound economic and statistical theory. Historical modeling and forecast drivers are based on economic and demographic variables that are easily measured and analyzed. The use of models by class and jurisdiction gives greater insight into how the NSP System is growing, thereby providing better information for decisions to be made in the areas of generation, transmission, marketing, conservation, and load management.

With respect to accuracy, forecasts of this duration are inherently uncertain. Planners and decision makers must be keenly aware of the inherent risk that accompanies long-term forecasts. They must also develop plans that are robust over a wide range of future outcomes.

D. Data Definitions

The following is a list of definitions of the variables considered in Xcel Energy's econometric models.

Table 4: Jurisdiction Abbreviations

Mi or MI	State of Michigan
M or MN	State of Minnesota
N or ND	State of North Dakota
S or SD	State of South Dakota
W or WI	State of Wisconsin

Table 5: Monthly MWh Sales Series

SLSReswo(Juris)	Residential without space heating for given jurisdiction
SLSResSH(Juris)	Residential with space heating for given jurisdiction
SLSSmCI(Juris)	Small commercial and industrial for given jurisdiction
SLSLgCI(Juris)	Large commercial and industrial for given jurisdiction

Table 6: Monthly Customer Series

CustReswo(Juris)	Residential without space heating for given jurisdiction
CustResSH(Juris)	Residential with space heating for given jurisdiction
CustSmCI(Juris)	Small commercial and industrial for given jurisdiction
CustLgCI(Juris)	Large commercial and industrial for given jurisdiction

Table 7: Monthly Economic and Demographic Series

HH_(Juris)	Number of Households in given jurisdiction
NR_(Juris)	Total Population in given jurisdiction
GMP_(MSA)	Gross Metro Product for given metropolitan statistical area
GSP_(State)	Gross State Product for given state
EE_(Juris)	Total Employment in given jurisdiction
IPMFG_(Juris)	Industrial Production Index - manufacturing in given jurisdiction
CYP_(Juris)	Real Personal Income in given jurisdiction
(Juris)TotRes_RAP	Real Average Price for electric sales to residential customers

Table 8: Monthly Data Variables used in Demand Model

THI12(Month)Cust	Temperature Humidity Index @12:00 noon on the peak day multiplied by total retail customers
THI15(Month)Cust	Temperature Humidity Index @3:00 PM on the peak day multiplied by total retail customers.
HDD(Season)	Normal Heating Degree Days on the day of the Peak multiplied by a binary variable for the season (winter - Wtr, shoulder month - sh)
WNActEnergy_LpYrAdj_12MoSum	12 month rolling sum of the weather normalized net energy requirements adjusted to remove the effect of leap years

Table 9: Monthly Weather Variables used in Sales Models

H65_bill (Juris)(Month)	HDD base 65 for given jurisdiction and month
T65_bill(Juris)(Month)	THI DD base 65 for given jurisdiction and month

Table 10: Other Monthly Variables

BillDaysCellnet21	Billing Month Days

Table 11: Monthly Binary Variables

Jan	Binary variable for the month of January
Feb	Binary variable for the month of February
Mar	Binary variable for the month of March
Apr	Binary variable for the month of April
May	Binary variable for the month of May
Jun	Binary variable for the month of June
Jul	Binary variable for the month of July
Aug	Binary variable for the month of August
Sep	Binary variable for the month of September
Oct	Binary variable for the month of October
Nov	Binary variable for the month of November
Dec	Binary variable for the month of December

E. Data Sources

MWh sales and MW peak demand. Xcel Energy uses internal and external data to create its MWh sales and MW peak demand forecast.

Historical MWh sales. Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. Historical coincident net peak demand data is obtained through company records. The load management estimate is added to the net peak demand to derive the base peak demand.

Weather data. Weather data (dry bulb temperature and dew points) were collected from www.weatherunderground.com and the National Oceanic and Atmospheric Administration for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. The heating degree-days and THI degree-days are calculated internally based on this weather data.

Economic and demographic data. Economic and demographic data is obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically they are accessed from IHS Global Insight, Inc. data banks, and reflect the most recent values of those series at the time of modeling.

