



MN **SOLAR** PATHWAYS  
illuminating pathways to 10% solar

# Solar Potential Analysis Report

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**PREPARED FOR**  
MINNESOTA DEPARTMENT OF COMMERCE  
AND THE MINNESOTA SOLAR PATHWAYS PROJECT

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## Disclaimer

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## Acknowledgements

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### **Core Team (alphabetic by organization)**

In addition to Clean Power Research, the following partner organizations are the project leads under Minnesota Solar Pathways: Illuminating pathways to 10% solar. These organizations contributed to the Solar Potential Analysis development and final report as described below.

**Center for Energy and Environment (CEE)** – CEE contributed to the technical analysis in the SPA (through development of the load shifting analysis) and to the generation of the SPA Final Report. In particular, CEE provided multiple cover-to-cover reviews that greatly enhanced the clarity and quality of the report. Josh Quinnell served as CEE’s project lead and his diligent and detailed work greatly improved the overall quality of this work.

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**MN Department of Commerce (Commerce)** – Commerce served as the MN Solar Pathways project manager and a member of the Technical Committee. Stacy Miller served in both of these roles for Commerce and provided extensive feedback on the SPA, including multiple cover-to-cover reviews of the SPA Final Report. Clean Power Research and the Core Team are greatly indebted for Stacy’s contributions to the project.

## MN Solar Pathways Technical Committee (alphabetic by organization):

The SPA benefited tremendously from feedback received during meetings of the MN Solar Pathways Technical Committee. Members of the Technical Committee are listed below.

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## Individual Contributors

The Core Team received support from a number of individuals (many of whom are listed above) during the development of the SPA and the writing of the report. These individuals took time to meet one-on-one, discuss modeling issues, and provide feedback on the final report that greatly helped to clarify technical concepts.

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## Executive Summary

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The Minnesota Solar Pathways (Pathways) initiative, sponsored by the U.S. Department of Energy Solar Energy Technologies Office, is a three-year project designed to explore least-risk, best-value strategies for meeting the State of Minnesota's solar goals. As part of this aim, the Pathways Team is modeling renewable generation costs, examining ways to streamline interconnection, and evaluating technologies that can increase solar hosting capacity on the distribution grid. For more details about the MN Solar Pathways project, including published reports and a list of project partners, please visit [mnsolarpathways.org](http://mnsolarpathways.org).

This report summarizes the modeling of future renewable generation costs as accomplished by the Solar Potential Analysis (SPA).

### What is the Solar Potential Analysis?



**Solar Potential ANALYSIS**

**The Solar Potential Analysis estimates the generation cost to achieve 10% solar by 2025 and 70% solar and wind by 2050 in MN**

The SPA is a modeling tool that estimates and optimizes the [generation cost](#) and resource capacities (e.g., solar capacity) to serve a specified percentage of Minnesota's electrical load with given production requirements (e.g., production that is aligned with a day-ahead forecast).

One purpose of the SPA is to provide key insights into transforming solar and wind generation into [dispatchable generation](#) resources. The purpose of the SPA is not to make decisions regarding specific generation resources: the SPA is not a resource plan.

**The Pathways Team used the SPA to model the generation cost (in \$/MWh) to achieve 10% of Minnesota's electricity from solar by 2025 and 70% of Minnesota's electricity from solar and wind by 2050.**

The Pathways Team modeled a number of scenarios to identify the likely range of generation costs and resource capacities for the 10% and 70% targets of interest. These

scenarios included different: 1) future technology costs; 2) solar distributions (spatial allocation and type of installation); and 3) production requirements.

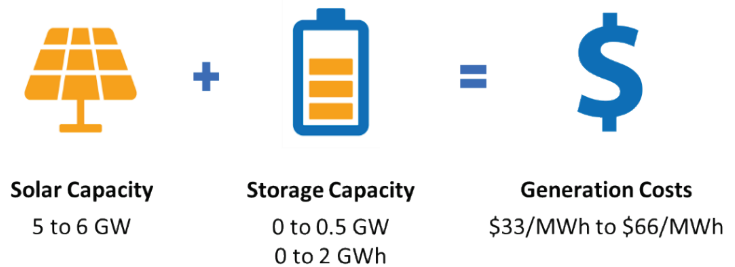
A number of important findings from the SPA are discussed in the body of the report. Key findings related to achieving 10% of Minnesota's electricity from solar by 2025 and 70% of Minnesota's electricity from solar and wind by 2050 are presented in the Executive Summary.

## 10% Solar by 2025

The SPA results indicate that Minnesota could achieve its goal of 10% solar at costs comparable to the cost of natural gas generation.<sup>1</sup>

Modelled [generation cost](#) for 10% solar by 2025 ranged from \$33/MWh to \$66/MWh.<sup>2</sup> The broad range is a result of cost forecasts and production requirements that were meant to bound the likely futures in Minnesota. The lower-end of the generation cost range is comparable to the variable cost of natural gas generation and the upper-end of the range is comparable to the levelized cost of new natural gas generation (as presented in Appendix I: Cost of Natural Gas Generation Resources).

### 10% Solar by 2025:



The ranges of solar and storage capacity reflect the different solar production requirements modeled. Scenarios with minimal production requirements (e.g., solar could produce as long as there was load to serve after accounting for wind and must-run resources) required 5 GW of solar capacity and no storage capacity. Scenarios with modest production requirements (e.g., solar was expected to match the forecasted day-ahead production) required 6 GW of solar capacity and up to 2 GWh of storage.

## 70% Solar and Wind by 2050

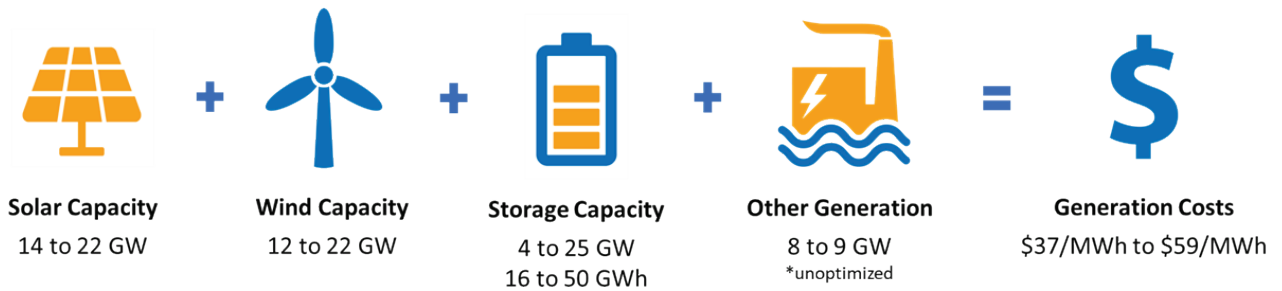
The SPA results reveal that the expected cost declines of solar, wind, and storage will enable Minnesota to achieve 70% solar and wind by 2050 with generation costs comparable to natural gas generation costs.

This is a particularly notable result given the conservative production requirements used when modeling the 2050 results: Minnesota-sited [solar, wind, and storage were asked to match Minnesota’s hourly load profile](#). An exception to this requirement was made during brief periods of low-solar and low-wind production, during which time [Other Generation](#) resources were used to support generation requirements.

<sup>1</sup> The Pathways Team uses natural gas as an accepted benchmark of cost comparison in common use, in part because natural gas is the leading traditional resource being developed in the U.S. The comparison does not imply that the SPA includes a full analysis of renewables vs. gas in terms of performance or adequacy.

<sup>2</sup> Costs are in current (nominal) dollars.

### 70% Solar and Wind by 2050:



### SPA Key Findings

1. **Solar and wind can serve 70% of Minnesota’s electrical load in 2050.**
  - Solar and wind can serve 70% of Minnesota load at [generation costs](#) that are comparable to the levelized generation cost of new natural gas generation.
2. **[Additional Capacity](#) coupled with energy curtailment is considerably less expensive than, and a viable alternative to, long-term or seasonal storage in a high renewables future.**
  - Declining costs of solar and wind generation (<\$20/MWh) will enable solar and wind to be economically curtailed during periods of high production and low load.
  - The ability to curtail surplus renewable production removes the need to use energy storage to seasonally shift renewable energy production to serve load.
3. **Flexible [Other Generation](#) resources used in limited amounts support a high renewables future.**
  - The strategic use of *Other Generation* resources during brief periods of low-solar and low-wind production significantly reduced the storage, solar, and wind capacities used to serve Minnesota’s hourly load. As a result, the generation cost for 70% solar and wind was reduced by nearly half.
4. **Storage is an important part of a high renewables future; it expands the dispatch capabilities of wind and solar assets.**
  - Sufficient quantities of storage smooth out the intra-hour variability of solar and wind.
5. **Shifting of key flexible loads may further decrease generation costs.**
  - Load shifting of new electric vehicle and residential domestic hot water loads demonstrated a potential 10-20% decrease in generation costs. While these figures are promising, results demonstrate further study is necessary.

## Scope of the SPA

The electrical grid can be described in terms of its Services, Markets, and Regulations:

- 1) **Services** – The technical services that allow the grid to operate in a stable manner. Services include: energy, capacity, balancing, frequency, and voltage stability.
- 2) **Markets** – The markets that address the procurement and compensation of services.
- 3) **Regulations** – Regulations that define how resources can or cannot participate in markets, including operator protocols.

Markets and Regulations are implementation and policy instruments for the delivery of energy. The SPA is a technical analysis focused on Services. Within Services, the SPA addresses energy and capacity at the hourly level. The SPA did not address balancing, frequency, or voltage stability. Minnesota decision-makers need to consider Services, Markets, and Regulations when evaluating possible energy futures. As such, the SPA results are one part of a larger picture.

## Constraints of the SPA

**The SPA did not include integration with the Midcontinent Independent System Operator (MISO) market.** Not modeling integration with MISO allowed the SPA to estimate [generation cost](#) without speculating about the flexibility the MISO market could provide. This meant that the model did not consider opportunities to export excess solar and wind production to MISO, or to import excess solar and wind production from MISO into Minnesota. There were members of the Minnesota Solar Pathways Technical Committee who felt that *the lack of integration with MISO led to a conservative analysis with higher generation costs and resource capacities*. This belief was borne out by reduced generation costs for SPA scenarios that included [Other Generation](#) resources.<sup>3</sup>

**The SPA did not include transmission or distribution costs.** Studies evaluating the impact of increasing solar and wind on transmission costs have been done and are on-going. Studies evaluating the impact of solar and wind on distribution costs in Minnesota are needed. With regard to transmission costs, two key studies worth noting are Minnesota Renewable Energy Integration and Transmission Study (MRITS)<sup>4</sup> and MISO's Renewable Integration Impact Assessment (on-going). *The MRITS study assumed integration with MISO and found that "the addition of wind and solar (variable renewable) generation to supply 40% of Minnesota's annual electric retail sales can be reliably accommodated by the electric power system" and that*

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<sup>3</sup> Allowing *Other Generation* resources to ramp-up during periods of low solar and wind production is similar to using the surrounding MISO region as a generation resource.

<sup>4</sup> Minnesota Renewable Energy Integration and Transmission Study. <http://mn.gov/commerce-stat/pdfs/mrits-report-2014.pdf> Oct 31, 2014.

*“further analysis would be needed to ensure system reliability at 50% of Minnesota’s annual electric retail sales from variable renewables.”*

**The SPA did not include a resource adequacy model.** Existing resource adequacy models in common use today do not holistically examine solar, wind, and storage resources. The strategic combination of solar, wind, and storage resources to provide generation capacity is currently not considered. *Improved resource adequacy models are needed to fairly evaluate the resource adequacy of combinations of solar, wind and storage resources.*

**The SPA did not address rate structures.** SPA generation costs are derived from installation and operating costs and do not consider market payments and/or customer rate structures. *The next model being developed under the Pathways initiative, the Solar Deployment Strategy, will evaluate the effect of rate structures and their impacts on value propositions of different solar deployment scenarios.*

## Use of SPA Results

At the highest-level the SPA results indicate that solar, wind, and storage resources can reasonably and cost-effectively serve a majority of Minnesota’s load. As such, the SPA results can change the way solar, wind, and storage are evaluated as part of Minnesota’s energy future – a process that many energy stakeholders in Minnesota have already identified as a need.

The SPA results provide important insights into the solar, wind, and storage capacities required to achieve a future where solar and wind served 70% of Minnesota’s annual load. Under a 70% scenario, the SPA results suggest that Minnesota could expect to have tens of GW of solar and wind with just tens of GWh of storage capacity; not 1000’s of GWh of storage capacity. In this way, the SPA results can be used *along with other studies* as decision-makers and stakeholders anticipate and plan for expanded solar, wind, and storage capacities.

The SPA results also highlight the future need for discussion about solar and wind compensation policies that account for [Additional Capacity](#) coupled with energy curtailment. To this end, the SPA results can be used to explore this important issue before it is pressing. Note that the Pathways project is agnostic on the numerous potential solutions, but rather raises this as a point of discussion. Early discourse will prove valuable since any new compensation policies will ultimately need to move through a regulatory process.

Finally, the SPA results provide some insight into the effect of different solar distributions on Minnesota’s possible energy futures. However, a deeper analysis is needed. The second phase of the Minnesota Solar Pathways project seeks to undertake such an analysis through the development of the Solar Deployment Strategies modeling tool, which will consider the value propositions of different solar deployment scenarios in addition to costs.

## SPA Terminology

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The Minnesota Solar Pathways project is focused on bringing together a diverse set of stakeholders (cities, corporations, non-profits, consumer representatives, solar installers, and electric utilities). And while that diversity of opinion is one of the project's greatest strengths, it also creates a challenge when we use different words to mean the same thing or the same words to mean different things – as has happened on occasion during the Minnesota Solar Pathways project.

Throughout this report we have sought to use clear and consistent language. Additionally, we define key terms or concepts in call-out boxes. A few of these are below. They are provided not only as an example, but as key terms which have already been used in the Executive Summary.

**Dispatchable generation** generally refers to the ability of a generation resource to flexibly respond to match the load shape in real time. While dispatch is a technical term with specific meaning for different groups, in practice all generation exhibits both some degree of dispatchability and limits on that dispatchability. For example subject to some limitations, utility-scale solar and wind generation resources are already dispatching into energy markets around the country.

*The aim with the use of the term dispatch is to highlight the increased flexibility and expanded dispatch capabilities of the solar and wind resources when paired with the strategies implemented in the SPA.*

**Additional Capacity** is solar and wind capacity over and above that needed to meet annual energy needs but still beneficial for improving the economic dispatchability of the solar/wind fleet.

**Other Generation resources** are non-solar and non-wind resources in Minnesota that meet a portion of the Hourly Production Requirements during brief periods of low-solar and wind resources.

If the SPA had included integration with MISO, solar and wind resources outside of Minnesota would have also been considered 'other generation' resources

**Generation Cost** includes the installation and operational costs of solar, wind, and storage resources plus the operational costs of *Other Generation* resources.

## What is *Additional Capacity*?

The Solar Potential Analysis (SPA) uses the concept of *Additional Capacity* to describe the capacity needed to cost effectively maximize the dispatchability of solar and wind energy. The “addition” is measured from the amount of capacity needed to meet annual solar production targets (10% by 2025 or 70% solar/wind by 2050). Additional solar and wind is capacity designed to ensure sufficient generation when solar or wind resources are low - such as cloudy days or near sunrise or sunset or calm days.

**Peaks and Valleys.** All generating capacity that serves a peaking or balancing function, such as a “peaking plant,” may be operated intermittently, even only a few times over a year. Peaking plants are “additional” generation capacity that serves a specific peaking function. Even though these facilities are idle for long periods of time, we do not consider them as “overbuilt,” nor do we say that we are “curtailing” the output of the power plant when the plants are not running. Peaking plant capacity has a critical grid function that enables the most cost effective deployment of other resources.

Additional solar or wind capacity similarly serves a critical function on the grid; producing energy at the needed time, as does a peaking plant. But instead of filling the need for more production when demand peaks, *Additional Capacity* fills the need for more production when solar and wind resources are low, effectively filling a valley.

Energy storage could be used in place of *Additional Capacity*, but the *Additional Capacity* is a cheaper solution than building more energy storage to perform the same peak/valley grid function.

**Curtailement.** *Additional Capacity* means additional energy and most likely curtailment. During periods of high solar and wind production, energy production greater than load will exist. Energy not utilized will be curtailed. However, it will be economical to curtail this excess energy due to the low cost of solar and wind production.

## MN Solar Pathways Overview

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Minnesota is a longstanding, nationally recognized leader in energy efficiency and wind development. In recent years, Minnesota has established leadership in solar deployment as well, including hosting the most community solar capacity in the country<sup>5</sup> and a 1.5% solar energy standard.<sup>6</sup> The State also adopted a goal of meeting 10 percent of the state's electricity needs with solar by 2030.<sup>7</sup>

The Minnesota Solar Pathways (Pathways) initiative, sponsored by the U.S. Department of Energy Solar Energy Technologies Office<sup>8</sup>, is a three-year project designed to explore least-risk, best-value strategies for meeting the State of Minnesota's solar goals. As part of this aim, the Pathways Team is modelling renewable generation costs, examining ways to streamline interconnection, and evaluating technologies that can increase solar hosting capacity on the distribution grid.

The Pathways Team is comprised of a Core Team and a Technical Committee. The Core Team consists of MN Department of Commerce (Commerce), Center for Energy and Environment (CEE), Clean Energy Resource Teams (CERTS), Clean Power Research (CPR), and the Great Plains Institute (GPI). The Technical Committee is the foundation for the project's stakeholder collaboration process and is comprised of the 22 organizations. These organizations include cities, corporations, non-profits, consumer representatives, solar installers, and utilities. See Figure 1 for a list of organizations involved.

### Responsibilities of the Core Team and the Technical Committee

To accomplish the Pathways goals, each of the five organizations making up the Core Team takes a lead role in various aspects of the project.

- Commerce is the project manager and fiscal agent responsible for reporting to the U.S. Department of Energy.
- The Great Plains Institute is the lead facilitator for the Technical Committee and other stakeholder work.
- Clean Power Research is responsible for the development of two models and leads all technical work with input from the Technical Committee.

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<sup>5</sup> Morehouse, Catherine. Minnesota community solar hits 400 MW. Utility Dive. <https://www.utilitydive.com/news/minnesota-community-solar-hits-400-mw/531305/>. Aug 2018.

<sup>6</sup> Minn. Stat. § 216B.691.

<sup>7</sup> *ibid.*

<sup>8</sup> The U.S. Department of Energy Solar Energy Technologies Office supports early-stage research and development to improve the flexibility and performance of solar technologies that contribute to a reliable and resilient U.S. electric grid. Learn more at [energy.gov/solar-office](https://energy.gov/solar-office).



- Center for Energy and Environment is the lead on quality control and supports Clean Power Research with data needs.
- Clean Energy Resource Teams is the lead partner responsible for communications including dissemination of project results and outreach.

Technical Committee members received and agreed to numerous conditions for participation, including meeting bi-monthly throughout the project to inform technical decisions that form the basis of the modeling. Members work collaboratively to make recommendations regarding inputs and variables to strengthen project results. The Technical Committee was instrumental in defining the scenarios and informing the analysis described in this report.

Figure 1. MN Solar Pathways Core Team and Technical Committee.

### Core Team



### Technical Committee



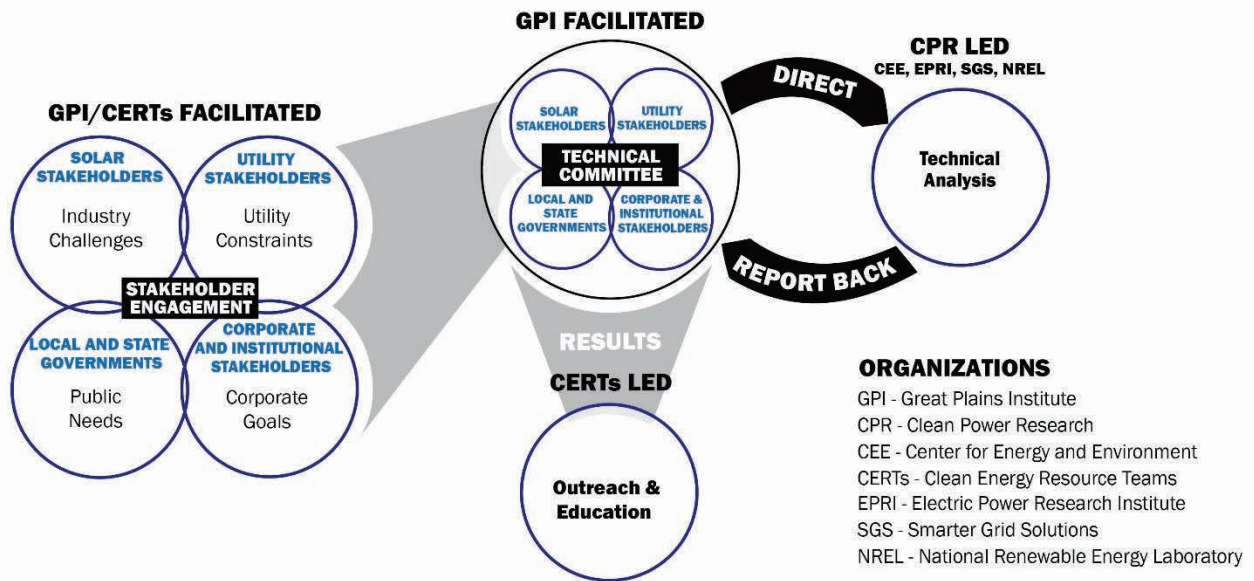
### Technical Analysis



Although the Technical Committee often reached agreement on key project inputs and recommendations, consensus was not a primary goal as modelling allowed for multiple scenarios to be run and compared.

The process for taking input and developing the SPA model was iterative as the Core Team completed work with input from the Technical Committee and reported back. See Figure 2 for the various roles and structure for completing technical work under Pathways.

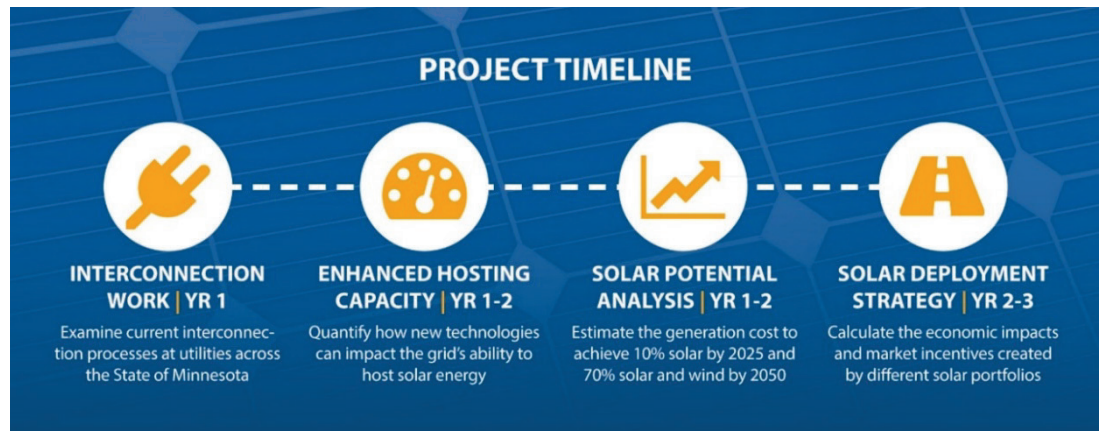
Figure 2. Organization of the MN Solar Pathways Project.



## Technical Analyses and Reports

In addition to this report, the MN Solar Pathways includes three other technical analyses that address: interconnection; hosting capacity; and solar deployment strategies. The timeline and scope of these technical analyses are described in Figure 3. Assessing Opportunities and Challenges for Streamlining Interconnection Processes<sup>9</sup> was published in December 2017, and the Enhanced Hosting Capacity<sup>10</sup> report was published in October 2018. For Pathways reports and more information on these studies please visit: [mnsolarpathways.org](http://mnsolarpathways.org).

Figure 3. Timeline and Scope of MN Solar Pathways Technical Analyses.



<sup>9</sup> Electric Power Research Institute. Assessing Opportunities and Challenges for Streamlining Interconnection Processes. <http://mnsolarpathways.org> December 2017.

<sup>10</sup> Smarter Grid Solutions. Enhanced Hosting Capacity Analysis. <http://mnsolarpathways.org>. October 2018.

## Solar Potential Analysis (SPA)

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The SPA is a modeling tool that estimates the generation costs and resource capacities (e.g., solar and storage capacity) to serve a specified percentage of Minnesota's electrical load with given production requirements (e.g., production that matches the day-ahead forecast).

### Goal of the SPA

The goal of the SPA is to ask and answer questions related to the deployment of increasing amounts of solar (and wind) energy. Such questions include:

- What range of generation costs might we expect to serve a percentage of Minnesota's load with solar? With solar and wind?
- What resource capacities (solar, wind, and storage) would be required under various deployment scenarios?
- Can the strategic combination of solar, wind and energy storage provide load-following generation?
- How does electrification of transportation and heating impact generation costs?
- Can load shifting reduce generation costs?

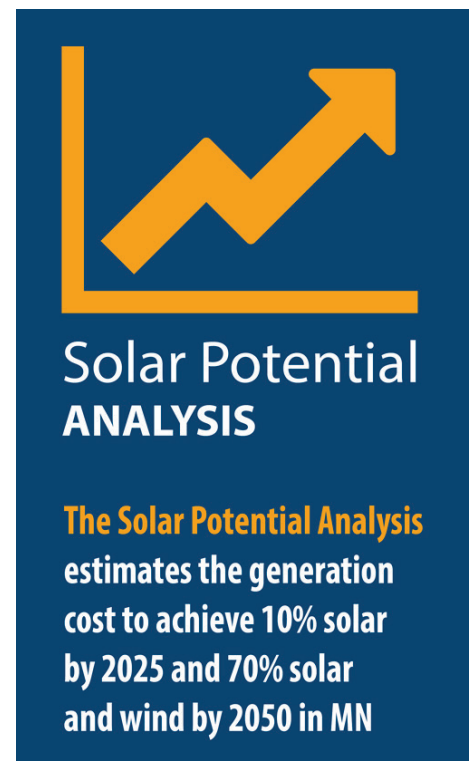
By answering these questions the SPA provides key insights for transforming solar and wind generation into [dispatchable generation](#) resources that can ultimately be relied on to serve load for nearly every hour of the year.

### How the Pathways Team Used the SPA

The Pathways Team used the SPA to model the generation cost (in \$/MWh) to achieve 10% of Minnesota's electricity from solar by 2025 and 70% of Minnesota's electricity from solar and wind by 2050.

The Pathways Team modeled a number of different scenarios using the SPA to identify a range of generation costs and resource capacities for the 10% and 70% targets of interest.

In particular, the Pathways Team used the SPA to evaluate scenarios with different: 1) future technology costs; 2) solar distributions; 3) production requirements; and 4) levels of electrification and load shifting (not present in all scenarios). Notably, future technology costs and production requirement inputs significantly affected modeled generation costs and resource capacities.



The graphic features a blue background with a white line graph showing an upward trend with a dip, and a large orange arrow pointing up and to the right. Below the graph, the text reads: **Solar Potential ANALYSIS**. Underneath that, in orange and white text, it says: **The Solar Potential Analysis estimates the generation cost to achieve 10% solar by 2025 and 70% solar and wind by 2050 in MN**.

## How the SPA Operates

**SPA Analysis.** The SPA is an optimization tool that contains two key components: 1) an hourly energy balance containing resource dispatch algorithms and 2) an economic engine to calculate the system-wide generation cost of a given amount of solar, wind, and storage capacity.

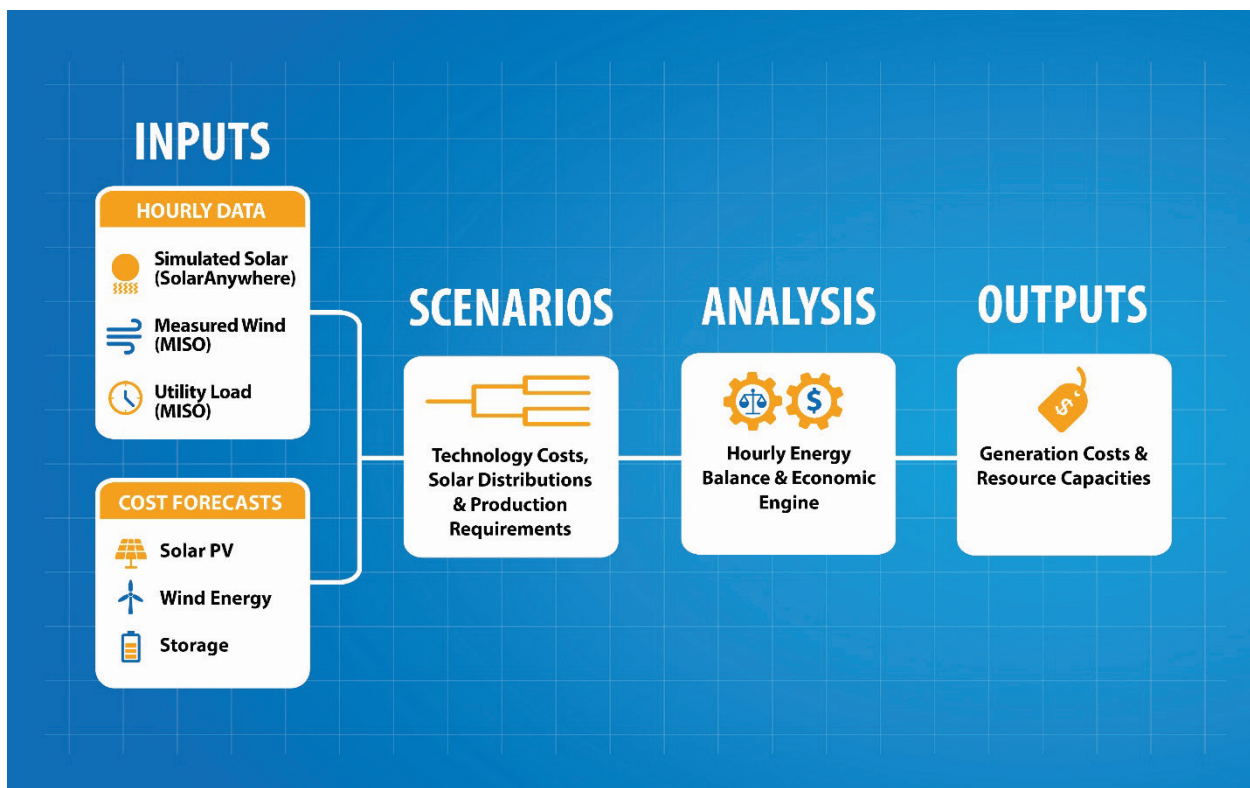
The SPA operates by first finding sets of resource capacities that will satisfy the specified production requirements on an hourly basis. For example, the SPA may find that a specified production requirement can be satisfied by 1 GW of solar, 1 GW of wind, and 3 GWh of storage and also by 2 GW of solar, 2 GW of wind, and 1 GWh of storage.

