



Affordable & Reliable Decarbonization Pathways for Montana

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1 Executive Summary

In order to investigate outcomes from the various pathways Montana could follow as it evolves its energy system, GridLab and 350.org commissioned Vibrant Clean Energy, LLC (VCE®) to model the Montana energy system using its flagship energy system modeling software WIS:dom®-P. To study the various pathways in this study, VCE modeled Montana along with the rest of the US portion of the Western Electricity Coordinating Council (WECC) region. The model was initialized using 2018 installed generation, loads, and transmission pathways. WIS:dom-P models the evolution of the electricity system over the whole WECC region (including Montana) from 2020 to 2050 in five-year increments.

The scenarios modeled in this study are:

- (1) **Business as Usual (“BAU”)**: This scenario is the counterfactual against which outcomes of other scenarios are compared. In this scenario, Montana along with the rest of the WECC region undergo optimal capacity expansion to meet business as usual load growth. There are no emission constraints except existing state renewable portfolio standards (RPS) and greenhouse gas emission constraints for the WECC region. Transmission is allowed to grow subject to historical growth constraints and WIS:dom-P co-optimizes the distribution grid with the utility-scale generation.
- (2) **Keep coal generation in Montana until 2040 (“keepCoal”)**: In this scenario, the coal generation in Montana is not allowed to retire until 2040. The rest of the electricity system in Montana and the WECC region undergo optimal capacity expansion under business-as-usual load growth. Transmission is allowed to grow subject to historical growth constraints and WIS:dom-P co-optimizes the distribution grid with the utility-scale generation.
- (3) **Decarbonize the Montana electricity grid by 2035 (“RPS100”)**: In this scenario, the electricity grid in Montana decarbonizes by 100% by 2035. The rest of the WECC region undergoes optimal capacity expansion under business-as-usual load growth. Transmission growth is allowed subject to historical growth constraints and WIS:dom-P co-optimizes the distribution grid with the utility-scale generation.
- (4) **Decarbonize the Montana electricity grid by 2035, while ensuring Montana remains a net exporter of energy (“RPS100Export”)**: In this scenario, the Montana electricity grid is decarbonized by 100% by 2035 while ensuring that Montana remains a net exporter of energy throughout. Transmission grows subject to historical growth constraints and WIS:dom-P co-optimizes the distribution grid with the utility-scale generation.
- (5) **Electrify energy-related activities in Montana while decarbonizing the electricity grid by 2035 (“RPS100Elec”)**: In this scenario, energy related activities in the rest of the economy in Montana are electrified while the electricity grid is decarbonized by 100% by 2035. Montana is constrained to remain a net exporter of energy. Transmission grows subject to historical growth constraints and WIS:dom-P co-optimizes the distribution grid with the utility-scale generation.



The “keepCoal” scenario has the highest total electricity system costs and retail rates (21% higher compared with the “BAU” scenario in 2040) as long as the coal generation remains on the grid. Once the coal generation is retired after 2040, total system costs drop along with the retail rates indicating that the coal generation increases costs and customer bills while creating higher emissions of greenhouse gases and other criteria pollutants that are harmful for health. In addition, the “keepCoal” scenario results in the lowest job growth of all scenarios modeled in this study.

Of all the scenarios modeled, the “RPS100” scenario results in the lowest total electricity system costs by 2050 as a result of retiring the expensive and older fossil fuel generation and replacing it with low-cost variable renewable energy (VRE) generation. However, the “RPS100” scenario also results in retail rates higher than the “BAU” scenario (13% higher compared with the “BAU” scenario by 2050) and the highest retail rates by 2050 as a result of Montana depending on imports to meet demand in the state.

The “RPS100Export” scenario results in slightly higher total electricity system costs compared with the “RPS100” scenario, however this scenario results in lower retail rates (32.6% reduction from 2020 values) compared with the “BAU” scenario as Montana makes revenues from exports which result in cost savings that are passed on to customers. WIS:dom-P assumes only 50% of the revenues from exports are passed on to customers in form of retail rate savings. The “RPS100Export” scenario results in significant job growth in the electricity sector, second only to the “RPS100Elec” scenario. This scenario also eliminates all criteria air pollutants in the electricity sector which should result in improved health outcomes in the state.

The “RPS100Elec” scenario results in the highest total electricity system costs as this scenario has a much larger electricity demand to serve due to electrification of the rest of the economy. However, the electrified load in Montana results in more efficient use of installed generation, which along with exports result in the lowest retail rates (40% reduction from 2020 values) for customers of all scenarios modeled. As a result of the lower retail rates, spending in all sectors of the economy for energy related activities see significant reductions. The “RPS100Elec” scenario saves a cumulative \$32.7 billion economy-wide by 2050 compared with the “keepCoal” scenario. The lower retail rates ensure electrification efforts advance smoothly as customers are incentivized to electrify given the opportunity to reduce annual spending by 47% compared with the “keepCoal” scenario. The “RPS100Elec” scenario also results in the largest job growth in the electricity sector in Montana led by the increased employment generated by the solar industry.

In terms of economy-wide emissions, the “keepCoal” scenario results in the highest emissions of all scenarios, generating 160 million metric tons (mmT) of additional CO₂ emissions compared with the “BAU” scenario, all of which come from the period when coal generation remains on the Montana grid. The “RPS100” scenario reduces CO₂ emissions by 26 mmT over the “BAU” scenario as a result of eliminating all fossil fuel generation in Montana. The “RPS100Export” scenario reduces emissions by 38 mmT over the “BAU” scenario as a result of not only removing emissions from the electricity sector, but also emissions from importing energy from the rest of the WECC region. The “RPS100Elec”



scenario which electrifies energy related activities in the rest of the economy reduces emissions by 180 mmT over the “BAU” scenario.

Therefore, the “RPS100Elec” scenario results in the largest reduction in economy-wide carbon emissions (while also completely eliminating criteria pollutants from the electricity sector) with the lowest retail rates for customers and creating the largest job growth in the state of Montana. The “RPS100Export” scenario results in slightly higher retail rates (12.5% higher) compared with the “RPS100Elec” scenario, but at lower total system costs. However, this scenario results in significantly higher carbon emissions as emissions from the rest of the economy remain unchanged.

In all scenarios modeled, WIS:dom-P ensures that load is satisfied at each time period while maintaining a 7% load following reserve and planning reserve margins (PRM) in accordance with recommendations from the North American Electric Reliability Council (NERC).



2 Economy-wide Impacts of Electrification

To investigate the impacts of economy-wide electrification, the evolution of costs in each sector of the economy (including traditional electricity) in the “RPS100Elec” scenario are compared against the “keepCoal” scenario. The above two scenarios are compared against one another as they represent the two extremes in terms of emissions and disruption of existing energy infrastructure. The “keepCoal” scenario requires the least disruption to existing energy infrastructure, but results in the highest emissions of all scenarios modeled with 160 mmT more cumulative carbon emissions compared with the “BAU” scenario by 2050. The “RPS100Elec” scenario, while requiring the largest changes to the energy infrastructure results in saving 180 mmT of carbon cumulatively by 2050 compared with the “BAU” scenario. Therefore, as shown in Fig. 2.1, the “keepCoal” scenario results in 340 mmT more cumulative carbon emissions by 2050 compared with the “RPS100Elec” scenario.

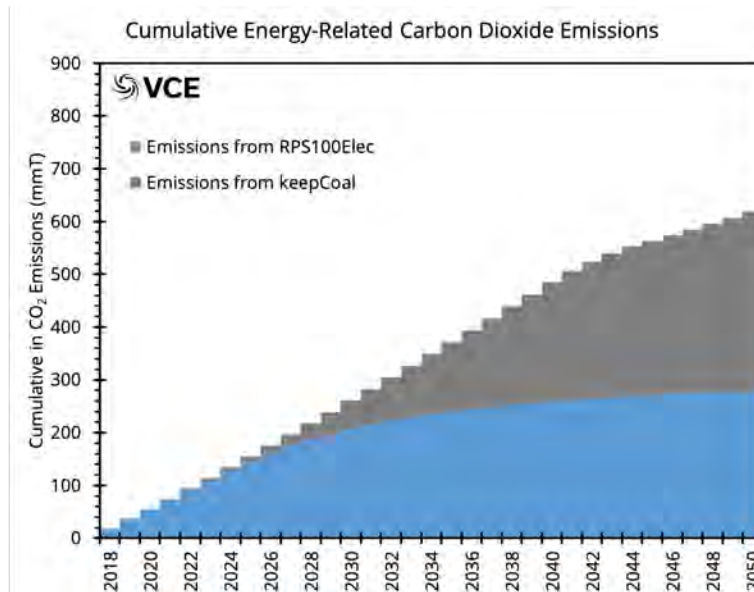


Figure 2.1: Cumulative carbon emissions in the “keepCoal” scenario and the “RPS100Elec” scenario.

In order to make a comprehensive comparison between the “keepCoal” and “RPS100Elec” scenarios, costs borne by consumers in the traditional electricity, space heating, transport and industrial sectors are compared between the two scenarios. The change in electrical load in the above sectors in the “RPS100Elec” scenario is shown in Fig. 2.2. The residential and commercial electricity loads increase only marginally from 2020 to 2050. The largest increase in electrical load in the “RPS100Elec” scenario is seen in the transportation and industrial sectors as they electrify from 2020 to 2050. The electricity demand in the industrial sector increases from 4.4 TWh in 2018 to 10.7 TWh in 2050 (a 240% increase) driven by shifting of industrial load from fossil fuels to electricity. Some of the harder to electrify industrial demand is met by hydrogen which is also produced using energy from the electricity sector using up another 1.5 TWh by 2050. The transportation load increases from 4.4 GWh in 2018 to 5.2 TWh in 2050 as a result of electrification of 90% of the vehicle fleet in Montana.



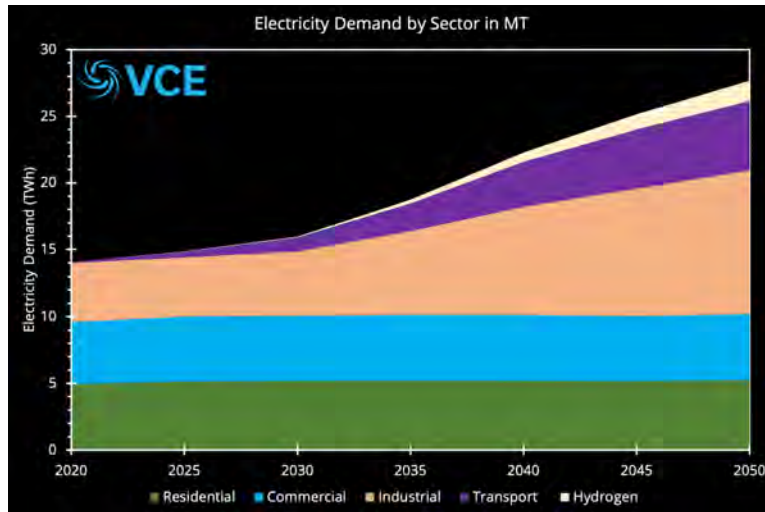


Figure 2.2: Electricity demand by sector in Montana for the "RPS100Elec" scenario.



2.1 Traditional Electricity Sector

The annual traditional electricity costs per customer in the residential, commercial and industrial sectors over the modeling period in the “keepCoal” and “RPS100Elec” scenarios are shown in Fig. 2.3. The two scenarios have the same traditional electricity costs until 2025 as the generation mix in the two scenarios are roughly similar until then. After 2025, the “RPS100Elec” scenario starts to retire the coal generation in Montana and coal is completely retired by 2030 and is replaced by low cost VRE generation. As a result, the electricity retail rates in the “RPS100Elec” scenario start to drop after 2025 resulting in a reduction in costs per customer also reducing after 2025 in the “RPS100Elec” scenario. The retail rates in the “keepCoal” scenario only reduce marginally until 2040 as this scenario keeps the coal generation on the Montana grid and thus incurring higher marginal cost of energy compared with the “RPS100Elec” scenario. Retail rates and average annual electricity spending per customer reduce after 2045 once the coal generation is retired and Montana has replaced it with VRE generation.

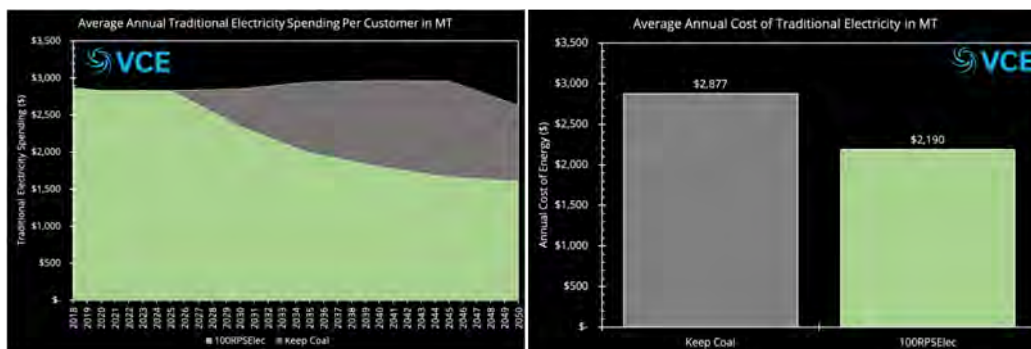


Figure 2.3: Change in annual traditional electricity spending per customer in Montana (left) and average annual spending for traditional electricity over the modeling period (right) for the “keepCoal” and “RPS100Elec” scenarios.

As a result of the reductions in retail rates, the average annual traditional electricity spending in Montana per customer in the “RPS100Elec” scenario is \$2,190 compared with \$2,877 in the “keepCoal”, a 24% reduction. As a result, the cumulative savings per customer in the modeling period is \$20,610 for traditional electricity spending. This shows that electrification of the rest of the economy and decarbonization of the electricity sector do not negatively impact customers who do not electrify or are unable to electrify due to financial constraints.



2.2 Spending on Space & Water Heating

The average annual spending in Montana for heating (space and water) over the years and the average over the modeling period for the “keepCoal” and “RPS100Elec” scenarios is shown in Fig. 2.4. In the “keepCoal” scenario, most of the space and water heating uses natural gas or other fossil fuels, while in the “RPS100Elec” all space and water heating is gradually electrified from using fossil fuels to heat pumps from 2020 to 2050. The spending for heating in the “keepCoal” scenario increases slightly from 2020 to 2050 as the price of natural gas increases in both the residential and commercial sectors. The forecasts for prices of coal¹, natural gas² and oil³ are obtained from Annual Energy Outlook (AEO) 2020 forecasts. On the other hand, in the “RPS100Elec” scenario, the heating load is increasingly shifted from natural gas and other fossil fuels to electricity while the electricity retail rates reduce over the years. In addition, heat pumps are more efficient at heating space and water compared with their fossil fuel alternatives. As a result, the total heating costs reduce dramatically from 2020 to 2050 in the “RPS100Elec” scenario.

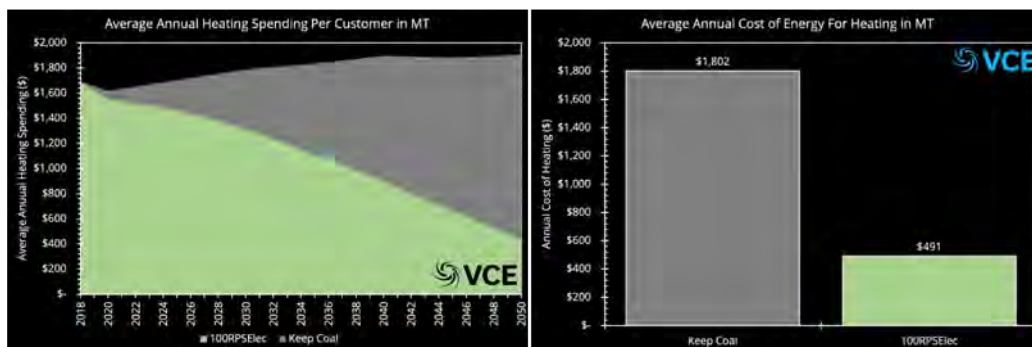


Figure 2.4: Change in annual spending for heating per customer in Montana (left) and average annual spending for space heating over the modeling period (right) for the “keepCoal” and “RPS100Elec” scenarios.

The average cost of heating over the modeling period in the “RPS100Elec” scenario is \$491 compared with \$1,802 in the “keepCoal” scenario, a 72% reduction. Therefore, the total savings for heating as a result of electrification is \$39,390 per customer over the modeling period. This reduction in heating costs come in addition to not only reduced carbon emissions, but also improved indoor air quality and reduction in methane emissions from leaks.

¹<https://www.eia.gov/outlooks/aeo/data/browser/#/?id=15-AEO2020®ion=0-0&cases=highogs&start=2018&end=2050&f=A&linechart=~highogs-d112619a.37-15-AEO2020&ctype=linechart&sourcekey=0>

²<https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2020®ion=0-0&cases=highogs&start=2018&end=2050&f=A&linechart=~highogs-d112619a.35-13-AEO2020~highogs-d112619a.36-13-AEO2020&ctype=linechart&sourcekey=0>

³<https://www.eia.gov/outlooks/aeo/data/browser/#/?id=12-AEO2020®ion=0-0&cases=highogs&start=2018&end=2050&f=A&linechart=~highogs-d112619a.12-12-AEO2020~highogs-d112619a.17-12-AEO2020&map=&ctype=linechart&sourcekey=0>



2.3 Spending in the Transportation Sector

The change in average annual spending in Montana on transportation and the average transportation spending over the modeling period for the “keepCoal” and “RPS100Elec” scenarios is shown in Fig. 2.5. In the “keepCoal” scenario, gasoline remains the primary fuel used for transportation, while in the “RPS100Elec” scenario, all the light and medium duty vehicles are electrified along with most of the heavy-duty transport resulting in 90% of the vehicles electrified by 2050. The change in gasoline prices over the modeling period is obtained from the AEO 2020 forecasts⁴. The forecasts of change in efficiency of the internal combustion engine vehicles is obtained from the AEO 2019 forecasts⁵. The electric vehicle efficiency is assumed to increase from 3.5 miles/kWh in 2018 to 5 miles/kWh in 2050. Vehicles in Montana are assumed to average 10,000 miles per year over the whole modeling period.

In the “keepCoal” scenario, the spending on transportation initially decreases from 2020 to 2025 as the cost of fuel reduces along with an increase in average vehicle efficiency. After 2025, the cost of fuel increases steadily reaching 17.5% higher compared with 2020 levels resulting in a steady increase in transportation spending in spite of the increase in vehicle efficiency. In the “RPS100Elec” scenario, as the penetration of electric vehicles increases, the transportation costs reduce steadily as the retail rates also reduce at the same time resulting in significantly lower transportation costs by 2050 in the “RPS100Elec” scenario compared with the “keepCoal” scenario.

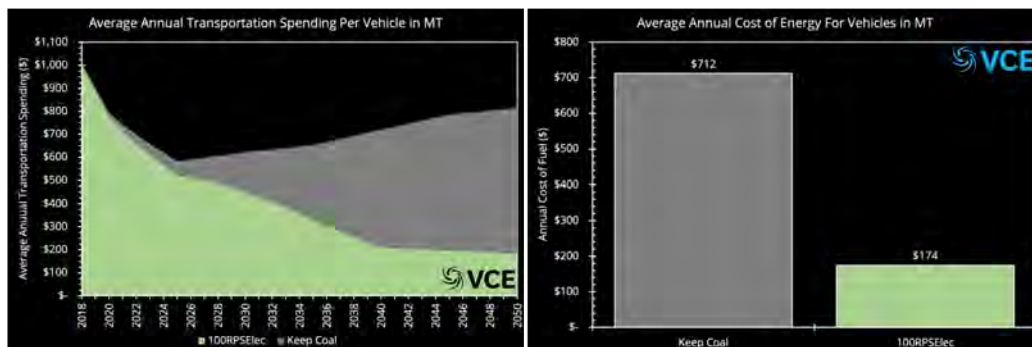


Figure 2.5: Change in annual spending for transportation per customer in Montana (left) and average annual spending for space heating over the modeling period (right) for the “keepCoal” and “RPS100Elec” scenarios.

The “RPS100Elec” scenario results in an average per customer spending for transportation of \$174 over the modeling period compared with \$712 per customer in the “keepCoal” scenario, a 75% reduction. This is a savings of \$16,140 in transportation costs over the modeling period for each customer. These savings do not include the additional savings that come from reduced maintenance required for electric vehicles due to much simpler mechanical construction and a smaller number of moving parts. In addition, to the cost

⁴<https://www.eia.gov/outlooks/aeo/data/browser/#/?id=12-AEO2020®ion=0-0&cases=highhogs&start=2018&end=2050&f=A&linechart=~highhogs-d112619a.30-12-AEO2020&map=&ctype=linechart&sourcekey=0>

⁵<https://www.eia.gov/outlooks/aeo/data/browser/#/?id=7-AEO2019®ion=0-0&cases=ref2019&start=2017&end=2050&f=A&linechart=ref2019-d111618a.21-7-AEO2019~ref2019-d111618a.25-7-AEO2019~ref2019-d111618a.28-7-AEO2019~ref2019-d111618a.31-7-AEO2019~ref2019-d111618a.34-7-AEO2019~ref2019-d111618a.35-7-AEO2019~ref2019-d111618a.36-7-AEO2019~ref2019-d111618a.37-7-AEO2019&ctype=linechart&sourcekey=0>



savings and reduced carbon emissions, the adoption of electric vehicles reduces emissions of other criteria air pollutants such as NO_x, SO₂, volatile organic compounds as well as particulate matter resulting in improved health outcomes in local communities.



2.4 Changes to Industrial Spending

The change in average annual industrial sector spending and average annual spending over the modeling period per customer in the “keepCoal” and “RPS100Elec” scenarios is shown in Fig. 2.6. In the “RPS100Elec” scenario, the electricity demand in the industrial sector increases by 240% compared with 2018 levels as significant portions of the industrial operations are electrified. In addition, demand for harder to electrify industrial activities are met using hydrogen, which is produced through electrolysis powered by energy supplied by the electricity sector. In the “keepCoal” scenario, industrial activities continue to be largely fueled by fossil fuel sources such as coal, natural gas and oil.

The industrial sector spending in the “keepCoal” scenario increases sharply from 2020 to 2025 as a result of an increase in industrial oil prices⁶. After 2025, prices of industrial oil, natural gas and coal continue to increase at a slower pace resulting in a more gradual increase in industrial sector spending after 2025 in the “keepCoal” scenario. In the “RPS100Elec” scenario on the other hand, as the industrial load shifts from fossil fuels to electricity and hydrogen, this sector is able to take advantage of the reducing electricity retail rates and hydrogen prices, resulting in a gradual reduction of industrial sector spending after 2025.