F. Energy Efficiency Programs

The regression model results for the residential classes and commercial and industrial classes are reduced to account for the expected impacts of energy efficiency programs.

The EE methodology implemented for the State of Minnesota utilizes a transparent method to project the impacts of energy efficiency (including the energy savings impacts from our current demand response programs) in sales forecasts. There are three distinct steps to this process:

- Collect and calculate historical and current effects of EE on observed sales
- Project the forecast using observed data with the impact of EE removed (i.e. increase historical sales to show hypothetical case without EE)
- Adjust the forecast to show the impact of all planned EE in future years.

The first step involves collecting data involving any measure that would cause an impact on the time period utilized in the sales forecast. In this model, we use the time period from 2003 to 2017, and therefore the historical EE would include any measure that results in decreased sales in any (or all) years from 2003 through 2017.

Since the vast majority of EE measures have a lifetime greater than one year (exceptions include but are not limited to behavioral energy savings programs), the impact on sales will include the year that a measure is installed as well as any years that follow until the measure has reached the end of its useful life. For example, a residential lighting measure that was installed in 2008 and has a life of six years will result in a sales reduction from 2008 to 2013 (six full calendar years). Though a measure may be installed in June of 2008 and, thus, would persist until May of 2013, the Company believes that the simplifying case in which all measures are installed for the entire calendar year is sufficient.

Due to the wide variation of measures available to customers, the Company sums the savings for each year by EE program to optimize the level of detail and depth of history included in the model. As a result of limitations in the quality of data prior to 1996, the Company has taken the conservative approach and omitted the impacts of achievements before 1996. While this may seem inconsequential, some programs have a 20-year lifetime, and EE from 1998 could therefore affect the 2017 usage. Achievement data are from the approved Conservation Improvement Program (CIP) Status Reports filed annually for each year since 1996.

Once the total impact of EE in effect is calculated for each year, a hypothetical sales data set is created. This series consists of the observed sales from 2003 through May 2017 plus the effective EE calculated for all EE measures installed in that year as well is achieved savings from programs in prior years that are still within the useful measure life.

The hypothetical sales data is used to generate a sales forecast that has entirely excluded the impacts of company-sponsored EE. It is important to note that customer-initiated EE or EE due to codes and standards (naturally-occurring EE) is not calculated as part of the CIP.

Once the sales forecast based on hypothetical sales has been generated, the Company subtracts the projected future EE from the total to determine the EE-adjusted sales. In addition, codes and standards changes resulting in decreased sales not documented within CIP may have separate adjustment factors applied in addition to the company-sponsored EE. The source for company-sponsored EE adjustments will be based on the CIP Plan in effect at the time of the forecast.

Exogenous adjustments were made to the Minnesota sales model output for future years to account for codes and standards changes for lighting in the Residential and Business segments. These adjustments are in addition to the adjustments made for future EE program achievement. The sales model implicitly accounts for some portion of changes in customer use, due to conservation and other influences, by basing projections of future consumption on past customer class energy consumption patterns. However, when technologies driving code and standard changes are adopted at an accelerated pace but can no longer be incentivized through EE programs, the sales forecast is not able to adequately adapt to future changes due to the difference between past and projected customer use, and the future changes are not accounted for in the exogenous adjustments made for EE program achievement.

As a result of recent changes in business and residential lighting practices, two new additional adjustments have been added to the sales forecast. The first is for residential customers only, and takes into account the new standard efficiency for general service lamps (also known as EISA standards). For the adjustment to the sales forecast, this only calculates the difference between a standard incandescent and an EISA-compliant halogen bulb, since additional efficiency will still be captured through EE programs. The second adjustment projects business class sales reductions resulting from accelerated technological improvements in the business lighting sector due to improvements in solid state lighting (LED).

A monthly forecast of the impact of new EE programs is developed by Xcel Energy's DSM Regulatory Strategy and Planning Department, and is used to reduce the class level sales forecasts that result from the regression modeling process. Impacts from all program installations through 2017 are assumed to be imbedded in the historical data, so only new program installations are included in the EE adjustment.

The Company's demand response programs result in short-term interruptions of service designed to reduce system capacity requirements rather than permanent reductions in energy use, so it is not considered here.