Having found sets of resource capacities that satisfy the specified production requirements, the SPA's economic engine then evaluates the generation cost of the different sets of resource capacities.

As a final step, the SPA then searches through the sets of resource capacities to find the set of resource capacities with the lowest generation cost.

The detailed operation of the SPA involves iteratively solving the hourly energy balance to produce 100 to 1000's of sets of resource capacities that satisfy the specified production requirements.

Figure 4. Overview of the Solar Potential Analysis.



**SPA Inputs.** The SPA uses three different types of inputs: hourly data; cost forecasts; and electrification and load shifting data (not included in all analyses and not shown in the graphic). Hourly data and cost forecasts are described in detail in [SPA Data Inputs](#). Electrification and load shifting data are described in detail in [Appendix B: Electrification and Load Shifting Models](#).

**SPA Scenarios.** As previously noted, the Pathways Team evaluated a number of scenarios with the SPA. These scenarios were comprised of different assumptions about 1) future technology costs, 2) solar distributions, 3) production requirements, and 4) levels of electrification and load shifting (not present in all scenarios). Further description of the different SPA scenarios is provided in [SPA Scenarios](#).

**SPA Outputs.** The key SPA outputs were generation cost (on a levelized cost of energy basis) and resource capacity (solar, storage, and wind). Another key SPA metric was the amount of energy curtailment. Additional SPA outputs, including optimization curves, hourly dispatch profiles, and ramp rate distributions, are discussed in [Appendix E: Additional SPA Datasets](#).

**The levelized cost of energy (LCOE) reflects the payment (in \$/MWh of delivered energy) an entity outlaying capital to build generation resources would require to break-even if they financed the system at a given cost of capital.**

### Electrification and Load shifting in the SPA

The SPA was capable of evaluating the impact on generation cost and resource capacities from the potential electrification of energy end-uses not currently power by electricity. The SPA was additionally capable of evaluating the potential for load shifting to reduce generation cost and resource capacities.

The Pathways Team chose to evaluate the potential electrification and load shifting of three such energy end-uses: Electric Vehicles (EVs), Domestic Hot Water (DHW) and HVAC (Heating, Ventilation and Air Conditioning).



Each of these technologies added a unique electric load profile to the existing Minnesota load, as detailed in [Appendix B: Electrification and Load Shifting Models](#).

Furthermore, each of these technologies had its own load shifting capabilities as defined by end-user needs, its technical specifications, and (in the case of HVAC) the weather.

## SPA Scope

The SPA scope is focused on estimating generation costs of increased levels of solar and is intended to complement prior studies. The SPA assumptions were developed with stakeholder input from the Technical Committee and refined by the Core Team. There are a few notable aspects of the SPA scope as discussed below:

- **The SPA is designed to provide insights, not decisions. The SPA is not a resource plan.**
  - The SPA does not perform an economic dispatch analysis to determine the specific assets that should be built or the economic returns that specific assets could expect. Rather, the SPA finds sets of resources that meet the specified production needs and then calculates the generation cost of the entire set of resources, including solar and storage capacities in 2025 and solar, wind, and storage capacities in 2050.
- **The SPA only considered solar and wind generation within Minnesota<sup>11</sup> and did not include integration with the MISO market.**
  - As noted earlier, excluding integration with MISO allowed the SPA to estimate generation cost without speculating about the flexibility the MISO market could provide. This meant that the model did not consider opportunities to export excess solar and wind production to MISO, or to import excess solar and wind production from MISO into Minnesota. Some members of the Minnesota Solar Pathways Technical Committee felt that the lack of integration with MISO led to a conservative analysis with higher generation costs and resource capacities. This belief was borne out by reduced generation costs for the SPA scenarios that included [Other Generation](#) resources.
- **The SPA only considers generation costs. It does not consider transmission and distribution costs.**
  - The SPA does not perform a power-flow analysis to examine whether the existing transmission and distribution infrastructure is sufficient to handle increasing penetrations of solar and wind.
  - It is important for Minnesota energy stakeholders to evaluate generation, transmission, and distribution costs when evaluating possible energy futures. As such, the SPA results are one part of a larger picture. Studies evaluating the impact of increasing solar and wind on transmission and distribution costs have been done and are on-going. With regard to transmission, two studies worth

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<sup>11</sup> Existing wind generation in North Dakota and South Dakota was considered if it was owned or contracted by Minnesota utilities.

noting are Minnesota Renewable Energy Integration and Transmission Study<sup>12</sup> and MISO's Renewable Integration Impact Assessment<sup>13</sup>.

- **The SPA calculates generation costs based on installation and operational costs, not market compensation mechanisms (e.g., rate structures).**
  - The installation and operation costs of solar, wind, and storage assets are considered.
  - The operational costs of *Other Generation* resources are considered (including fuel). The installation costs of *Other Generation* resources are not considered. It is assumed that *Other Generation* resources are already built.
  - Installation and operation costs of the load shifting resources (EVs, hot water heaters, smart thermostats) are not considered in the load shifting analysis, as discussed later.
- **The SPA accounted for Minnesota's must-run resources** (discussed in the next section).

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<sup>12</sup> GE Energy Consulting. Minnesota Renewable Energy Integration and Transmission Study. <http://mn.gov/commerce-stat/pdfs/mrits-report-2014.pdf> Oct 2014.

<sup>13</sup> An on-going study to assess possible renewable energy-driven impacts on the reliability of the electric system.

## SPA Data Inputs

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As noted above, the SPA contained two main types of data inputs: hourly data and cost forecasts. Hourly data consisted of solar production data, wind production, and Minnesota load data. Cost forecasts were used for solar, storage, and wind resources. Hourly data and cost forecasts are described in this section.

Electrification forecasts and load shifting capabilities for domestic hot water (DHW), electric vehicles (EVs), and heating, ventilation and air conditioning (HVAC) were also data inputs into the SPA. These data inputs are described in [Appendix B: Electrification and Load Shifting Models](#).

### SPA Hourly Data

#### Solar Production Data

Hourly solar irradiance and production data were obtained from [SolarAnywhere](#). SolarAnywhere is a commercial solar irradiance and weather data set produced by Clean Power Research. SolarAnywhere irradiance estimates are derived from satellite data and are available from 1998 through present.

SolarAnywhere additionally includes proprietary solar production simulation capabilities that are derived from Sandia's PV Form model (the same base model for PV Watts).

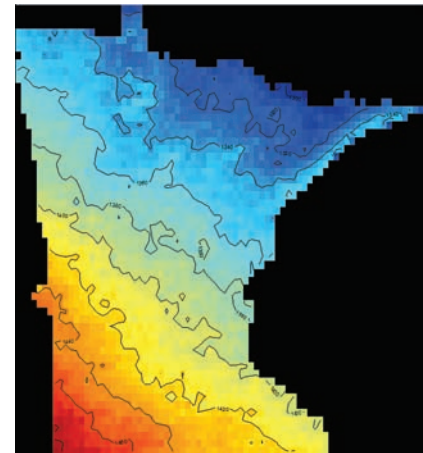
Historical solar production (2014-2016) was simulated for every tile of a 10-km grid across the State of Minnesota.

Solar systems were assumed to be south-facing with a 30-degree tilt.

#### Wind Production Data

Hourly wind production data from 2014-2016 was obtained from MISO for existing wind assets owned by Great River Energy (GRE), Minnesota Power (MP), Otter Tail Power (OTP), Southern Minnesota Municipal Power Authority (SMMPA), and Xcel Energy (Xcel).

The hourly wind production data was then combined with wind plant commissioning data from the above utilities to create a wind production profile that could be scaled to a desired wind





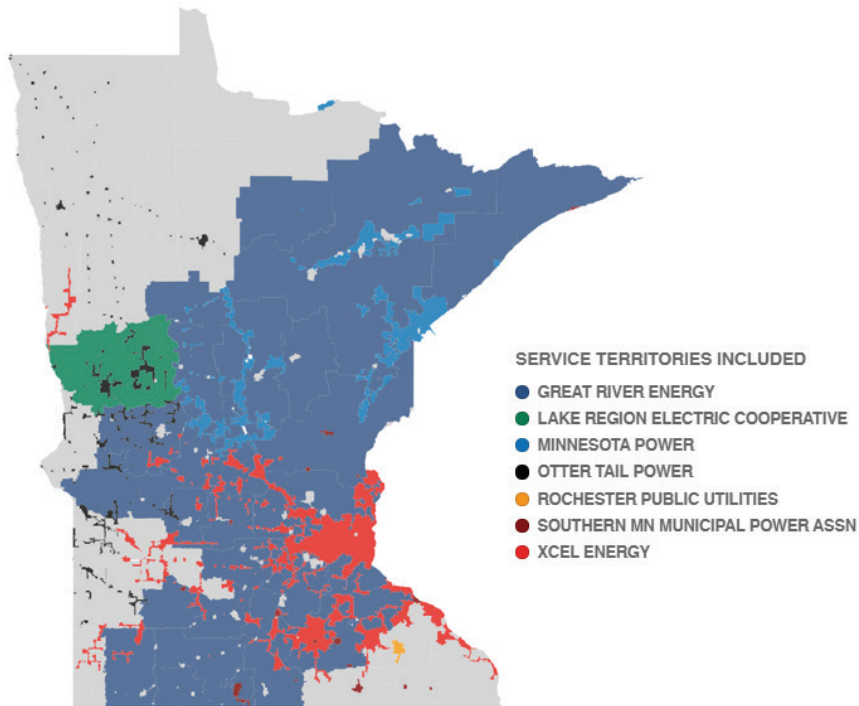
capacity. For example, the wind production data was scaled to serve 25% of Minnesota’s load for the SPA’s 2025 analyses, as previously noted.

### Minnesota Load Data

Hourly load data from 2014-2016 was obtained from MISO for five balancing areas that serve the overwhelming majority of Minnesota’s load: GRE, MP, Xcel, OTP, and SMMPA. The geographic coverage of these five balancing areas is represented below and serves 86% of electricity customers in the state<sup>14</sup>, including the state’s largest urban centers.

The aggregation of the hourly load from these balancing areas is used to represent the hourly load for the State of Minnesota.

Figure 5. Service Territories Included in Creation of Minnesota Load Data.



### Use of Historical Data

The SPA used historical production and load data. The SPA did not use typical year data.

The use of historical data enables the time-correlation of production data and load data. Time-correlation is critical for accurately capturing the impact of solar and wind production variability.

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<sup>14</sup> Minnesota Department of Commerce 2014 data.

### Must-Run Resources (2025 Only)

An indirect component of the hourly datasets described above was the identification of must-run resources. Must run resources are resources that must-run independent of the hourly load and/or solar and wind production. For example, nuclear generation resources are assumed to run at their rated production capacity.

The proper accounting of must-run resources by the SPA is important during periods of high solar and wind production and low load. During these periods, solar and wind production may exceed the load available to be served after accounting for must-run resources. As such, the SPA either stored or curtailed excess solar and wind production when these conditions occurred.

The Pathways Technical Committee determined that must-run resources were applicable in the 2025 timeframe, but that no must-run resources were applicable in the 2050 timeframe. The agreed upon must-run resources in the 2025 timeframe are provided in Table 1. Notably, as a conservative assumption, wind was included as a must-run resource in the 2025 timeframe to account for wind generation assets that have already been built or are in development. The minimum generation for wind was assumed to be its generation for the hour of interest.

Table 1. Must-Run Resources in the 2025 Timeframe.

Utility	Plant	Plant Type	Capacity (MW)	Min Gen. Cap. (MW)
Multiple	Multiple	Wind	6109	n/a
MP	Boswell 3 & 4	Coal	940	423
OTP	Big Stone	Coal	257	115
Xcel	Monticello	Nuclear	671	671
Xcel	Prairie Island	Nuclear	1100	1100
Xcel/ SMMUA	Sherco 3	Coal	876	394
Xcel	New CC <sup>15</sup>	Gas	785	353
		<b>Total (excluding wind)</b>	<b>4629</b>	<b>3056</b>

<sup>15</sup> Xcel Energy notes that its new combined cycle plan is considered a must-run resource but will likely operate in a more flexible manner.

As evident in Table 1, the different resources had different minimum generation capacities. Coal and gas resources were assumed to have minimum generation capacities equivalent to 45% of their rated production capacity, while nuclear resources were assumed to have minimum-generation capacities equivalent to their rated production capacity.

Not listed in Table 1 is Coal Creek Station, a 1,146 MW coal generation plant owned by GRE. Per its 2017 IRP, GRE is “beginning to more flexibly operate the station to match lower market prices and to provide energy when intermittent resources are not available.” Additionally, GRE has announced an accelerated depreciation schedule for Coal Creek Station that would allow it to retire as early as 2028. Given Coal Creek Station’s increased flexibility of operation and its potential retirement date near the 2025 timeframe it was not included as a must-run resource.

## Cost Forecasts

The solar, wind, and storage cost forecasts used by the SPA are provided in the [Forecasted Technology Costs](#) sub-section of the [SPA Scenarios](#) section. This section discusses the development of the SPA cost forecasts.

The SPA cost forecasts were developed based on a collection of cost forecasts provided by NREL. There were six key sources utilized for solar cost forecasts, two key sources for wind cost forecasts, and four key sources for storage cost forecasts. The sources of the cost forecasts provided by NREL are in Table 2.

Table 2. Cost Forecasting Sources.

Solar						
Source	Title & Year	Years Covered	Residential	Commercial	Community	Utility
NREL	Annual Technology Baseline - Dec 2017	2015-2050	✓	✓	n/a	✓
BNEF	New Energy Outlook - 2017	2010-2045	✓	✓	n/a	✓
ITRPV	8th Edition - 2017	2016-2027	n/a	n/a	n/a	✓
GTM	US PV System Pricing - H2 2017	2016-2023	✓	✓	n/a	✓
Lazard	LCOE 11.0 - 2017	2012-2017	✓	✓	n/a	✓
LNBL	Tracking the Sun 10 - 2017	2012-2016	✓	✓	n/a	✓

On-Shore Wind			
Source	Title & Year	Years Covered	TRG 5
NREL	Annual Technology Baseline - Dec 2017	2015-2050	✓
LNBL	Forecasting Wind Energy Costs - June 2016	2014-2030	n/a

Storage						
Source	Title & Year	Years Covered	Residential	Commercial	Community	Utility
NREL	Utility-Scale Li-ion - H2 2017	2015-2050	n/a	n/a	n/a	✓
BNEF	Li-Ion Battery Cost Forecast - 2017	2017-2030	n/a	n/a	n/a	n/a
Lazard	LCOS 3.0 - 2017	2017-2021	✓	✓	n/a	✓
GTM	US Energy Storage Monitor - Q4 2017	2014-2017	✓	✓	n/a	✓

Cost forecasts were generally not available for community solar. As such, community solar costs were assumed to fall halfway between commercial solar and utility-scale solar costs given that community solar systems are generally between commercial (50kW-500kW) and utility-scale solar (5-20 MW) systems in size and that system cost declines with system size for large PV systems.<sup>16</sup>

The storage cost forecasts were largely for Li-ion batteries, though some storage cost forecasts included costs for flow batteries. Most forecasts did not distinguish between the size/type of storage systems deployed (e.g., residential, commercial, or utility-scale). As such, the technology cost projections focused on the cost forecasts for Li-ion batteries and did not differentiate cost by battery size/type.

As a final note, the wind cost forecast from NREL's 2017 Annual Technology Baseline was for a wind resource with a weighted average wind speed of 7.5 m/s (TRG 5), which was viewed as appropriate for wind projects in Minnesota.

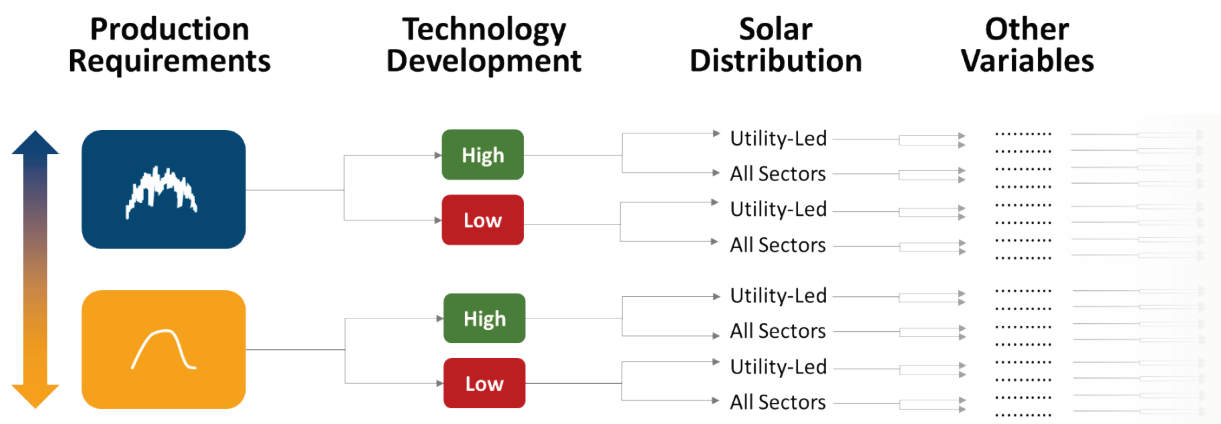
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<sup>16</sup> NREL System Cost Benchmark Q1 2016 (<http://www.nrel.gov/docs/fy16osti/66532.pdf>)

## SPA Scenarios

The Pathways Team used the SPA to evaluate scenarios with different: 1) Production Requirements; 2) future technology costs and adoption levels (collectively, Technology Development); and 3) Solar Distributions. Notably, future technology costs and Production Requirements significantly affected modeled generation costs and resource capacities.

Figure 6. Construction of SPA Scenarios from Choice of Production Requirements, level of Technology Development, and Solar Distribution.



Having produced SPA results from the initial set of scenarios, two sensitivity studies were conducted on two of the SPA scenarios. The first sensitivity study examined the change in the SPA results if Minnesota load was served with *Other Generation* resources during periods of low solar and low wind production. The second sensitivity study examined the effect of the cost of capital on the SPA results.

Note, the SPA scenarios studied were developed by the MN Solar Pathways Core Team in coordination with the Technical Committee. The Core Team presented to the Technical Committee the different components that would comprise the SPA scenarios studied (namely Production Requirements, level of Technology Development, and Solar Distribution) and then worked with the Technical Committee to develop the initial set of SPA scenarios to be modelled.

### Production Requirements

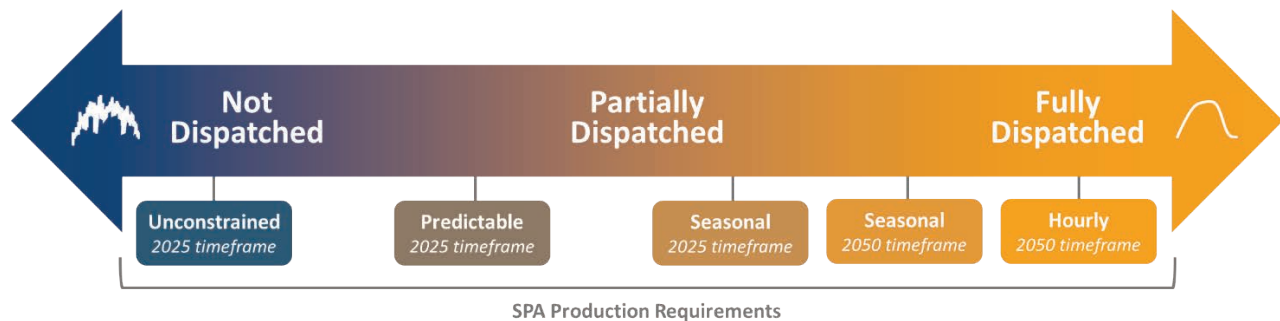
The choice of production requirements strongly influences the SPA’s calculated generation cost and resource capacities. As such, the production requirements selected by the Pathways Team were an important part of the process for bounding the generation cost and resource capacities to achieve the 10% and 70% targets of interest in the 2025 and 2050 timeframes, respectively.

**Dispatchable generation** generally refers to the ability of a generation resource to flexibly respond to match the load shape in real time. While dispatch is a technical term with specific meaning for different groups, in practice all generation exhibits both some degree of dispatchability and limits on that dispatchability. For example subject to some limitations, utility-scale solar and wind generation resources are already dispatching into energy markets around the country.

*The aim with the use of the term dispatch is to highlight the increased flexibility and expanded dispatch capabilities of the solar and wind resources when paired with the strategies implemented in the SPA.*

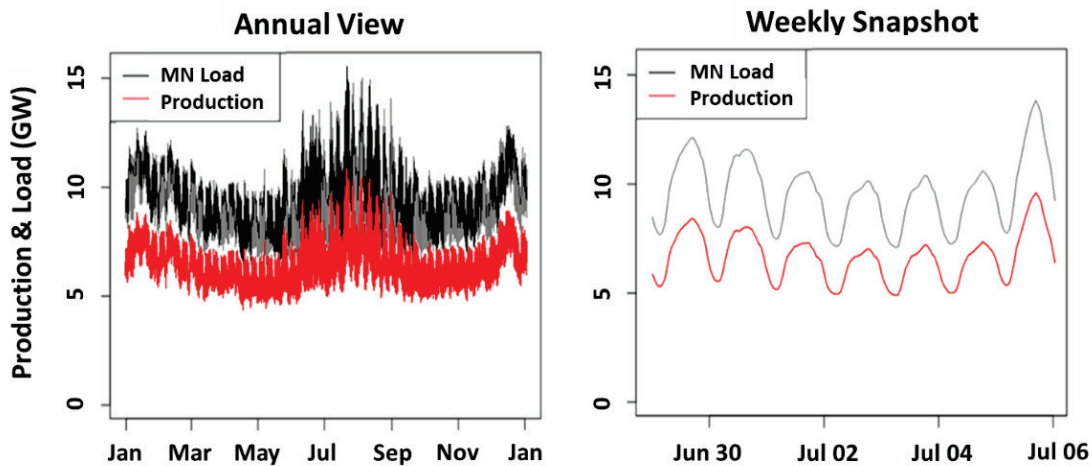
The Pathways Team selected production requirements that represented a range of production dispatchability – from a set of production requirement with almost no dispatchability (‘Unconstrained’ production requirements) to a set of production requirements that was nearly fully dispatchable (the ‘Hourly’ production requirements). The full list of production requirements studied and their relative dispatchability are shown in Figure 7. These production requirements are also discussed in detail in [Appendix A: Production Requirements](#).

Figure 7. Dispatchability of SPA Production Requirements.



As an illustrative example, the ‘Hourly’ production requirements are shown in Figure 8. For the Hourly production requirements, solar, wind, and storage are tasked with guaranteeing delivery of a constant percent (e.g., 70%) of Minnesota’s load for each hour of the year.

Figure 8. Illustration of Solar, Wind, and Storage Production Requirements ('Hourly' Production Requirements are shown).



## Technology Development

Clean Power Research developed high and low Technology Development scenarios for both the 2025 and 2050 timeframes. Each of these Technology Development scenarios contained forecasted technology costs and forecasted technology adoption components.

### Forecasted Technology Costs

Technology cost forecasts were developed as described in the [Cost Forecasts](#) sub-section of the [SPA Data Inputs](#) section. The forecasted technology costs are shown in Table 3 for the 2025 and 2050 timeframes.

Table 3. SPA Technology Costs for the 2025 and 2050 Timeframes.

#### 2025 Timeframe:

Technology Development Scenario	Residential PV (\$/kW)	Commercial PV (\$/kW)	Community PV (\$/kW)	Utility PV (\$/kW)	Wind (\$/kW)	Storage (\$/kWh)
High	\$1,250	\$1,000	\$875	\$750	\$1,250	\$175
Low	\$1,600	\$1,500	\$1,250	\$1,000	\$1,600	\$400

#### 2050 Timeframe:

Technology Development Scenario	Residential PV (\$/kW)	Commercial PV (\$/kW)	Community PV (\$/kW)	Utility PV (\$/kW)	Wind (\$/kW)	Storage (\$/kWh)
High	\$750	\$600	\$500	\$400	\$1,070	\$100
Low	\$1,250	\$1,000	\$850	\$700	\$1,500	\$300

### Technology Cost Forecast FAQ

**Do the Cost Forecasts include either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC)?**

The cost forecasts do not include an ITC or PTC – they are unsubsidized costs. Additionally, the SPA does not include an ITC or PTC.

**Are the Cost Forecasts in Real or Nominal dollars?**

The cost forecasts are in nominal (aka current) dollars.

### Forecasted Technology Adoption

Technology adoption forecasts for domestic hot water, domestic heating, ventilation and air conditioning, and electric vehicles were developed by the Center for Energy and Environment (CEE), as described in [Appendix B: Electrification and Load Shifting Models](#). CEE based its adoption projections on current penetrations, published growth projections from a number of sources, and an aggressive electrification campaign for the high adoption estimates.

Forecasted technology adoption is provided in Table 4 for the 2025 and 2050 timeframes. The adoption forecasts assume significant electrification of residential heating and transportation loads over time.

Table 4. SPA Technology Adoption for the 2025 and 2050 Timeframes.

#### 2025 Timeframe:

Technology Development Scenario	Technology Deployment (# Units)		
	Hot Water	HVAC	EVs
High	330,000	433,000	110,000
Low	140,000	289,000	32,500

#### 2050 Timeframe:

Technology Development Scenario	Technology Deployment (# Units)		
	Hot Water	HVAC	EVs
High	2,807,000	1,579,000	4,930,000
Low	600,000	789,000	349,000

### Solar Distribution

The solar distribution scenarios consist of two components. The first component is the type of the solar, and the second is the spatial allocation of the solar. The spatial allocation of solar depends partly on the type of solar. For example, utility solar has siting limitations that differ from rooftop solar and community solar.



### Type of Solar

Clean Power Research developed two solar scenarios using results from its Technical Committee survey and Technical Committee feedback on draft scenarios. In the first scenario, the Utility-Led scenario, most of the solar capacity comes from utility solar. In the second scenario, the All Sectors scenario, each type of solar (residential, commercial, community, and utility) makes a meaningful contribution to the overall solar capacity. The percentage of solar capacity in each solar sector is provided in Table 5 for the Utility-Led and All Sectors scenarios.

Sector	Scenario	
	Utility-Led	All Sectors
Residential	5%	15%
Commercial	5%	25%
Community	20%	25%
Utility	70%	30%

Table 5. Solar Capacity by Type of Solar for the Solar Distribution Scenarios.

### Spatial Allocation of Solar

The Core Team surveyed the Technical Committee for key factors related to the deployment of solar capacity within Minnesota. Through the survey and discussions at the Technical Committee meeting, the following key factors were identified:

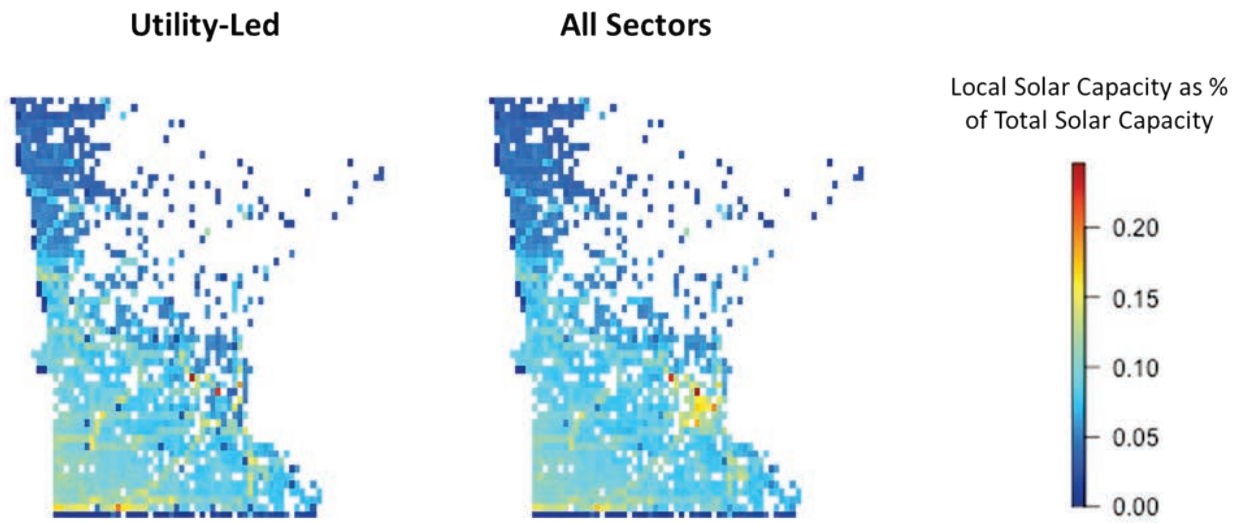
- Population density
- Proximity to transmission
- Annual irradiance
- Exclusion of wetlands, forest, and open-water

Population density was identified as a key factor since residential and commercial solar capacity is located on the customer’s property. Proximity to transmission was identified as a key factor for utility-scale solar since it is connected to the transmission grid and thus should be located close to existing transmission capacity if possible. The average annual irradiance was included because of its direct effect on the economic value of the solar asset. Lastly, wetlands, forest, and open-water were excluded given the sensitive nature of these land types.

