
Minnesota Energy Efficiency Potential Study: 2020–2029

Appendix A: Methodology and Data Sources

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Prepared for: Minnesota Department of Commerce, Division of Energy Resources
Prepared by: Center for Energy and Environment, Optimal Energy and Seventhwave



Prepared by:

Center for Energy and Environment

Carl Nelson
Jon Blaufuss
Christopher Plum
Josh Quinnell
Nick Brambilla
Elena Foshay

Jennifer Edwards
Rabi Vandergon
Audrey Partridge
Maureen Quaid
Mike Bull
Brady Steigauf

Optimal Energy

Phil Mosenthal
Matthew Socks

Seventhwave

Scott Pigg
Jeannette LeZaks
Doug Ahl

With input and assistance from ACEEE:

Marty Kushler, Maggie Molina, and Neal Elliott

Center for Energy and Environment
212 3rd Ave N, Suite 560
Minneapolis, MN, 55401
www.mncee.org

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Prepared for Minnesota Department of Commerce, Division of Energy Resources:

Jessica Looman, Commissioner, Department of Commerce
Bill Grant, Deputy Commissioner, Department of Commerce, Division of Energy Resources

Adam Zoet, Project Manager
Phone: 651-539-1798
Email: adam.zoet@state.mn.us

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Appendix A: Methodology and Data Sources

Minnesota has a thirty-plus year history of leadership in energy efficiency policy and achievements. In order to continue to maximize the benefits of cost-effective energy efficiency resource acquisition by utilities, the project team, consisting of Center for Energy and Environment (CEE), Optimal Energy (Optimal) and Seventhwave, was commissioned to:

- Estimate statewide electric and natural gas energy efficiency and carbon-saving potential for 2020-2029;
- Produce data-driven and stakeholder-informed resources defining market segments, end uses, measures, and programs that could be targeted in the decade ahead to realize the state's cost-effective energy efficiency potential; and
- Engage stakeholders in order to help advance robust energy policies and energy efficiency programs in the state, and to inform future efficiency portfolio goals.

The full report, supporting documentation, and associated presentations can be found at the following website: <https://www.mncee.org/mnpotentialstudy/final-report/>

This appendix provides a detailed description of the methodology and key data sources employed in the calculation of energy efficiency potential. The scope of the study includes the calculation of economic and achievable utility-driven energy efficiency for Minnesota. No calculation of fuel switching (e.g., from propane to electricity for space heating to increase overall fuel efficiency) was included in the analysis, although this issue is discussed further in Chapter 6.

The methodology the project team used is consistent with national best practices for conducting potential studies. By its nature, estimating the potential for energy efficiency for more than a decade into the future involves a large number of technology and market assumptions. An effort was made to ensure the maximum amount of transparency in documenting these assumptions.

Types of potential calculated

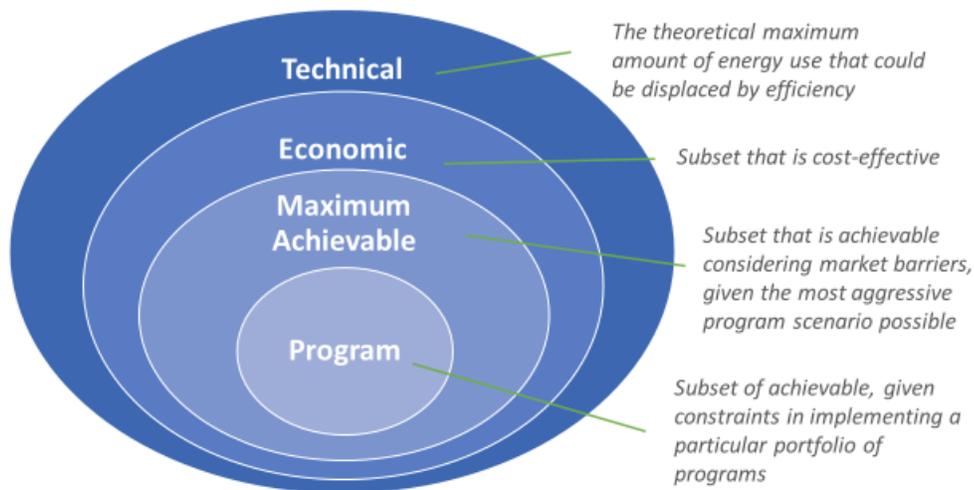
Four levels of potential were calculated for this study, as described below and summarized in Figure 1.

- **Technical potential:** Technical potential is a necessary step to assessing the full economic and achievable potential. It represents in theory the maximum amount of energy use that could be displaced by efficiency. However, as with virtually all studies, the modelling did not include many energy efficiency measures that are technically possible, but realistically are not practical or typically pursued because of cost or other reasons.¹ In this study, technical potential represents implementing all of the most aggressive energy efficiency measures that were identified for inclusion in the modeling (Step 2 in the following section).

¹ Since it is known technically how to build super insulated buildings that have no heating loads; for example, true technical potential approaches 100% for some end uses and is not particularly useful to report.

- **Economic potential:** This is the subset of the technical potential that is cost-effective, based on the societal cost test, as used in Minnesota. Most measures that did not pass the cost-effectiveness screen were removed from the analysis, but all cost-effective measures were assumed to be fully implemented regardless of market barriers.² This is described in Step 3 below.
- **Maximum achievable potential:** This is the subset of economic potential that is achievable considering market barriers, given the most aggressive program scenario possible. In this study, the project team assumed financial incentives would cover 100% of the incremental costs of each measure, along with very aggressive marketing and program designs to achieve maximum market penetration of the measures. The process for estimating measure penetrations and budgets is described in Step 4 below.
- **Program potential:** The program potential is a subset of the maximum achievable, given constraints in implementation. This study assumed that financial incentive levels are dropped to 50% of the incremental cost of the measure, which is a typical scenario used for planning purposes in Minnesota,³ and a good benchmark for aggressive programs nationally. The project team still assumed aggressive marketing and program designs for this scenario.

Figure 1. Types of potential calculated for this study.



² To avoid double counting, where there was more than one measure that could be used to address a specific efficiency opportunity, the project team assumed full penetration of the highest saving measure option.

³ Xcel Energy, for example, typically will use a 50% incentive scenario for planning purposes and for conducting their potential studies.

Primary data collection

This study used hundreds of data sources to develop inputs to the models, including past CARD studies, utility-provided data, residential audit data, secondary data from the northern Midwest region, U.S. Department of Energy studies, and others. Many of these sources are listed in the following section. In addition, the project team undertook additional data collection efforts to fill in some of the gaps of these other data sources. This included three components:

- Residential building phone and on-site surveys;
- Commercial large building phone and on-site surveys; and
- Energy efficiency contractor (trade ally) surveys.

In total, over 136 on-site surveys and 1,797 telephone surveys were completed (Table 1).

Table 1. Summary of primary data collection efforts.

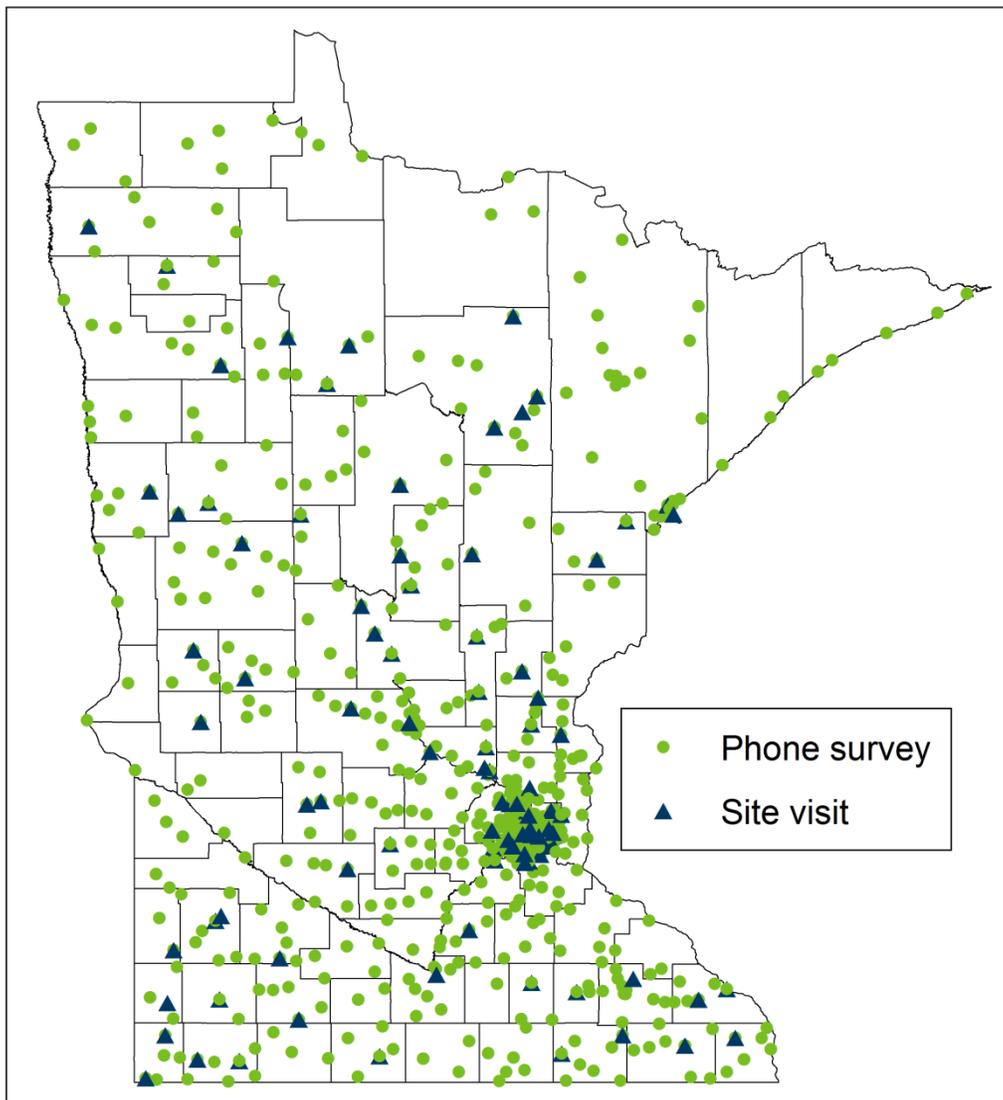
Sector	Phone surveys completed	On-site surveys completed
Residential building data collection	1,491	106
Large commercial building data collection	201	30
Total trade ally surveys (subtotals below)	105	-
<i>HVAC contractors</i>	29	-
<i>New construction design professionals</i>	20	-
<i>Insulation contractors</i>	20	-
<i>Electricians</i>	26	-
<i>Plumbers</i>	10	-
Total:	1,797	136

The data collection efforts were conducted throughout the state, with an emphasis on non-metro areas (Figure 2). While the project team did collect data in many different utility territories across the entire state, the sample sizes for different territories were not large enough to distinguish statistically significant differences among utility territories or the seven analysis regions in the state that were used for modeling.

In addition, the project team contracted with D+R International to purchase statewide data on HVAC sales.

In total, this primary data collection helped to inform key parameters of the study, such as the prevalence of measure opportunities and existing levels of measure saturation. The primary data collection effort is discussed more thoroughly in Appendices J, K, L, and M.