G. Behind-the-Meter Distributed Solar Generation

In response to the establishment of a Solar Energy Standard (SES) by the Minnesota Legislature an increased emphasis has been placed on distributed solar generation. A forecast of the expected impact on demand and energy has been developed based on new programs designed to meet goals established for the SES. The process of incorporating behind-the-meter distributed solar generation into the forecast process is similar to how EE program savings are incorporated in the sales and peak demand forecasts. Historical behind-the-meter distributed solar generation is added-back to the historical sales and peak demand modeling data, similar to how historical company-sponsored EE programs savings are added back to the historical sale and peak demand modeling data. The forecast output, based on the hypothetical sales and peak demand data with behind-the-meter solar generation added back to the historical sales and peak demand data, is then reduced for the future impacts of behind-the-meter installations on the class level sales in Minnesota and South Dakota and the NSP System peak demand.

H. Forecast Adjustments

Adjustments have been made to the forecast to account for planned changes in production levels for several large customers in Minnesota and Wisconsin. The most significant of these changes is the reduction of sales and demand related to the scheduled installation of customer-owned Combined Heat and Power generating facilities in 2017 and 2018.

I. Overview of Probability Distributions

Xcel Energy uses a straightforward extension of the peak demand econometric model to assess risk around the expected value of the peak demand by conducting a Monte Carlo simulation on the main drivers of the peak model (weather and native energy requirements). For the Monte Carlo energy probability distribution model, the main drivers are weather, Minnesota Households (HH_MN), and Minnesota Real Gross State Product (CGSP_MN).

The Monte Carlo stochastic simulation of peak demand (MW) or energy (MWh) involves taking 10,000 random draws from the weather probability distributions as well as 10,000 draws from the 12-month sum of energy probability distribution (or HH_MN and CGSP_MN probability distributions), which, in turn, produces 10,000 forecasts of peak demand (or energy), and thus generates a probability distribution around the mean peak demand (or mean energy).

For example, if the econometric model forecasts that the mean peak demand for 2025 is 9,309 MW, then using the same econometric model, the Monte Carlo simulation method forecasts that there is a 90 percent probability that the 2025 peak demand will be less than 10,317 MW, or alternatively, a 10 percent chance that the peak will be less than 8,288 MW.

In summary, the Monte Carlo stochastic simulation method adequately captures the effect of extreme weather on monthly peak demand and monthly energy usage, while preserving the expected value or mean forecast of peak demand and energy.

J. Data Adjustments and Assumptions

Weather Adjustments. Xcel Energy adjusts the monthly weather data to reflect billing schedules. Therefore, the monthly weather data corresponds exactly with the billing month schedule.

Economic Adjustments. All Consumer Price Index data is deflated to 1982=1 and related economic series are deflated to 2009 constant dollars.

K. Assumptions and Special Information

The data used in Xcel Energy's forecasting process has already been discussed in a general way. Descriptions and citations of sources for the data sets have been mentioned within this documentation under different sections.

Xcel Energy believes that its process is a reasonable and workable one to use as a guide for its future energy and load requirements. The underlying assumptions used to prepare Xcel Energy's median forecast are as follows:

- *Demographic Assumption.* Population or household projections are essential in the development of the long-range forecast. The forecasts of customers are derived from population and household projections provided by IHS Global Insight, Inc., and reviewed by Xcel Energy staff. Xcel Energy customer growth mirrors demographic growth over the forecast period.
- *Weather Assumption.* Xcel Energy assumes "normal" weather in the forecast horizon. Normal weather is defined as the average weather pattern over the 20-year period from 1998-2017. The variability of weather is an important source of uncertainty. Xcel Energy's energy and peak demand forecasts are based on the assumption that the normal weather conditions will prevail in the forecast horizon. Weather-related demand uncertainties are not treated explicitly in this forecast.
- *Loss Factor Assumptions.* The loss factors are important to convert the sales forecast to energy requirements. Xcel Energy uses a historical average loss factor for each jurisdiction, and assumes it will not change in the future.