Once these key factors were determined, Clean Power Research developed a spatial allocation algorithm for the Utility-Led and All-Sectors scenarios, as detailed in [Appendix D: Spatial Allocation of Solar](#).

Using the algorithm the solar spatial allocations shown in Figure 9 were developed. For the Utility-Led spatial allocation, more of the solar capacity is in southwestern Minnesota. For the All-Sectors spatial allocation, much of the solar capacity is in the Minneapolis Saint Paul metropolitan area.

Figure 9. Spatial allocation of solar for the Utility-Led and All Sectors scenarios.



## SPA Results

The SPA work produced an extensive set of results. The final results included nearly 100 scenarios, each of which has associated hourly datasets and key summary criteria.

In this section, we discuss:

- 2025 SPA Results
- 2050 SPA Results
- Electrification and Load Shifting

### 10% Solar by 2025

Table 6 presents SPA results for the 2025 timeframe. Two levels of Technology Development (High and Low); three sets of Production Requirements (Unconstrained, Predictable, and Seasonal); and two Solar Distributions (Utility-Led and All Sectors) were studied. Key results include: generation cost (\$/MWh), solar capacity (GW), and storage capacity (GWh). As a reminder, the reported generation cost is a levelized cost of energy that is calculated based on the set of resources (solar, wind, and storage) required to guarantee delivery of the specified production requirements.

Table 6. Key SPA Results in the 2025 Timeframe.

2025 Timeframe: 10% Solar Generation					
Tech. Development Scenario	Production Requirements	Solar Distribution Scenario	Generation Cost (\$/MWh)	PV Capacity (GW)	Storage Capacity (GWh)
High	Unconstrained	Utility-Led	33	5.3	0
		All Sectors	38	5.3	0
	Predictable	Utility-Led	38	5.9	1.5
		All Sectors	44	5.7	2.3
	Seasonal	Utility-Led	88	11.1	13.7
		All Sectors	98	11.0	14.8
Low	Unconstrained	Utility-Led	46	5.3	0
		All Sectors	55	5.3	0
	Predictable	Utility-Led	56	5.9	1.5
		All Sectors	66	5.9	1.5
	Seasonal	Utility-Led	129	13.7	3.2
		All Sectors	153	13.9	3

**Unconstrained Production Requirements impose only a single constraint on the production from solar resources: the solar production cannot exceed the Minnesota load after subtracting out the must-run resources.**

**Predictable Production Requirements are similar to the Unconstrained Production Requirements but impose an additional constraint to account for day-ahead production forecasting error.**

**Seasonal (2025) Production Requirements allow for the seasonal variability of the solar resource but requires that solar and storage smooth out the daily variability of solar to match the expected seasonal production of the resource.**

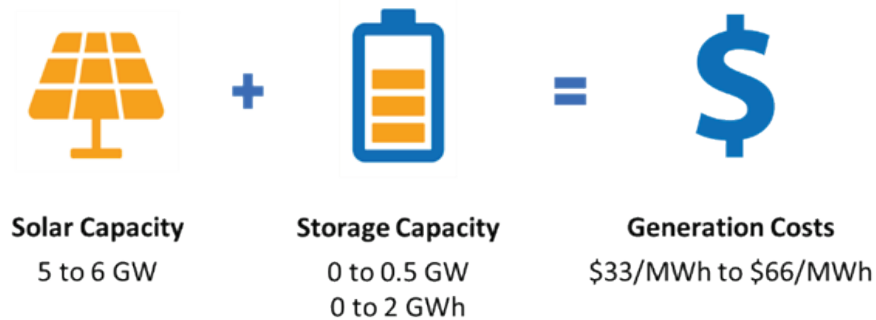
**The SPA results for the Seasonal Production Requirements are presented in light-grey to deemphasize their relevance in the 2025 timeframe.** This was a decision made by the Core Team after realizing that the Seasonal SPA results were heavily influenced by periods of low-solar production. (This dependence was also found for the 2050 SPA results as discussed in the next section). While this is appropriate at high-penetrations of solar and wind generation, it is not relevant at a 10% solar penetration where existing generation resources could be utilized during a multi-day period of low solar production.

Examining Table 6 we note the following:

- As expected, generation cost and resource capacities increased slightly between scenarios with Unconstrained Production Requirements (with no storage requirements) and scenarios with Predictable Production Requirements (increased dispatchability with solar plus storage sufficient to meet the day ahead hourly forecast and any shortfall in actual production).
- 6 GW of solar capacity and 2 GWh of storage capacity would enable solar to meet its day-ahead forecasted production.
- Generation costs are 15%-20% higher when comparing All Sectors scenarios with their Utility-Led counterparts.

Overall, the 2025 SPA results indicate that Minnesota could achieve its statutory but non-binding goal of 10% solar by 2030 at a cost that is comparable with natural gas generation costs (see [Appendix I: Cost of Natural Gas Generation Resources](#)). Note, this is not to say that the sets of solar and storage resources above can be dispatched in a manner equivalent to a natural gas generation resource or vice-versa.

### 10% Solar by 2025:



### 70% Solar and Wind by 2050

In this section, we present 2050 SPA results with and without *Other Generation* resources and discuss four of the five key findings from the 2050 SPA results. The fifth key finding is discussed in [Electrification and Load Shifting](#).

#### 2050 SPA Results without *Other Generation* Resources

Table 7 presents SPA results for the 2050 timeframe. Two levels of Technology Development (High and Low); two sets of Production Requirements (Seasonal and Hourly); and two Solar Distributions (Utility-Led and All Sectors) were studied.

Table 7. 2050 SPA Results without *Other Generation* Resources.

2050 Timeframe: 70% Solar and Wind Generation; No <i>Other Generation</i> Resources					
Tech. Development Scenario	Production Requirements	Solar Distribution Scenario	Generation Cost (\$/MWh)	Energy Curtailment (%)	Storage Capacity (GWh)
High	Seasonal	Utility-Led	56	32%	221
		All Sectors	59	26%	244
	Hourly	Utility-Led	64	53%	195
		All Sectors	67	54%	181
Low	Seasonal	Utility-Led	121	60%	97
		All Sectors	131	49%	153
	Hourly	Utility-Led	128	54%	181
		All Sectors	132	54%	184

**Seasonal (2050) Production Requirements are similar to the Seasonal (2025) Production Requirements but blend in a portion of Minnesota’s hourly load.**

**Hourly Production Requirements require solar, wind, and storage to follow Minnesota’s hourly load, independent of hourly solar and wind production..**

Generation costs for the High Technology Development scenarios are comparable to or slightly higher than natural gas generation costs under a range of fuel and capital costs (see [Appendix I: Cost of Natural Gas Generation Resources](#)). Generation costs for the Low Technology Development scenario are roughly twice natural gas generation costs.

As expected, an increase in generation cost (5-10%) was observed between scenarios with Seasonal Production Requirements (seasonally dispatchable) and scenarios with Hourly Production Requirements (dispatchable). The Pathways Team elected to focus on the Hourly Production Requirements as being of most interest given the ultimate need to serve Minnesota’s hourly load.

Similar to the 2025 SPA results, the All Sectors scenarios exhibited higher generation costs than their Utility-Led counterparts. However, the optimization across solar, storage *and* wind in the 2050 results meant that the SPA could utilize more wind and less solar in the All Sectors scenario than in the Utility-Led scenarios. This resulted in generation costs that were only slightly higher (~5%) for the All Sectors scenarios in 2050.

The most notable results in Table 7 are the storage capacity and energy curtailment. The SPA found the optimal storage capacity to be roughly 200 GWh (about 20 hours of Minnesota’s average load). This is a significant amount of storage capacity but at the same time one-hundred fold less than existing studies of 100% renewable energy suggest<sup>17</sup> (i.e., storage capacity equivalent to weeks of load). The SPA also found that energy curtailment is key to minimizing generation costs. As discussed below, this is because energy curtailment significantly reduces the need for storage capacity.

**Key Finding #1: Additional Capacity coupled with energy curtailment is considerably less expensive than, and a viable alternative to, long-term or seasonal storage in a high renewables future.**

A key finding of the 2050 SPA results is that *Additional Capacity* coupled with energy curtailment is an important strategy in a high renewables future. Figure 10 illustrates the effect of energy curtailment on the 2050 SPA generation cost.

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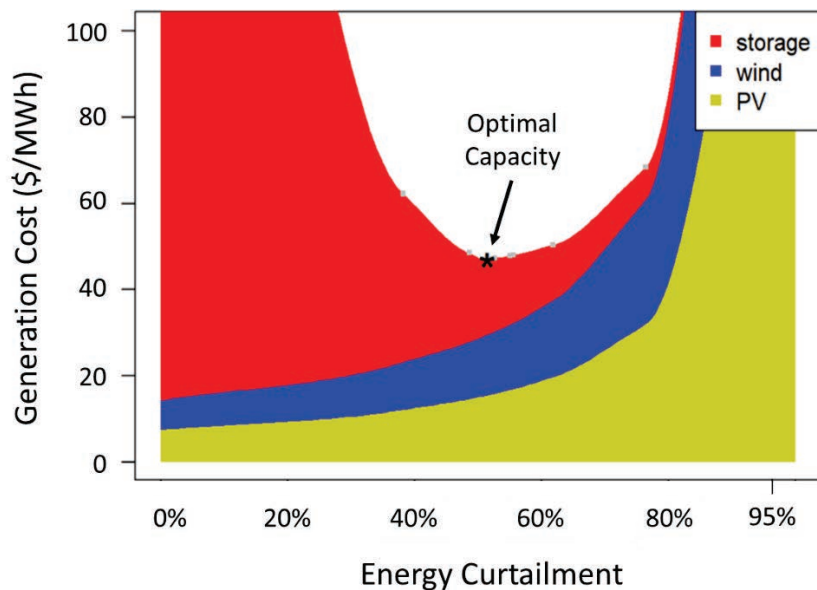
<sup>17</sup> Roberts, David. “Is 100% renewable energy realistic? Here’s what we know.” *Vox*. Feb. 7<sup>th</sup> 2018. <https://www.vox.com/energy-and-environment/2017/4/7/15159034/100-renewable-energy-studies>

**Additional Capacity** is solar and wind capacity over and above that needed to meet annual energy needs but still beneficial for improving the economic dispatchability of the solar/wind fleet.

As the SPA adds solar and wind capacity, their respective generation costs increase. However, **as additional solar and wind capacity are added, storage capacity (and storage capacity costs) significantly decrease.** The net effect is that the total generation cost (the SPA generation cost) initially decreases as additional solar and wind capacity are added, levels as the optimal set of capacities is reached, and finally rises as the cost increases associated with additional solar and wind capacity outpace the cost reductions associated with storage capacity. For the Hourly Production Requirements the SPA generation cost-minimum occurs around 50% energy curtailment, due in part to the stringent requirements of the Hourly Production Requirements.

The results shown are for Hourly Production Requirements with High Technology Development and a Utility-led Solar Distribution. However, similar results were found for Hourly Production Requirements using Low Technology Development scenarios and All Sector Solar Distribution scenarios.

Figure 10. Influence of *Additional Capacity* coupled with Energy Curtailment on Generation Cost and Resource Deployment.



*Additional Capacity* coupled with energy curtailment is a strategy that runs counter to the goal of sizing renewable capacity in a manner that avoids ‘wasting’ it. However, designing for 100% use of renewable energy would require a storage capacity sufficient to shift a large quantity of energy over a seasonal time-period (as shown in [Appendix J: Benefits of Additional Capacity](#)).

By contrast, energy curtailment alleviates the need to seasonally shift renewable energy, thus enabling much smaller storage capacities.

**Other Generation resources** are non-solar and non-wind resources in Minnesota that meet a portion of the Hourly Production Requirements during brief periods of low-solar and wind resources.

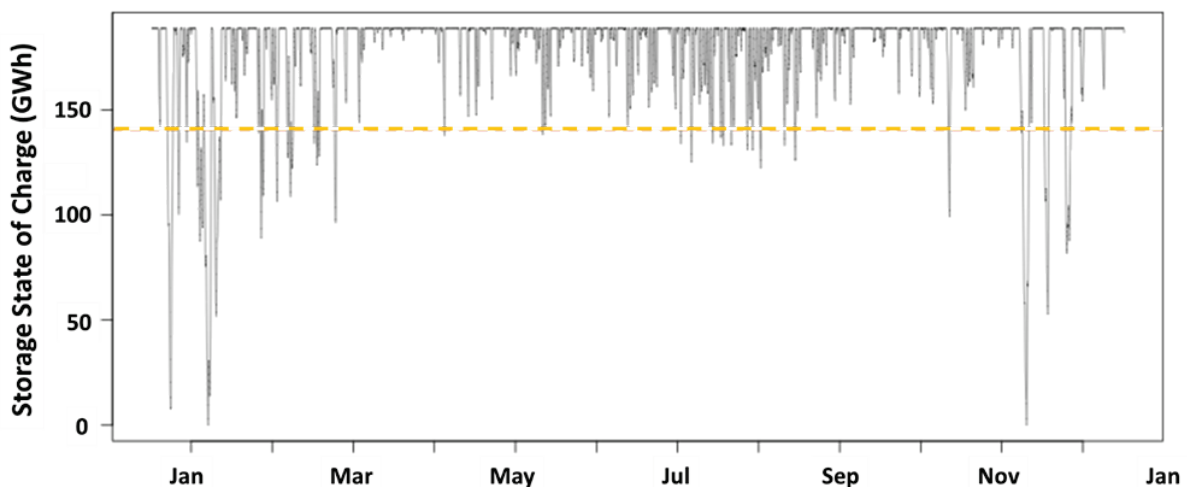
If the SPA had included integration with MISO, solar and wind resources outside of Minnesota would have also been considered ‘other generation’ resources

**Key Finding #2: Flexible *Other Generation* resources used in limited amounts support a high renewables future.**

Another key finding from the 2050 SPA results is the ability of *Other Generation* to support a high-renewables future. The strategic use of *Other Generation* resources during brief periods of low-solar and low-wind production significantly reduced the storage, solar, and wind capacities used to serve Minnesota’s hourly load. As a result, the generation cost for 70% solar and wind was reduced by nearly half. This is best understood by examining how a few brief periods of low solar and low wind production are responsible for over half the storage capacity specified in the SPA results without *Other Generation* resources.

Figure 11 illustrates the storage state of charge for the Hourly Production Requirements, High Technology Development, Utility-Led Solar Distribution scenario. For most of the year, the 195 GWh of storage capacity maintains state of charge levels above 74% of the maximum energy capacity (145 GWh). However, during a few periods of low wind and solar production the storage is discharged more fully. The total storage capacity and costs are determined from the largest drawdown, a total discharge in early January.

Figure 11. Storage State of Charge (GWh) – minimum state of charge plotted for each day in a calendar year. Dashed line in gold denotes 74% or 145 GWh state of charge.



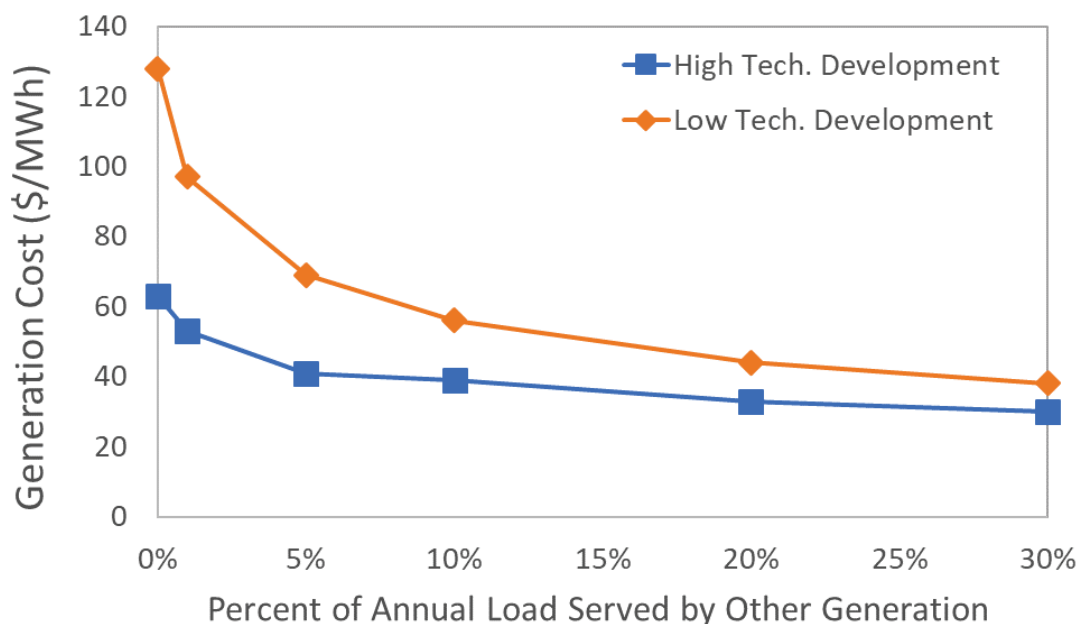


Considering these results, it is apparent that ***Other Generation* resources could significantly reduce the SPA’s storage capacity (and generation cost) by providing generation during periods of low solar and wind production.**

The ability to utilize *Other Generation* resources during periods of low solar and low wind production was added into the SPA. *Other Generation* resources could include existing non-renewable resources in Minnesota or imports from MISO. For the purpose of economic modeling, *Other Generation* resources were assumed to be existing natural gas resources (fuel and O&M costs were included, capital costs were not included).

Figure 12 plots the SPA’s calculated generation cost against the fraction of total energy generation provided by *Other Generation* resources.<sup>18</sup> Initially, generation costs fall markedly as *Other Generation* resources are allowed to serve up to 10% of the SPA’s annual load target (e.g., 10% of 70%). However, generation cost declines less significantly beyond 10% of the annual load target. Focusing on the range where *Other Generation* resources serve 5-10% of the annual load target, the Pathways Core Team notes that generation costs are reduced either 35% (High Technology Development) or 55% (Low Technology Development) from the cost to meet the Hourly Production Requirements using solely solar and wind resources in Minnesota. This significant reduction in costs is a general indication of the value of the flexibility from *Other Generation* resources or the MISO market.

Figure 12. Effect of Utilizing *Other Generation* Resources during Periods of Low Renewables Production.



<sup>18</sup> Results shown are for Hourly Production Requirements and Utility-led Solar Distribution.

### 2050 SPA Results with 10% *Other Generation*

The SPA results that include *Other Generation* resources (Table 8) provide significant value by reducing the SPA’s 2050 generation cost range from \$56-\$132/MWh with no *Other Generation* resources to a much tighter and more actionable range of \$36-59/MWh with *Other Generation* resources serving 10% of the annual target load.

Table 8. 2050 SPA Results with 10% *Other Generation* Resources.

2050 Timeframe: 70% Solar and Wind Generation; 10% <i>Other Generation</i> Resources					
Tech. Development Scenario	Production Requirements	Solar Distribution Scenario	Generation Cost (\$/MWh)	Energy Curtailment (%)	Storage Capacity (GWh)
High	Seasonal	Utility-Led	36	19%	46
		All Sectors	37	18%	48
	Hourly	Utility-Led	37	20%	50
		All Sectors	39	22%	46
Low	Seasonal	Utility-Led	55	33%	17
		All Sectors	57	34%	17
	Hourly	Utility-Led	57	36%	16
		All Sectors	59	38%	16

Note, when *Other Generation* resources are used during periods of low solar and low wind production, the Hourly Production Requirements need to serve a greater percentage of the hourly Minnesota load. When *Other Generation* resources serve 10% of the annual target load, Minnesota solar and wind would serve 78% of the hourly Minnesota load (except during periods of low solar and low wind production when they would serve less of the load) in order to serve 70% of Minnesota’s annual load.

### Key Finding #3: Storage is an important part of a high renewables future; it expands the dispatch capabilities of wind and solar assets

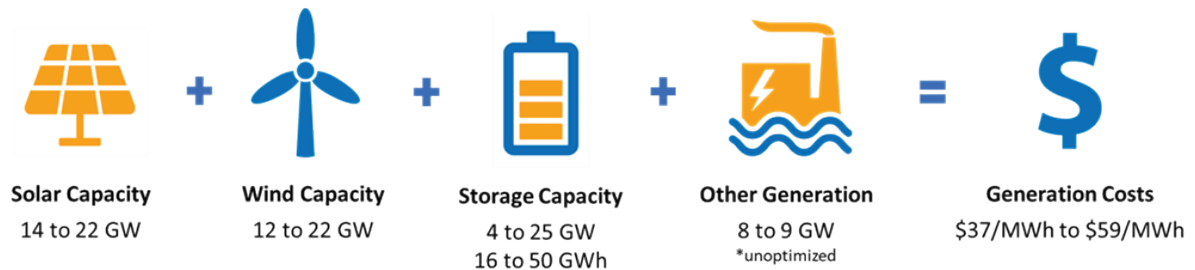
The storage capacity found by the SPA (16 to 50 GWh – equal to roughly one to five hours of Minnesota’s average hourly load) is sufficient to address the intra-hour variability of solar and wind, as well as of Minnesota’s load. It is further sufficient to shift solar and wind production to meet load on a daily basis. *Other Generation* resources can be utilized when production shifting beyond a daily basis is required.

### Key Finding #4: Solar and wind can serve 70% of Minnesota’s electrical load

Overall the 2050 SPA results indicate that the expected cost declines of solar, wind, and storage will enable Minnesota to achieve 70% solar and wind by 2050 with generation costs comparable to natural gas generation costs (\$39/MWh to \$64/MWh, see Appendix I: Cost of Natural Gas Generation Resources).

This is noteworthy given the stringent production requirements used when modeling the 2050 results: solar, wind, and storage were modeled with a requirement to serve a constant fraction of Minnesota’s hourly load profile (for every hour of the year). An exception was made during periods of low-solar and low-wind production, during which time *Other Generation* resources were used to support generation requirements, reducing costs to meet the Hourly production profile by approximately half.

#### 70% Solar and Wind by 2050:



### Electrification and Load Shifting

In this section we discuss how electrification and load shifting can impact the SPA results. Electrification is the conversion of fleets of appliances and transportation powered by burning fuel like natural gas and gasoline to electricity. Examples considered in the SPA included transportation, space heating and domestic hot water (DHW). Load shifting refers to the ability to move energy consumption to a different hour, or in limited cases, a different day. The greater the time shift, the more difficult it can be for the end user to accommodate.

Prior to discussing SPA results, we summarize how residential electrification could impact Minnesota’s hourly load profile by 2050 assuming nearly complete electrification of residential load. We also summarize the degree to which electrified loads can be shifted. For greater discussion of these findings please see Appendix C: Electrification and Load Shifting Results.

#### Electrification:

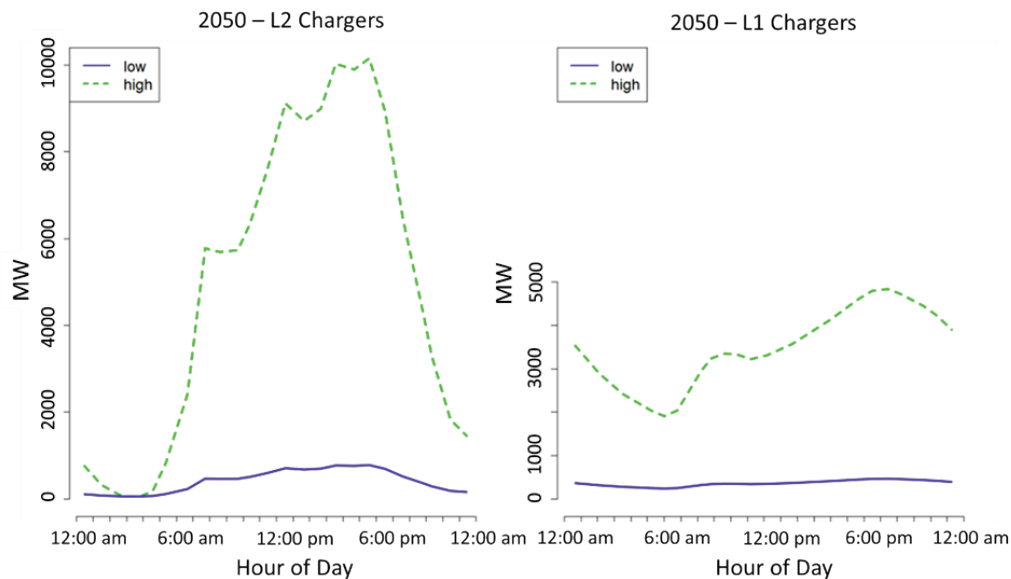
- **DHW would add ~1 GW of load (on average) from 2.8 million electric water heaters**
  - DHW load peaks in the morning and is lowest over-night
- **EVs would add roughly ~4 GW of load (on average) from 4.9 million electric vehicles**

- EV load peaks in the early evening and the sharpness of the peak is heavily dependent on charger type (e.g., L1 chargers vs. L2 chargers) – see Figure 13
- **HVAC would add ~3 GW of load (on average) during the coldest weeks of the year**
  - Timing of HVAC load peaks are weather dependent and vary on a daily basis

**Load shifting:**

- **DHW could shift ~10 GWh of load throughout a day**
- **EVs could shift ~30 GWh of load throughout a day and a few GWh over a 2-3 day period**
- **HVAC could shift a few GWh of load over 1-3 hours**

Figure 13. EV Load in 2050 with L1 (right) and L2 (left) chargers. (The dashed green line is the EV load with High Technology Development, the solid blue line is the load with Low Technology Development).



**SPA Results with Electrification and Load Shifting**

The electrification results indicate that electrification of DHW, residential heating (using air source heat pumps), and transportation has a minimal effect on the generation costs found by the SPA. Generation costs of supplying the Predictable Production Requirements in 2025 decrease by about 5% with electrification. Generation costs of supplying the Hourly Production Requirements in 2050 increase by about 5% with electrification. Resource capacities increase to cover the additional load in both timeframes.

**Key Finding #5: Shifting of key flexible loads may further decrease generation costs.**

Load shifting residential DHW and EV loads in 2025 provides 10% generation cost reductions from electrified generation costs for the Predictable Production Requirements. Load shifting

residential DHW and EV loads in 2050 provides either 20% generation cost reductions from electrified generation costs (High Technology Development) and 3% generation cost reductions (Low Technology Development) for the Hourly Production Requirements.

This result represents an optimistic scenario for the possible benefits from electrification paired with load shifting for three reasons now discussed. First, EV chargers were assumed to be available whenever a vehicle was parked. Second, the SPA did not attribute a cost to load-shift resources. Third, the SPA modified the existing load profile with electrification to the point where the load profile with load shifting would likely impinge on transmission and distribution capacity limits. Coordinated load control will help reduce potential impacts.

## Discussion of SPA Results

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### SPA Scope:

After examining the SPA results, it is worth considering the effect of two of the constraints associated with the SPA scope on the SPA results:

- The SPA does not include integration with MISO
- The SPA is based on installed and operational costs (it does not consider rate structures)

In discussing the effects of the constraints, there were members of the MN Solar Pathways Technical Committee who felt that the lack of integration with MISO led to a conservative analysis with higher generation costs and resource capacities. This belief was borne out by reduced generation costs for SPA scenarios that included small amounts of *Other Generation* resources.<sup>19</sup> Conversely, there were members of the Technical Committee who noted that the use of installed and operational costs (as compared to costs derived from market payments and/or current rate structures) would underestimate total costs, especially for the All-Sectors scenarios. The MN Solar Pathways Core Team acknowledges these perspectives. The net effect will be subject to market and regulatory decisions and is unknowable at this time. The Core Team additionally notes that the next model being developed under the Pathways initiative, the Solar Deployment Strategy, *will evaluate the effect of rate structures and their impacts on markets along with value propositions of different solar deployment scenarios.*

### The Value Proposition of *Additional Capacity* coupled with Energy Curtailment

At present there is a significant industry focus on the use of generation flexibility (i.e., fast-ramping resources) and load shifting to accommodate the production variability of solar and wind resources. By comparison, relatively little attention has been paid to the use of *Additional Capacity* (solar and wind) combined with energy curtailment.

The SPA results suggest that *Additional Capacity* offers a low-cost way to overcome the production variability of solar and wind resources. Specifically, *Additional Capacity* is uniquely positioned to address seasonal and multi-day periods of production variability that:

- cannot be provided by load shifting due to the multi-day time-scales required
- cannot be provided by natural gas resources without carbon emissions

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<sup>19</sup> Allowing other in-state generation resources to ramp-up in periods of low resource is similar to using the surrounding MISO region as a generation resource.

- cannot be provided by storage alone without significant storage costs<sup>20</sup>

A final note on *Additional Capacity*: while the Pathways Team was quick to recognize its value proposition, the Pathways Team understands that existing solar and wind compensation mechanisms would need to be adjusted to accommodate the associated energy curtailment.

## Cost of Capital

The cost of capital is an important input into the SPA. The results presented above assumed a cost of capital of 5%. SPA results with cost of capital between 4% and 6% are presented in [Appendix G: Cost of Capital](#) for a subset of SPA scenarios (Hourly Production Requirements, Utility-Led Solar Distribution scenarios in the 2050 Timeframe). The SPA results presented in the appendix indicate that cost of capital has a moderate effect on generation costs, but a much smaller effect on the type (solar, wind, storage) and capacity (GW or GWh) of resources that are deployed.

## Historical Load Data

The SPA utilized historical load data from three years: 2014, 2015, and 2016. The original goal of the study was to model these years as a three-year period. Due to time and resource constraints it was only possible to model each year individually. The results presented in this report are for 2016. SPA results for 2014 and 2015 exhibited similar trends and costs. Clean Power Research notes that multi-year modeling is important as the optimized resource set will vary slightly from one year to the next. As such, the generation cost and resource capacities would be slightly higher for a resource set that meets the needs of a multi-year period.