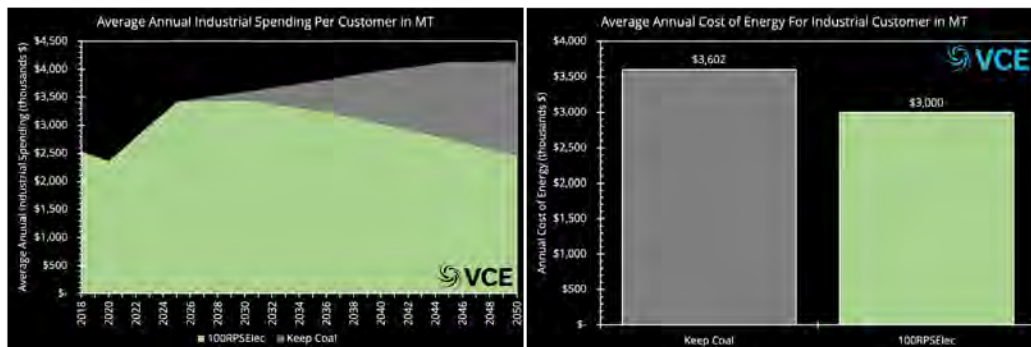


Figure 2.6: Change in annual industrial sector spending per customer in Montana (left) and average annual industrial sector spending over the modeling period (right) for the “keepCoal” and “RPS100Elec” scenarios.

Over the modeling period, the average per customer industrial spending reduces from \$3.6 million in the “keepCoal” scenario to \$3.0 million in the “RPS100Elec” scenario, a 16.7% reduction. As a result, the “RPS100Elec” scenario reduces industrial spending through increasing efficiencies and electrification which not only results in reduced carbon emissions, but also 16.7% lower costs, the benefits of which will be passed on to other sectors of the economy.

⁶<https://www.eia.gov/outlooks/aeo/data/browser/#/?id=12-AEO2020®ion=0-0&cases=highhogs&start=2018&end=2050&f=A&linechart=~highhogs-d112619a.12-12-AEO2020~highhogs-d112619a.17-12-AEO2020~highhogs-d112619a.23-12-AEO2020&map=&ctype=linechart&sourcekey=0>



2.5 Combined Impact on Economy-wide Spending

The annual economy-wide savings and cumulative savings in the “RPS100Elec” scenario compared with the “keepCoal” scenario broken out by sectors is shown in Fig. 2.7. The savings in all sectors accelerate after 2025 which coincides with the start of retirement of the coal generation and shifting the energy related activities in the rest of the economy to the electricity sector. Savings accumulate at a faster rate between 2025 and 2040 during which the “keepCoal” scenario maintains all the coal generation on the Montana grid.

By 2050, the economy-wide spending in the “RPS100Elec” scenario is lower by \$2.1 billion per year compared with the “keepCoal” scenario. The largest savings come from the transportation sector where spending is lower by \$713 million in 2050, followed closely by the industrial sector which has \$580 million lower spending in 2050. Cumulatively, the “RPS100Elec” scenario saves \$32.7 billion by 2050 compared with the “keepCoal” scenario largely driven by savings in the transportation and industrial sectors.

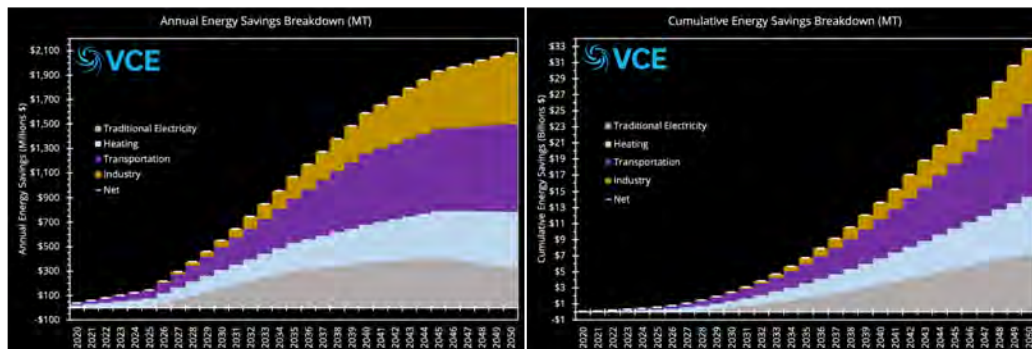


Figure 2.7: Annual economy-wide savings (left) and cumulative economy-wide savings (right) in the “RPS100Elec” scenario compared with the “keepCoal” scenario.

Figure 2.8 shows the average annual per customer spending in the residential and commercial sectors over the modeling periods for the “keepCoal” and “RPS100Elec” scenarios. The total annual spending in the “keepCoal” scenario is \$5,391 versus \$2,855 in the “RPS100Elec” scenario, a 47% reduction. Thus the “RPS100Elec” scenario almost halves the annual spending in the residential and commercial sectors of the economy giving a boost to disposable incomes for local businesses and households. The increased economic activity that results from the population having larger disposable incomes comes alongside improved air quality as a result of significantly reducing not only carbon emissions, but also all criteria air pollutants from the electricity, industrial and transportation sector.



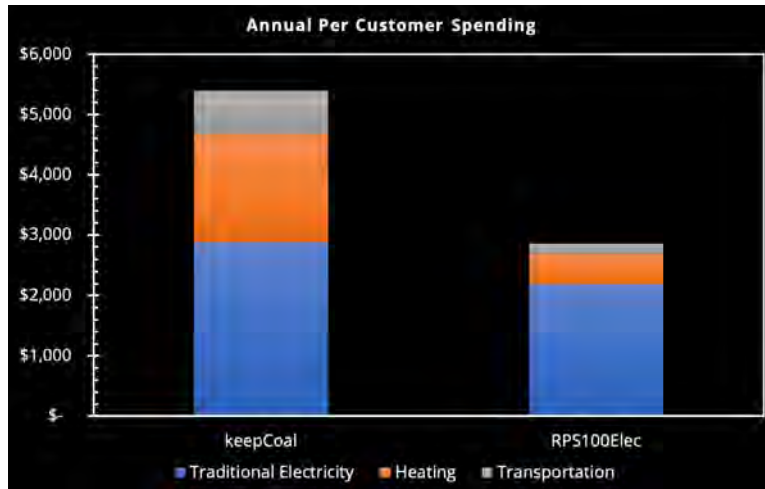


Figure 2.8: Average annual per customer spending in the residential and commercial sectors in the “keepCoal” and “RPS100Elec” scenarios.



3 Study Description

3.1 Modeled Scenarios

To investigate the various pathways available for the state of Montana to reduce carbon emissions through decarbonizing the electricity sector and electrifying the rest of the economy, 350.org and GridLab retained Vibrant Clean Energy (VCE®) to model the electricity system in Montana under various scenario. VCE performed detailed modeling of Montana and the rest of the Western Electricity Coordinating Council (WECC) to study various scenarios Montana could undertake. All scenarios modeled in this study use high resolution weather dataset from the High-Resolution Rapid Refresh (HRRR) model to inform variable renewable energy (VRE) generation, load shapes, energy infrastructure impacts (heat rates, transmission line ratings, losses etc.) as well as available load flexibility. The scenarios modeled in this study use VCE's flagship energy system modeling software WIS:dom®-P.

The scenarios modeled in this study are:

- (1) **Business as Usual ("BAU"):** This scenario is the counterfactual against which other scenarios are compared. In this scenario, Montana undergoes optimal capacity expansion to meet the business-as-usual load growth occurring over the years. WIS:dom-P meets all the renewable energy portfolio standards (RPS) set by the various states (including 100% RPS for Helena and Missoula counties in Montana) and greenhouse gas emission mandates. Transmission is allowed to grow subject to historical growth constraints and WIS:dom-P co-optimizes the distribution grid with the utility-scale generation.
- (2) **Keep coal generation in Montana until 2040 ("keepCoal"):** In this scenario, the coal generation in Montana is kept online until 2040. The rest of the electricity system and WECC region undergo optimal capacity expansion. Transmission is allowed to expand subject to historical growth constraints and WIS:dom-P co-optimizes the distribution grid along with the utility-scale generation.
- (3) **Decarbonize Montana electricity grid by 2035 ("RPS100"):** In this scenario, Montana decarbonizes its electricity grid by 100% by 2035. The rest of the WECC region continues on business-as-usual and only follow existing RPS and greenhouse gas mandates. Transmission is allowed to grow subject to historical growth constraints and WIS:dom-P co-optimizes the distribution grid with the utility-scale generation.
- (4) **Decarbonize Montana electricity grid by 2035 but ensure Montana is a net exporter of energy ("RPS100Export"):** This scenario is similar to the "RPS100" scenario that decarbonizes the Montana electricity grid by 2035, however it ensures that Montana remains a net exporter of energy throughout the modeling period. The rest of the WECC region continues on business-as-usual trajectory only following existing RPS and greenhouse gas mandates. Transmission is allowed to grow constrained by historical growth and WIS:dom-P co-optimizes the distribution system with the utility-scale generation.



- (5) **Electrify Montana while decarbonizing the electricity sector (“RPS100Elec”):** In this scenario, the state of Montana undergoes economy-wide electrification while decarbonizing the electricity sector by 2035. The state of Montana is constrained to remain a net exporter of energy throughout. The rest of the WECC region continues business-as-usual following existing RPS and greenhouse gas mandates. Transmission is allowed to grow subject to historical growth constraints and WIS:dom-P co-optimizes the distribution system with the utility-scale generation.

All the scenarios modeled in this study use 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 scenarios use forecasts from the Annual Energy Outlook (AEO) 2020 High Oil and Gas supply scenario.⁷

To model the above scenarios, VCE used 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). All scenarios are initialized and calibrated with 2018 generator, generation, and transmission topology datasets. WIS:dom-P determines a cost-optimal pathway from 2020 through 2040 with results outputted every 5 years while meeting the constrained imposed for each scenario. Detailed technical documentation describes the mathematics and formulation of the WIS:dom-P software along with input datasets and assumptions⁸. Discussion of the generator input datasets is included in Section 5.1. A description of the wind and solar resource (as well as siting potential) is contained in Section 5.2. Economic and policy inputs are presented in Section 5.3. Finally, Section 5.4 documents the general weather behavior for Montana and the WECC region.

The results of the scenarios modeled are discussed in Section 4. The change in system costs, retail rates and jobs are provided in Section 4.1. The changes to generating capacity, installation rates of utility and distributed generation are detailed in Section 4.2. Section 4.3 discusses changes to the generation mix along with a description of how WIS:dom-P uses variable renewable energy resources (VREs) to meet demand during periods of high system strain. The impact on pollution and emissions is discussed in Section 4.4. Section 4.5 describes the transmission buildout selected by WIS:dom-P for each of the scenarios. As part of the optimal capacity expansion, WIS:dom-P must ensure each balancing region 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 4.6 discusses the details around how capacity value of both thermal and VRE generation is estimated. Finally, Section 4.7 shows the detailed siting, at 3-km resolution, of the capacity expansion performed for each of the scenarios.

⁷<https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2020®ion=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>

⁸[https://vibrantcleanenergy.com/wp-content/uploads/2020/08/WISdomP-Model_Description\(August2020\).pdf](https://vibrantcleanenergy.com/wp-content/uploads/2020/08/WISdomP-Model_Description(August2020).pdf)



3.2 WIS:dom-P Model Setup

To accurately study the evolution of the electricity grid over Montana, WIS:dom-P modeled the whole WECC region and its interconnections to Canada. The unshaded region in Fig. 3.1 (left panel) is the modeled domain with the existing generators and transmission pathways shown in Fig. 3.1 (right panel). The model domain in each scenario is simulated with all its generators, demands, and transmission connections and their interaction with the weather data from the HRRR model. The rest of this section discusses the loads and transmission topology used to initialize WIS:dom-P.

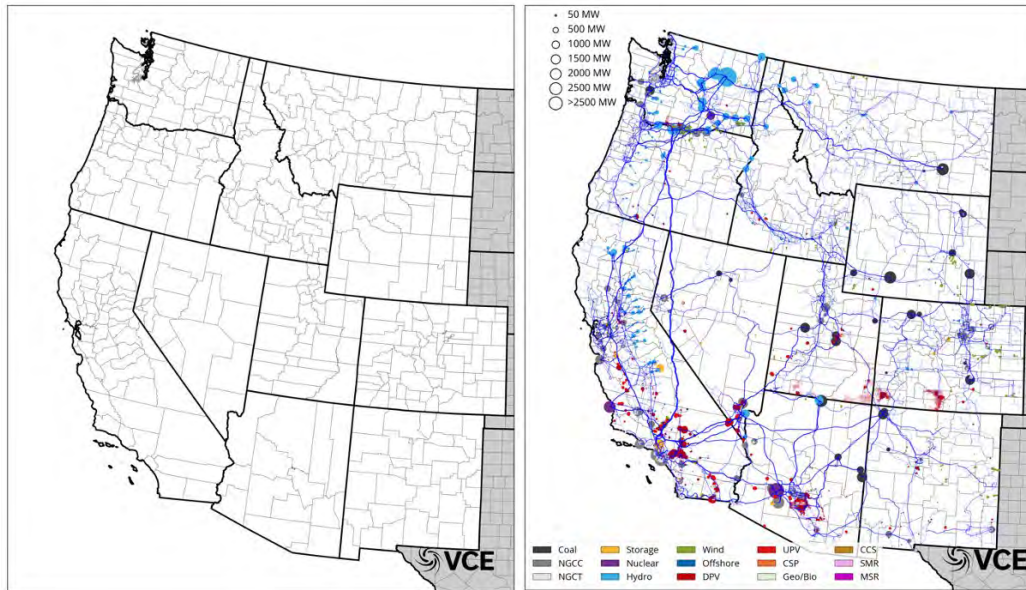


Figure 3.1: WIS:dom-P model domain (left) and existing generators with transmission (right).

The initialized generator dataset is created by aligning the Energy Information Administration Form 860 (EIA-860) dataset⁹ with the High-Resolution Rapid Refresh (HRRR)¹⁰ model grid. More details on creation of the generator dataset can be found in Section 4.1.

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 as shown in Fig. 3.2. The conventional load makes up the largest fraction of the total load with a peak demand of 2.2 GW peaking in summer. The space and water heating are smaller

⁹ <https://www.eia.gov/electricity/data/eia860/>

¹⁰ <https://rapidrefresh.noaa.gov/hrrr/>

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



components of the total load with peaks in the winter periods. Transportation is a negligible part of the electricity demand in 2018.

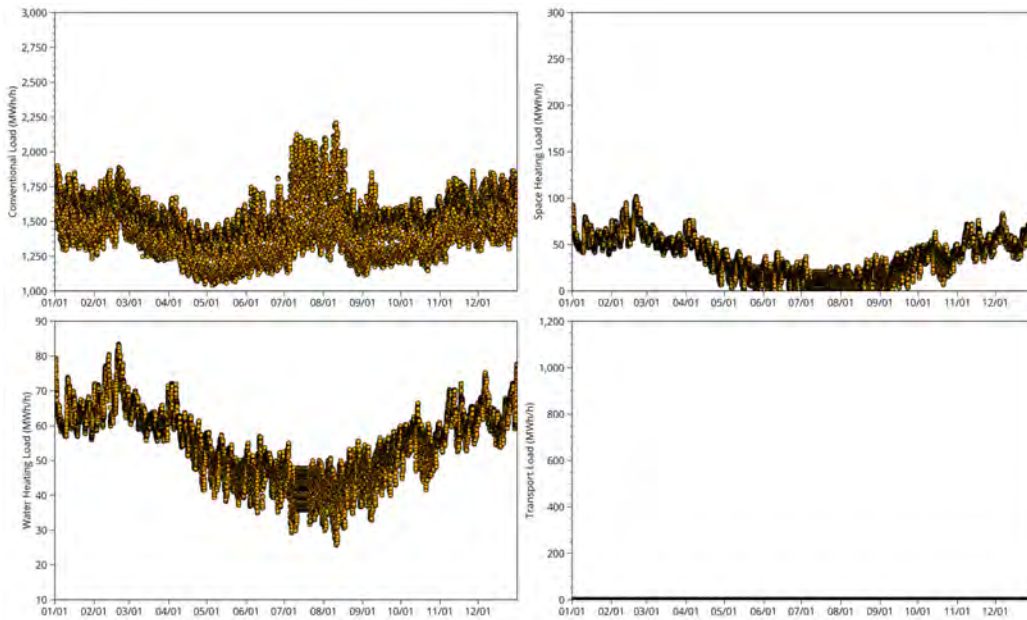


Figure 3.2: Aggregated demand profiles for Montana in 2018. Conventional (top left), space heating (top right), water heating (bottom left) and transport (bottom right).

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. 3.3. As seen from Fig. 3.3, the state of Montana has a summer and winter peaking demand profile in 2018 with a peak load of 2.23 GW in summer. The winter peaks both in the early and later parts of the year are smaller than the summer peak. The load is at its lowest in the late spring and early fall periods coinciding with the milder weather during these times of the year. 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

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



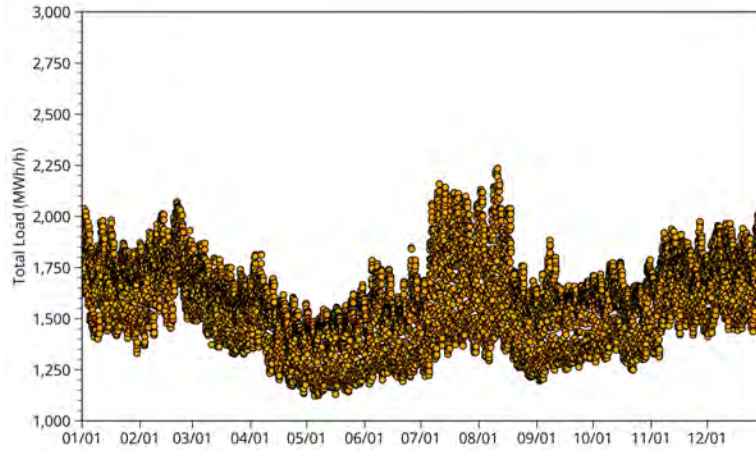


Figure 3.3: Aggregated total demand profile for the state of Montana in 2018.

The change in the various components of the demand as a result of business-as-usual load growth is shown in Fig. 3.4. The conventional load increases by 18% by 2050 over 2018 levels with a peak load of 2.6 GW. Space heating load increases only slightly as any increase in load is offset by increased efficiencies from switching space heating from resistive heating to heat pumps or from investing in newer more efficient heat pumps. The water heating load decreases from 2018 level as the population switches from electric water heater to gas water heaters. Transportation load increases slightly, but remains a very small portion of the total load.

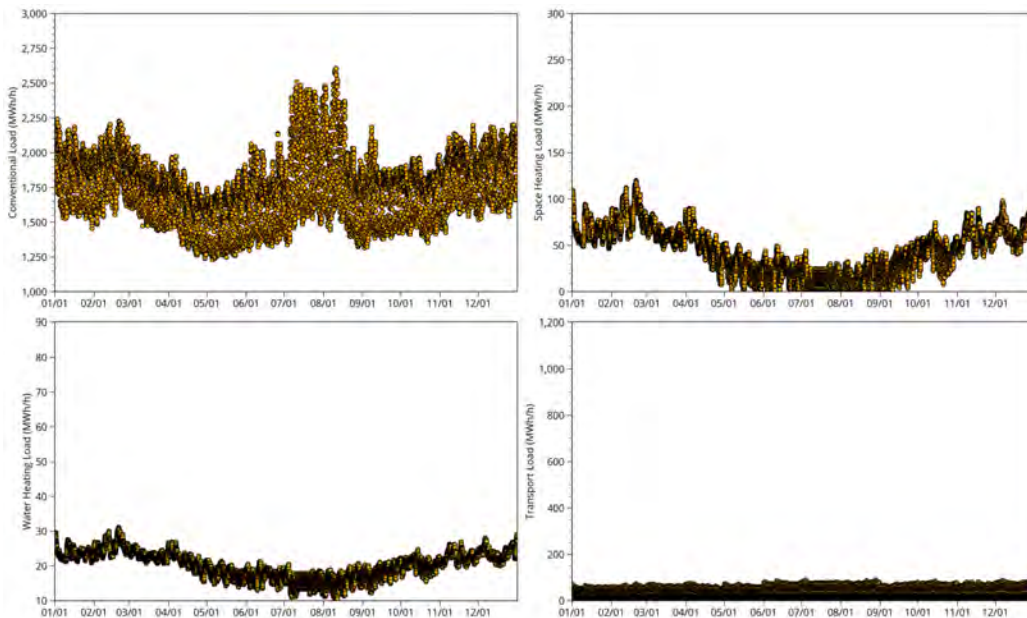


Figure 3.4: Aggregated demand profiles for Montana in 2050. Conventional (top left), space heating (top right), water heating (bottom left) and transport (bottom right).

In contrast, in the electrification scenario modeled (see Fig. 3.5), conventional load increases by 30% compared with 2018 levels with a peak load of 2.85 GW in summer. The space heating load also increases substantially as gas power space heaters are switched with heat pumps. Water heating load remains at about the same levels as 2018 as water heater are



converted to heat pumps rather than gas heaters. The largest load growth is seen in the transportation sector as most of the vehicle fleet is electrified.

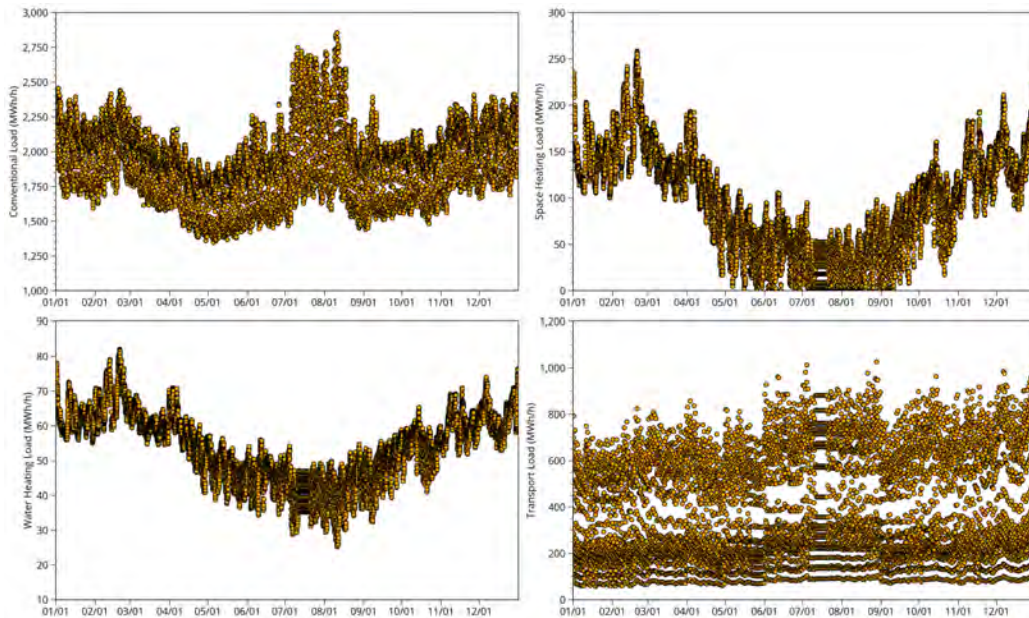


Figure 3.5: Aggregated demand profiles for Montana in 2050 in the economy-wide electrification scenario. Conventional (top left), space heating (top right), water heating (bottom left) and transport (bottom right).

The aggregated total load shapes for the state of Montana in 2050 for the business-as-usual load growth scenarios and electrification scenario are shown in Fig. 3.6 (top and bottom panels respectively). In the business-as-usual load growth scenario, the total load increases by 17% by 2050 over 2018 levels with a peak load of 2.65 GW. The load still has a higher summer peak with smaller peaks in the winter periods.