Figure 2. Map of statewide primary data collection sites.⁴



Analysis regions

To account for the diversity of utility types in Minnesota, as well as climate differences from the northern and southern parts of the state, the state was split into seven different analysis regions (Figure 3). A separate model was used for each region, and for the presentation of statewide potential, the results of these individual models were aggregated together. This gave the study team the ability to use separate assumptions and data for each of these analysis areas, rather than global assumptions for the state. For example, as discussed later in this appendix, different assumptions were used for the avoided

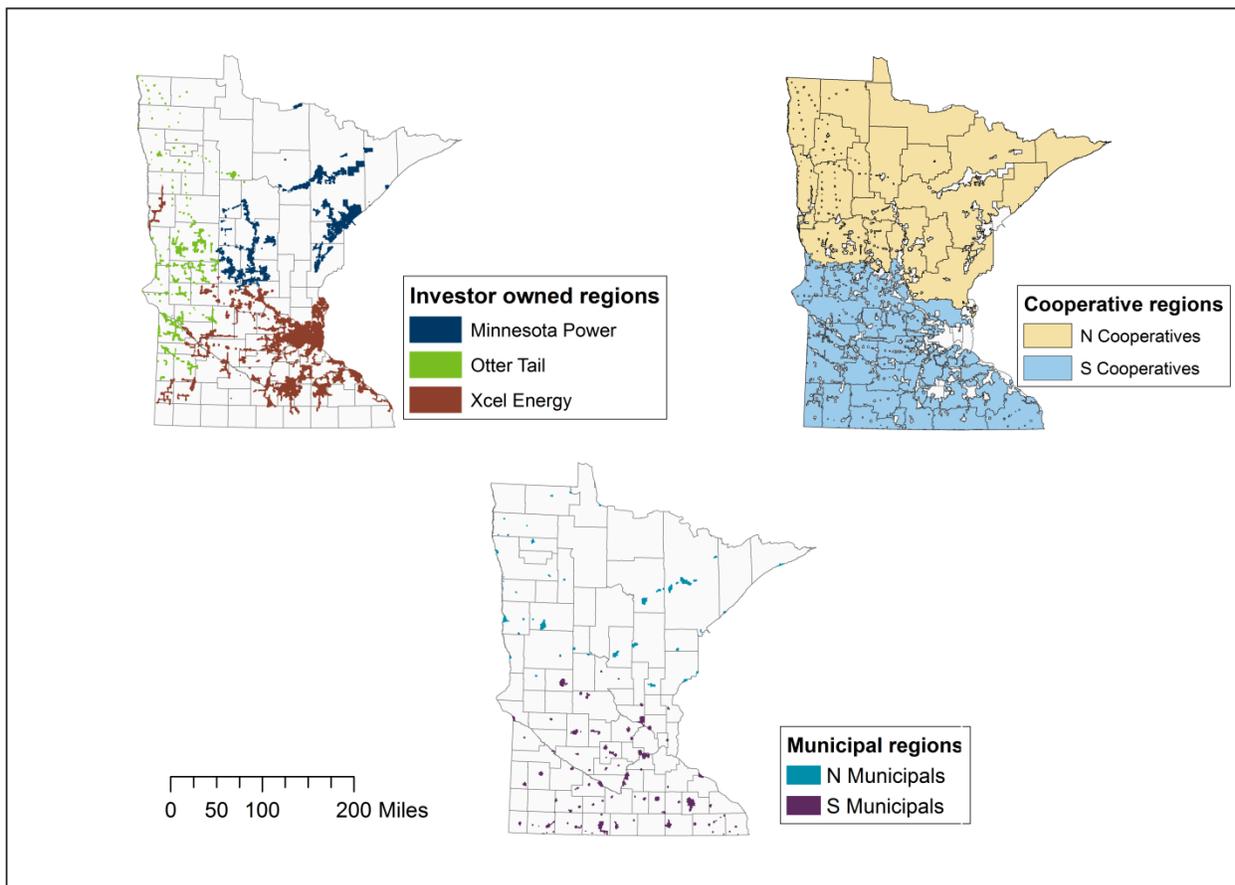
⁴ Due to data privacy considerations, the points on this map represent primary data collection sites by zip code. Many zip codes had more than one phone survey or site visit, but are still represented by a single point.

cost of energy for each of the seven regions, to reflect utility-specific differences among IOUs, cooperative utilities, and municipal utilities.

The seven regions are based on the territories of electric utilities in the state as follows:

- Separate regions for the territories of each of the three electric IOUs (Xcel Energy, Minnesota Power, Otter Tail Power).
- A northern and southern model for groupings of cooperative utilities and municipal utilities respectively (four models total: northern cooperatives, southern cooperatives, northern municipals, and southern municipals).

Figure 3. Map of seven regions used for the analysis.



The model conducted an integrated analysis of both electric and natural gas potential, so the natural gas potential was also calculated for these same regions. While this did not allow for setting utility-specific parameters for the natural gas utilities, it did allow for the consideration of climate and other differences across a given utility's territory. For example, the model is able to account for climatic differences across Minnesota Energy Resources' territory, which spans from Worthington in the southern end of the state to International Falls in the northern end of the state. While the initial groupings were related to electric utility territories, the project team also disaggregated the gas potential in each model to develop the natural gas potential separately for the five IOUs (CenterPoint Energy, Xcel Energy gas, Minnesota Energy Resources, Great Plains Natural Gas, and Greater Minnesota

Gas), as well as groupings of northern municipal and southern municipal gas utilities. This process included disaggregation of gas potential in each electric territory by sector, building type, and end use to develop customized gas utility results. These results are reported in Appendix B.

Although some of the major model inputs were varied by analysis region, data and study limitations limited how many of the inputs the project team could make region-specific. Some of these major inputs are shown in Table 2, which are discussed further later in this appendix, and in Appendix B. The major differences between electric and natural gas utility territories, in terms of using statewide analysis versus region-specific inputs, include, but are not limited to, the use of region-specific avoided cost inputs for electric utilities and customized disaggregation of customer loads by sector, building type and end use, load forecasts, and weather impacts.⁵

Table 2. List of select model inputs, and whether they varied by analysis region or were statewide.

Region-specific inputs
Demographic and energy usage data by sector and building type ⁶
Avoided electric energy and capacity costs (electric utilities only)
Impact of weather on gas and electric measure savings
Statewide inputs
Avoided natural gas energy and capacity costs (the same for all gas utilities)
Energy efficiency measures included in modeling
Existing measure saturation levels
Program budgets and incentive costs for modeled programs ⁷
Market penetrations for modeled energy efficiency programs
Societal discount rate ⁸

Steps in calculating potential

There are two general approaches commonly used to calculate energy efficiency potential: the “bottom-up” approach and the “top-down” approach. While both approaches use detailed measure level data inputs, a top-down approach applies those bottom-up measure data to actual applicable baseline loads, whereas a pure bottom-up approach assumes certain quantities of measures are adopted and does not link directly to actual baseline loads. The top-down approach was used for this study and involves five

⁵ Typically the Department defines statewide avoided commodity costs that all natural gas utilities use for CIP purposes, while electric utilities use utility-specific avoided energy costs.

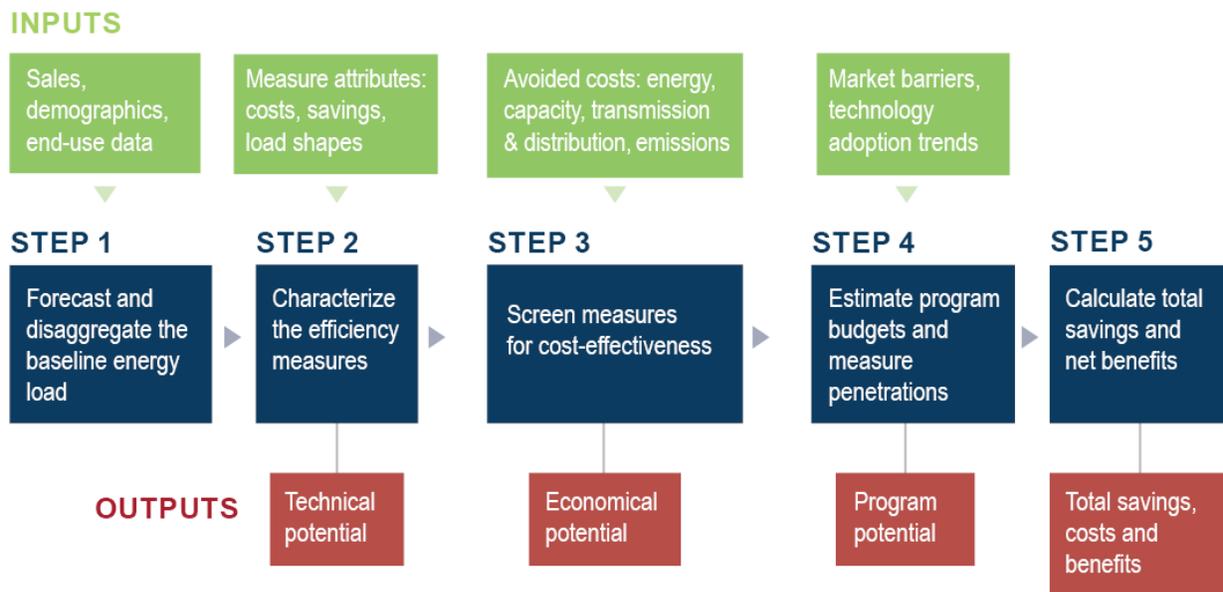
⁶ This includes the proportion of energy consumed by 16 different building types and 14 (electric) or 6 (gas) different energy end uses (refer to Figure 8 for electric & Figure 9 for gas for a list of the building types and sectors). Other demographic information was also region-specific, such as the proportion of low-income customers.

⁷ The budgets are modeled to scale with measure implementation, so costs vary based on the quantity of measures installed, but the program and incentive costs for a given measure do not vary by region.

⁸ As discussed further in the below “Step 3” section, a rate of 2.55% was used for the societal discount rate, consistent with Department guidance.

major steps. The approach is illustrated in Figure 4. Major data sources used for each of the steps are summarized at the end of this section in Table 7.

Figure 4. Modeling approach used for this study.



Step 1: Forecast and disaggregate the baseline energy load

Sales Forecast Development

Sales forecasts were obtained from publicly filed Integrated Resource Plans as well as directly from nine different utilities or utility associations. As an initial step, the potential study team collected available forecasts as published in the most recent integrated resource plans (IRPs) of all Minnesota investor-owned utilities (IOUs), municipal power agencies, and cooperatives. IRP forecasts were collected for Xcel Energy (Xcel), Otter Tail Power (Otter Tail), Minnesota Power (MN Power), Dairyland Power Cooperative (Dairyland), Minnkota Power Cooperative (Minnkota), Great River Energy (GRE), Minnesota Municipal Power Agency (MMPA), Missouri River Energy Services (MRES), and Southern Minnesota Municipal Power Agency (SMMPA).

Next, a data request was submitted to all utilities directly requesting the most recent forecasts available, if more recent than those published in the IRPs. Where available, the forecasts provided by the utilities directly were prioritized over the IRP data. Additional forecast data was provided directly by Xcel Energy, Otter Tail, Minnesota Energy Resources (MERC), CenterPoint Energy, Dairyland, Minnkota, Central Minnesota Power Agency and Services (CMPAS), and SMMPA.

The collected forecast data represents the vast majority of energy sales in the state. The following table presents, by utility type and climate zone, the percentage of total electric and natural gas sales for which utility forecasts were obtained:

Table 3. Collected forecast representation in terms of energy sales by utility type and CZ.

