A "Consumers Plan" For Clean Energy Across NSPM By 2035

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1 Executive Summary

The study presented in this report, investigates a scenario ("Consumers Plan") to decarbonize and electrify the Northern States Power Minnesota (NSPM) region by at least 80% from 2005 levels by 2030. This study was commissioned by Citizens Utility Board of Minnesota (CUB) and GridLab. Vibrant Clean Energy (VCE®) performed the modeling and analysis of the results presented. The modeling was performed using the WIS:dom®-P modeling suite which is a state-of-the-art capacity expansion and production cost model.

The "Consumers Plan" models electrification of Minnesota (including the NSPM region) while decarbonizing the electricity sector by 80% from 2005 levels by 2050. The NSPM region is additionally constrained to decarbonize by 80% from 2005 levels by 2030 in accordance with Xcel Energy's decarbonization goal.[1] The "Consumers Plan" scenario is proposed as an alternative to the "Preferred Plan" (Scenario #9) from the Xcel Energy (supplement) Integrated Resource Plan (IRP).[2]

The "Consumers Plan" shows that it is possible to achieve significant carbon dioxide emission reductions (86% from 2005 levels by 2030) while reducing total system cost and retail rates for customers. This scenario results in cumulative savings for the NSPM region of $6.45 billion by 2040 resulting in a 36% reduction to retail rates compared to 2020 levels and adds 50,000 new full-time jobs in the electricity sector. The "Consumers Plan" achieves this through retiring all the coal generation in the NSPM region by 2025 and replacing it with wind, solar and storage. This scenario assumed no new natural gas generation can be added in Minnesota and the existing nuclear fleet can be relicensed to 2040. As a result of the capacity turnover, the NSPM region generates 89% of its electricity through carbon-free generation by 2035.

The "Consumers Plan" scenario unlocks greater efficiencies in the electricity system operation through co-optimizing the distribution system with the utility-scale generation. As a result of this co-optimization, by 2035 2.5 GW of distributed solar is added to the NSPM grid along with 1.3 GW of distributed storage. Through optimal deployment and use of the distributed energy resources, the NSPM region is able to defer distribution system upgrades even as the load increases due to electrification.

The "Consumers Plan" scenario utilizes the rich resource potential in the Mid-west region through building transmission lines within Minnesota and with Iowa to exchange electricity to meet load. As a result of the increased electricity exchange, the NSPM region is able to offset some of its system costs through revenues from offsystem sales. The offsystem sales are not allowed to exceed 25% of NSPM load in accordance with Xcel Energy's IRP.

[1] https://www.xcelenergy.com/environment/carbon_reduction_plan

[2] https://www.edockets.state.mn.us/EFiling/verification/viewServedDocument.do?method=showSubmissionInfo&reqFrom=viewServedDocuments&selectedId=143762&docketNumber=E002/RP-19-368&showList=true#displayInfo

Reliability and resource adequacy for the NSPM region are ensured by requiring a 7% load following reserve at all time while maintaining the North American Electric Reliability Council (NERC) recommended planning reserve margins. The “Consumers Plan” shows that the NSPM region can maintain reliable and robust grid operation even with 78% of the installed capacity being variable renewable energy.

2 Study Description

2.1 Modeled Scenarios

For the present study, the Citizens Utility Board of Minnesota (CUB) and GridLab commissioned Vibrant Clean Energy (VCE®) to perform a scenario ("Consumers Plan") that electrifies and decarbonizes the Northern States Power Minnesota (NSPM) footprint by at least 80% from 2005 levels by 2030. The remaining geographic footprint within Minnesota follows the state mandated economy-wide emission reduction targets and the broader Midcontinent Independent System Operator (MISO) electricity system continues as business-as-usual (BAU): performing optimal capacity expansion driven by economics, while meeting existing state emission and renewable portfolio standards (RPS) mandates.

The "Consumers Plan" scenario is modeled with Minnesota (including NSPM) undergoing economy-wide decarbonization to match the 80% reduction (from 2005) in greenhouse gas (GHG) emissions goal by 2050.[3] The electricity system of NSPM is, additionally, assumed to reduce GHG emissions by 80% from 2005 levels by 2030 in accordance with Xcel's decarbonization goal.[4] The "Consumers Plan" scenario is proposed as an alternative to the "Preferred Plan" (Scenario #9) from the Xcel Energy (supplement) Integrated Resource Plan (IRP).[5]

The "Consumers Plan" scenario uses the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) low-cost projections for installed capital and Operation and Maintenance (O&M) costs. For fuel costs, the "Consumers Plan" uses the "base-price" forecasts for coal and natural gas detailed in the Xcel Energy resource plan supplement for Minnesota, while the broader MISO footprint uses forecasts from the Annual Energy Outlook (AEO) 2020 High Oil and Gas supply scenario.[6]

The "Consumers Plan" restricts Minnesota to ***zero*** new natural gas power plant construction. This constraint is not applied across the wider MISO footprint. Electricity transmission capacity is allowed to expand subject to historical installation rates. Net electricity exchange and total off system sales from the NSPM region are restricted to not exceed 25% of load served in accordance to the resource plan supplement submitted by Xcel Energy. The "Consumers Plan" includes the current Power Purchase Agreement (PPA) with Manitoba Hydro for import and export from the NSPM region as well as re-negotiated adjustments set to take effect in 2025.

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[3] https://www.revisor.mn.gov/data/revisor/slaws/2007/0/136.pdf
[4] https://www.xcelenergy.com/environment/carbon_reduction_plan
[5] https://www.edockets.state.mn.us/EFiling/verification/viewServedDocument.do?method=showSubmissionInfo&reqFrom=viewServedDocuments&selectedId=143762&docketNumber=E002/RP-19-368&showList=true#displayInfo
[6] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2020&region=1-0&cases=highogs&start=2018&end=2050&f=A&linechart=highogs-d112619a.3-3-AEO2020.1-0~highogs-d112619a.36-3-AEO2020.1-0~highogs-d112619a.37-3-AEO2020.1-0~highogs-d112619a.38-3-AEO2020.1-0~highogs-d112619a.39-3-AEO2020.1-0~highogs-d112619a.40-3-AEO2020.1-0&map=highogs-d112619a.4-3-AEO2020.1-0&sourcekey=0

To model the “Consumers Plan”, VCE customized its grid planning modeling software WIS:dom®-P. A state-of-the-art combined capacity expansion and production cost model, WIS:dom-P performs detailed capacity expansion and production cost while co-optimizing utility-scale generation, storage, transmission, and distributed energy resources (DERs). The “Consumers Plan” was initialized and calibrated with 2018 generator, generation, and transmission topology datasets. The “Consumers Plan” determines a pathway from 2020 through 2040 with results outputted every 5 years. Detailed technical documentation describes the mathematics and formulation of the WIS:dom-P software along with input datasets and assumptions[7]. Discussion of the generator input datasets is included in Section 4.1. A description of the wind and solar resource (as well as siting potential) is contained in Section 4.2. Economic and policy inputs are presented in Section 4.3. Finally, Section 4.4 documents the general weather behavior over the Minnesota and MISO region.

The results of the “Consumers Plan” are delivered in Section 3. The change in system costs, retail rates and jobs are provided in Section 3.1. The changes to generating capacity, installation rates of utility and distributed generation are detailed in Section 3.2. Section 3.3 discusses changes to the generation mix along with a description of how WIS:dom-P uses variable renewable energy resources (VREs) to meet demand without fail. The impact on pollution and emissions is discussed in Section 3.4. Section 3.5 describes the transmission buildout selected by WIS:dom-P for the “Consumers Plan.” As part of the optimal capacity expansion, WIS:dom-P must ensure each grid meets reliability constraints through enforcing the planning reserve margins specified by the North American Electric Reliability Corporation (NERC) and having a 7% load following reserve available at all times. Section 3.6 discusses the details around how capacity value of both thermal and VRE generation is estimated. Finally, Section 3.7 shows the detailed siting, at 3-km resolution, of the capacity expansion performed for the “Consumers Plan.”

[7]https://vibrantcleanenergy.com/wp-content/uploads/2020/08/WISdomP-Model_Description(August2020).pdf

2.2 WIS:dom®-P Model Setup

To accurately study the evolution of the electricity grid over the NSPM territory, it is necessary for WIS:dom®-P to include the entire MISO grid (along with its interconnections to Manitoba Hydro). The entire modeled footprint is shaded blue in Fig. 2.1 with the NSPM territory overlaid in yellow. The NSPM territory is simulated with all its generators, demands, and transmission connections to the rest of Minnesota at a 3-km resolution. The NSPM region has access to the full state of Minnesota to site and deploy utility-scale generation, but is restricted to within the boundaries of its territory for developing distribution-scale generation (distributed solar and distributed storage).

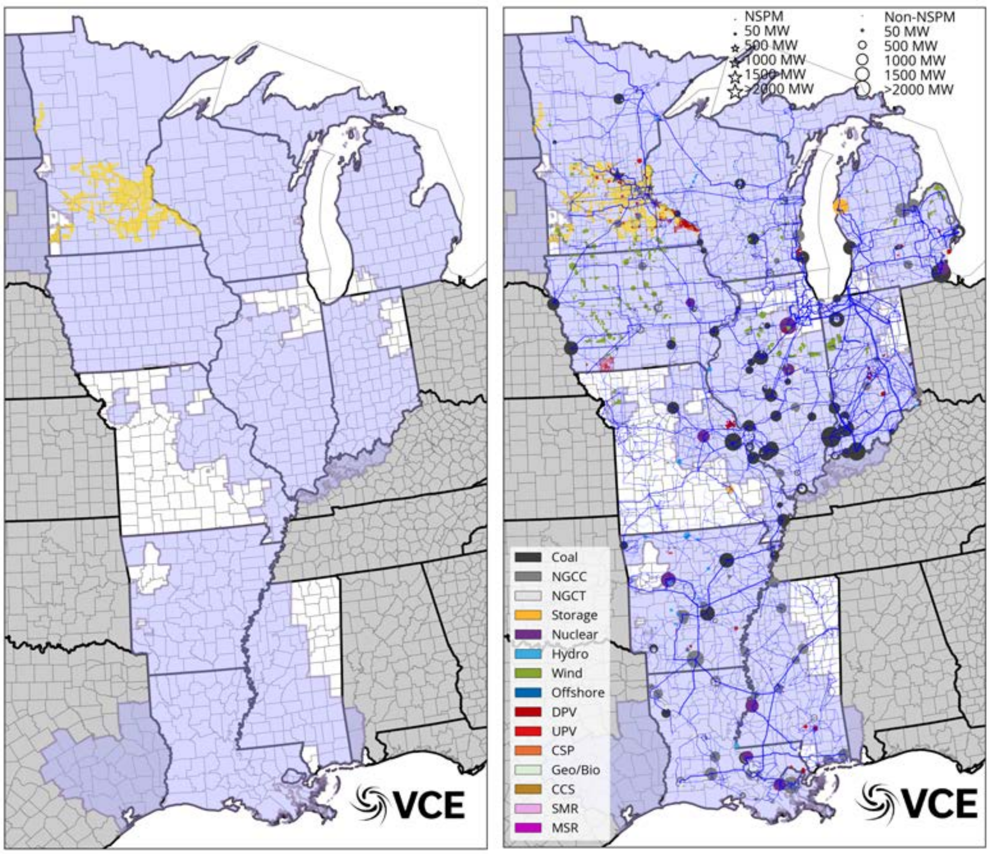

Figure 2.1: WIS:dom-P model domain (left) and existing generators with transmission (right).

The initialized generator dataset is created by aligning the Energy Information Administration Form 860 (EIA-860) dataset[8] with the High-Resolution Rapid Refresh (HRRR)[9] model grid. More details on creation of the generator dataset can be found in Section 4.1. The initialized generator dataset was also aligned with installed generation information obtained from the Xcel Energy 2019 Annual Report,[10] shown in Fig. 2.2.

[8] https://www.eia.gov/electricity/data/eia860/

[9] https://rapidrefresh.noaa.gov/hrrr/

[10] https://www.annualreports.com/HostedData/AnnualReports/PDF/NASDAQ_XEL_2019.pdf

Plant Name	Technology Description	Nameplate Capacity (MW)	State	Included in Investment Year	Notes
Black Dog-Burnsville	Natural Gas	562.8	MN	2018, 2020	
Hennepin Island	Conventional Hydroelectric	13.7	MN	2018, 2020	Not mentioned explicitly in the IRP, but small enough to be left in.
High Bridge-St. Paul	Natural Gas	644	MN	2018, 2020	
Inver Hills-Inver Grove Heights	Natural Gas	284.4	MN	2018, 2020	
A.S. King-Bayport	Conventional Steam Coal	598.4	MN	2018, 2020	
Monticello	Nuclear	685	MN	2018, 2020	
PI-Welch	Nuclear	1186.2	MN	2018, 2020	
Red Wing	Municipal Solid Waste	23	MN	2018, 2020	Not mentioned explicitly in the IRP, but small enough to be left in.
Riverside (MN)	Natural Gas	585.9	MN	2018, 2020	
Wilmarth	Municipal Solid Waste	25	MN	2018, 2020	Not mentioned explicitly in the IRP, but small enough to be left in.
Sherco-Becker	Conventional Steam Coal	2084.43	MN	2018, 2020	Based on NSP-Minnesota's ownership of 59%
Blue Lake-Shakopee	Natural Gas	559.4	MN	2018, 2020	
Lake Benton-Pipestone County	Onshore Wind Turbine	103.5	MN	2018, 2020	
Grand Meadow-Mower County	Onshore Wind Turbine	100.5	MN	2018, 2020	
Nobles-Nobles County	Onshore Wind Turbine	201	MN	2018, 2020	
Laverne Battery	Batteries	1.1	MN	2018, 2020	Not mentioned explicitly in the IRP, but small enough to be left in.
Pleasant Valley-Mower County	Onshore Wind Turbine	200	MN	2018, 2020	
Foxtail Wind, LLC	Onshore Wind Turbine	150	ND	2020	Not availabe in 2018 but built in time for 2020.
Angus Anson-Sioux Falls	Natural Gas	405.7	SD	2018, 2020	
Courtenay Wind-Stutsman County	Onshore Wind Turbine	200	ND	2018, 2020	
Border-Rolette County	Onshore Wind Turbine	150	ND	2018, 2020	

Figure 2.2: The VCE generator overview incorporated for the NSPM territory.

The demand profiles are computed using a combination of weather data and Federal Energy Regulatory Commission form 714 (FERC-714) data.[11] The FERC-714 data provides total demand by reporting agency over the Continental United States (CONUS) at an hourly time resolution. The created demand dataset is split into four components: (1) Space heating demand, (2) water heating demand, (3) transportation demand, and (4) conventional demand (including industrial demands, residential cooling demands, lighting demands, and so on). Using the weather data, profiles for space heating, water heating, and transportation are created for the required temporal and spatial resolution.

The historical demand curve derived from the FERC-714 data is adjusted to remove the weather-derived profiles of space heating, water heating, and transport to produce a weather-aligned conventional demand profile. The aggregated demand profile (obtained by summation of the four components of the demand) is shown in Fig. 2.3. As seen from Fig. 2.3, the NSPM region has a summer peaking demand profile in 2018. Further details on the procedure to create the demand dataset is discussed in Sections 2.5 and 2.6 of the WIS:dom-P technical documentation.[12]

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[11] https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data

[12] https://vibrantcleanenergy.com/wp-content/uploads/2020/08/WISdomP-Model_Description(August2020).pdf

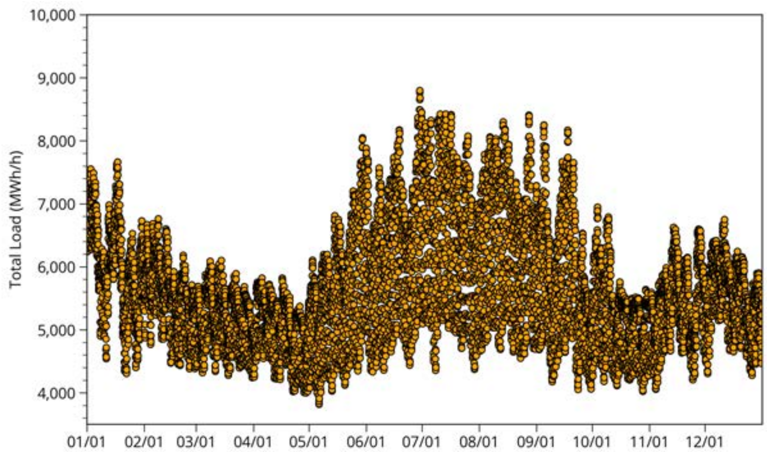

Figure 2.3: Aggregated total demand profile for the NSPM territory in 2018.

The change in electricity demand as a result of electrification is included by using the data from the Minnesota Smarter Grid study.[13] A detailed description of the electrification potential and assumptions made is available in Section III of the Minnesota Smarter Grid report. In the electrification loads modeled, conventional load does not change much between 2018 and 2040 as a result of energy efficiency countering any increase in demand. The space heating demand increases only slightly as increase in demand due to switching heating to heat pumps is offset by energy efficiency measures such as replacing resistive heating and older heat pumps with high efficiency heat pumps. Water heating demand approximately doubles as the water heating switches from gas water heaters to heat pump water heaters. Transportation demand grows dramatically due to conversion of most of the vehicle fleet from gasoline to electric.

The combined total demand profile for the NSPM region by 2040 is shown in Fig. 2.4. The total demand profile evolves from being summer peaking to having a dual summer and winter peak, with the winter peak only slightly lower than the summer peak. The increase in winter load is from electrification of space heating, water heating and transport, while the summer load is seen to remain largely similar as increases in load due to electrification are offset by energy efficiency measures. This implies that the "Consumers Plan" is more aggressive than the NSPM Preferred Plan (Scenario #9) with respect to electrification of other sectors and increases electricity demand faster.

[13] https://www.vibrantcleanenergy.com/wp-content/uploads/2018/07/Minnesotas-SmarterGrid_FullReport.pdf

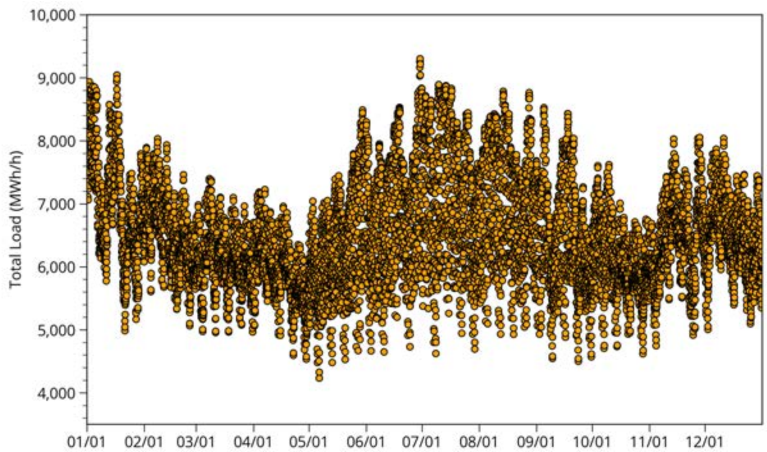

Figure 2.4: Aggregated total demand profile for the NSPM territory modeled in 2040.

The above demand profiles already account for reductions due to energy efficiency (EE) measures. These measures were included from the MN Smarter Grid Study.[14] The energy efficiency measures include converting resistive heating to heat pumps (both for space heating and water heating) as well as other measures to reduce demand outside of space and water heating. The cumulative reductions in energy consumption over the investment periods in the electricity sector due to EE measures is shown in Fig. 2.5. The largest cumulative reductions in energy consumption (about 9,463 GWh by 2040) is in the conventional load that includes industrial load and air conditioning. Space heating and water heating combined contribute another 2,251 GWh and 1,363 GWh, respectively, in cumulative energy consumption reduction by 2040. The cumulative reductions due to EE average to about 622 GWh of reductions in electricity use per year, which is lower than the NSPM IRP assumed 780 GWh of EE measures applied each year. This implies that the "Consumers Plan" is more conservative than the NSPM Preferred Plan (Scenario #9) with respect to EE measures. Therefore, NSPM could pursue additional amounts of EE and lower customer costs further.

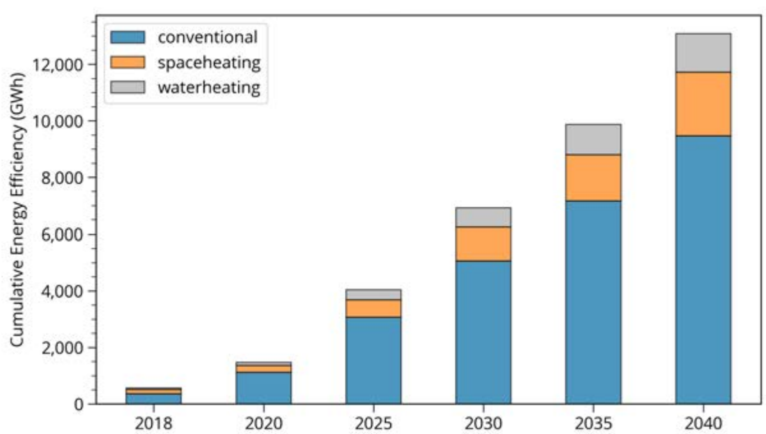

Figure 2.5: Energy efficiency accounted for in load projections.

[14] https://www.mcknight.org/wp-content/uploads/Minnesotas-SmarterGrid_FullReport_NewFormat.pdf

WIS:dom-P also incorporates demand flexibility, which is tied to the weather data as discussed in detail in Section 2.5 of the WIS:dom-P technical documentation. The total demand flexibility available in the years 2025, 2030, 2035 and 2040 is shown in Fig. 2.6. The demand flexibility available is greater in the winter periods as there is more space and water heating demand to flex. Industrial demand is assumed to be less flexible and hence in summer only a small portion of the conventional load is available for demand flexibility. The peak demand flexibility available in 2025 is 213 MW in winter and about 175 MW in summer. The demand flexibility increases gradually to 1,014 MW in winter and about 650 MW in summer by 2040. The NSPM IRP assumes a constant 1,500 MW available for demand flexibility by 2034. This implies that the "Consumers Plan" is more conservative than the NSPM Preferred Plan (Scenario #9) with respect to demand flexibility.

It is critical to model the temporal availability of flexibility to ensure a reliable operation of the simulated grid. The demand flexibility is bound by the capacity of the demands themselves as well as the physics of the weather that drives some of the flexibility. For instance, the non-coincident peak demand flexibility available in 2040 is 2,134 MW. However, due to physical limitations such as weather conditions and coincident availability, the actual demand flexibility that can be called upon changes at every timestep. Figure 2.6 shows the actual demand flexibility that can be called upon in the NSPM territory at each timestep over the investment periods. Demand response is modeled as NSPM programs currently exist, but is not called upon by the WIS:dom-P model. This implies that NSPM has the ability to pursue more demand response that could be beneficial for customers to assist with reliability.

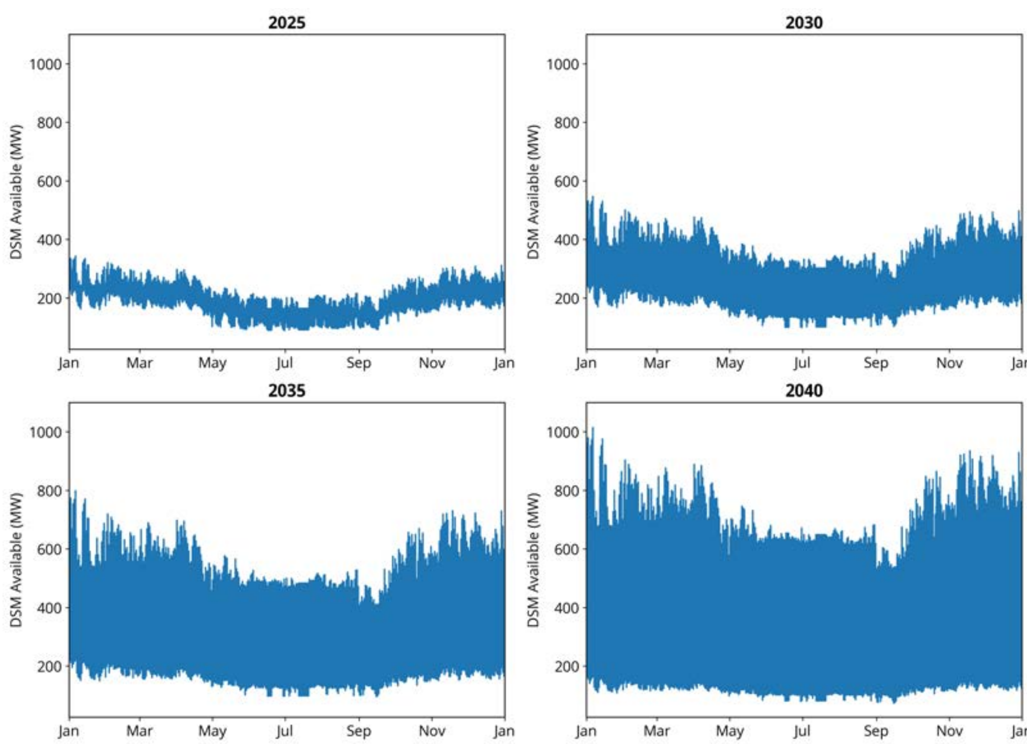

Figure 2.6: Available demand flexibility during each time period of the year over the investment periods.

The various components that contribute to the evolution of demand for the NSPM region are shown in Fig. 2.7. It is seen that the BAU demand growth has a small impact on overall demand, while electrification is a significant contributor. Electrification of transportation is the largest contributor to demand growth. Other components of electrification such as space and water heating contribute only small portions to demand growth as most of the increase in demand is offset by energy efficiency measures. The NSPM "Preferred Plan" serves approximately 43.1 TWh in 2020, while the "Consumers Plan" serves 43.4 TWh. By 2034, the NSPM "Preferred Plan" serves 45.0 TWh, while the "Consumers Plan" serves 49.4 TWh in 2035.

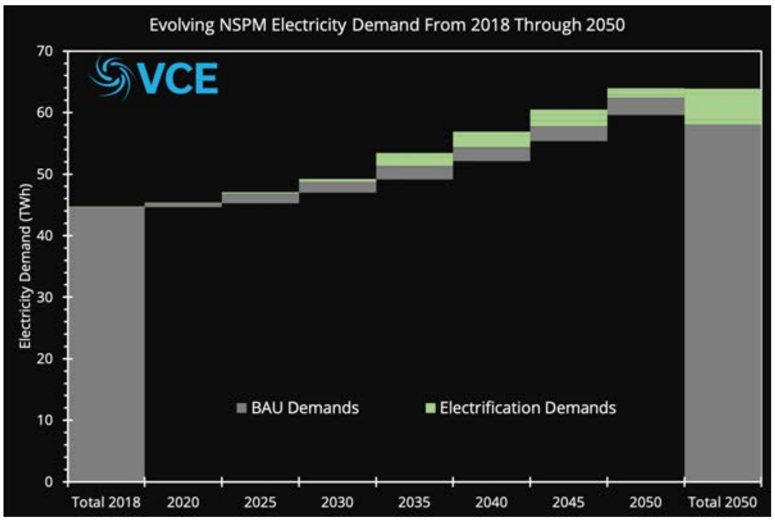

Figure 2.7: Electrification contributing to change in total demand for the NSPM region.

WIS:dom-P resolves the transmission topology of the modeled grid down to each 69-kV substation resolution as shown in Fig. 2.8 (left panel). The transmission topology can be aggregated to create a reduced-form (county- or state- level) as required for each model simulation. The transmission topology aggregated to county-level resolution is shown in Fig. 2.8 (middle panel). The outer simulation utilizes the state- and county- level reduced-form transmission systems (middle and right panels). The county-level is for the spur lines connections, while the state-level is for the bulk transmission. The inner simulation uses the results from the outer simulation reduced-form transmission as boundary conditions upon the full 69-kV resolution transmission system.

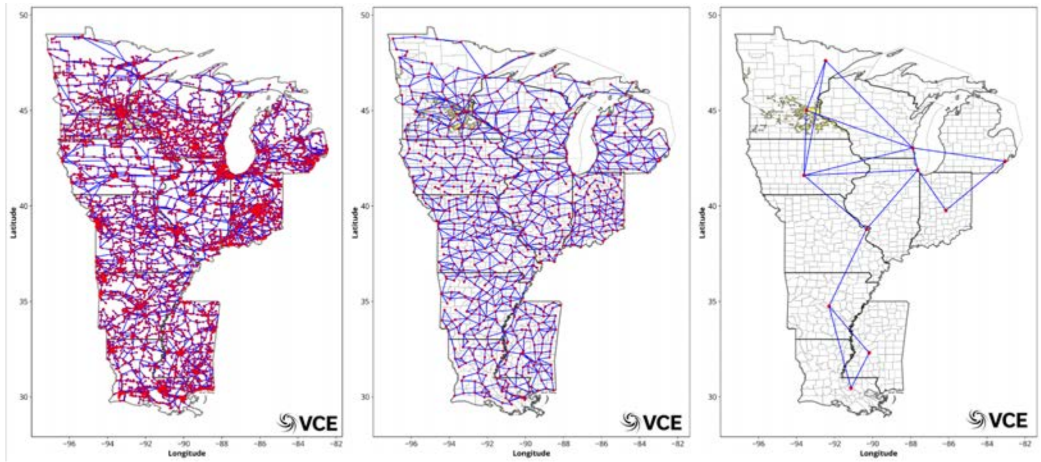

Figure 2.8: Transmission topology of the utility scale electricity system across MISO down to 69-kV substation (left), aggregated to county level resolution (middle), and aggregated to state-level (right).

A unique feature of WIS:dom-P is its ability to resolve the utility-scale electricity grid with detailed granularity over large spatial domains. This unique feature has recently been expanded to allow for the model to co-optimize and coordinate the utility grid with the distribution grid. The tractability of such a co-optimization requires parameterization of all the distribution-level grid topology and infrastructure. Therefore, WIS:dom-P disaggregates the DER technologies, but aggregates the distribution lines and other infrastructure as an interface (or "*grid edge*") that electricity must pass across. The model does assign costs and can compute inferred capacities and distances from the solutions, but cannot (with current computation power) resolve explicitly all the infrastructure in a disaggregated manner.

The main components of deriving the utility-distribution (U-D) interface are:

a. Utility-observed peak distribution demand;
b. Utility-observed peak distribution generation;
c. Utility-observed distribution electricity consumption.