The load shape in the electrification scenario shows a much larger growth in load due to moving energy related activities in the rest of the economy to the electricity sector. The total load in 2050 in the electrification scenario is 56% higher compared with 2018 levels with a peak load of 3.47 GW in summer. The winter peaks are only slightly lower at 3.3 GW with lowest load during the late spring period. The loads during the second half of the year (fall and winter seasons) grow more compared with the business-as-usual case driven by growth in the transportation sector which sees more vehicle miles drives in this time of the year.



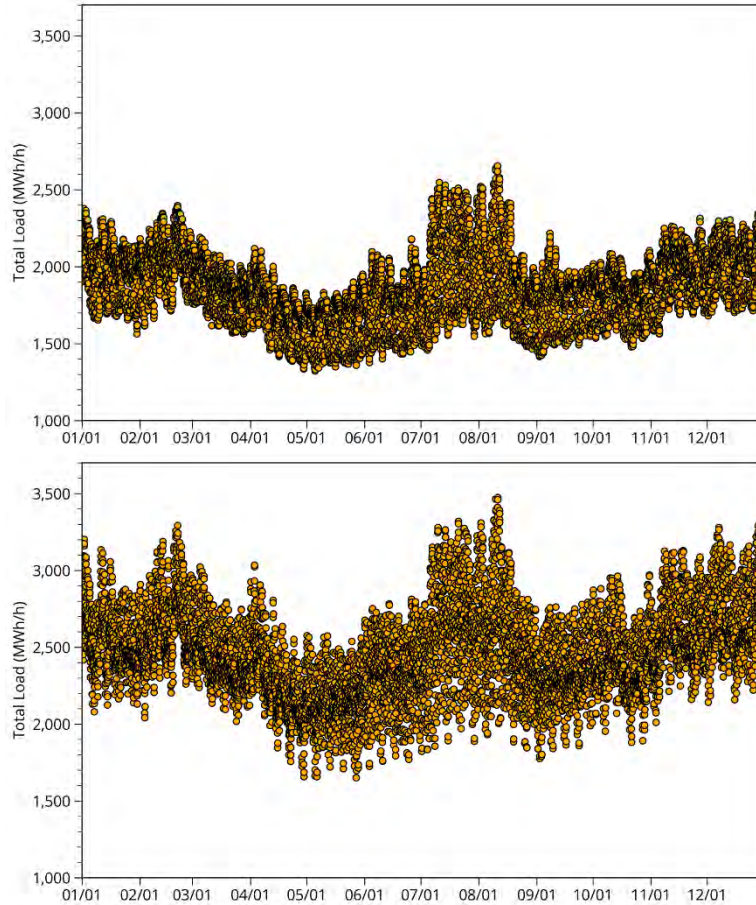


Figure 3.6: Aggregated total demand profile for the state of Montana in 2050 with BAU load growth (top) and electrification (bottom).

The above demand profiles already account for reductions due to energy efficiency (EE) measures. 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. 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 2020, 2030, 2040 and 2050 is shown in Fig. 3.7. The demand flexibility available is greater in the summer periods as most of the water and space heating demand is satisfied through natural gas in the business-as-usual load scenarios. Therefore, the summer demand from air-conditioning and some industrial load is the major source of demand flexibility in the business-as-usual load scenarios. The maximum load flexibility available in 2050 is 842 MW during the summer periods.



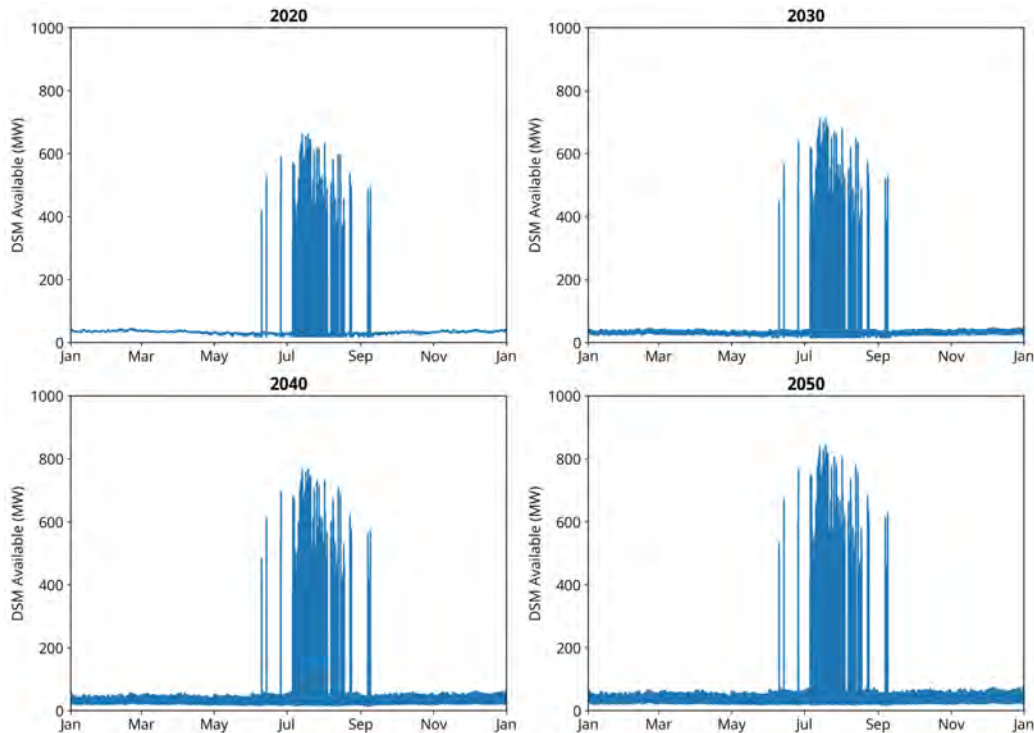


Figure 3.7: Available demand flexibility in MT for the business-as-usual load scenarios during each time period of the year over the investment periods.

The demand flexibility available in the electrification scenario in years 2020, 2030, 2040 and 2050 is shown in Fig. 3.8. In the electrification load scenario, the peak demand flexibility available is still in the summer with a maximum load flexibility of 1,400 MW in 2050. However, due to electrification of space and water heating loads as well as transportation, there is significant load flexibility available in the winter periods as well with peak flexibility of 850 MW in winter by 2050.

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 2050 in the electrification scenario is 2,638 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 as shown in Figs 3.7 and 3.8.



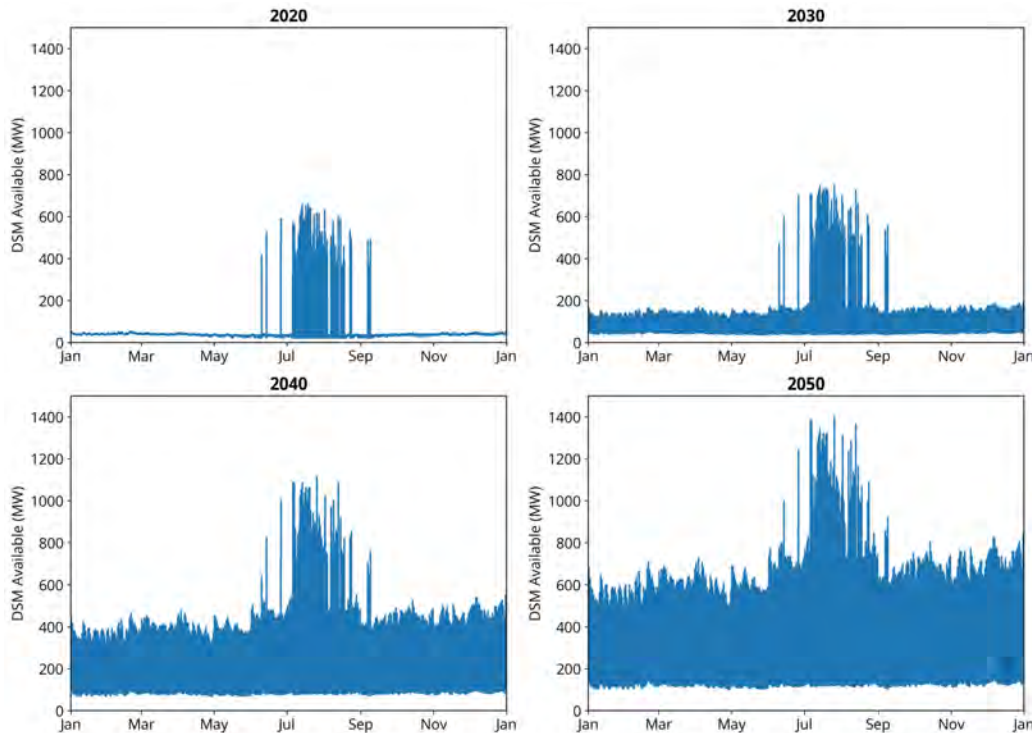


Figure 3.8: Available demand flexibility in MT during each time period of the year over the investment periods.

The various components that contribute to the evolution of demand for the state of Montana are shown in Fig. 3.9. 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 in the electrification scenario. 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.

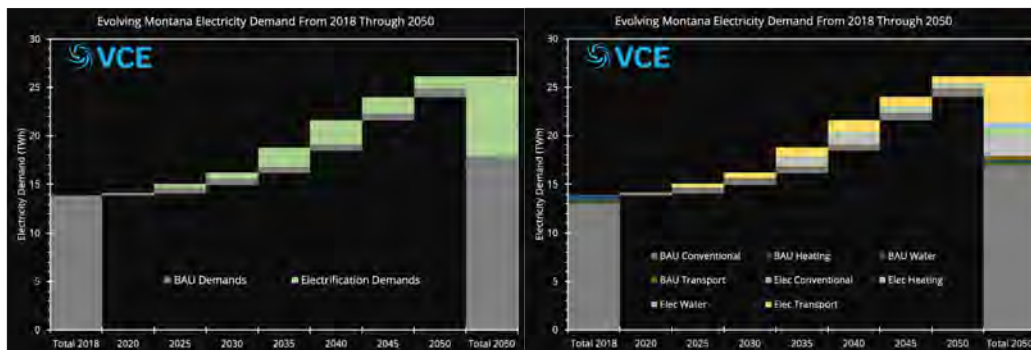


Figure 3.9: Electrification contributing to change in total demand for the state of MT.

WIS:dom-P resolves the transmission topology of the modeled grid down to each 69-kV substation resolution as shown in Fig. 3.10 (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. 3.10 (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 3.10: Transmission topology of the utility scale electricity system across WECC 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 3.11 is a schematic of how WIS:dom-P represents the U-D interface and Fig. 3.12 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*).



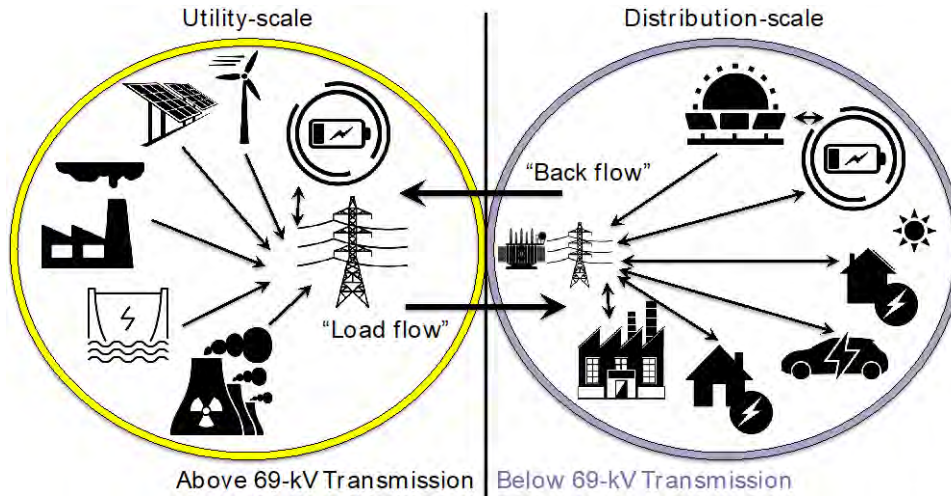


Figure 3.11: A schematic picture of the U-D interface within the WIS:dom-P modeling platform.

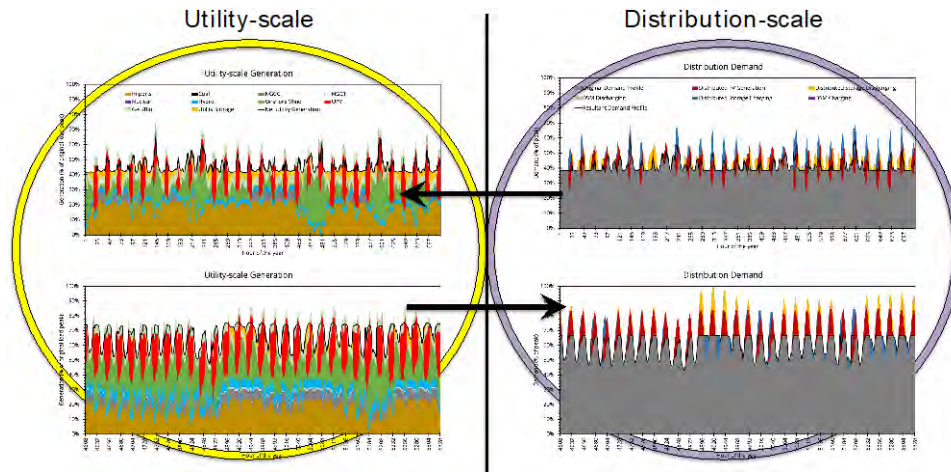


Figure 3.12: Example coordination at the utility- and distribution-scale within the WIS:dom-P model.

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

$$\Lambda \cdot \left\{ c_L^{dp} \cdot [\varepsilon_L^p + \lambda_a \cdot (\varepsilon_L^b + \varepsilon_L^m)] + h \cdot c_L^{de} \cdot \sum_t (\varepsilon_{Lt} - \lambda_b \cdot J_{Lt}) \right\}. \quad (1)$$

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:

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

$$\mathcal{E}_{\mathcal{L}}^b + \mathcal{E}_{\mathcal{L}t} + \Lambda \cdot \sum_{\mathcal{D} \in \mathcal{L}} \left[\sum_{\mathcal{D}} (r_{\mathcal{D}\mathcal{D}t}^+ - r_{\mathcal{D}\mathcal{D}t}^-) + (\mathcal{C}_{\{dist\}\mathcal{D}t} - \mathcal{D}_{\{dist\}\mathcal{D}t}) - \mathcal{P}_{\{DPV\}\mathcal{D}t} \right] \geq 0, \quad \forall \mathcal{L}, t \quad (3)$$

$$\sum_{\mathcal{D} \in \mathcal{L}} \left\{ \mathcal{J}_{\mathcal{D}t} - \Lambda \cdot \left[\mathcal{P}_{\{DPV\}\mathcal{D}t} + \sum_{\mathcal{D}} (r_{\mathcal{D}\mathcal{D}t}^- - r_{\mathcal{D}\mathcal{D}t}^+) + (\mathcal{D}_{\{dist\}\mathcal{D}t} - \mathcal{C}_{\{dist\}\mathcal{D}t}) \right] \right\} = 0, \quad \forall \mathcal{L}, t. \quad (4)$$

Equations (1) – (4) and the terms within them are described in detail within the WIS:dom-P technical documentation.¹³ 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 $\mathcal{C}_{\mathcal{L}}^{dp}$ 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”¹⁴ 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 $\mathcal{C}_{\mathcal{L}}^{dp}$ 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.

¹³ [https://vibrantcleanenergy.com/wp-content/uploads/2020/08/WISdomP-Model_Description\(August2020\).pdf](https://vibrantcleanenergy.com/wp-content/uploads/2020/08/WISdomP-Model_Description(August2020).pdf)

¹⁴ https://energy.utexas.edu/sites/default/files/UTAustin_FCe_TDA_2016.pdf



4 Modeling Results

4.1 System Costs, Energy Prices, and Retail Rates

The change in the total resource costs over the WECC region for the various scenarios modeled is shown in Fig. 4.1. As seen from Fig. 4.1, total resource costs reduce significantly from \$73 billion in 2020 to \$60 billion in 2030 as the WECC region retires older fossil fuel generation and replaces it with lower cost variable renewable energy (VRE) generation. After 2030, total resource costs increase slightly to about \$64 billion by 2050 as more generation is added to meet the growing load. However, the average retail rates over the WECC region continue to fall after 2030 even though the total resource costs increase as the additional costs are spread over a larger load. The total resource costs for the WECC region are almost the same in all scenarios modeled as Montana makes up a small part of the load in the WECC region and hence changes in goals set by Montana have a very small impact on the rest of the region.

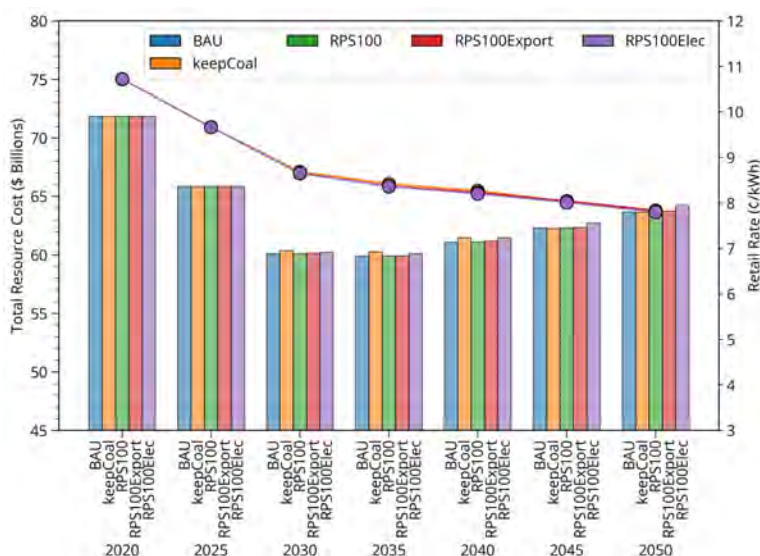


Figure 4.1: Total system cost (bars) and the average retail rates (solid lines) for the WECC domain.

The change in total resource cost and retail rates for the electrical system in Montana is shown in Fig. 4.2. In the “BAU” scenario, the total system costs in Montana initially reduce dramatically from \$2.15 billion in 2020 to \$1.36 billion in 2030 as the coal generation is retired from the Montana grid. After 2030, the total resource costs increase again slightly to \$1.55 billion by 2050 as more VRE generation is added to help meet the growing load. The retail rates in the “BAU” scenario also drop significantly from 2020 to 2030 in response to the drop in total resource costs and then continue to drop more slowly after 2030 (27% reduction by 2050 compared with 2020 values) as the increase in load over the years reduces the cost of each kWh of electricity produced.

In the “keepCoal” scenario, the total resource costs do not reduce due to the coal generation remaining on the grid until 2040. As a result, there is a negligible reduction in retail rates until 2040. After 2040, the coal generation is retired which results in an



immediate drop in costs from \$2.12 billion in 2040 to \$1.3 billion in 2045. The retail rates do not see a significant drop between 2040 and 2045 as Montana imports energy instead of exporting to make up for the loss in coal generation. Retail rates then drop significantly after 2045 as Montana is able to replace the lost generation and resume exports resulting in the same retail rates as the “BAU” scenario in 2050. This shows that the coal generation is the main impediment to achieving lower system costs and retail rates for customers in Montana.

In the “RPS100” scenario, the drop in total resource costs is larger compared with the “BAU” scenario as the Montana grid removes all fossil fuel generation and replaces it with zero marginal costs VRE generation. However, as the thermal generation is removed from the Montana grid, Montana becomes a net importer of energy by 2030. As a result, the drop in retail rates is not as high as that of the “BAU” scenario (13% higher in 2050 compared with the “BAU” scenario) as the Montana region loses some revenues from exporting energy. However, the retail rates remain significantly lower than the “keepCoal” scenario until 2045 after which the “keepCoal” scenario results in lower retail rates as Montana is able to resume exports in that scenario by 2050.

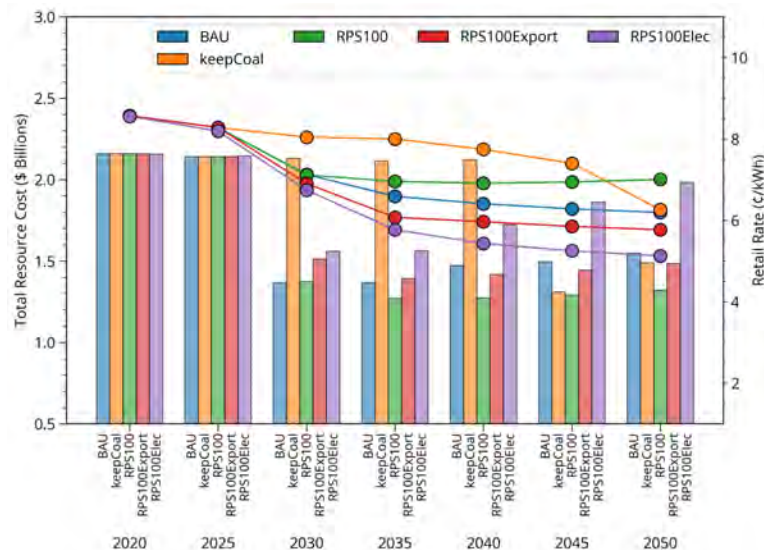


Figure 4.2: Total system cost (bars, left) and retail rates (solid line, right) for the state of Montana.

In the “RPS100Export” scenario, Montana decarbonizes its electricity grid similar to the “RPS100” scenario, but ensures that Montana remains a net exporter of energy throughout. As a result, while the total resource costs in the “RPS100Export” scenario are higher than the “RPS100” and the “BAU” scenarios, however, the retail rates are lower (32.7% lower by 2050 compared with 2020 values). The lower retail rates are driven by the additional revenues made by the utilities in Montana by exporting energy, some of which are passed on to the consumers. WIS:dom-P assumes that 50% of the revenues made from exports are passed on to the consumers in the form of reduced retail rates.

The “RPS100Elec” scenario which electrifies the rest of the economy while decarbonizing the electricity sector by 2035 also sees large reductions in total resource costs until 2030. After 2030, the total resource costs start to increase again as the load growth picks up due to electrification. However, this increase in total resource costs remains much lower



compared with the “keepCoal” scenario until 2040. This shows that not retiring the coal generation is more expensive than decarbonizing the electricity sector while electrifying the rest of the economy at the same time. In addition, the “RPS100Elec” scenario results in the lowest retail rates of all scenarios (40% reduction by 2050 compared with 2020 levels) which help reduce costs in other sectors as discussed in Section 2. The lower retail rates are due to a combination of this scenario ensuring that Montana remains a net exporter of energy and the more effective use of installed generation due to electrification. Therefore, electrification of economy-wide energy related activities combined with decarbonizing the electricity sector result in lowest retail rates which will encourage consumers to embrace electrification resulting in lowering their bills while reducing carbon emissions economy-wide.

The various components of the electricity sector that contribute to the cost of electricity is shown in Fig. 4.3. In 2020, the largest contributor to the cost of electricity is the coal generation responsible for a little under 50% of the total cost of energy. In the scenarios that retire the coal generation, the cost per kWh of electricity reduces by 40% or more as the remaining generation on the grid is zero marginal cost clean energy sources. After the coal generation, the next largest contributor to total system costs is the hydro generation responsible for about 35% of the total cost of the energy.