Utility Type	Climate Zone	Electric Energy (Represented % Electric Sales)	Electric Demand (Represented % Electric Sales)	Natural Gas (Represented % Natural Gas Sales)
Investor Owned	North	100%	100%	N/A
	South	100%	100%	97%
Cooperative	North	86%	86%	N/A
	South	69%	69%	N/A
Municipal	North	23%	23%	0%
	South	66%	60%	0%
Private	North	N/A	N/A	N/A
	South	N/A	N/A	0%
Grand Total		88%	87%	91%

For example, electric peak demand forecasts for cooperative utilities in the southern climate zone were obtained representing 69% of total electric sales for cooperative utilities in that zone. In total, electric energy and peak demand forecasts were obtained representing, respectively, 88% and 87% of total Minnesota electric energy sales. Obtained natural gas forecasts represent 91% of statewide natural gas sales. It is important to note that even for utility type/climate zone combinations where forecast data representation is relatively low (e.g., northern municipal utilities), we obtained historical sales data that was used in conjunction with representative growth rates derived from other, similar regional utilities to estimate sales forecasts.

The following steps were taken to modify the raw forecast data identified above to a useable form for the energy efficiency potential model. A similar approach was used for both electric energy and natural gas sales.

1. **Aggregate raw forecasts to the sector level.** Because the format of the raw forecast data varied significantly from utility to utility, the data for each utility is aggregated to the sector level (i.e., residential, commercial, industrial). In some cases, the appropriate aggregation is obvious. For example, “residential” and “residential seasonal” both clearly belong in the residential sector. However, in other cases, it is not possible to perfectly aggregate the raw forecast data to match the study’s analysis sectors. For example, some utilities provided forecasts for “small C&I” and “large C&I” as separate classes. Since it was unclear how to apportion these classes to the commercial and industrial sectors, in such cases, we aggregated the sales to a combined C&I category.
2. **Fill internal gaps and extrapolate through the end of the impacts period.** The longest measure life in the analysis is 20 years; therefore, the forecasts used in the potential model needed to extend through 2049 to accurately quantify the impacts of those measures relative to total sales. Where raw utility forecasts were available, these were used directly for all reported years. If the raw forecasts did not extend through 2049, we assumed linear extrapolation based on the final five years (or the maximum number of data years available, if less than five) in the raw forecasts. Any internal data gaps were filled assuming simple linear interpolation based on the nearest known data points (this was uncommon).
3. **Develop forecasts for utilities with no raw forecast data.** Using the utility-specific, sector level forecasts resulting from the steps above, we calculated, for each combination of utility type and

climate zone, an average sales-weighted forecast (expressed annually as a percentage of 2016 sales) by analysis sector.⁹ For utilities for which we have not obtained forecasts, we apply the appropriate average forecast, depending on utility type and climate zone, to the historical utility sales to estimate the unknown forecasts.

4. **Adjust for embedded future energy efficiency program impacts.** Since the forecasts were developed using econometric models, they implicitly include impacts of future efficiency programs, along with past and future codes and standards trends. Therefore, the forecasts were adjusted upward to remove the impacts of continued efficiency programs, based on historical levels of energy efficiency achievement. This helped ensure that the potential study reflects the full efficiency potential over and above a no-program scenario with only naturally-occurring and known codes and standards impacts. Based on historical efficiency achievement data, electric forecasts were adjusted upward by 1.5% annually, and gas forecasts were adjusted upward by 1.0% annually.¹⁰
5. **Aggregate individual utility forecasts to the seven model regions.** Finally, the appropriate individual utility forecasts were summed to develop forecasts that align with the seven individual potential models used in the analysis. In short, each northern cooperative, southern cooperative, northern municipal, and southern municipal utility is aggregated into its respective category. IOU-specific forecasts are used for their respective model regions.

The resulting electric and gas sales forecasts by sector are presented in Table A1 in the embedded Microsoft Excel workbook. 

Sales Disaggregation by Segment and End-Use

The study team then used a variety of data and methods to disaggregate total energy sales into 16 different building types (three residential, twelve commercial, and the industrial sector). For each of these building types, the energy load was further disaggregated into 19 separate end uses for electric utilities and seven end uses for gas utilities. These building types and end-uses were used to classify the measures according to their applicability to different building types and end-uses, as discussed in the next section. This ensures that the potential of any given set of measures is limited by the total energy used in each relevant building type and end use for those measures. The disaggregation approach is discussed in more detail by sector below.

Residential

To estimate disaggregated energy consumption in the residential sector, we first obtained Census estimates of housing units (by type of housing) for each of about 2,700 Minnesota cities and rural townships and intersected these with geographic information system (GIS) shapefiles of the Minnesota electric utility service areas. For cities and townships with more than one electric utility, we allocated

⁹ The forecast was expressed relative to 2016 as this was the data year used to disaggregate the sales into segments and end-uses.

¹⁰ Based on Minnesota Conservation Improvement Program: Energy and Carbon Dioxide Savings Report for 2013-2014, December 2016, <https://www.leg.state.mn.us/docs/2017/mandated/170154.pdf>

housing units in proportion to the fraction of developed (impervious) land area in each utility's service area. This provided an estimate of total housing-unit counts by type of housing, place and electric utility.

A similar procedure was used to allocate homes to natural gas utility service areas. However, gas service areas are only known at the city/township level, many of which have multiple gas providers. With a few ad hoc exceptions (e.g. Duluth), we assumed equal allocations of housing units among gas providers within cities and townships with multiple gas providers. For Xcel, which provides both natural gas and electricity, we assumed that Xcel natural-gas customers were also Xcel electric customers.

The above steps yielded a dataset with one observation for each housing unit in the state, coded for location (city or rural township), housing type, electric provider and natural-gas service area. This data set of about 2.4 million records formed the framework for imputation of end-use equipment and energy consumption within each utility's service area, as described below.

We then assigned heating fuel to each record in the database. For single-family homes, this was based on a multinomial logistic model derived from the single-family telephone survey. For other housing types, heating fuel was assigned according to Census proportions (by housing type) within each of approximately 40 regions defined by American Community Survey (ACS) Public Use Microdata Areas (PUMAs). Natural-gas heat was only allocated to homes that fell within defined gas service areas, with probability adjustments to ensure that the total number of housing units with natural-gas heat matched the overall Census PUMA proportions.

In addition, we employed ACS microdata at the PUMA level to impute (by housing type) vacant/seasonal home status, household low-income status, household size and age of home within each PUMA. As described below, these parameters were used as inputs to estimating various electric and gas end uses.

Using various datasets—principally the single-family residential telephone survey completed for this study, the CARD Minnesota Multifamily and Manufactured Homes characterization studies and the U.S. Energy Information Agency (EIA) Residential Energy Consumption Survey—we imputed fuels and equipment types for various end uses for each home in the database. For example, the probability of a single-family household having a tankless water heater was based on a logistic model employing household income and size, derived from the single-family survey data. This step resulted in the assignment of the presence and type of equipment for various end uses for each home in the database in a manner that tracked demographic and housing type differences in each utility's service area.

We then imputed energy consumption for each end-use device using various methods and various data sources. For example, energy consumption for domestic hot water was based on household size (which affects hot-water use), type of water heater (which affects the efficiency of making and maintaining hot water) and location (which affects the temperature of cold water entering the water heater). Space-heating and space-cooling usage estimates were also scaled to local heating and cooling degree days for each city or rural township.

Finally, we then summed these initial granular estimates of energy consumption by utility and compared them to weather-normalized aggregate EIA sales data for 2016.¹¹ Ad hoc adjustments to various end use

¹¹Comparisons between imputed and reported sales data were made for the *combination* of residential and farm sales, due to difficulties in separating farm residence from farm operation energy consumption for the latter. The State of Minnesota collects sales data that provides more detailed breakouts of sales by type of customer,

estimation algorithms were then made until imputed statewide consumption matched actual sales to within about 10 percent, then utility-specific scaling factors were employed to adjust the estimates to match aggregate reported sales. On a statewide basis, imputed consumption was within 4 percent of sales for electricity prior to application of scaling factors, and was within 5 percent for natural gas. Scaling factors for individual utilities varied: large utilities generally required small adjustments; very small utilities sometimes required large adjustments, presumably due mainly to imputation errors in smaller service areas.

Commercial

The following steps were used to estimate the disaggregated electricity and natural gas consumption (energy use) within each utility service territory. Disaggregated energy use consists of estimated equipment energy use by building type and end use.

1. We used CBECS¹² data (2012) for census division four to provide the base estimate of end use energy by building type. The building types used in the potential study generally correspond with those used by CBECS. CBECS building types were apportioned by estimated building size for large and small office and retail.
2. CBECS data were combined in a list of Minnesota electric utilities that contained population weighted average heating and cooling degree days for 2012 for the utility service territory. For each utility, segment, and end-use, a heating and cooling degree day scalar was applied to derive an estimate of expected energy use and energy use intensity by utility service territory, building type and end use.
3. Using Infogroup¹³ business database for Minnesota, NAICS code for primary business activity were mapped to potential study business types. The Infogroup database indicated that there were approximately 230,000 businesses in Minnesota. A major assumption in our methodology is that the Infogroup database contains reasonable data. It is unclear how Infogroup inspects quality, updates their data, or what sources they use. Seventhwave has used Infogroup data in a related manner for past research projects. The U.S. Census also produces a count and classification of businesses for each state (and census tract/zip). Generally, Census has a consistently lower count compared to Infogroup across NAICS levels. The figure below compares Census business counts to Infogroup business counts, which shows that the two datasets are highly, positively correlated. We undertook an assessment of NAICS code 44-45 for zip code 55369, Maple Grove, MN, and verified each Infogroup listed business. Results show:
 - a. 240 out of 293 Infogroup businesses (82%) were verified using Google maps and business searches. The remaining businesses (53) appear to be closed or unlisted.

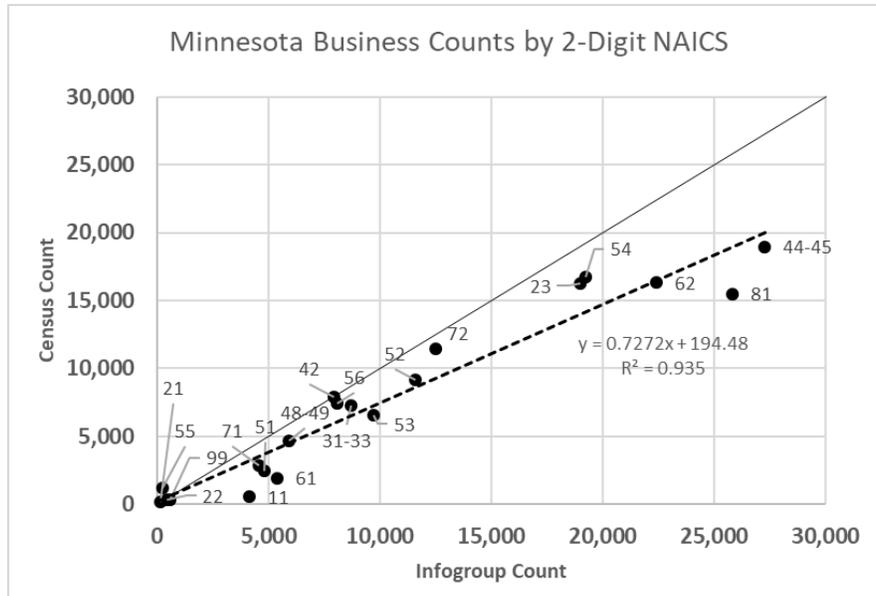
including farm sales. These data were reconciled to the EIA sales data and used to estimate residential and farm sales.