The definition of "*Utility-observed*" is the appearance of the metric at 69-kV transmission substation or above. Below the 69-kV, the model is implicitly solving with combinations of DERs, and what remains is exposed to the utility-scale grid at the substation. Figure 2.9 is a schematic of how WIS:dom-P represents the U-D interface and Fig. 2.10 displays an illustration of how the distribution co-optimization results in two distinct concerts playing out: DERs coordinating to reshape the demand exposed to the utility-scale (*load shifting to supply*) and utility-scale generation and transmission coordinating to serve the demand that appears at the 69-kV substation (*supply shifting to load*).

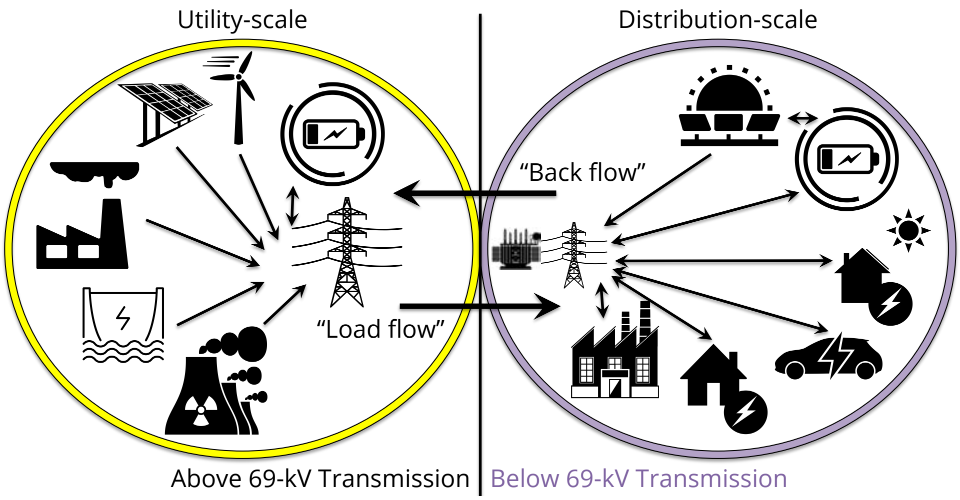

Figure 2.9: A schematic picture of the U-D interface within the WIS:dom-P modeling platform.

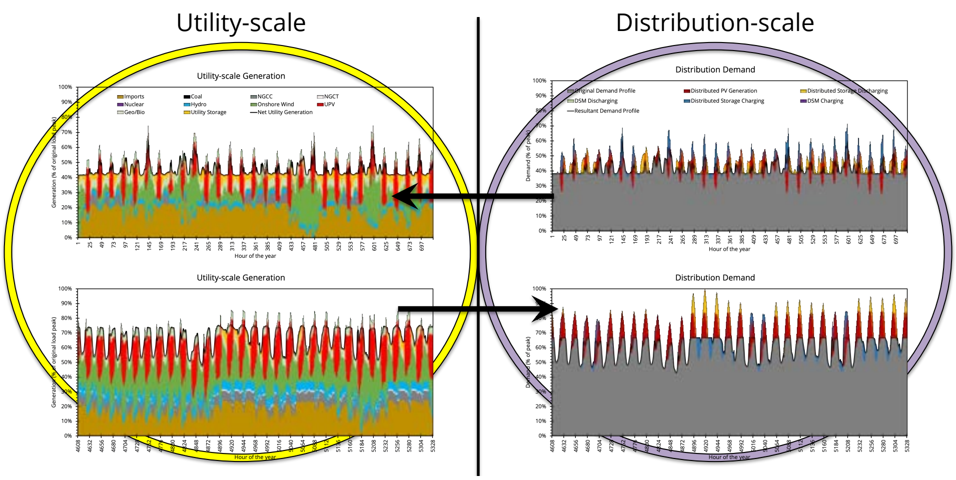

Figure 2.10: Example coordination at the utility- and distribution-scale within the WIS:dom-P model.

To generate an interface for the modeling requires the parameterization of the three components enumerated above. The equations that define the U-D interface directly link to the objective function via the term

$$\Lambda \cdot \left\{ \mathcal{C}_{\mathcal{L}}^{dp} \cdot \left[\mathcal{E}_{\mathcal{L}}^{p} + \lambda_a \cdot \left(\mathcal{E}_{\mathcal{L}}^{b} + \mathcal{E}_{\mathcal{L}}^{m} \right) \right] + \hbar \cdot \mathcal{C}_{\mathcal{L}}^{de} \cdot \sum_{t} \left(\mathcal{E}_{\mathcal{L}t} - \lambda_b \cdot \mathcal{J}_{\mathcal{L}t} \right) \right\}. \tag{1}$$

This direct link provides more cost details to the objective function with respect to the distribution infrastructure requirements that results in changes in model logic to find the least-cost system. The U-D interface equations are relatively simple, but have a direct influence on a substantial number of variables and can result in a completely different solution space being accessible to WIS:dom-P compared with other models that do not solve for the co-optimization of the distribution grid.

The U-D interface equations are written as:

$$\mathcal{E}_{\mathcal{L}}^{\mathscr{p}} - \mathcal{E}_{\mathcal{L}t} + \Lambda \cdot \sum_{\mathfrak{L}\in\mathcal{L}} \left[\mathscr{p}_{\{DPV\}\mathfrak{L}t} + \sum_{\mathfrak{D}} (\mathscr{r}_{\mathfrak{D}\mathfrak{L}t}^{-} - \mathscr{r}_{\mathfrak{D}\mathfrak{L}t}^{+}) + (\mathfrak{D}_{\{dist\}\mathfrak{L}t} - \mathfrak{C}_{\{dist\}\mathfrak{L}t}) \right] \geq 0, \qquad \forall\, \mathcal{L}, \mathscr{t} \tag{2}$$

$$\mathcal{E}_{\mathcal{L}}^{\mathscr{b}} + \mathcal{E}_{\mathcal{L}t} + \Lambda \cdot \sum_{\mathfrak{L}\in\mathcal{L}} \left[\sum_{\mathfrak{D}} (\mathscr{r}_{\mathfrak{D}\mathfrak{L}t}^{+} - \mathscr{r}_{\mathfrak{D}\mathfrak{L}t}^{-}) + (\mathfrak{C}_{\{dist\}\mathfrak{L}t} - \mathfrak{D}_{\{dist\}\mathfrak{L}t}) - \mathscr{p}_{\{DPV\}\mathfrak{L}t} \right] \geq 0, \qquad \forall\, \mathcal{L}, \mathscr{t} \tag{3}$$

$$\sum_{\mathfrak{L}\in\mathcal{L}} \left\{ \mathcal{J}_{\mathfrak{L}t} - \Lambda \cdot \left[\mathscr{p}_{\{DPV\}\mathfrak{L}t} + \sum_{\mathfrak{D}} (\mathscr{r}_{\mathfrak{D}\mathfrak{L}t}^{-} - \mathscr{r}_{\mathfrak{D}\mathfrak{L}t}^{+}) + (\mathfrak{D}_{\{dist\}\mathfrak{L}t} - \mathfrak{C}_{\{dist\}\mathfrak{L}t}) \right] \right\} = 0, \qquad \forall\, \mathcal{L}, \mathscr{t}. \tag{4}$$

Equations (1) – (4) and the terms within them are described in detail within the WIS:dom-P technical documentation.[15] Simply, Eq. (2) defines the peak distribution electricity demand observed by the utility-scale grid. Equation (3) defines the peak back flow from the distribution grid to the utility-scale grid. Equation (4) defines the total distributed generation for each time step.

The Eqs (2) – (4) provide the values to the cost term in the objective function. The exogenous parameters control the relative value of each of the terms. For Λ, there is only a binary option (activate or deactivate). For $\mathcal{C}_{\mathcal{L}}^{d\mathscr{p}}$ and $\mathcal{C}_{\mathcal{L}}^{de}$, we take values from the report "*Trends in Transmission, Distribution and Administration Costs for US Investor Owned Electric Utilities*"[16] by the University of Texas at Austin. These values are national averages, and VCE apply a regionalization by State using internal datasets for locational cost multipliers. For the "Consumers Plan," we set $\mathcal{C}_{\mathcal{L}}^{d\mathscr{p}}$ to be \$55.90 / kW and $\mathcal{C}_{\mathcal{L}}^{de}$ to be 1.18¢ / kWh. Finally, λ_a and λ_b influence the relative importance of the back flow and distributed generation on the co-optimization of the U-D interface. Here these values are both set to unity.

[15] https://vibrantcleanenergy.com/wp-content/uploads/2020/08/WISdomP-Model_Description(August2020).pdf
[16] https://energy.utexas.edu/sites/default/files/UTAustin_FCe_TDA_2016.pdf

3 Modeling Results

3.1 System Costs, Energy Prices, and Retail Rates

The change in annual total system cost for the MISO domain modeled in this study is shown in Fig. 3.1. As seen from Fig. 3.1, the total system cost reduces steadily from $75.2 billion in 2020 to $57.7 billion in 2040 as WIS:dom-P optimizes installed generation on the grid through retiring older and more expensive fossil fuel generation with lower-cost variable renewable (VRE) generation. The cumulative savings in the electric sector by 2040 is about $257 billion compared with continuing to operate the grid as today. As a result of the reduction in total system costs, the average retail rates across the MISO domain also reduce from 9.72 ¢/kWh in 2020 to 6.37 ¢/kWh in 2040, a 34% savings for consumers within the MISO region.

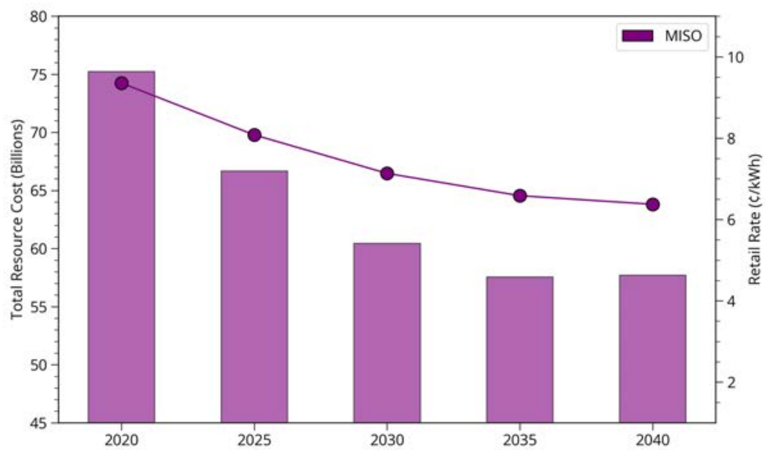

Figure 3.1: Total system cost (bars) and retail rates (solid lines) for the MISO footprint.

The evolution of total system costs for the NSPM territory is shown in Fig. 3.2, where the total resource costs for NSPM reduces from $2.64 billion in 2020 to $2.24 billion in 2025, and then increases gradually to $2.32 billion annually by 2040. The cumulative savings in the electric sector as a result of these change in costs is approximately $6.5 billion by 2040. The decrease in annual total system costs between 2020 and 2025 is due to retirement of all the coal fleet in NSPM territory. The model only determines that the coal plants are economically retired by 2025. It is possible that an earlier date is economic, but the WIS:dom-P used for the present study did not resolve the interim years. The subsequent increase in annual total system costs is due to addition of wind, solar and storage to meet the growing demand created by electrification and BAU load growth.

Even though total system costs climb after 2025, the average retail rate remains low and continues to decline. The average retail rates reduce from approximately 12¢/kWh in 2020 to 7.6 ¢/kWh in 2040, a 36% decrease. This decrease in retail rates is caused by the increasing demand and spreading the system costs over more units of electricity. This indicates that electrification does not increase the energy cost burden on Minnesotans. The lower rates assist those that cannot electrify by making electricity cheaper for them, while those that have electrified reduces the cross-sectoral spending on energy as a whole.

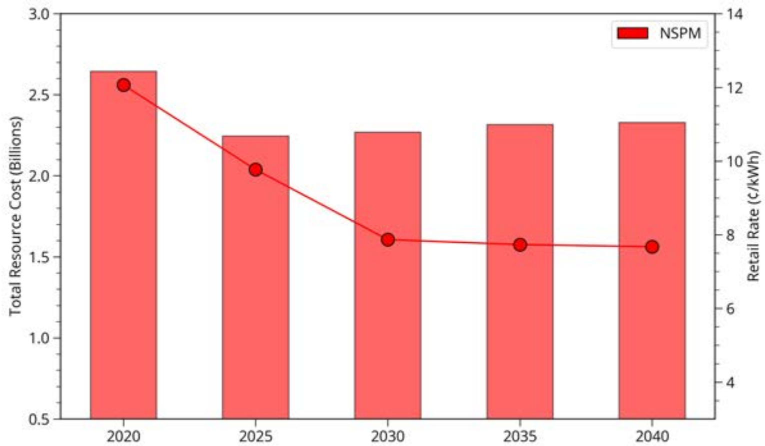

Figure 3.2: Total system cost (bars, left) and retail rates (solid line, right) for the NSPM footprint in Minnesota.

The cost of providing electricity to meet demand disaggregated by sector is shown in Fig. 3.3. It shows that the initial decrease in total system costs is due to retirement of all the coal plants (2.13 ¢/kWh) in NSPM territory, which was the second largest contributor to total system cost after the distribution system at 2.23 ¢/kWh. By 2025, the coal generation is replaced mostly by wind and to smaller extent by solar (both utility-scale and distribution-scale) backed up with storage. The distribution system remains the largest contributor to the cost of delivered electricity after all the coal is retired by 2025. However, as WIS:dom-P co-optimizes the distribution system, the cost per kWh of the distribution system reduces from 2.23 ¢/kWh in 2020 to 1.83 ¢/kWh in 2040 even though the demand increases 13.75% between 2020 and 2040 due to combination of electrification and BAU load growth.

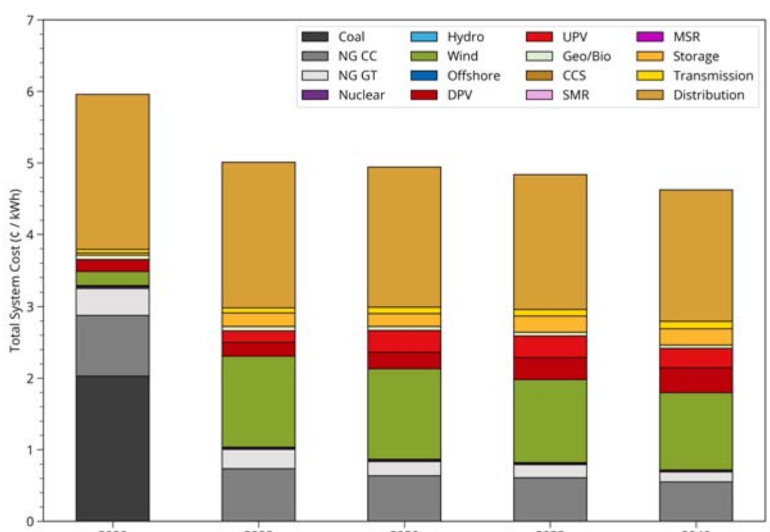

Figure 3.3: System cost per kWh load for each technology.

The cost of delivered electricity remains mostly constant after 2020 (see Fig. 3.3), the retail rate on the other hand reduces by 20% from 2020 to 2025 and then remains mostly constant after that as shown in Fig. 3.2. The reason for the reduction in retail rate is that NSPM is able to offset some of the electric system costs through revenues from exports during periods of excess generation. While some of these exports are through PPAs setup with Manitoba Hydro, others are through electricity exchanges with the rest of Minnesota.

To further analyze the cost differential between the NSPM “Preferred Plan” and the “Consumers Plan”, the Present Value Revenue Requirement (PVRR) of the “Preferred Plan” is computed and compared against the PVRR of the “Consumers Plan”. For the purposes of the comparison, the input costs described in the Xcel Energy’s IRP are used. Since the actual dispatch of the generation proposed by the “Preferred Plan” is not available, a conversative average capacity factor of 45% is assumed for all thermal generation. The PVRR deltas calculated between the two scenarios is shown in Fig. 3.4. On the basis of PVRR, the “Preferred Plan” is found to be more expensive over all the investment periods. In the initial years, the PVRR of the “Preferred Plan” is higher as it keeps the coal generation around longer and adds additional NGCC capacity. As a result, the “Preferred Plan” relies more on thermal generation which has marginal costs of operation. In contrast, the “Consumers Plan” relies more on VRE generation, which has zero marginal cost of operation, and hence is able to meet demand at a lower cost. By 2035, most of the electricity in the “Consumers Plan” comes from zero marginal cost VRE generation and hence results in the largest delta in PVRR between the two scenarios. The difference in costs between the two scenarios is 2.15 ¢/kWh by 2035 ($1 billion total). Therefore the “Consumers Plan” can result in substantial savings for customers served by NSPM.

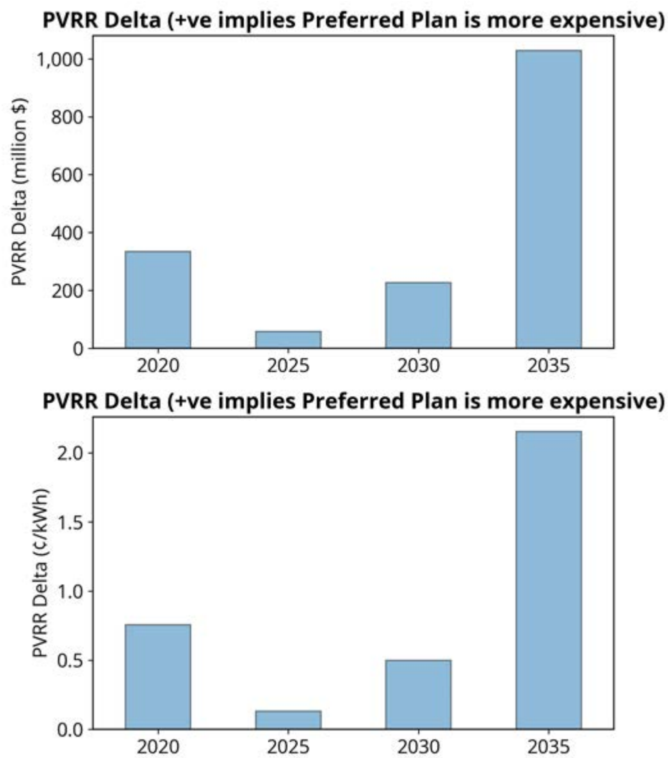

Figure 3.4: PVRR deltas (top) and PVRR delta per kWh load served (bottom) between the "Preferred Plan" and "Consumers Plan" over the investment periods.

The direct full-time equivalent (FTE) jobs created in the electricity sector are shown in Fig. 3.5. In 2020, the electricity sector supported 20,000 FTEs in the NSPM region. By 2040, the electricity sector in the NSPM region supports approximately 72,750 FTEs, a 350% increase over 2020 job numbers. A majority of the new jobs created are in the solar industry with distributed solar being the largest job creator due to its higher labor requirements per MW installed. Jobs in the distribution sector remain almost constant as the distribution system co-optimization performed by WIS:dom-P defers distribution system upgrades that would otherwise be required through use of distributed solar and storage.

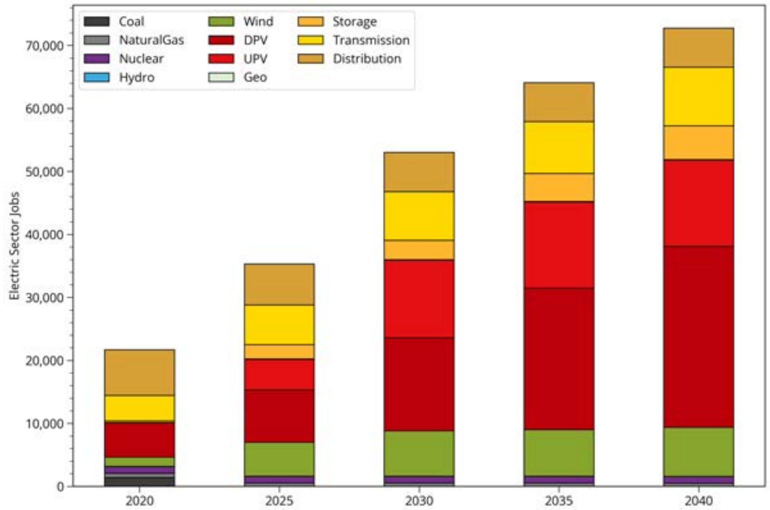

Figure 3.5: Direct full-time equivalent jobs created in the electricity sector by industry.

3.2 Generating Capacity

The turnover of the installed capacities over the investment periods is shown in Fig. 3.6. As discussed in the previous section, all the coal generation is retired by 2025 and is replaced by mostly wind generation and to a lesser extent by distributed photovoltaic (DPV) and utility scale photovoltaic (UPV). Since this scenario does not allow new natural gas in Minnesota, no new natural gas combined cycle (NGCC) generation is built and the existing NGCC is maintained until 2040. About 550 MW of existing natural gas combustion turbine (NGCT) capacity is retired in 2025. By 2040, another 186 MW of NGCT capacity is retired leaving 741 MW of NGCT on the grid. The total natural gas on the grid belonging to NSPM by 2040 is about 2.3 GW.

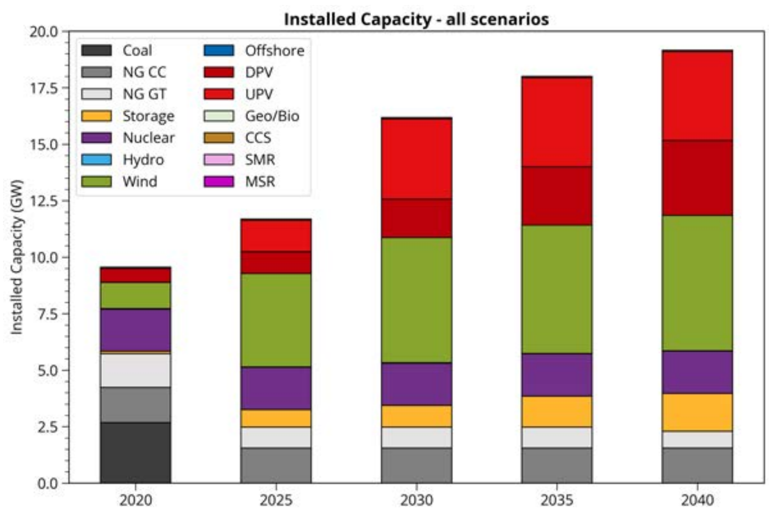

Figure 3.6: WIS:dom-P installed capacities for the scenarios modeled in the NSPM territory.

To help meet the growing demand and replace the retired coal generation, WIS:dom-P installs about 3,000 MW of wind in 2025 along with 350 MW of DPV and 1,400 MW of UPV, which includes 460 MW of already planned UPV plant by NSPM near Sherco. By 2030, there is another large change in installed capacity with an additional 1,400 MW of wind, 740 MW of DPV and 2,100 MW of UPV installed by NSPM to meet the growing electrified demand and reduce reliance on imports to meet this demand as well as to help fulfill export PPAs signed with Manitoba. The additional generation capacity also takes advantage of the transmission built to sell excess generation to the rest of Minnesota and Iowa. All the existing nuclear generation is retained until 2040. The model selects to relicense both nuclear plants. It is assumed that to relicense each of the nuclear plants (Prairie Island and Monticello) will cost $250 million. In addition, the running costs of the nuclear plants are assumed to be $367 million for Prairie Island and $289 million for Monticello. The cost assumptions are based upon the Nuclear Energy Institute estimated values.[17]

By 2035, the WIS:dom-P model installed a total of 5,682 MW utility-scale wind, 3,940 MW utility-scale solar PV, 2,589 MW distributed solar PV, 1,368 MW storage (7 hours)

[17] https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/nuclear-costs-context-201810.pdf

within Minnesota for the NSPM territory. It also retired 2,683 MW of coal and 745 MW of natural gas combustion turbines. It did not add any new fossil generating capacity.

Figure 3.7 shows the comparison of installed capacities from the NSPM IRP using the EnCompass model[18] in year 2034 to WIS:dom-P installed capacities in 2035. Comparison of the total installed capacities between the models show that WIS:dom-P has about 1,900 MW less of natural gas generation on the grid by 2035. The natural gas generation is replaced by wind, solar and storage by WIS:dom-P resulting in lower costs and emissions. EnCompass installs 2,600 MW of "firm peaking" generation by 2034 to help meet the capacity needs in NSPM. WIS:dom-P did not model the "firm peaking" generation deployed by EnCompass as the operation details of this generator were not available. However, WIS:dom-P demonstrates that it is possible to meet load reliably at low cost and low emissions using VREs and extending the current nuclear fleet. By 2035, the installed capacities in the "Consumers Plan" enables 89% of generation to be carbon-free compared to 75% in the NSPM "Preferred Plan". The "Consumers Plan" achieves this high level of carbon-free generation by installing about 2,400 MW more wind, 440 MW more UPV and 1,400 MW more DPV.

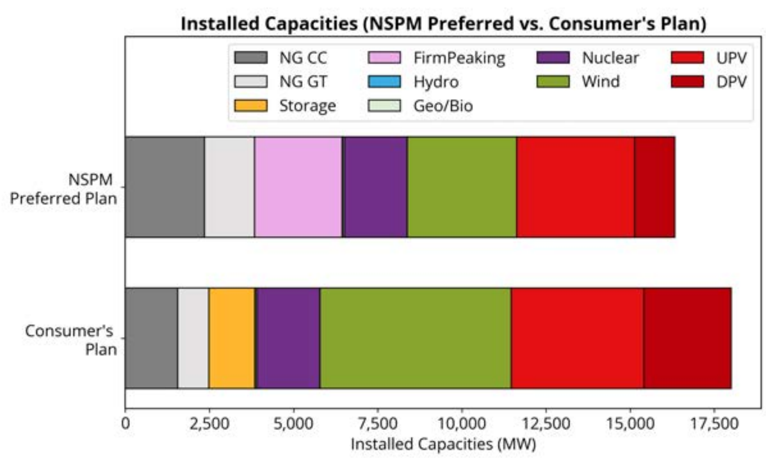

Figure 3.7: Comparison of installed capacities from the NSPM Preferred Plan (year 2034) to Consumers Plan (year 2035).

The storage (utility-scale and distribution-scale) installed over the investment periods is shown in Fig. 3.8. As a result of the distribution co-optimization, all the new storage installed by WIS:dom-P is on the distribution grid. The distribution-scale storage discharges behind the 69-kV substation during periods of high demand to reduce the peak load seen by the utility-scale generation. The distribution-scale storage works with the distributed solar, which makes up 45% of the total solar deployed in the NSPM region (see Fig. 3.9). WIS:dom-P chooses to install significant DPV apart from UPV in the NSPM territory as there is limited space for UPV deployment and its ability to work with the distributed storage to ameliorate the need for distribution upgrades during the electrification process. Therefore, DPV and distributed storage help meet demand

[18] https://anchor-power.com/encompass-power-planning-software/

in the NSPM territory with lower transmission losses, while deferring distribution system upgrades.

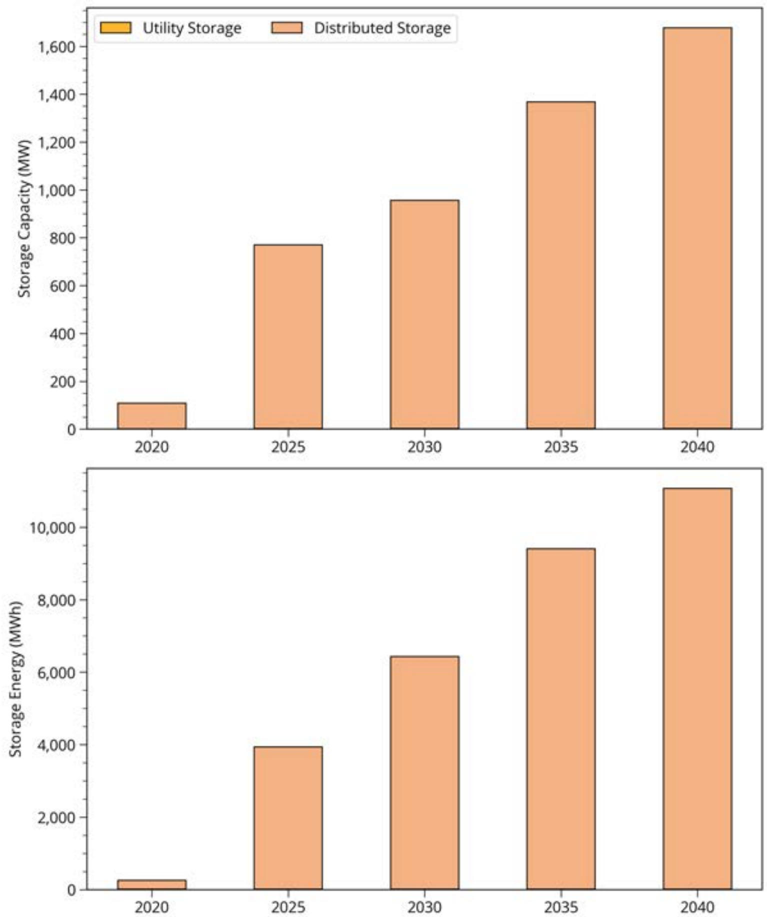

Figure 3.8: Utility storage and distributed storage installed in each investment period for the "Consumers Plan).

Between 2020 and 2025, WIS:dom-P installs 1,400 MW of UPV, which includes the 460 MW solar farm already planned by NSPM at the Sherco site, in addition to 300 MW of DPV. WIS:dom-P installs 2,100 MW of utility-scale solar between 2025 and 2030 and another 740 MW of DPV to help meet the high summer demand and complement the wind generation installed to meet nighttime loads. After 2030, almost all the new solar installed is on the distribution grid as the best UPV sites are taken and DPV becomes more advantageous due to its ability to defer some distribution system upgrades while saving on transmission costs. Figure 3.10 shows the size distribution of DPV installations at the 3-km resolution. WIS:dom-P allows a full range of DPV installation sizes with no lower or upper limit (apart from a siting criteria and upper limit of the technical potential available in each 3-km grid cell).