L. MISO Coincident Peak Demand Forecast

Once we complete the NSP System Peak Demand Forecast, we develop a forecast for the NSP System Peak Demand coincident with the MISO system peak. MISO has published the date and time of the MISO system peak for each of the four summer months (June – September) of 2005 – 2017. Company records were queried to determine the NSP System uninterrupted peak at the time of each of the MISO monthly peak days.

We then develop a forecast of the NSP System peak demand coincident with the MISO peak using a regression model based on the NSP System peaks coincident with

MISO, the NSP System peaks not coincident with MISO, and the weather variable representing the temperature-humidity index at 3:00 PM on the MISO coincident peak day for each summer month. MISO only requires an annual coincident peak forecast for the next planning year. The current forecast is for the NSP System peak coincident to the MISO annual peak during the 2019-20 planning year (June 2019 – May 2020).

M. Forecast Coordination

Xcel Energy reports its energy and peak demand forecasts to MISO, who then combines the forecasts of all its member utilities. Xcel Energy also reports its forecast to the Public Service Commission of Wisconsin as part of its Strategic Energy Assessment (SEA) process. In this process, the Wisconsin portion of the total Xcel Energy system load is combined with other Wisconsin electric utilities to form a statewide Wisconsin forecast.

III. DISTRIBUTED ENERGY RESOURCES FORECAST

A. Distributed Solar

We offer several programs to customers interested in solar as a renewable opportunity. Specifically we provide incentives under our Solar*Rewards program, and the opportunity to earn bill credits for community solar gardens in our Solar*Rewards Community program. In addition, we offer a net-metering option for customers installing incentivized small scale solar. We have factored all of these distributed solar PV options into our Reference Case, Medium, and High distributed solar forecast.[3] We note that the methodology used to forecast distributed solar for this Resource Plan is consistent with what we used in our November 2018 Integrated Distribution Plan, filed in Docket No. E999/CI-18-251.

1. Reference Case Assumptions

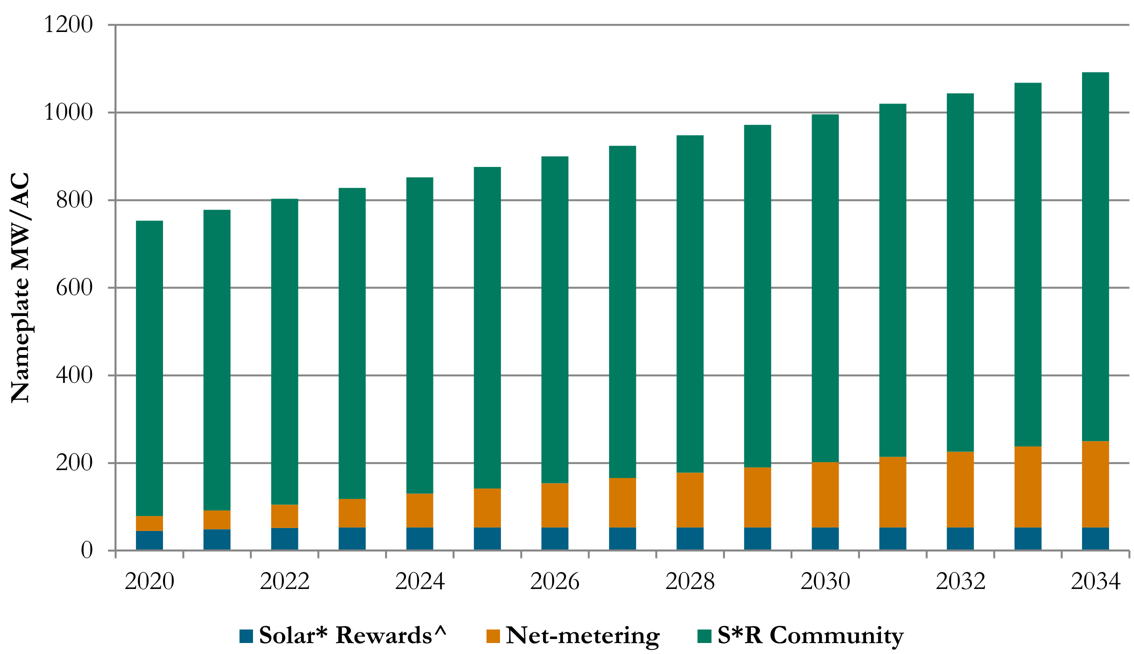
In determining our Reference Case, we updated our goals to be consistent with 2017 legislative outcomes that: (1) increased 2018-2020 Solar*Rewards incentive funding, (2) eliminated new Made in Minnesota awards after 2017, with final installations completed by October 2018, and 3) eliminated new Solar*Rewards systems after 2021, with final installations completed by 2023. We assumed net-metering only system additions would continue at current annual levels through 2021 and increase in 2022 to accommodate for demand from the elimination of the Solar*Rewards program in