## Utility-Led vs All Sectors

Generation costs for the Utility-Led scenarios were 5-20% lower than generation costs for the All Sectors scenario. The lower cost of the Utility-Led scenarios is expected given the difference in the modeled resource costs between the Utility-Led and All Sectors scenarios (Table 3). Overall these results indicate that Minnesota has flexibility in the distribution of solar resources.

Resource capacities were similar between Utility-Led and All Sectors. Some All Sectors scenarios had greater wind capacities (relative to solar capacities). This makes sense when considering that solar costs are higher relative to wind costs in the All Sectors scenarios.

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<sup>20</sup> The forecast for storage cost reductions assumed in the SPA is aggressive. Unless there are unexpected cost declines in Lithium Ion or other storage technologies, the Pathways Team asserts the value of 'additional' solar and wind.

The Pathways Team acknowledges that there may be reasons to invest in distributed solar (as with the All Sectors scenarios) notwithstanding the higher generation cost relative to utility-scale solar (Utility-Led scenarios). The SPA specifically examines generation costs and is not a tool for evaluating the *value* of one type of deployment over another. The Solar Deployment Strategy model being developed in the latter half of the Pathways project is intended to be useful in comparing costs and benefits of different deployment strategies.

### **Limitations to Existing Generation Capacity Credit Methods**

During discussions of the SPA results with the Technical Committee, the question was raised whether the resource capacities found by the SPA would satisfy generation resource adequacy requirements. The Pathways Team did not evaluate this question in detail. However, a quick look at existing capacity credit methods reveals an obvious challenge for the SPA results. Existing generation capacity credit methods look at resources individually, as opposed to holistically. For example, solar and wind would receive fixed capacity credits (currently 50% and 15%, respective class averages, in MISO),<sup>21</sup> while storage would not receive a capacity credit under current MISO resource adequacy methodologies as it is not a generation resource.

Ongoing discussions at Federal Energy Regulatory Commission (FERC) center around how to value storage in markets and include related conversations about eligibility and rules in capacity markets and for resource adequacy. FERC Order 841 requires independent system operators to implement a method of assigning capacity credit to storage.<sup>22</sup> To fairly evaluate the generation resource adequacy of a set of solar, wind and storage resources, a holistic generation capacity credit method is needed.

### **Area Required for Solar Deployment**

During discussions with the Technical Committee, the question arose as to whether there was sufficient roof-space within the Minneapolis Saint Paul metropolitan area to accommodate the allocated solar capacity in the All Sectors scenario. Great Plains Institute has previously studied the rooftop solar potential through the Local Government Project for Energy Planning project, based on Minnesota's LiDAR-based (1-meter resolution) solar resource map. GPI found that cities typically had enough economic rooftop solar resource to generate an equivalent of 40-60% of the total electric consumption within the city, which exceeds the distributed solar capacity modeled for the All Sectors and Utility-Led scenarios in both timeframes (without

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<sup>21</sup> After a year of operation, a unit's capacity credit is based on historical coincidence with peak.

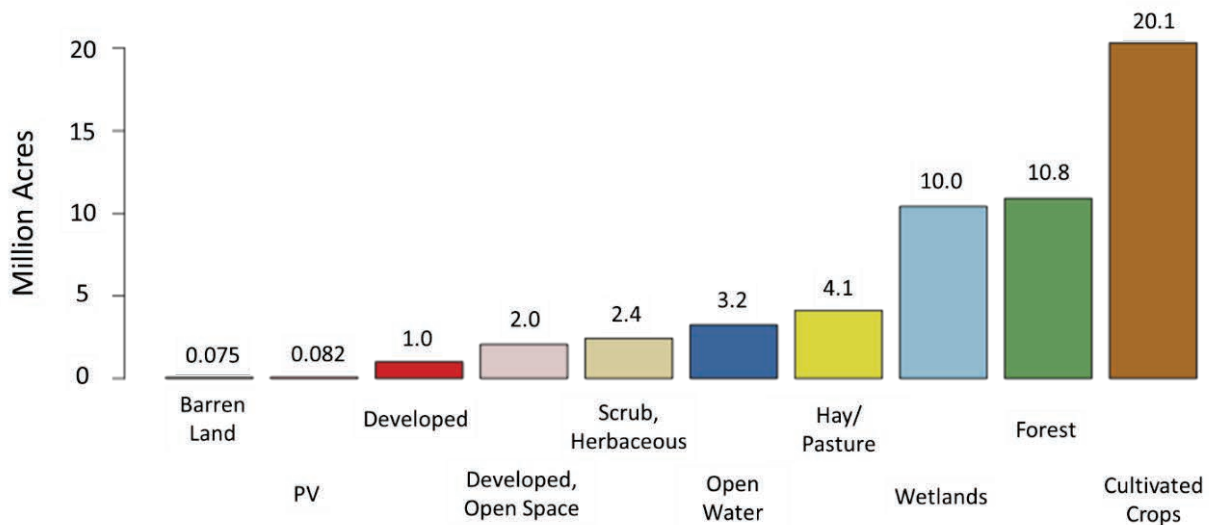
<sup>22</sup> Order 841 Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators. Federal Energy Regulatory Commission. <https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf>. Feb. 15, 2018.



considering any accessory use ground-mount capacity). GPI’s measured analysis aligns with NREL findings that modeled the rooftop solar resource across the nation. NREL estimated that the national technical potential (gross resource) of rooftop solar was approximately 39% of national electric usage.<sup>23</sup>

Clean Power Research separately calculated the area required for the *extreme* case of serving all of Minnesota’s electrical load with solar energy (82,000 acres). See Appendix F: Land Use. While 82,000 acres might sound large, it is actually quite small when compared with existing land use in the State of Minnesota. As can be seen in Figure 14 below, 82,000 acres is comparable to the area of Barren Land<sup>24</sup> in Minnesota and over 10-fold less than the area of Developed Land in Minnesota, based on data from the [National Land Cover Database](#).

Figure 14. Area Required for Solar Deployment Compared with Existing Land Use in Minnesota.



### 84% Reduction of Minnesota’s Carbon Intensity

The 2050 SPA results represent an 84% reduction in the carbon intensity of Minnesota’s electric sector from 2005 levels if the *Other Generation* resources are solely comprised of natural gas (blend of CT and CCGT). The reduction in carbon intensity would be even greater if the *Other Generation* resources included nuclear resources and/or solar and wind resources from outside of Minnesota.

<sup>23</sup> NREL; Rooftop Solar Photovoltaic Technical Potential in the United States. (2016)

<sup>24</sup> Barren Land (Rock/Sand/Clay) – areas of bedrock, ..., gravel pits, and other accumulations of earthen material.

Figure 15. Carbon Intensity of Minnesota’s Electric Sector.

Generation Resource	Minnesota's Carbon Intensity			
	2005 Generation (%)	CO2 Emissions (Metric Tons /MWh)	2050 Generation (%)	CO2 Emissions (Metric Tons /MWh)
Nuclear	24%	0.00		
Coal	62%	0.98		
Natural Gas Blend	5%	0.44		
Wind, Hydro, Biomass	7%	0.00		
Petroleum	2%	0.79		
Solar and Wind			70%	0.00
Hydro, Wood, Biomass			5%	0.00
Gas - CT			8%	0.53
Gas - CCGT			17%	0.35
<b>Total (%)</b>	<b>100%</b>	n/a	<b>100%</b>	n/a
<b>Weighted Average CO2 Emissions (Metric Tons/MWh)</b>	n/a	<b>0.64</b>	n/a	<b>0.10</b>
<b>Reduction from 2005 Carbon Intensity</b>				<b>84%</b>

## Conclusion

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The SPA afforded a unique opportunity for a broad set of energy stakeholders in the State of Minnesota to meet regularly over an 18-month period to develop a shared understanding of the opportunities and challenges associated with increasing levels of solar and wind generation.

At the highest-level the SPA results indicate that solar, wind, and storage resources can reasonably serve a majority of Minnesota's load in terms of generation costs. As such, the SPA results can be used to justify the thorough evaluation of solar, wind, and storage as part of Minnesota's energy future – a process that many energy stakeholders in Minnesota have already begun.

The SPA results provide important insights into the solar, wind, and storage capacities that would achieve a future where solar and wind serve 70% of Minnesota's annual load. Under a 70% scenario, the SPA results suggest that Minnesota could expect to have tens of GW of solar and wind with just tens of GWh of storage capacity; not 1,000's of GWh of storage capacity. In this way, the SPA results can be useful in combination with *other studies*, as decision-makers and stakeholders anticipate and plan for expanded solar, wind, and storage capacity.

The SPA results also highlight the value of *Additional Capacity* (solar and wind) and the future need for discussion about solar and wind compensation policies that account for *Additional Capacity* (and its associated energy curtailment). To this end, the SPA results can be used to begin examining this important issue before it is pressing. Note that the Pathways project is agnostic on the numerous potential solutions, but rather raises this as a point of discussion. Early discourse will prove valuable since any new compensation policies will ultimately need to move through a regulatory process.

Finally, the SPA results provide some insight into the effect of different solar distributions on Minnesota's possible energy futures. However, a deeper analysis of the effects of different solar distributions is needed. The second phase of the Minnesota Solar Pathways project seeks to undertake such an analysis through the development of the Solar Deployment Strategies modeling tool, which will consider the value propositions of different solar deployment scenarios in addition to costs.

## Appendix A: Production Requirements

The SPA relies on user specified Production Requirements or “production profiles.”

A production profile is the production that will be delivered (by solar, wind, and storage) for each hour of the year and can vary greatly in terms of dispatchability. In this report, the SPA included production profiles that varied from minimal constraints for achieving 10 percent solar (low dispatchability) to serving 70 percent of Minnesota’s load every hour of the year (high dispatchability).

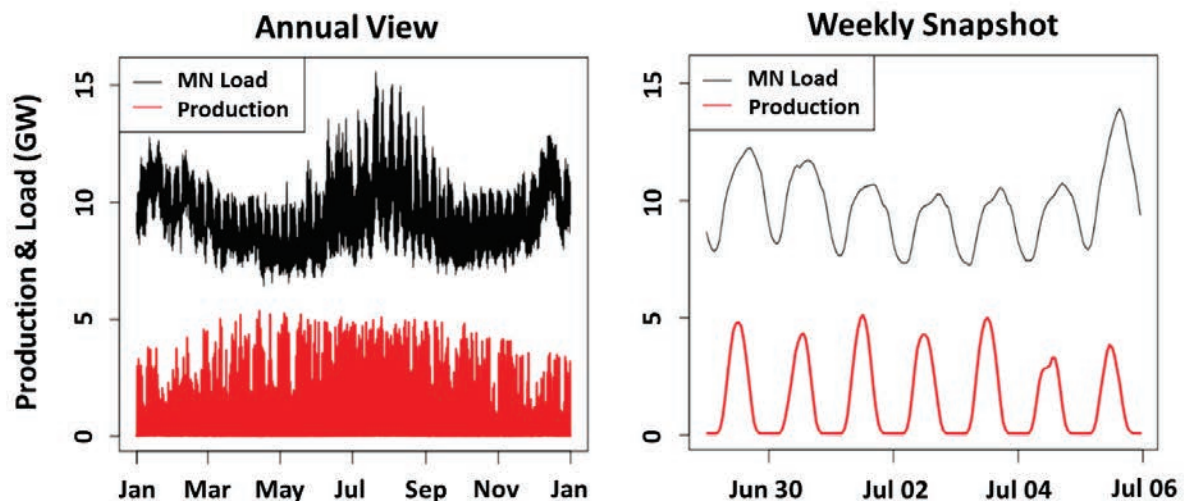
Each production profile has 8760 values (24 hrs/day \* 365 days/year) and may also be referred to as an ‘8760’ profile by utility engineers. Each of the five production profiles specified by the Technical Committee and analyzed in this report is defined below.

### 2025 Production Profiles

#### Unconstrained Production Profile (2025 Timeframe Only)

The Unconstrained production profile imposes only a single constraint on the production from solar resources: the solar production cannot exceed the Minnesota load after subtracting out the must-run resources. As can be seen in Figure 16 below, the Unconstrained production profile has significant variability relative to Minnesota’s hourly load on an annual basis (left) and a weekly basis (right).

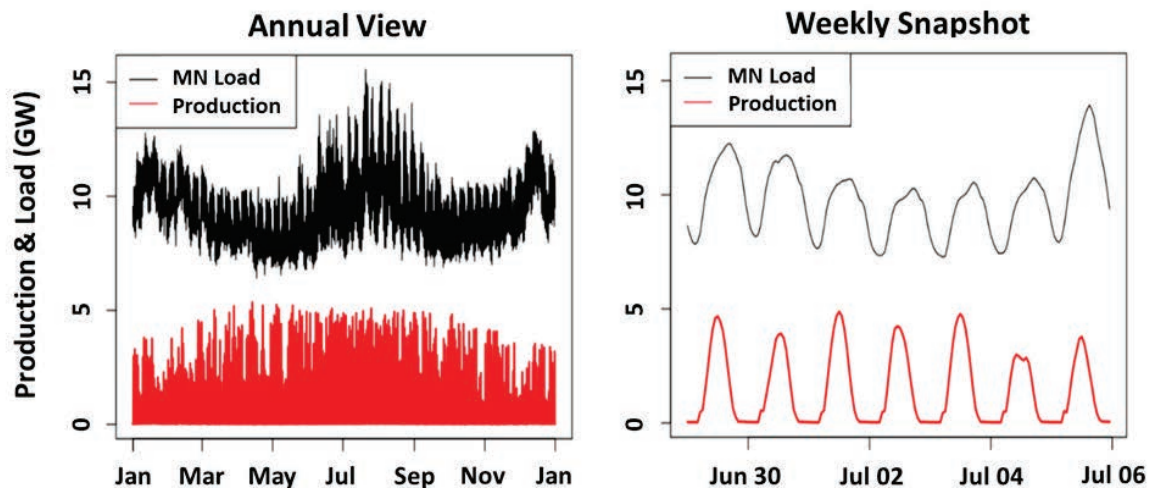
Figure 16. Unconstrained production profile plotted on an annual basis (left) and a weekly basis (right).



### Predictable Production Profile (2025 Timeframe Only)

The Predictable production profile is like the Unconstrained production profile but imposes an additional constraint to account for production forecasting error. The requirement of the Predictable production profile is that there must be adequate solar and storage capacity to make up the difference between the solar generation forecasted on the previous day for the current day (a day-ahead forecast) and the actual generation that occurred. As can be seen in Figure 17, the Predictable production profile does not differ from the Unconstrained production profile on the annual basis (left). The Predictable production profile does differ from the Unconstrained production profile on the hourly basis (right) but this difference is hard to observe as plotted – examine July 4<sup>th</sup> to observe a difference in the production profiles. Despite their similarities, the difference between the Predictable and Unconstrained production profiles at the hourly level does produce meaningful generation cost and resource requirement differences in the SPA results.

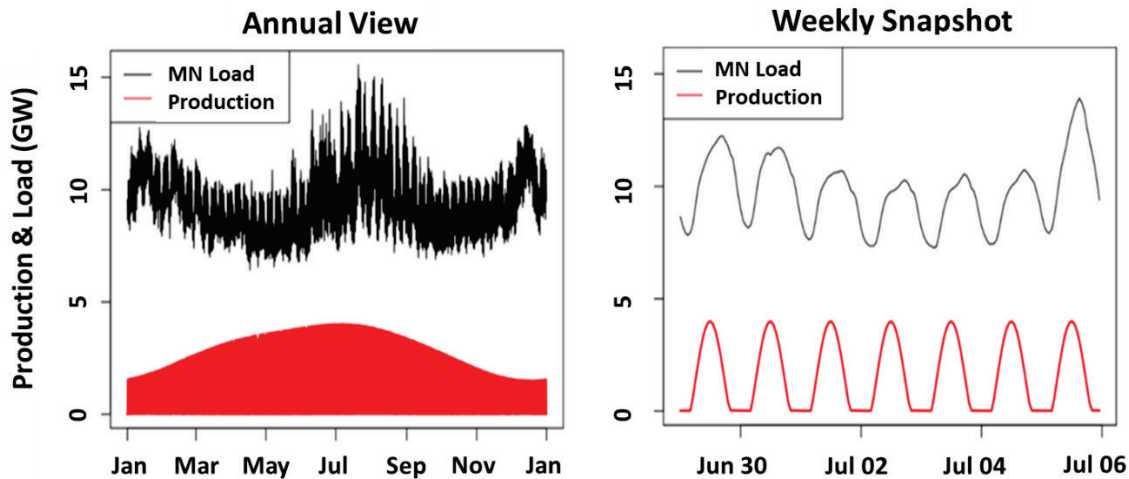
Figure 17. Predictable Production Profile plotted on an annual basis (left) and a weekly basis (right).



### Seasonal-Diurnal Production Profile (2025 Timeframe Only)

The Seasonal-Diurnal production profile represents a profile that allows for the seasonal variability of the solar resource but requires that solar and storage smooth out the daily variability of solar to match the expected seasonal production of the resource. This is illustrated in Figure 18, where the hourly and daily variability of the solar resource is eliminated with the Seasonal-Diurnal profile (right), while the seasonal variability is still present (left).

Figure 18. Seasonal-Diurnal Production Profile plotted on an annual basis (right) and a weekly basis (left).



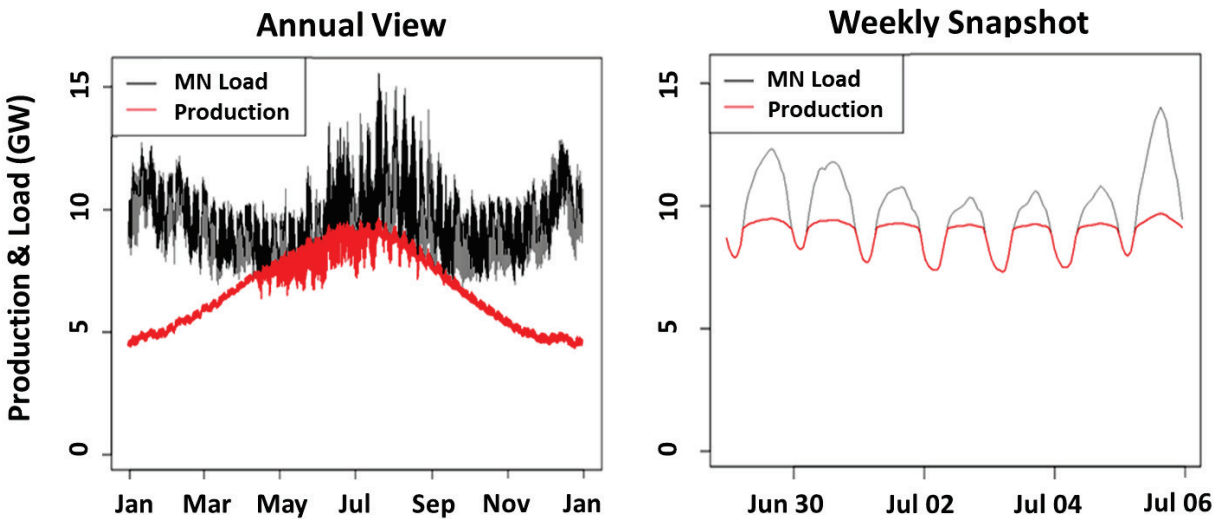
## 2050 Production Profiles

### Seasonal Production Profile (2050 Timeframe Only)

Like the Seasonal-Diurnal production profile, the Seasonal production profile smooths out the hourly and weekly production variability of the solar (and now wind) resources while allowing for seasonal variability. Unlike the Seasonal-Diurnal profile, the Seasonal production profile blends in a portion of Minnesota’s hourly load profile. This ensures that the Seasonal production profile produces some energy every hour of the year as can be seen in Figure 19 (right). Blending Minnesota’s hourly load into the Seasonal-Diurnal profile also limits the magnitude of the ramp rates to which the non-solar and non-wind resources would be exposed (not shown). Additionally, it ensures that the production profile partially tracks the daily (but not seasonal) variability of the load, producing more energy on days with greater load and less energy on days with lower load – this effect can be seen most easily when looking at the annual basis (left).

One of the key rationals behind the design of the seasonal production profile is that it allows the solar and wind resources to produce more during periods of the year when their production is naturally the greatest (e.g., the summer months for solar and certain months of the year for wind). It was expected (and to a lesser degree found) that this would reduce the generation costs and resource requirements found by the SPA in comparison with a production profile that more closely tracked Minnesota’s hourly load across the year.

Figure 19. Seasonal Production Profile plotted on an annual basis (left) and a weekly basis (right).

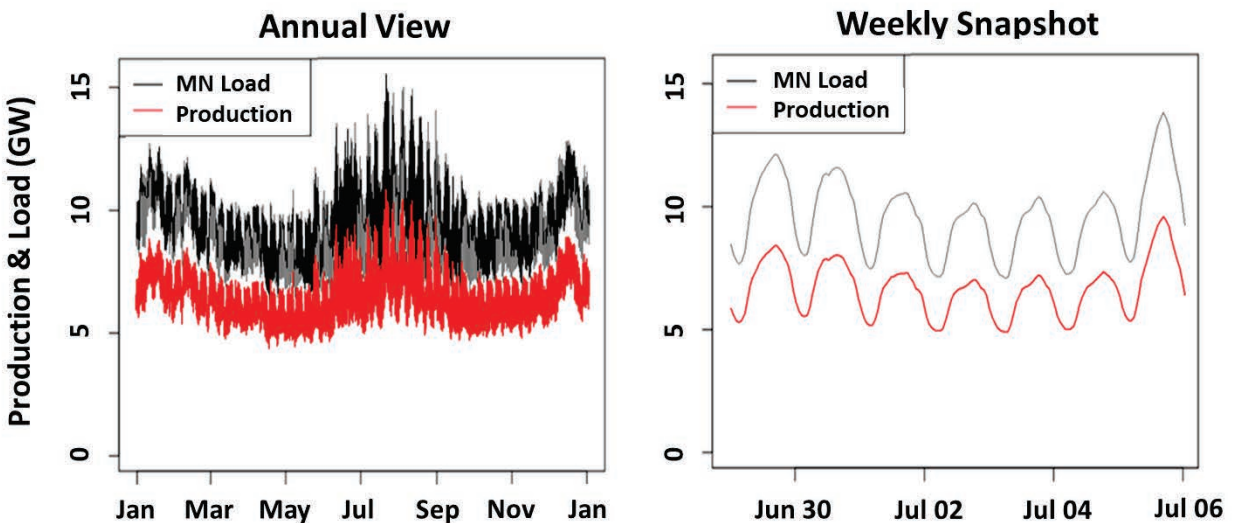


Note, because the seasonal production profiles of solar and wind are different, the seasonal production profile depended on the exact capacity of solar and wind found in the optimized SPA solution.

### Hourly Production Profile (2050 Timeframe Only)

The Hourly production profile, shown in Figure 20, is simply 70% of Minnesota’s hourly load for each hour of the year. The Hourly profile does not consider any of the production variability associated with solar and wind assets. Rather, it forces solar and wind to exactly match the shape of the Minnesota load profile, independent of the solar and wind production.

Figure 20. Hourly Production Profile plotted on an annual basis (left) and a weekly basis (right).



The Seasonal production profile was intended to be an easier production profile than the Hourly production profile.<sup>25</sup> However, the Seasonal production profile did not reduce generation cost and/or resource requirements to the degree expected. The reason for this became clear to the Core Team after realizing the importance of brief periods of low solar and low wind production on the generation cost and resource requirements found by the SPA. The Seasonal production profile did result in different resource allocations (more solar and less wind) than the Hourly production profile.

The Hourly production profile was chosen in part because it would ensure that synchronous generation<sup>26</sup> resources to serve at least 30% of the load each hour of the year.<sup>27</sup> Allowing synchronous generation resources to serve a fraction of the hourly load addresses one of the concerns that grid operators have with increasing levels of renewable penetration. The Hourly production profile would not be the most cost-effective way to serve 70% of Minnesota's annual load since it would limit the production of renewables to no greater than 70% of Minnesota's hourly load.

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<sup>25</sup> Lower generation cost and resource requirements.

<sup>26</sup> Generation resources that are coupled to the grid through the magnetic field from a spinning rotor. Synchronous generation acts as a stabilizing force on the grid.

<sup>27</sup> The percentage decreases to 22% when *Other Generation* resources serve 10% of the annual load, except during periods of low solar and low wind production when *Other Generation* resources would turn on and increase the fraction of synchronous generation above 22%.



## Appendix B: Electrification and Load Shifting Models

SPA scenarios include assumptions about strategic electrification and the availability of these loads as a load shifting resource. Initial models were developed outside the SPA by Center for Energy and Environment to characterize the loads and their flexibility. Some of this work was incorporated into the SPA with modification by Clean Power Research.

### Load Resources Considered

Several loads were considered for electrification and load shifting. These loads were predominately the larger well-characterized residential and commercial electricity loads that make up about half of Minnesota load. These are listed by sector and size in Table 9.

Table 9: Specific loads considered for electrification and load shifting and their fraction of Minnesota’s total load (current and 2050 forecast assuming significant load electrification).

% Total Load					
Residential Load	Current Estimate	2050 “High” Scenario	Commercial Load	Current Estimate	2050 “High” Scenario
HVAC	3.6%	8.9%	Lighting	5.9%	3.4%
DHW	1.6%	5.6%	Ventilation	5.2%	3.0%
Refrigeration	0.5%	0.3%	Refrigeration	4.7%	2.7%
Electric Vehicles	0.0%	25.7%	Cooling	3.8%	2.2%
			Computer	3.1%	1.8%

Of these loads, three end-use loads were considered: residential domestic hot water (DHW), heating & cooling systems (HVAC), and electric vehicles (EV). These loads were selected because they are currently or have the potential to be among the largest end-use loads on the electrical grid and they are all inherently shift-able.

Ultimately, the SPA was able to incorporate the electrification effect of DHW, EV, and residential heating loads and the load shifting effect of DHW and EV loads (but not residential heating).

### Definition of Load shifting

In this report, load shifting is defined as moving energy demand to another point in time, either before or after that time where the load would otherwise occur. Load shifting does not rely on behind the meter storage; it requires either the natural ‘inertia’ unique to certain loads (e.g. HVAC or DHW) or true flexibility over time (e.g. EV charging) to meet the same demand only at a different point in time. As applied in the SPA model, these load shifting resources have no procurement or operational costs. In practice, there are costs associated with these resources, but existing programs using them are generally deemed cost effective. The perspective taken

here is that future demand response resources will confer multiple benefits to utilities and grid operators. Distributing costs appropriately across these benefits is beyond the scope of this study. Thus, load shifting results here may represent a technical potential that may be lowered by additional economic constraints.

## General Methodology Used by Electrification and Load Shifting Models

Each SPA Technology Development Scenario included assumptions about the relative pace of technological development. For the electrification and load shifting models, it was generally assumed that a high rate of Technology Development would yield an accelerated rate of electrification and load shifting compared to a low rate of Technology Development.

Each estimate of the amount of load shifting resource is comprised of a fleet of end-use devices that can be turned on and off within a specified range, determined by the device characteristics and load requirements. There are three major parts to each electrification and load shifting estimate:

1. Market Penetration – For each load shifting resource, the market penetration is an estimate for the number of units that are available for control at the SPA scenario baseline year. Market penetration estimates are comprised of current penetrations and published growth projections from various agencies and sources. ***This portion of the estimate has the largest uncertainty of all three components due to the inherent uncertainty in forecasting changes 8 to 33 years in the future. These projections ultimately depend on unknown policy, market, and consumer forces.***
2. Opportunity – The load shifting opportunity generally describes how much capacity (energy units, kWh) and how much load (power units, kW) are available from the fleet of devices. This figure is constructed from the bottom up. This means that it considers the power and capacity metrics associated with the average end-use loads that make up the fleet of shift-able load. ***This portion of the estimate has a relatively low uncertainty because it is based on published data for actual units. Uncertainty is limited to how these figures may change between now and SPA baseline years.***
3. Constraints – This estimate sets the limits or the range of control for these technologies. It is a bottom up estimate based on the requirements of each load. For example, domestic hot water systems need to provide sufficient hot water, electric vehicles need sufficient capacity to meet driving requirements, and heating and cooling systems must keep occupied spaces conditioned. Additionally, there are maximum power and energy limits of the fleet. ***This estimate has a relatively low uncertainty as these requirements are derived from typical aggregated use patterns. The fleet of shift-able loads is constrained such that it must meet the same capacity requirements as the uncontrolled load.***

## Market Penetration Summary

Figures 21-23 present the forecasted market penetration of DHW, EV, and residential heating units with load control from 2018 through 2050 for the low and High Technology Development scenarios. These projections were made by first combining existing equipment penetration rates<sup>28</sup> with Minnesota population and household growth forecasts<sup>29</sup>. DHW and HVAC growth projections are developed from this baseline coupled with the electrification of natural gas and propane based systems and adjusted based on MISO's Independent Load Forecast Update<sup>30</sup>. Growth forecasts for electric vehicles were developed by blending recent national EV forecasts<sup>31</sup>. Load shifting participation rates are based on those found from existing programs<sup>32</sup>. The 2050 High Technology Development scenario assumes full electrification of domestic hot water, light-duty transportation, and 50% electrification of the single-family residential heating load to bound upper potential of this resource.

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<sup>28</sup> Residential Energy Consumption Survey 2009. (2009). Energy Information Administration. <https://www.eia.gov/consumption/residential/>. Accessed May 2017.

Residential Energy Consumption Survey 2015. (2015). Energy Information Administration. <https://www.eia.gov/consumption/residential/>. Accessed May 2017.

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<sup>29</sup> Minnesota State Demographic Center Database, <https://mn.gov/admin/demography/data-by-topic/population-data/our-projections/>. Accessed May 2017.