The median installed DPV size by 2040 is 880 kW within a 3-km grid cell indicating most of the installed DPV is rooftop solar. However, there are some larger DPV installations reaching a maximum value of 40 MW in a 3-km grid cell. It is important to note that the model does not have resolution beyond the 3-km grid size and hence the exact make-up of these larger DPV installation is not known. However, they do indicate WIS:dom-P deploys some community solar farms to meet demand behind the 69-kV substation.

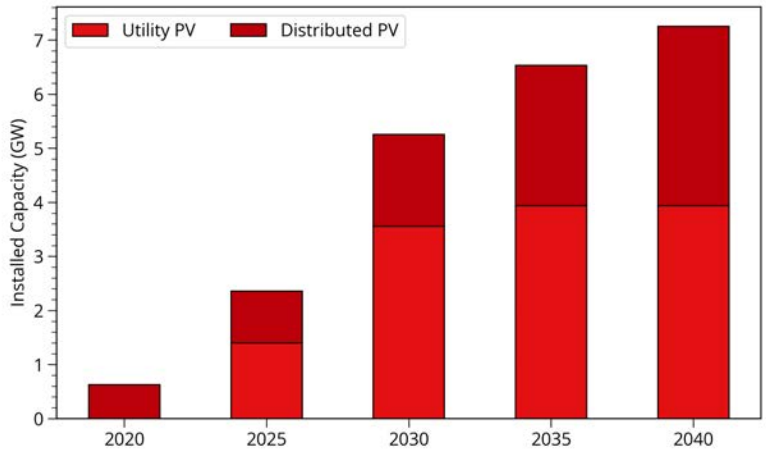

Figure 3.9: Utility PV and Distributed PV installed over the investment periods in the NSPM territory.

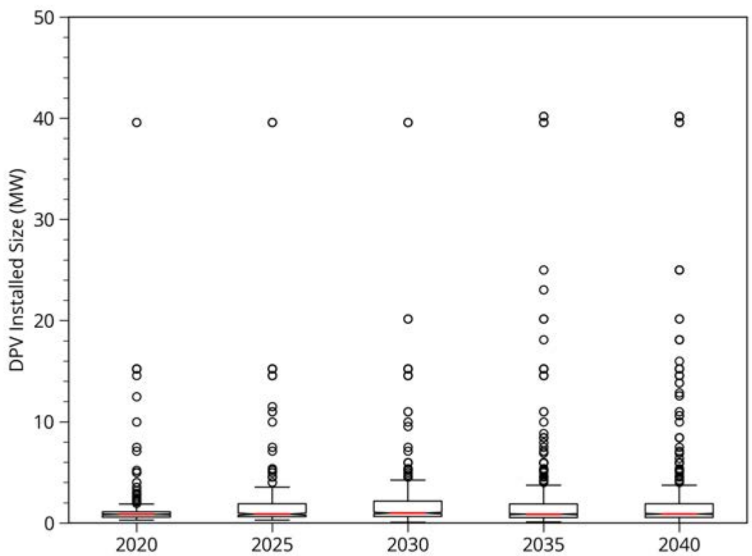

Figure 3.10: Distribution of DPV installation sizes in a 3-km grid cell within the NSPM territory.

3.3 Electricity Generation

The evolution of the generation mix in the NSPM region over the investment periods is shown in Fig. 3.11. In 2020, the NSPM region has net imports of about 13% to meet demand, which contributes to an increased cost of delivered electricity and a reliance on outside generation. However, the imports are reduced gradually over the years and by 2030 NSPM is a net exporter of electricity. The electricity exports increase revenues, which help bring down retail rates (see Fig. 3.3) while ensuring NSPM is self-reliant in providing electricity to its customers. The retired coal generation and imports are replaced through increased use of existing natural gas generation, and significant increases in wind generation. The portion of electricity coming from wind generation goes from 8.7% in 2020 to 41% in 2040. Nuclear, DPV and UPV make the next largest contributions to electricity generated. By 2040, more than 89% of electricity is generated from carbon free sources.

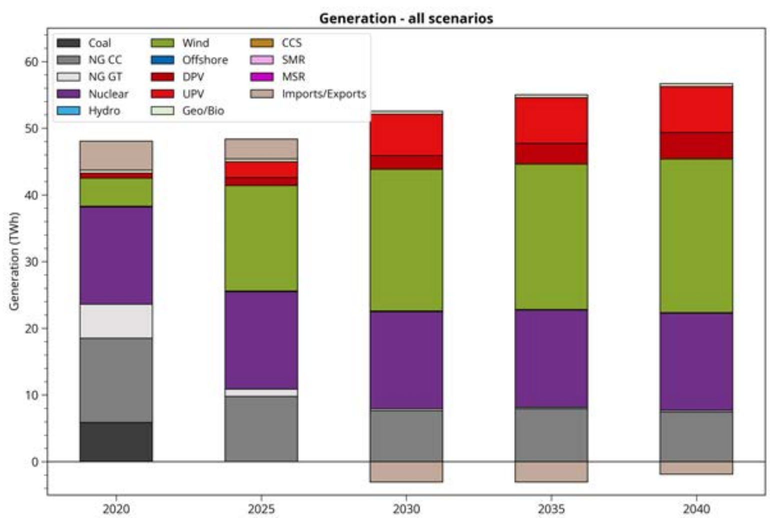

Figure 3.11: Breakdown of the evolution of generation sources for the "Consumers Plan".

The daily total electricity dispatched in 2020 is shown in Fig. 3.12. The NSPM region utilizes its thermal generation to a larger extent in winter to meet load, while in the summer, imports are used to replace the thermal generation and thus saving fuel costs from the higher heat rates of thermal generators in the summer. Nuclear is used as a "baseload" generator throughout the year in order to minimize cost per kWh generated. Coal is exclusively used in winter (seasonally) due to its higher fuel costs and higher heat rates compared to natural gas. In order to meet daily peaks, the NGCT generation is seen to be deployed almost every day in 2020 resulting in increased costs and carbon emissions.

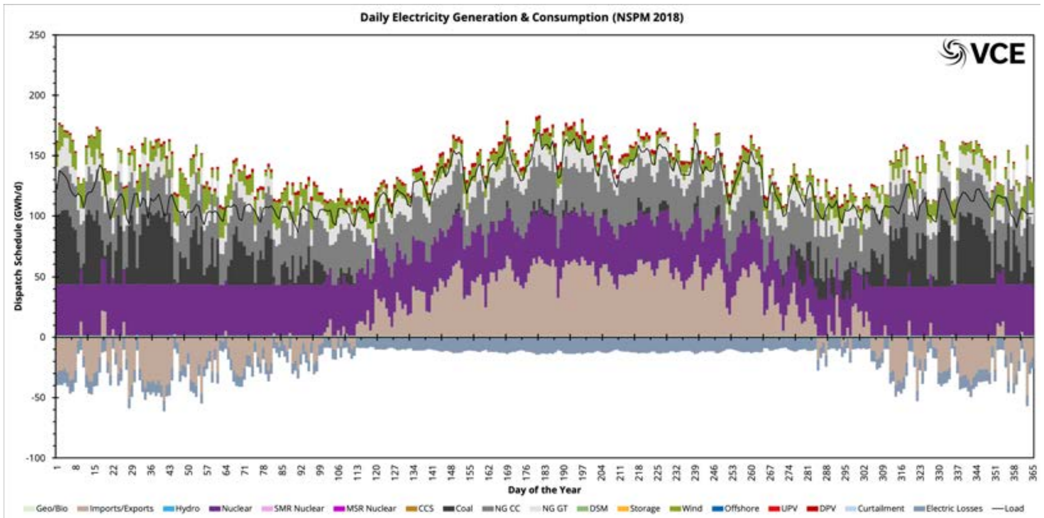

Figure 3.12: The daily generation over the NSPM territory in 2020.

The daily total electricity dispatch stack in 2040 is displayed in Fig. 3.13 where fossil generation makes up a significantly smaller portion of the electricity dispatched compared with 2020 and is only deployed during periods of "high system strain". Nuclear continues to be used as a "baseload" generator running at a relatively constant output throughout the year. Wind generation is the dominant contributor to meeting load, with solar playing a larger role in summer compared to winter. Storage is deployed daily to meet the daily peak loads instead of NGCT, which is only deployed during periods of "high system strain". In addition, the NSPM region dramatically cuts down on imports and also exports electricity during periods of excess generation, thus creating revenues to offset system costs.

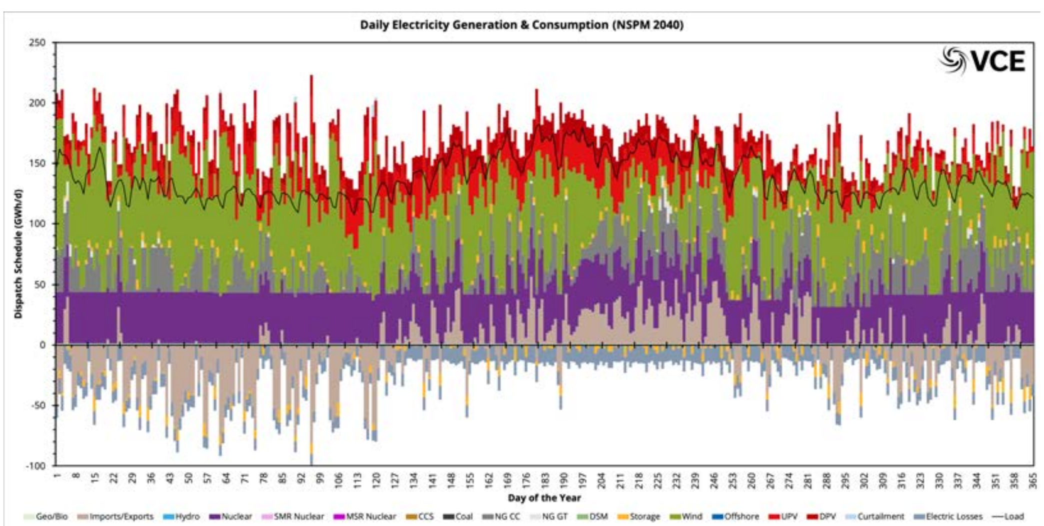

Figure 3.13: The daily generation of over the NSPM region in 2040.

The dispatch stack during the week of highest system strain in 2040 is shown in Fig. 3.14. System strain is defined as the product of thermal generation utilization rate, missing VRE generation fraction and load factor. Therefore, the electric system is considered in higher strain when thermal generators are being used to their maximum, VRE generation is at its lowest and load is at its highest. The highest system strain for the NSPM region occurs during the week of Jan 01 to Jan 07, 2040. In the early morning and evening periods of Jan 04, wind generation does not show up and, hence, WIS:dom-P must dispatch NGCT generation to help storage along with importing electricity to ensure demand is satisfied during this period of high system strain. The dispatch during this period of high system strain shows that reliability of the system can be ensured at high annual VRE penetrations through a combination of other resources with minimal increases in emissions.

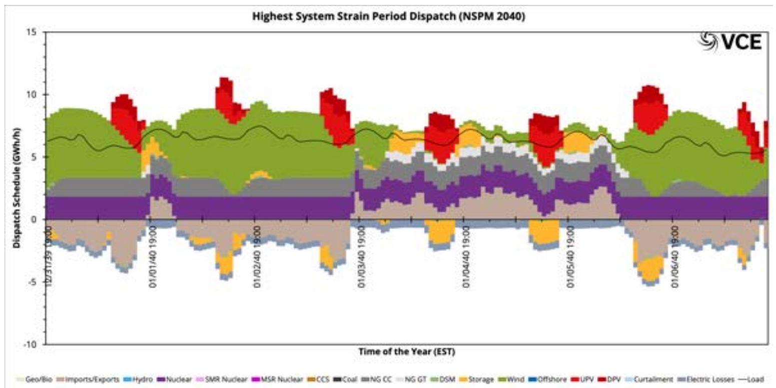

Figure 3.14: The most difficult week to supply demand over the NSPM region in 2040.

The storage behavior as a function of system strain is shown in Fig. 3.15. Storage charges during periods of excess generation and discharges during periods of high system strain to help meet demand. As seen from Fig. 3.14, storage does not charge when system strain is above 35%. Storage is seen to charge at 100% capacity only during periods of low system strain (less than 30%), when significant excess generation is expected. When discharging, the storage discharges at close to 100% capacity over a wide range of system strain values over 15%. The highest system strain value observed for the NSPM region is 44.8% in 2040.

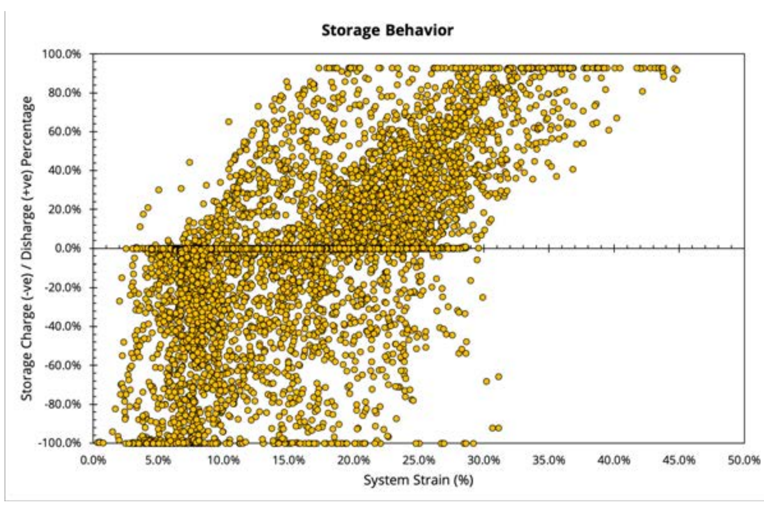

Figure 3.15: Storage behavior as a function of the strain metric over the NSPM territory in year 2040.

In addition to system strain, storage behavior also responds to electricity prices since storage uses electricity price arbitrage to make revenues. Figure 3.16 shows the diurnal marginal price and system strain (left panel) and the seasonal marginal prices and monthly average system strain (right panel). As seen from Fig. 3.16, when the system strain is higher, the electricity prices also go up as more thermal generation is dispatched to meet load. In winter, demand has dual peaks over a day with one in the morning period and one in the evening and the marginal price of electricity is correlated with the system strain resulting in dual peaks in marginal prices. In summer, the system strain is low throughout the day except for a brief period in the evenings when the solar generation is ramping down while demand is ramping up. The marginal price peak in summer coincides with the peak strain period during the evenings.

The seasonal trend in marginal prices show that the marginal prices and average system strain are at their minimum in spring and fall due to the lower demand as a result of fairer weather and higher VRE generation. The average system strain and marginal prices are at their highest during the summer due to higher loads while wind generation being lower compared with the winter periods. The winter periods show slightly lower system strain compared to summer, but much lower marginal prices compared to summer. The reason for this is that while winter loads are higher, wind generation is also higher and therefore is able to ameliorate the effect of the higher loads. Storage takes advantage of the above trends in marginal price to charge during the daytime (see Fig. 3.18) and discharge during early morning and evening hours during winter. Storage also takes advantage of seasonal trends in prices by having a higher utilization rate in spring and fall seasons (see Fig. 3.28) to take advantage of the high price variability observed during those times of the year.

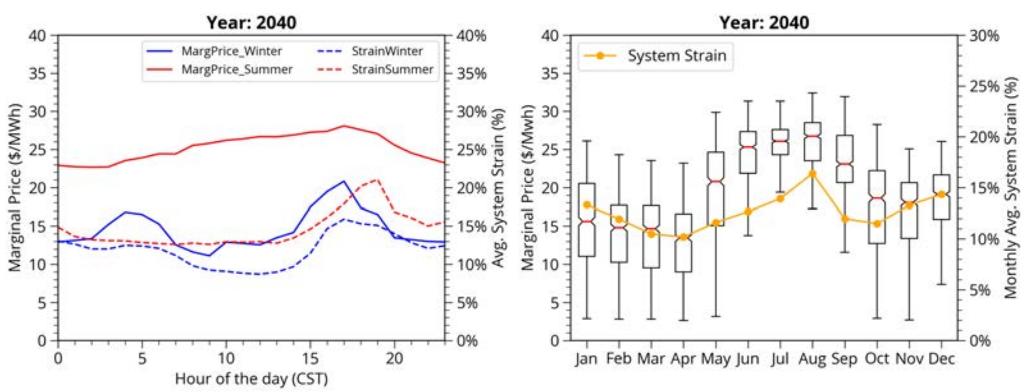

Figure 3.16: Diurnal (left) and seasonal (right) trends in average marginal price and system strain in the NSPM region in year 2040.

The duration curves of the original load and the DER-modified load in 2040 is shown in Fig. 3.17. The original load has a peak value of 9,164 MW and a minimum value of 3,659 MW. The DER-modified load has a maximum value of 6,900 MW, a 24.7% reduction, as a result of distributed generation meeting or shifting the load to periods of lower demand. The DER-modified load has a minimum value of 3,928 MW, a 7% increase over the original load due to shifting demand to lower load periods. As a result of the co-optimization between the utility-scale and distribution system, the peak load seen by the utility-scale generation is lower while having a higher load factor

(77% for DER-modified load versus 62% for the original load), which improves operating efficiencies of the utility-scale generation.

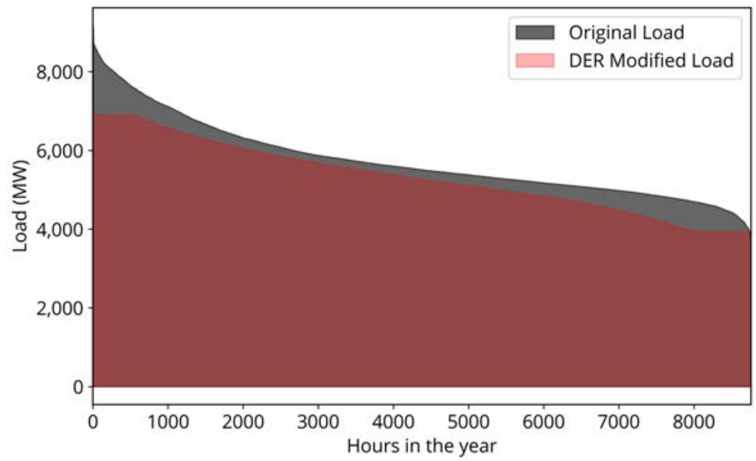

Figure 3.17: Duration curves of the original load and the DER modified load in 2040.

3.3.1 VRE Operation

The diurnal operation of VREs and storage demonstrate how WIS:dom-P takes advantage of the diurnal and seasonal characteristics of wind and solar to meet load. Figure 3.18 shows average diurnal capacity factors for wind, solar and storage in winter (top) and summer (bottom). As seen from Fig. 3.18, wind and solar generation complement one another both in the winter and summer seasons. The winter diurnal load is almost flat throughout the day with a peak during the evening periods. In winter, the wind generation meets majority of the load during the nighttime and early morning hours while solar generation helps meet load during the day. Storage comes into play during the transition periods from wind to solar generation and vice-versa to help meet load. Storage generation is higher during the evening transition period as the wind generation ramps up slower than the solar generation ramps down and, hence, storage plays a more dominant role in bridging the generation between wind and solar in the evenings. In winters, the NSPM region is a net exporter as there is excess wind generation during nighttime and excess solar generation during the daytime. The magnitude of exports is lower during nighttime and peak during the daytime, when there is significant excess generation from solar.

During summer, the solar generation is better correlated with the load profile and helps meet the majority of the load during the daytime hours. However, the load peaks approximately around 20:00 hours local time, which is after the solar generation ramps down. Therefore, storage generation ramps up to help meet demand along with wind generation, which is higher at nighttime. In summer, the NSPM region imports electricity to help meet load along with storage. The magnitude of imports is roughly correlated with storage generation with peak imports occurring during the evening hours to help meet the peak demand.

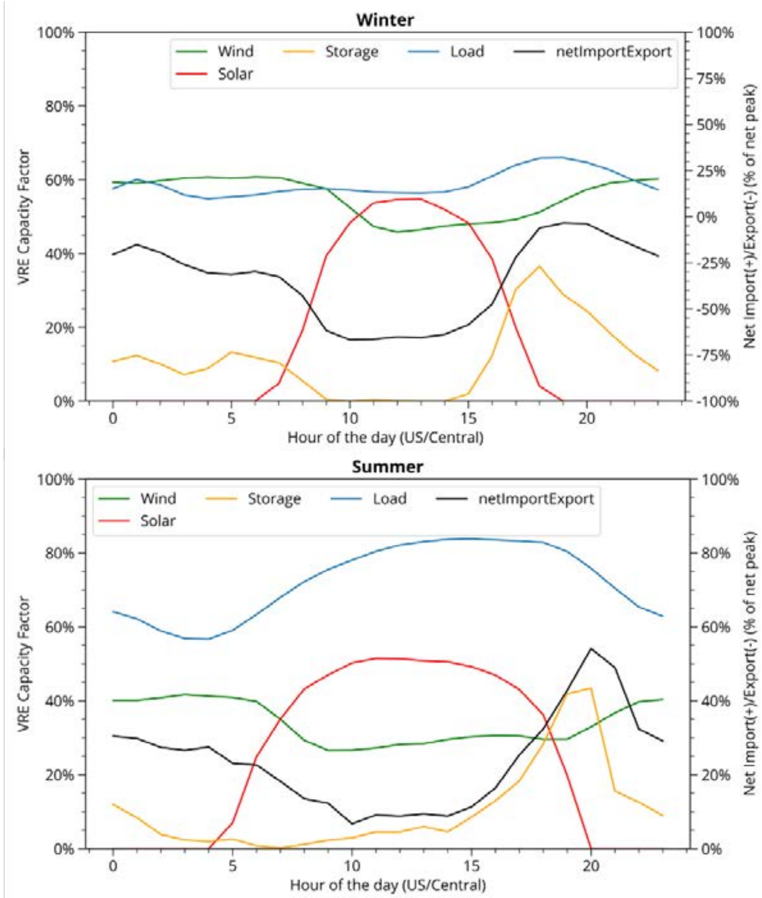

Figure 3.18: Diurnal VRE operation pattern observed over the NSPM region in winter (top) and summer (bottom) in year 2040.

The storage charge and discharge behavior of utility-scale and distribution-scale storage in winter (top) and summer (bottom) is shown in Fig. 3.19. In winter, both the utility-scale and distribution-scale storage charge during the daytime when there is excess solar generation and discharge to meet load in the early morning and nighttime periods. The distribution-scale storage discharges behind the 69-kV substation to reduce the generation that has to cross the 69-kV bus from the utility side. There is a brief surge in charging of the utility-scale storage from 09:00 to 10:00 local time when wind generation is still high and solar generation has ramped up enough to cause excess generation on the utility side. This periods also coincides with a ramp up in exports (see Fig. 3.1, top panel).

The utility- and distribution- scale storage also follow similar trends in summer. Since the summer load peaks during the daytime and the solar generation is well correlated with demand resulting in storage charging during the early morning and daytime hours due to presence of the excess solar generation. There is a brief surge in utility-scale storage charging around 06:00 local time due to high wind and solar generation creating excess electricity on the utility side. The storage stops charging and starts discharging after 15:00 local time as the demands gets closer to its peak value, which occurs around 20:00 local time.

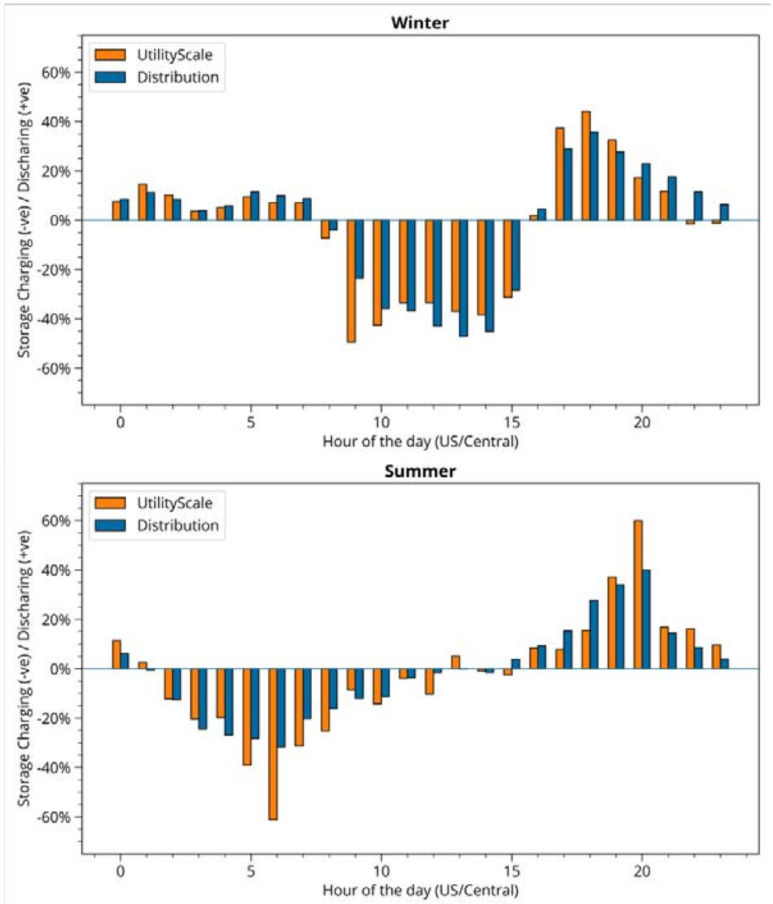

Figure 3.19: Behavior of utility scale and distribution scale storage over the NSPM region in winter (top) and summer (bottom) in the year 2040.

3.4 Emissions and Pollutants

The change in electricity sector emissions compared with 2005 levels is shown in Fig. 3.20. The carbon dioxide emissions include combustion for electricity within Minnesota and imported emissions from MISO generation consumed in NSPM. It is seen that the electricity sector emissions steadily decrease from 2020 to 2030 by approximately 86% of 2005 levels (compared to 81% reduction by 2030 in the NSPM Preferred Plan) as a result of retirement of the coal generation and replacing with VRE generation driven by the decarbonization goal of NSPM. Therefore, the “Consumers Plan” follows a more aggressive emission reduction pathway compared to the NSPM Preferred Plan resulting in higher cumulative carbon dioxide emission savings by 2030.

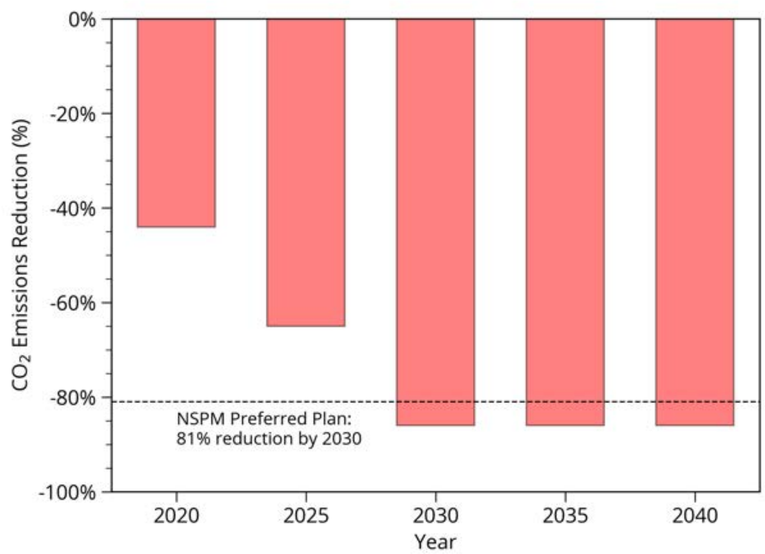

Figure 3.20: Percentage change in annual emissions in NSPM territory compared to 2005 levels.

The cumulative emissions from the electricity sector from 2020 onwards is shown in Fig. 3.21. The emissions accumulate at a faster rate until about 2025 after which the rate of accumulation reduces and emissions accumulate at a slower rate as the generation remaining on the grid is cleaner and relies less on fossil fuel generation. The total CO_2 emission savings in the electricity sector from the “Consumers Plan” with respect to the reference case of continuing with the generation mix present in 2020 is 140 mmT of CO_2 by 2040. The “Consumers Plan” also electrifies large portions of the rest of the economy, which results in emission savings of 564.7 mmT of CO_2 from electrification alone. The total emission savings from electrification and decarbonizing the electricity sector combined is shown in Fig. 3.22. The total emission savings from electrification of the rest of the economy and decarbonizing the electricity sector is 703 mmT of CO_2.

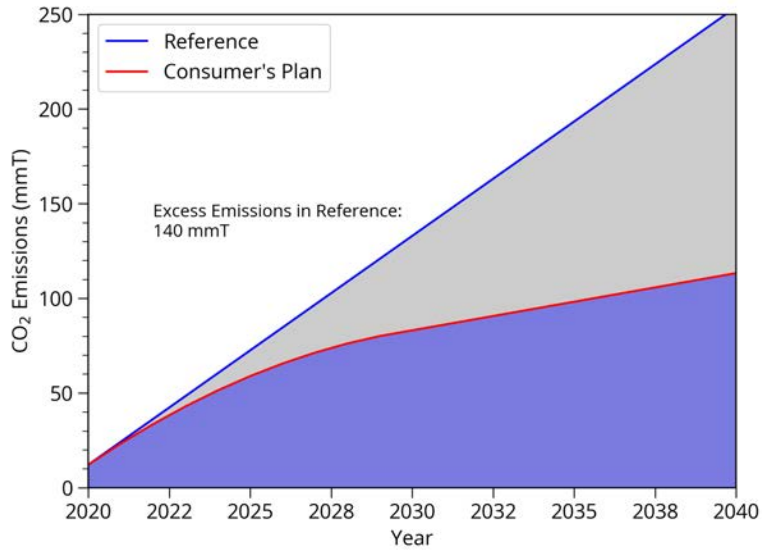

Figure 3.21: Cumulative carbon dioxide emission in the electric sector.

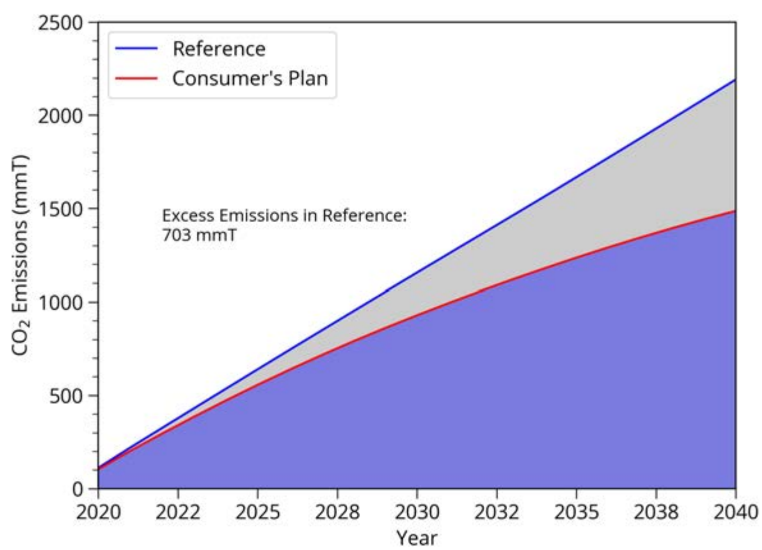

Figure 3.22: Economy-wide cumulative emissions.