¹² Commercial Buildings Energy Consumption Survey. <https://www.eia.gov/consumption/commercial/>
2012 was the latest survey data available.

¹³ Purchased separately by Seventhwave from Infogroup. <https://www.infogroup.com/>

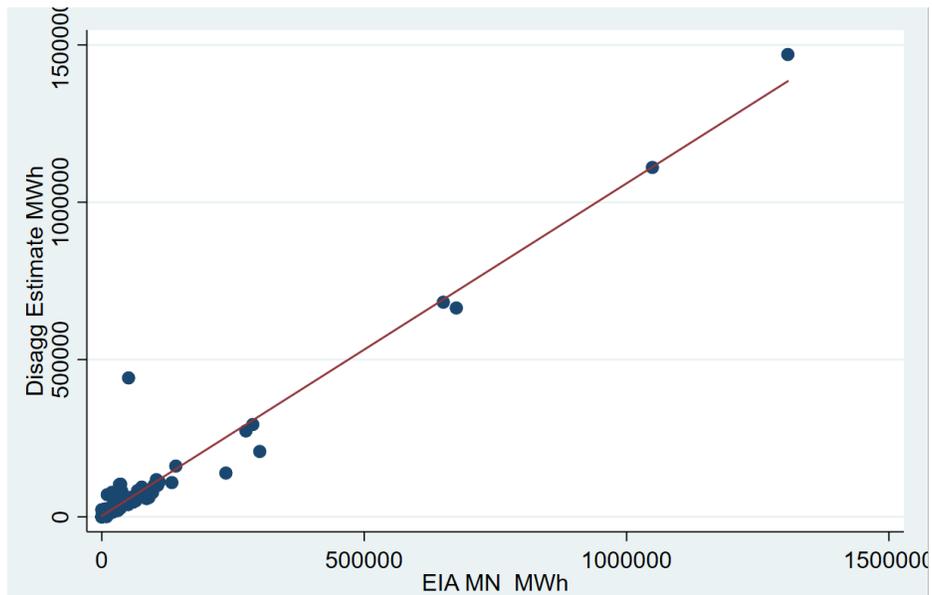
- b. The U.S. Census lists 205 businesses, or 85% of the 240 we verified.

Figure 5. Minnesota business counts by 2-Digit NAICS.



- Using a geographic information system, the Infogroup database from (3) was combined with electric utility territory boundaries. The result was an estimate of the number of businesses by segment (or NAICS code) for each utility service territory. Total minimum, maximum and mean business square footage was estimated from the Infogroup data within each utility service territory by building type. General reasonableness was compared to expected square footage from CBECS data. In some cases, individual business square footage was changed to align better with business type and estimated number of employees. For example, a small office business with one to four reported employees is not likely to be 100,000 square feet. This situation seemed to occur with small businesses that are a part of strip malls.
- The dataset from (4) was then joined with the CBECS-utility dataset from (2). Total segment and end use energy use was derived by multiplying total utility segment square footage by utility segment energy use intensity. This was repeated for the range of square footage estimates calculated in (4). The assumption used here is that degree day adjusted energy use intensity (EUI) for commercial buildings is not significantly different from CBECS calculated EUI. A much larger uncertainty is likely contained in the estimated number of segment types and square footage within each utility service territory.
- Using the range of end use energy consumption calculated in (5), total energy was aggregated to the utility level and compared to that reported by the utility to the Energy Information Administration for 2012. An iterative process was used to recalculate aggregated utility energy using different ranges of square footage estimates until the best match was found. The figure below shows the unadjusted result of this process.

Figure 6. Unadjusted 2012 electric disaggregation/aggregation for each utility (not showing Xcel Energy)



7. An adjustment factor for each utility was applied to segments and end use energy such that the total would match the reported 2012 utility sales. The resulting adjustments were examined for outliers or blunders and compared again to CBECS expected energy use intensity for reasonableness. The resulting disaggregated data represented energy use in 2012 and were scaled to 2016 (baseline) using a sales adjustment between the two years.

Industrial

Industrial end use energy consumption followed a similar process to that used for commercial businesses, but there was only one industrial segment with about 13 end uses. Similar to the commercial end use energy, we needed to estimate industrial end use energy from publicly available estimates of industrial activity in Minnesota. The following process was used:

1. For each electric utility service territory, the number of industrial businesses by NAICS code was estimated using census data and the Infogroup database. Number of employees by NAICS code was also compiled from the same data.
2. Regional energy consumption estimates were taken from the Manufacturing Energy Consumption Survey¹⁴ (MECS) data for each relevant NAICS code, census region, end use and employee count. Energy use per employee by NAICS and end use was the applicable metric.

¹⁴ MECS 2014 data were used. <https://www.eia.gov/consumption/manufacturing/index.php>

3. Climate dependent industrial loads (e.g., HVAC) were scaled to Minnesota 2016 with degree day estimates we developed for each service territory.
4. Data from (1) and (3) were combined (multiplied) to produce an initial industrial energy end use estimate by utility.
5. Aggregated industrial energy use was compared to reported industrial sales by each utility to the Energy Information Administration and adjusted. We also compared our approach and results to the Minnesota Technical Assistance Program industrial report update of 2017.

Farm

Because electricity use by rural utilities was a focus area under the study, a special effort was made to disaggregate farm electricity consumption by type of farm operation and end-use. This assessment used different methods for each of three types of farm operations: (1) livestock production; (2) crop production other than irrigation; and, (3) and irrigation.

Livestock production

Electricity use for livestock production was estimated for each utility in the state using a database of feedlots maintained by the Minnesota Pollution Control Agency (MPCA). The geocoded database allows all significant livestock-production operations to be assigned to utility service territories, and further provides head counts for various types of livestock. We combined literature estimates of per-head electricity consumption with livestock counts from the MPCA database to estimate utility-specific end-use electricity loads for the following livestock types:

- Dairy
- Swine (breeder, nursery, finish)
- Broiler chickens
- Layer chickens
- Turkeys
- Cattle

Crops (except irrigation)

We used the U.S. Department of Agriculture's CropScape GIS imagery to calculate the acres of cropland in each utility's service territory for the following categories of crops:

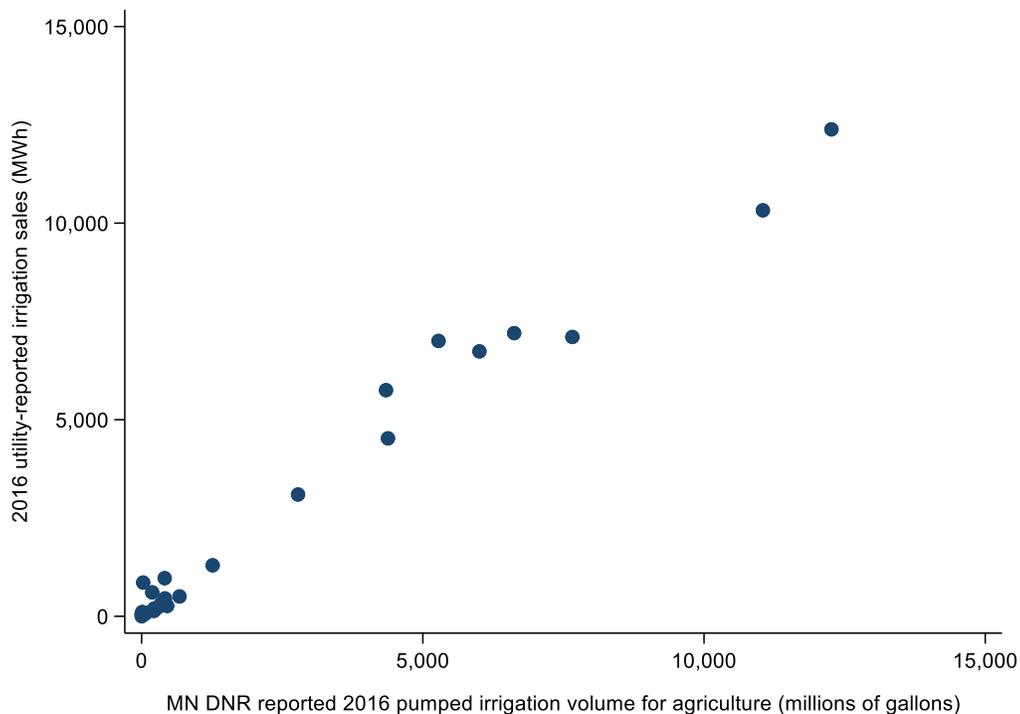
- Corn
- Soybeans
- Wheat
- Sugarbeets
- Hay
- All other crops

We then applied literature-derived estimates of annual per-acre electricity requirements for each crop type to estimate total electricity consumption for crop production in each utility's service area. For natural gas, we estimated the fraction of corn drying that is done with natural gas (most corn is dried with propane), and applied estimates of gas consumption for corn drying to natural gas utilities according to the acreage of corn production in their service areas.

Irrigation

Estimates of electricity use for irrigation came from two sources. First, some (but not all) utilities provide sales data on irrigation load as part of their sales-data reporting to the State of Minnesota. Where available—and deemed reliable—we used those data. Second, the Minnesota Department of Natural Resources maintains a database of irrigation sources with recent pumped volumes. We used this geocoded database to calculate total pumped irrigation volume in each utility's service territory by type of irrigation (agricultural, nursery, orchard, pasture, sod and wild rice). We then regressed utility-reported irrigation sales against these pumped volumes, and used the resulting regression model to impute irrigation load for utilities that do not report irrigation sales to the state. As the figure below shows, there is a high correlation between reported utility sales and pumped volume for the utilities that reported irrigation sales. In total, irrigation load came directly from reported utility sales for 26 utilities and was imputed for another 28 utilities with non-zero pumped volumes from the MN DNR database.

Figure 7. Utility-reported irrigation sales versus MN DNR reported pumped irrigation volume for agriculture in utility service areas.



The results of this disaggregation process are summarized for electric sales (Figure 8) and gas sales (Figure 9) below. The sales disaggregation for the Xcel Energy model is detailed in Table A2 in the embedded Microsoft Excel workbook. [📎](#)

Figure 8. Statewide electric energy load by building type segments and end use.