Minnesota State Profile and Energy Estimates, (2016), Energy Information Administration, [https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep\\_use/res/use\\_res\\_MN.html&sid=MN](https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_use/res/use_res_MN.html&sid=MN), Accessed May 2017.

<sup>30</sup> Gotham, D.J. et al. (2016). MISO Independent Load Forecast Update. State Utility Forecasting Group. The Energy center at Discovery Park, Purdue University. West Lafayette Indiana.

<sup>31</sup> Annual Energy Outlook 2017. (2017). Light-Duty Vehicle Stock by Technology Type: Case: Reference Case. U.S. Energy Information Administration, <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=49-AEO2017&sourcekey=0>. Accessed May 2017.

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Shepard, S. and Abuelsamid, S. (2016). Electric Vehicle Geographic Forecasts: Battery and Plug-In Hybrid Electric Vehicle Sales and Populations in North America, <https://www.navigantresearch.com/wp-assets/brochures/DB-EVGEO-16-Executive-Summary.pdf>. Accessed July 2017.

<sup>32</sup> Ottetail Power, Private Conversation, May 2017.

Hledik, R. et al. (2016) The Hidden Battery: Opportunities in Electric Water Heating. Technical Report.

Kaluza, S. et al. (2016) BMW i ChargeForward: PG&E's Electric Vehicle Smart Charging Pilot. BMW Group, Pacific Gas and Electric Company, 2016. <http://www.pgecurrents.com/wp-content/uploads/2017/06/PGE-BMW-iChargeForward-Final-Report.pdf>. Accessed July 2017.

Figure 21: Forecasted market penetration of controlled DHW units.

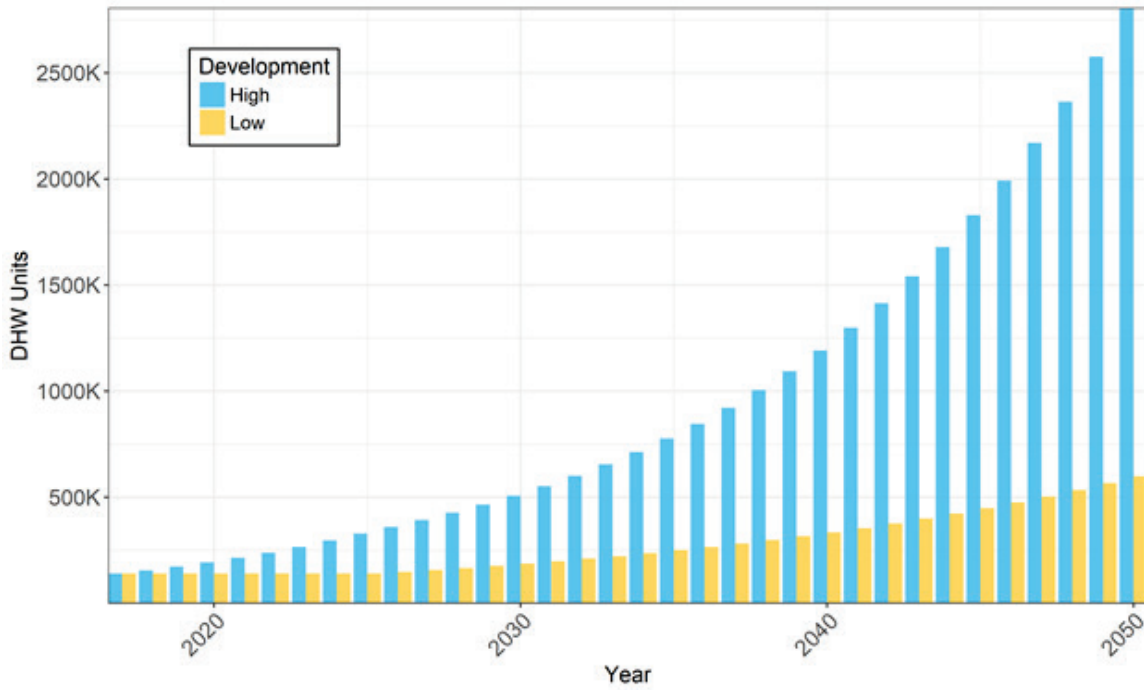


Figure 22: Forecasted market penetration of controlled EV units.

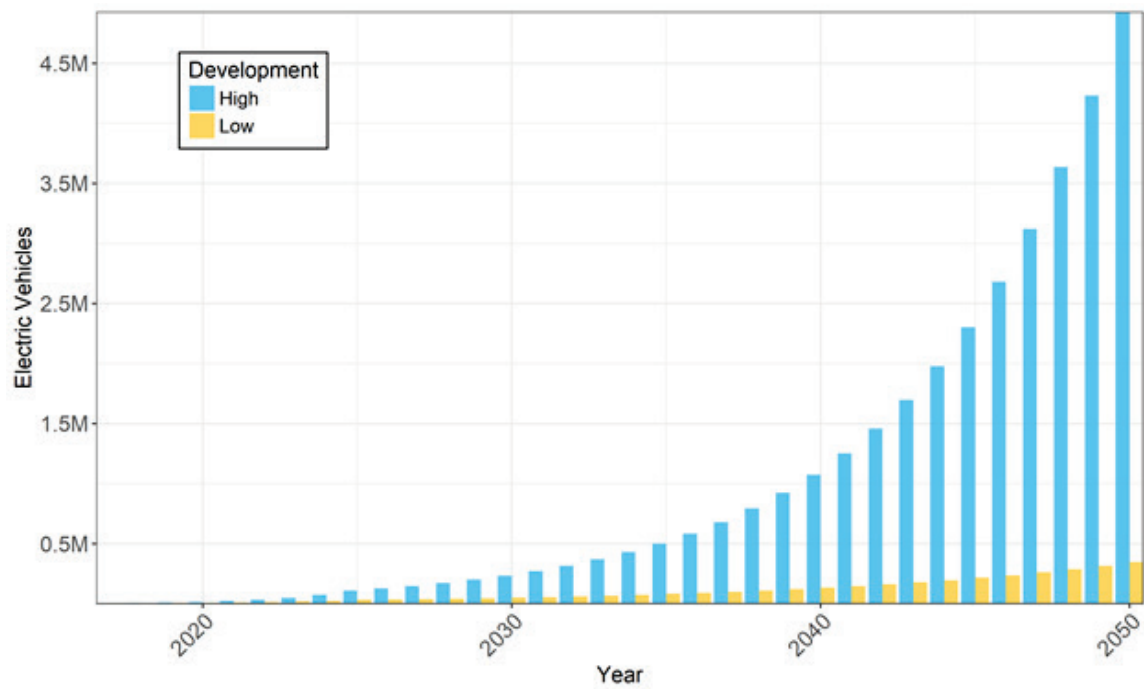
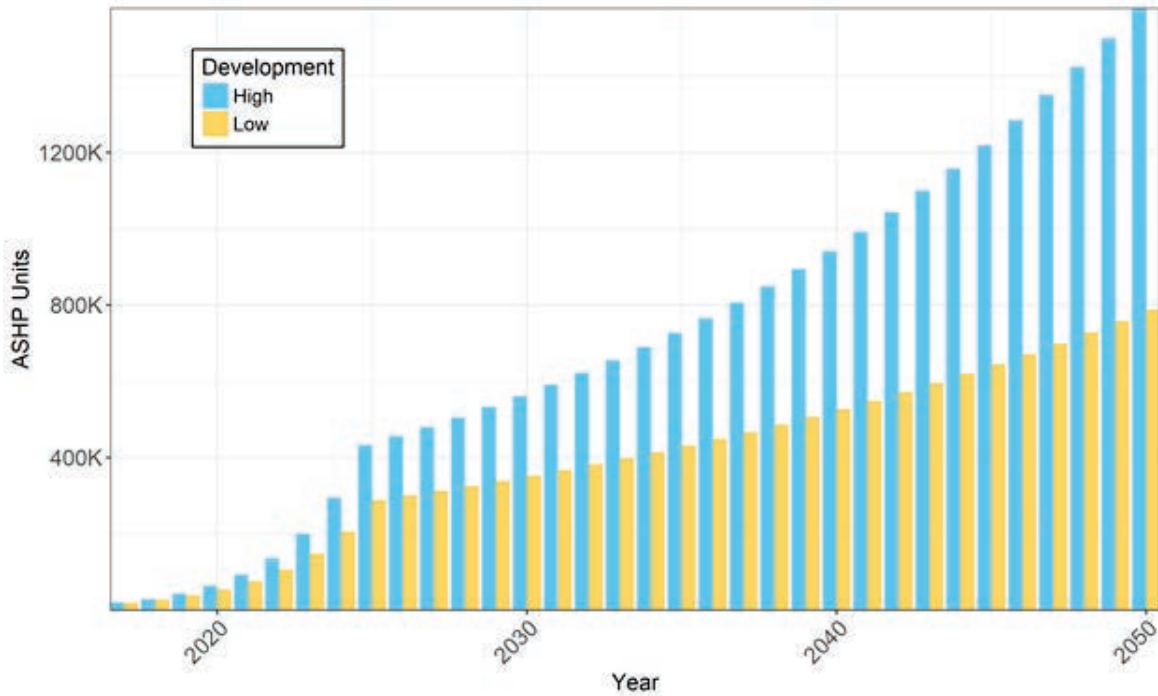


Figure 23: Forecasted market penetration of controlled residential heating units.



The number of participating units and their aggregate load are provided in Table 10 for the 2025 and 2050 timeframes, Low and High Technology Development scenarios. Each of these loads represents new electrification beyond load growth estimates, excluding the 2025 DHW scenario which represents the current installed base of controllable DHW units.

Table 10: Number of participating units and their aggregate load for the SPA scenarios.

2025				
	Low		High	
Load	Units	Load (GWh)	Units	Load (GWh)
Res. HVAC	289,000	500	433,000	1,450
Res. DHW	140,000	600	330,000	800
EV	32,250	200	110,000	600
2050				
	Low		High	
Load	Units	Load (GWh)	Units	Load (GWh)
Res. HVAC	789,000	3,500	1,579,000	15,500
Res. DHW	600,000	2,200	2,807,000	9,800
EV	349,000	2,100	4,930,000	29,600

## Domestic Hot Water Analysis

### Summary:

Electric resistance water heaters (ERWH) and heat pump water heaters (HPWH) convert electrical energy into heated potable water for domestic hot water (DHW) consumption. These systems are typically coupled with storage tanks to meet regular hot water consumption requirements for 4 to 24 hours without drawing electrical power. Storage times and capacity can be increased with the use of mixing valves and higher storage temperatures. When coupled with remote controllers, these units can be turned on and off at coordinated times to increase or decrease the load. This flexibility enables load shifting of the controlled DHW loads to accommodate periods of low or high solar or wind generation.

This section outlines the approach taken for estimating the load shifting potential of DHW units in the SPA model.

1. Market Penetration – The market penetrations of controllable DHW units is divided into two groups. The first market considers the **existing electrical DHW units**. These loads are already part of the SPA load model and load shifting control is enabled on some portion (market penetration). The second group considers **new electrical DHW units**, for example those units that may switch over from liquefied petroleum gas (LPG) or natural gas fuels under strategic electrification scenarios. These two markets must be accounted for separately because they represent existing and new electrical loads, respectively.
2. Opportunity – ERWH systems have standardized around uniform capacities (50-80 Gal) and loads (<4.5kW), especially those units that have been used in existing demand response programs. Furthermore, their utility for load shifting is substantially increased by including mixing valves, such that the tanks can be charged to higher capacity (135 – 160 °F), yet only discharge 120 °F water. The load shifting opportunity reflected by DHW is comprised of different unit types and charging temperatures depending on the Technology Development scenario.
3. Constraints – Much research has been performed on DHW consumption behavior to produce estimates of average DHW load. The assumption used here is that these existing profiles represent, on average for the load shifting DHW units, the **minimum** amount of energy that need be available to meet hot water requirements. In other words, the controlled DHW units must have the same capacity available on an hourly basis as the uncontrolled units. Additionally, the controlled units have a **maximum capacity** (when they are full of hot water at set point) and a **maximum load** (all turned on at the same time).

The technical details of how these units are controlled are beyond the SPA model. Nonetheless, there currently exist smart water heater controllers and demand response controllers that can

provide similar functionality at relatively low cost. The incremental cost of compatible units is assumed insignificant in the model.

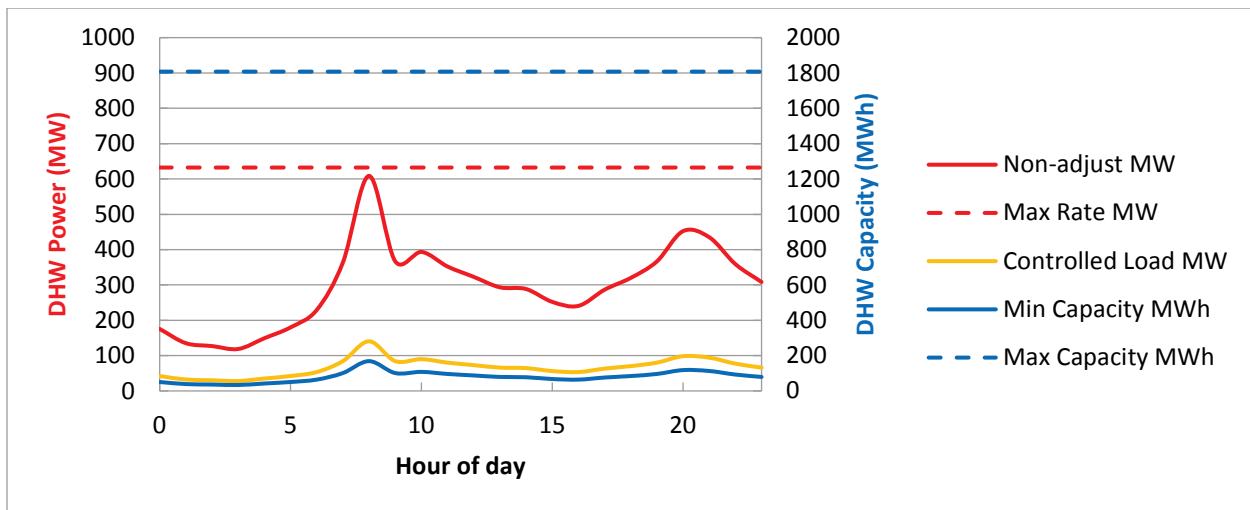
**Key Assumptions:**

- An average DHW profile is sufficient to describe the minimum required energy necessary to meet residential hot water requirements for a large fleet of units.
- Strategic electrification initiatives will add new electric load by converting natural gas and LPG DHW units to electric heat pump DHW units.

**Example Scenario**

The 2025 Low Technology Development scenario provides a conservative estimate of the number of units available for load shifting. It assumes current rates of participation in existing DHW demand response programs in Minnesota under modest load growth, yielding about 140,000 units. The exact distribution of unit types is not known, so they are conservatively assumed to be 50 Gal ERWH. Coupled with earlier assumptions and data sources, these values sufficiently outline the extent of operation to which the fleet of units can be turned on or off to accommodate solar energy while meeting consumer requirements. An example of this operational space and load shifting flexibility is given in Figure 24.

Figure 24: Example scenario of working range of DHW load shifting.



**High Level Calculation Steps**

*Maximum Flexible Load*

$$Participating\ DHW\ Units \times Max\ Power\ Draw\ (kW) = Total\ kW\ Flexible\ Power\ (kW)$$

The load for these units can range between 0 and the maximum flexible load.

*Minimum Storage Capacity*

$$\text{Average Hot Water Demand (kWh/hr)} \times \text{Participating DHW Units} \times \\ = \text{Minimum Storage Capacity (kWh)}$$

The minimum storage capacity is based on the assumption that hot water needs are met, on average, if the controlled DHW units have the capacity necessary to match the uncontrolled (regular) DHW load.

*Maximum Storage Capacity*

$$\text{Hot Water Tank Capacity (kWh)} \times \text{Participating DHW Units} \\ = \text{Maximum Storage Capacity (kWh)}$$

The maximum storage capacity is the fleet-wide sum of the energy each tank can hold.



## Electric Vehicles

### Summary

Electric vehicles (EVs) currently comprise a negligible amount of electrical load in Minnesota, but they are anticipated to grow at exponential rates through the timeframe of the SPA model. Given that the magnitude of transportation energy consumption is of the same order as building energy, it is assumed EV charging loads will be significant in the timeframe of this study. Most vehicles are used to commute between work and home and the energy requirements of these commutes are typically only a fraction of an EV's energy storage capacity. Therefore, EV chargers can be turned on and off at coordinated times to increase or decrease electric load. This flexibility enables load shifting to accommodate solar energy production goals. In the SPA, only the time and the rate at which the EV's charge is considered flexible. In other words, EVs are not considered to be true Vehicle-to-Grid (V2G) resources and therefore cannot directly replace the need for grid-connected storage on a 1:1 basis.

This section outlines the approach taken for estimating the load shifting potential of electric vehicles in the SPA model.

1. Market Penetration – The market penetrations of controllable EVs were based on their projected growth between now and the SPA baseline years of 2025 and 2050. There are multiple published growth rates that were used to develop high and low estimates for the adoption of electric vehicles in the state of Minnesota.
2. Technological Performance – Currently EVs come with a wide variety of battery sizes and potential charging rates. It was assumed that these capacity and charging rates will increase toward values currently represented at the high end of the EV market. In order to not over-bias the results towards the high-end, vehicle efficiency (miles per kilowatt hour) is set to the weighted average of EVs available in the market today.
3. Behavior— An agent-based model was created that randomly samples behavioral profiles from the 2009 National Household Travel Survey (NHTS)<sup>33</sup>. Roughly 3500 agents were selected, each with their own unique travel behavior between home, work and “other”. The constraining requirement is that each agent must guarantee meeting their travel requirements but is flexible in terms of when, at what magnitude and for how long they charge their vehicles.

### Key Assumptions

- Charging is available at home, work and ‘other’

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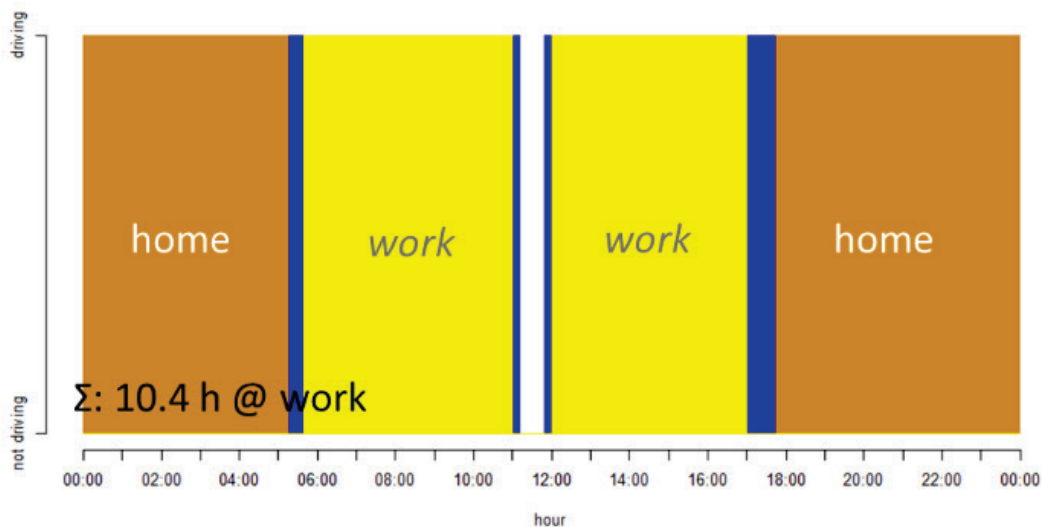
<sup>33</sup> National Household Travel Survey. (2009) Trip Chaining Dataset, U.S. Department of Transportation, Federal Highway Administration. <https://nhts.ornl.gov/download.shtml>. Accessed December 2017

- Charging is not available when driving between any of the aforementioned locations
- Two unique sets of scenarios were run: (1) using 100% saturation of Level 1 chargers (charge rate up to 1.9 kW at 120 V) and (2) 100% saturation of Level 2 chargers (charge rate up to 19.2 kW at 240 V), respectively
- Agent based model with 3500 agents selected at random from the 2009 NHTS
- Before shifting, agents are assumed to charge their batteries until full as soon as they stop driving
- Battery size for each agent is assumed to be 60 kWh
- EV performance for each agent is assumed to be 3.27 miles/kWh (the weighted average rate based on current EV market share)
- Average annual mileage of 14,600 miles (the mean extracted from the NHTS)
- 100% of vehicles are assumed to participate in a utility-controlled EV charging load shifting program
- Charging time and magnitude is shifted based on the magnitude of surplus renewable generation

### Baseline Charging Behavior for an Individual Agent and on the Aggregate

Figure 25 illustrates driving behavior for Agent 20004480:2 in the NHTS (a typical agent). The agent leaves home in the morning, heads to work, drives to lunch, and then drives home in the evening. This agent is available to charge when they are not driving (the blue sections).

Figure 25. Driving Behavior for Agent 20004480:2 in the NHTS.



The nominal state of charge of the agent’s battery is shown in Figure 26 and the agent’s charge-discharge profile is shown in Figure 27 (blue: charging, red: discharging). One can see that this agent is able to quickly recharge their battery each time they stop driving.

Figure 26. EV Battery State of Charge Associated with Agent 20004480:2.

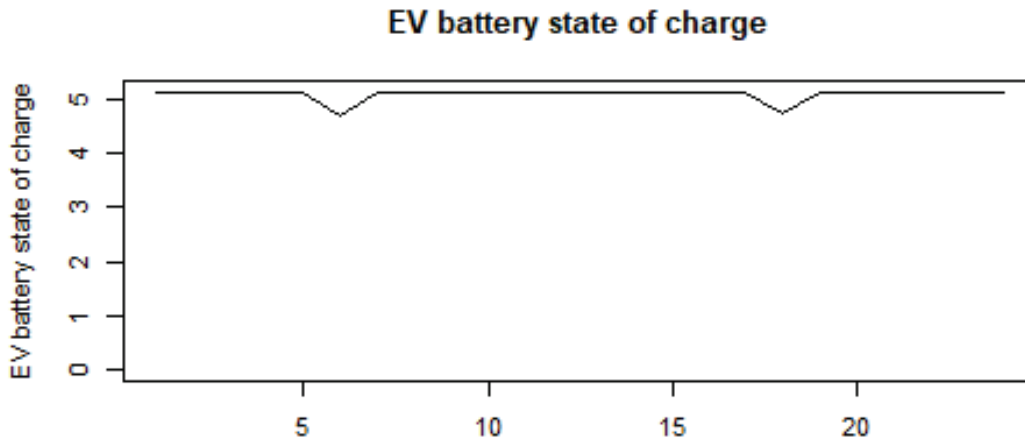
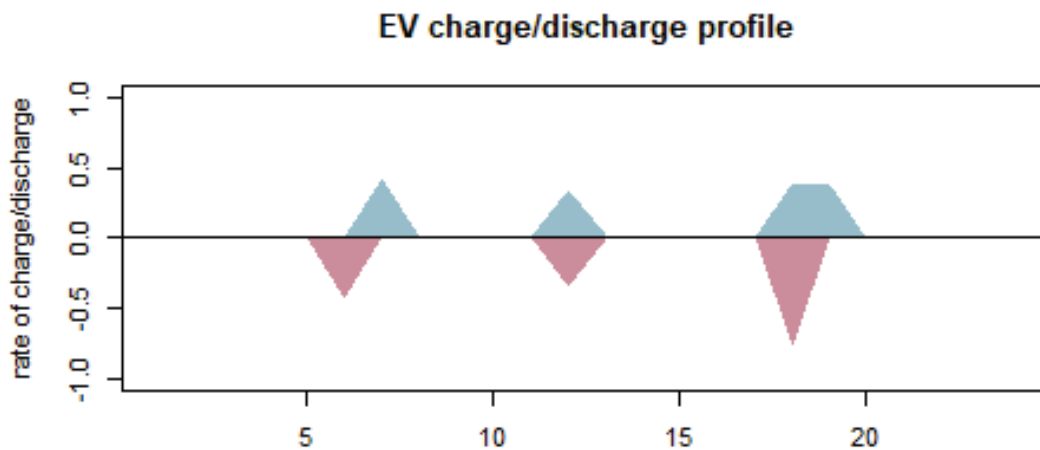


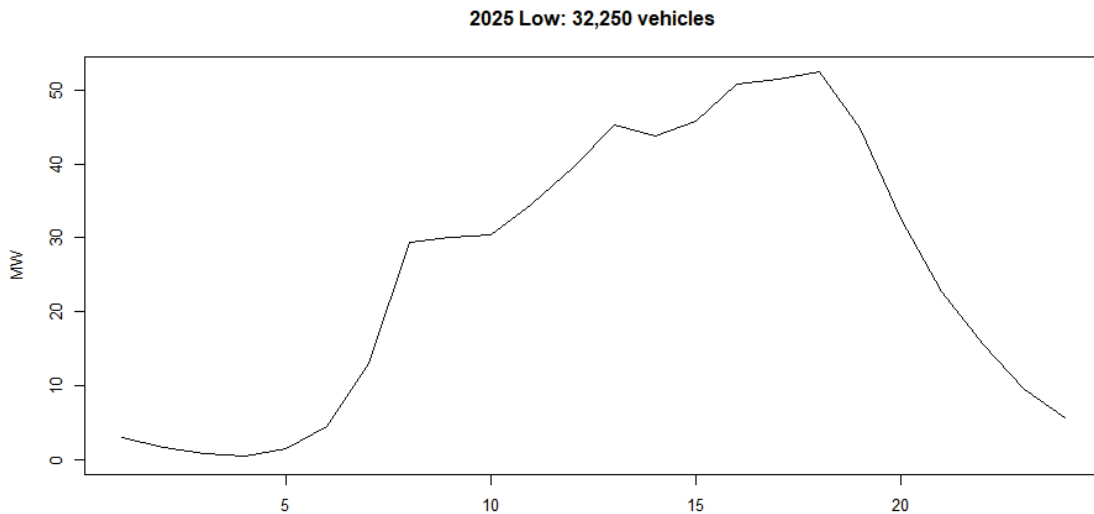
Figure 27. EV Battery Charge/Discharge Profile Associated with Agent 20004480:2.



The aggregate EV load impact in Minnesota is determined by repeating this analysis for each of the 3500 agents selected from the NHTS, aggregating the results, and scaling the aggregate results to account for the forecasted EV adoption.

For the 2025 timeframe, 32,250 EVs are expected in Minnesota under the Low Technology Development scenario. The load impact from these EVs is shown in Figure 28. In the Low Technology Development scenario EVs are expected to add 50 MW of load in the late afternoon and early evening.

Figure 28. 2025 EV Load Impact for the Low Technology Development scenarios.



### Load Shifting

Agent 20004480:2 is now asked to charge their EV in a manner that is proportional to the amount of renewable production surplus, as shown in Figure 29 for a day with excess solar production. The blue area of the subplot (indicating when and how much this agent is charging their EV) shifts to hours with solar production. Note, it does not exactly match the shape of the solar surplus (not shown) due to the fact that the agent briefly uses their vehicle in the middle of the day. A plot of the battery state of charge (Figure 30) reveals that in order to consume excess solar production during the middle of the day, the EV battery must start and end the day in a partially discharged state (for this agent on this particular day).

Figure 29. EV Battery Charge/Discharge Profile with Load Shifting (Agent 20004480:2).

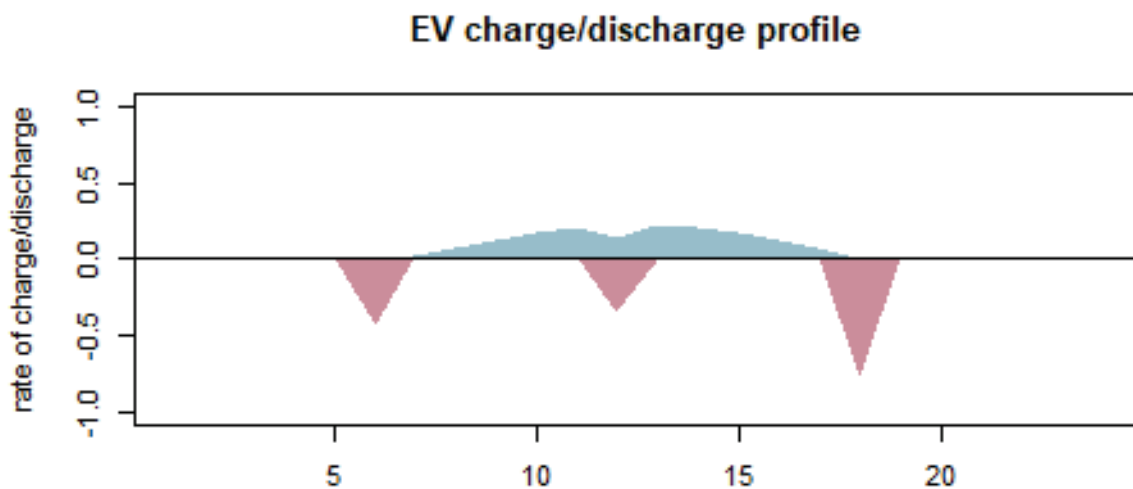


Figure 30. EV Battery State of Charge with Load Shifting (Agent 20004480:2).