In addition to CO_2 emission savings, the changes to the electricity sector also result in reductions to other criteria pollutants tracked by WIS:dom-P as shown in Fig. 3.23. The SO_2 emissions drop to zero by 2025 as a result of retirement of all coal power generation own by NSPM. Similarly, PM_{10} and $PM_{2.5}$ also drop to zero due to the coal retirements. The NO_x emissions also show a significant drop by 2025 due to the coal retirements and then stays fairly constant as the remaining natural gas generation operates through 2040. Emissions of CH_4 and volatile organic compounds (VOC) also reduce drastically by 2025 from coal retirements and then remain largely constant after that until 2040. The CH_4 and VOC emissions include a leakage rate of 2% for the production of the natural gas fuel.

The emission savings is not only CO_2, but also other criteria pollutants in the electricity sector and the rest of the economy occur while cumulatively saving $6.45 billion in the electricity sector. Therefore the "Consumers Plan" will result in not only savings for the electricity consumers, but will also bring improved health outcomes as a result of reduced air pollution.

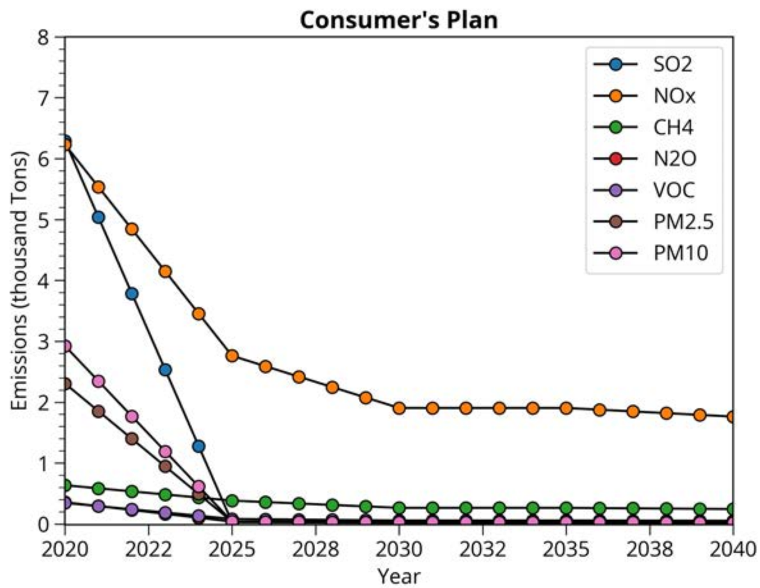

Figure 3.23: Emissions from other criteria pollutants tracked by WIS:dom-P.

3.5 Transmission Buildout

As discussed in Section 2.2, WIS:dom-P is initialized using the generation existing in 2018 along with the transmission topology. WIS:dom-P then determines the initial transmission required to meet load constrained by existing generators and existing transmission paths. As the model progresses through the investment periods, WIS:dom-P adds to the existing transmission as required for optimal capacity expansion and dispatch. All transmission added is modeled as new builds, therefore actual transmission costs can be lower than modeled if existing transmission pathways can be upgraded. Every new generation plant added by WIS:dom-P interconnects to the bulk transmission lines through spur lines. Based on the size and length of these spur lines each generator has to build, the median "shadow" interconnect cost in the NSPM territory is found to be $149/MW. The incremental inter-state transmission (along with transmission from the NSPM domain) added over the investment periods over the modeled domain is shown in Fig. 3.24.

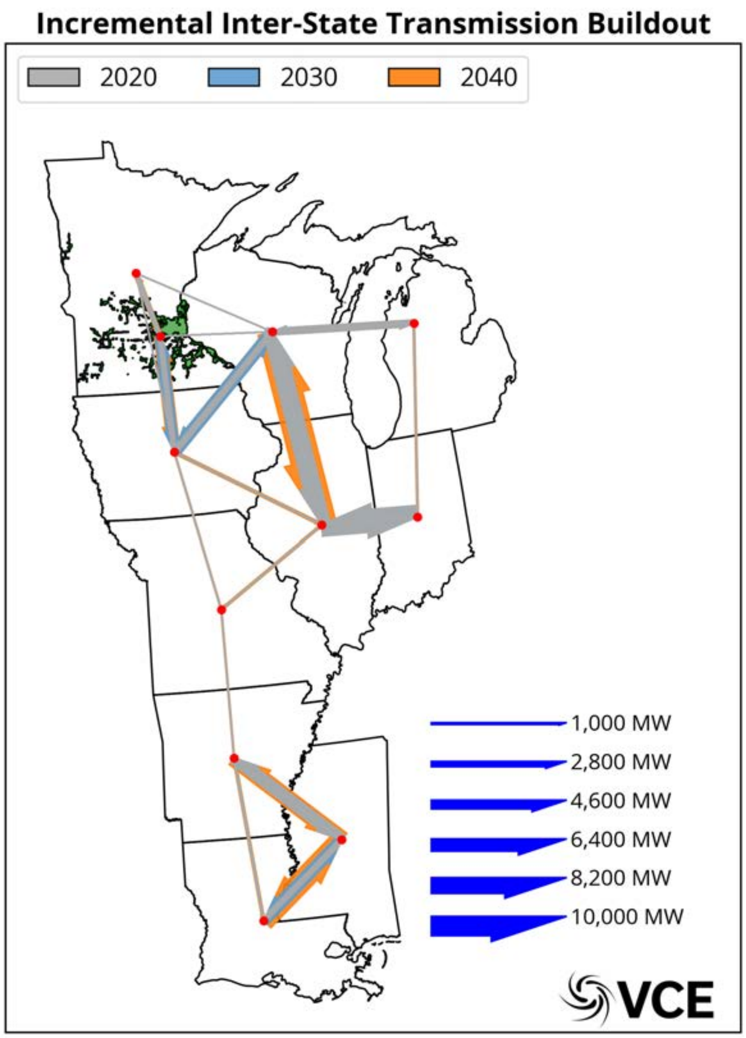

Figure 3.24: Incremental inter-state transmission added over the investment periods.

Most of the new transmission built is between Louisiana and Mississippi in the southern load zones of MISO. In the northern load zones, Iowa and Wisconsin, Wisconsin and Indiana, Iowa and NSPM, and rest of Minnesota and NSPM show the largest inter-state transmission builds. Figure 3.25 shows that by 2040 NSPM builds about 450 MW of additional transmission to rest of Minnesota to allow for more electricity exchange between the regions. Most of this new transmission capacity from NSPM to rest of Minnesota can be built by upgrading existing transmission pathways and thus should cost less than the model estimates. By 2040, WIS:dom-P adds in total 2,095 MW of transmission connecting the NSPM region to Iowa to import the excess wind generation or export the excess solar generation from the NSPM region. In spite of the significant new transmission built, as seen from Fig. 3.3, transmission costs are a negligible portion of the cost of delivered electricity for NSPM.

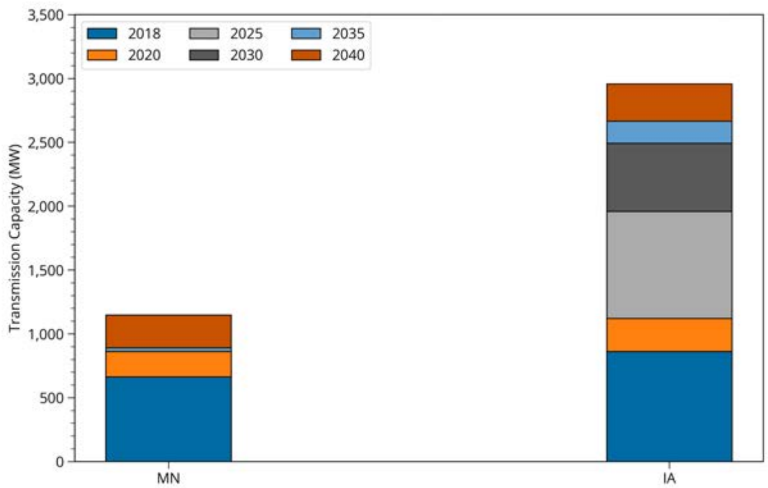

Figure 3.25: Transmission capacity built from NSPM region to other states over the investment periods.

The NSPM region also builds significant in-territory transmission, including spur lines, to connect the VRE generation installed to load centers. The additional GW-miles of in-territory transmission built by NSPM after 2018 over the investment periods is shown in Fig. 3.26. There is significant new transmission built in the NSPM region between 2020 and 2030 to connecting the large buildout of wind and solar that occurs during this period to replace the retired coal generation and help meet the growing load due to electrification. New transmission built after 2030 slow as rate of addition of new generation also slows down.

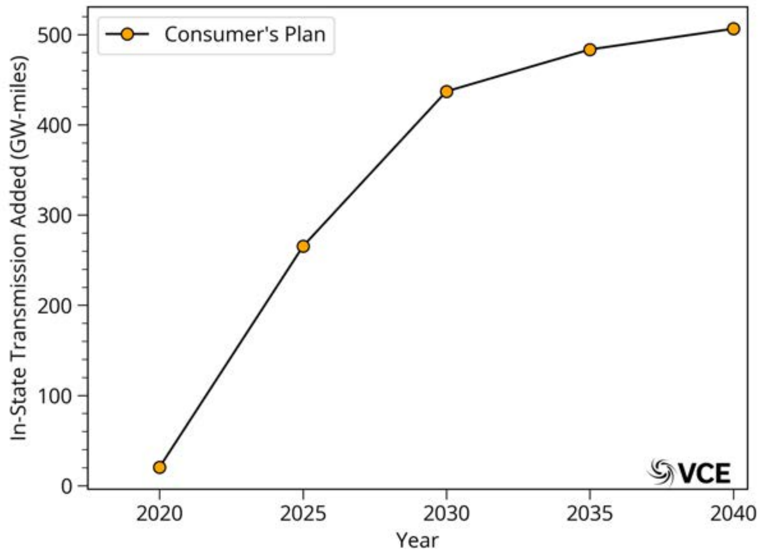

Figure 3.26: In-state transmission built in the NSPM region over the investment periods.

3.6 Reliability and Resource Adequacy

WIS:dom-P ensures reliability by making sure that the installed capacity in each investment period can meet demand along with a 7% load following reserve without fail at each time period. Resource adequacy is ensured by meeting the North American Electric Reliability Council (NERC) specified unforced capacity (UCAP) Planning Reserve Margins (PRM) for each balancing area modeled. UCAP represents the capacity available at a given time taking into account the generator's forced outrage rate. The modeled forced outage rates for thermal generators are given in Table 3.1.

WIS:dom-P models the reliability and resource adequacy as part of the capacity expansion process. As a result of including reliability and resource adequacy as part of the capacity expansion, WIS:dom-P ensures that at every timestep, the sum of expected generation from VREs and the unforced capacity for thermal units is greater than the load plus the PRM for the balancing region in question, while ensuring that there is enough generation at each timestep to meet load plus an additional 7% load following reserve. Thus, in addition to choosing sites with best capacity factors and correlation to load, WIS:dom-P also has to consider the impact on the grid when the generation from VREs is low or non-existent. As a result, WIS:dom-P ensures that the even for periods of lowest or zero VRE generation, the PRM requirements are met for each balancing region, which overcomes limitation of traditional methods that assume a single (or seasonal) capacity value for VRE generators. More details on how the model handles reliability and resource adequacy is described in WIS:dom-P technical documentation Section 3.14).[19]

Generator	Coal	NGCC	NGCT	Nuclear	Hydro	Geo	CCS	SMR	MSR
UCAP	87.7%	86%	85.3%	90.3%	89.5%	89.1%	86%	95%	95%

Table 3.1: Unforced capacity fractions for thermal generators

In order to express reliability using the traditional reliability metrics, the WIS:dom-P software outputs can be post-processed to determine these values. One of the commonly used reliability metrics is the Equivalent Load Carrying Capacity (ELCC). ELCC is determined by calculating the additional load that the system can carry due to the addition of a VRE generator while maintaining the same loss of load probability as before the VRE generator was added. The ELCC of the installed VRE generation in the NSPM territory over the investment periods is shown in Fig. 3.27. Solar deployed in the NSPM region has an ELCC of about 26% in 2020, which falls drastically to 2% by 2025 as significant amounts of solar (both UPV and DPV) are deployed in the NSPM region. The solar ELCC then rises steadily reaching 9.5% by 2040 as a result of increasing load due to electrification, which is correlated with the solar generation.

[19] https://vibrantcleanenergy.com/wp-content/uploads/2020/08/WISdomP-Model_Description(August2020).pdf

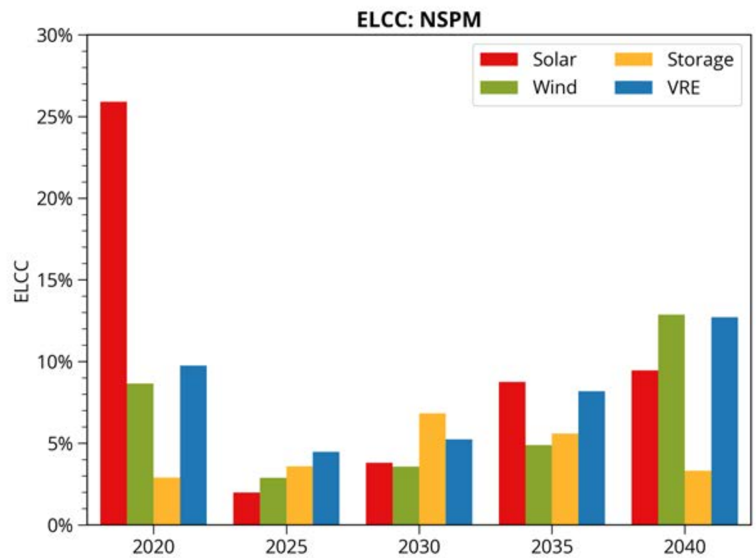

Figure 3.27: ELCC of wind, solar, storage and combined VRE system.

Wind generation has an ELCC of 8.6% in 2020 over the NSPM territory. Over the investment periods the ELCC of wind reduces further as more wind is installed on the grid reaching a minimum of 2.8% by 2025. After 2025, the ELCC of wind starts increasing again as electrification increases winter-time loads, which results in ELCC of wind increasing again to 12.8% by 2040. Storage is seen to have very low ELCC over the whole modeled period starting at 2.9% in 2020 and reaching a maximum of 6.8% in 2030 before reducing to 3.3% by 2040. The low ELCC values for storage are driven by storage coming into play during transition periods going from dominantly wind generation to dominantly solar generation and vice-versa. In addition, WIS:dom-P employs storage as a peaker unit, which also contributes to a lower ELCC value.

Another method to estimate capacity value is based on the role the VRE generation plays in meeting load during periods of highest demand. The capacity value is calculated as the reduction in net load during periods of peak demand as a fraction of installed VRE capacity. Figure 3.28 shows the capacity value of the VRE generators calculated during periods of high demand. The solar capacity value calculated in this manner is 0.1% in 2020 increasing to 8.1% by 2040 as electrification and BAU load growth results in more peak load periods to occurs during periods of high solar generation. The capacity value of wind generation is found to be about 1.8% in 2020, increasing in later year to reach 4.1% by 2040. The wind capacity value does not increase as much as solar as wind generation works with storage to meet load during peak load hours in the later years when load increases due to electrification. As a result, the capacity values of wind and storage calculated using this method track closely to one another. Storage capacity value is found to be less than 0.1% in 2020 as storage is deployed mainly during the transition periods which are not periods of highest system stress. The storage capacity value increases over the years as it works along with wind to meet load reaching a capacity value of 3.4% (similar to wind) by 2040.

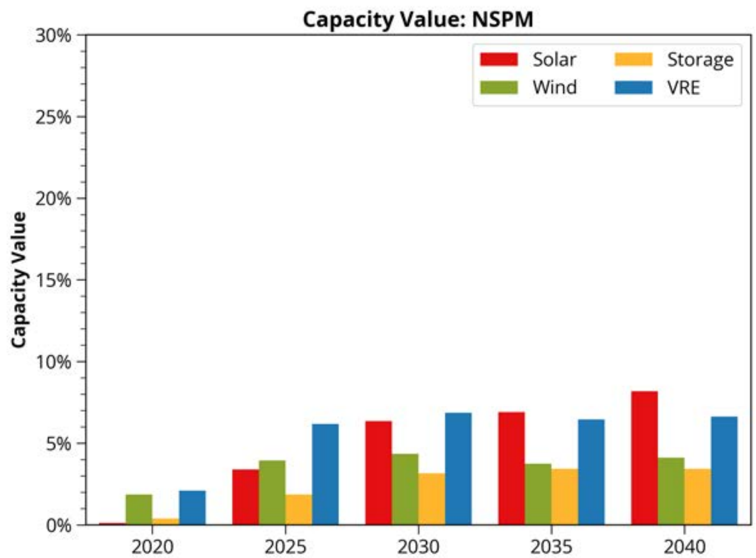

Figure 3.28: Capacity value of VREs calculated based on contribution during periods of peak demand.

Since VRE generation has seasonal characteristics (see Section 4.4), their capacity value is also expected to show seasonal trends. Figure 3.29 shows the monthly averaged daily capacity value calculated as the generation available from a VRE generator as a fraction of its installed capacity during the daily peak load periods for year 2040. The solar capacity value peaks during the summer with a sharp peak in July when the total solar generation is highest due to longer days and low cloud cover resulting in higher generation available during peak load periods. The wind capacity value is complementary to the solar capacity value as wind generation is higher in winter, which correlates better with winter loads that peak during periods of higher wind generation. Wind capacity value reaches its minimum in the month of August where warmer temperatures result in peak load occurring during daytime hours when wind generation is lower. Storage capacity value shows a bimodal trend with peaks in the spring and fall seasons. This trend in storage capacity value is expected as storage is seen to play a dominant role during the transition periods.

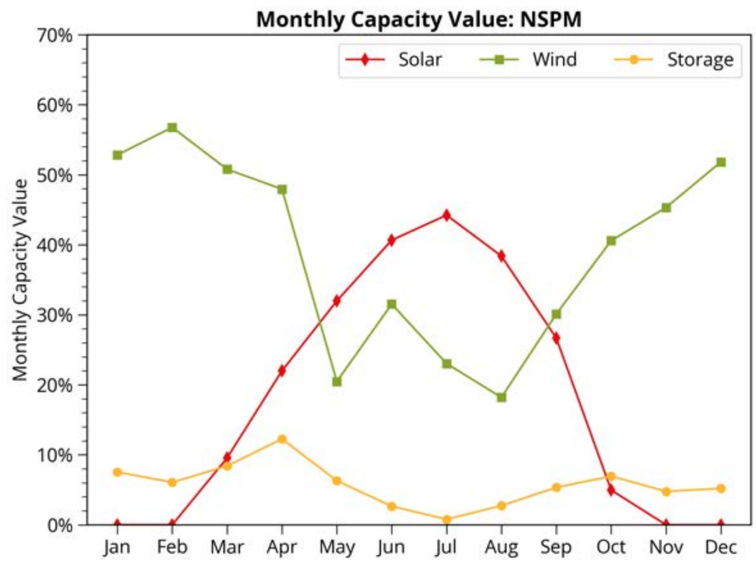

Figure 3.29: Monthly average capacity values in 2040 for the NSPM region.

3.7 Siting of Generators (3-km)

WIS:dom-P uses weather dataset spanning multiple years at 3-km spatial resolution and 5-min temporal over the contiguous United States. WIS:dom-P performs an optimal siting of generators on the 3-km HRRR model grid. The existing generator layout reduced to 3-km resolution along with the transmission paths above 115 kV is shown in Fig. 3.30 (left panel), while the WIS:dom-P installed capacity by 2040 is shown in Fig. 3.30 (right panel). As seen from Fig. 3.30, the grid is largely composed of fossil fuel generation in 2018, which is transforms to VRE dominated by 2040. Apart from significant wind generation, the Mid-West region also deploys significant levels of solar generation both at utility-scale and distribution-scale.

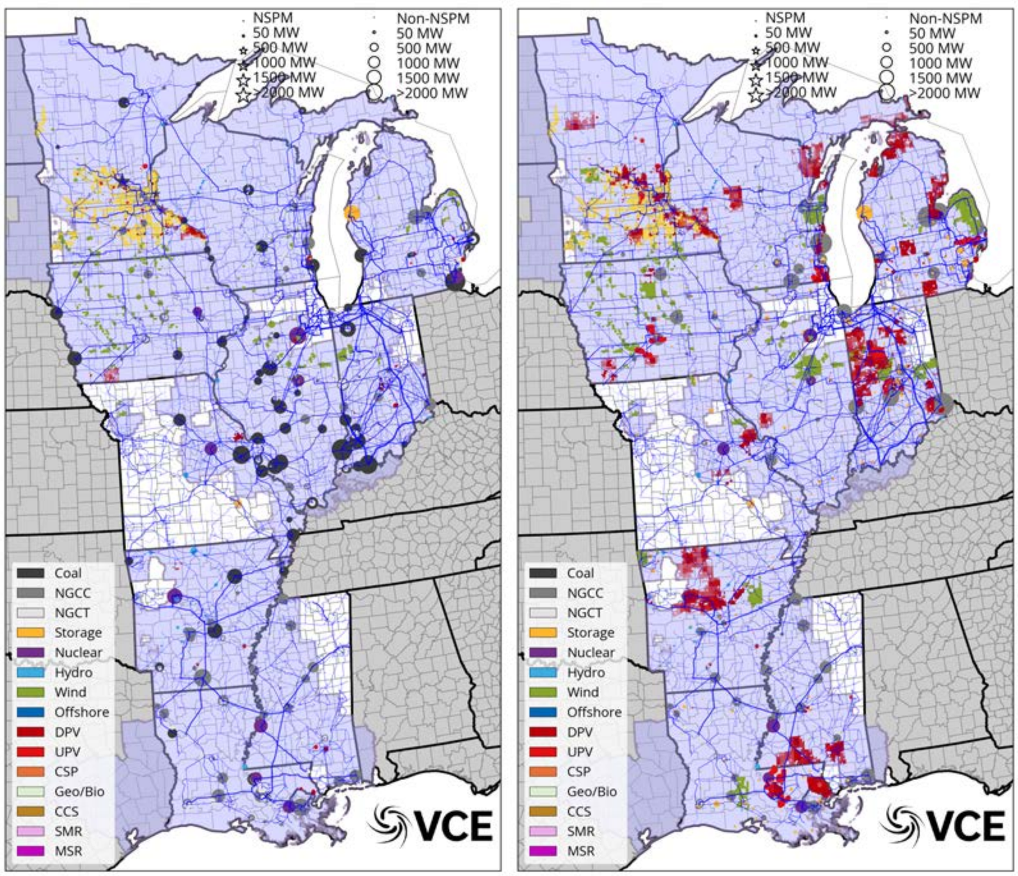

Figure 3.30: Installed generation layout in 2018 (left) and 2040 (right) at 3-km resolution along with transmission paths above 115 kV.

As a result of co-optimization of the distribution system, the grid is composed of almost equal parts of utility-scale solar and distribution-scale solar PV. The northern portion of the model domain is seen to deploy significant levels of solar in spite of the lower capacity factors due to higher correlation with the summer loads profiles. Figure 3.31 shows the installed capacities in MN belonging to NSPM (stars) and rest of the domain (circles). As seen from Fig. 3.31, WIS:dom-P installs utility-scale generation for NSPM even outside of NSPM territory due to lack of available space inside NSPM territory. These generators are then connected through transmission lines belonging to NSPM to bring power to the load centers. Distributed generation is limited to being installed within the NSPM territory as this generation is installed behind the 69-kV substation.

As seen from Fig. 3.31, significant DPV is deployed near the twin-cities area as well as near St. Cloud. Other smaller population centers also get DPV deployed in order to reduce moving electricity over long distances and thus saving on transmission line losses. Most of the wind generation installed by NSPM is outside its territory due to lack of space for large wind projects.

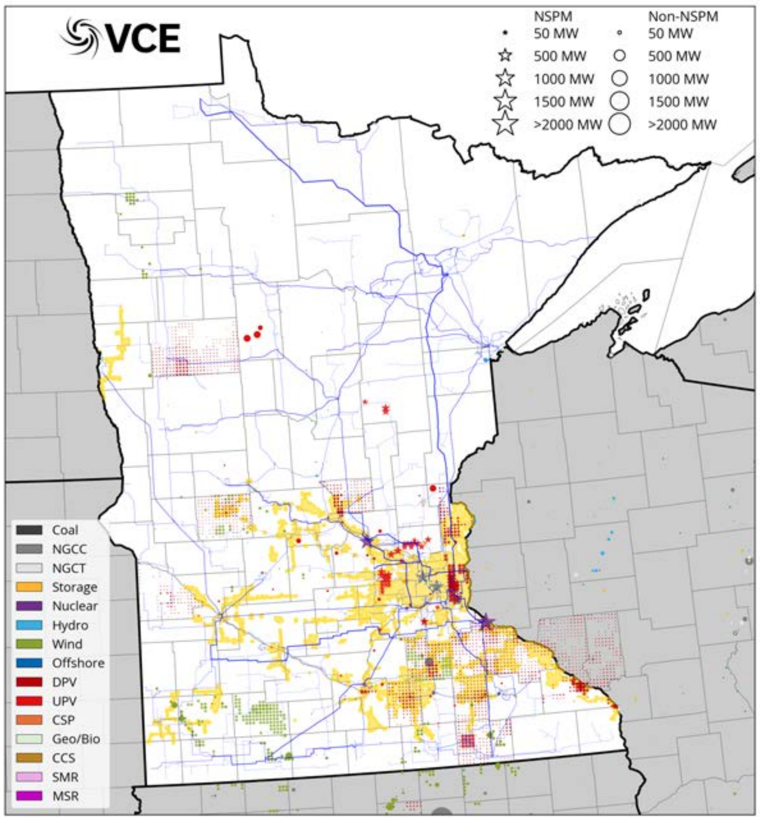

Figure 3.31: Optimal siting of NSPM generators (stars) and rest of the generators in the domain (circles) by year 2040.

When making the siting decisions. the model takes into account several criteria to determine the optimal siting for the generators. In addition to taking into account expected generation and distance from the load, the model ensures that generation is not sited in unsuitable locations. The criteria used to filter out unsuitable locations for VRE generation are discussed in Section 4.2. In addition, the model has to ensure that it does not exceed the technical potential of each grid 3-km grid cell. The technical potential for the various VRE technologies in each grid cell is determined by taking into account several factors such as population, land cover, terrain slope etc. In addition, each technology is limited by the maximum packing density allowed to ensure that the generators do not hamper performance of other generators in the grid cell such as through wakes for wind turbines and excessive shading for solar panels. The details on these metrics and the available technical potential for the CONUS are discussed in greater detail in Section 4.2.

4 VCE® Datasets & WIS:dom-P Inputs

4.1 Generator Input Dataset

VCE® processed the Energy Information Administration annual data from 2018 to create the baseline input generator dataset for this study. From this dataset, information for Northern States Power Company in Minnesota (NSPM), the entire state of Minnesota and the MISO footprint was obtained. These regions include roughly 8.7, 18.5 and 178.7 GW respectively. WIS:dom has the ability to solve over such scales at 5-minute resolution for several years chronologically. The NSPM Integrated Resource Plan (IRP) was used to update the subset of their generator dataset for this study. The NSPM IRP shows capacities as a summer capacity. Here nameplate capacities are discussed as those values are necessary as input into the model. This study focused on the NSPM territory in particular, however, the scenarios were modeled as a subset of MISO to ensure proper representation. For this study, generators under MISO but within North Dakota, South Dakota, Montana and Texas were not considered. This ISO has a large geographic extent and contains approximately 192,677 MW of generation capacity. The reduced MISO area contains approximately 178,739 MW of generation capacity. The reduction comes mostly from some coal and wind plants in the Dakotas as well as some gas plants in southeast Texas. This reduction does not change the overall layout of the types of technologies MISO currently oversees. This reduced MISO region is what will be discussed and referred to as MISO for the remainder of this report. The NSPM generators outside of Minnesota are shown in plots below in their actual state. However, for modeling purposed these generators were incorporated into the closest NSPM county within Minnesota. This allowed these generators to be a part of the modeling done for the NSPM footprint within Minnesota.

The WIS:dom-P generator input datasets are built upon the publicly available EIA 860 and EIA 923 data. The 2018 data is what was available for this study. VCE carry out several steps to align and aggregate technology types to the 3-km model grid space that matches the National Oceanic and Atmospheric Administration (NOAA) High-Resolution Rapid Refresh (HRRR). In the process, year-on-year changes were analyzed. Across the United States, general trends show (for fossil fuels) coal capacities falling with natural gas combined cycle growing. Wind, solar and storage plants are on the rise as well. The trend continues in the data throughout 2019 based upon the recently released EIA 860 annual data for that year.

Below, we outline the VCE process to prepare the generator input datasets:

1. *Data is merged, aligned, and concatenated between the EIA 860 and EIA 923 data.*
2. *Initial quality control is applied to the data to ensure accuracy between datasets.*
3. *Align the location of the generators to the nearest 3-km HRRR cell. Care is taken to ensure the correct grid cell is chosen within state boundaries and water sites.*
4. *Aggregation of the generator types within each 3-km cell; e.g., multiple generators of the same fuel type are summed for capacity and capacity-weighted averaged are applied to operational parameters.*
5. *Further spatial verification is performed to ensure the output aligns with the original data.*

6. *Final model input format produced. A county level average of all generator types is also created.*

VCE coordinates with the Catalyst Cooperative (https://catalyst.coop/), a company with the goal to help the energy research community by processing major publicly available sources into a format that is organized and stream-lined to use. This assists our processes and will allow it to become more rapid and frequent for these input datasets.