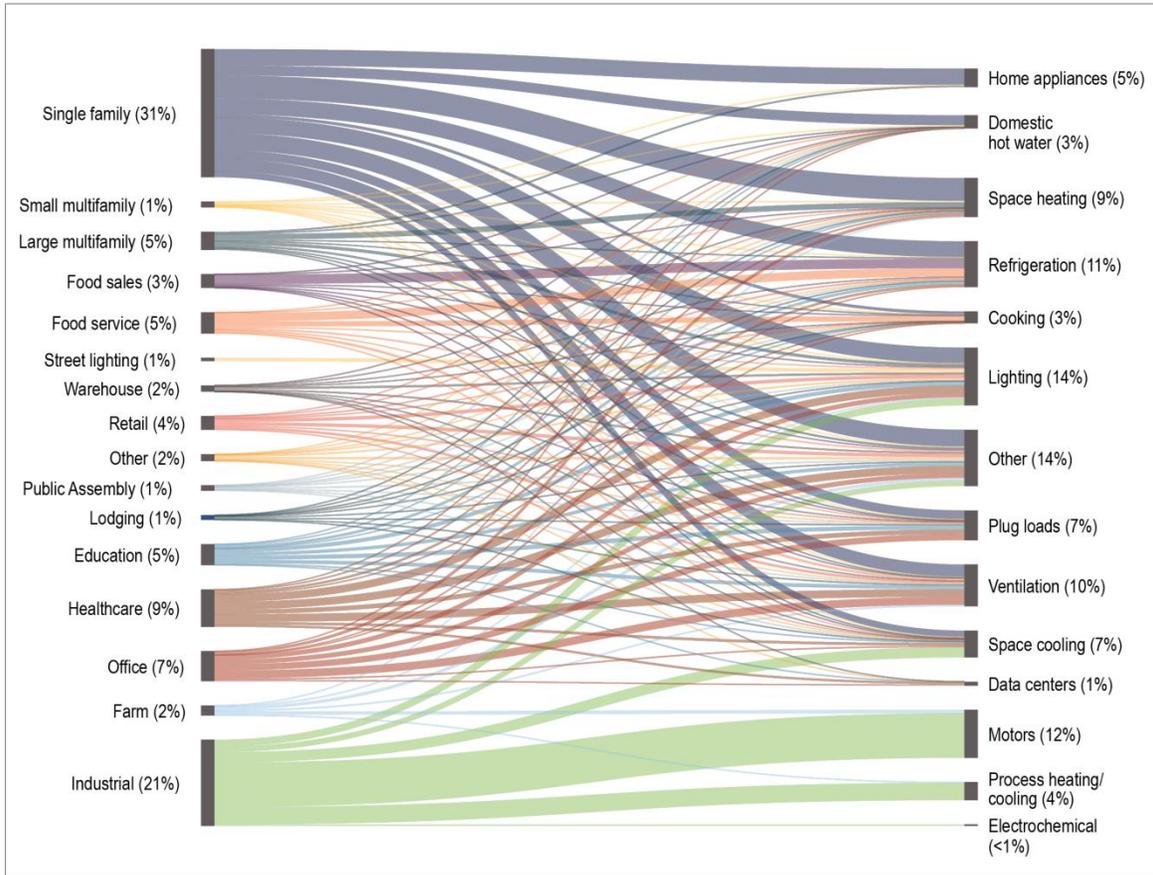
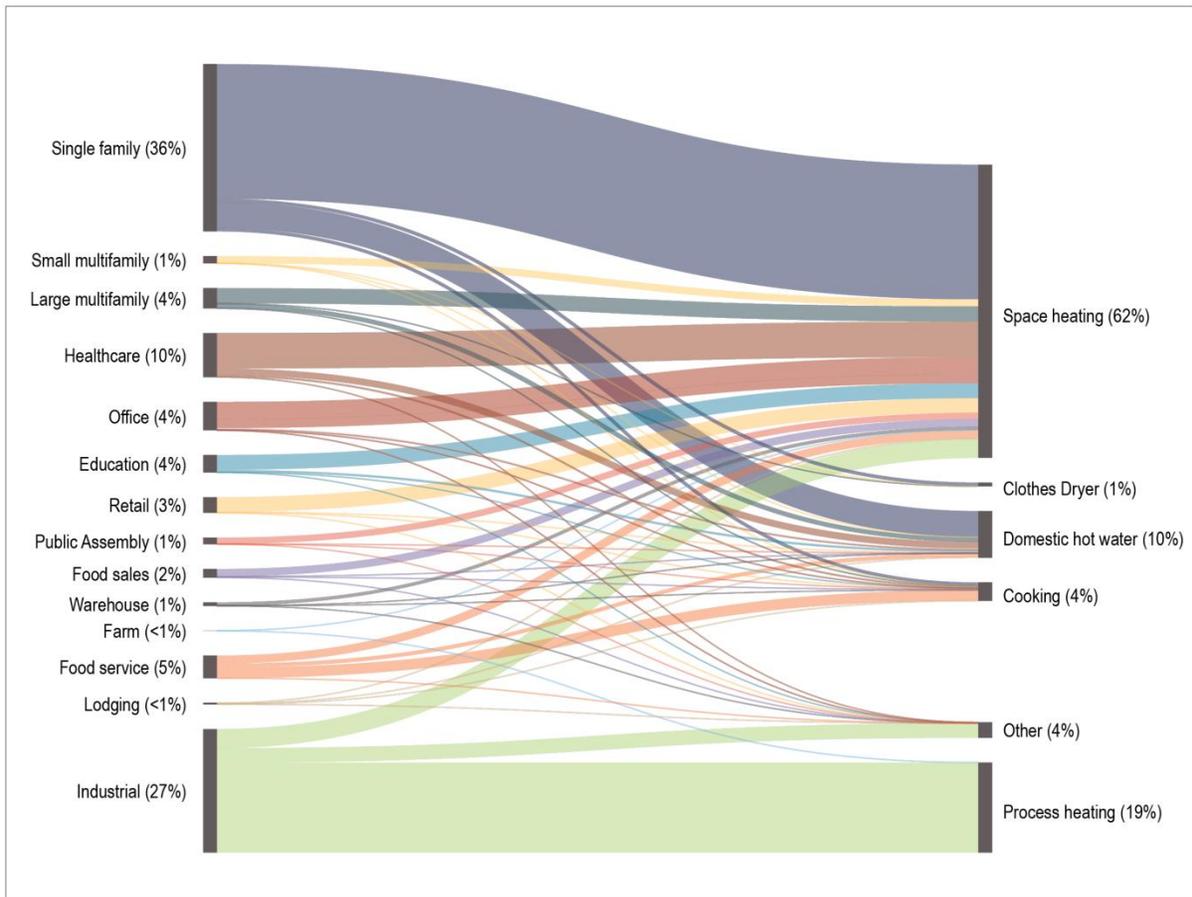


Figure 9. Statewide natural gas energy sales by building type segments and end use.



Step 2: Characterize the efficiency measures

The study team undertook an extensive investigation of measures to include for the study, described in Appendix C. Based on this review, a total of 303 measures were selected for inclusion in the study (Table 4); of these, 69 were gas-only technologies, 181 were electric-only, and 53 saved both gas and electricity. No fuel-switching measures were included. Each technology or practice was then analyzed individually by four market approaches as applicable (i.e., retrofit, replacement, renovation or new construction, as discussed below) and by the 16 individual building segments. In some cases, separate tiers of efficiency levels of a given technology were also analyzed as separate measures (e.g., “Tier 1” simple programmable thermostats and “Tier 3” smart thermostats). This resulted in modelling of a total of 3,378 individual measure permutations.

Table 4. Source of measures selected for the study.

Source of measure	Residential	Commercial/ Industrial	Total
Conventional (MN & other state’s TRMs)	84	156	240
Emerging Tech Screening	18	18	36
Behavioral Program Screening	10	7	17
Demand-Response Screening ¹⁵	5	5	10
Total	117	186	303

A qualitative screening was performed to identify any measures that should be removed from consideration. This ensured that resources were not wasted investigating measures with negligible savings potential or measures that were highly unlikely to pass cost-effectiveness screening. This process also served to document decisions to omit certain technologies or practices. The vast majority of measures screened passed this qualitative screening and were subsequently fully characterized.

Once the measures were selected, measure-specific assumptions were defined for each measure, including:

- Annual energy and electric coincident peak demand savings (including any baseline shifts over the study period), adjusted for differing climate regions where applicable;
- Incremental cost;
- Lifetime; and
- Future O&M and capital replacement cost impacts

Measure characterizations must always be stated relevant to an appropriate baseline; how much energy an efficiency measure will save is always estimated relative to some other less efficient technology or practice. As appropriate, measure baseline assumptions were reviewed for consistency with current Minnesota building codes, federal equipment standards, and market trends. In addition, planned

¹⁵ Per current CIP policy, demand-response measures were only included if they also had energy consumption savings.

revisions to codes and standards were incorporated to adjust the baselines of measures installed when those revisions are expected to go into effect.¹⁶

Measures were characterized according to which types of markets they could apply to, as measure baselines and incremental costs vary significantly depending on the market situation that drives the efficiency improvement:

- **Retrofit** – This refers to measures that are non-time-discretionary. In other words, customers can adopt them at any point and they are not dependent on some other market activity to happen. This includes equipment that is replaced prior to the end of its useful life, such as the early replacement of an inefficient boiler with a more efficient version before the boiler fails or requires extensive repairs. It also includes new measure adoptions where the measure had not been there before, such as for many controls and building envelope measures. For most early replacement measures, the incremental cost reflects the entire equipment and labor cost of the retrofit, and the initial baseline energy usage is the existing measure or usage, which is often below current code and standard market practices.¹⁷
- **Replacement**– This includes measures that are time dependent, including replace-on-failure or end-of-life, such as a boiler that is at the end of its useful life and is replaced with a more efficient version. Significantly, the incremental cost for replacement measures is the difference between a new inefficient baseline version and the efficient version. Likewise, the baseline for calculating energy savings is not the equipment that was replaced, but the inefficient, new version of the equipment, which is often set by current code or standards, or based on typical market practice. Also significant is that replacement, like new construction and renovation, are time-sensitive opportunities that can only be captured at the time of some other natural market event or investment. As a result, the magnitude of eligible opportunities is more limited than with retrofit measures, and successfully intervening in the market at the appropriate time can be challenging.
- **New construction & renovation** – This includes measures that are installed in new buildings, or those undergoing major renovation, that are above the applicable energy code. This can include, for example, a high-efficiency furnace. The baseline energy use is typically the currently applicable standard or code for the measure.

A summary of primary measure characteristics is presented in Table A3 in the embedded Microsoft Excel workbook. 

In addition to these parameters, various measure-specific factors are applied to the forecasted building-type and end use sales by year to derive the potential for each measure for each year in the analysis period. These factors include:

¹⁶ Because of the magnitude of the impact on the estimated potential, we note that general service lamps (under the expanded definition resulting from the final rules published on January 19, 2017) are assumed to be a viable opportunity through 2021. Beyond 2021, it is assumed that the backstop provision of the Energy Independence and Security Act of 2007 will have transformed the market to LEDs for nearly all general service lamp applications.

¹⁷ A baseline shift was generally applied at the point where it was expected that the average existing equipment would naturally be replaced with code level equipment.

- **Applicability** is the fraction of the end use energy sales (from the sales disaggregation) for each building type and year that is attributable to equipment that could be replaced by the high-efficiency measure. For example, for replacing office interior linear fluorescent lighting with a higher efficiency LED technology, we would use the portion of total office building interior lighting electrical load consumed by linear fluorescent lighting. The main sources for applicability factors were the primary data collected for this study, Minnesota studies, such as CARD-funded energy-use characterization studies, the EIA’s Residential Energy Consumption Survey (RECS), and the Commercial Buildings Energy Consumptions Survey (CBECS).
- **Feasibility** is the fraction of end use sales for which it is technically feasible to install the efficiency measure. Numbers less than 100% reflect engineering or other technical barriers that would preclude adoption of the measure. Feasibility is not reduced for economic or behavioral barriers that would reduce penetration estimates. Rather, it reflects technical or physical constraints that would make measure adoption impossible or ill advised. An example might be an efficient lighting technology that cannot be used in certain low temperature applications. The main sources for feasibility factors are the primary data collected for this study and engineering judgment.
- **Turnover** is the percentage of existing equipment that will be naturally replaced each year due to failure, remodeling, or renovation. This applies to the natural replacement (“replace on failure”) and renovation markets only. In general, turnover factors are assumed to be 1 divided by the baseline equipment measure life (e.g., assuming that 5% or 1/20th of existing stock of equipment is replaced each year for a measure with a 20 year estimated life).
- **Not Complete** is the percentage of existing equipment that already represents the high-efficiency option. This only applies to retrofit markets. For example, if 30% of current single family home sockets already have compact fluorescent lamps, then the not complete factor for residential CFLs would be 70% (1.0-0.3), reflecting that only 70% of the total potential from CFLs remains. The main sources for not complete factors are the primary data collected for this study, Minnesota studies, such as CARD-funded energy-use characterization studies, the EIA’s RECS, and CBECS.