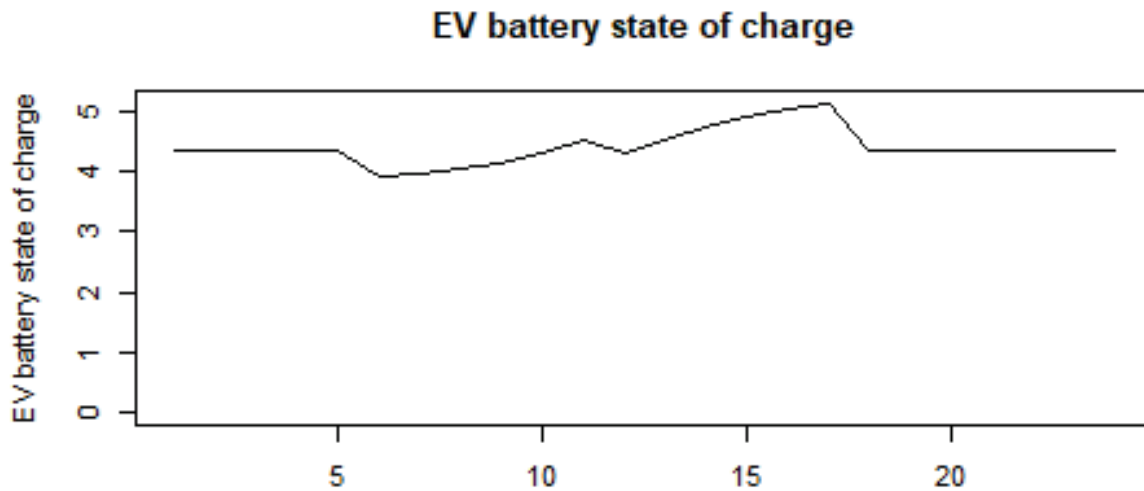
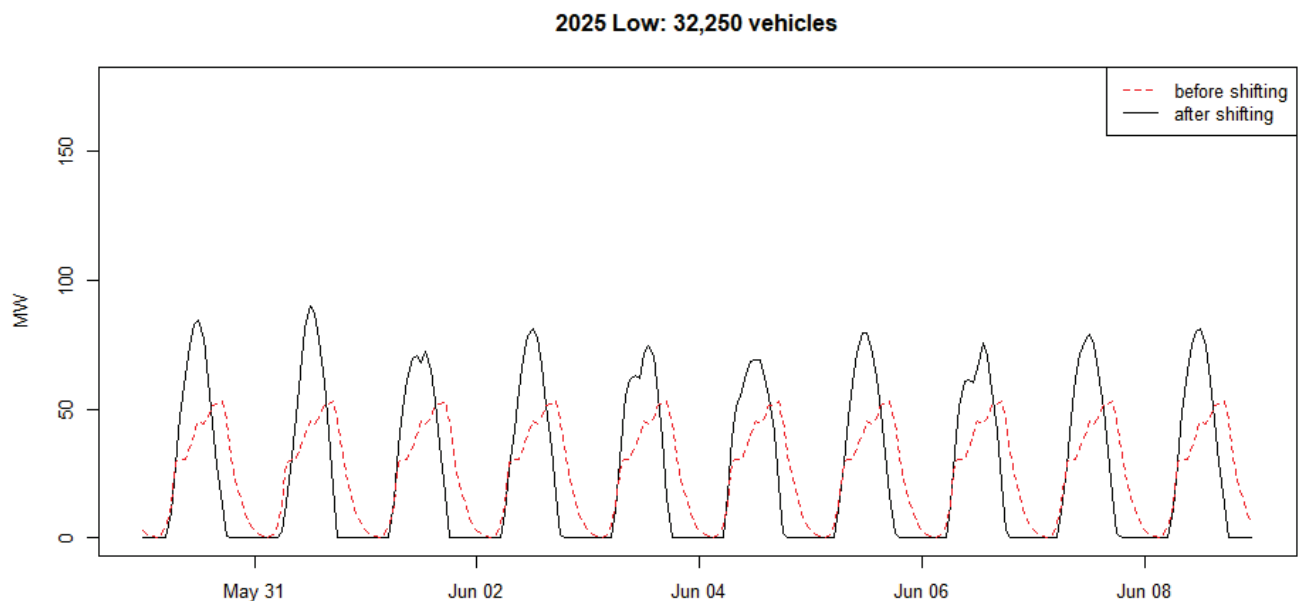


Figure 31 shows the aggregate load impact with and without load shifting for a sequence of days in the summer for a 100% solar scenario (a 100% solar scenario is used to provide visual simplicity). Each agent attempts to shift charging to hours with excess solar production. This reduces the amount of solar energy that is curtailed and also reduces the load that solar needs to serve in the late afternoon and early evening. At the same time, this increases the peak load associated with EV charging from 50 MW to roughly 80 MW (for the low EV adoption scenario in the 2025 timeframe).

Figure 31. Aggregate EV Load Impact with and without Load Shifting.



## Heating, Ventilation and Air Conditioning Summary

Heating, Ventilation, and Air Conditioning (HVAC) systems are the largest energy loads in Minnesota buildings. Today heating loads are mainly served using natural gas, but improvements to cold climate heat pump technology and decreasing grid emissions factors increase the potential for the widespread adoption of high efficiency heating under strategic electrification initiatives. Heat pumps consume electricity in order to transfer heat from inside to outside (air conditioning) or from outside to inside (heat pumping). Modern heat pumps have the ability to run at variable speed such that they can be ramped up or down to meet the load. Combined with occupant flexibility, these loads can be modulated by changing the set point or the dead band temperature range. In this way, these units can be used to pre-condition spaces or allow space temperatures to float beyond the set point. When coupled with remote controllers, this control increases or decreases the current energy load and shifts it to another time. This flexibility enables load shifting of the controlled HVAC loads to accommodate solar energy production goals.

Heat pump-based residential and commercial cooling systems for large retail, medium office, and K-12 schools were initially tested for load shifting capabilities but neglected in the final model.

This section outlines the approach taken for estimating the load shifting potential of residential & commercial HVAC units in the SPA model and the basis for not including them in the final results.

1. Market Penetration – The market penetrations of controllable HVAC units is divided into two groups. For commercial systems, the **existing air conditioning systems are considered for the following DOE reference building types: medium office, school, and retail**. These loads are already part of the SPA load model and load shifting control is enabled on some portion (market penetration). The second group considers **new residential electrical HVAC units or heat pumps**, for example those units that may switch over from natural gas heating under strategic electrification scenarios. The difference between the two groups is seasonal; existing air conditioning systems can be leveraged in cooling season and future heat pump systems can be leveraged year-round.
2. Opportunity – Heat pump systems come in a variety of sizes and more importantly residential single-family construction has a large variety of heating and cooling loads. Nonetheless, there exists an average home that when multiplied by the total number of single-family dwellings yields a representative net HVAC load for the purposes of the SPA model. Residential utility energy consumption, average house size, and typical thermal capacity of stick- frame construction are sufficient to characterize this average home. Assuming heat pump systems are properly sized, this representative home approximately requires a 4 Ton heating and 2.5 Ton cooling system.

Commercial buildings have more variation in thermal properties and cooling system types compared to residential buildings. To simulate commercial loads that may become available for load shifting, four types of DOE reference buildings are used. The reference buildings are run through an EnergyPlus simulation using SPA weather data from Clean Power Research. From these simulations, thermal properties and cooling system sizes are extracted to construct the load shifting model. These per-building data are then aggregated across the state by scaling the loads to the average building size for the reference building type and estimated number of each building type.

3. Constraints – HVAC loads are constrained based on the need to properly condition a space. The assumption used here is that occupants will tolerate changes in set points and dead bands depending on occupied state: 1) home, 2) away or 3) night. The **minimum** amount of energy that need be available to meet space conditioning requirements changes based on occupancy and weather. Additionally, the controlled units have a **maximum capacity** (furthest beyond the set point) and a **maximum load** (all HVAC systems activated simultaneously). These dead band temperature limits and schedules vary for each of the building types (residential single family, medium office, school, and retail).

HVAC loads are likely to require some real time weather forecasting to properly plan HVAC consumption with respect to renewable energy production. The technical details of how these units are controlled are beyond the SPA model. Nonetheless, there currently exist smart thermostats and demand response programs that can provide similar functionality at relatively low cost. The incremental cost of compatible units is assumed insignificant in the model.

#### Key Residential Assumptions:

- An average residential home with respect to size, heating and cooling loads, and thermal capacitance and the incidence of participating homes is sufficient to estimate the thermal inertia that can be leveraged for load shifting.
- Strategic electrification initiatives will add new electric load by converting natural gas and LPG space heating units to heat pump DHW units.
- Occupancy schedules are assumed from average commuting data (residential) or DOE reference building schedules (commercial). The dead bands are given in Table 11.

Table 11. Temperature Dead-bands for HVAC modeling.

Heat	Residential	Medium Office	Retail	School
Occupied	±2	n/a	n/a	n/a
Unoccupied	±4	n/a	n/a	n/a
Night	+4 -8	n/a	n/a	n/a
Cool	Residential	Medium Office	Retail	School
Occupied	+2 -4	+2 -7	±2	+1 -3
Unoccupied	+6 -6	+5 -7	±4	+5 -6
Night	+6 -6	+5 -7	+10 -6	+10 -6

### Example Scenario

The 2025 Low Technology Development scenario provides a conservative estimate of the number of existing air conditioning systems that will be available for load shifting. It does not assume any kind of strategic electrification program. It assumes 20% of eligible single-family homes will participate, yielding about 290,000 units. Unlike other the other shift-able loads, HVAC shifting strongly depends on the weather. More specifically, the size of the heating or cooling load compared to the size of the equipment.

### High Level Calculation Steps

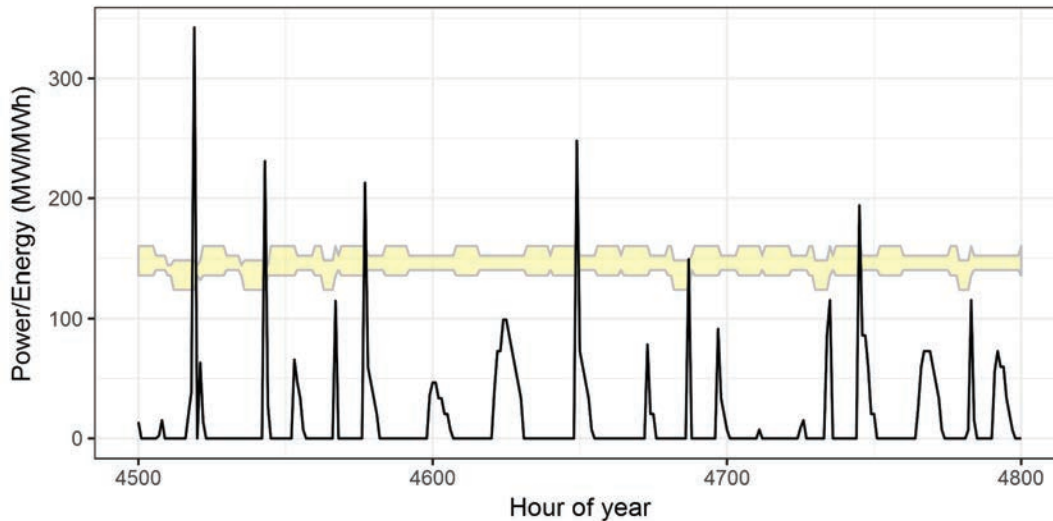
The calculation treats the fleet HVAC systems and buildings as a thermal battery with limits that change depending on occupancy. The first step is to determine the heating (or cooling load) on the building. This is followed by a calculation of the thermal capacity of the battery, which changes depending on the season, time of year, and occupancy as it floats with respect to outdoor conditions. The minimum power for the fleet of HVAC systems is that necessary to maintain the bottom of the dead band range in the given time step (i.e. low temperature in heating or high temperature in cooling). The maximum power for the fleet of HVAC systems is that necessary to maintain the top of the dead band range in the given time step (i.e. high temperature in heating or low temperature in cooling). The SPA model can manipulate the total power of the system within this range and shape the demand curve in response to solar and wind energy production. The effects of the current power draw are carried forward into the next time step with potentially new HVAC loads, new thermal battery capacities, and new generation constraints.

The following figure shows an example of residential load shifting during a two-week period in July defined by TMY3 weather for Minneapolis, MN. In this period there are heating and cooling loads. The yellow area shows how the capacity of the thermal battery (MWh) changes in response to the type of load, occupancy, and day and night periods. The black line is the aggregated power of the controlled homes at the grid level. In this plot, the grid is randomly



requesting zero power, maximum power, or the nominal power required to maintain the default set point, in order to demonstrate possible variations.

Figure 32. Demonstration of HVAC load shifting capabilities. The black line represents shifted load. (Unshifted load is not shown). The yellow region shows the capacity (MWh) of the thermal battery change as thermostat set points, dead bands temperatures, and outside air temperatures vary over time. The black line is the power (MW) input into the thermal battery as a function of its capacity, heating and cooling requirements, and grid demands.

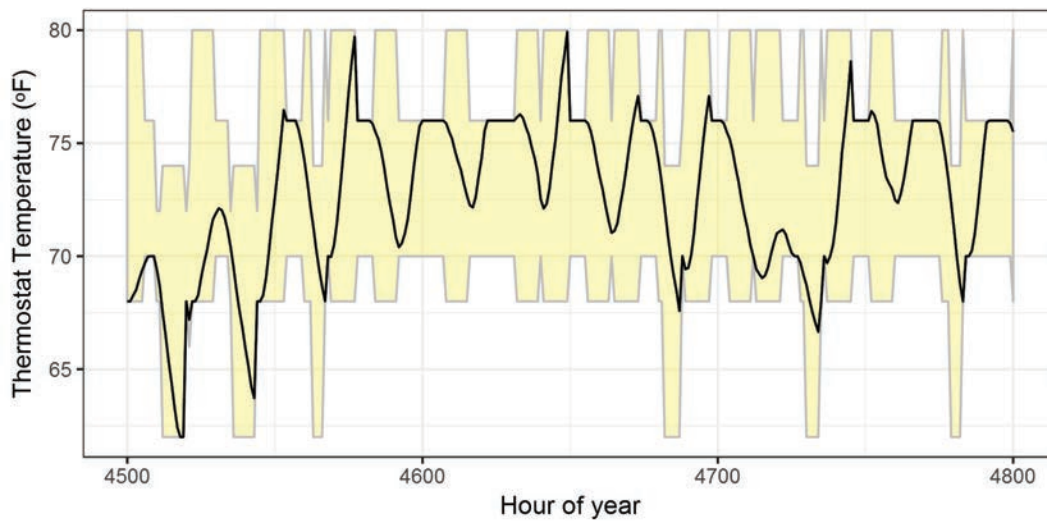


A better understanding of the model is available by looking at the average value of indoor temperature for the thermal battery during this period as seen in Figure 33 (next page). The available thermal battery capacity is represented by the dead band temperature range as the yellow shaded region. The actual temperature in the dwelling swings throughout this dead band depending on how the HVAC system is externally controlled.

Initial model runs (demonstrated in the prior figures) highlight two key attributes that prevented the inclusion of building thermal storage as a load-shifting component of the SPA model. First, the capacity of the system is relatively small compared to DHW and EV loads, particularly during peak heating and cooling periods. At peak conditions the systems are sized to meet the load and buildings lose capacity very quickly, usually providing a few hours or less of load shifting. This has high value as a demand response measure because peak loads can be temporarily curtailed, but it does not align with the daily or multi-day periods that drive costs in the SPA model. Alternatively, these loads are most flexible during mild weather periods; however, their overall energy demand is also very small, which limits their utility for accommodating solar and wind production profiles. Secondly, these thermal batteries are somewhat impactful when pre-conditioned and coasted to the limits of thermal comfort. While this strategy allows stretching a one or two-hour shift to 4 hours or more, it is also questionable from a comfort perspective – particularly if it is a common occurrence. For example, pre-cooling

a commercial building to 64 °F and allowing it to coast to 80 °F is likely a taxing experience for building occupants from a comfort perspective. A temperature swing of half this value (68°F to 76°F) approximately halves the duration of an eligible shift (for example, from four to two hours), but also still likely pushes the limits of thermal comfort. In light of these observations, the overall diminished load shifting utility compared to the DHW and EV loads, and integration work required, HVAC shifting was not integrated into the SPA model.

Figure 33. Plot of the indoor (thermostat) temperature against time as HVAC load is shifted (black line). The indoor temperature limits are shown by the yellow region and depend on time of day and occupancy.



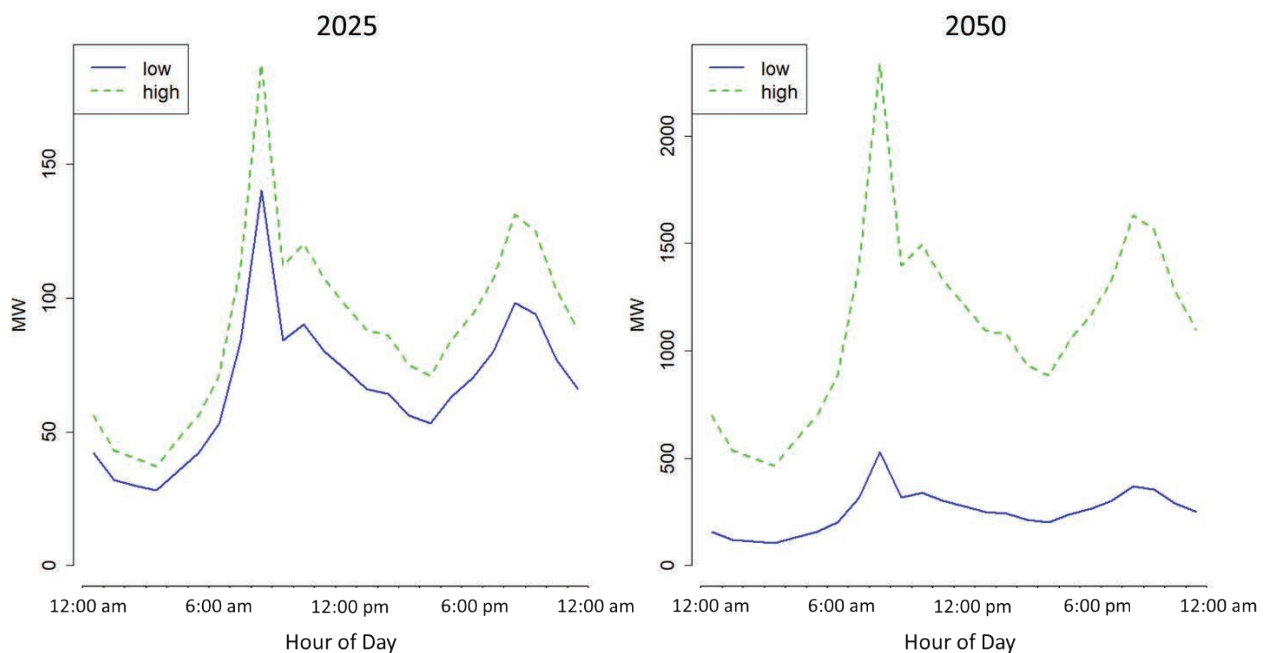
## Appendix C: Electrification and Load Shifting Results

### Load Impact of Domestic Hot Water (DHW) Electrification

A daily load profile for DHW was developed through an analysis by Center for Energy and Environment (CEE). In combination with DHW electrification estimates that were also developed by CEE<sup>34</sup>, daily DHW load profiles were developed for the Low and High Technology Development scenarios in both the 2025 and 2050 timeframes.

Figure 34 plots the DHW load in the 2025 and 2050 timeframes for the High Technology Development scenario (dashed green line) and Low Technology Development scenario (solid blue line). The maximum effect of DHW electrification on Minnesota’s load profile in the 2025 timeframe is 200 MW, which is fairly small relative to a peak load of 15 GW. However, DHW electrification becomes more significant in the 2050 timeframe. Absent load control, DHW electrification is expected to add 2.5 GW of load in the early morning, 1-1.5 GW of load during the day, and roughly 0.5 GW of load during the night for the High Technology Development scenario in the 2050 timeframe.

Figure 34. DHW Load in 2025 and 2050. (The dashed green line is the DHW load with High Technology Development and the solid blue line is the DHW load with Low Technology Development).



<sup>34</sup> Reference appendix

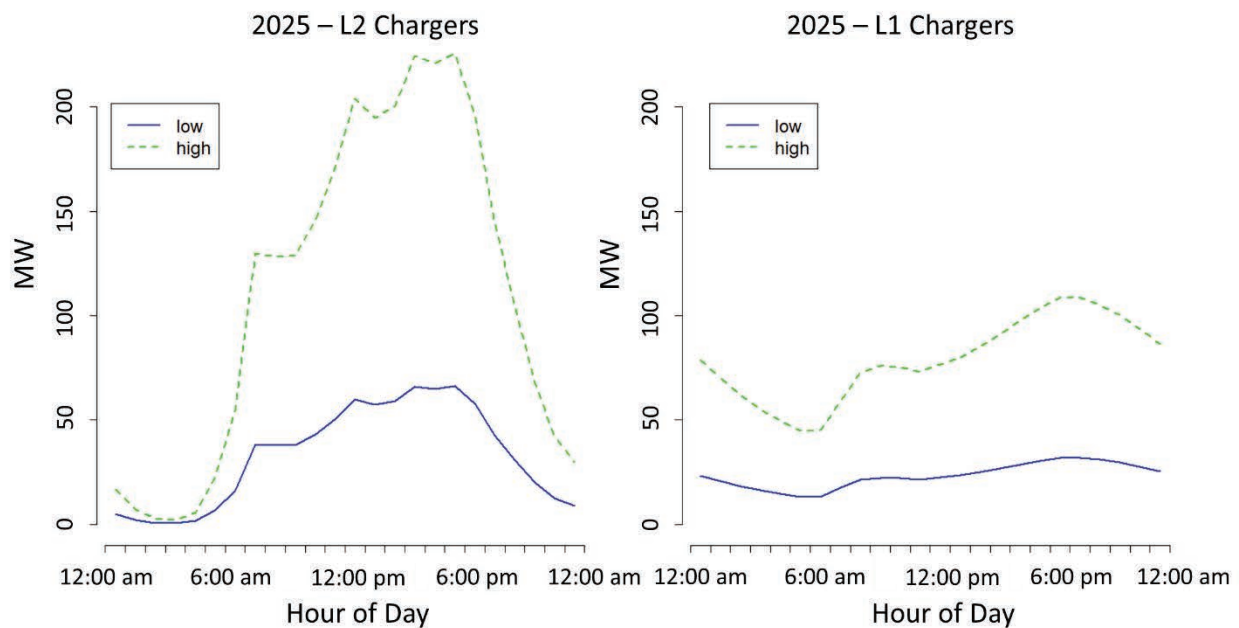
## Load Impact of Electric Vehicles

The load impact of transportation electrification depends on electric vehicle (EV) adoption rates and charging behaviors. Electric vehicles can draw significant amounts of power. For example, a single L2 charger demands 19.2 kW at peak charging rates.

A daily charging profile was developed based on a dataset of household driving behavior, as described in [Appendix B: Electrification and Load Shifting Models](#). It was assumed these vehicles charge at the peak rate of the charger type when the vehicle is parked. This assumption produces a peakier charging profile than would occur if charging was modulated to support the needs of the grid.

Figure 35 plots the load impact of vehicle electrification in the 2025 timeframe for Low and High Technology Development scenarios assuming for both L1 chargers (left panel) and L2 chargers (right panel).

Figure 35. EV Load in 2025 with L1 (right) and L2 chargers (left). (The dashed green line is the EV load with High Technology Development, the solid blue line is the load with Low Technology Development).

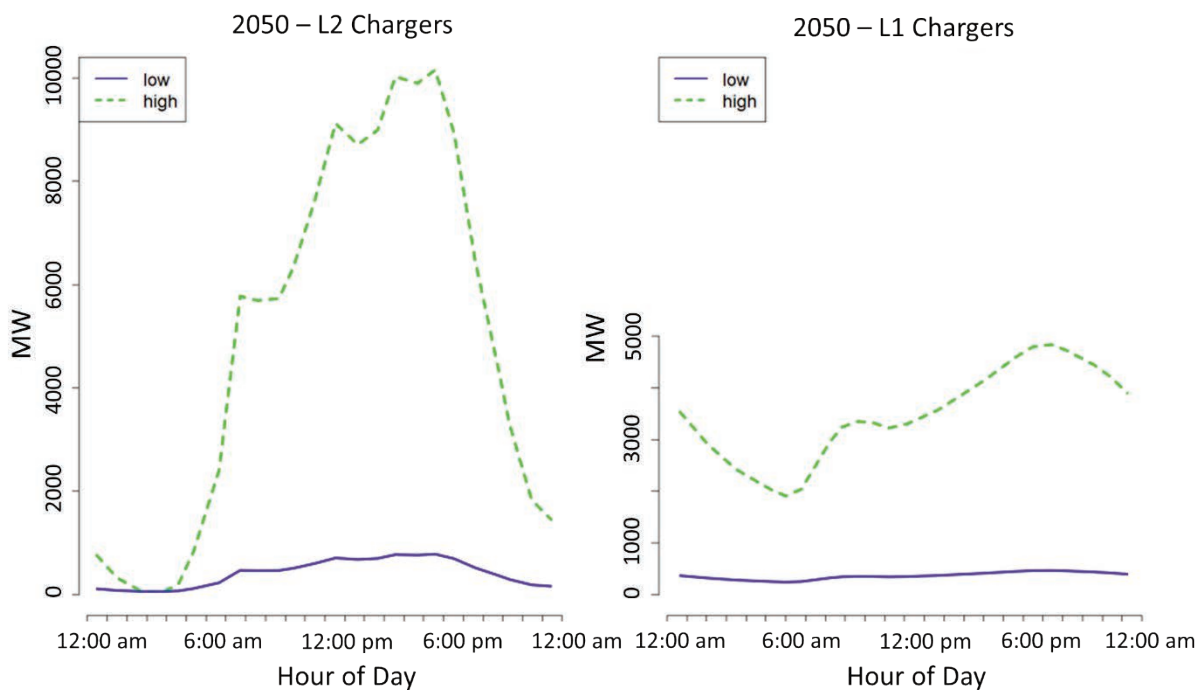


The charger type has a marked effect on the shape and peak load of EV load. L1 chargers, which draw up to 1.9 kW, take eight or more hours to recharge a vehicle’s batteries. By comparison, L2 chargers draw up to 19.2 kW and can recharge a vehicle’s batteries within a couple hours. Absent load control, L2 chargers result in a peaky load compared with the load profile from L1 chargers, which distribute EV charging over many hours, including overnight hours.

In the 2025 timeframe the load impact of EVs on Minnesota’s load is projected to be small, a maximum of 200 MW relative to Minnesota’s 15 GW peak load. In the 2050 timeframe the impact of EV Load is quite significant, as seen in Figure 36. Either the 8 GW of peak load associated with L2 chargers or the roughly constant 4 GW of load associated with L1 chargers represents a significant addition of load to Minnesota’s existing hourly load (10-15 GW).

As noted in the SPA Scenarios section, the Low and High Technology Development scenarios are meant to bound the possible future outcomes. Given that significant adoption of EVs still has a degree of uncertainty associated with it, the Low Technology Development scenario has much more modest EV adoption compared with the High Technology Development scenario.

Figure 36. EV Load in 2050 with L1 (right) and L2 (left) chargers. (The dashed green line is the EV load with High Technology Development, the solid blue line is the load with Low Technology Development).



### Load Impact of Residential Heating Electrification from Air Source Heat Pumps

The load impact of residential heating is weather-dependent. As such, CEE developed a model for determining the hourly load impact from residential heating based on historical weather data and the known thermal performance of Minnesota homes. Combined with air source heat pump (ASHP) adoption estimates developed by CEE<sup>35</sup>, hourly load profiles for each hour of the

<sup>35</sup> Reference appendix

year were developed for the Low and High Technology Development scenarios in both the 2025 and 2050 timeframes.

Figure 37 plots the hourly load from ASHP's for a week in mid-January for the Low and High Technology Development scenarios in the 2025 timeframe. As seen in the plot, ASHP's add a variable load that changes with changing weather conditions, sometimes quickly over the course of a few hours, sometimes slowly over the course of a day. ASHP's are expected to add modest amounts of load in the 2025 timeframe for both the Low Technology Development scenarios (200 MW – 800 MW of load) and High Technology Development scenarios (400 MW – 1400 MW of load) during the peak heating season.

Figure 38 plots the daily energy requirements from ASHP's for each day in 2016 for the Low and High Technology Development scenarios in the 2025 timeframe. Examining the figure one sees the expected seasonal dependency of residential heating load.

Figure 39 and Figure 40 plot the hourly load and daily energy requirements from ASHP's for the 2050 timeframe. By 2050, the load impact of residential heating will add as much as 5 GW of load in the winter months as shown in Figure 42. This is a significant amount of load and has the potential to shift Minnesota's load from summer-peaking to winter-peaking. Additionally, while the load added by residential heating is greatest during the middle of winter, it is clear from Figure 43 that meaningful amounts of load will be added from November through April.

Figure 37. Residential Heating Load in 2025 during a Cold Winter Week. (The dashed green line is the residential heating load with High Technology Development, the solid blue line is the residential heating load with Low Technology Development).

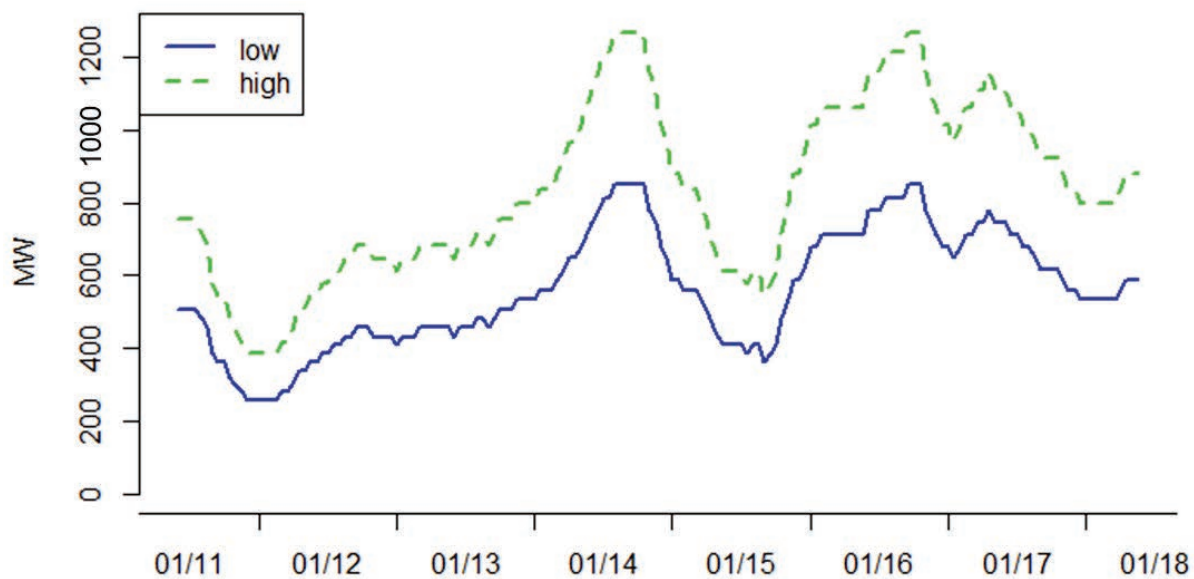


Figure 38. Daily Residential Heating Load in 2025. (The blue line is the residential heating load with **High Technology Development**, the grey line is the Minnesota load).