1	Coal
2	Natural Gas Combined Cycle
3	Natural Gas Combustion Turbine
4	Storage
5	Nuclear
6	Hydroelectric
7	Onshore Wind
8	Offshore Wind
9	Residential Solar
10	Utility-scale Solar
11	Concentrated Solar Power
12	Geothermal
13	Biomass
14	Other Natural Gas
15	Other Generation
16	Natural Gas - CCS
17	Pumped Hydro Storage
18	Small Modular Reactors
19	Molten Salts

Figure 4.1: The VCE® generator technology bins.

Figure 4.1 displays the generation technology types that are standard within the WIS:dom-P modeling. Figure 4.2a, Fig. 4.2b and Fig. 4.2c show the installed capacities over the NSPM territory, the entire state of Minnesota and the entire MISO footprint respectively. NSPM has more nuclear and coal installed in place of Variable Renewable Energy (VRE) sources such a wind, solar and hydro when compared to Minnesota as a whole. There is no solar in the NSPM portfolio and limited hydro. When comparing NSPM to MISO's portfolio, it is shown that NSPM has more nuclear in place of VRE sources such as solar and hydro as well as natural gas. For comparison, the same chart is shown in Fig. 4.3 for all the installed capacity across the contiguous US. Note that across the contiguous US, the share of thermal generation is lower than in NSPM, mostly due to coal and nuclear. There is also more natural gas in exchange for coal and nuclear in Fig. 4.3 compared with Fig. 4.2a. Further, VRE has more representation in the wider US than the NSPM territory.

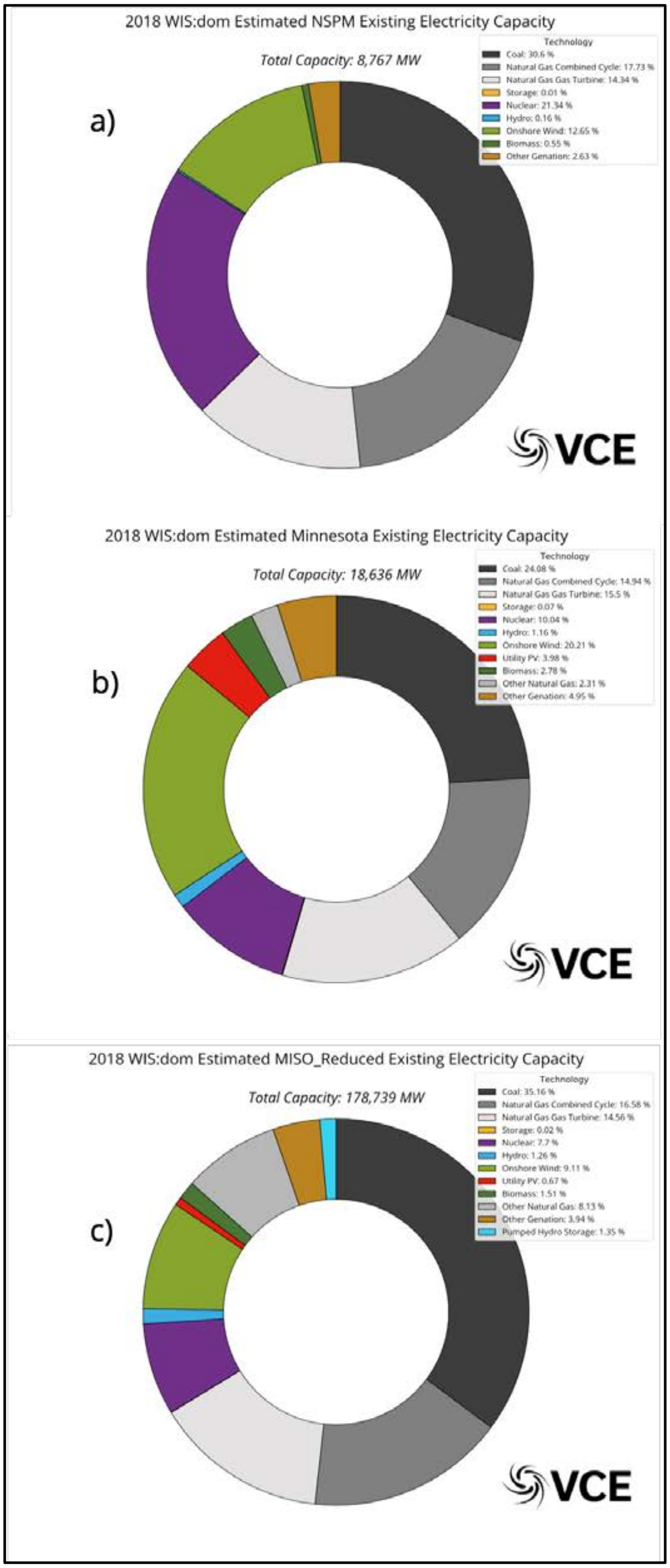

Figure 4.2: WIS:dom estimated capacity for the (a) the Northern States Power Company - Minnesota (b) all Minnesota and (c) for the entire MISO region. The capacity is 8.7, 18.6 and 178.7 GW respectively.

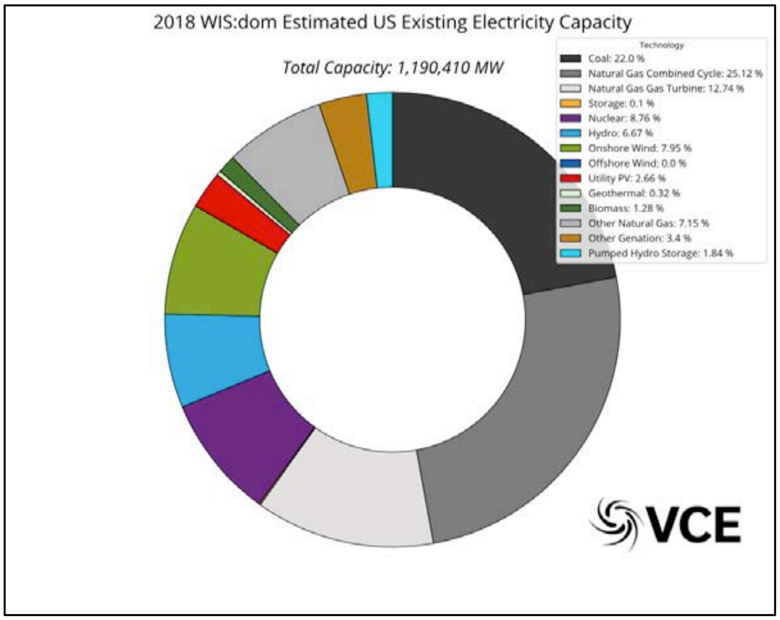

Figure 4.3: WIS:dom estimated capacity share for the contiguous United States. The total capacity modeled is 1,190 GW.

Figure 4.4 shows the technology capacity stacked totals for each state within a) the NSPM territory, b) Minnesota and c) MISO. Some wind comes into account from North Dakota and a gas plant from South Dakota. For MISO, Michigan has the highest amount of capacity installed of all the states considered in the region. Louisiana is only a couple thousand megawatts behind Michigan. Nuclear has a presence in all MISO states except Indiana and Kentucky. Nuclear has the highest presence in Arkansas, Louisiana, Michigan and Minnesota. The nuclear capacity totals are also fairly equivocal in those states. Coal also has a large presence in many MISO states with Indiana and Michigan holding the most capacity. Minnesota, as a whole, has the largest amount of utility scale solar installations in MISO. This solar is not in the NSPM generator profile.

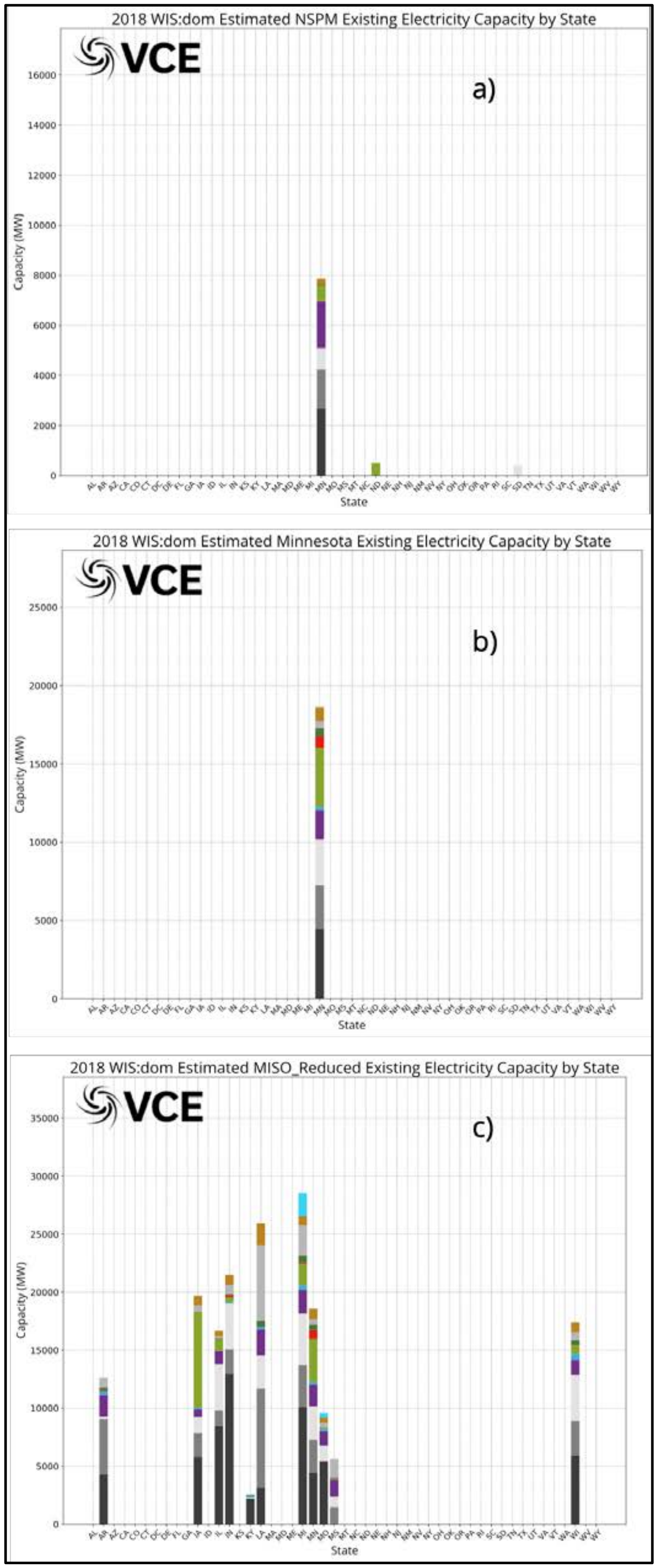

Figure 4.4: WIS:dom Capacity installed in a) NSPM, b) Minnesota and c) MISO for this study.

Figure 4.5 shows the technology layout spatially across a) NSPM, b) Minnesota and c) MISO. Most Northern State Power Minnesota generators are near Minneapolis. Some wind plants are in southern Minnesota and North Dakota. In Minnesota, most generators are installed in the southern half of the state. Several smaller solar projects are installed across the lower half of the state. Wind is most prominent closer to the Iowa and South Dakota borders. Hydro is observed throughout the state, but more units exist in the northern half of the state. Coal is also a technology that is mostly observed in the northern half of the state. Most of the larger thermal generators exist closer to the more populous Minneapolis area. For the MISO footprint as a whole, many coal plants are stationed along the Ohio, Missouri and Mississippi rivers. Solar shows up noticeably in southern Minnesota. Some smaller solar plants can also be observed across Indiana and eastern Iowa. Iowa holds the majority of the wind capacity under MISO. Southern Minnesota also has many wind farm installations in comparison to other MISO states. Along the shores of Lake Huron, in the thumb of Michigan, there are also many wind farms established. Hydroelectric facilities appear most notably throughout Wisconsin, Arkansas and northern Michigan. Natural gas shows up most prominently in southeast Wisconsin, southern Illinois and within Indiana and Louisiana.

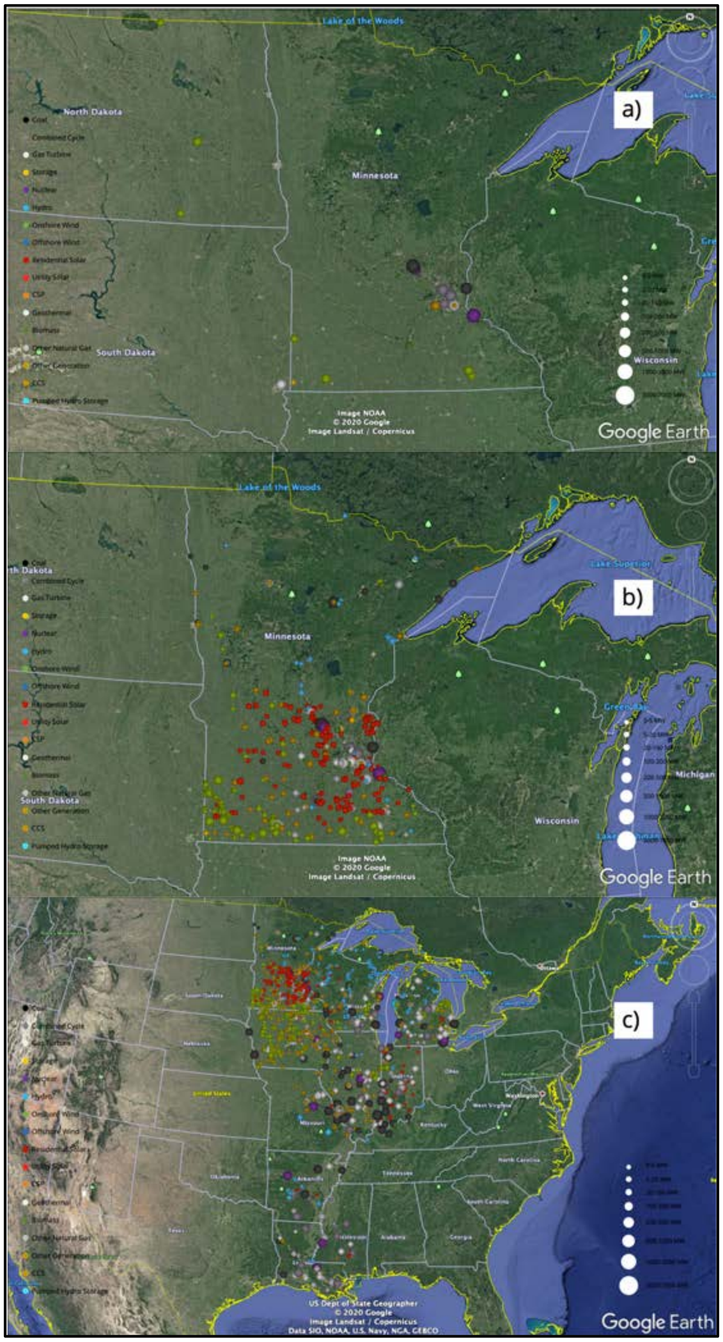

Figure 4.5: WIS:dom estimated location of various technologies for the a) NSPM, b) Minnesota and c) the MISO footprint.

Quality control efforts were employed to ensure generators in the Xcel NSPM IRP were correctly represented from the EIA 860 datasets. For modeling purposes, NSPM generators that were outside of Minnesota were pulled into the closest NSPM Minnesota county. The 2018 EIA dataset was used to initialize the 2018 investment period within WIS:dom-P. The 2019 EIA generator dataset adjusted what the model had built by investment period 2020 for the NSPM generators. In particular, a wind farm named Foxtail was added with a 150 MW capacity.

4.2 Renewable Siting Potential Dataset

VCE performs an extensive screening procedure to determine the siting potential of new generators across the contiguous US. This ensures that the WIS:dom model has constraints on where it can build new generation. First, USGS land cover information is utilized as a base within each 3 km grid cell to determine what is there (Fig. 4.6, top left panel). The siting constraint information for onshore wind, offshore wind, utility-scale solar PV and distributed solar PV is displayed in a zoomed view of Minnesota in Fig 4.7a and the main states within MISO in Fig. 4.7b.

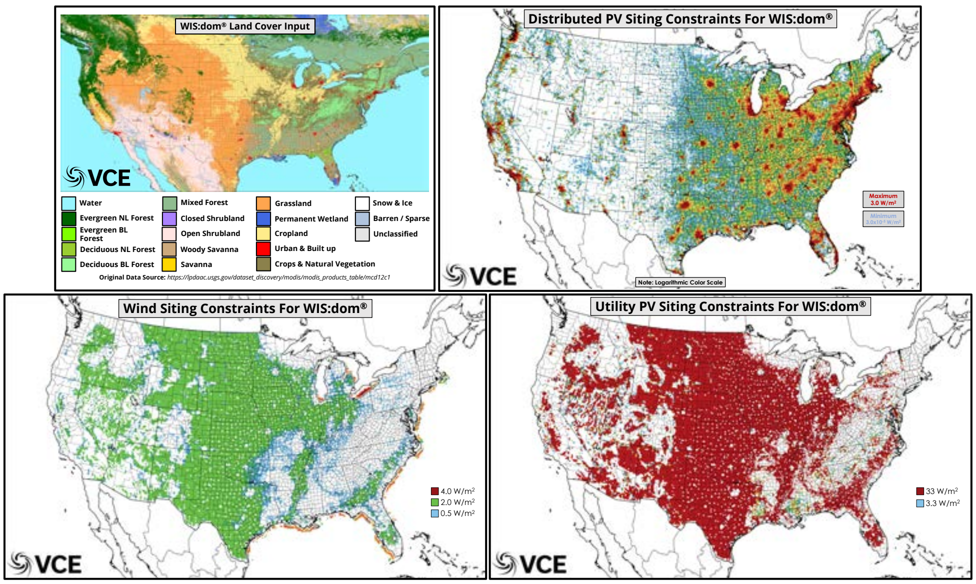

Figure 4.6: WIS:dom land cover (top left), distributed solar PV siting bounds (top right), utility-scale wind bounds (bottom right) and utility-scale solar PV (bottom right).

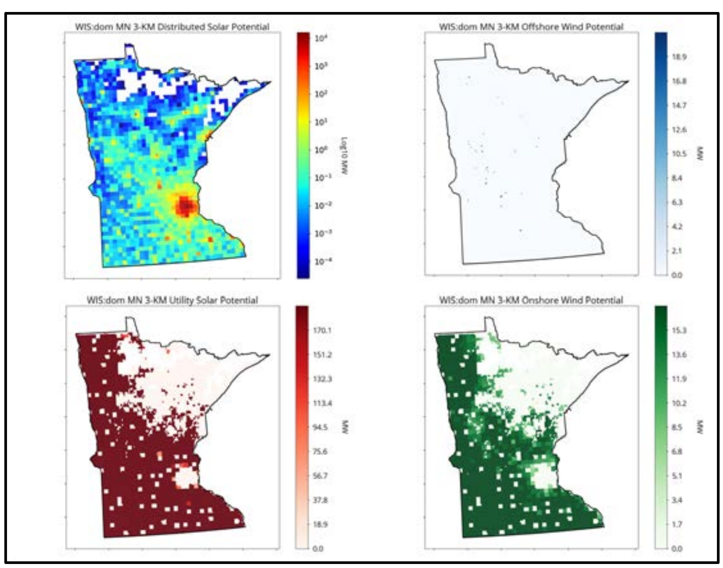

Figure 4.7a: WIS:dom-P Rooftop Potential (top left), Offshore Wind Potential (top right), Utility-scale Solar Potential (bottom left) and Onshore Wind Potential (bottom right) in MW for Minnesota. The Distributed Solar Potential is converted to a Logarithmic Base 10 scale due to the ranges of value for that parameter.

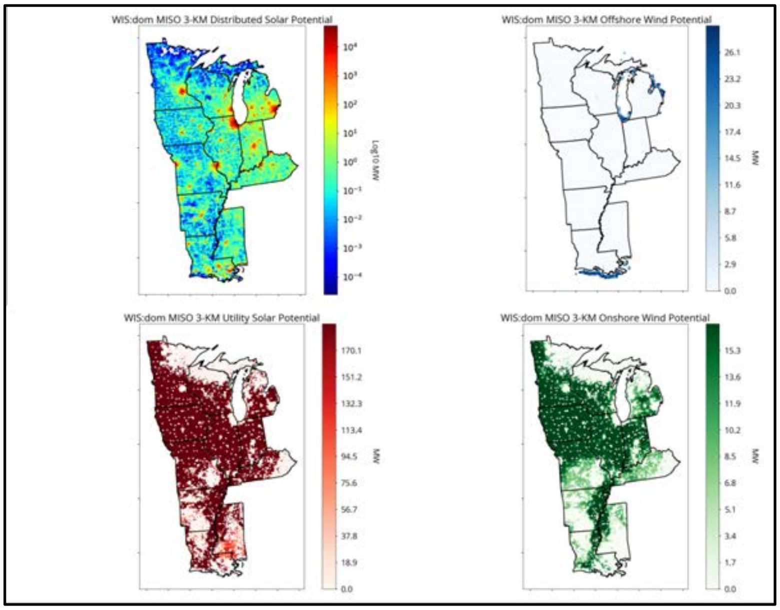

Figure 4.7b: WIS:dom-P Rooftop Potential (top left), Offshore Wind Potential (top right), Utility-scale Solar Potential (bottom left) and Onshore Wind Potential (bottom right) in MW for MISO. The Distributed Solar Potential is converted to a Logarithmic Base 10 scale due to the ranges of value for that parameter.

The first screening algorithm follows these steps:

1. *Remove all sites that are not on appropriate land-use categories.*
2. *Remove all sites that have protected species.*
3. *Remove all protected lands; such as national parks, forests, etc.*
4. *Compute the slope, direction and soil type to determine its applicability to VRE installations.*
5. *Determine the land cost multipliers based on ownership type.*
6. *Remove military and other government regions that are prohibited.*
7. *Avoid radar zones and shipping lanes.*
8. *Avoid migration pathways of birds and other species.*

The above, along with the knowledge of what is already built within a HRRR cell from the Generator Input data, provides WIS:dom with a view of where it can technically build certain generators as well as certain technologies. Figure 4.6 shows the siting constraints for wind, utility-scale solar PV and distributed solar PV.

For wind, utility-scale solar PV, distributed solar PV, and electric storage the available space use converted into capacity (MW & MWh) by assuming a density of the technologies. This is particularly important for wind and solar PV because of wake effects and shading effects, respectively. The maximum density of wind turbines within a model grid cell was restricted to no more than one per km^2 (< 4 MW / km^2). Solar PV was restricted to a maximum installed capacity of 33 MW per km^2. For storage, it is assumed for a 4-hour battery the density is 250 MW / km^2. For all thermal generation, the density assumed for new build is 500 MW / km^2. Thus, for a 3-km grid cell the resulting maximum capacities (in the CONUS) are:

- ***Wind – 36 MW;***
- ***Utility Solar PV – 297 MW;***
- ***Distributed solar PV – 68 MW;***
- ***Storage (4-hr) – 2,250 MW or 9,000 MWh;***
- ***Thermal generators – 4,500 MW.***

These densities and values also ensure that WIS:dom does not over build in a single grid cell because the combined space is constrained, as these numbers are maximums assuming only that technology exists.

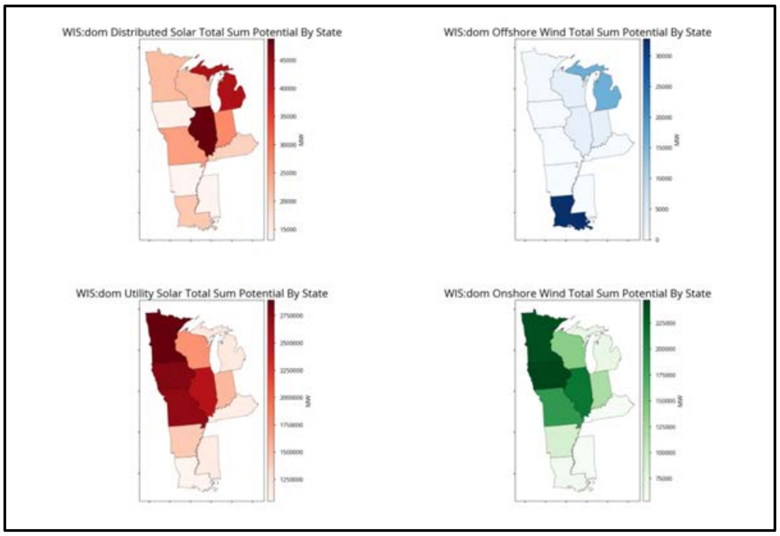

Figure 4.8: WIS:dom Total Sum Potential by state for Rooftop (top left), Offshore Wind (top right), Utility-scale Solar (bottom right) and Onshore Wind (bottom right) in MW.

The above (Fig. 4.8) shows the sum of the land use potential for each variable resource in Minnesota as well as the other states within MISO. It is shown that Illinois, followed by Michigan has the largest potential for rooftop solar development across the state. The large metropolitan areas in those states drive this. Offshore potential is highest in the Gulf of Mexico off the coast of Louisiana. The Great Lakes, in particular along the shorelines of Michigan, show the next highest offshore potential for MISO. The utility scale solar potential is highest in Minnesota with Iowa and Missouri not far behind. Utility scale wind potential is highest in Iowa with Minnesota, Illinois and Missouri following. These are less populous and more plains-like states suitable for wind and solar. The potential for utility solar and wind technologies generally decreases going south and east through the MISO footprint.

4.3 Standard Inputs

There is a standard suite of input data for the WIS:dom-P model that sets the stage for several base assumptions about the energy grid and generator technologies. This includes:

- *Generator cost data (capital, fixed, variable, fuel);*
- *Generator lifetime terms;*
- *Standard generator heat rates;*
- *Transmission/Substation costs;*
- *Legislature in the energy sector:*
- *Renewable portfolio standards;*
- *Clean energy mandates;*
- *GHG emissions requirements;*
- *Storage and offshore mandates);*
- *PTC/ITC;*
- *Jobs for various technologies.*

This is a list of the most commonly discussed standard inputs the model uses and are looked at in this document. The above list is not exclusive and much more information is ingested by WIS:dom-P to narrow down characteristics of various generation technologies. The list of standard files is continuously growing as the industry evolves. Additional inputs can be easily incorporated into WIS:dom-P.

The standard inputs remain constant throughout the scenarios modeled for the study unless specifically requested to change. However, the standard inputs are changing within each scenario throughout each investment period modeled. The overnight capital, fixed O&M and variable O&M costs for each generator technology are predominantly based upon the NREL ATB values. It is noted where this is not the case. The NREL values were chosen to be reputable values; are used by RTOs in their modeling; give high granularity and are updated frequently. The fuel costs typically come from the EIA Annual Energy Outlook data, another source that is reputable and regularly updated. For this study, this is the case for all technologies apart from coal and natural gas. These two generator types had fuel costs updated from the NSPM IRP. Please see Section 2 for more details. VCE® provides fuel and capital costs multipliers by state to further tune the areal layout of these standard cost inputs. Other standard inputs are a combination of VCE® internal research and work with various partners in the industry.

These input assumptions are ingested into WIS:dom-P to provide insight and bounds to the optimization selections for each investment period. It offers the model a picture of what cost options are available to optimize.

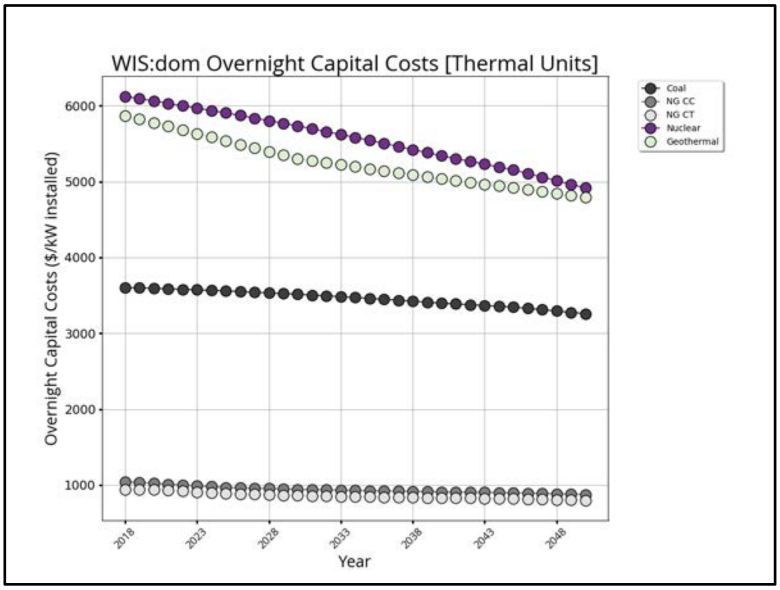

Figure 4.9: The overnight capital costs in real $/kW-installed for thermal power plants in WIS:dom-P. All costs are from NREL Mid ATB 2020.

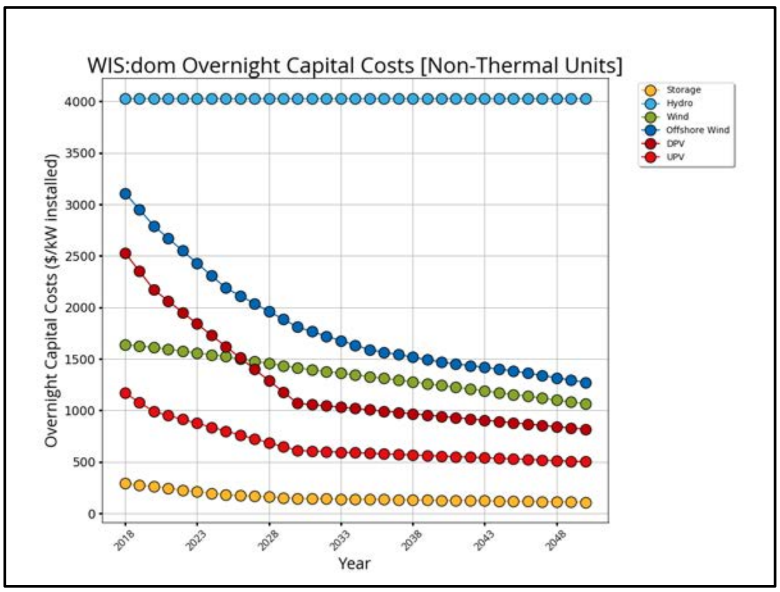

Figure 4.10: The overnight capital costs in real $/kW-installed for non-thermal power plants in WIS:dom-P. All costs are from NREL Mid ATB 2020.