As a result of the distribution system co-optimization performed by WIS:dom-P, the distribution costs as a share of the electricity cost remain fairly constant although the load increases over the investment periods. The distribution system costs are seen to reduce in all scenarios except the “RPS100Elec” scenario where the distribution costs increase by 2.8% by 2050 over 2018 values although the load served by the electricity system increases by 56%. Although all scenarios build new transmission within the state as well as increase inter-state transmission, it never contributes more than 0.36 ¢/kWh to the electricity cost.

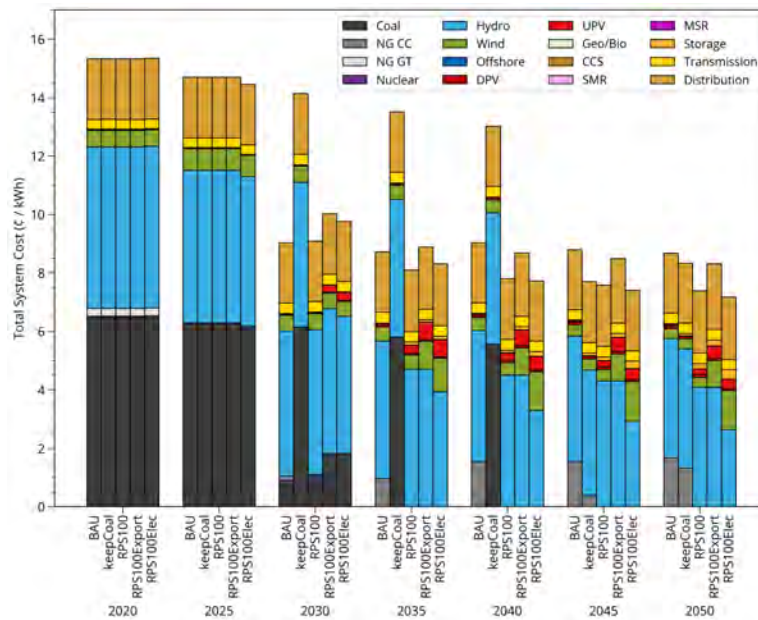


Figure 4.3: System cost per kWh load for each technology.



The direct full-time jobs supported by the electricity sector in Montana over the investment periods for the scenarios modeled is shown in Fig. 4.4. The largest employer in the electricity sector in Montana is the Transmission industry and remains so over all the investment periods. The “keepCoal” scenario results in the least job growth by 2050 of all the scenarios modeled as this scenario loses out on opportunity to build VRE generation which creates more jobs per MW installed compared with thermal generators. The “RPS100Elec” scenario results in the highest job creation driven mainly by the utility solar industry, while the storage, wind and distributed solar industries make the next largest contributions.

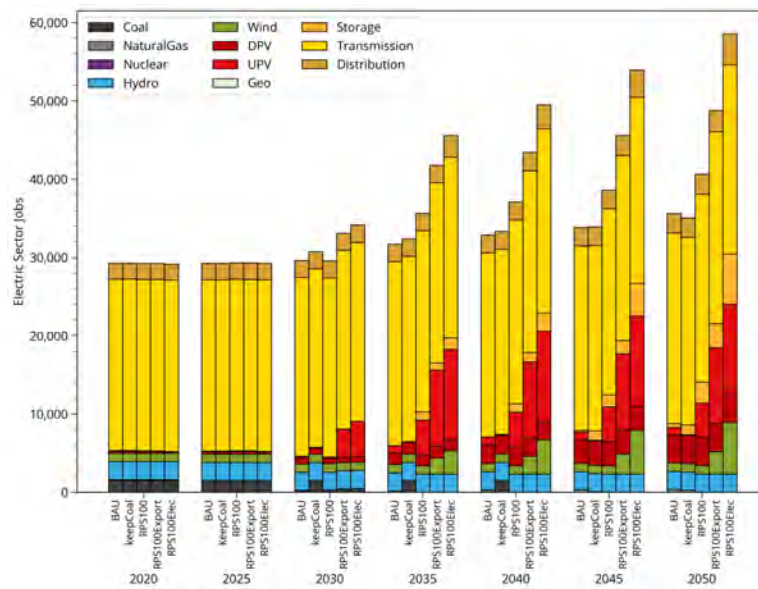


Figure 4.4: Direct full-time equivalent jobs created in the electricity sector by industry.



4.2 Generating Capacity

The evolution of the installed capacity on the Montana grid in the various scenarios modeled is shown in Fig. 4.5. In all scenarios except “keepCoal” the coal generation is retired by 2035 as it is uneconomic to run. In the “BAU” scenario, the retired coal generation is replaced with natural gas combined cycle (NGCC) generation. In the “RPS100” and “RPS100Export” scenarios, the retired coal generation is replaced with a combination of solar, storage and wind generation. The “RPS100Export” scenario builds more wind and solar compared with the “RPS100” scenario as it is constrained to be a net exporter of energy. The largest growth of wind and solar generation installed in Montana occurs in the “RPS100Elec” scenario as this scenario has to meet a growing load due to electrification while ensuring that Montana remains a net exporter of energy. In all scenario, the existing natural gas combustion turbine (NGCT) generation is completely retired by 2025 as the remaining generation on the grid is able to meet load while ensuring reliability and resource adequacy.

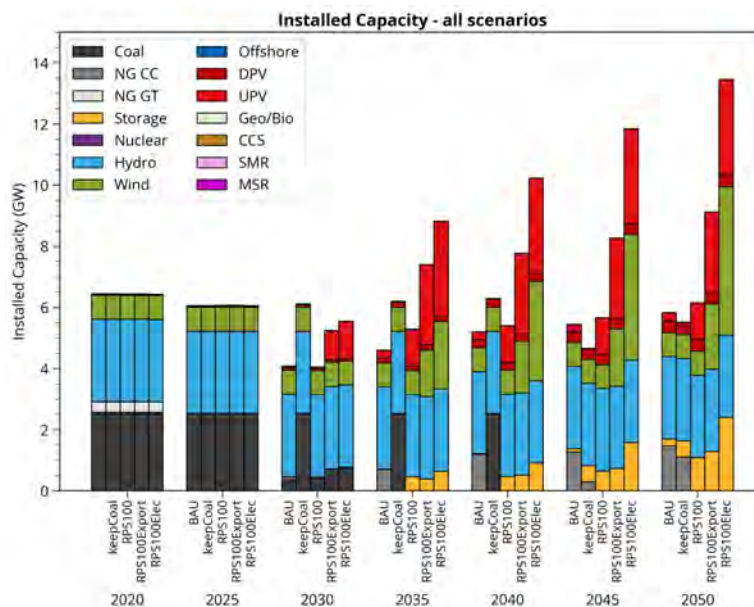


Figure 4.5: WIS:dom-P installed capacities for the scenarios modeled in Montana.

Figure 4.6 shows differences in capacity buildout over the investment periods between different pairs of scenarios modeled. Figure 4.6 (top left panel) shows the differences in capacity buildout between the “BAU” and “keepCoal” scenario. From 2020 to 2040, while the “keepCoal” scenario makes little changes to installed capacities on the grid, the “BAU” scenario replaces the coal generation with NGCC generation. The other difference observed between the two scenario is that the “keepCoal” scenario does not install any utility-scale photovoltaic (UPV) generation and instead installs distributed photovoltaic (DPV) and storage to better utilize the existing VRE generation on the grid.

The difference between capacity installations in the “RPS100Export” and “RPS100” and between “BAU” and “RPS100Export” is shown in Fig. 4.6 (top right panel and bottom left panel respectively). The “RPS100Export” scenario retires coal at a slightly slower pace compared with the “RPS100” scenario and then installs about 3-4 GW more wind and solar



generation every investment period compared with the “RPS100” scenario. The “RPS100Export” scenario installs a negligibly small amount of additional storage compared with the “RPS100” scenario. Therefore, all the excess generation in the “RPS100Export” scenario is aimed at exporting energy. As a result, while this scenario has higher total resource costs due to the excess VRE capacity, the retail rates for customers are lower due to the revenues from exports reducing cost burden for the rate-payers. This lower cost burden is assuming a conservative scenario where only 50% of the revenues from exports are passed on to consumers. With respect to the “BAU” scenario, the “RPS100Export” scenario retires coal more slowly and builds wind, solar and storage instead of NGCC generation.

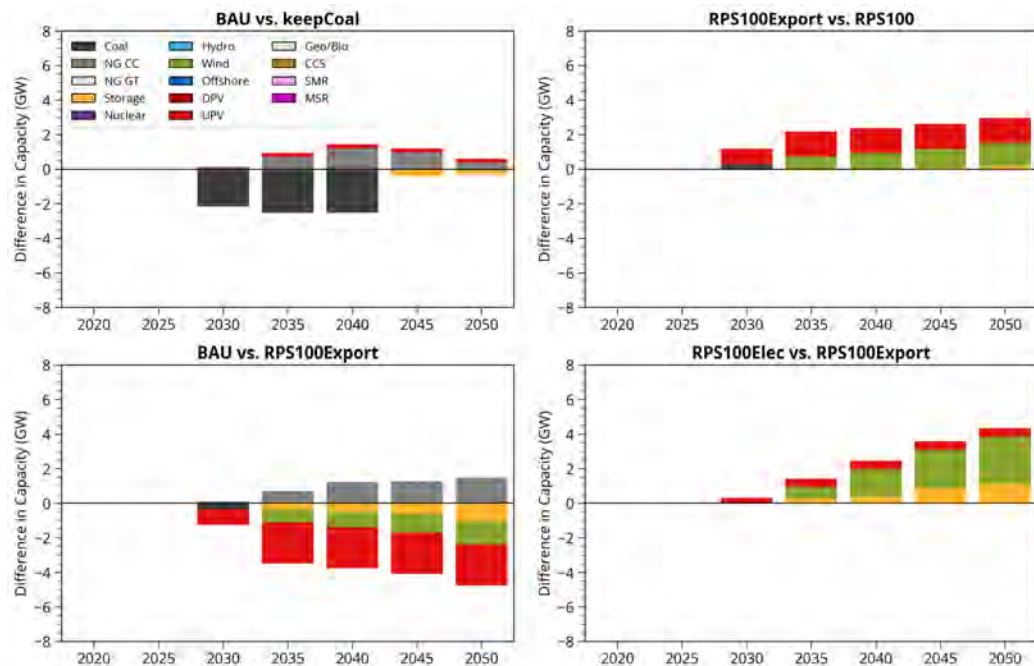


Figure 4.6: Comparison of installed capacities in the various scenarios in Montana

The difference between the “RPS100Elec” and “RPS100Export” is shown in Fig. 4.6 (bottom right panel). The “RPS100Elec” scenario installs more generation on the grid compared with the “RPS100Export” scenario as it has to meet a higher load as a result of electrification. The excess generation installed by the “RPS100Elec” scenario is mostly wind generation along with some storage and solar makes only a small portion of the excess generation. The preference for wind generation in the “RPS100Elec” scenario is due to electrification increasing winter-time and nighttime loads which are better correlated with wind generation.

Figure 4.7 shows the utility-scale and distribution-scale storage capacity (top panel) and energy (bottom panel) installed in Montana. In all the scenarios modeled, WIS:dom-P chooses an equal amount of utility-scale and distribution-scale storage to help meet load in Montana. The “BAU” scenario installs the least amount of storage on the Montana grid as in this scenario the model ramps the NGCC generation around the VRE generation to meet load and any excess generation is exported. In the “keepCoal” scenario, while the model installs less VRE generation, it installs more storage between 2040 and 2045



compared with the “BAU” scenario. The reason for the higher storage installation in the “keepCoal” scenario is that the model is trying to transition away from coal as quickly as it can after 2040. As a result, it replaces all the coal generation with NGCC generation, but is not able to install enough VRE generation quickly enough. As a result, to more effectively utilize the VRE generation it can build, the Montana region installs more storage.

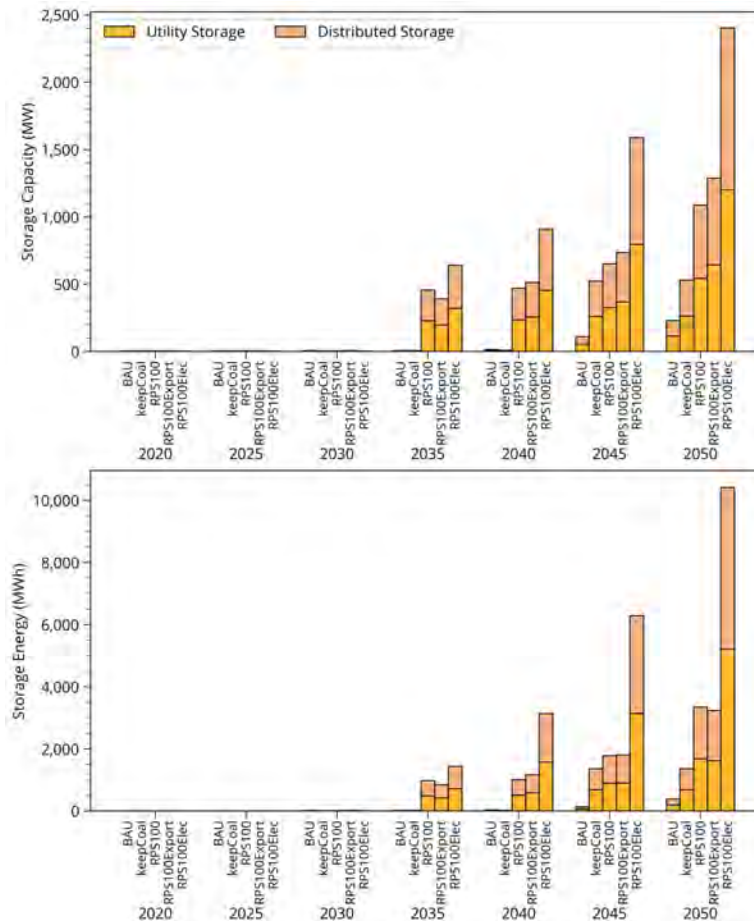


Figure 4.7: Utility storage and distributed storage installed in each investment period in Montana.

The “RPS100” and “RPS100Export” scenarios deploy significantly more storage compared with the “BAU” and “keepCoal” scenarios by 2050. The additional storage is used to store energy during periods of excess generation and discharge during periods of higher system strain. While the “RPS100Export” scenario installs more storage capacity compared with the “RPS100” scenario, it installs slightly less storage energy. The reason for this is that the “RPS100Export” scenario has higher solar capacity installed and needs the higher storage power to effectively soak up the excess generation during the day. However, since the “RPS100Export” scenario also has more wind generation installed compared with the “RPS100” scenario, it does not need any more storage energy to meet load during periods of higher system strain.

The “RPS100Elec” scenario has the highest storage capacity and energy installed with double the storage energy and capacity of the “RPS100Export” scenario. The large jump in installed storage for this scenario is due to the fact that this scenario has to meet load that is 32% larger in 2050 compared with the non-electrification scenarios.



The installed UPV and DPV on the Montana grid in the scenarios modeled is shown in Fig. 4.8. The “BAU” and “keepCoal” scenario add the least amount of solar generation with higher fraction of the solar generation added on the distribution grid. In the “keepCoal” scenario, all the solar added is on the distribution grid. The “RPS100Export” and “RPS100Elec” scenarios, which add the most solar generation, a majority of the solar installed is on the utility-scale grid as the solar generation contributes the most to exports (see Figs 4.18 and 4.19).

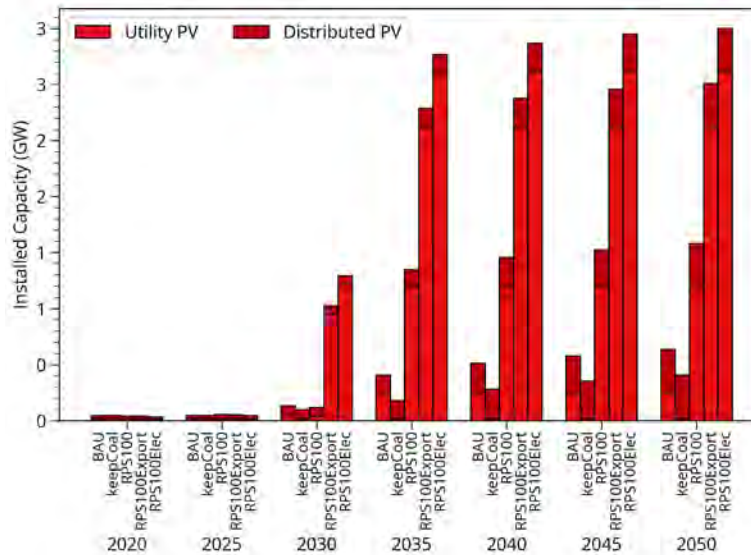


Figure 4.8: Utility PV and Distributed PV installed over the investment periods in Montana.



4.3 Electricity Generation

The evolution of the contributions to total energy generated in Montana from the various sources of energy in Montana is shown in Fig. 4.9. In all scenarios, there is a temporary increase in coal generation from 2020 to 2025 to meet the growing load. By 2030, coal generation in all scenarios, except the “keepCoal” scenario, reduces significantly as Montana retires some of the coal generation, and is completely eliminated by 2035. As a result of the reduced coal generation, the “BAU” and “RPS100” scenarios completely eliminate exports by 2030 and the “RPS100” scenario becomes a net importer by 2035. The “RPS100” scenario remains a net importer of energy until 2050.

The “keepCoal” scenario remains a net exporter of energy until 2040. Once the coal generation is retired, Montana becomes a net importer of energy as it transitions to building gas and VRE generation to replace the retired coal. After 2045, the “keepCoal” scenario transitions Montana back to being a net exporter as a result of the excess VRE generation.

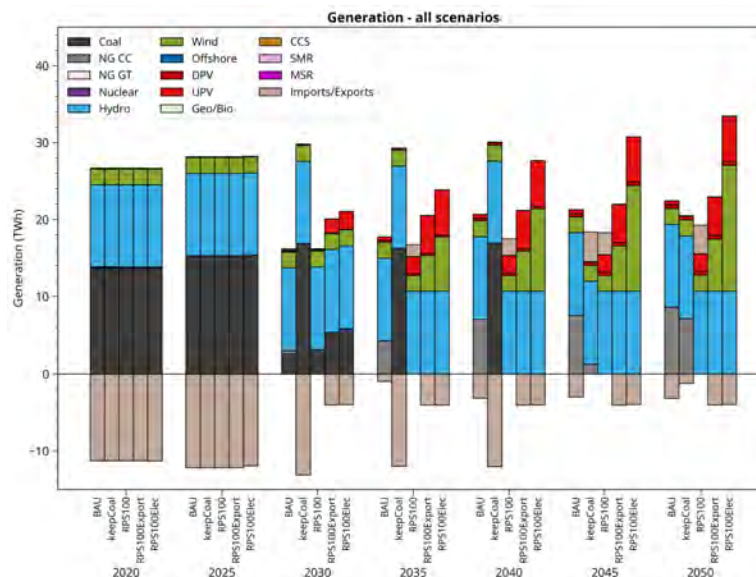


Figure 4.9: Breakdown of the evolution of generation sources for the scenarios modeled.

The “RPS100Export” and “RPS100Elec” scenarios retire coal generation slower than the “BAU” and “RPS100” scenarios while building significantly more solar and wind generation. Most of the exports in these scenarios is from the excess solar generation installed on the utility grid. The “RPS100Elec” scenario installs significantly more wind generation as it is better correlated with the electrified loads.

The daily dispatch of energy in 2020 in Montana is shown in Fig. 4.10. As seen from Fig. 4.10, a significant portion of the coal generation is used for exports with a majority of it going to Washington state. A majority of the load in Montana is met by hydro generation, with remaining met by wind and coal in 2020.



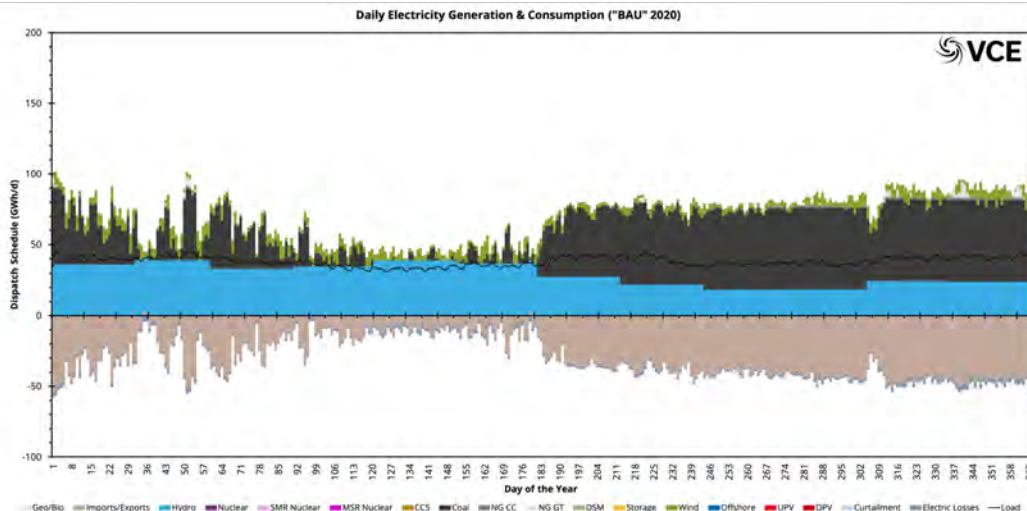


Figure 4.10: The daily generation in Montana in 2020.

By 2050, in the "RPS100Elec" scenario, all the generation in Montana comes from clean energy sources as shown in Fig. 4.11. Hydro generation helps meet majority of the load in the state, with the rest being met by wind and solar. Most of the exports from Montana are from the excess solar generation. Montana imports energy during periods of high system strain when load is high, and VRE generation is low. In addition, exports are higher in the early part of the year and reduce in the second half of the year. This behavior of imports and exports is driven by the higher load in the second half of the year driven by higher transportation load (more vehicle miles are driven in Montana in second half of the year).

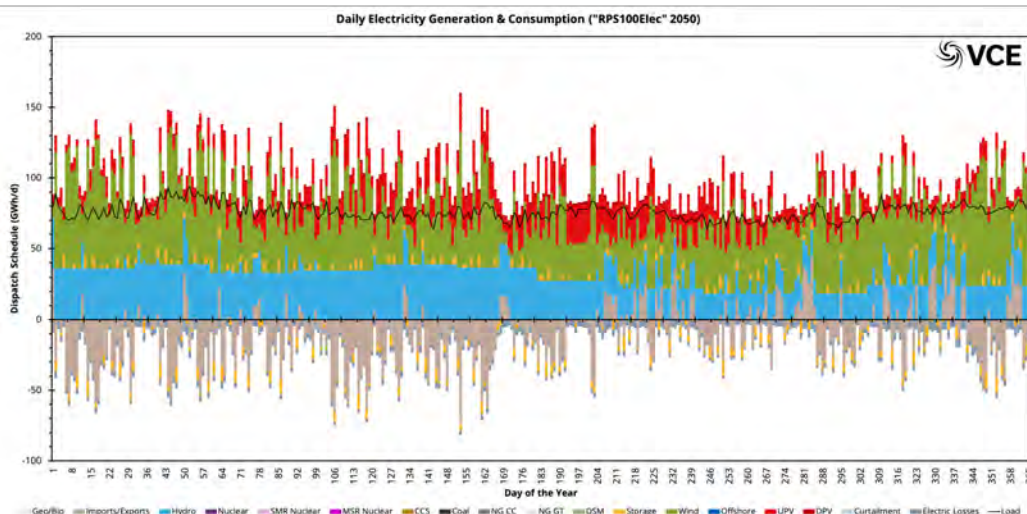


Figure 4.11: The daily generation in Montana in 2050 in the "RPS100Elec" scenario.