[3] We note that we provide information specific to just Solar*Rewards Community as Appendix N8.

this scenario. We based attrition and completion lag rates on historical analysis of cancelled and completed projects, and applied these to program application forecasts to derive final installation estimates.

Due to the large response to our Solar*Rewards Community program, which has no statutory budget or capacity limit, we are forecasting additions of 673 MW through 2019 in this filing. For our Reference Case assumptions through the Resource Plan planning period, we assume Solar*Rewards Community adjusts to approximately 12 MW per year after 2021 to account for significant early adoption of CSGs and reduction in tax benefits. The graph below reflects the Reference Case forecast of distributed solar PV forecast.

Figure 11: Reference Case – NSP System Distributed Solar PV Forecast (Nameplate MW/AC)



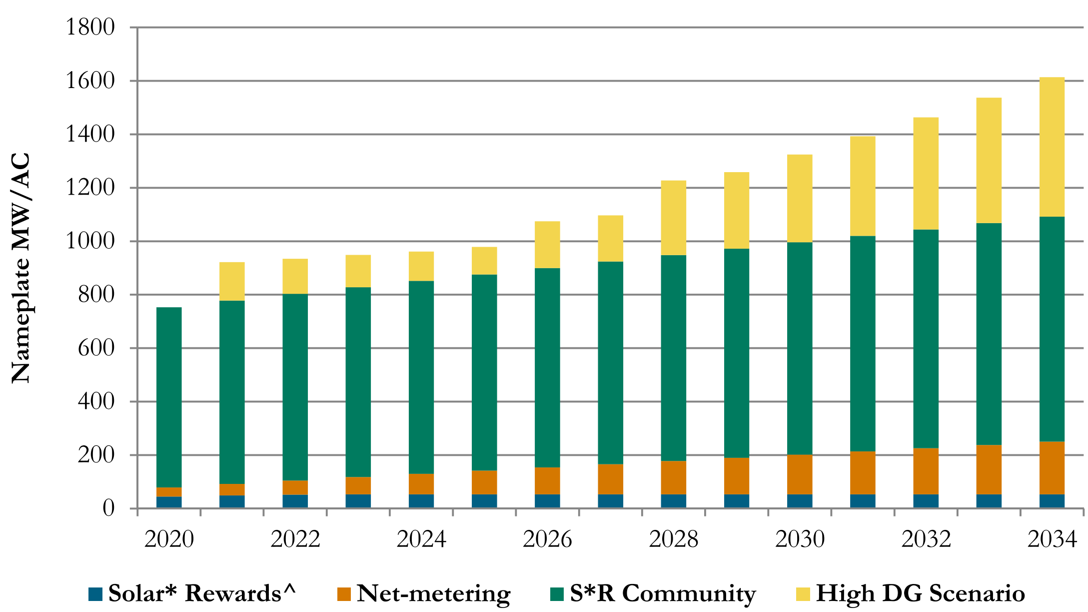
^Includes Made in Minnesota

2. *Reference vs High Forecasts*

The Reference and High scenarios hold the levels of Solar*Rewards and Made in Minnesota constant for the reasons discussed above. For net metering and CSG, we assume that customers that participate in solar programs would consider, in the majority of cases, that these programs are substitutes for each. Therefore the incremental growth in one category is interchangeable with another category. For example, we are estimating that total solar PV in 2034 is approximately 1,100 MW – of which, approximately 850 MW is net metering and CSG.