Applicability, Feasibility, and Not Complete factors used in the analysis are presented in Table A5, Table A6, and Table A7 in the embedded Microsoft Excel workbook, respectively. 

Step 3: Screen measures for cost-effectiveness

Measures were screened for cost-effectiveness using the societal cost-effectiveness test (SCT), which is the primary test used by the Department for assessing proposed utility programs. The SCT considers the full incremental cost of each measure, whether it is the utility or participant that pays for that cost. For behavioral measures, the estimated cost of running the program was used for screening the measures, since often the measure itself is zero cost. Note that for screening purposes, program administration costs are not included in the initial cost-effectiveness screening.

There are four primary sources of benefits from the measures: avoided energy costs, avoided generation, transmission and distribution capacity costs, and a monetized value for emissions reduction benefits. Shifts in capital replacement cycles were also quantified. The project team attempted to use avoided cost assumptions consistent with existing Department guidance and policy where possible.

Available Minnesota Utility Data

The study team issued comprehensive data requests to the Minnesota investor-owned utilities (IOUs) and the customer-owned utilities (COUs), as well as DER soliciting their latest avoided costs or related data. The utility-specific avoided cost data were received from a subset of all MN utilities. This subset included all of the IOUs and some COUs, encompassing the vast majority of statewide electric load. For the gas avoided costs, we relied primarily on a standardized and consistent statewide methodology and assumptions developed by DER for use by all utilities in the state, which has been updated with actual data where available.¹⁸ The table below lists the utility data received in support of this study.

Table 5. Utility and DER statewide avoided cost available data

Utility	Period	Electric Energy	Electric Generation Capacity	Electric T&D Capacity
Xcel Energy	2017 – 2038	Y (8,760 hourly)	Y	Y (thru 2038 from DER T&D Study)
Otter Tail Power	2017	Y (24 hourly typical monthly weekday and weekend day)	Y	Y (thru 2038 from DER T&D Study)
Minnesota Power	2016 – 2041	Y (8,760 hourly)	Y	Y (thru 2038 from DER T&D Study)
SMMPA	2017 – 2035	Y (single annual)		Y (T only, not DER/State methodology)
CMPAS	2018 – 2027	Y (single annual)		
Great River Energy	2017 – 2045	Y (8,760 hourly)	Y	
Dairyland Power		Y (single annual)		
CenterPoint Energy	2017	N/A	N/A	N/A
MERC	2017	N/A	N/A	N/A
DER Statewide Decisions	2038	N/A	N/A	Y (for IOUs only)

¹⁸ Minnesota Department of Commerce, Decision in Docket No. G999/CIP-16-36, February 19, 2016.

The study period is 2020-2029. Given the longest measure life is 20 years, avoided cost values are required through 2049. For electricity, the longest period of avoided cost estimates from any utility extends to 2045. Therefore, the utility estimated forecast growth rates were used through 2045, and the average annual forecast growth rate from 2020-2045 was used to escalate them beyond 2045.

Avoided energy costs

For electric utility systems, the value that efficiency brings in reducing energy usage varies with the time period (both the time of day and the season of the year) that the energy reduction occurs. It is generally more valuable to reduce energy during times of high-energy usage than at other times because utilities must draw on increasingly more expensive generation resources to meet the higher demand.

Therefore, the study’s model separated avoided energy costs into six time periods, developed from hourly avoided energy costs from selected IOUs. The load shape curves for each measure were used to estimate energy savings during each period, and for peak demand impacts. The model used utility-specific avoided costs for all the IOUs. For the municipal utility regions the model used a weighted average of Southern Minnesota Municipal Power Agency’s (SMMPA) and Central Minnesota Municipal Power Agency’s (CMMPA) avoided cost data. For the cooperative utility regions the analysis used avoided costs provided by GRE. The time period definitions are shown below in Table 6, along with the average prices in those periods for the start of the study period for SMPPA; the only utility that provided non-trade-secret pricing data (from MISO).

Table 6. Avoided cost period definitions and average costs for Southern Minnesota Municipal Power Agency (2020 projections).

Period	Period definition	% of total hours for year	Avg price in 2020 (\$/MWh)
Summer on-peak	Jun-Aug: weekdays 9 a.m. – 10 p.m.	10%	\$30
Summer off-peak	Jun-Aug: weekdays 10 p.m. – 9 a.m.	8%	\$17
Winter on-peak	Nov-Mar: weekdays 8 a.m. – 10 p.m.	17%	\$26
Winter off-peak	Nov-Mar: weekdays 10 p.m. – 8 a.m.	12%	\$19
Shoulder on-peak	Apr-May & Sep-Oct: Weekdays 7 a.m. – 11 p.m. + All weekend days 9 a.m. – 11 p.m.	33%	\$27
Shoulder off-peak	Apr-May & Sep-Oct: Weekdays 11 p.m. – 7 a.m. + All weekend days 11 p.m. – 9 a.m.	20%	\$16

Figure 10 shows these periods superimposed on the (8760) hourly energy prices, for one year of one of the data sets used for the analysis.¹⁹ The boxed areas in the figure represent the peak and off-peak times (summer, winter, and shoulder).

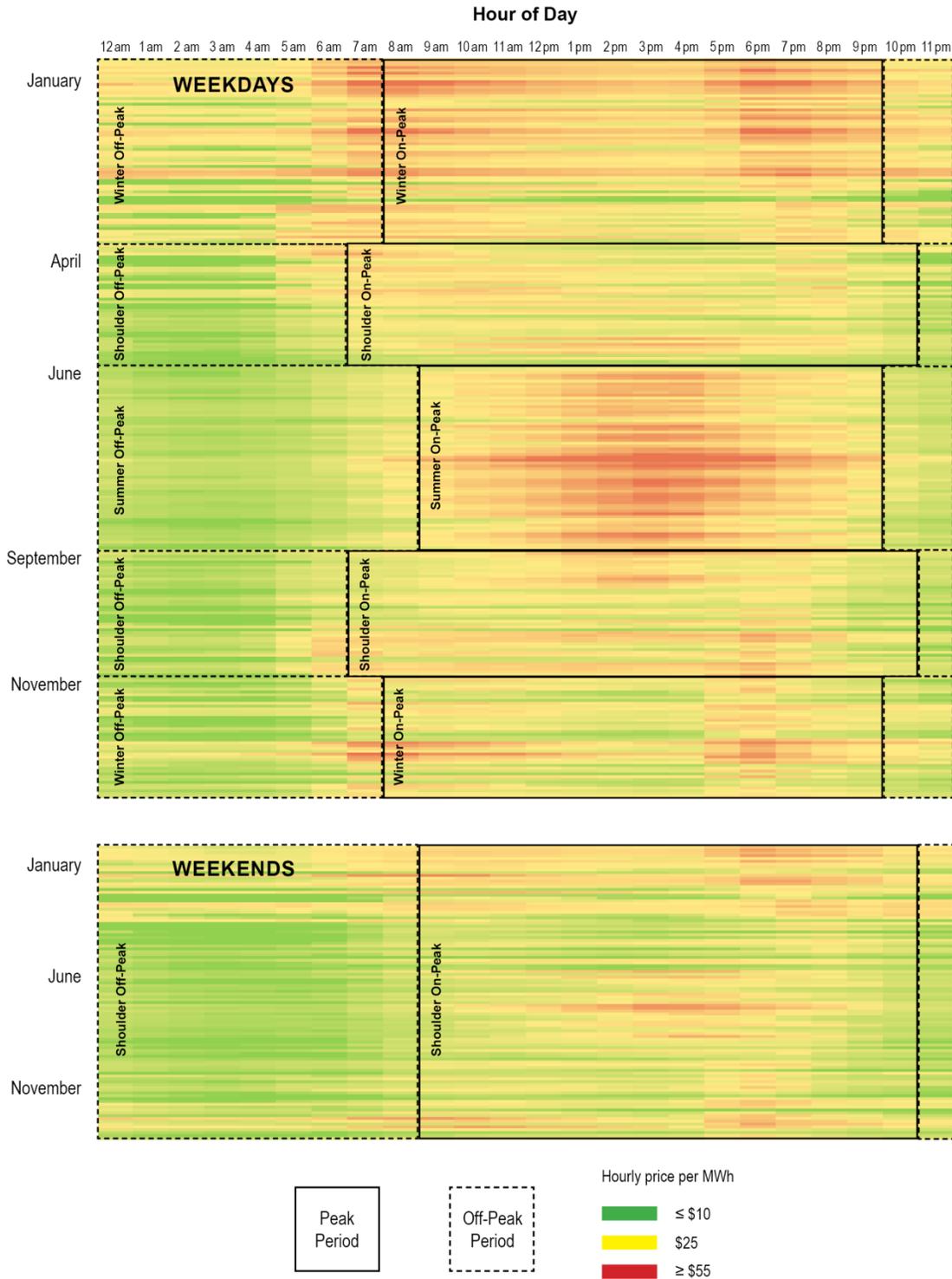
While Minnesota is primarily a summer peaking state (experiencing the highest hourly costs in summer months), northern parts of the state can be winter peaking, and other parts of the state can be close to

¹⁹ Data set received from SMMPA, based on MISO projections of 2020 energy costs.

being winter peaking, due to the high prevalence of electric space heating in some parts of the state. Although SMMPA is in the southern part of the state, you can see a prominent price spike in the winter, as shown in Figure 10; although the peak hours are different compared to summer. Winter peaking occurs early in the morning, and later in the evening, compared to summer peak periods primarily in the mid-afternoon.²⁰ Thus, the study's model attempts to capture the price differentials in the summer as well as winter peaks. Avoided electric energy costs for the Xcel Energy model are presented in Table A11 in the embedded Microsoft Excel workbook. 

²⁰ The difference in hours between winter peaking and summer peaking demonstrated in Figure 20 is perhaps due to the primarily residential nature of winter peaking, compared to the higher commercial A/C load that plays a greater role in driving the peak summer periods.

Figure 10. Hourly projected 2020 avoided electricity costs for SMMPA, overlaid with the peak and off-peak periods used for modeling.



For natural gas utilities, the project team used the Department-approved avoided energy and capacity costs for all utilities and regions.²¹ The team escalated the avoided commodity costs by the Energy Information Administration's 2017 Annual Energy Outlook estimates of future wholesale natural gas commodity price increases. The 2020 estimated avoided commodity cost for gas is \$4.85/Dth.

While avoided gas costs also vary by time period like electricity, the project team analyzed the recent daily commodity price changes and determined that applying daily or period specific costs and impacts at the measure level would yield very little difference in benefits in Minnesota. This likely reflects ample pipeline supply and storage facilities in Minnesota. Therefore, all measures and programs are screened based on annual average costs, consistent with current Department guidance. Avoided natural gas costs are presented in Table A12 in the embedded Microsoft Excel workbook. 