The week with highest system strain for the "RPS100Elec" scenario in Montana in year 2050 is shown in Fig. 4.12. System strain is defined as the product of thermal utilization rate, fraction of missing VRE generation and load factor. Therefore, system strain is highest when thermal utilization rate is at its maximum, VRE generation is at its minimum and load is at its maximum. The highest system strain in Montana in the "RPS100Elec" scenario occurs on May 25th, at 04:00. During this time, the wind generation does not show up and as a result, Montana imports energy to help meet load during this time period.



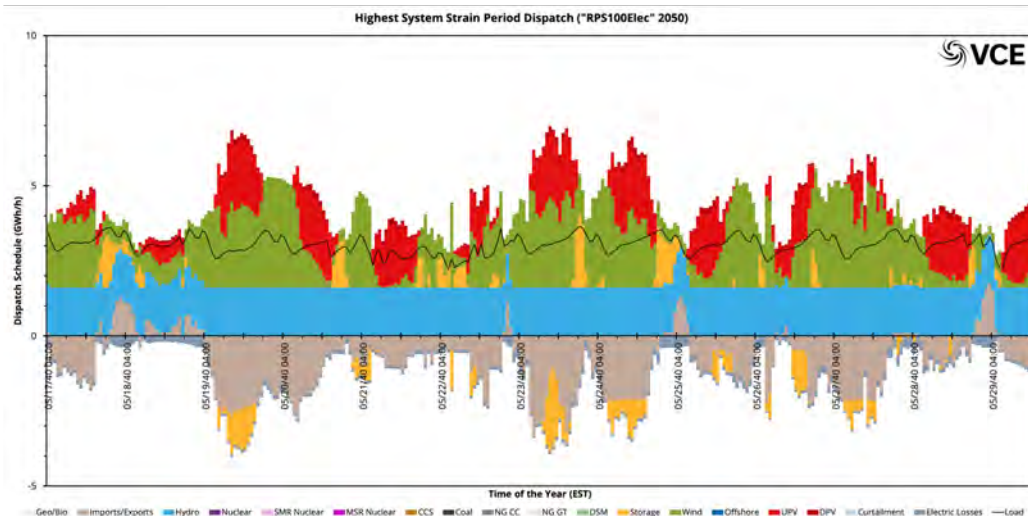


Figure 4.12: The most difficult week to supply demand in Montana in 2050.

System strain also affects operation of storage. The storage operation as a function of system strain for the "RPS100Elec" scenario in 2050 is shown in Fig. 4.13. As seen from Fig. 4.13, storage only charges when system strain is low, below 21% in the "RPS100Elec" scenario in 2050. Storage discharges over a large range of system strain values, with highest discharge capacity factors observed during periods of higher system strain (above 25% in the "RPS100Elec" scenario).

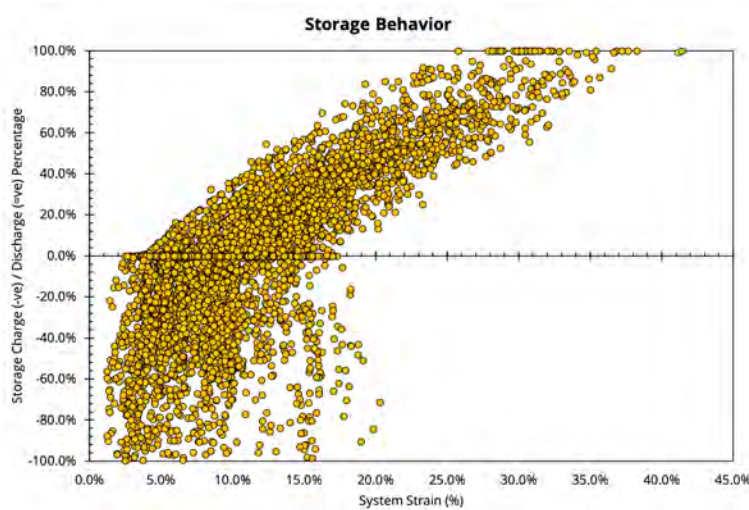


Figure 4.13: Storage behavior as a function of the strain metric in Montana in year 2050.

The impact of system strain on marginal prices is shown in Fig. 4.14. As shown in Fig. 4.14 (left panel), the system strain shows different diurnal patterns in winter and summer with the marginal prices responding to it. In winter, the system strain is higher in early morning and evening periods with low system strain in the daytime. Therefore, in the winter, the marginal prices are lowest during the daytime and higher in the early mornings and evenings. In summer, the system strain has a sharp peak in the evenings as the solar generation ramps down, but demand remains high. The marginal price also shows a slightly higher peak coinciding with this system strain peak. However, the marginal price in summer



shows much lower variability compared with winter, while having a higher marginal price on average (see Fig. 4.14 – right panel) as VRE generation is lower and Montana relies more on imports during this time of year. As seen from Fig. 4.14 (right panel), marginal prices are lower and more volatile in the early part of the year and higher and less volatile in the second half of the year. The reason for this is that Montana relies on imports more in the second half of the year and hence results in higher marginal prices and lower volatility in marginal prices. The average system strain is seen to remain fairly constant at about 4% throughout the year.

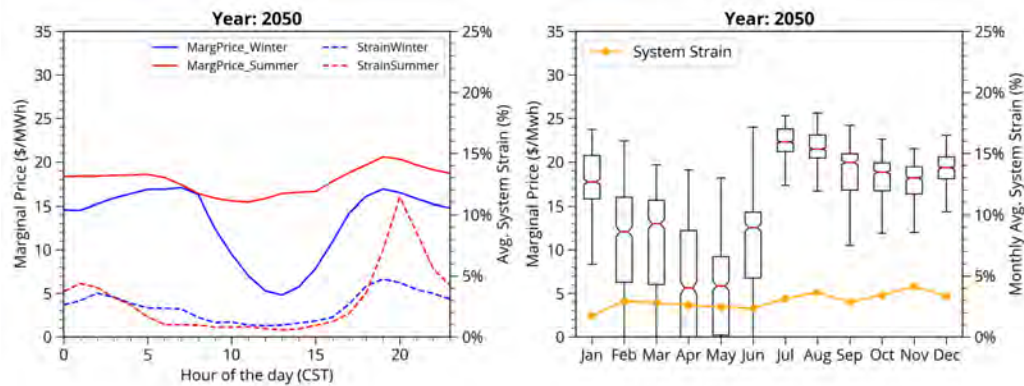


Figure 4.14: Diurnal (left) and seasonal (right) trends in average marginal price and system strain in Montana in year 2050 in the "RPS100Elec" scenario.

The change in exports from Montana to its neighbors over the investment periods for the "RPS100Elec" scenario is shown in Fig. 4.15. The largest exports from Montana are to Washington state with 4.9 TWh exported in 2020. Exports to Washington state increase to 7.3 TWh in 2030 before reducing again and settling at 2.9 TWh by 2050. Exports to Idaho reduce gradually from 3.6 TWh in 2020 to 1.2 TWh in 2050 while exports to Wyoming remain fairly constant at 1 TWh over the investment periods.

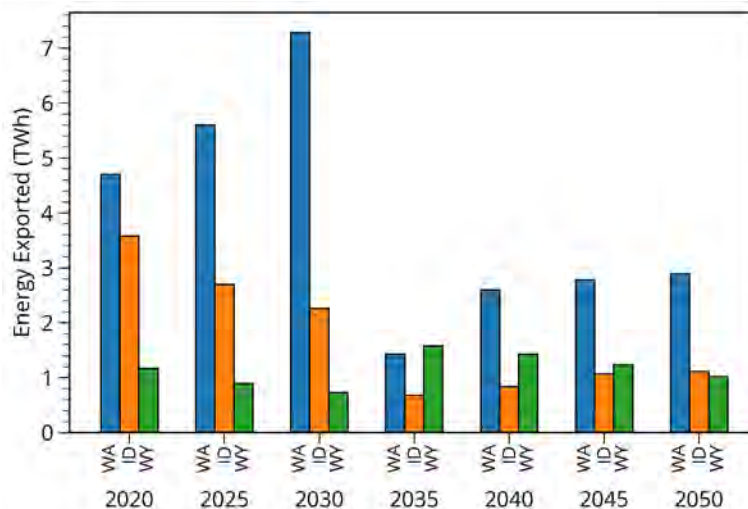


Figure 4.15: Exports from the state of Montana to its neighbors over the investment periods in the "RPS100Elec" scenario.



The duration curve of the original load and the DER modified load in the "RPS100Elec" scenario in 2050 is shown in Fig. 4.16. As a result of the DER co-optimization, the DER modified load has a peak load 3% lower than the original load which helps defer some distribution system upgrades and thus savings total system costs. The peak load reductions are larger in scenarios which do not impose export constraints. For example, in the "BAU" scenario the reduction in peak load is 6% over the original load peak.

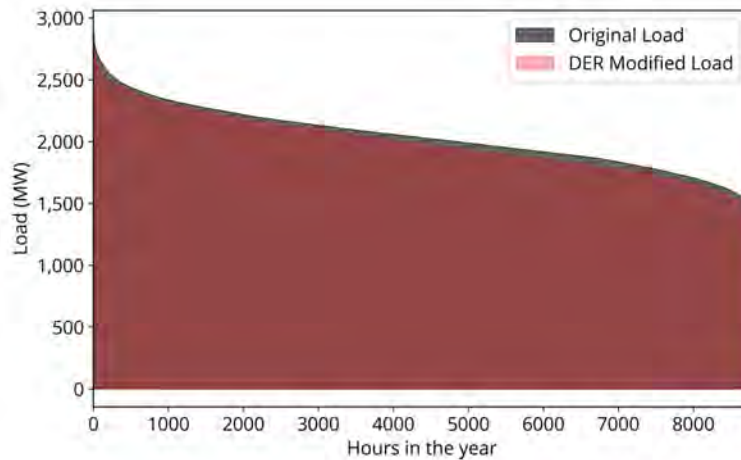


Figure 4.16: Duration curves of the original load and the DER modified load in 2050.



4.3.1 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 4.17 shows average diurnal capacity factors for wind, solar and storage in winter (top) and summer (bottom). As seen from Fig. 4.17, wind and solar generation complement one another both in the winter and summer seasons. In winter, demand has a tri-modal shape with peaks in the early morning, daytime and evening periods. The early morning periods peak is due to electric vehicle charging load, while the daytime and evening peaks coincide with heating load coming online. The wind generation which is higher in the evening and early morning periods is well suited to meet this load shape and is responsible for meeting a large fraction of the winter load.

As a result of the winter load shape, the storage discharges coinciding with the load peaks as well as during periods of transition as solar generation ramps up and wind generation ramps down and vice-versa. During the daytime, Montana has excess generation from the solar generation which is used to charge storage (see Fig. 4.19) and export energy to neighboring states.

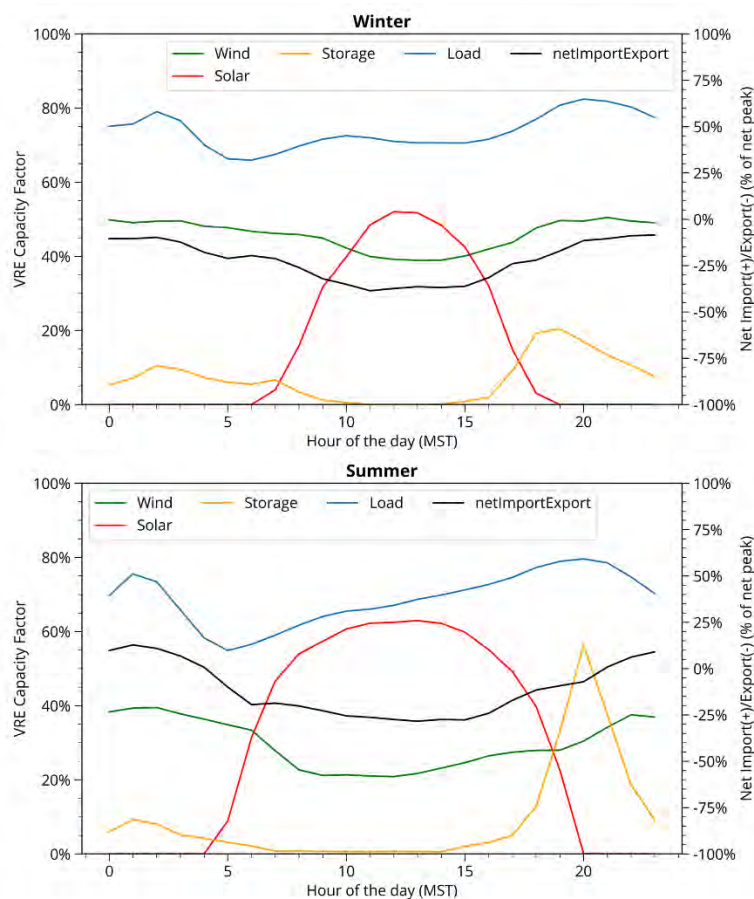


Figure 4.17: Diurnal VRE operation pattern observed in Montana in winter (top) and summer (bottom) in year 2050 in the "RPS100Elec" scenario.



In summer, load shows a bimodal shape with a peak in early morning coinciding with electric vehicle charging load and another in the evenings coinciding with increase in air-conditioning and energy use as people return home from work. The early morning peak in load is met by a combination of wind generation, storage discharging and imports of energy. As load decreases during that daytime, combined with increase in generation due to solar coming online, Montana exports energy to its neighbors. During the evening hours as load increases again and solar generation ramps down, the load is met by storage ramping up sharply to meet load as wind generation ramps up slowly. Exports are reduced and completely eliminated as solar ramps down in the evenings.

The correlation of exports with solar generation is stronger in the "RPS100Export" scenario as shown in Fig. 4.18. In winter and in summer, exports increase coinciding with increased solar generation during the daytime and reduce in the nighttime periods to ensure wind generation along with storage can meet load. As seen in Fig. 4.18, the load shapes in winter and summer in the "RPS100Export" scenario are similar to that of "RPS100Elec" except for the lack of the early morning peak in load from electric vehicle charging.

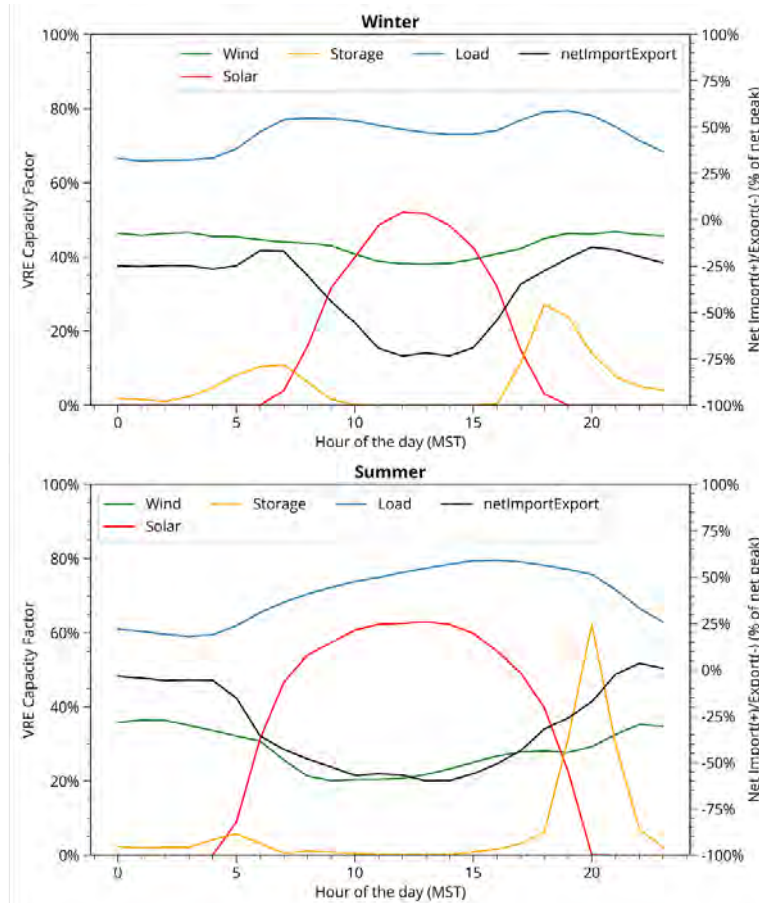


Figure 4.18: Diurnal VRE operation pattern observed in Montana in winter (top) and summer (bottom) in year 2050 in the "RPS100Export" scenario.

The charge and discharge behavior of storage on the utility and distribution grid for the "RPS100Elec" scenario is shown in Fig. 4.19. The storage shows exactly the same behavior on the utility and distribution grid. In winter, storage charges during the daytime when



there is excess solar generation and in the early morning and evening periods, storage discharges to work with wind to meet load as solar generation ramps down.

In summer, when solar is generating energy over a longer period as a result of the longer days, storage charges at lower capacity factors, while the rest of the solar generation is exported. Storage discharges a little during the early morning period to help wind generation with the electric vehicle charging load, and discharges at higher capacity factors during the evenings as solar generation ramps down and wind generation is not high enough to meet load.

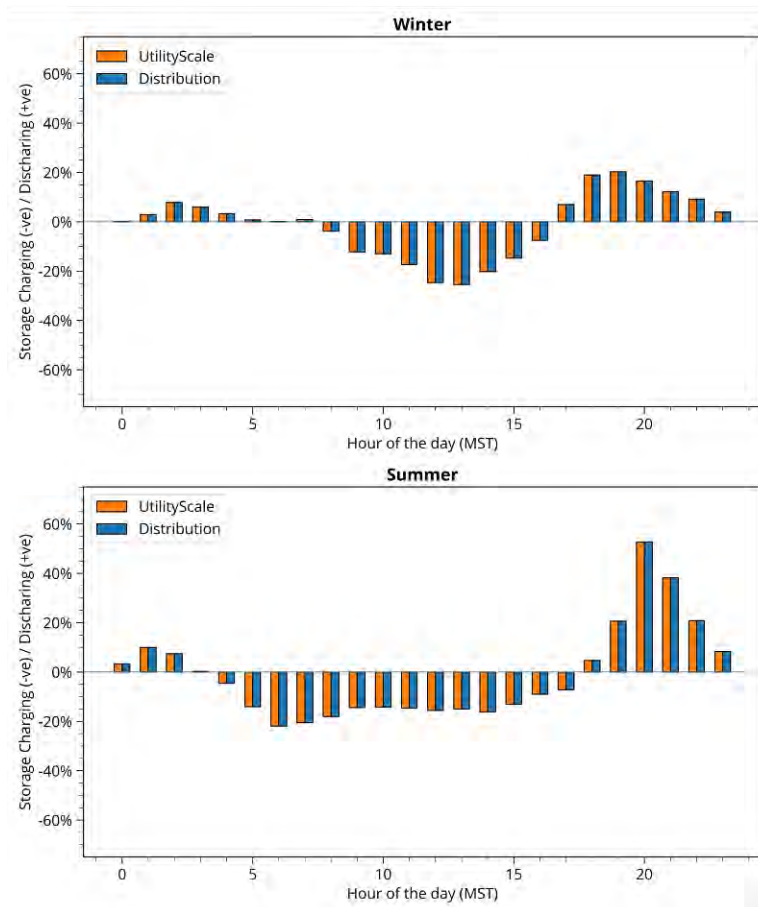


Figure 4.19: Behavior of utility scale and distribution scale storage in Montana in winter (top) and summer (bottom) in the year 2050 in the "RPS100Elec" scenario.



4.4 Emissions and Pollutants

The economy-wide annual carbon-dioxide (CO₂) emission differences in Montana between the various scenarios with respect to the “BAU” scenario is shown in Fig. 4.20. The “keepCoal” scenario results in additional CO₂ emissions after 2025 as the “BAU” scenario starts to retire its coal generation in Montana while the “keepCoal” scenario does not. Annual emissions from “keepCoal” scenario are more than twice that of the “BAU” scenario by 2035 and stay there until 2040. After 2040, as the “keepCoal” scenario retires its coal generation, annual emissions fall sharply and are less than those from the “BAU” scenario by 2045.

The “RPS100” scenario initially result in slightly higher annual CO₂ emissions compared with the “BAU” scenario until 2030 as this scenario imports energy from the rest of the WECC region which has higher CO₂ emissions per kWh generated compared with Montana. However, as this scenario retires all fossil generation, its annual CO₂ emissions are lower than the “BAU” scenario after 2030. The “RPS100Export” scenario similarly shows higher annual CO₂ emissions compared with the “BAU” scenario until 2030. However, in the case of the “RPS100Export” scenario, the higher emissions are a result of the slower retirement of coal generation compared with the “BAU” scenario. However, once the fossil fuel generation is completely retired, the “RPS100Export” scenario results in lower CO₂ emissions compared with the “BAU” and “RPS100” scenarios as this scenario does not import any energy from the rest of the WECC region and hence has zero CO₂ emissions in the electricity sector.

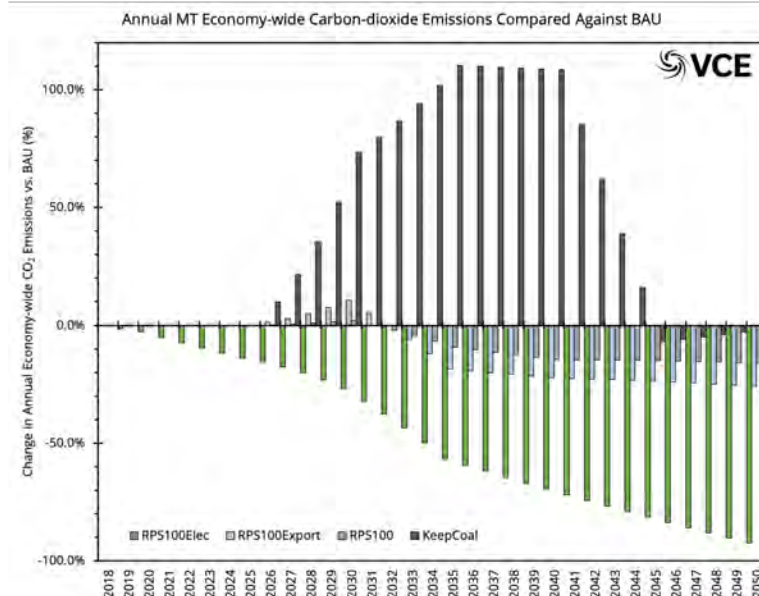


Figure 4.20: Percentage change in economy-wide annual CO₂ emissions in Montana compared with the “BAU” scenario.

The “RPS100Elec” scenario which electrifies energy related activities in the rest of the economy results in an immediate reduction in CO₂ emissions compared with the “BAU” scenario. By 2050, the “RPS100Elec” scenario has annual economy-wide CO₂ emissions that are 92.5% lower than the “BAU” scenario. A significant portion of the emission reductions



in the “RPS100Elec” scenario come from electrification of energy related activities in the rest of the economy. The cumulative emissions from the electricity sector in the “RPS100Elec” scenario are almost equal to the cumulative electricity sector emissions in the “RPS100Export” scenario.