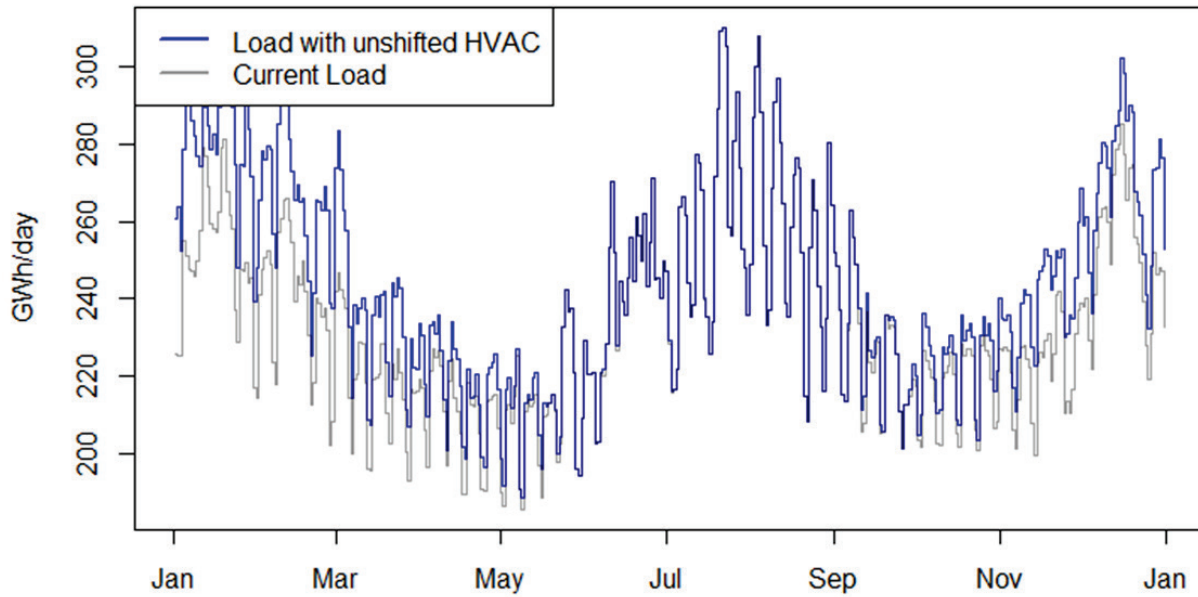


Figure 39. Residential Heating Load in 2050 during a Cold Winter Week. (The dashed green line is the residential heating load with High Technology Development, the solid blue line is the residential heating load with Low Technology Development).

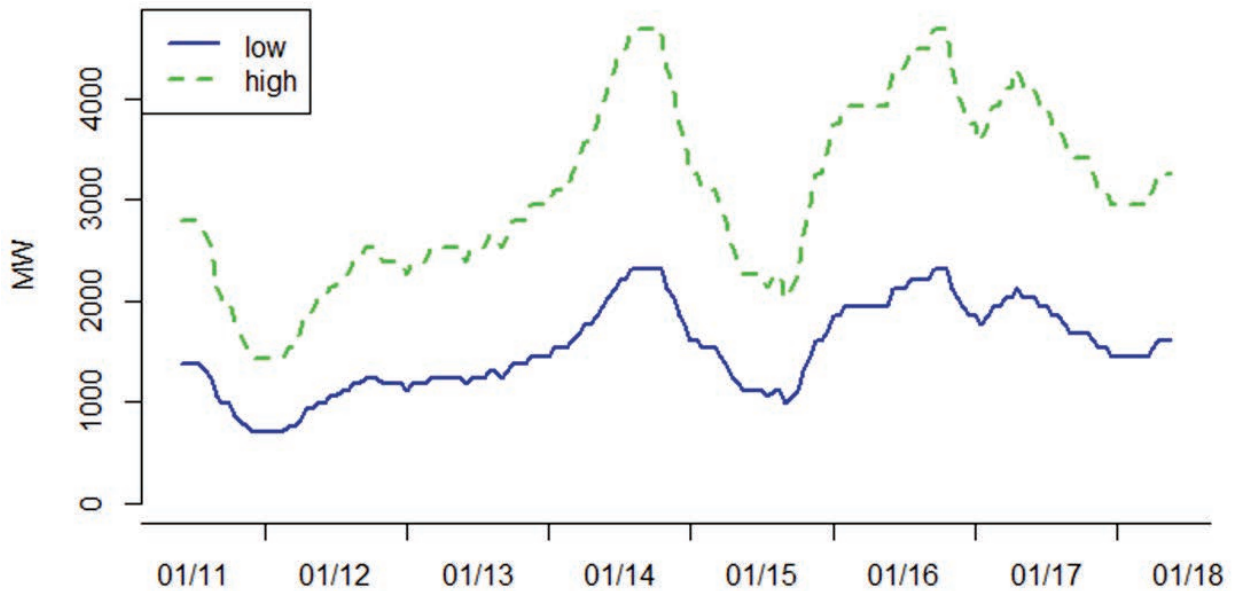
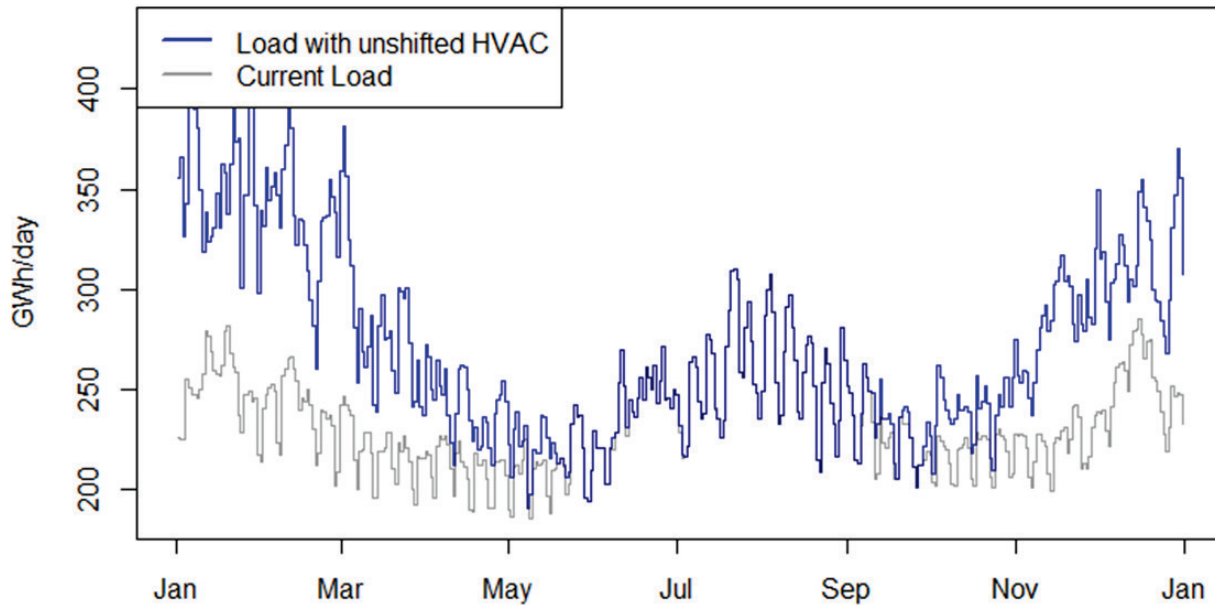


Figure 40. Daily Residential Heating Load in 2050. (The blue line is the residential heating load with High Technology Development, the grey line is the Minnesota load).



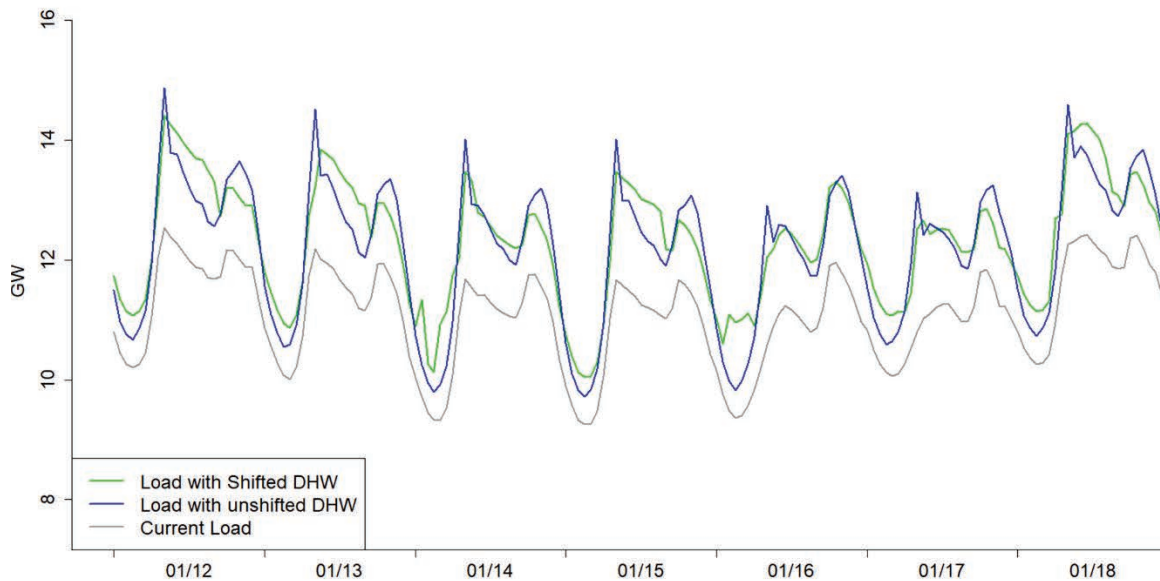
### DHW Load Shifting

The green line in Figure 41 illustrates the amount of load shifting that can be accomplished using DHW without violating modeled customer constraints (i.e., without preventing a customer from being able to have access to hot water). Domestic hot water heaters store enough energy when full that their load profile can be modified to shift load within a single-day and can even shift a fraction of their load from one day to the next. Shifting DHW load beyond a single day is not possible given that domestic hot water heaters only store slightly more energy than their daily needs.

The effect of DHW load shifting on the SPA results was not studied in isolation from EV load shifting. The combined effect of DHW and EV load shifting on the SPA results is discussed further below.



Figure 41. DHW load shifting in 2050 High Technology Development scenario. (The dark grey line is the Minnesota load, the blue line is the Minnesota load + the unshifted DHW load, the green line is the Minnesota load + the shifted DHW load.



## Electric Vehicle Load Shifting

Figure 42 and Figure 43 plot the EV load shifting possible in the 2050 High Technology Development scenario with L2 and L1 chargers, respectively. As can be seen from these figures, significant amounts of EV load can be shifted into hours with excess solar and wind production (relative to load). Additionally, some EV load can be shifted over a period of multiple days (not easily visible in the figures, but verified from a deeper analysis of the load shifting data).

Notably, the load shifting algorithm in the SPA seeks to charge a vehicle's battery as quickly as possible without considering the potential for excess solar and wind production in future hours (e.g., from load and renewable production forecasts). As such, the algorithm produces a significant increase in load as soon as an excess of solar and wind production is present. This is most notable when L2 chargers are assumed (Figure 42) and is easily visible in the early morning hours. This load spike can be as much as 20 GW in the 2050 High Technology Development scenario. As noted above, the load in this spike could be spread over several hours with excess renewable production using load and renewable production forecasts. Nonetheless, the magnitude of the current spike raises the important concern of whether load shifting (to reduce generation costs) might require increased distribution capacity (and thus increase distribution costs). Future studies should examine this trade-off.

Figure 42. EV load shifting in 2050 High Technology Development scenario with L2 chargers. (The dark grey line is the Minnesota load, the blue line is the Minnesota load + the unshifted DHW load, the green line is the Minnesota load + the shifted DHW load.

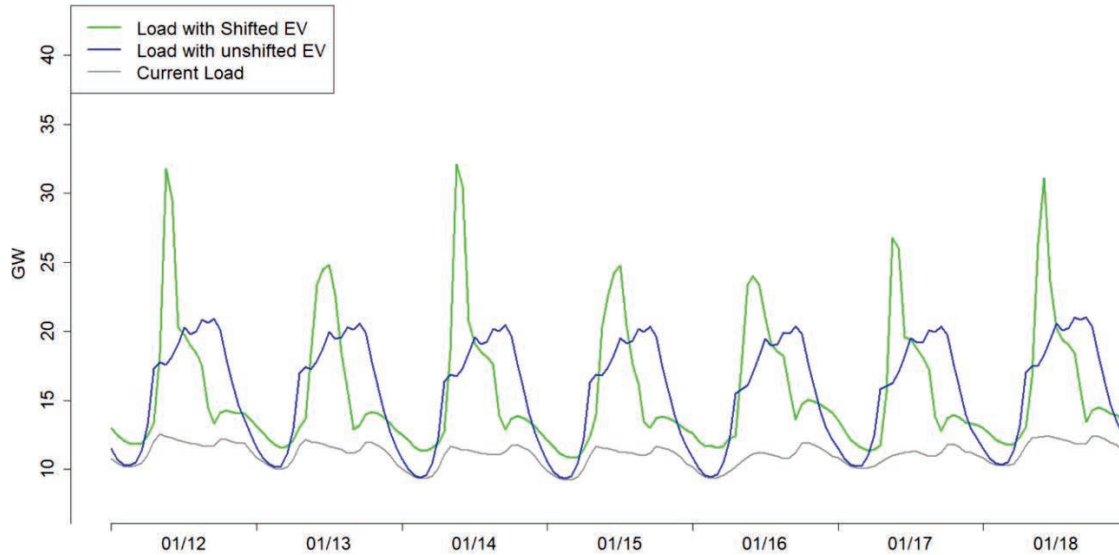
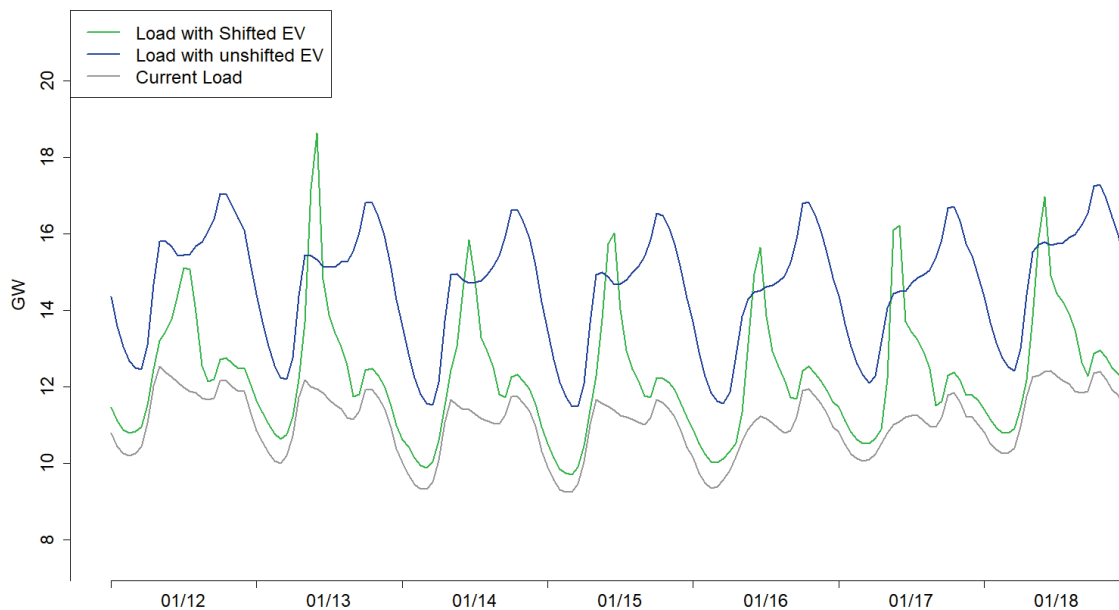


Figure 43. EV load shifting in 2050 High Technology Development scenario with L1 chargers. (The dark grey line is the Minnesota load, the blue line is the Minnesota load + the unshifted DHW load, the green line is the Minnesota load + the shifted DHW load.



## **Air Source Heat Pump Load Shifting**

Preliminary analysis suggested little ability to impact the SPA results with residential air source heat pump (ASHP) load shifting because generation costs are driven by multi-day winter time periods of low solar and wind production. Hence, ASHP load shifting was not included in the SPA. For existing single family residential construction, heating loads can seldom be shifted beyond a few hours during these periods, especially during the periods of high heating load that drive SPA generation costs. Other short term demand response strategies were not explored because their benefits to the transmission & distribution system are not a component of the SPA.

## Appendix D: Spatial Allocation of Solar

Equation 1 below presents the general form of the formula that Clean Power Research used to spatially allocate solar capacity in the solar deployment scenarios. In this formula,  $w_x$  refer to weights that are applied to each of the three parameters. Figure 44 provides a visual illustration of the calculation process implied by Equation 1.

$$\text{Eqn 1. Solar Deployment Scenario} = \left( \begin{array}{c} \text{Transmission} \times w_1 \\ + \\ \text{Irradiance} \times w_2 \\ + \\ \sqrt{\text{Population}} \times w_3 \end{array} \right) \times \left( \begin{array}{c} \text{Non-Deployment} \\ \text{Zone Filter} \end{array} \right)$$

Figure 44. Illustration of the calculation process implied by Equation 1.

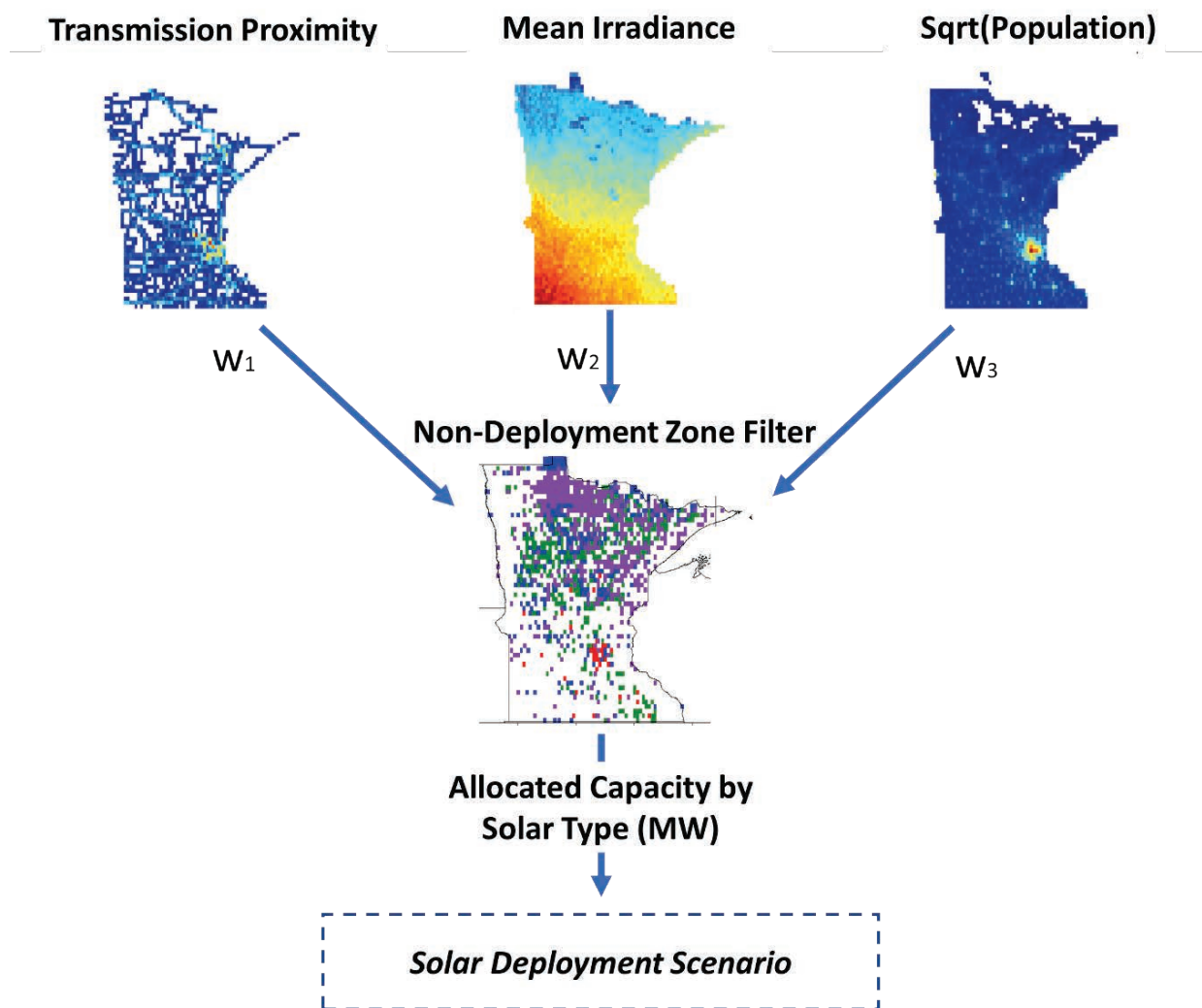


Figure 45 below provides a visual demonstration of the creation of the non-deployment zone filter. Urban coverage (red tiles) are excluded as candidates for PV deployment for utility-scale solar.

Figure 45. Illustration of the creation of the Non-Deployment Zone Filter<sup>36</sup>.

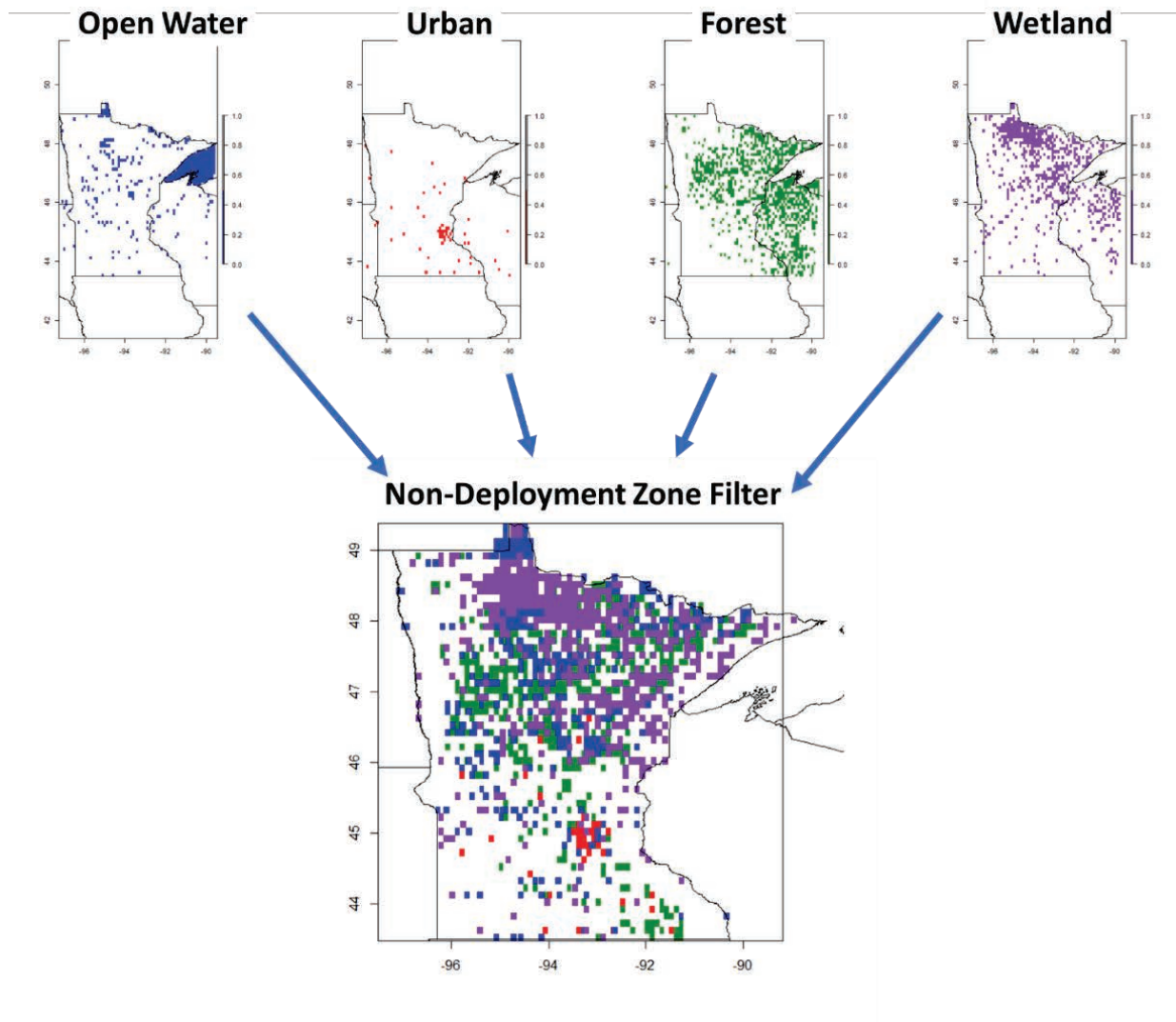


Figure 46 demonstrates the results of this process for sample utility and non-utility solar allocations. These examples allocate 5,000 MW of PV across the state with the weighting and

<sup>36</sup> The Non-Deployment filter was created using the USGS National Land Cover Database (NCLD) and omits spatial tiles as candidates for PV deployment where over 30% of its constituent land is classified as open water, urban zone (in the utility-scale case), forest or wetland

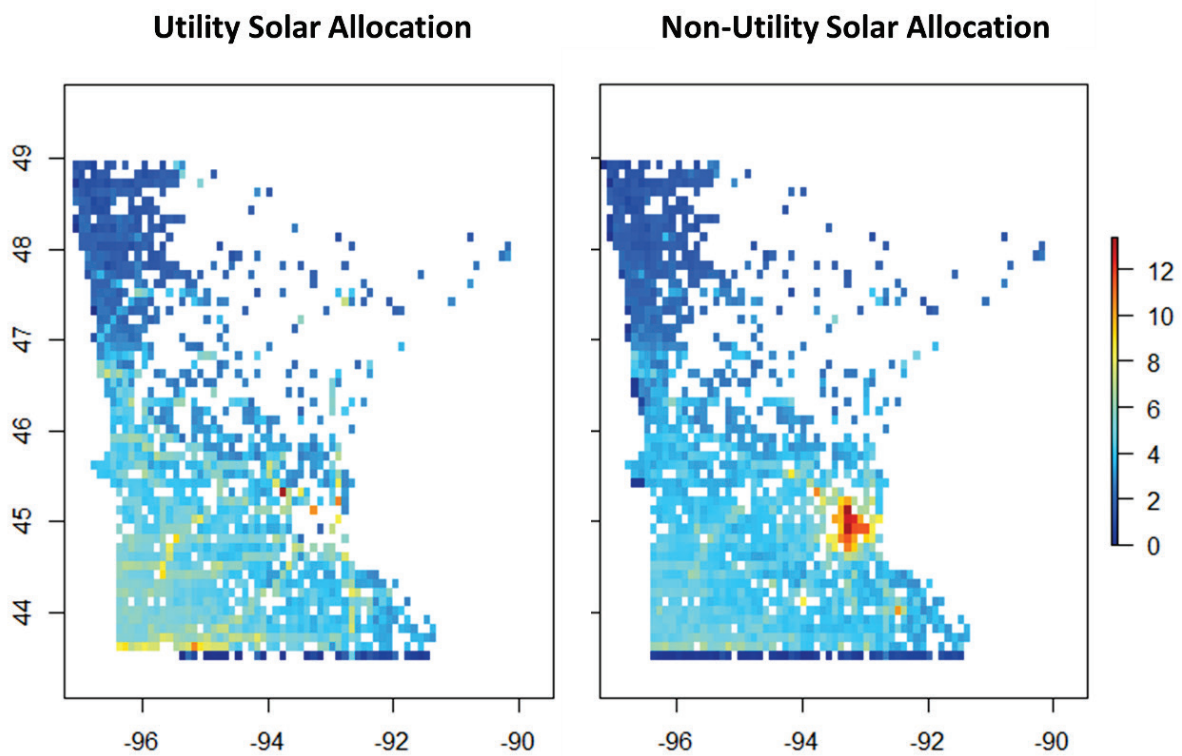
non-deployment zone filters listed below. The vectors of weights refer to transmission proximity, irradiance and sqrt(population), in that order.

Figure 46. Example Utility and Non-Utility Solar Allocations.

**Example using**

**Allocated Capacity (MW) : 5,000**

- $w_{\text{utility}} = \{2, 1, -1\}$  ← filtering: lakes, forest, wetland and urban
- $w_{\text{non-utility}} = \{1, 1, 2\}$  ← filtering: lakes, forest, wetland



## Appendix E: Additional SPA Datasets

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The SPA generated a significant volume of data. Key datasets produced by the SPA but not contained in this report include:

- Optimization Curves
- Hourly Dispatch Profiles
- Ramp Rate Distributions

Clean Power Research may be able to make some or all of this data available through a publicly accessible website. If data is made available, instructions on how to access the data will be provided through the MN Solar Pathways website ([mnsolarpathways.org](http://mnsolarpathways.org)).