For the High scenario, we used a Payback adoption model with lower installation costs. We also applied a 10 percent reduction to the solar installation cost curve starting in 2020. Solar installation costs in the High scenario are set to be higher for the first year due to new import tariffs and contracts already in place. Hence, there is a low probability that the solar installation prices will drop significantly below the Reference scenario for 2019. The adoption of solar is flat in the early 2020s, because the decline in solar installation cost is offset by the decline in Investment Tax Credit (ITC). The Payback model results indicate around 1,600 MW for total installed distributed solar by 2034. The graph below reflects the high forecast of distributed solar PV forecast.

Figure 12: High Forecast Case – NSP System Distributed Solar PV Forecast (Nameplate MW/AC)



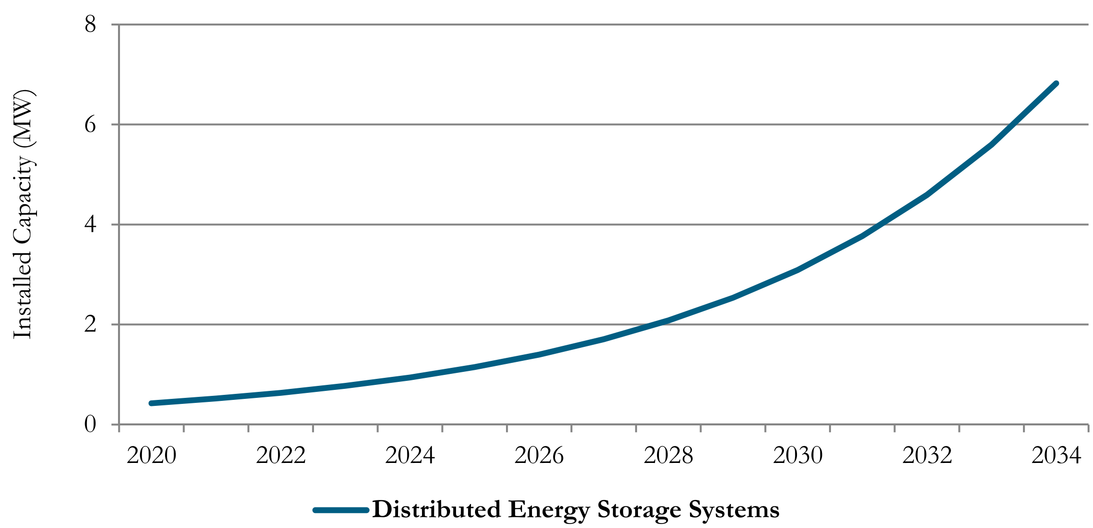
B. Distributed Wind

We presently have a small number of distributed wind projects on our system, with a total of 59 projects that comprise 14 MW. We believe distributed wind will continue to be a very small proportion of DER on our distribution system, largely due to the rapid development of solar and storage markets – and their relative ease of adoption, compared to wind. Additionally, there is little information available in the industry regarding the adoption of distributed wind. For these reasons, we are not providing a forecast in conjunction with this Resource Plan.

C. Distributed Storage

Navigant Research's Global DER Overview, 2Q 2019, projects a growth rate of 21.9 percent for Distributed Energy Storage Systems (DESS). From 2017 through April 2019, we received approximately 50 interconnection applications for energy storage on our distribution system. Of these 50 applications, 32 are complete and in operation, comprising approximately 350 kW. Figure 13 below extrapolates the current installations at the Navigant projected rate of growth.

Figure 13: NSP System Distributed Energy Storage Systems Forecast



The impact of DESS is, currently, not incorporated into demand forecasting or as a specific supply side resource. We discuss the utility-scale storage as it applies to the modeling underlying this Resource Plan in Appendix F6: Resource Options.

D. Electric Vehicles

Our customers are procuring EVs in greater numbers than ever before. In our Upper Midwest service area, the total number of EVs is currently approximately 9,500.[4] Nationally, annual sales of EVs increased by 81 percent from 2017 to

[4] IHS Markit, 2019. The IHS Markit data is provided at the zip code level for zip codes within the Company's service territory. Utility jurisdictions do not exactly follow zip code boundaries, so there may be some margin

2018.[5] Forecasts suggest that we may see increased adoption as EVs are poised to grow into a more mainstream new vehicle option, with over 40 models of EVs available in the United States today. The nascent nature of this market however, makes the possibility of significantly more or less adoption a large variable, and thus difficult to forecast.