The cumulative economy-wide CO₂ emissions in the various scenarios is shown in Fig. 4.21. The dark grey shaded region in Fig. 4.21 shows the additional emissions from the “keepCoal” scenario compared with the reference case of the electricity sector and the rest of the economy emitting emissions at 2018 levels. Cumulative emissions from the “keepCoal” scenario grow at a faster rate compared with the reference case and only slow down after the coal generation is retired after 2040. By 2050, the “keepCoal” scenario results in 36 million metric tons (mmT) of higher CO₂ emissions compared with the reference case. The “BAU” scenario on the other hand results in 124 mmT of lower cumulative CO₂ emissions compared with the reference case as a result of early retirement of the coal generation and replacing it with NGCC generation. By 2050, the “keepCoal” scenario results in a cumulative 160 mmT of higher CO₂ emissions compared with the “BAU” scenario at a cumulative higher cost of \$9.5 billion resulting in higher retail rates of customers for the period that the coal generation remains on the Montana grid.

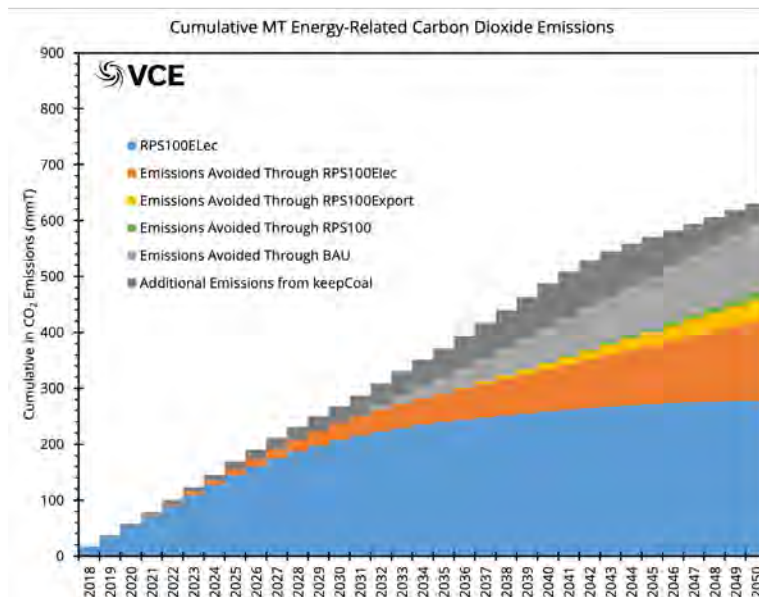


Figure 4.21: Cumulative carbon dioxide emission in the electric sector.

By 2050, the “RPS100” scenario results in 25 mmT cumulative lower CO₂ emissions compared with the “BAU” scenario while reducing total system costs by \$1 billion cumulatively by 2050 (a negative carbon price of -\$40/tonCO₂). However, these reduced system costs do not translate to lower electricity bills as the state of Montana becomes a net importer of energy resulting in increased retail rates. In the “RPS100Export” scenario on the other hand, the cumulative emission reductions are higher (38 mmT of CO₂ lower by 2050 compared with the “BAU” scenario) with a cumulative additional total system cost of \$0.7 billion by 2050 compared with the “BAU” scenario. However, this scenario ensures that Montana is self-sufficient in terms of the energy needs and exports excess energy to its neighbors. As a result, while the total system costs are higher, the retail rates paid by customers are lower assuming conservatively that only 50% of the revenues from electricity



sales are passed on to customers in Montana. The additional system cost of the "RPS100Export" scenario is equivalent to a shadow carbon price of \$18.42/tonCO₂.

In the "RPS100Elec" scenario, Montana reduces its cumulative CO₂ emission by 180 mmT by 2050 over the "BAU" scenario with an additional cumulative total system cost of \$2.73 billion by 2050. However, this additional cost in the electricity sector drives significant cost reductions in other sectors of the economy due to electrification (see Section 2 for more details). As a result of the economy-wide electrification, the "RPS100Elec" scenario cumulatively reduces spending economy-wide by \$32.7 billion by 2050 compared with the "keepCoal" scenario. In addition, the "RPS100Elec" scenario results in the lowest retail rates of all scenarios modeled due to the more effective use of generation installed in Montana as a result of electrification and revenues from selling excess energy to its neighbors. Similar to the "RPS100Export" scenario, only 50% of the revenues from electricity sales are passed on to customers.

Apart from CO₂, WIS:dom-P tracks all criteria air pollutants from the electricity sector. The emissions of criteria air pollutants in Montana from the electricity sector for the scenarios modeled is shown in Fig. 4.22. In all scenarios, except the "keepCoal" scenario the emissions of all criteria air pollutants in the electricity sector are reduced significantly by 2035. In the "RPS100", "RPS100Export" and "RPS100Elec" scenarios, the criteria pollutants are completely eliminated from the electricity sector by 2035 as all fossil fuel generation is retired in the state of Montana. The "keepCoal" scenario shows an increase in all criteria air pollutants until 2040 as the coal generation increases to meet the growing load. After 2040, the criteria pollutant emissions sharply reduce as the coal generation is retired and replaced with NGCC generation. However, the "keepCoal" scenario still retains significant methane emissions due to upstream losses from natural gas transport for NGCC generation.

The "RPS100Export" and "RPS100Elec" scenarios modeled in this study show that it is possible to eliminate greenhouse gas emissions in Montana while reducing retail rates for customers. In addition to eliminating greenhouse gas emissions, these scenarios also reduce emissions of harmful air pollutants resulting in better health outcomes for the population in Montana. The additional investments spurred by transitioning the grid to clean renewable energy help create jobs and boost economic activity in Montana.



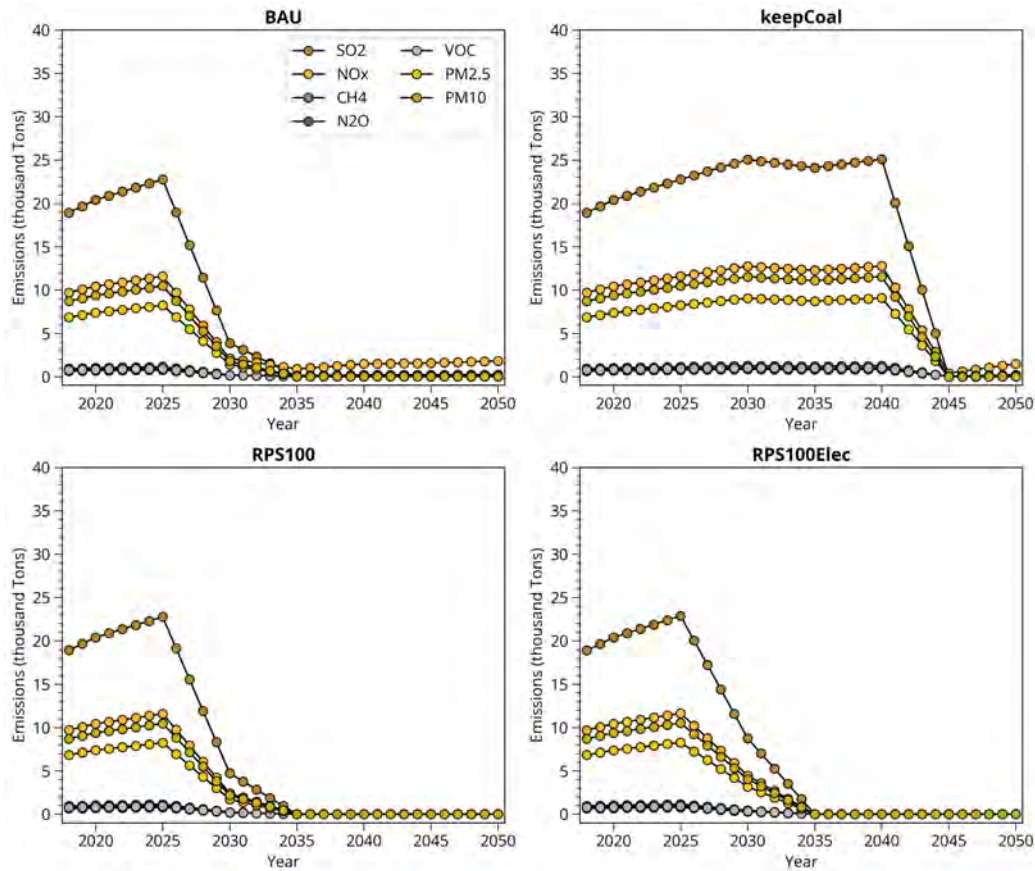


Figure 4.22: Emissions from other criteria pollutants tracked by WIS:dom-P.



4.5 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. The incremental inter-state transmission added over the investment periods over the modeled domain in the “RPS100Elec” scenario is shown in Fig. 4.23. The only new inter-state transmission added after 2020 is between Montana and Wyoming with about 530 MW of transmission capacity added between the two states.

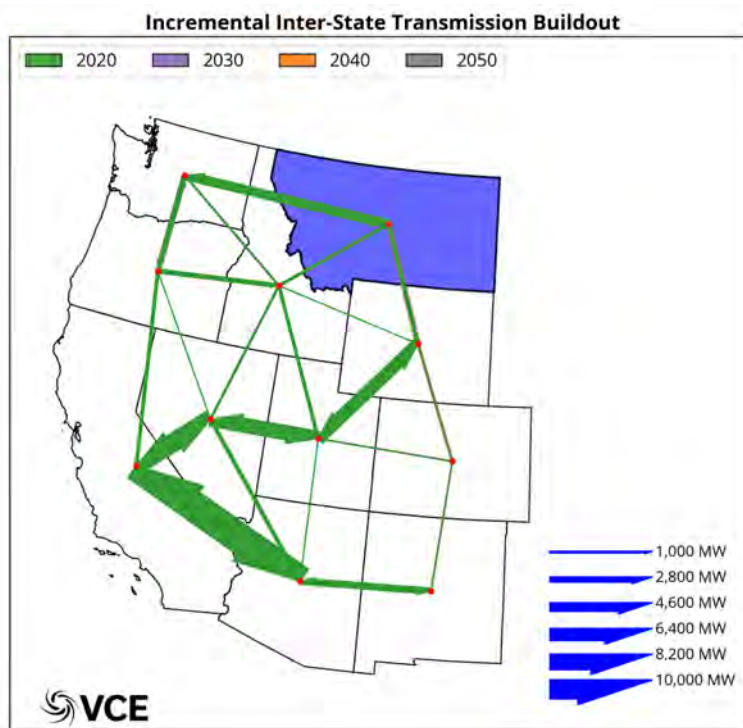


Figure 4.23: Incremental inter-state transmission added over the investment periods.

The transmission utilization rate for connections between Montana and its neighbors is shown in Fig. 4.24. The utilization rate shown in Fig. 4.24, does not account for dynamic line rating. The transmission utilization rate in all scenarios is reduced for transmission to Washington and Idaho. The reduction in transmission utilization to Washington is reduced once the coal generation is retired as that is the major source of exports to this state. In the “keepCoal” scenario where the coal generation stays on the Montana grid until 2040, the utilization of the transmission to Washington stays high until 2040 and then drops to similar values as the other scenarios which retire coal early.



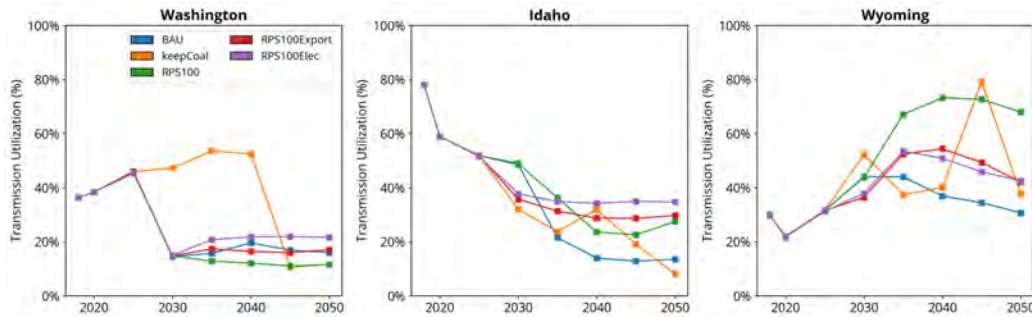


Figure 4.24: Transmission utilization rate for states connected with Montana for the scenarios modeled.

The transmission utilization rate for transmission to Wyoming increases for all scenarios modeled. The smallest increase in utilization rate is in the “BAU” scenario and the largest increase is in the “RPS100” scenario, except for a brief jump in 2045 in the “keepCoal” scenario. The “keepCoal” scenario significantly increases transmission utilization with Wyoming to import wind generation to replace the retired coal generation in the previous investment period. In the “RPS100” scenario, the connection with Wyoming increases steadily over the investment periods as Montana imports wind generation from Wyoming to help meet load as it retires all its thermal generation. The low utilization rates of the transmission lines to Washington and Idaho give Montana an additional reserve margin to call upon (and provide to Washington and Idaho) if generation within the state is unable to meet demand during extreme events.

The in-state transmission built in Montana in the various scenarios modeled is shown in Fig. 4.25. In all scenarios except the “RPS100Export” and “RPS100Elec”, in-state transmission capacity is reduced by 2050. The reduction in transmission capacity is due to retirement of lines no longer in use after retiring the fossil fuel generation connected by those lines. In the “RPS100Export” and “RPS100Elec” scenarios, new transmission is added as significant new VRE generation is built within the state.

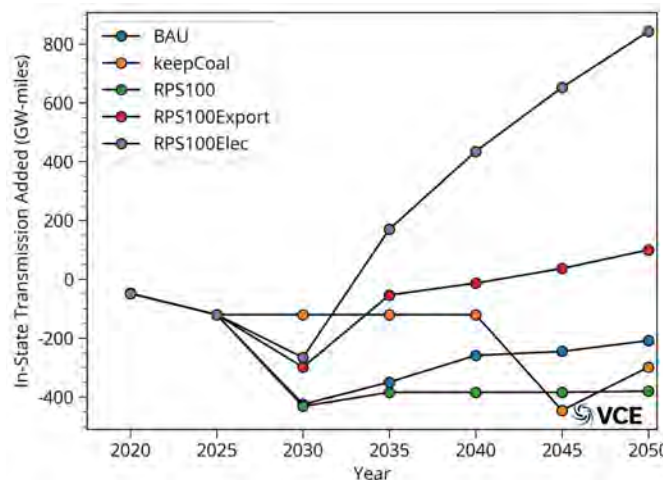


Figure 4.25: In-state transmission built in Montana over the investment periods for the scenarios modeled.



4.6 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 outage 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).¹⁵

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 Montana for the "RPS100Elec" scenario over the investment periods is shown in Fig. 4.26. The ELCC of solar in Montana is found to be really low with an average ELCC over the investment periods below 0.5%. The low ELCC of solar is due to the load shapes in both winter and summer resulting in load peaking before solar generation ramps up or after solar generation ramps down. Therefore, as discussed in Section 4.3.1, solar generation is mainly used for charging storage and exports in the "RPS100Elec" scenario.

The ELCC of wind generation starts at 3% in 2020 and initially reduces until 2030 as most of the load growth occurs in the summer periods. After 2030, as load growth due to electrification increases the ELCC of wind increases steadily as the load becomes more correlated with the wind generation resulting in 5.5% by 2050. In the "RPS100Elec" scenario,

¹⁵ [https://vibrantcleanenergy.com/wp-content/uploads/2020/08/WISdomP-Model_Description\(August2020\).pdf](https://vibrantcleanenergy.com/wp-content/uploads/2020/08/WISdomP-Model_Description(August2020).pdf)



storage has an ELCC of 2% in 2020 and reduces further reaching 0.5% in 2050. The ELCC of storage is found to reduce over the investment periods as the load shape transforms to be more correlated with the wind generation and storage comes into play during the transition periods working along-side wind and solar generation.

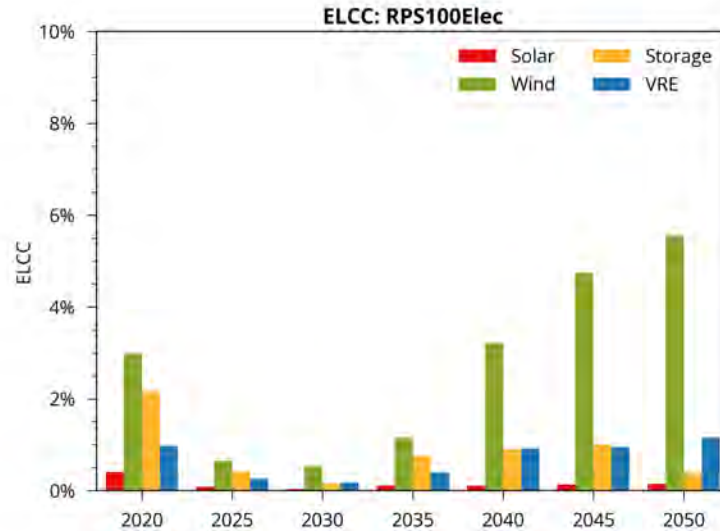


Figure 4.26: ELCC of wind, solar, storage and combined VRE system.

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 4.27 shows the capacity value of the VRE generators calculated during periods of highest net demand. The solar capacity value gradually increases over the investment periods from zero in 2020 reaching 2.5% in 2050. The reason the capacity values of solar increases in this metric is due to the fact that this metric uses the altered load which includes storage charging load. As seen in Section 4.3.1, solar generation is used to charge storage and export energy, resulting in higher capacity values based on this metric.

The wind generation capacity value is seen to increase steadily from 1% in 2020 to 5% in 2050 as the load shape changes as a result of electrification and becomes more correlated with wind generation. As a result, wind plays an increasingly important role in meeting peak loads as Montana undergoes electrification. The storage capacity value is also seen to increase from zero in 2020 to approximately 2.3% in 2050 as storage discharges during periods of transition from solar to wind generation on the grid which also are usually periods of highest system strain. As a result, storage has higher capacity value based on this metric.



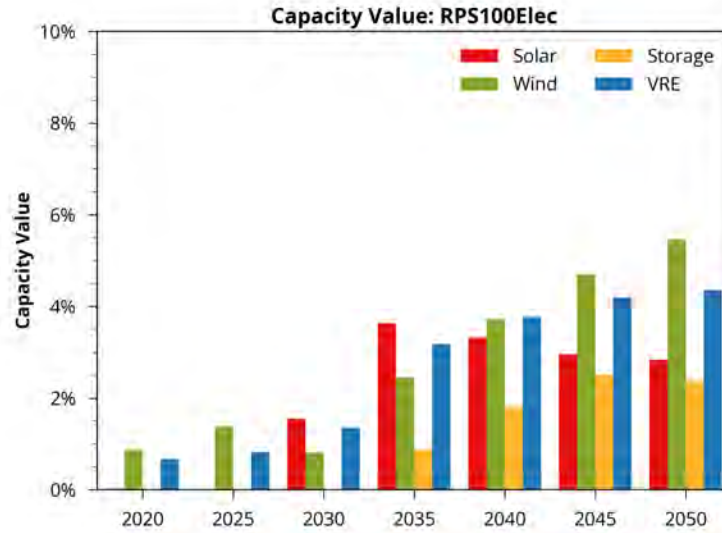


Figure 4.27: Capacity value of VREs calculated based on contribution during periods of peak demand.

Since VRE generation has seasonal characteristics (see Section 4.4), their capacity value is also expected to show seasonal trends. Figure 4.28 shows the monthly averaged daily capacity value for the VRE generator calculated during the period of peak load on each day. Solar capacity values are seen to be higher in summer as solar generation is higher during this time of the year and the load is better correlated with the solar generation. The wind generation has the highest monthly averaged capacity value during the winter periods as the load is better correlated with wind generation during this time of the year. Even in summer, wind generation has a higher capacity value compared with solar as the peak load occurs as solar generation is ramping down and wind generation is ramping up. Storage capacity value also peaks in the summer periods as it works with wind and solar generation to meet the peak load that occurs during the evening periods as shown in Fig. 4.17.

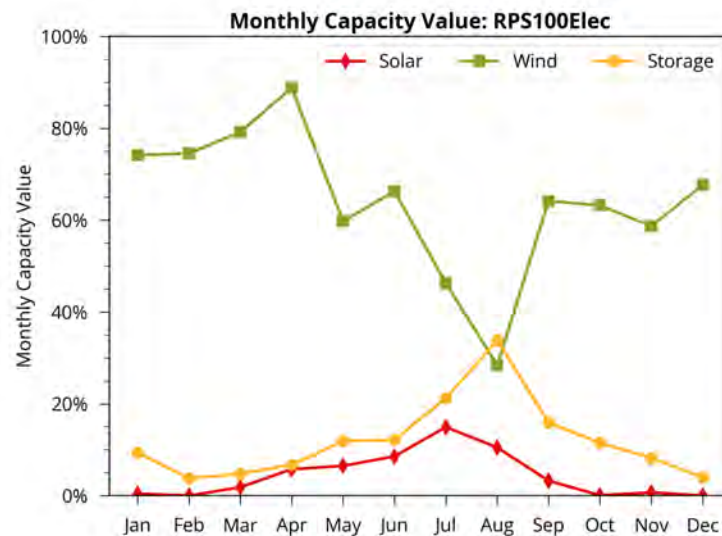


Figure 4.28: Monthly average capacity values in 2050 in Montana for the "RPS100Elec" scenario.



4.7 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. 4.29 (left panel), while the WIS:dom-P installed capacity by 2050 for the "RPS100Elec" is shown in Fig. 4.29 (right panel). As seen from Fig. 4.29, the grid is largely composed of fossil fuel generation in 2018, which is transforms to VRE dominated by 2050. The WECC region installs a significant amount of solar (especially DPV) although only Montana decarbonizes its electricity grid while the rest of the region undergoes business-as-usual capacity expansion.

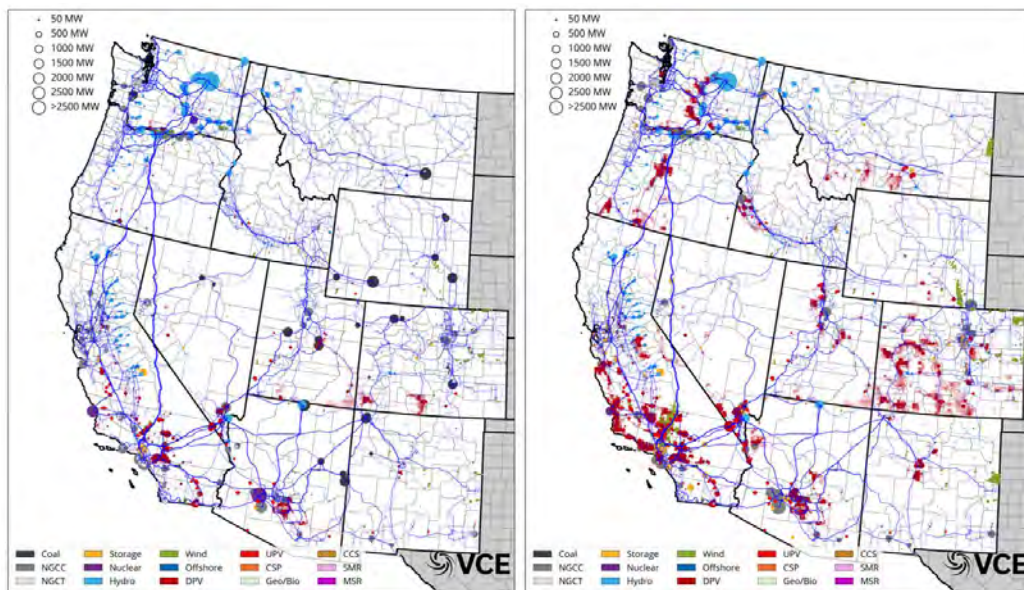


Figure 4.29: Installed generation layout in 2018 (left) and 2040 (right) at 3-km resolution along with transmission paths above 115 kV.