Avoided generation capacity costs

For electric utilities, capacity avoided by energy efficiency has traditionally been based on the projected cost to build a new natural gas simple-cycle combustion turbine (CT) generation facility. The project team received utility-specific estimates of this cost from several utilities and used a single weighted-average capacity value of \$61.50/kW-yr (2018\$). This is based on the assumption that the cost to build a new CT will not likely vary significantly depending on which utility retains ownership, and that utilities can have wholesale transactions between them. Note that since this is a statewide study, the study's model implicitly assumes that there is an avoided capacity value for all the utilities included in this analysis, even though some individual utilities may not need to add capacity for the next decade or more. Avoided electric generation capacity costs are presented in Table A11 in the embedded Microsoft Excel workbook. 

Avoided transmission and distribution capacity costs

For the IOU electric utilities, the project team used utility-specific avoided transmission and distribution (T&D) costs, based on the Continuous Valuation avoided costs from the most recent Department Decision that establishes a consistent methodology statewide for T&D avoided cost estimation.²² The team used a weighted average of the three IOUs results to represent the northern and southern municipal and cooperative utility models. Avoided electric transmission and distribution capacity costs for the Xcel Energy model are presented in Table A11 in the embedded Microsoft Excel workbook. 

While the Department decision for gas utility avoided costs also quantifies peak avoided transmission (pipeline) capacity costs, the Department-approved methodology bundles the capacity costs into the commodity charge based on typical load shapes. The project team also included an additional local distribution system capacity costs based on the Department-approved values for CenterPoint and

²¹ MN EDocket No. G999/CIP-16-36. The project team also relied on this decision for some additional global assumptions, such as inflation and discount rates.

²² Minnesota Department of Commerce, Decision in Docket No. E999/CIP-16-541, September 29, 2017. Note that while the Decision calls for use of the Discrete Approach methodology T&D cost estimations for the current 2017-2019 plan, the project team deemed these less appropriate than the Continuous Valuation estimations for a longer term potential study.

Minnesota Energy Resources, bundled into a single composite commodity charge.²³ The study, therefore, did not separately estimated gas peak-day impacts and benefits. The total T&D 2020 capacity cost translates into an annual average value of \$1.29/Dth (2018\$).

Avoided emissions

The benefits of cleaner air because of avoided criteria pollutants²⁴ and carbon dioxide (CO₂) have long been included as a benefit in CIP. The project team updated the values used for these pollutants based on the latest MPUC ruling on externalities in the power generation sector, per guidance from the Department. Although not currently in the most recent Department guidance document, the Department expects to include these values in a future version of its guidance document.²⁵ These are the same values that are applied in Integrated Resource Planning proceedings before the MPUC.²⁶ The study's model used a single state-wide value²⁷ for calculating the emissions intensity in lbs/MWh, which resulted in a total value of \$17.65/MWh for electric, and \$1.84/Dth for gas (2018\$). Of the total emissions factor, CO₂ represents 74% of the total impact for electric, and 84% of the impact for gas.

While emissions rates for electric can be expected to decline over the study period as the grid becomes increasingly powered by renewables, the project team did not attempt to model this in this study. The model could not easily accommodate this, and the team did not have good data on projected statewide emissions declines over the study period. Based on existing filed Integrated Resource Plans, the statewide CO₂ emissions rate is expected to decrease 12% from 2020 to 2029.²⁸ The emissions rates used in this study are presented in Table A14 in the embedded Microsoft Excel workbook. 

Other than avoided emissions benefits, no other non-energy benefits were included in the modeling, even though water benefits and benefits from reduced maintenance are allowable under current CIP guidance, and used by some utilities in their calculation of net benefits.

Other Global Inputs

In addition to the above main categories of avoided costs, there are a number of overarching assumptions and values that were estimated to properly apply the avoided costs and cost-effectiveness analysis. These are discussed below.

²³ Both CenterPoint Energy and Minnesota Energy Resources provided identical distribution capacity cost estimates, so they were applied statewide.

²⁴ Criterial pollutants include sulfur dioxide (SO₂), particular matter less than 2.5 microns (PM_{2.5}), carbon monoxide (CO), oxides of nitrogen (NO_x), and lead (Pb).

²⁵ The last guidance document, for natural gas utilities, was released in 2016. Docket No. G999/CIP-16-36, "In the matter of Inputs to BENCOST for Natural Gas 2017-2019, Conservation Improvement Program," February 19, 2016.

²⁶ MPUC Docket No. 15-21, Xcel Energy 2015 Integrated Resource Planning Docket.

²⁷ MPUC Docket No. 14-643, Order Updating Environmental Cost Values.
<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPop&documentId={5066BD60-0000-C71B-9B5B-305CF65BCAE1}&documentTitle=20181-138585-01>.

²⁸ See **Error! Reference source not found.** for projected statewide emissions rates, and footnote **Error! Bookmark not defined.** for description of how this was calculated.

Discount Rate

The DER gas decision proposed use of a societal nominal discount rate of 2.55%, based on long-term treasury bonds. This value was adopted for the analysis. It is noted that the DER decision envisions that for any Participant Test the societal rate should be used for residential, but the utility-weighted average cost of capital (WACC) should be used for commercial and industrial customers. However, the cost-effectiveness screening model does not accommodate separate discount rates by sector for the participant test. Further, the Societal Test is the primary test that impacts economic and achievable potential, with any other test results simply provided for reader interest. We therefore used the societal discount rate for the Participant Test in all sectors. We acknowledge that Minnesota utilities currently use their WACC to calculate utility benefits for use in the Utility Cost Test (UTC) for purposes of performance incentives. However, this would not be appropriate when considering the overall value of efficiency potential to ratepayers for a number of reasons. Further, the team notes that a forthcoming Conservation Applied Research and Development (CARD) project reviewing Minnesota cost-benefit tests has recommended that the Department change the discount rate to the utility test to the societal discount rate, and thus, according to this CARD project, this project's approach is reasonable.

Nevertheless, current Department guidance directs utilities to use the weighted average cost of capital (WACC) for the Utility Cost Test discount rate. Therefore, the project team conducted a sensitivity analysis to calculate the net utility benefits using the WACC discount rate,²⁹ while still conducting economic screening using the societal test discount rate. Although the study's model used the SCT as the primary screen for determining cost-effectiveness, we also examined the impact of screening measures for cost-effectiveness using the utility cost test at the higher discount rate as well.

Inflation

The DER gas decision established an inflation rate of 2.16% ("GDP Escalation Rate"). While the analysis relied on real 2018 dollars for all figures, to the extent any nominal economic values needed to be converted to real 2018 dollars this inflation rate was used.

Electric Line Losses

The DER gas decision initially established an overall electricity line loss factor of 5.28% to be used for electric savings from gas programs. However, this reflects the average line losses over the entire annual electricity load. Because energy efficiency by definition creates reductions in load on the margin during each hour of the year, and losses are exponentially impacted by the loading on the T&D lines, use of an average line loss factor would significantly underestimate true impacts of efficiency. We therefore applied a typical ratio of marginal to average annual line losses of 1.5³⁰ to the average residential and commercial energy line loss values provided by Xcel Energy—8.8% and 6.6%, respectively.³¹

²⁹ This study's analysis used a nominal discount rate of 7.3%, which approximates the weighted average of the IOUs reported weighted average cost of capital.

³⁰ Lazar & Baldwin, Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements, Regulatory Assistance Project, August 2011.

³¹ Tinjum, A. Xcel Energy. Personal Communication. February 2018.

Energy Retail Rates

Average energy retail rates are used to determine participant benefits for the Participant Cost Test. Minnesota 2016 average retail rates for electricity were determined by sector and utility from the U.S. Energy Information Administration (EIA).³² Statewide average retail rates for natural gas were also determined by sector using EIA data.³³ The EIA estimates retail rates by dividing estimated utility revenue by estimated energy sales. Retail rates for each fuel were projected through the analysis period assuming average annual growth rates from the avoided cost forecasts for the appropriate model region. The average retail rates, by fuel, sector, and year are presented in Table A13 in the embedded Microsoft Excel workbook 

Electric Load Shapes

Electric energy load shapes are used to divide annual efficiency measure kWh savings into the energy costing periods of the avoided costs. For this project, load shapes have been developed based on 2002 Itron eShapes 8760 load profile data for New York. While the selected load shapes are based on weather stations from a different state, they provide the nearest and best data at the level of granularity necessary to support the analysis. For the purposes of this study, it is unlikely that the load shapes in Minnesota would differ significantly from the load shapes in New York.

The eShapes data provide 8760 load profile data for electric energy usage, by sector, and for various end uses and building types. The data were based on approximately 20,000 building audits performed nation-wide mainly in the early 1990s. More than half of the roughly 20,000 audits were performed on-site. These were very highly detailed audits, including an inventory of building energy usage; specific equipment types, characteristics and quantities (e.g., down to numbers of lamps); end use metering; thermostat settings; operating schedules by zone; fuel types for hot water, space heating and cooking; thermal shell details; building orientation and size; etc. The mail surveys were less detailed, but attempted to collect the same information. Building simulations were then performed with proprietary modeling software for many of the audited buildings, to develop a set of prototype buildings calibrated to the measured data for individual sites.

Measure electric load shapes are presented Table A4 in the embedded Microsoft Excel workbook. 

Step 4: Estimate program budgets and measure penetrations

In addition to the economic potential scenario, the project team defined two achievable scenarios — a “maximum achievable” scenario and a constrained “program potential” assuming 50% of the measure costs on average are covered by programs, with a 50% customer contribution. The maximum achievable

³² U.S. Energy Information Administration. October 2017. “Electric Sales, Revenue, and Average Price”

³³ U.S. Energy Information Administration. “Average Residential Price,” July 2018; U.S. Energy Information Administration, “Average Commercial Price,” July 2018; July 2018; U.S. Energy Information Administration, “Average Industrial Price,” July 2018

scenario assumes that 100% of the incremental measure cost was covered by programs with no customer contribution. While in theory a program could provide even larger financial incentives, this is unlikely for numerous policy reasons and it is common practice to assume 100% cost coverage for maximum achievable potential scenarios. In practice, there are many reasons why rebating 100% of the measure cost may not be desirable, so the project team also analyzed a scenario that assumes 50% of the measure costs are covered by the program, which is more consistent with current Minnesota program planning.

For all achievable scenarios, the study did not model specific, detailed program designs. Rather, measures were bundled into appropriate broad program markets, which collectively cover all efficiency opportunities and do not include any double counting. For example, the study distinguished between new and existing buildings, between retrofit and market driven opportunities, and by particular market segments. The project team assumed well designed, marketed, and implemented programs, with optimal administrative and delivery frameworks to support success. The team recognizes that this implicitly assumes some coordination, or more likely, jointly delivered efforts spanning across utility territories and fuels to provide consistent market messages and benefits from appropriate economies of scale.³⁴

In addition to financial incentives, there are administrative, marketing, technical support, and other costs to running programs modeled in the maximum achievable and program potential estimates.³⁵ The project team estimated program budgets based on benchmarking typical ratios of measure-related to non-measure-related spending by Minnesota and other utilities.