The approach we took in this Resource Plan to forecast EVs allows for consideration of a wide range of potential futures, and represents an advancement and change from our approach in our November 1, 2018 Integrated Distribution Plan (IDP). The IDP used a forecast based on national level adoption that had informed early- to mid-2018 filings in other dockets.[6] At that time we noted our intent to improve, benchmark, and validate our forecasting models and assumptions, which is underway. We also noted that we were doing work around electrification to support our upcoming Resource Plan.

That said, for the purposes of this Resource Plan, we made an exogenous adjustment for a base level of light duty electric vehicle adoption in both our energy and demand forecasts. We then worked with E3 to develop a high "electrification" load forecast sensitivity, which includes a broader range of EV adoption – as well as other electrification impacts.[7] This creates a wide band of possible outcomes to inform our modeling. We believe that by limiting the modeling of a highly dynamic external factor to a Base and High view, we are better able to examine the base needs of the system, while also considering the long-term impacts of potential high electrification across Minnesota's economy.

We illustrate the Base and High Electrification forecasts that informed this Resource Plan in Figure 14 below. We additionally show the Base EV forecast for this Resource Plan to give perspective on the magnitude of electrification the High Electrification sensitivity affords the modeling in this Plan.

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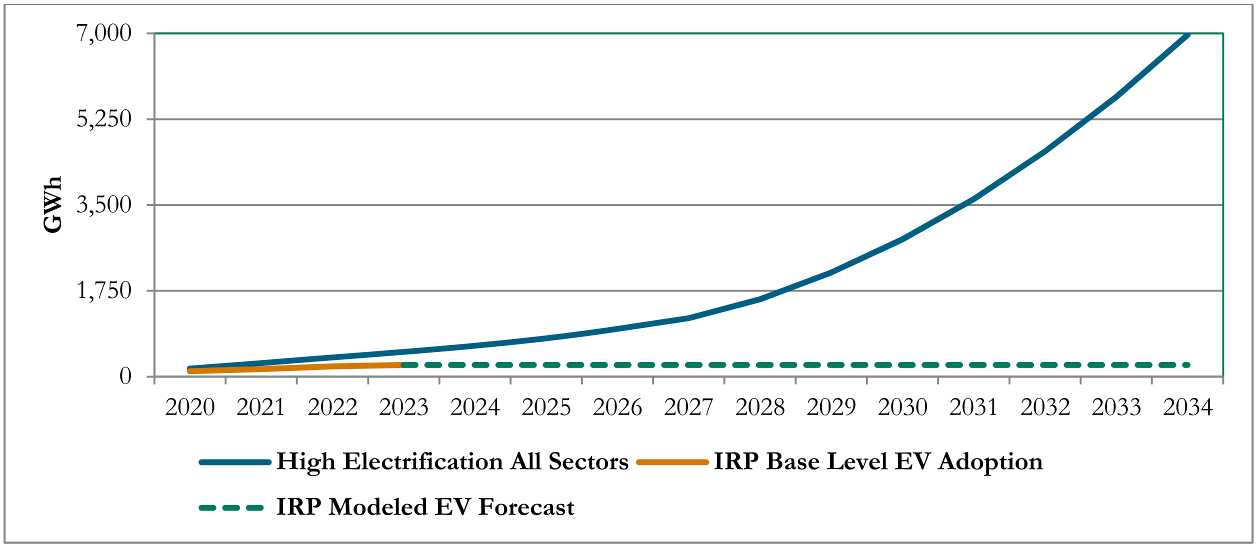
of error in this value.

[5] InsideEVs PEV Scorecard, https://insideevs.com/monthly-plug-in-sales-scorecard/.

[6] June 1, 2018 filing in Docket No. E002/M-15-111 and a January 11, 2018 response to Minnesota Commission Staff Information Request No. 8 in our hosting capacity proceeding in Docket No. E002/M-17-777.

[7] We provide a full discussion of the E3 high electrification sensitivity as Appendix F4.