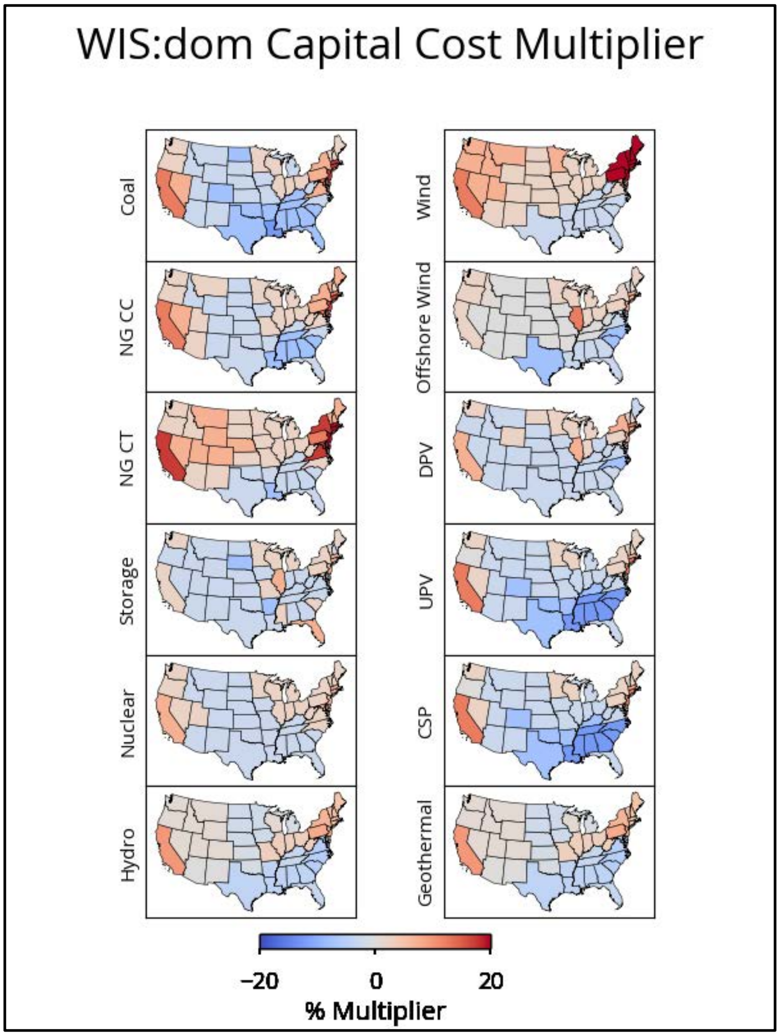

Figure 4.11: The WIS:dom-P Capital Cost Multiplier is shown by state for each technology across the US. Shades of red show where the capital cost is scaled higher by a given percentage. Cool shades show where technology capital costs in the model are scaled down by a given percentage.

Figure 4.11 shows that certain states and regions actually experience lower capital costs when building many technologies from the NREL ATB values. It is shown that Texas and, in general, the Southeast United States, have lower capital costs for all generator technologies. Storage capital cost is the one exception in the southeast that is more expensive, though not for all southeast states. Certain technologies like Wind and Natural Gas Combustion Turbine technologies are more expensive in the Intermountain West. Wind is especially expensive in the northeast. In general, California and the New England states consistently show higher capital costs multipliers for all generator technologies.

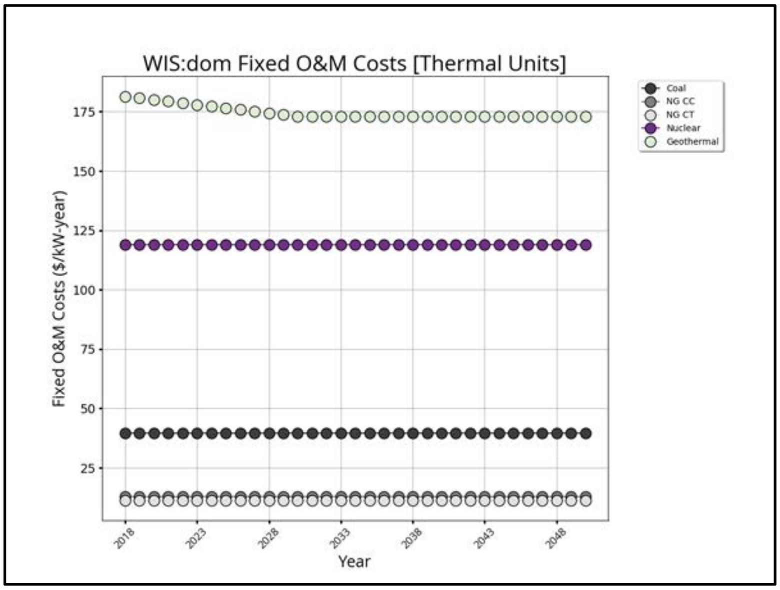

Figure 4.12: The fixed operations and maintenance (O&M) costs in real $/kW-yr for thermal power plants in WIS:dom-P. All fixed costs are from NREL Low ATB 2020.

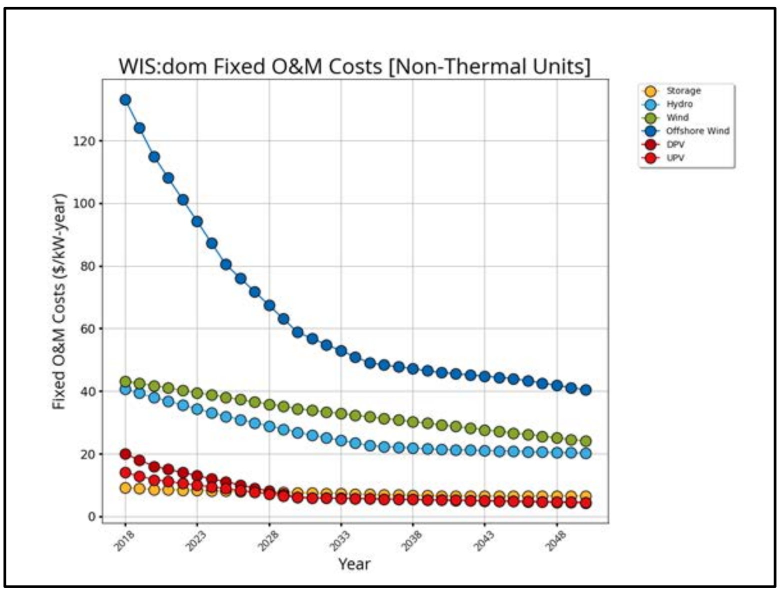

Figure 4.13: The fixed operations and maintenance (O&M) costs in real $/kW-yr for non-thermal power plants in WIS:dom-P. All fixed costs are from NREL Low ATB 2020, with the exception of storage costs, which were provided by Able Grid, Inc.

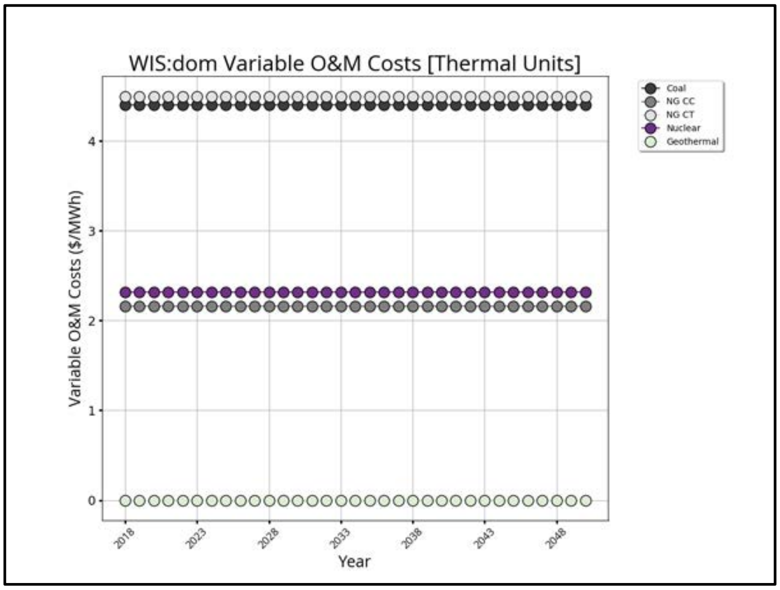

Figure 4.14: The non-fuel variable O&M costs for thermal generators in WIS:dom-P in real $/MWh. All variable costs are from NREL Low ATB 2020. The non-thermal units have zero variable O&M costs for renewables as those costs are combined into the fixed O&M costs.

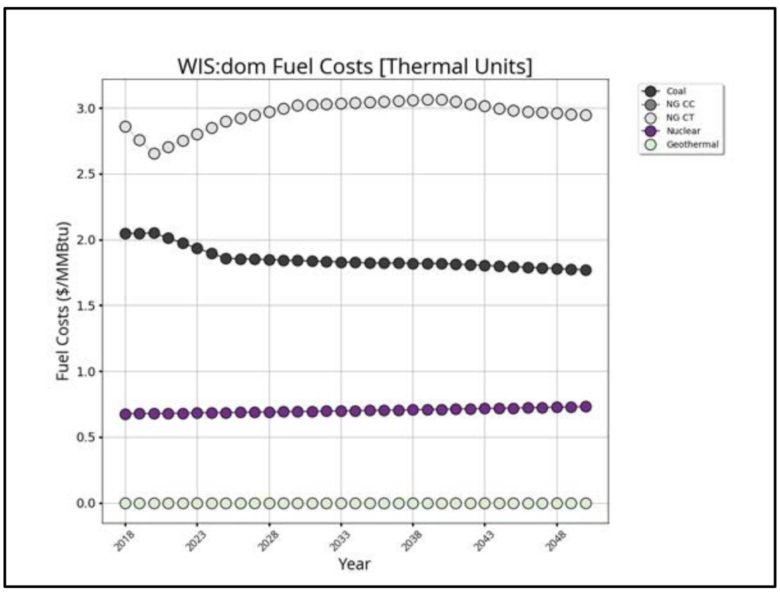

Figure 4.15a: The fuel costs for thermal generators in WIS:dom-P in real $/MMBtu. All costs are from the 2020 EIA Annual Energy Outlook (High Oil and Gas Supply Scenario). This was not used for Coal or Natural Gas for this study.

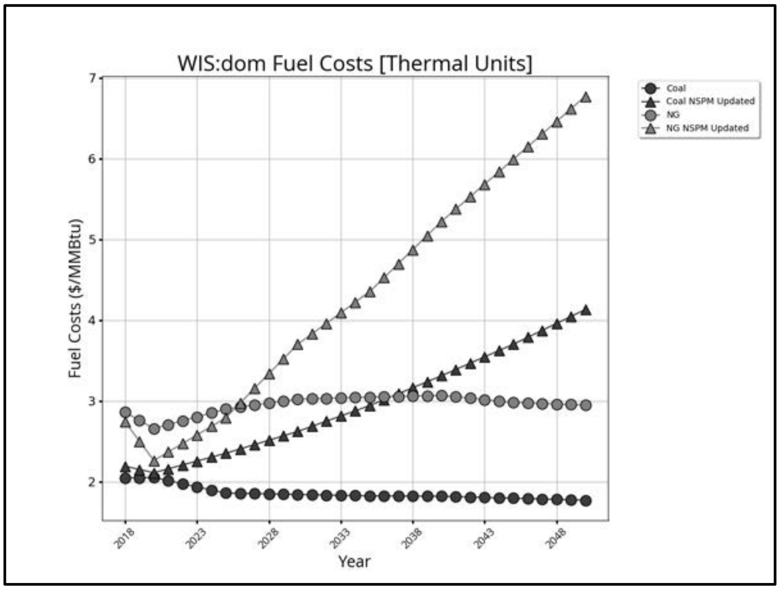

Figure 4.15b: The VCE (circles) and NSPM IRP (triangles) fuel cost for coal and natural gas in $/MMBtu. The fuel costs for coal and natural gas from the IRP were used for this study.

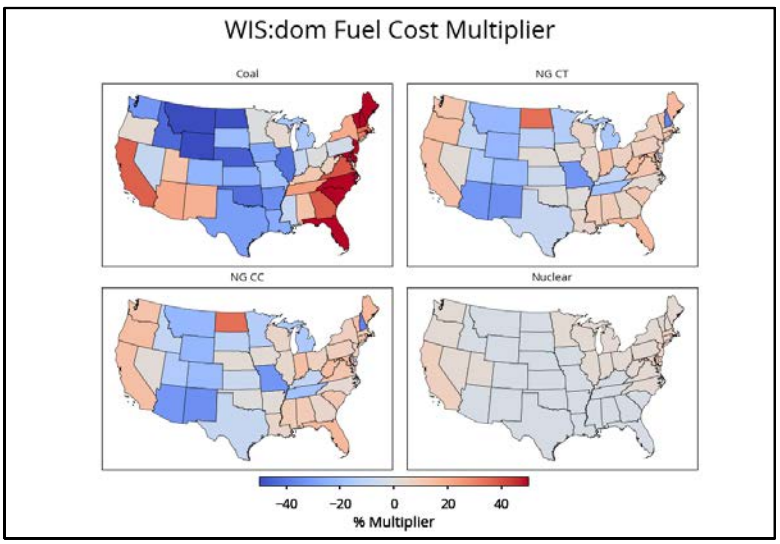

Figure 4.16: The WIS:dom-P Fuel Cost Multiplier is shown by state for each technology across the US. The color scale shows a percentage multiplier applied to standard fuel costs. Shades of red show where the fuel cost is scaled higher by a given percentage. Cool shades show where technology fuel costs in the model are scaled down a given percentage. Renewable fuels are not shown here as those fuel costs are the same no matter where the technology is and those fuel costs are null.

The previous Fig. 4.16 shows the spatial variations of fuel costs for thermal units (except geothermal since that cost is zero). California and the New England states show higher fuel costs for most of the technologies. New Hampshire is an exception for natural gas. Fuel costs for coal are much lower in the middle portion of the country. Natural Gas fuel costs are notably lower in Idaho, Utah, New Mexico, Missouri and New Hampshire. There is no fuel cost multiplier applied to renewable fuels (wind, solar, hydro) as those are the same everywhere across the US and they are fuels that have no cost.

Storage is one of the most discussed inputs. Storage can have highly variable cost input values depending on sources. It also is a heavy driver as to how the model handles renewables, transmission and future baseload. The following Fig. 4.17 shows the difference between the 2020 NREL Low ATB costs for storage versus sources from the industry company Able Grid, Inc. VCE used the former in the modeling for storage in the present study.

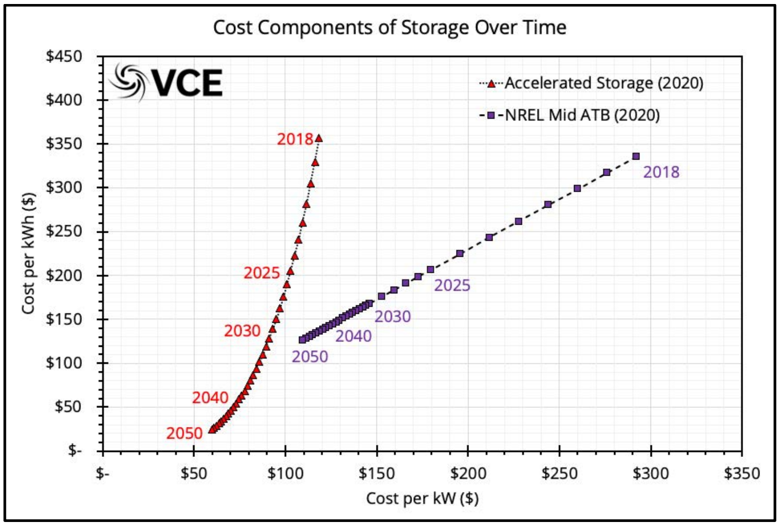

Figure 4.17: The Balance of System Capital Cost ($/kw) versus the Battery Pack Capital Cost ($/kWh). This is shown for the 2020 Mid NREL ATB values in purple. The same information is shown in red for an "accelerated" storage cost. For this study, the former is used in the WIS:dom-P model.

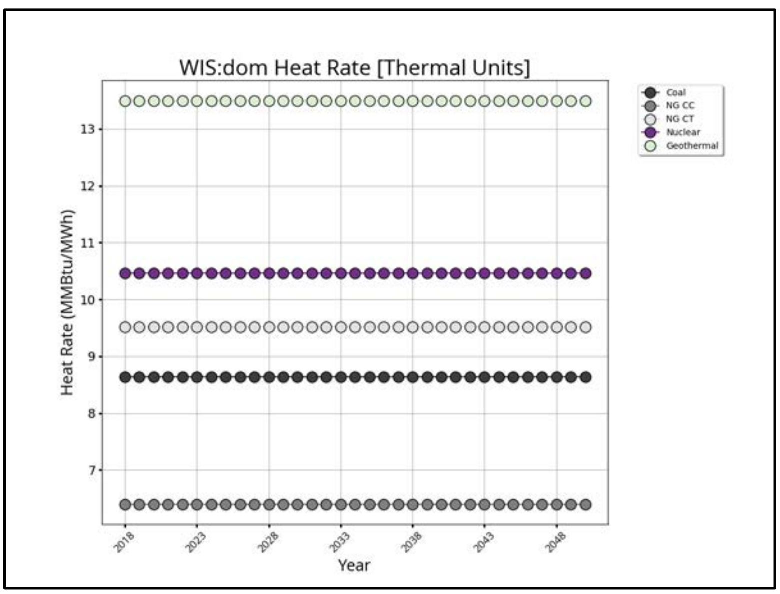

Figure 4.18: The generic heat rate for thermal generators in WIS:dom-P in MMBtu/MWh of electricity generated. Explicit heat rates for currently installed generators come into the model through the Input Generator Datasets and the EIA 860/923 data. This is from 2020 NREL ATB.

There are three typical advanced technologies that can be easily included in modeling scenarios. These include Natural Gas Carbon Capture Systems (CCS), Small Modular Reactors (SMR) and Molten Salt Reactors (MSR). Figure 4.18b shows the standard cost data for CCS and SMR technologies. The CCS costs are simply the costs from Low NREL ATB. These costs reflect a natural gas plant with CCS, not the CCS unit alone. Variables costs for SMR units are rolled into other costs shown for this technology. Figure 4.18c shows the standard cost data for the MSR technology. There is currently no fixed or variable cost for MSRs as that is rolled into the capital cost. The SMR and MSR cost values are created by VCE in conjunction with multiple industry partners.

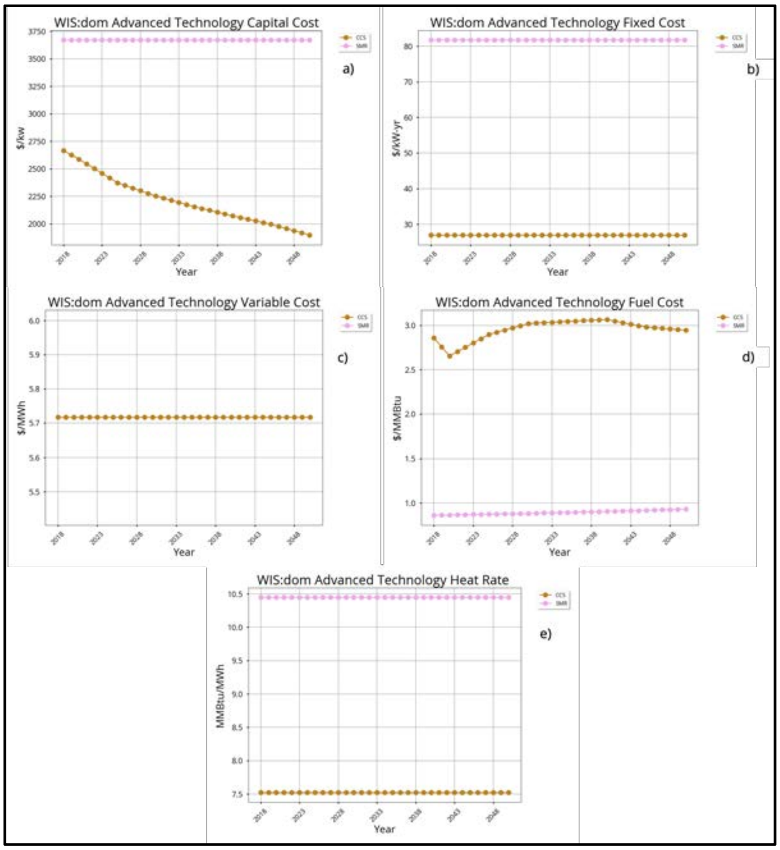

Figure 4.18b: The a) capital cost ($/kw), b) fixed cost ($/KW-yr), c) variable cost ($/MWh), d) fuel cost ($/MMBtu) and e) heat rate (MMBtu/MWh) for CCS and SMR technologies in WIS:dom-P.

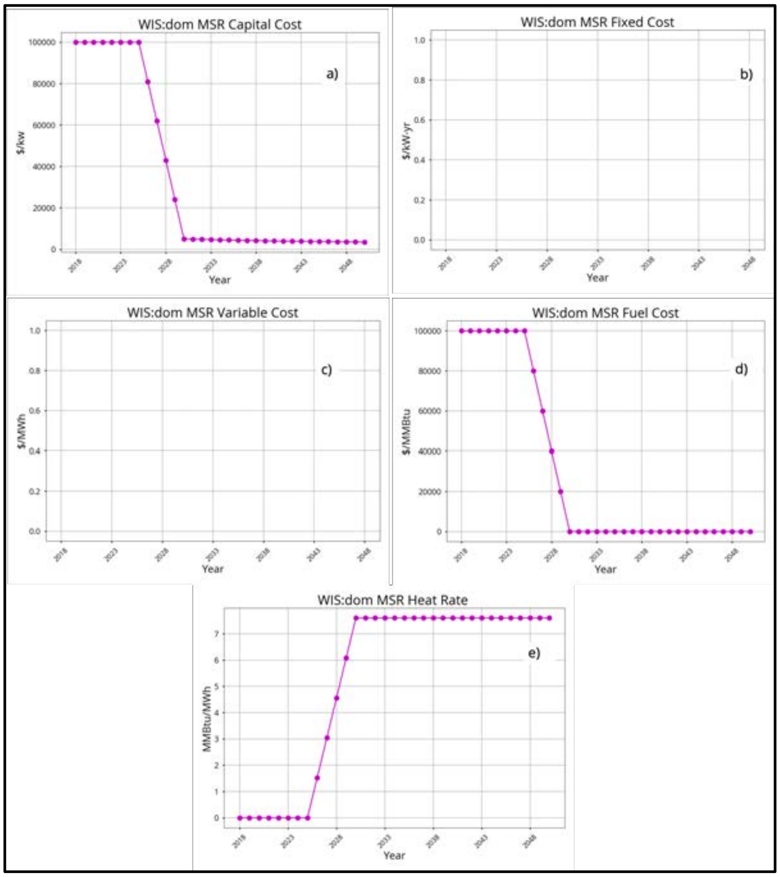

Figure 4.18c: The a) capital cost ($/kw), b) fixed cost ($/KW-yr), c) variable cost ($/MWh), d) fuel cost ($/MMBtu) and e) heat rate (MMBtu/MWh) for the MSR technology in WIS:dom-P. The high capital and fuel costs in early investment years is intentional. It forces the model not to choose this technology yet since it in not available currently. The fixed and variable costs are rolled into capital cost shown here.

We use the same ***real*** discount rate for all generator technologies in the WIS:dom-P model. This value is 5.87%, which is applied with the book life of the technologies to provide the model with the amortized capital costs. The lifetime of the various technologies also impacts what/when the model optimally deploys generation as well as when it can retire units. The following figures shows the standard economic lifetimes for the various technologies used within WIS:dom-P.

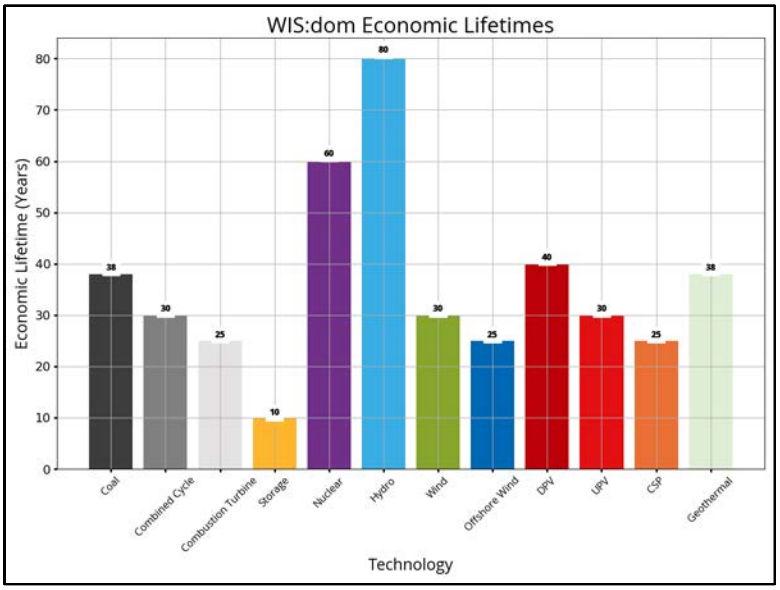

Figure 4.19: The economic lifetime for each generator type within WIS:dom-P in years. The economic lifetime means the time that the debt must be cleared from the units.

Transmission plays a large part in the optimized decisions that the WIS:dom-P model executes. The decision to build renewable technologies can be affected by the standard inputs around transmission aspects.

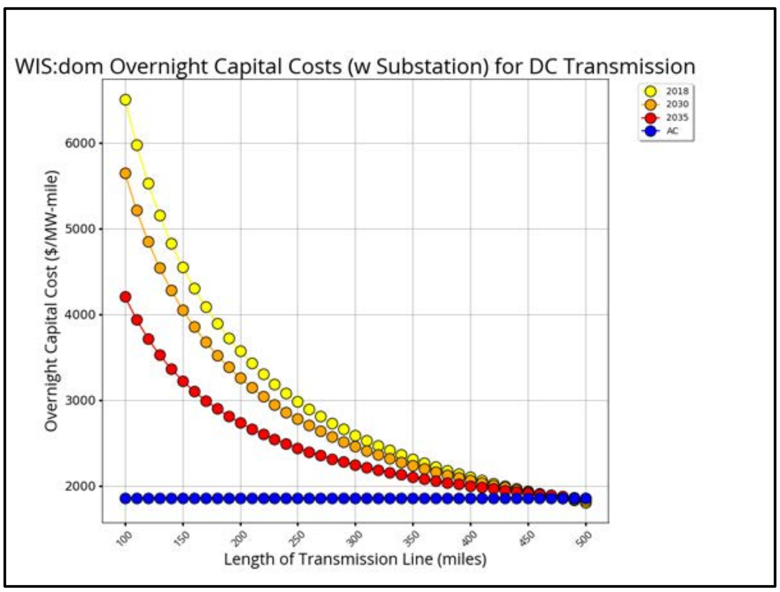

Figure 4.20: Shows the overnight capital cost of DC transmission in WIS:dom-P in real $/MW-mile installed over various distances. Costs are shown for 2018, 2030 and 2050. The overnight capital cost of AC transmission (including substations) is also shown in blue. This is the same cost no matter the investment period.

The economic lifetime, or rather, length of amortization, of the transmission assets in the model are 60 years for all investment periods.

VCE documents and researches the various state legislature and renewable energy goals by tracking Renewable Portfolio Standards, Clean Energy Mandates, Offshore Wind Mandates, Storage Mandates and GHG Emission Reduction Mandates. These are utilized to inform the WIS:dom-P model of what is expected and what goals are set. This provides the bounds and definitions of what the model is required to build as it optimizes systems of the future. Over 30 states have a renewable portfolio standard in place. Just over 10 states currently have a clean energy mandate. The northeast has become increasingly aggressive in setting offshore wind energy targets. Storage mandates have started to show up in the recent years as well. The following images lay out the legislative goals by 2050. The Production Tax Credit and the Investment Tax Credit for renewables is also discussed. This directly ties into the cost of renewables built in WIS:dom-P.

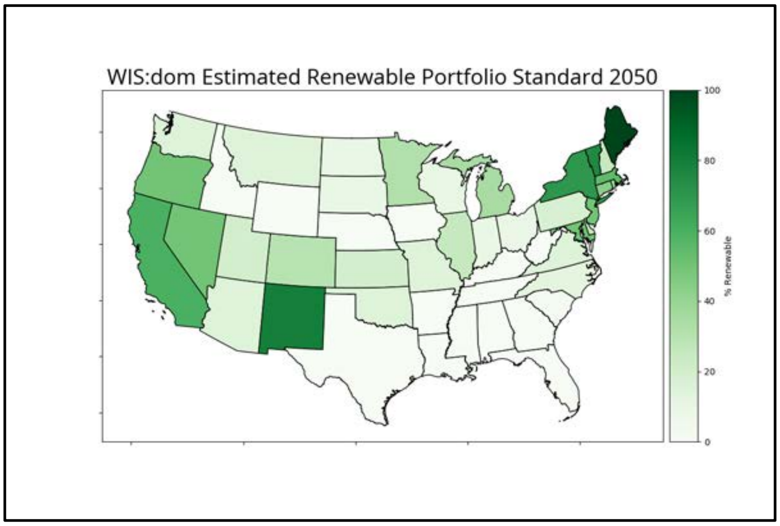

Figure 4.21: The Renewable Portfolio Standards percentage requirement of each state across the US.

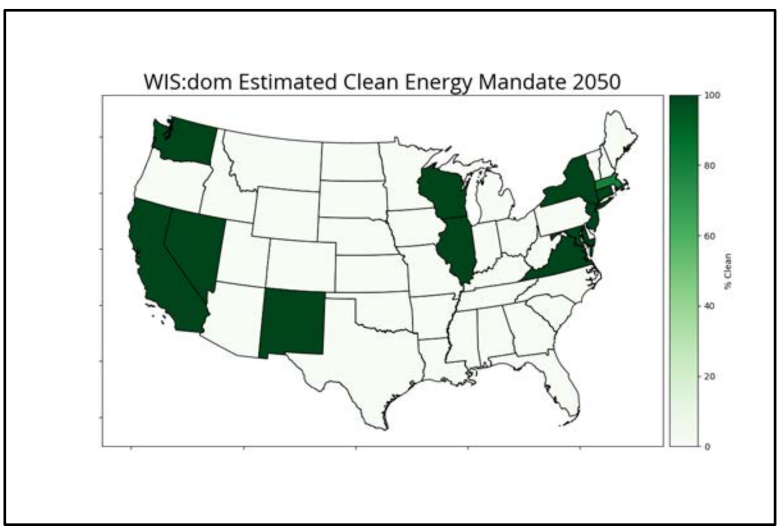

Figure 4.22: The Clean Energy Mandate percentage requirements of each state across the US.