A brief description of these datasets is provided below for those interested in better understanding the analysis performed.

### Optimization Curves

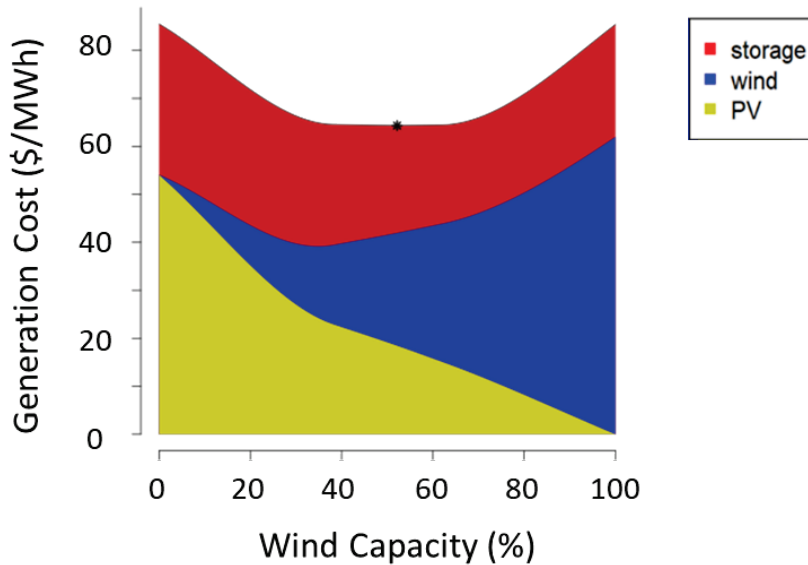
Optimization curves contain results from many SPA analyses (one of which produced the lowest cost set of resources to serve the production target and many of which did not produce the lowest cost set of resources). By holding many variables constant and varying a single variable, optimization curves can produce significant insights such as the generation cost reduction provided by *Additional Capacity* (see Figure 10). Another insight produced by optimization curves (and previously discussed) was the ability of small amounts of *Other Generation* to produce significant generation cost reductions (see Figure 12).

Three types of optimization curves were produced during the SPA

- Dispatchable Solar optimization curves
- Solar-to-Wind optimization curves
- *Other Generation* optimization curves

An example of a solar-to-wind optimization curve is shown below in Figure 47 (the black dot is placed at the generation cost minimum). This optimization curve demonstrates that there is a relatively flat minimum in the generation cost as a function of the percentage of wind capacity serving the Hourly Production Requirements with a Utility-Led Solar Distribution and High Technology Development scenario (please remember that wind has roughly twice the capacity factor of solar, thus equal capacities translate to twice as much energy production from wind than solar). This indicates that moderate flexibility exists in the deployed solar and wind capacities without a significant impact to the generation cost.

Figure 47. Solar to Wind Optimization Curve.



### Hourly Dispatch Profiles

Hourly dispatch profiles were produced for each generation/storage resource (solar, wind, storage, and *Other Generation*) and load shifting resource (residential domestic hot water and electric vehicles). Dispatch profiles were used by Clean Power Research to better understand the results produced by the SPA. An aggregation of the hourly dispatch profiles is shown in Figure 48 for a week in January.

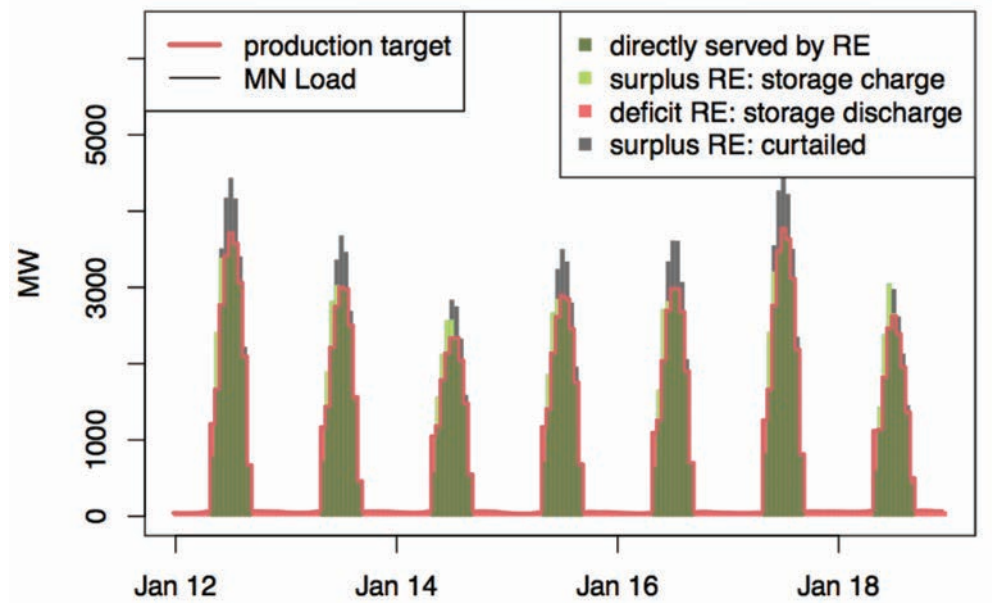
### Ramp Rate Distribution Curves

Ramp rate distribution curves were produced to determine whether the system ramp rates increased or decreased for each of the SPA scenarios. Ramp rate was defined as the current Minnesota load less the production profile less the previous hour's Minnesota load less the production profile:  $(\text{Minnesota Load} - \text{Production Profile})_{\text{Current Hour}} - (\text{Minnesota Load} - \text{Production Profile})_{\text{Previous Hour}}$

The ramp rate distribution curves are most interesting for the Production Requirements in the 2025 Timeframe, where the solar resource can have greater variability. By comparison, the 2050 Production Requirements have significantly less variability since solar, wind, and storage are expected to serve Minnesota's hourly load.



Figure 48. Aggregation of hourly dispatch profiles for a week in January (Predictable Production Requirements).

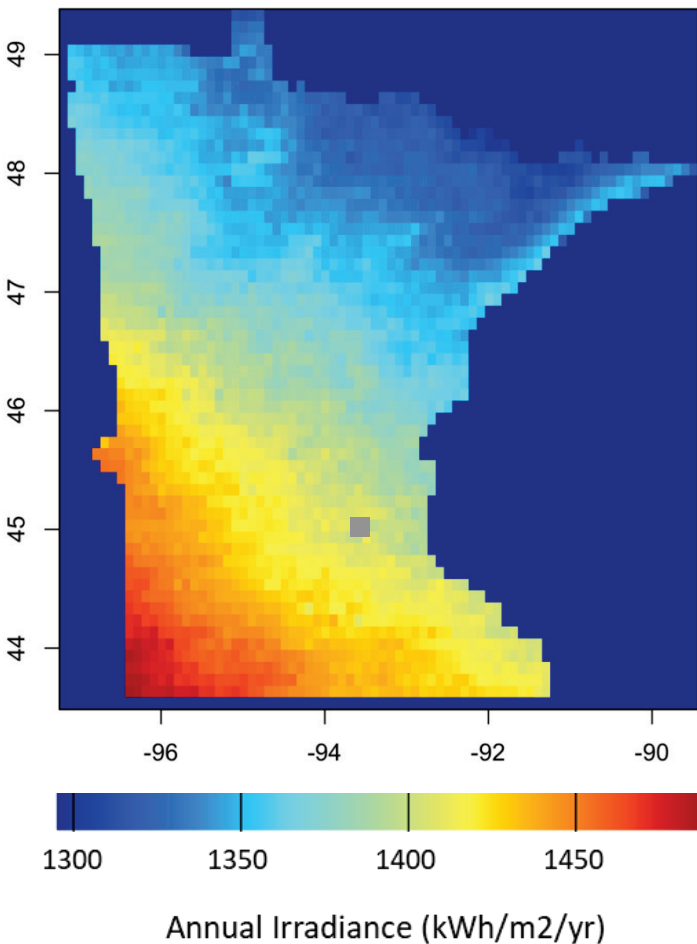


## Appendix F: Land Use

### Area Required by Solar

To add some context to the results generated in this report, it is useful to examine how much area is required to meet the production targets we discuss above with solar. In 2016, Minnesota’s electrical load was 86 TWh. Below, we explore how much solar is required to generate 86 TWh and its dependence on location.

Figure 49: Horizontal Irradiance across the state of Minnesota in kWh/m<sup>2</sup>/yr. The dark grey square represents the 330 km<sup>2</sup> of area needed by solar to generate the amount of electricity in Minnesota’s annual electric load.



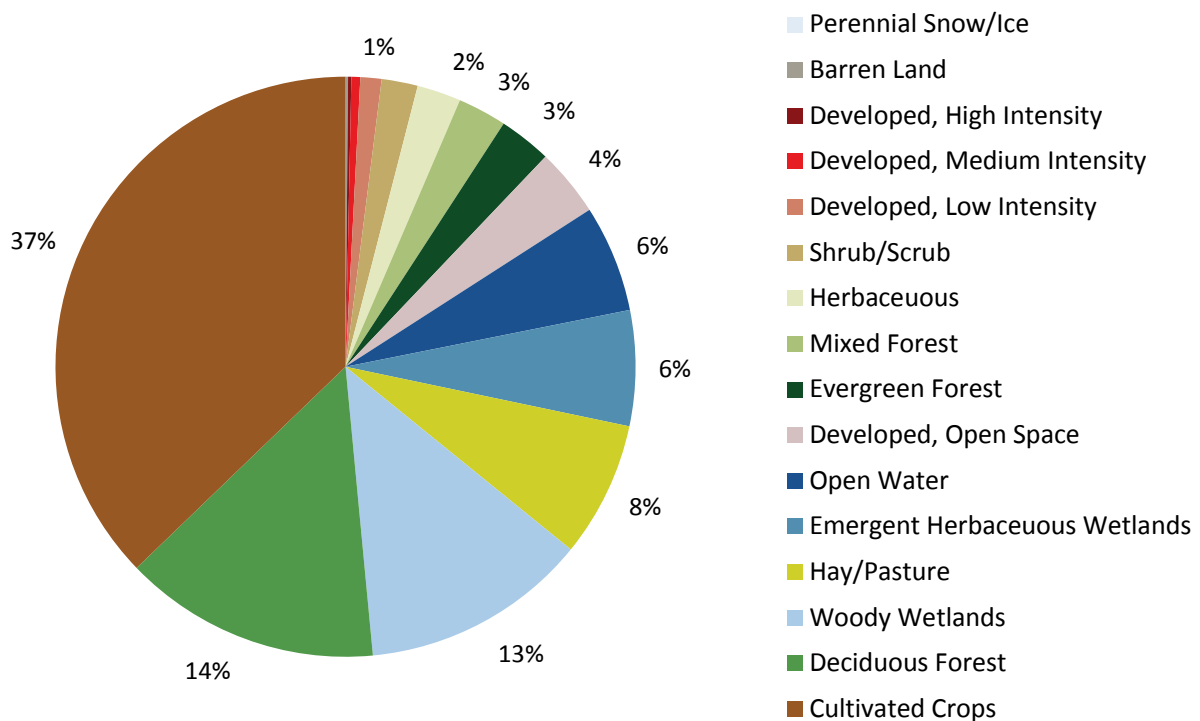
Let’s take for instance the average irradiance across the state of Minnesota as a proxy for the irradiance impinging on the solar allocated according to one of the two spatial scenarios discussed in this report. On average Minnesota receives 1,380 kWh/m<sup>2</sup>/yr. A south-facing solar array at a 30-degree fixed tilt (the most common solar array configuration and the one modeled in the SPA) will receive 1,640 kWh/m<sup>2</sup>/yr of solar irradiation in Minnesota (on average). With a sunlight-to-electricity conversion efficiency of 20% and a DC-to-AC conversion efficiency of 80%, a solar array in Minnesota will generate 262,000 MWh per square kilometer per year. This means that Minnesota could generate the amount of electricity to meet Minnesota’s annual electric load with 330 square

kilometers. **Notably, this 330 km<sup>2</sup> of required area is only 0.15% of the total area of Minnesota (218,559 km<sup>2</sup>).**

## Existing Land Use in Minnesota

Using the [Multi-Resolution Land Characteristics Consortium \(MRLC\)'s National Land-Cover Database \(NLCD\)](#), we can compare this 330 km<sup>2</sup> to other land coverage types across the state. The MRLC was set up in 1992 as a joint effort between nine different federal agencies and uses the Landsat series of satellites (operated by NOAA). From the NLCD, we can access land classification information for every thirty-meter by thirty-meter tile in the United States.

Figure 50: Existing Land Use in Minnesota.



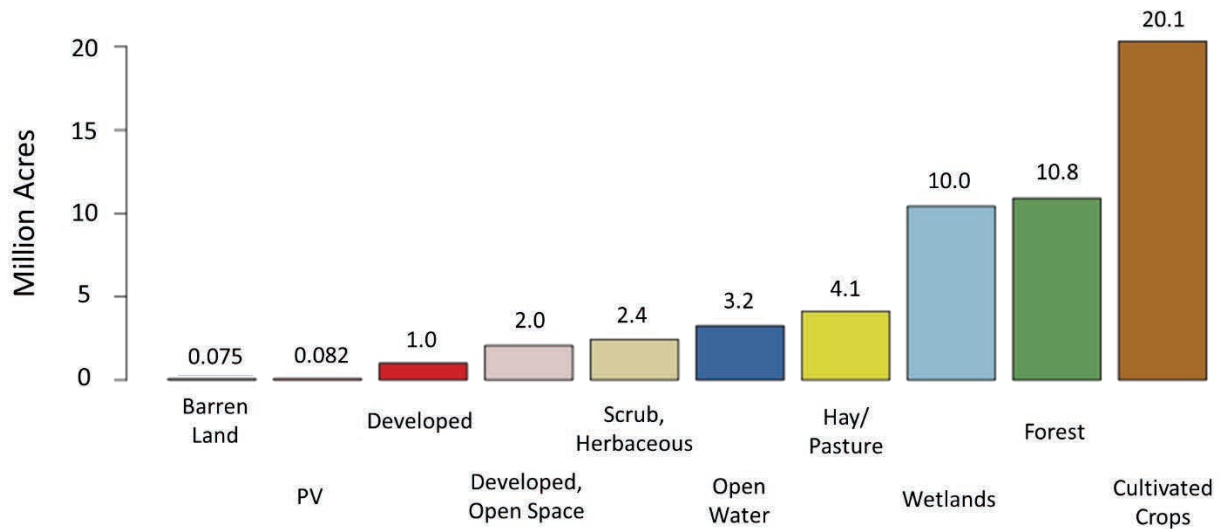
Above is a pie-chart showing the breakdown of land coverage across the state. As can be seen, the majority of the state is covered by either cultivated crops or deciduous forest. A striking 37% of the state is covered with cultivated cropland which the MRLC defines as “areas used for the production of annual crops, such as corn, soybeans, vegetables, tobacco, and cotton, and also perennial woody crops such as orchards and vineyards. [...] This class also includes all land being actively tilled.”

The following bar-chart compares the 330 km<sup>2</sup> (82,000 acres) of area required to meet 100% of MN’s electricity needs using solar to the other land-use categories. One of the distinct advantages of solar versus alternative electricity generation sources is its ability to integrate into existing infrastructure (parking lots, building rooftops, even roadways). While there is

nearly enough barren land across the state to accommodate this solar, there is over 7x more developed land than required (not including developed open space where impervious surfaces cover less than 20% of each acre).

Viewed in the context of existing land use in Minnesota, the area required for solar is quite small, even when considering the extreme case of serving 100% of Minnesota’s load with solar.

Figure 51: Comparison of Required Area for PV with Existing Land Use in Minnesota.



## Conclusion

The area required for solar to serve all or a portion of Minnesota’s electrical load is quite small. In the case where solar served 100% of Minnesota’s electrical load, 0.15% of the area of Minnesota would be required. This is an area nearly equivalent to the area of Barren Land in the state and one-tenth the area of the Developed Land in the state, according to the NLCD.

## Appendix G: Cost of Capital

Tables 12-13 present SPA results for different cost of capital for the Hourly Production Requirements and Utility-Led Solar Distribution scenarios in the 2050 Timeframe. As previously noted, the results shown in the body of the report are for a cost of capital of 5%.

Table 12. SPA Results for the Hourly Production Requirements with No *Other Generation* Resources.

No Other Generation Resources							
Tech. Development Scenario	Cost of Capital	Solar Distribution Scenario	Generation Cost (\$/MWh)	Additional Capacity (%)	Storage Capacity (GWh)	PV Capacity (GW)	Wind Capacity (GW)
High	4%	Utility-Led	58	108%	192	36	21
		All Sectors	61	117%	181	31	25
	5%	Utility-Led	64	108%	195	38	20
		All Sectors	67	117%	181	31	25
	6%	Utility-Led	71	108%	195	38	20
		All Sectors	74	117%	181	31	25
Low	4%	Utility-Led	116	117%	181	31	24
		All Sectors	120	117%	184	23	29
	5%	Utility-Led	128	117%	181	31	24
		All Sectors	132	117%	184	23	29
	6%	Utility-Led	141	117%	181	31	24
		All Sectors	144	117%	184	23	29

Table 13. SPA Results for the Hourly Production Requirements with 10% *Other Generation* Resources.

10% Other Generation Resources							
Tech. Development Scenario	Cost of Capital	Solar Distribution Scenario	Generation Cost (\$/MWh)	Additional Capacity (%)	Storage Capacity (GWh)	PV Capacity (GW)	Wind Capacity (GW)
High	4%	Utility-Led	35	25%	49	22	12
		All Sectors	36	25%	49	22	12
	5%	Utility-Led	37	25%	50	22	12
		All Sectors	39	27%	46	20	13
	6%	Utility-Led	40	23%	50	22	12
		All Sectors	42	28%	45	19	14
Low	4%	Utility-Led	53	56%	16	15	21
		All Sectors	54	56%	16	14	22
	5%	Utility-Led	57	56%	16	15	21
		All Sectors	59	56%	16	14	22
	6%	Utility-Led	62	54%	17	15	21
		All Sectors	64	54%	17	14	22

## Appendix H: Scalability of the Hourly Results

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The scalability of the SPA Results with Hourly Production Requirements is not immediately obvious to many and can be counter-intuitive when considering a well-known axiom of renewables: the generation cost of renewables increases with the fraction of load being served (e.g., due to curtailment or storage needs). However, an important feature of the Hourly Production Requirements is that the same fraction of Minnesota's load is served every hour of the year. The Hourly Production Requirements do not serve a greater fraction of the load when solar and wind production are highest, or a lower fraction of the load when solar and wind production fall off. By definition, the Hourly Production Requirements account for the increased costs of serving load at 100% renewable penetration.

If you're not yet fully convinced of the scalability of the Hourly production profile, consider this thought experiment. Imagine serving 50% of Minnesota's hourly load every hour using solar, wind, storage, and *Other Generation* resources. Halving the capacity of solar, wind and storage would result in 25% of hourly load being served. Doubling the capacity of the solar, storage, wind, and *Other Generation* resources would mean that these resources would then be serving 100% of Minnesota's hourly load. Note, this would not change the generation cost (in \$/MWh) since one would also be either halving or doubling the amount of energy served.

The other production profiles considered in the SPA are not scalable as they don't serve a constant fraction of the hourly load.

## Appendix I: Cost of Natural Gas Generation Resources

The following tables present an analysis of the levelized cost of natural gas generation. The analysis was put together using the listed references and input from the Minnesota Department of Commerce (with regard to resource capital cost and economic lifetime). Note, the combustion turbine (CT) and combined cycle generation turbine (CCGT) resource utilization factors are higher than those currently observed in the market. This was intentionally done to make the analysis more comparable to the SPA results (where operating reserve margins are not accounted for and where one assumes an optimal build out of system resources).

### References

<https://www.nrel.gov/analysis/tech-lcoe-documentation.html>

NREL - Annual Technology Baseline

### Calculation Assumptions

Calculation Assumptions			
	Generation Resource	CT	CCGT
Resource Assumptions	Capital Cost (\$/MW)	\$700,000	\$1,050,000
	Economic Lifetime (Yrs)	30	40
	1/Heat Rate (MWh/MM BTU)	0.1	0.15
	Assumed Utilization Factor (%)	30%	80%
	Cost of Delivering Natural Gas (\$/MM BTU)	\$1	\$1
	Carbon Tax (\$/Metric Ton)	\$20	\$20
	CO2 Emissions (Metric Tons CO2/MWh)	0.53	0.35
	Variable Operational Cost (\$/MWh)	\$1.0	\$0.6
System Assumptions	Capacity as Fraction of Peak Capacity (%)	30%	70%
	Annual Load Served (%) (Calculated Value)	14%	86%

### Intermediate Calculations by Resource

CT - Generation Resource Costs				
Cost of Delivered Gas (\$/MM BTU)	Variable Cost of Generation (\$/MWh)	Cost of Carbon (\$/MWh)	Cost of Capital (%)	Fixed Capital Costs (\$/MWh)
\$3	\$31	\$11	3%	\$14
\$4	\$41		4%	\$15
\$5	\$51		5%	\$17
\$6	\$61		6%	\$19
\$7	\$71		7%	\$21

CCGT - Generation Resource Costs				
Cost of Delivered Gas (\$/MM BTU)	Variable Cost of Generation (\$/MWh)	Cost of Carbon (\$/MWh)	Cost of Capital (%)	Fixed Capital Costs (\$/MWh)
\$3	\$21	\$7	3%	\$6
\$4	\$27		4%	\$8
\$5	\$34		5%	\$9
\$6	\$41		6%	\$10
\$7	\$47		7%	\$11

### Levelized Cost of Energy for a CT

CT Levelized Cost of Energy (\$/MWh) No Carbon Tax			
	Cost of Delivered Gas		
Cost of Capital	\$4/MM BTU	\$5/MM BTU	\$6/MM BTU
4%	\$56	\$66	\$76
5%	\$58	\$68	\$78
6%	\$60	\$70	\$80

CT Levelized Cost of Energy (\$/MWh) With Carbon Tax			
	Cost of Delivered Gas		
Cost of Capital	\$4/MM BTU	\$5/MM BTU	\$6/MM BTU
4%	\$67	\$77	\$87
5%	\$69	\$79	\$89
6%	\$71	\$81	\$91



### Levelized Cost of Energy for a CCGT

CCGT Levelized Cost of Energy (\$/MWh) No Carbon Tax			
	Cost of Delivered Gas		
Cost of Capital	\$4/MM BTU	\$5/MM BTU	\$6/MM BTU
4%	\$35	\$42	\$48
5%	\$36	\$43	\$49
6%	\$37	\$44	\$51

CCGT Levelized Cost of Energy (\$/MWh) With Carbon Tax			
	Cost of Delivered Gas		
Cost of Capital	\$4/MM BTU	\$5/MM BTU	\$6/MM BTU
4%	\$42	\$49	\$55
5%	\$43	\$50	\$56
6%	\$44	\$51	\$58

### Levelized Cost of Energy for the System

System Levelized Cost of Energy (\$/MWh) No Carbon Tax			
	Cost of Delivered Gas		
Cost of Capital	\$4/MM BTU	\$5/MM BTU	\$6/MM BTU
4%	\$39	\$46	\$53
5%	\$40	\$48	\$55
6%	\$42	\$49	\$56

System Levelized Cost of Energy (\$/MWh) With Carbon Tax			
	Cost of Delivered Gas		
Cost of Capital	\$4/MM BTU	\$5/MM BTU	\$6/MM BTU
4%	\$47	\$54	\$61
5%	\$48	\$55	\$62
6%	\$49	\$57	\$64

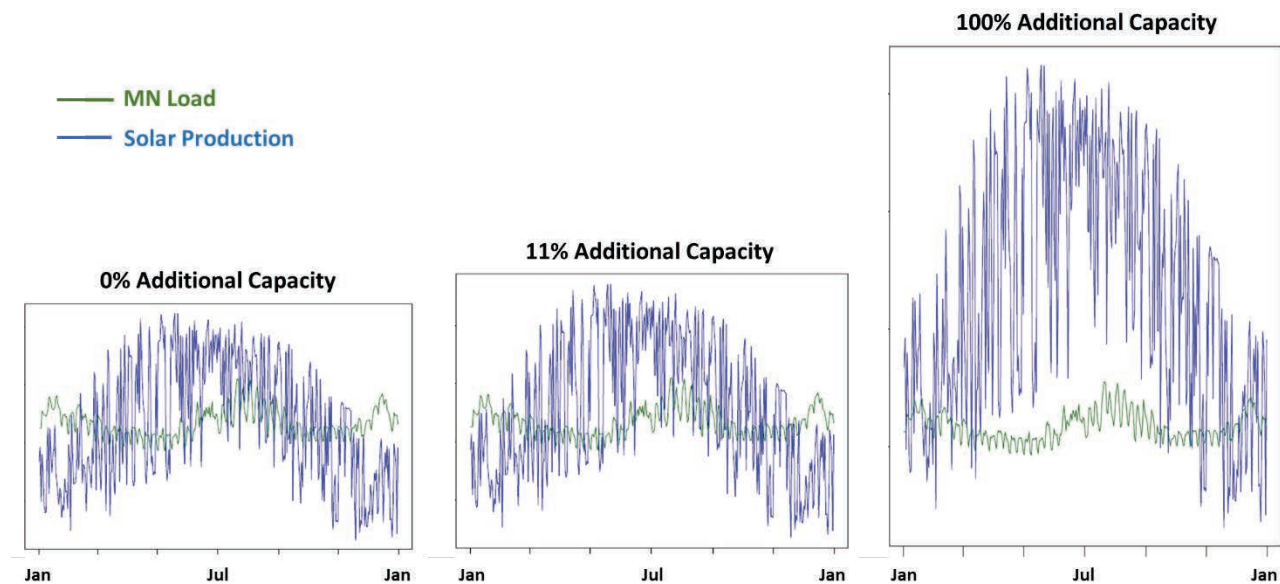
## Appendix J: Benefits of *Additional Capacity*

The following figures illustrate how *Additional Capacity* reduces storage capacity. **Note that the following figures are for a hypothetical solar-only scenario for the purpose of visual clarity.**

Figure 52 plots the daily energy production from solar and the daily Minnesota load for three different solar capacities:

- *0% Additional Capacity* – produces an amount of energy equal to the Minnesota load on an annual basis
- *11% Additional Capacity* – produces 10% more energy than the Minnesota load on an annual basis
- *100% Additional Capacity* – produces 50% more energy than the Minnesota load on an annual basis

Figure 52. Daily Load and Solar Production in GWh.



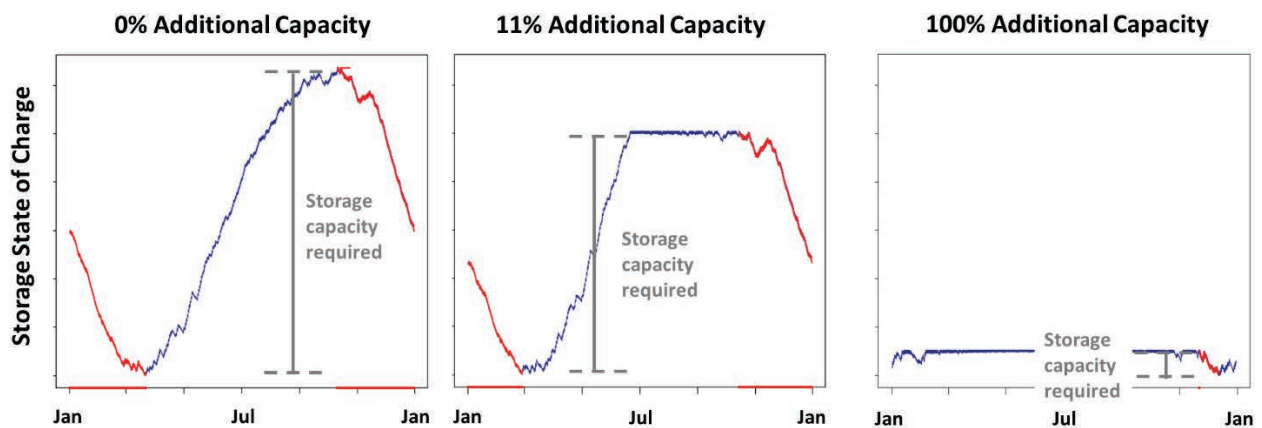
*Additional Solar Capacity* clearly results in a greater number of days for which daily solar production exceeds the daily load. More importantly, ***Additional Solar Capacity* reduces the amount of energy and the length of time over which energy must be shifted by storage resources.**

Of course, curtailment of solar energy also increases as *Additional Capacity* is added, so the actual choice of using storage or *Additional Capacity* will depend on the relative costs (as determined by the markets and rate structures), the availability and costs of flexibility in the

MISO market, and the possible uses for the otherwise curtailed energy. This analysis is focusing only on the direct relationship between *Additional Solar Capacity* and storage without considering these other factors that would influence actual deployment.

Figure 53 plots the daily storage state of charge associated with the analyses shown in Figure 52. As can be clearly seen, *Additional Solar Capacity* produces a dramatic reduction in the required storage capacity – **roughly a ten-fold reduction in storage capacity is achieved with 100% Additional Solar Capacity.**

Figure 53. Impact of Capacity Overbuilding on Required Storage Capacity.



It is worth noting that work by Shaner M. et al, published in *Energy and Environmental Science* in March 2018 produced similar insights regarding the benefit of *Additional Solar and Wind Capacity*.<sup>37</sup> The work of Shaner did not include economic cost modeling, but sought to examine whether a set of wind and solar resources could satisfy hourly load requirements.

<sup>37</sup> <https://pubs.rsc.org/en/content/articlelanding/2018/ee/c7ee03029k#!divAbstract>