Figure 14: NSP System Base Level Compared to High Electrification Sensitivity – 2020-2034



We discuss our development of the Base Forecast below. We discuss the details of the High Electrification Sensitivity in Appendix F4: High Electrification Sensitivity and note that it was developed as part of E3's PATHWAYS study, provided as Appendix P3: Minnesota PATHWAYS Report June 2019 (E3).

1. Base EV Adoption

The Base EV forecast projects adoption of light duty vehicles in the first five-years of the planning period and then holds constant from year six through the remainder of the planning period. This Base level of light duty EV adoption is used in all modeling scenarios, and is consistent with the likely forecast from the IDP. The rate and level of EV adoption impacts the energy forecast, and customer charging behavior assumptions impact the demand forecast, which we discuss in turn below.

a. EV Adoption Levels

Our Base EV forecast is based on an internally-developed methodology that incorporates both economic payback and Bass diffusion (technology adoption) model.[8] Key variables informing our adoption estimates for the base energy forecast

[8] The Bass Model or Bass Diffusion Model was developed by Frank Bass. It consists of a simple differential equation that describes the process of how new products get adopted in a population. The model presents a rationale of how current adopters and potential adopters of a new product interact. The basic premise of the model is that adopters can be classified as innovators or as imitators and the speed and timing of adoption

include:

- Electricity Prices
- Vehicle Battery Prices
- Gasoline Prices
- Car ownership
- Car usage
- Efficiency

In addition to EV adoption, customer charging behavior is an important consideration to factor into our load forecasts. Because we are reflecting adoption of only light duty EVs in our base forecast, our primary considerations are the share of charging done at homes, and penetration of managed charging stations. Our source for this was the DOE EV Project Data Set.

Forecasting is very sensitive to various assumptions, especially for new technologies like EVs that are in early stages of adoption. Forecasts are also sensitive to several externalities like policy changes (such as incentives), technology changes (such as battery improvements and autonomous vehicles), geopolitical issues (such as trade and tariff issues), availability of raw materials (such as shortages of lithium or cobalt), etc. Additionally, many of the inputs change frequently and could produce significant swings in the model outputs.

2. *High Electrification Sensitivity*

We worked with E3 to develop a High Electrification load forecast sensitivity, derived from the E3 statewide decarbonization analysis using PATHWAYS,[9] which we ran for each Resource Plan modeling scenario. The objective of this sensitivity was to create a "bookend," examining the possible impacts on load growth and peak demand growth on our Upper Midwest NSP System service area, under a scenario with electrification sufficiently aggressive to achieve Minnesota's economy-wide goal of an 80 percent reduction in greenhouse gas (GHG) emissions below 2005 levels by 2050.[10]

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depends on their degree of innovativeness and the degree of imitation among adopters. The Bass model has been widely used in forecasting, especially new products' sales forecasting and technology forecasting.

[9] In summary, for the PATHWAYS study, E3 developed a set of long-term economy-wide, deep decarbonization scenarios for the state of Minnesota. These scenarios provide an exploration of the cross-sectoral implications of meeting economy-wide carbon reduction goals, and highlight the role of Xcel Energy, and the electric sector as a whole, in meeting the state's economy-wide carbon goal. For details, see the E3 Minnesota PATHWAYS Report as Appendix P3.

[10] Minn. Stat. 216H.02, Subd. 1. *See* https://www.pca.state.mn.us/air/state-and-regional-initiatives.

Without suggesting this much electrification will or should occur, this sensitivity asks: If there were very aggressive electrification of transportation, buildings, and other end uses, what are the potential impacts on energy consumption and peak demand during the planning period?

We summarize the E3 High Electrification sensitivity in Appendix F4, and provide as Attachment A to that Appendix, E3's detailed discussion of their methodology.

3. Summary

We believe planning for electrification must contemplate a variety of future state scenarios, but also that EVs and electrification broadly are not a primary driver that will influence resource decisions in this Resource Plan. We are continuing to refine our EV forecasting methods as we learn more about the EV industry and adoption trends nationally. We expect to provide updated EV-specific forecast scenarios in our November 2019 IDP.