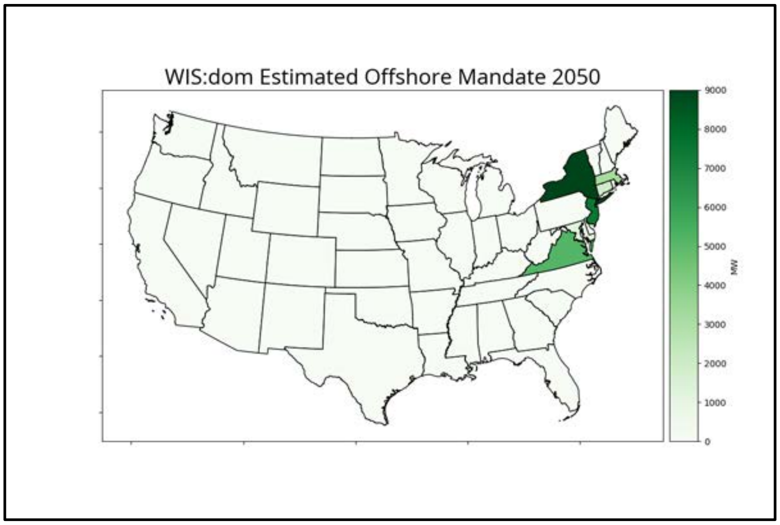

Figure 4.23: The Offshore Wind requirement in MW for each state across the US.

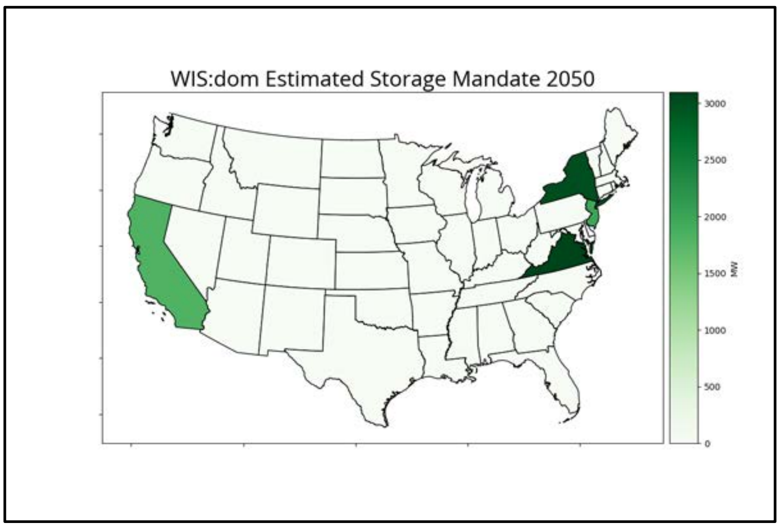

Figure 4.24: The Storage Mandates requirement in MW for each state across the US.

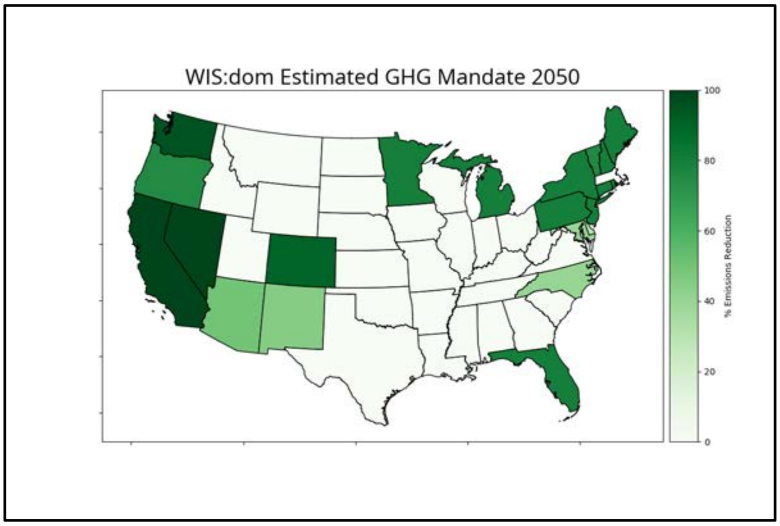

Figure 4.25: The GHG Emissions Reduction percentage requirement of each state across the US.

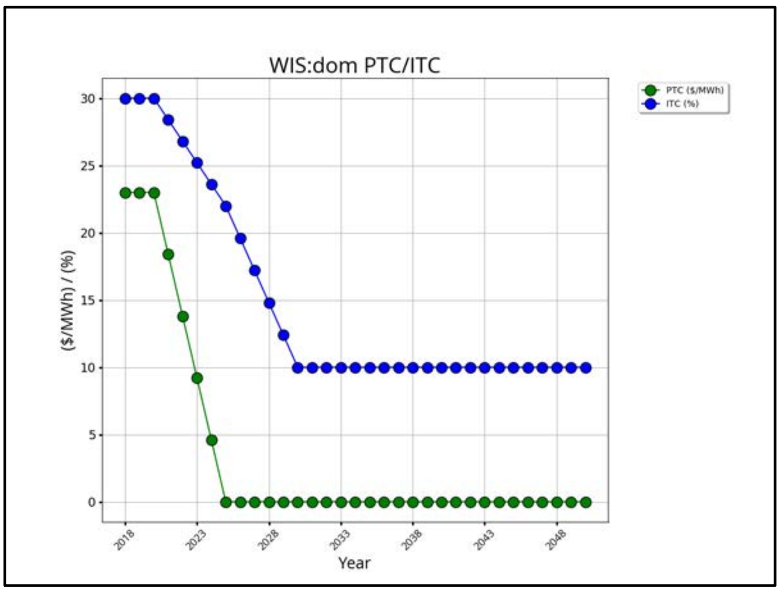

Figure 4.26: The Production Tax Credit subsidiary and the Investment Tax Credit. Note that for 2030 and beyond, the 10% ITC remaining is for utility scale projects only.

VCE also performs work and analysis to represent job numbers that arise from various technologies and transmission across the US. These inputs set the stage for how many jobs become available depending on what is deployed during the various investment periods. This is an important metric for decision makers to know and understand as the energy industry evolves. VCE uses a combination of sources to derive these numbers including IMPLAN, JEDI and US Energy Job reports.

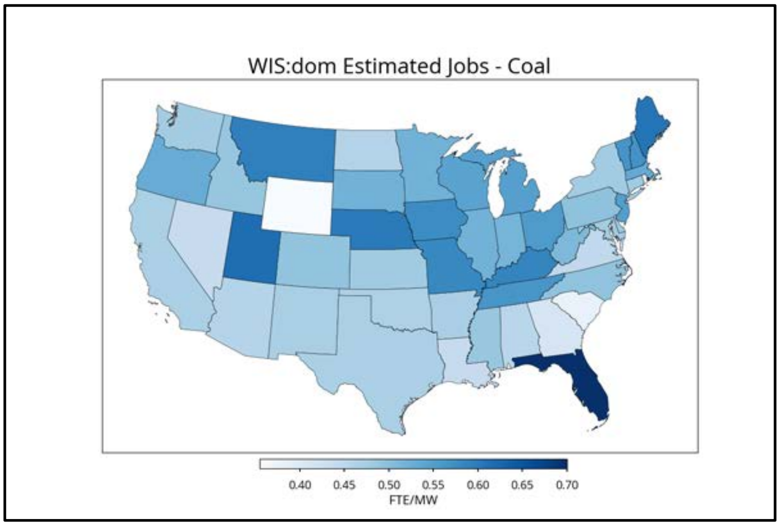

Figure 4.27: Employment per MW available from Coal.

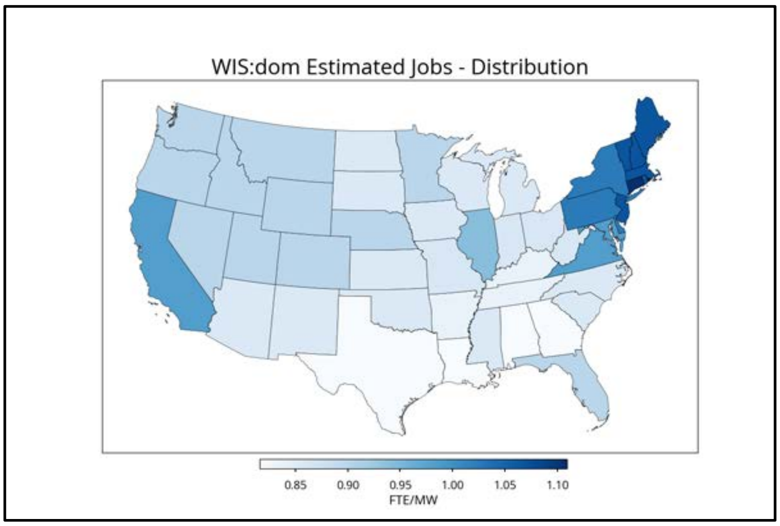

Figure 4.28: Employment per MW available from Distribution.

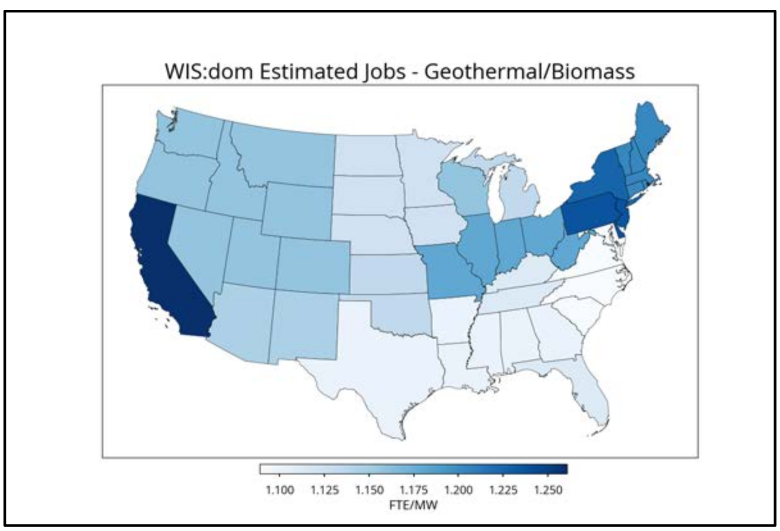

Figure 4.29: Employment per MW available from Geothermal and Biomass.

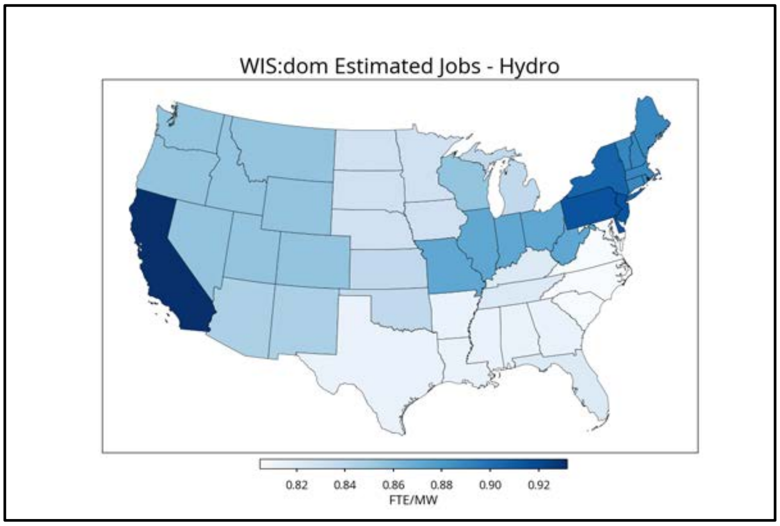

Figure 4.30: Employment per MW available from Hydro.

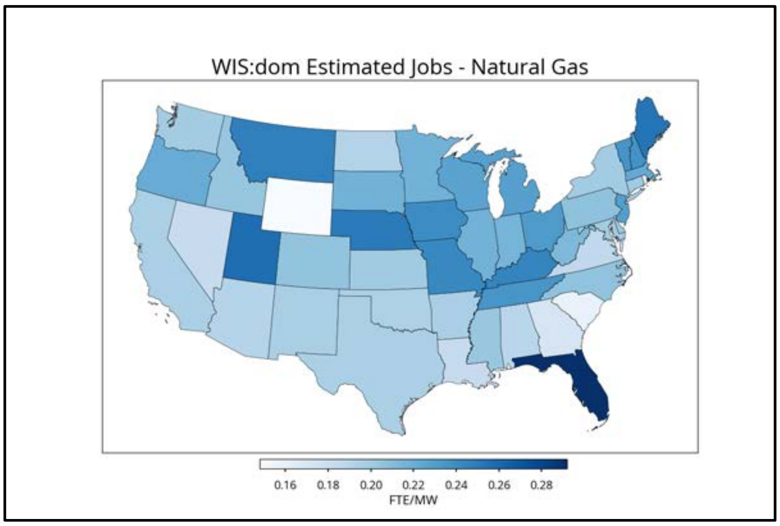

Figure 4.31: Employment per MW available from Natural Gas.

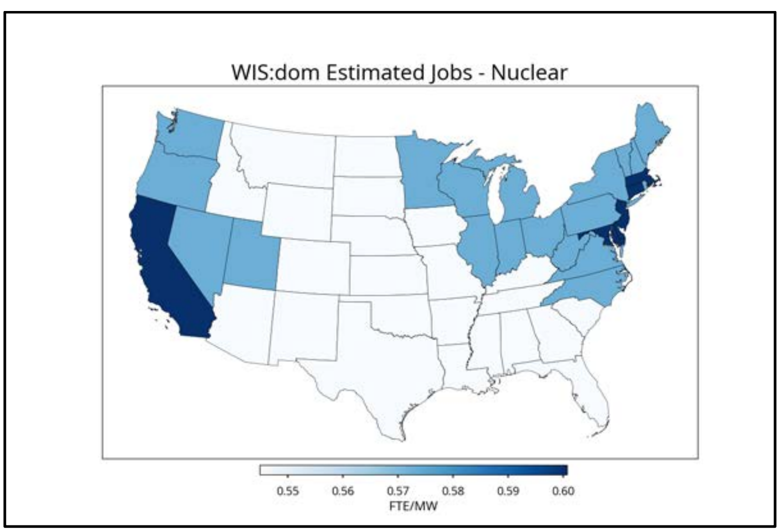

Figure 4.32: Employment per MW available from Nuclear.

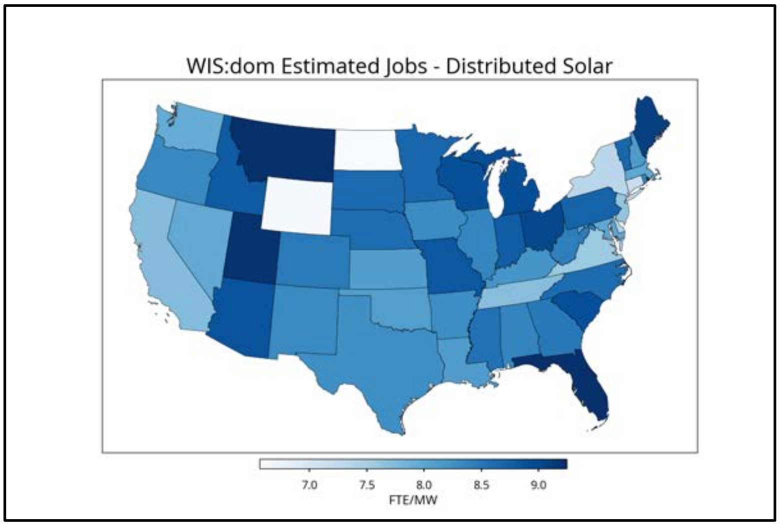

Figure 4.33a: Employment per MW available from Distributed Solar.

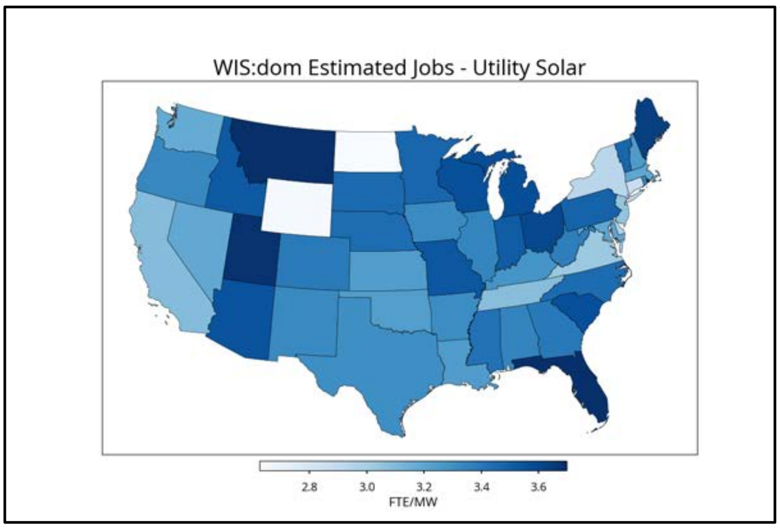

Figure 4.33b: Employment per MW available from Utility Solar.

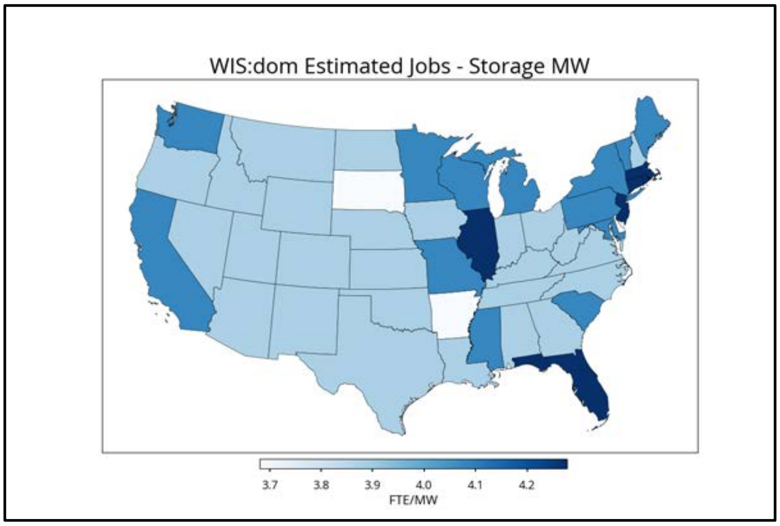

Figure 4.34: Employment per MW available from Storage MW.

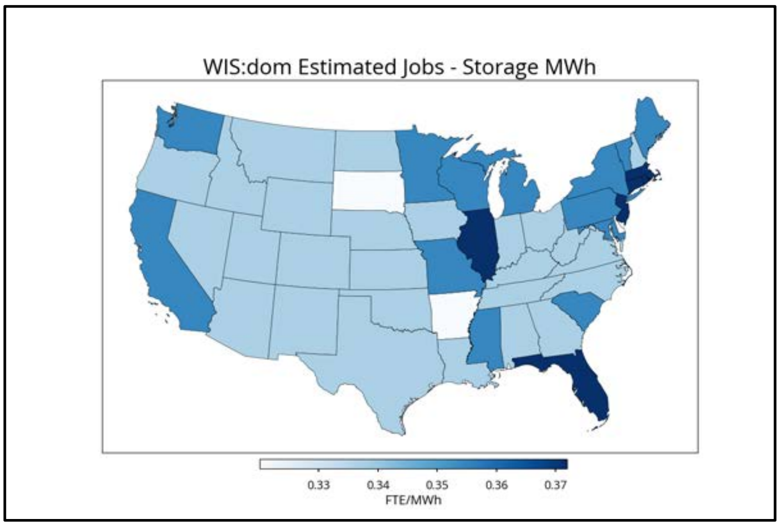

Figure 4.35: Employment per MWh available from Storage.

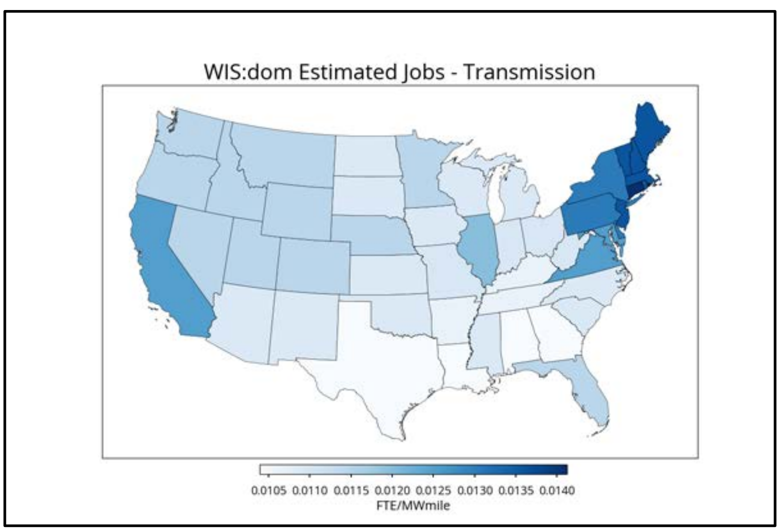

Figure 4.36: Employment per MW available from Transmission.

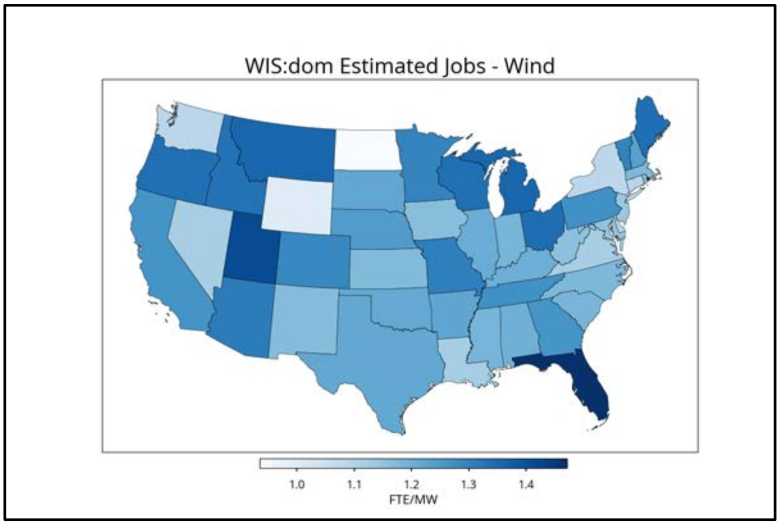

Figure 4.37: Employment per MW available from Wind.

4.4 Minnesota Weather Analysis

The present section will analyze the weather data specific to the state of Minnesota for this study. Where applicable, images and references will be also be given to the wider MISO region for context; Including Minnesota, Wisconsin, Iowa, Illinois, Indiana, Michigan, Missouri, Kentucky, Arkansas, Louisiana and Mississippi. This section will provide some insight into how certain renewable sources are selected by the model. Figure 4.38a and Fig. 4.38b display the average wind and solar capacity across this region by hour of the day. The wind is for the 100-meter (above ground) level. The solar technology is single axis tracking pitched to latitude tilt. The load is also displayed for comparison. The series are shown for the average of the entire year and then the summer (June, July, August) and winter (January, February, March) seasons. The weather year for 2018 is used as the basis for this analysis. Figure 4.38a shows a typical normalized load pattern. Figure 4.39b shows a normalized electrified load pattern for comparison.

Figure 4.38a and Fig. 4.38b show the solar resource is both higher in peak and longer in duration during the summer, reaching above a 50% capacity factor in those months for Minnesota. For wind, the reverse occurs where this resource drops during the summer and increases during the winter. The stronger jet stream and weather patterns in winter are apparent. Wind also exhibits a diurnal pattern where stronger resource is observed during the nighttime hours. This is a normal phenomenon for wind when the decoupling of the boundary layer near the surface at night allows for wind speeds to regularly increase due to less friction from the surface. Nighttime hours can see an almost 50% capacity factors from the wind resource on average for the whole year. It is easy to see the complementary temporal patterns in the wind and solar resource. The load in Fig. 4.38a for NSPM shows a standard load pattern. It is much higher in the summer months than in the winter months. For Fig. 4.38b, an electrified load pattern is plotted for NSPM. The electrified load is increased in many hours compared to the standard load outline. The electrified load tends to “flatten out” throughout a 24-hour day with nighttime loads being higher. In summer, the electrified load is still higher than other seasons. In winter, the nighttime increases are higher. In the electrified scenario, the daytime solar peak continues to provide support to daytime load, especially in the summer. In addition, the higher wind resource at night becomes much more important to help serve the increasing loads in those hours. Wind resources become more valuable in an electrified load scenario.

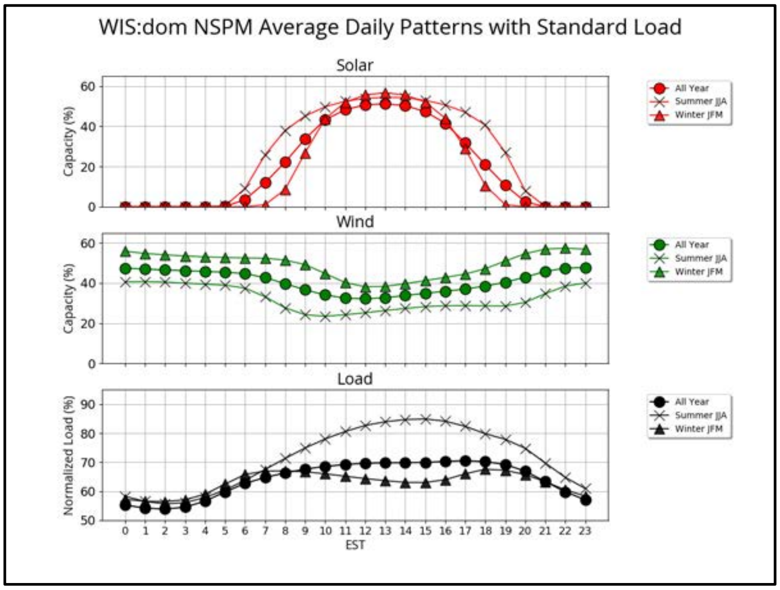

Figure 4.38a: The average solar (red) and wind (green) resource shown for the states in MISO alongside the corresponding normalized standard load (black) by hour of the day (EST). The circles show the hourly averages for the entire 2018 year. The other two series look at the summer (JJA) and winter (JFM) months of 2018.

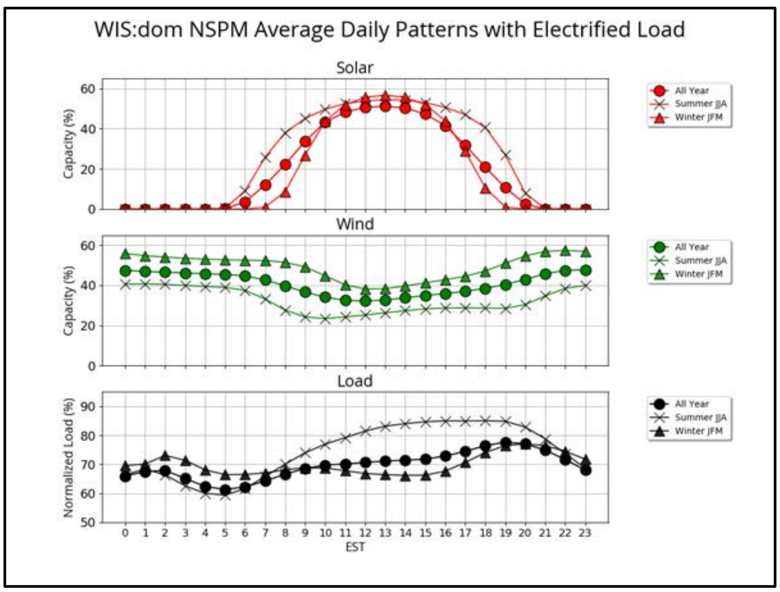

Figure 4.38b: The average solar (red) and wind (green) resource shown for the states in MISO alongside the corresponding normalized electrified load (black) by hour of the day (EST). The circles show the hourly averages for the entire 2018 year. The other two series look at the summer (JJA) and winter (JFM) months of 2018.

The following Fig. 4.39a and Fig. 4.39b are similar to Fig. 4.38a and Fig. 4.38b; but displaying the three parameters (solar, wind or load) together, to identify how they change against each other for the whole year, summer and winter. In Fig. 4.39a, with a normalized standard load, it is clearer that the solar resource peaks near the load peak. In the yearly average, but especially in the summer months, the shapes of these two series align well, though slightly offset. The peak of the solar tends to occur on average a few hours in advance of the diurnal peak load (leading to large evening ramps, typically described in the "duck curve"). In winter, the shape of the wind resource is highly correlated with the shape of the standard load. This observation along with the anti-correlated nature of wind and solar shows the viability of wind. In Fig. 4.39b, the load is electrified and stays consistently higher throughout all hours, including at night. With electrification, the shape and alignment of the wind resource is much more correlated with an electrified load during the entire year as well as each season considered.

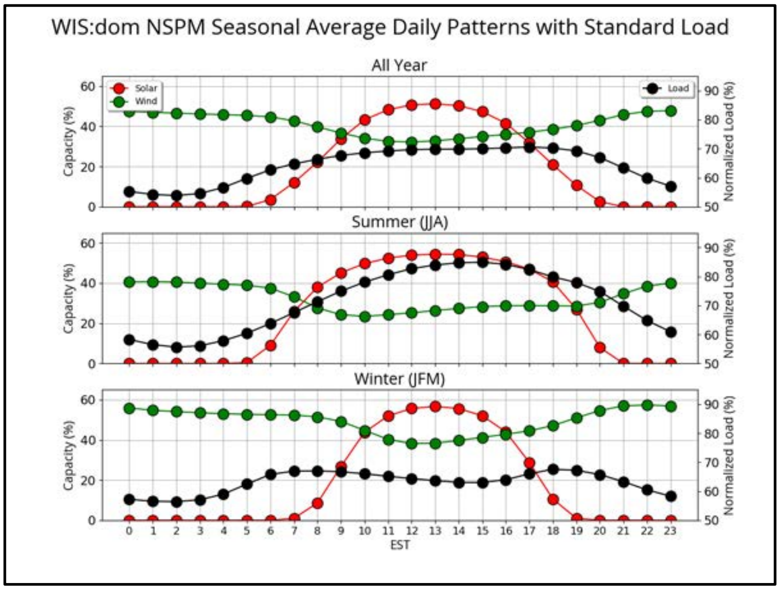

Figure 4.39a: The average solar (red) and wind (green) resource shown for the MISO states alongside the corresponding normalized standard load (black) by hour of the day (EST). This is shown in seasonal groupings now; the entire 2018 year, the summer (JJA) of 2018 and winter (JFM) of 2018.