The study's model projected annual penetration rates for each measure based on a market adoption model, which requires measure-specific awareness and willingness-to-adopt factors as inputs. The determination of individual measure awareness, willingness, and overall market penetration potential was informed by a review of Minnesota — and other national programs, other program literature and evaluations, and the levels of financial and non-financial barriers associated with each measure. The Participant Cost Test benefit-cost ratio is another factor used in the adoption model (e.g., the more cost-effective to the participant, the higher market adoption). The development of penetrations for each potential scenario is described in more detail below.

Economic Potential

As the economic potential is intended to quantify all cost-effective energy efficiency potential, it was assumed that all measures were fully implemented. In other words, measure adoption was fixed at 100% as part of the definition of this potential scenario. However, there are some nuances to the implementation of this assumption that warrant additional explanation.

For market-driven measures (e.g., replacement, new construction and renovation), the model assumed that measures were adopted at the rate of equipment turnover or construction/renovation. For

³⁴ For example, the project team implicitly assumed that a small muni still has the maximum achievable because it could contract to deliver programs through third parties, or aggregate its programs with other smaller utilities to achieve scale.

³⁵ As is common practice, the economic potential does not assume any program costs (incentive or non-incentive). Measures are screened purely on their own economic merits and it is assumed all cost-effective measures would be installed.

example, if it is assumed that rooftop unitary HVAC equipment has a 15 year life, the model would assume that one fifteenth of all such equipment will be replaced, or “turn over,” each year. The economic potential scenario assumed that all failed equipment was replaced with the highest efficiency, cost-effective equipment.

For time-discretionary retrofit measures, including early retirement, the model assumed that all available cost-effective opportunities were implemented evenly over the 10-year study period.³⁶ While the model could have simply assumed that all cost-effective retrofits were implemented instantaneously, spreading the potential over the study period provided a more realistic, if somewhat arbitrary, picture of the available economic potential over time.

The economic potential penetrations are presented in Table A8 in the embedded Microsoft Excel workbook. 

Achievable Potential

The achievable potential scenario built on the economic potential analysis. This study estimated the maximum achievable potential or what is theoretically achievable given high incentive and non-incentive spending levels and optimal program delivery. We estimated achievable measure adoption rates based on a variety of factors, including: market barriers; applicable markets (replacement, retrofit, new construction and renovation); incentive levels; non-incentive spending on marketing and technical assistance; and appropriate program strategies (e.g., upstream buy down, direct install, etc.).

For the purposes of this methodology, market barriers were grouped into four categories:

- **Cost:** initial cost, operation and maintenance costs, access to financing
- **Awareness:** of efficiency measures’ potential application, benefits, and possible incentives
- **Willingness:** due to magnitude of lifetime benefits, personal/organizational practices, split incentives, uncertainty or distrust of performance/benefits, fear of unintended consequences, hassle factor, irreversibility, etc.
- **Availability:** of equipment or contractors.

To estimate a measure’s maximum achievable penetration, the maximum awareness of the measure due to efficiency program activity was approximated and it was assumed that incentives were available to cover the full incremental cost (in the case of early-retirement measures, the incremental cost reflects the total project cost since it is incremental to taking no action). Measure availability can limit the rate of adoption; however, availability is not usually the limiting factor for measure penetration rates in an achievable scenario. If demand for an efficient technology substantially exceeds the supply, then in general the supply will respond in the near term to meet the market demand. Awareness and willingness are therefore the key market barriers considered for estimating the maximum achievable adoption rates.

³⁶ Retrofit measures were generally assigned annual penetrations of 10% for the economic potential scenario. In cases where measure life was less than 10 years, the retrofit penetrations were set to one divided by the measure life.

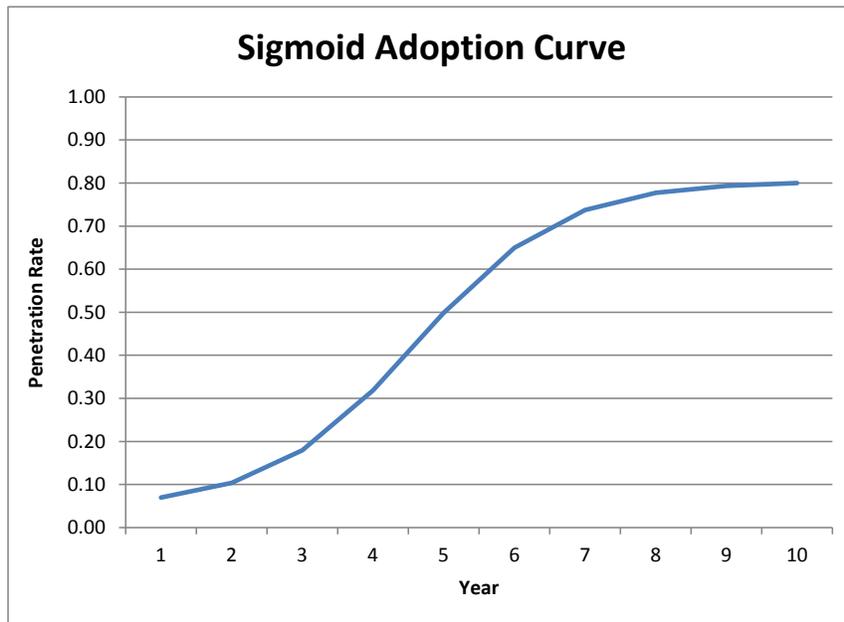
Participants and/or other market actors must be “aware” of an efficiency measure before it has the potential to be installed. “Awareness” means that one knows enough about the measure to have some opinion as to whether it’s worth consideration. An awareness factor is applied to the overall population to estimate the portion that might be willing to install a measure. The initial awareness for a measure will vary depending on its availability and how widely it’s been promoted in the past. Over time the awareness level will increase in response to program intervention, reaching a maximum awareness over a period of about 5 to 15 years depending on factors such as the measure’s breadth of application, complexity, and potential savings. Note that for some technologies it is possible for customers to participate in a program, and receive an indirect incentive, without being aware of the program, as with upstream/midstream buy-down or supplier training programs. Therefore, “awareness” may represent a barrier of the program strategy, or the supplier awareness as well as the customer awareness.

A willingness factor was then applied to the “aware” portion of the population. In general, the maximum achievable penetration for the aware population is estimated in the range of about 60% to 85% for market-driven measures, and about 50% to 80% for retrofit measures, depending on the specific measure and applicable options for program delivery. The number of years needed to overcome market barriers and reach these maximum penetration rates is generally estimated in the range of 5 to 15 years, depending on the measure.

Once the maximum penetration had been estimated for each measure, the adoption curve over the study period needed to achieve that ultimate maximum penetration was developed. A standard S curve (sigmoid curve) was used where the adoption rate generally increases in the initial years in response to program intervention, eventually leveling off as it approaches the maximum penetration. The initial and final rates of adoption varied depending on the level of market barriers associated with each measure.

The sample adoption curve in the figure below illustrates a measure for which program intervention is just beginning and adoption is at a naturally occurring level commensurate with the beginning of the sigmoid-curve period. In some cases, current product adoption may already reflect a point farther along the sigmoid curve, in which case the curve may appear truncated and reflect more rapid initial increase and reaching maturity earlier (e.g., as has been seen for LEDs and condensing furnaces).

Figure 11: General sigmoid adoption curve



For each year, the awareness factor was multiplied by the “aware” penetration from the adoption curve to estimate the overall measure penetration. The overall penetration was then applied to the applicable end-use energy, along with the measure’s percent savings, to determine the overall energy savings. Note that some measures apply to both the natural replacement and retrofit markets. In this case, applying the measure in one market reduces the applicable energy available in the other market.

The maximum achievable potential penetrations are presented in Table A9 in the embedded Microsoft Excel workbook. [📎](#)

Program Potential

The program potential scenario assumes that incentives cover only 50% of incremental measures costs. For this scenario, it is assumed that customer economics limit measure adoption; therefore, the Participant Cost Test benefit-cost ratio is used to adjust the maximum achievable penetrations. In short, the model formulaically estimates the percentage of the maximum achievable penetration that can be reached given a participant BCR.

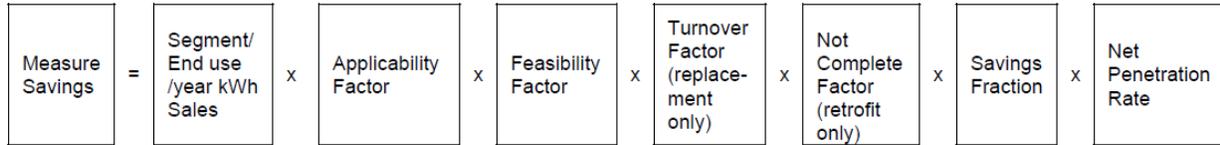
The program potential penetrations are presented in Table A10 in the embedded Microsoft Excel workbook. [📎](#)

Step 5: Calculate total savings and net benefits

As described above, the general approach for this study, for all sectors, is “top-down” in that the starting point is the actual forecasted loads for each fuel and each sector. We then break these down into loads attributable to individual building equipment. In general terms, the top-down approach starts with the energy sales forecast and disaggregation and determines the percentage of the applicable end use energy that may be offset by the installation of a given efficiency measure in each year.

As described in the context of Step 2, various measure-specific factors are applied to the forecasted building-type and end use sales by year to derive the potential for each measure for each year in the analysis period. This is shown below in the following central equation:

Figure 12: Fundamental savings potential equation



The product of all these factors results in the total potential for each measure permutation. Costs are then developed by using the “cost per energy saved” for each measure applied to the total savings produced by the measure. The same approach is used for other measure impacts, e.g., operation and maintenance savings.

The model applies all the inputs developed as discussed above, and performs year-by-year calculations to roll up all impacts, costs, and benefits; applying the appropriate penetrations to each set of measure and load inputs for all 3,378 measures. The model accounts for the rolling impact over time of building and equipment stock and associated load adjustments based on prior measures assumed to be adopted. It also accounts for measure interaction and mutual exclusivity with other measures.

Table 7. Summary of major data sources used for each step of potential study.

	1. Forecast sales & disaggregate energy load	2. Characterize the energy efficiency measures	3. Screen for cost-effectiveness	4. Estimate program budgets and measure penetrations
Utility-provided load forecasts from the IOUs and several municipal and cooperative utility aggregators	•			
Primary data collected for this study	•	•		•
Other available Minnesota studies, such as CARD-funded energy-use characterization studies	•	•		
Other available studies from outside Minnesota, with a preference for those in neighboring states	•	•		
U.S. Department of Energy, Energy Information Agency data on 2016 utility load	•			
Sales data by customer type reported by utilities to the State of Minnesota	•			
American Community Survey and other U.S. Census data for Minnesota	•			
Commercial Building Energy Consumption Survey (2015) (CBECS) for the Northern Midwest region, U.S. Energy Information Agency	•	•		
Residential Energy Consumption Survey (2015) (RECS) for the Northern Midwest region, U.S. Energy Information	•	•		
Manufacturing Energy Consumption Survey (2015) (MECS) U.S. Energy Information Agency	•			
Minnesota Technical Reference Manual, version 2.0		•		
Current and likely future codes & standards		•		•
Baseline and appliance saturation surveys		•		•
Utility-specific assumptions found in utility Triennial CIP plans		•		•
Utility-specific program evaluations or other data sources		•		•
Weather data		•		
Engineering analyses		•		
Utility-specific avoided energy costs for each hour of the year (if available)			•	
Department of Commerce assumptions for cost-effectiveness screening			•	
Utility-provided avoided capacity costs			•	
Historical CIP information on program achievements and budgets				•