Figure 4.30 shows the 3-km siting of generators in Montana in year 2050 in the "RPS100Elec" scenario. Most of the wind generation installed in Montana is deployed in the eastern-most part of the state around the I-94 corridor which has the best wind resource in the state. Solar generation on the other hand is installed near the population centers (both utility scale and distributed solar). The largest solar installations are seen near Billings and Bozeman. Storage is installed near the population centers around the state in order to store the excess generation from wind and solar and supply it locally when needed.



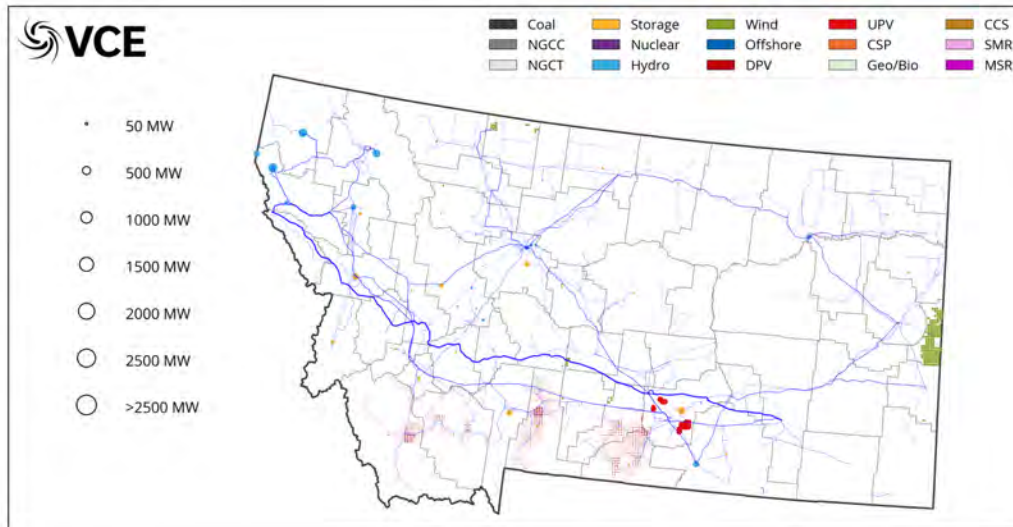


Figure 4.30: Optimal siting of generators in Montana in 2050 in the "RPS100Elec" scenario.

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 5.2. 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 5.2.



5 VCE Datasets & WIS:dom-P Inputs

5.1 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 Montana as well as the wider WECC footprint was obtained. The western US has a very large geographic extent. Montana and WECC contain approximately 6.7 and 234.8 GW of generation capacity respectively. WIS:dom has the ability to solve over such scales at 5-minute resolution for several years chronologically.

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 5.1: The VCE generator technology bins.



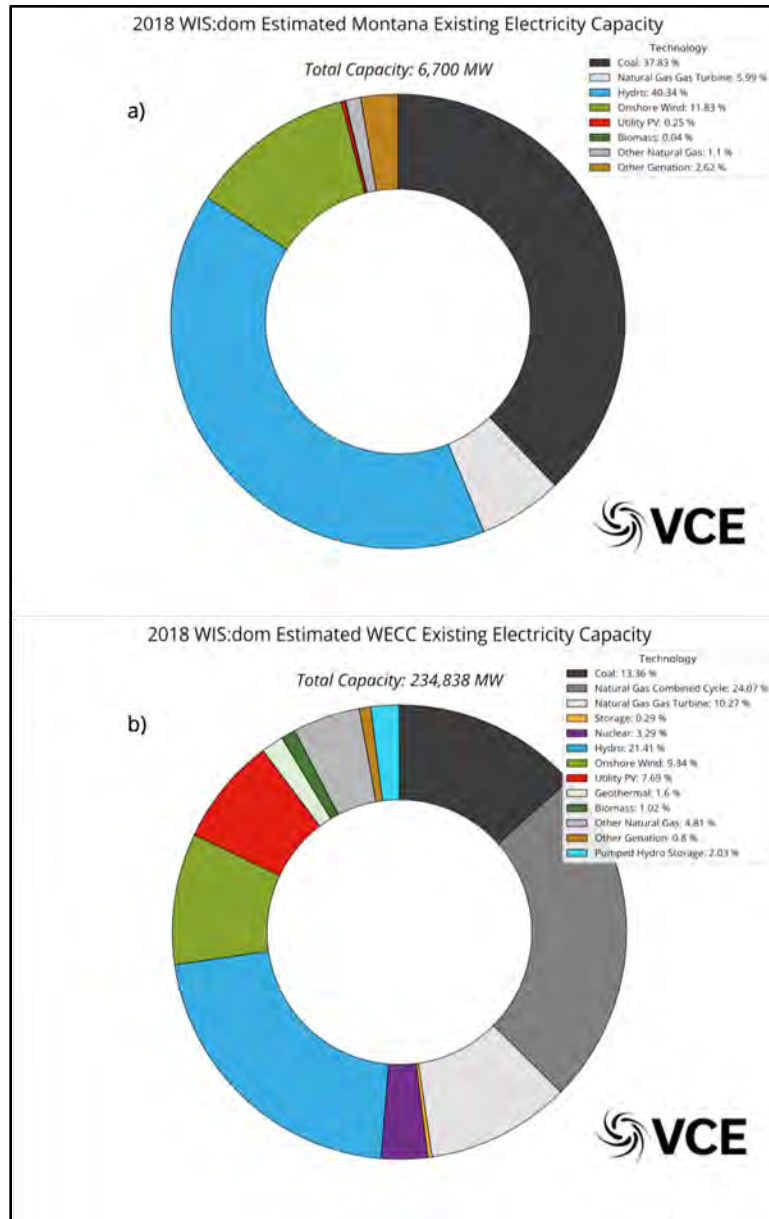


Figure 5.2: WIS:dom estimated installed capacity for a) Montana and b) WECC. The total capacity modeled for each region is 6.7 and 234.8 GW respectively.

Figure 5.1 displays the generation technology types that are standard within the WIS:dom-P modeling. Figure 5.2a and Fig. 5.2b show the installed capacities over Montana and the entire WECC footprint respectively. The WECC footprint includes Montana. Hydro and coal are the dominant technologies across Montana. Wind capacity follows behind at a distance third when compared with hydro and coal. A very small amount of large-scale solar exists in Montana. WECC is widely comprised of natural gas with coal being a smaller portion of the installed thermal capacity. A small amount of nuclear is also existent in the WECC mix. Variable Renewable Energy (VRE) capacities are generally higher in the western US, with highest shares from hydroelectric, wind and solar. For comparison, the same chart is shown in Fig. 5.3 for all the installed capacity across the contiguous US. Note that across the contiguous US, the share of thermal generation is higher than that in WECC, mostly due to



coal, natural gas and nuclear. There is also more coal in exchange for natural gas in Fig. 5.3 compared with Fig. 5.2b. Further, VRE has more representation in WECC than the wider US. In particular, this is driven by the hydro assets across the mountain west ranges.

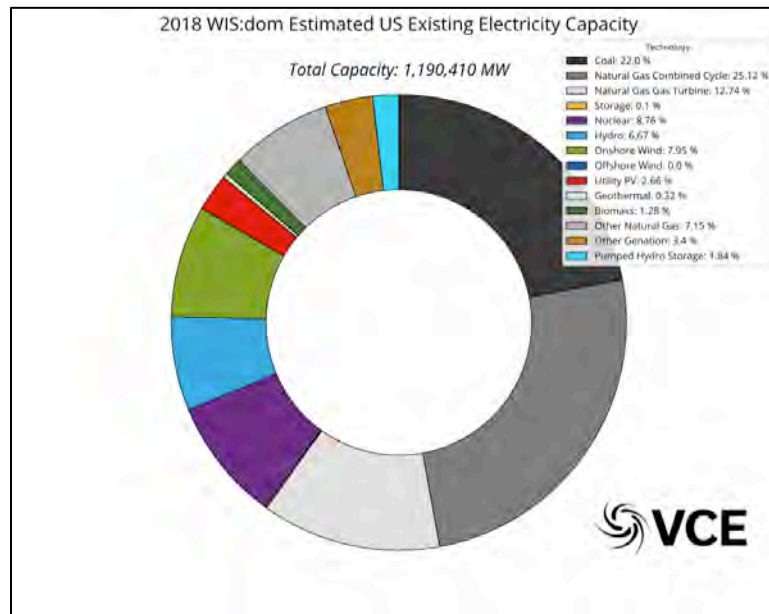


Figure 5.3: WIS:dom estimated capacity share for the contiguous United States. The total capacity modeled is 1,190 GW.



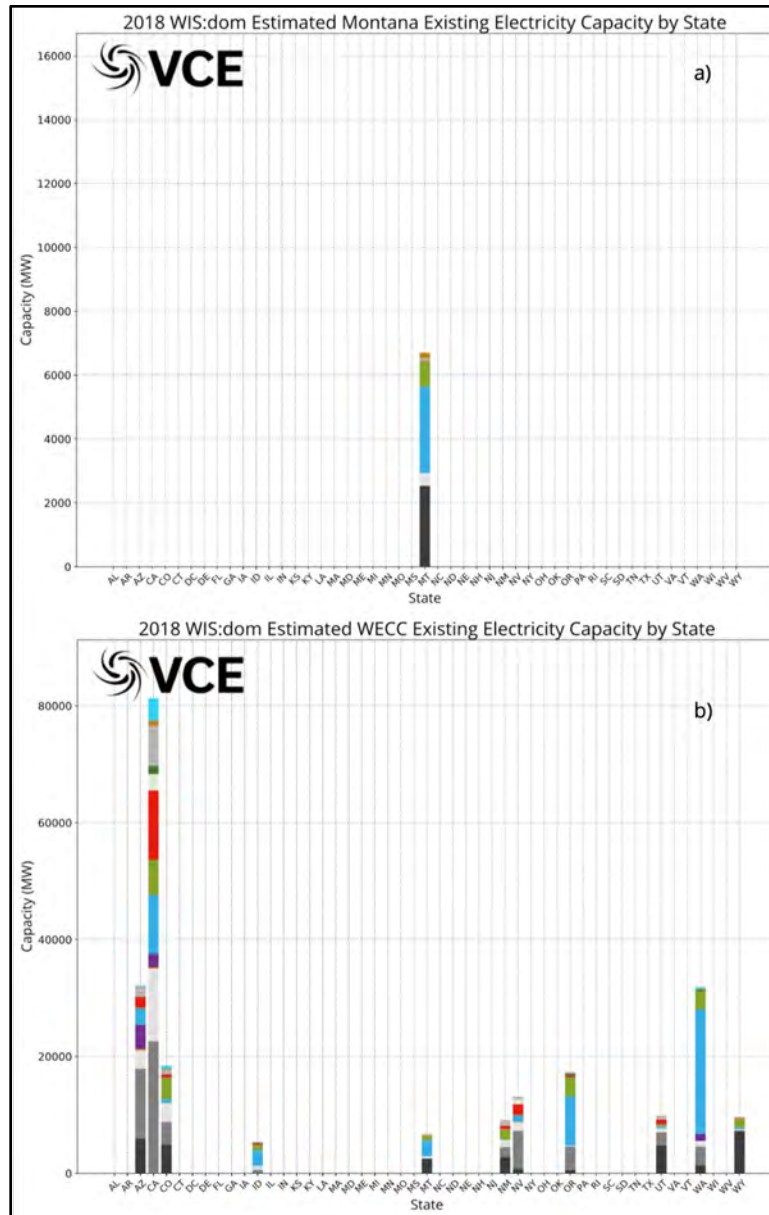


Figure 5.4: WIS:dom Capacity for the states considered in a) Montana and b) WECC for this study.

Figure 5.4 shows the technology capacity stacked totals for each state within a) Montana and b) WECC. In the west, the capacity installed in California dwarfs all other western states. Montana has the second lowest amount of capacity installed across WECC. Idaho has the least amount of generator capacity. There is little coal installed in California. Coal makes up most of the installed asset mix in Wyoming, but also shows up in decent amounts in Arizona, Colorado and Utah. Washington state is home to the largest amount of hydro. Nuclear plants exist in Arizona, California and Washington. Idaho has the cleanest mix of generators amongst all the western states.

Figure 5.5 shows the technology layout spatially across a) Montana and b) WECC. The largest coal plant in Montana is located near Billings. Wind plants are installed along the eastern edge of the front range. This captures the downslope wind phenomenon that can



occur on the leeside of any tall mountain range. Many hydroelectric units are also observed throughout the Rocky Mountain range in western Montana. Across the wider WECC region, the majority of hydro exists in the Rocky Mountain, the Sierra Nevada and the Cascades ranges. Solar installations are very prominent along the southwestern portion of California. Wind installations are prominent along the eastern side of the Rocky Mountains from Montana all the way down to New Mexico. Wind is also prominent in the Columbia River Gorge and Tehachapi. Large coal plants are most prominent in the intermountain west regions of the four corner states and Wyoming.

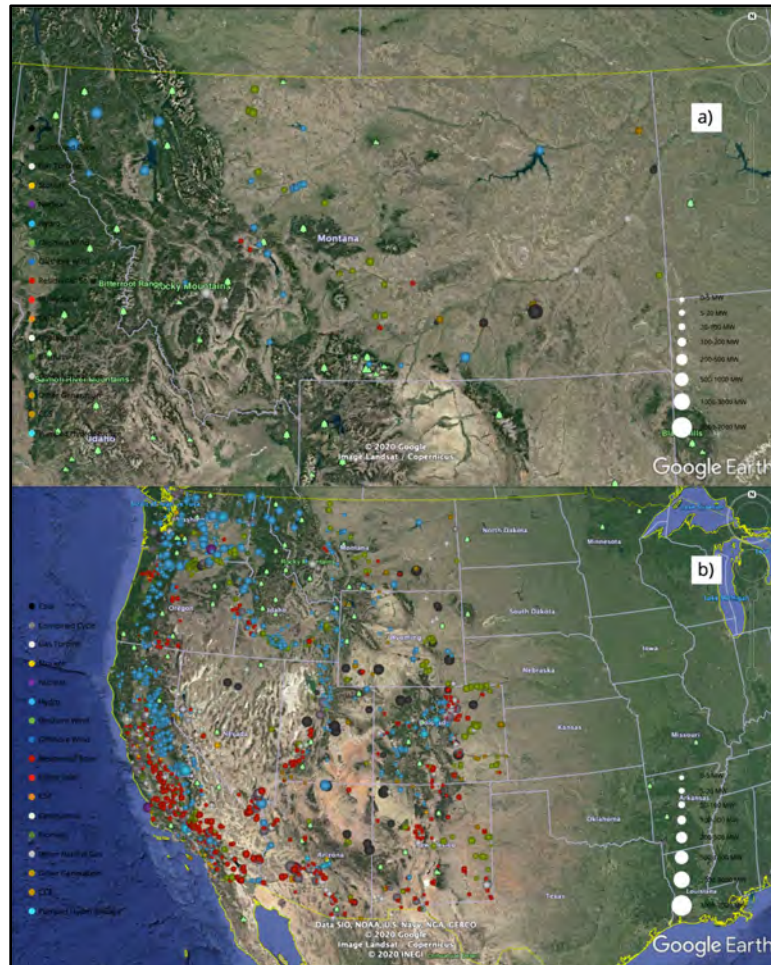


Figure 5.5: WIS:dom estimated location of various technologies for a) Montana and b) WECC.



5.2 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. 5.6 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 Montana in Fig 5.7a and the states within WECC in Fig. 5.7b.

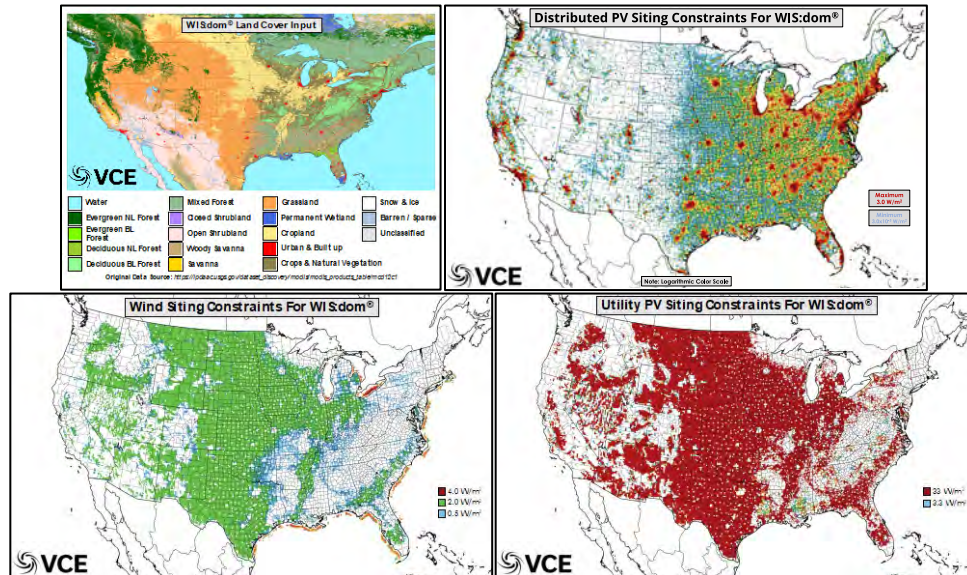


Figure 5.6: WIS:dom land cover (top left), distributed solar PV siting bounds (top right), utility-scale wind bounds (bottom left) and utility-scale solar PV (bottom right).

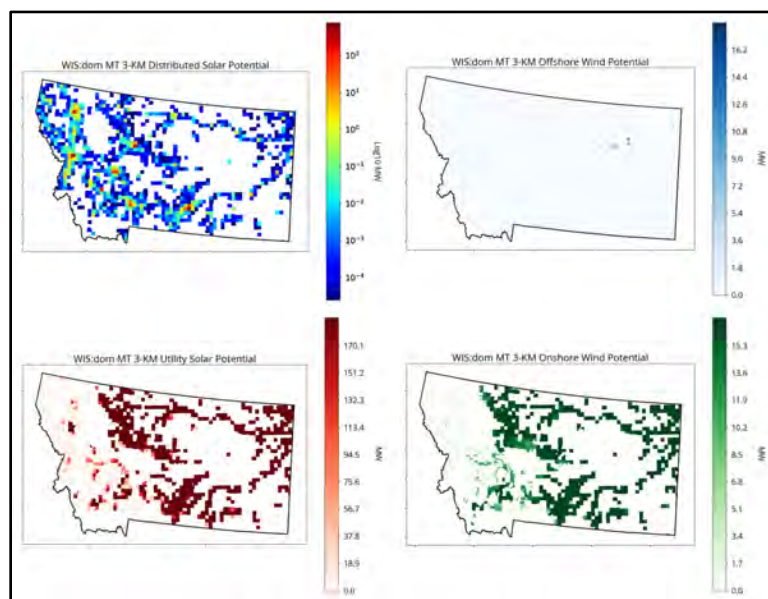


Figure 5.7a: WIS:dom Rooftop Potential (top left), Offshore Wind Potential (top right), Utility-scale Solar Potential (bottom left) and Onshore Wind Potential (bottom right) in MW. The Distributed Solar Potential is converted to a Logarithmic Base 10 scale due to the ranges of value for that parameter. This is a closer look at



Montana.

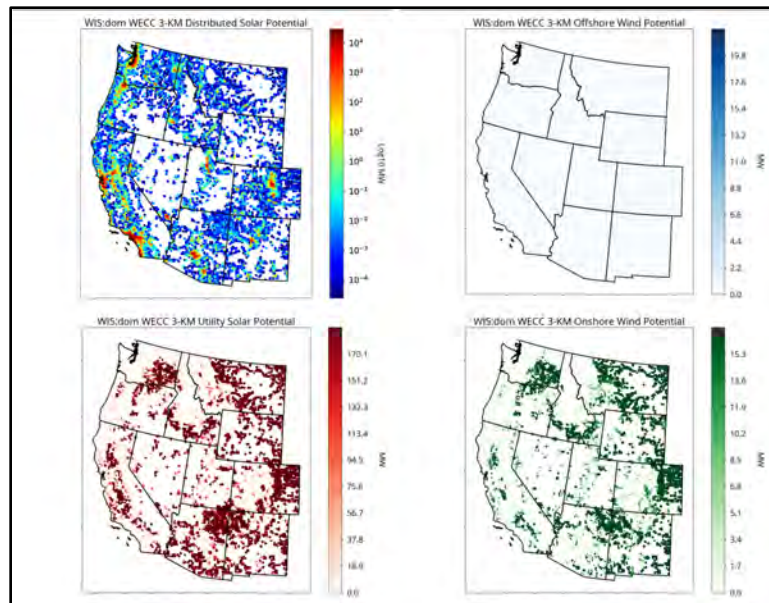


Figure 5.7b: WIS:dom Rooftop Potential (top left), Offshore Wind Potential (top right), Utility-scale Solar Potential (bottom left) and Onshore Wind Potential (bottom right) in MW. The Distributed Solar Potential is converted to a Logarithmic Base 10 scale due to the ranges of value for that parameter. This is a closer look at the WECC footprint.

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 5.6 also 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 km² (< 4 MW / km²). Solar PV was restricted to a maximum installed capacity of 33 MW per km². For storage, it is assumed for a 4-hour battery the density is 250 MW / km². For all thermal generation, the density assumed for new build is 500 MW / km². 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.

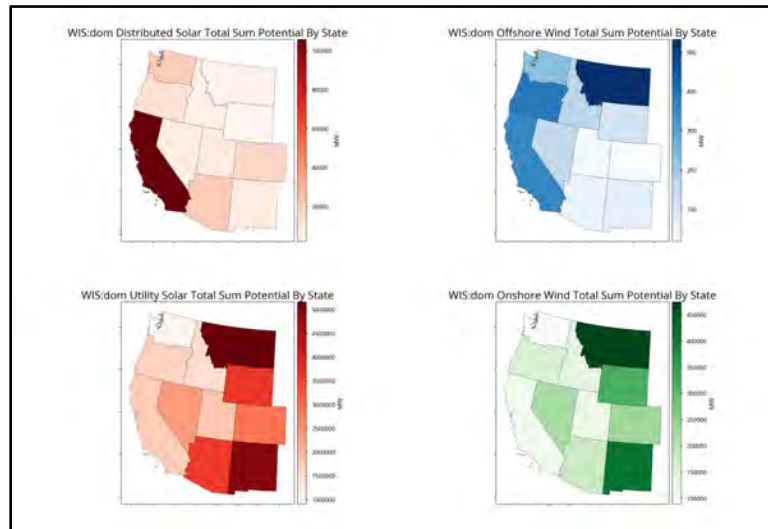


Figure 5.8: WIS:dom Total Sum Potential by state for Rooftop (top left), Offshore Wind (top right), Utility-scale Solar (bottom left) and Onshore Wind (bottom right) in MW.