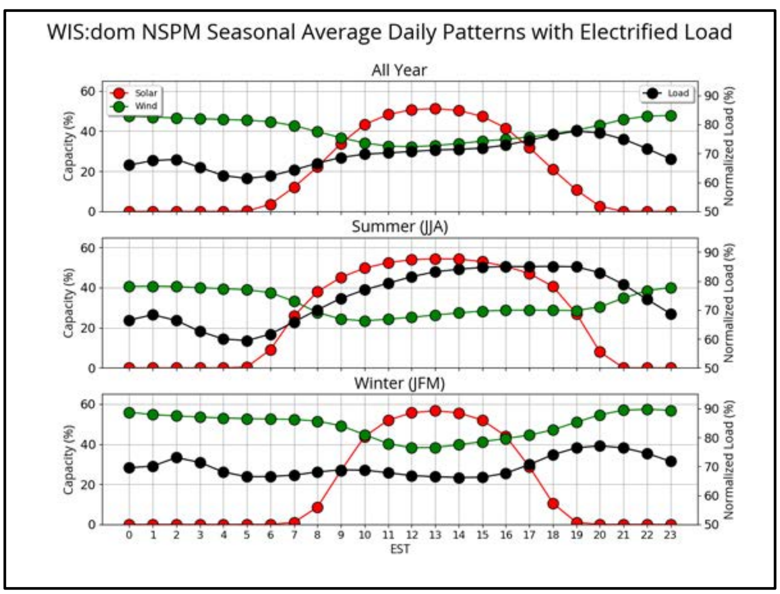

Figure 4.39b: The average solar (red) and wind (green) resource shown for the MISO states alongside the corresponding normalized electrified load (black) by hour of the day (EST). This is shown in seasonal groupings now; the entire 2018 year, the summer (JJA) of 2018 and winter (JFM) of 2018.

Figure 4.40 and Fig. 4.41 show the average diurnal solar and wind resources respectively throughout the day for Minnesota versus the same resource available over all the MISO states. The solar patterns are similar between the two regions. This speaks to a more uniform solar resource across the middle of the US both temporally and in magnitude. The wind in MISO on average is lower for all hours than the wind experienced in Minnesota. As will be discussed and shown in Fig 4.43, the southern portion of MISO does not have as good wind resource as the northern portion.

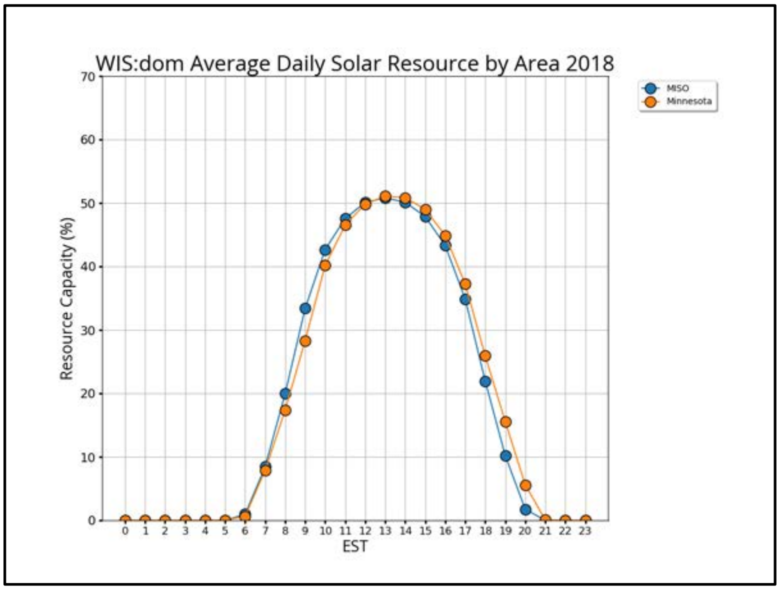

Figure 4.40: The 2018 average hourly solar resource capacity factors for modeled regions.

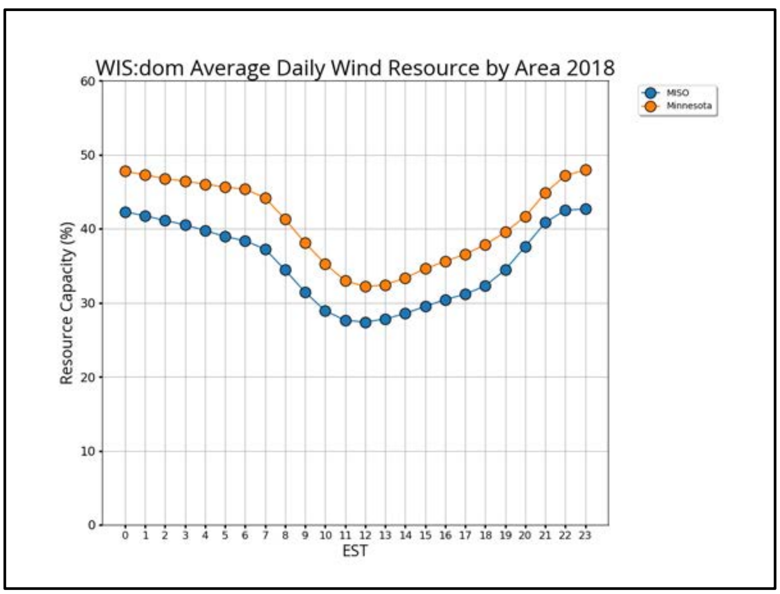

Figure 4.41: The 2018 average hourly wind resource capacity factors for modeled regions.

VCE investigated the wind and solar resources at different spatial granularities as well for the present analysis. This was performed for the modeled states within MISO to provide regional representation. Figure 4.42 and Fig. 4.43 show the average annual wind and solar resources throughout the day for each of the MISO states. Note that for those states where offshore potential sites are available, that data is included in the state wind resource average. Figure 4.44 and Fig 4.45 shows the average wind and solar resource for the 2018 weather year for each state. These four images combined show that Iowa has the strongest wind resource followed by Minnesota and Illinois. Missouri's wind resource tracks closer to the wind of the upper MISO footprint, albeit on the low end of that group of states within MISO. The southern states within MISO (Kentucky, Arkansas, Mississippi and Louisiana) all have a noticeably lower wind regime. Mississippi shows the lowest daytime lull in wind in 2018. On the solar side, Iowa, Wisconsin and Minnesota show the best resource in 2018. Kentucky and Michigan peak slightly sooner than the other MISO states. In general, given the shape of MISO's footprint, there is not much temporal solar diversity. Michigan and Kentucky also come in with the lowest solar resource.

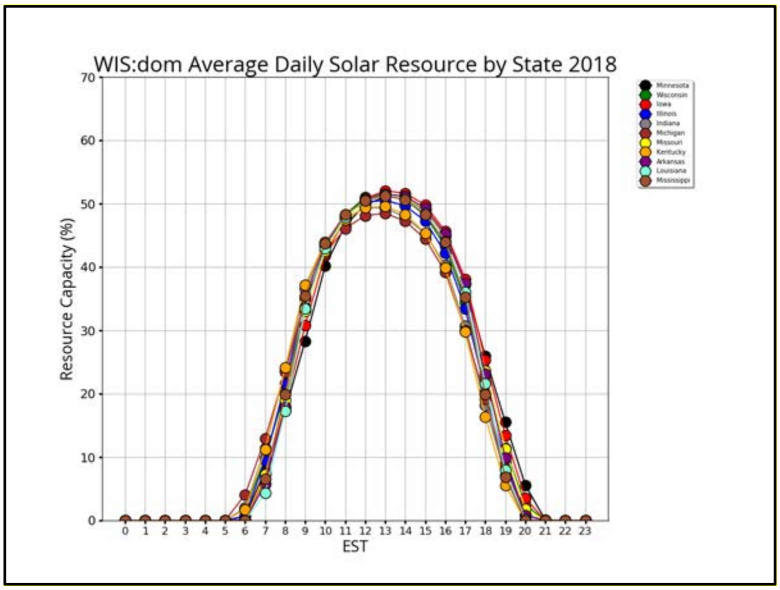

Figure 4.42: The 2018 average hourly solar resource capacity factor for each MISO state.

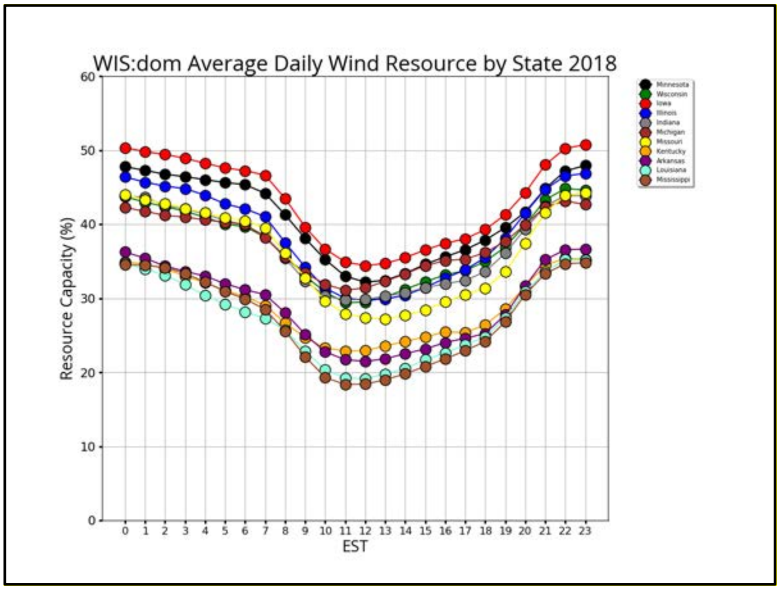

Figure 4.43: The 2018 average hourly wind resource capacity for each MISO state.

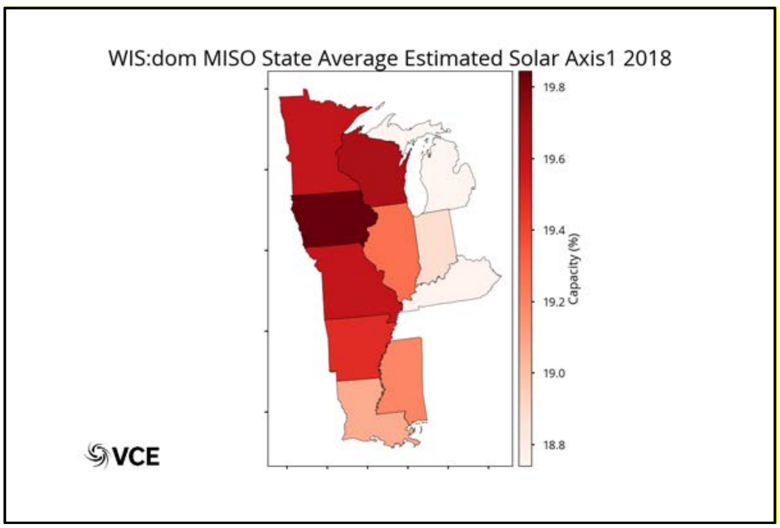

Figure 4.44: The average solar capacity factor (%) for 2018 by state in the MISO footprint modeled.

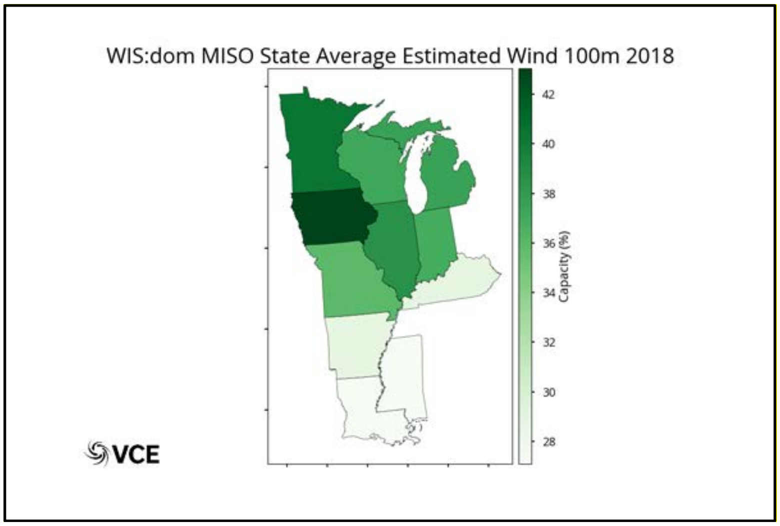

Figure 4.45: The average wind capacity factor (%) for 2018 by state in the MISO footprint modeled.

VCE utilizes the 3-km NOAA HRRR weather model as the raw inputs for the weather and power datasets. Below, Fig. 4.46, is a plot of the wind capacity resources across MISO. The high onshore wind resource is quickly apparent over southern Minnesota and all of Iowa. Western Minnesota and parts of Illinois also have areas of decent wind. Offshore winds are high over the Great Lakes as well. Generally, the wind resource decreases from north to south across the MISO footprint. On the solar side, from Fig. 4.47, Iowa shows the highest pockets of solar resource. Northeastern Minnesota, Wisconsin and all of Michigan display the lowest solar resource. Southern Minnesota has decent solar resource when comparing to the surrounding MISO states. It is clear from Figs 4.46 and Fig. 4.47 that the wind resource is far more heterogenous than the solar resource, but that MISO as a whole has very good resource quality in both.

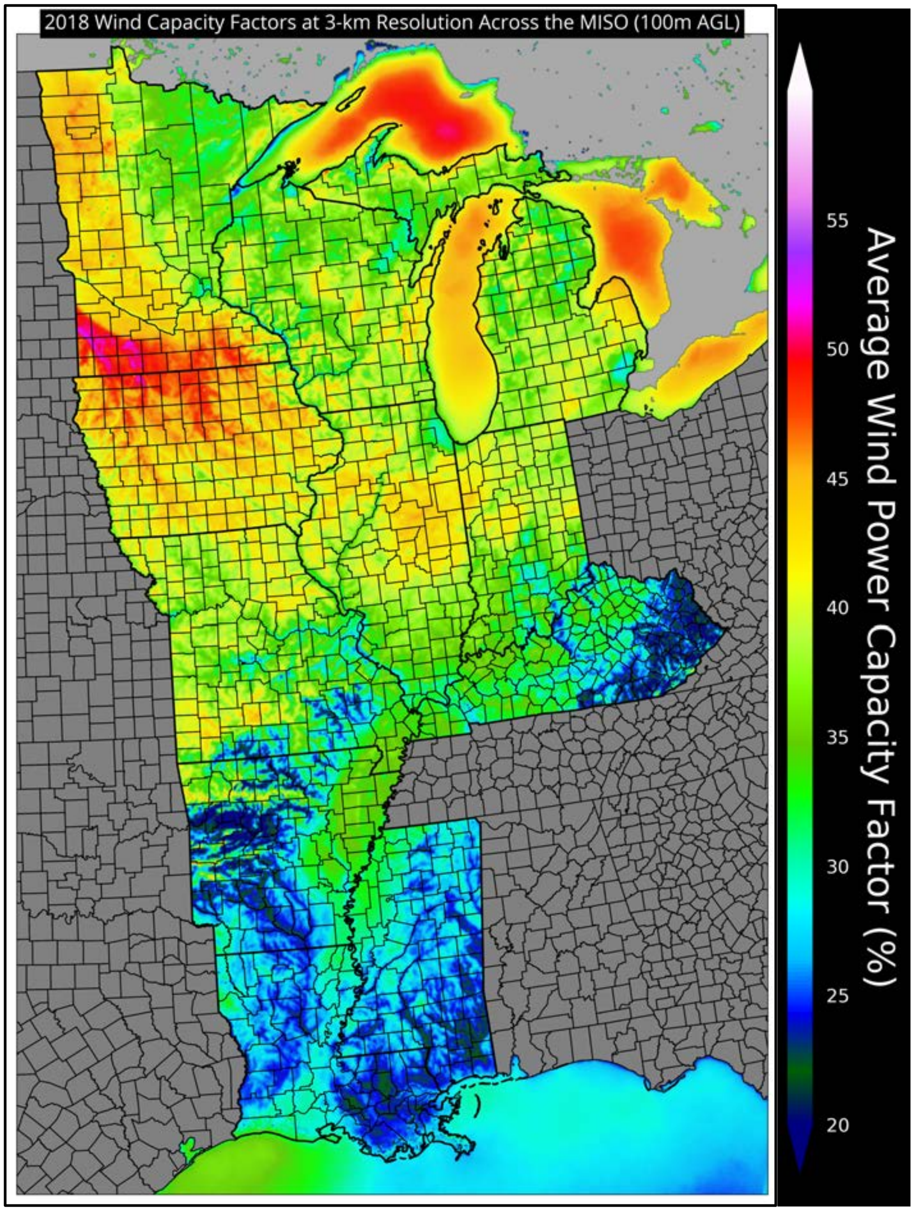

Figure 4.46: The 3-km 100-meter wind capacity resource across the MISO states modeled in 2018.

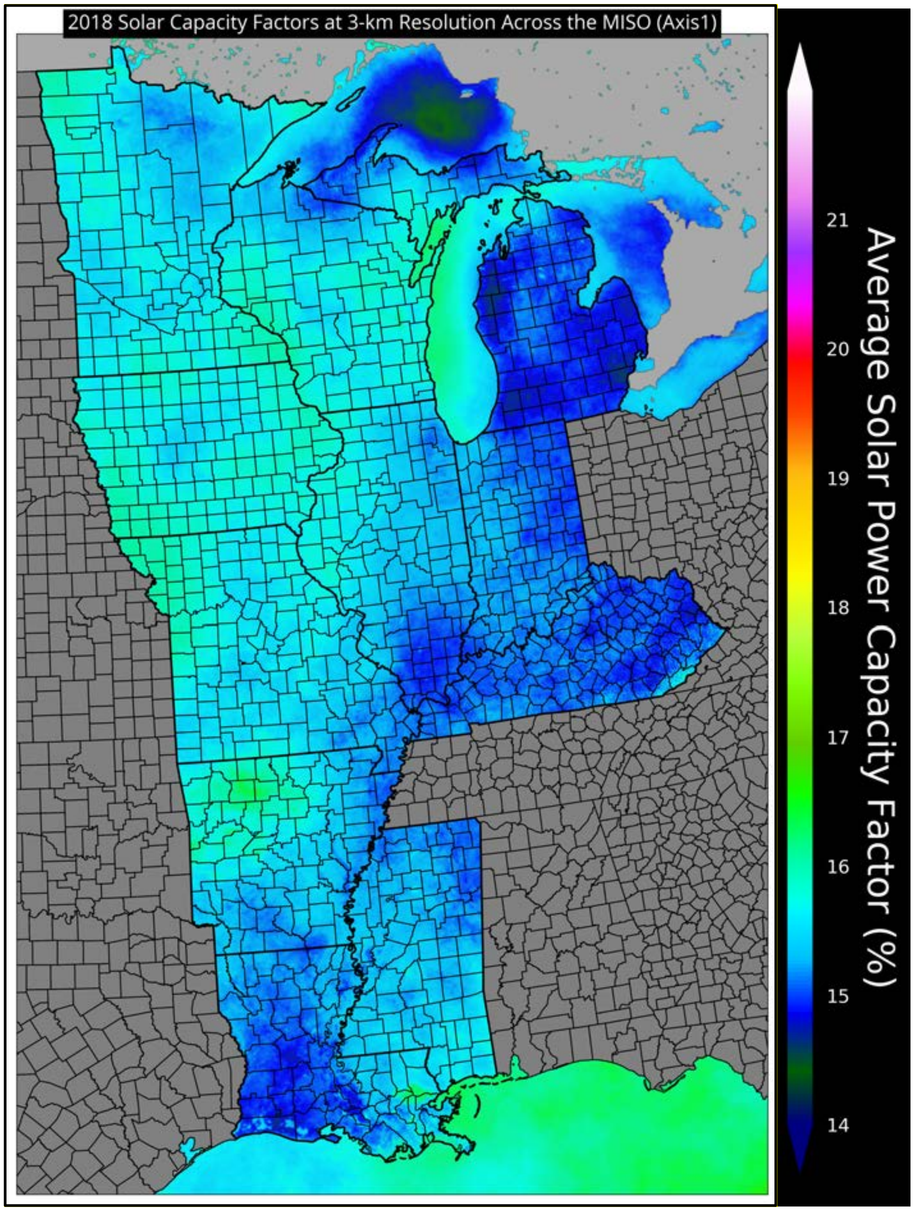

Figure 4.46: The 3-km latitude-tilted solar capacity resource across the MISO states modeled in 2018.

Figure 4.48, reproduced from the NOAA weather archives, shows a surface weather analysis in April 2018. This was during a strong wind event for the middle and eastern portions of the US. During the week in April, a very strong pressure gradient set up across the mid-continent. Building low pressure over Kansas/Missouri, coupled with a high pressure airmass pushing south into the US from Canada brought consistently strong pressure gradients across Minnesota. This regime lasted for several days. A time series of wind and solar resource alongside a standard load shape is shown below in Fig. 4.49a. Wind capacity factors reach almost 100% for the entire state during the peak of this event. Load is reduced since April is a weather shoulder season. However, solar still nicely correlates with diurnal load peaks. Figure 4.49b shows the same weather data against a normalized electrified load. The higher nighttime load is supported by the wind resource that maintains itself throughout all hours of the day during this period.

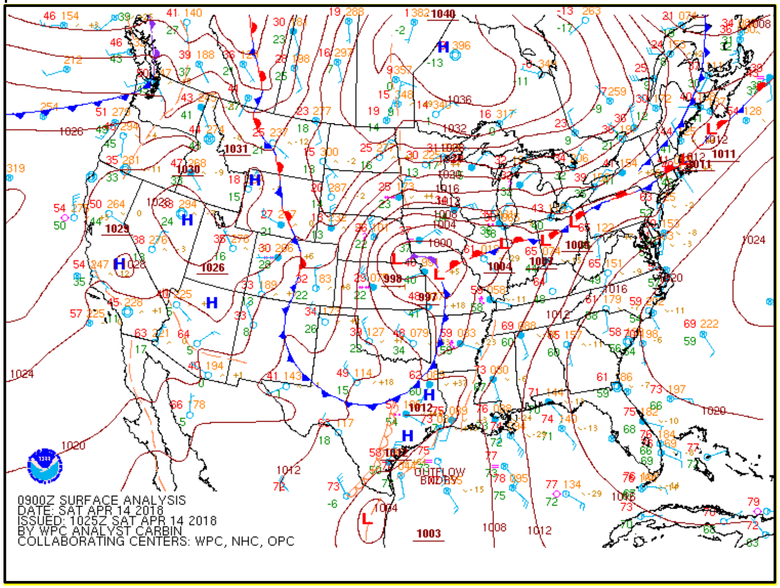

Figure 4.48: Surface Weather Analysis Plot from Saturday April 14th, 2018 at 09 UTC. This surface plot is provided from NOAA's Weather Prediction Center Archives (https://www.wpc.ncep.noaa.gov/archives/web_pages/sfc/sfc_archive.php).

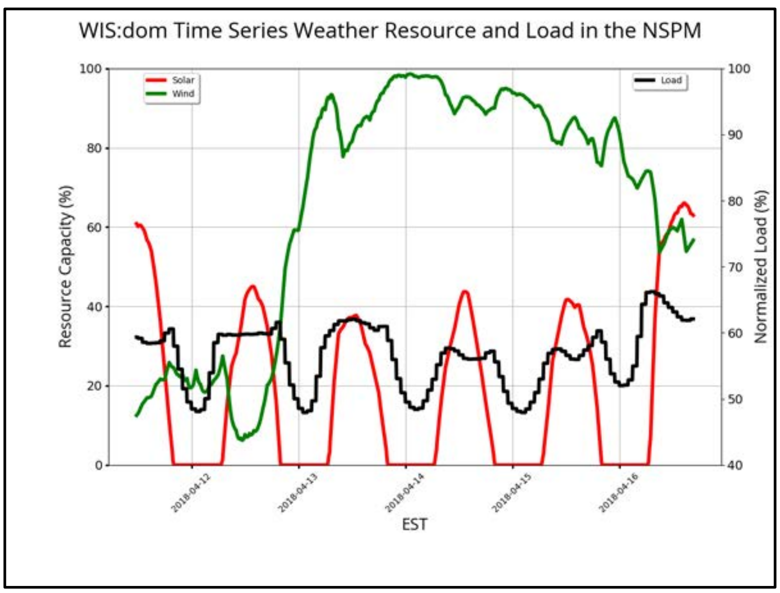

Figure 4.49a: A time series of the average solar (red) and wind (green) resources across Minnesota in April 2018. The normalized standard load (black) is also plotted. This was one of the highest wind periods from 2018.

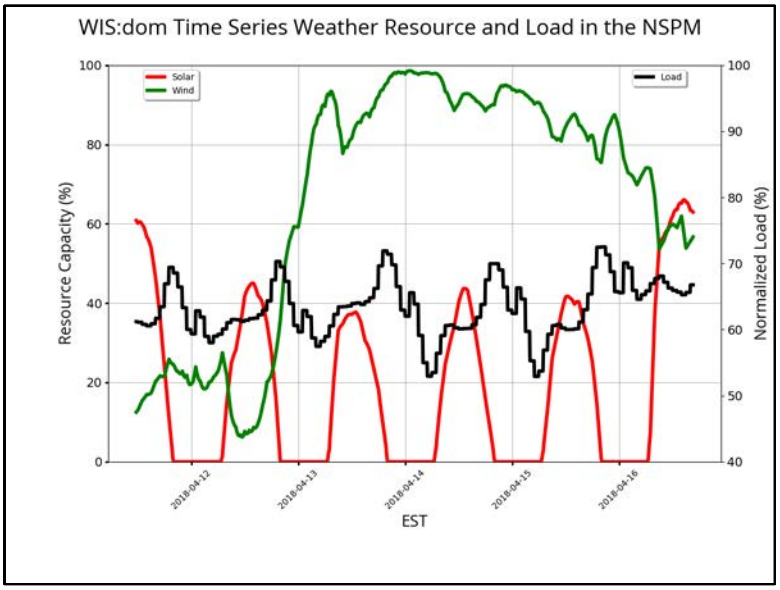

Figure 4.49b: A time series of the average solar (red) and wind (green) resources across Minnesota in April 2018. The normalized electrified load (black) is also plotted. This was one of the highest wind periods from 2018.

The next figures (Fig. 4.50a and Fig. 4.50b) shows a July week that had some of the lowest wind observed in 2018 for the state of Minnesota. A summer wind doldrum established itself for a few days. The diurnal nighttime increase in wind speed is still slightly apparent. The wind resource is not high during this period, falling to zero many hours of this week. The plots do show that wind does not stay low for long as the edges of the week observed see wind resource recover. Further, solar is very strong and consistent in this period and aligns well with the daily peak load in an electrified load scenario, but especially against a standard load. This distinctly shows the anti-correlated nature of wind and solar. The slight nighttime increases in wind do align many nights with the increased nighttime loads in an electrified scenario.

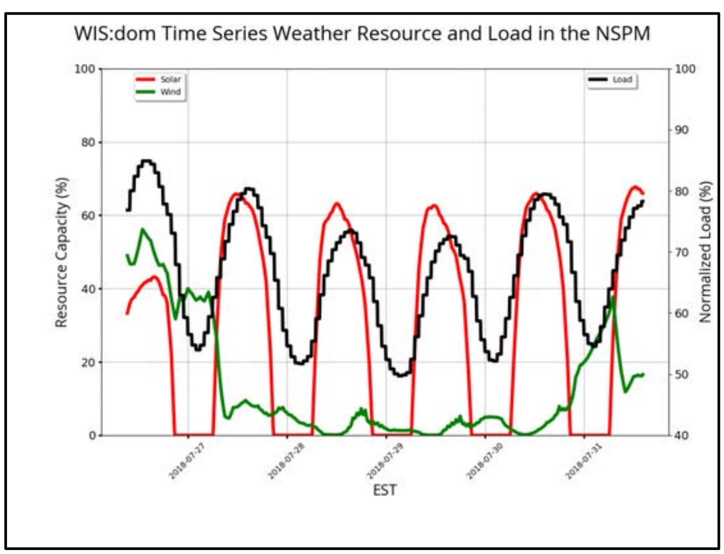

Figure 4.50a: A time series of the average solar (red) and wind (green) resources across Minnesota in July

2018. The normalized standard load (black) is also plotted. This was one of the lowest wind periods from 2018.

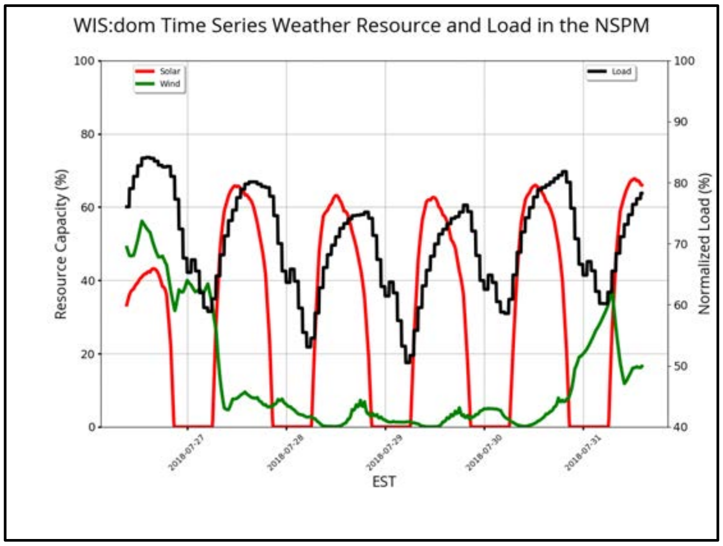

Figure 4.50b: A time series of the average solar (red) and wind (green) resources across Minnesota in July 2018. The normalized electrified load (black) is also plotted. This was one of the lowest wind periods from 2018.