The above (Fig. 5.8) shows the sum of the land use potential for each variable resource in Montana as well as the other states within WECC. It is shown that California has the highest potential for distributed solar. Colorado, Arizona and Washington show the next highest distributed solar potential. In general, the more populous states provide more buildings for rooftop solar. Offshore wind has the highest potential in Montana with bodies of water like Lake Fort Peck considered as potential. Offshore potential is low along the west coast where the ocean shelf floor is very deep. Utility solar potential is highest in Montana and New Mexico. This pattern is also similar with onshore wind. Plenty of space in both of those states helps drive this.



5.3 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 come from the EIA Annual Energy Outlook data, another source that is reputable and regularly updated. 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.



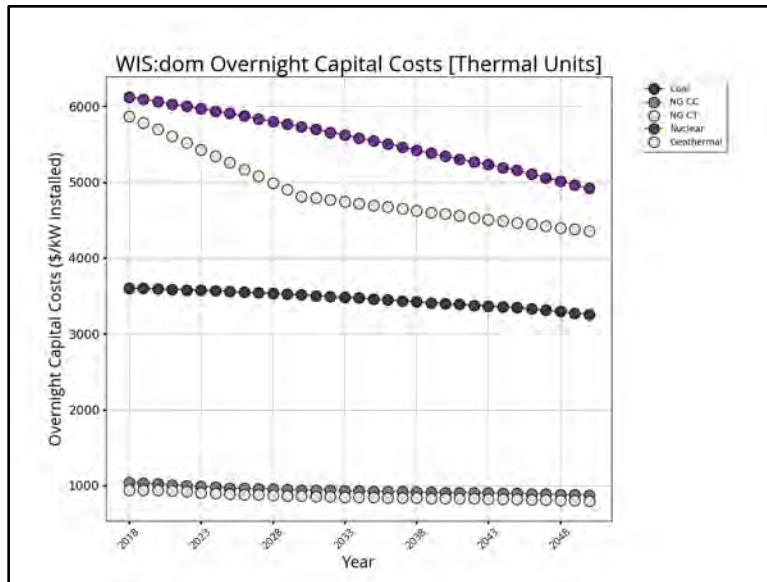


Figure 5.9: The overnight capital costs in real \$/kW-installed for thermal power plants in WIS:dom-P. All costs are from NREL Low ATB 2020.

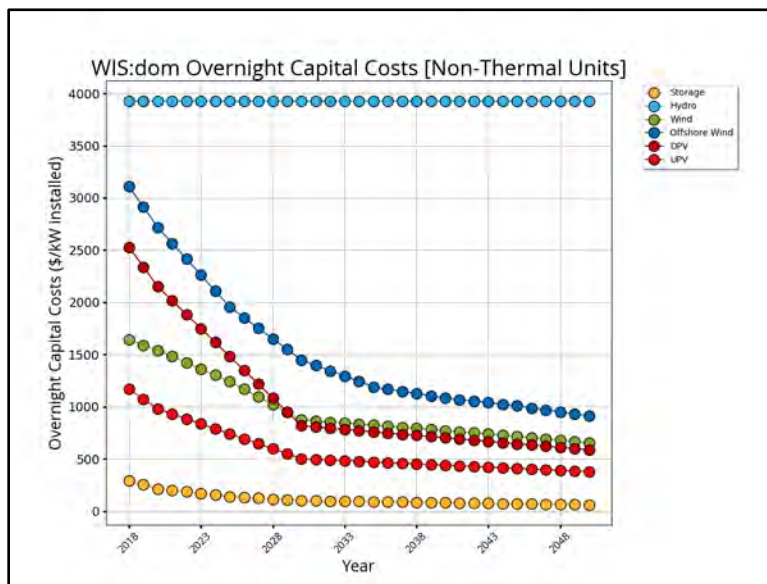


Figure 5.10: The overnight capital costs in real \$/kW-installed for non-thermal power plants in WIS:dom-P. All costs are from NREL Low ATB 2020.



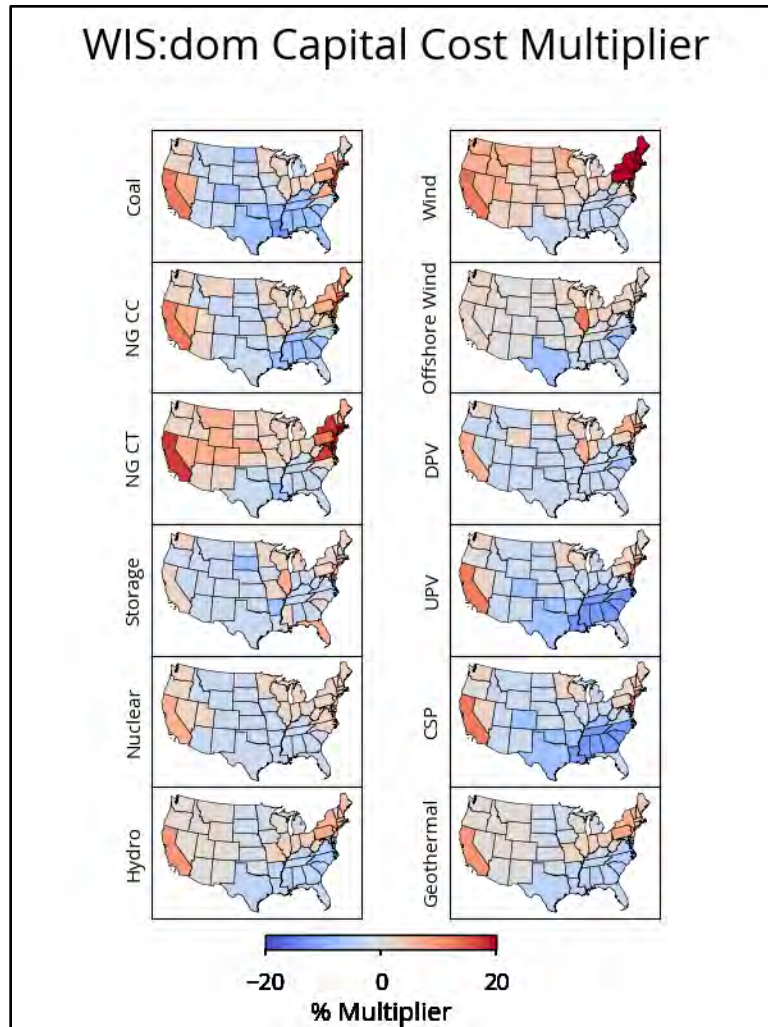


Figure 5.11: The WIS:dom-P Capital Cost Multiplier is shown by state for each technology across the US. Shades of red show where the capital cost is scaled higher by a given percentage. Cool shades show where technology capital costs in the model are scaled down by a given percentage.

Figure 5.11 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.



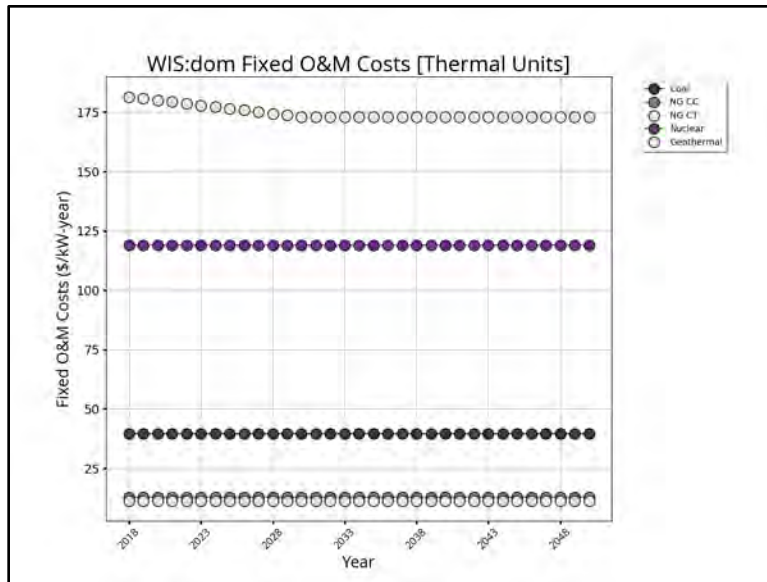


Figure 5.12: The fixed operations and maintenance (O&M) costs in real \$/kW-yr for thermal power plants in WIS:dom-P. All fixed costs are from NREL Low ATB 2020.

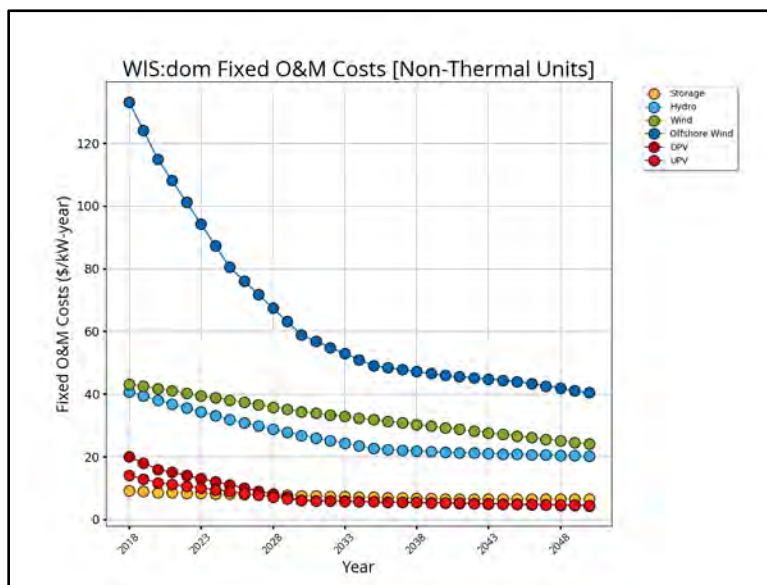


Figure 5.13: The fixed operations and maintenance (O&M) costs in real \$/kW-yr for non-thermal power plants in WIS:dom-P. All fixed costs are from NREL Low ATB 2020, with the exception of storage costs, which were provided by Able Grid, Inc.



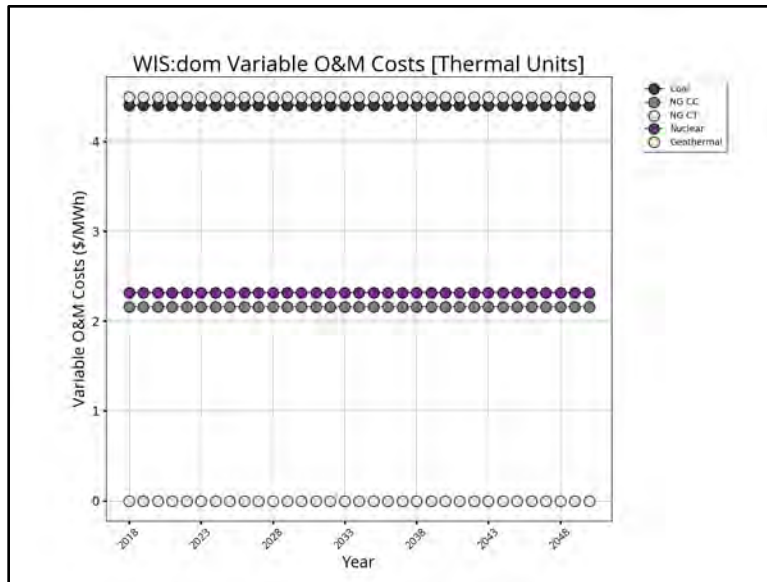


Figure 5.14: The non-fuel variable O&M costs for thermal generators in WIS:dom-P in real \$/MWh. All variable costs are from NREL Low ATB 2020. The non-thermal units have zero variable O&M costs for renewables as those costs are combined into the fixed O&M costs.

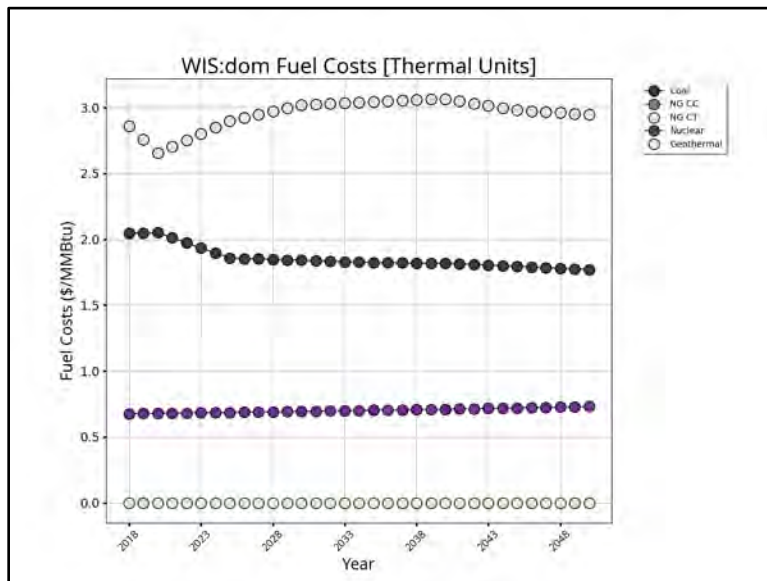


Figure 5.15: The fuel costs for thermal generators in WIS:dom-P in real \$/MMBtu. All costs are from the 2020 EIA Annual Energy Outlook (High Oil and Gas Supply Scenario).



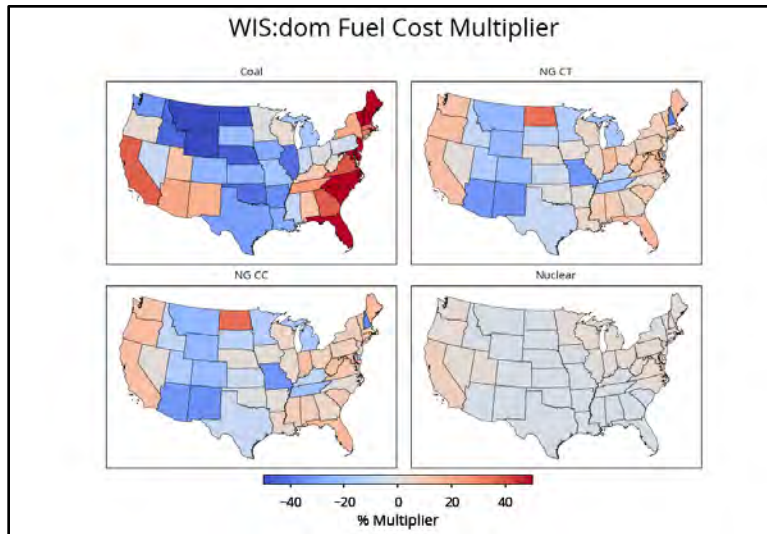


Figure 5.16: The WIS:dom-P Fuel Cost Multiplier is shown by state for each technology across the US. The color scale shows a percentage multiplier applied to standard fuel costs. Shades of red show where the fuel cost is scaled higher by a given percentage. Cool shades show where technology fuel costs 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. 5.16 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. 5.17 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.



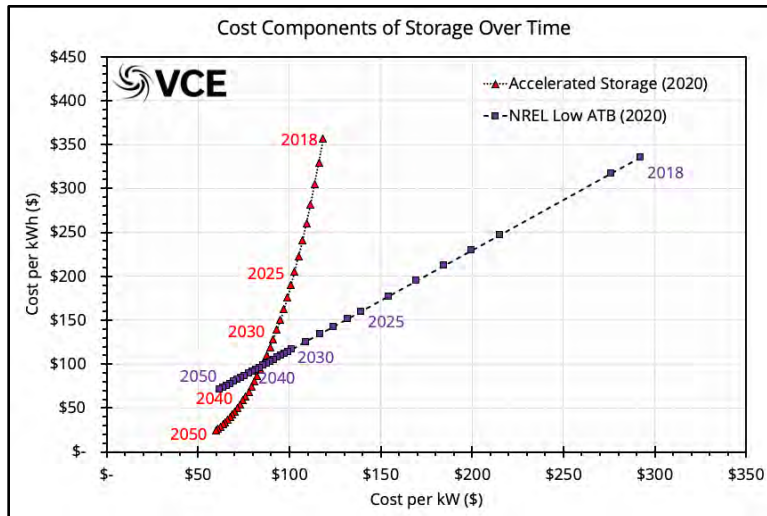


Figure 5.17: The Balance of System Capital Cost (\$/kW) versus the Battery Pack Capital Cost (\$/kWh). This is shown for the 2020 Low NREL ATB values in purple. The same information is shown in red for an “accelerated” storage cost. For this study, the former is used in the WIS:dom-P model.

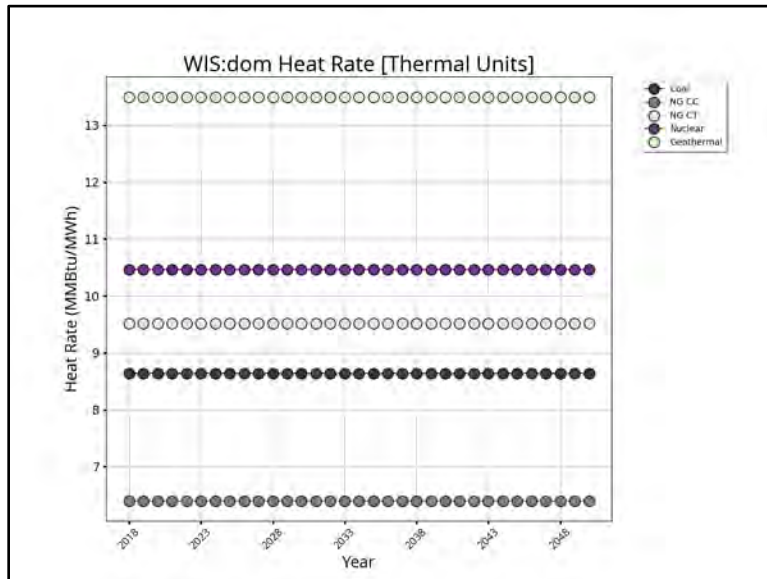


Figure 5.18: The generic heat rate for thermal generators in WIS:dom-P in MMBtu/MWh of electricity generated. Explicit heat rates for currently installed generators come into the model through the Input Generator Datasets and the EIA 860/923 data. This is from 2020 NREL ATB.

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 5.18b 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. Variable costs for SMR units are rolled into other costs shown for this technology. Figure 5.18c 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.



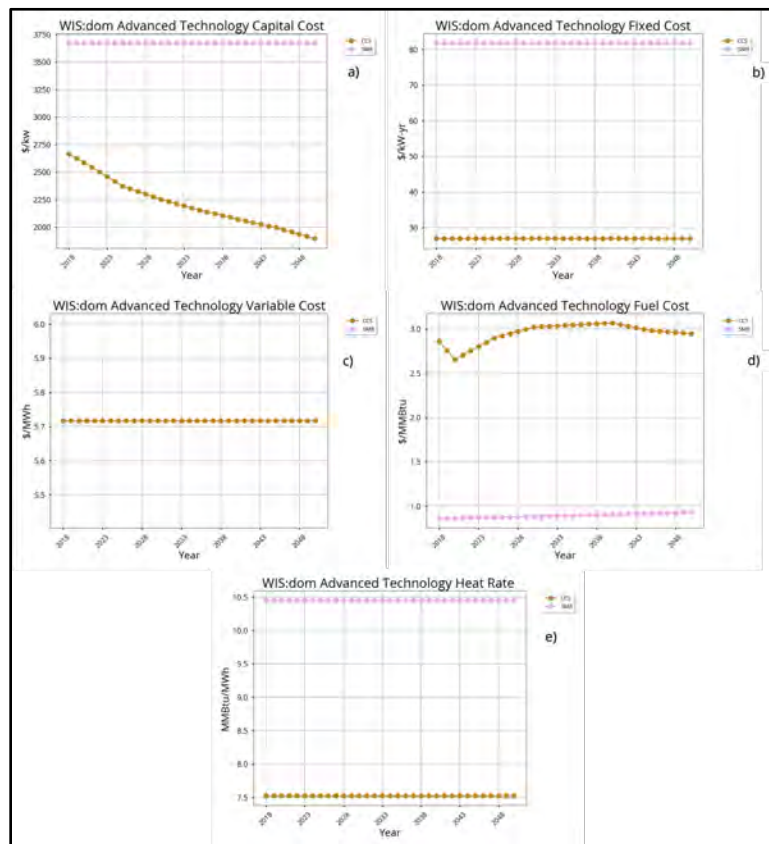


Figure 5.18b: The a) capital cost (\$/kW), b) fixed cost (\$/kW-yr), c) variable cost (\$/MWh), d) fuel cost (\$/MMBtu) and e) heat rate (MMBtu/MWh) for CCS and SMR technologies in WIS:dom-P.



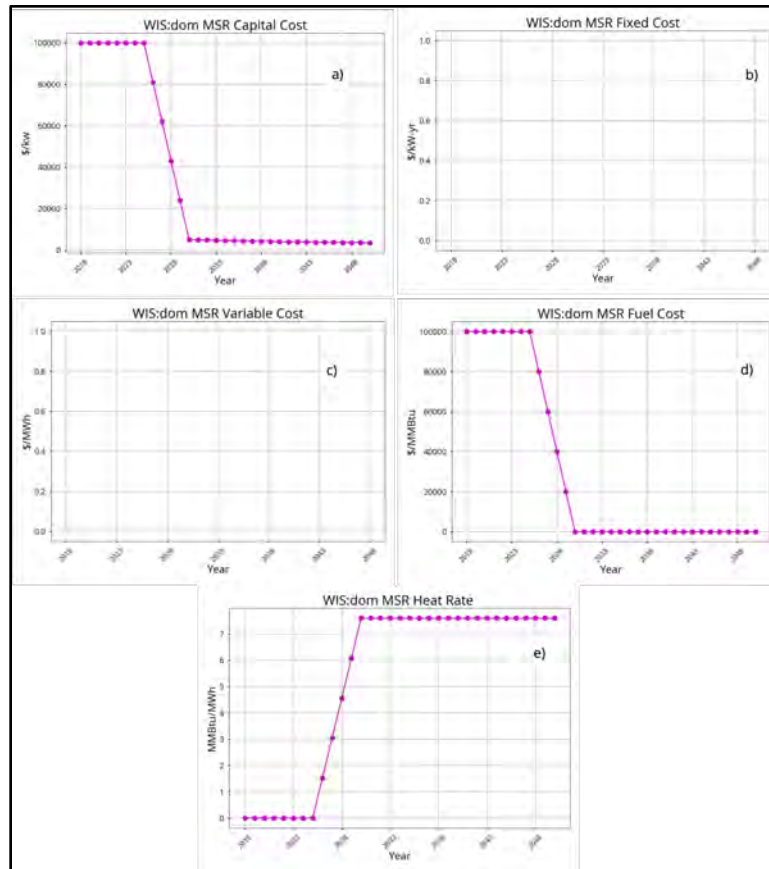


Figure 5.18c: The a) capital cost (\$/kw), b) fixed cost (\$/KW-yr), c) variable cost (\$/MWh), d) fuel cost (\$/MMBtu) and e) heat rate (MMBtu/MWh) for the MSR technology in WIS:dom-P. The high capital and fuel costs in early investment years is intentional. It forces the model not to choose this technology yet since it is 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 show the standard economic lifetimes for the various technologies used within WIS:dom-P.



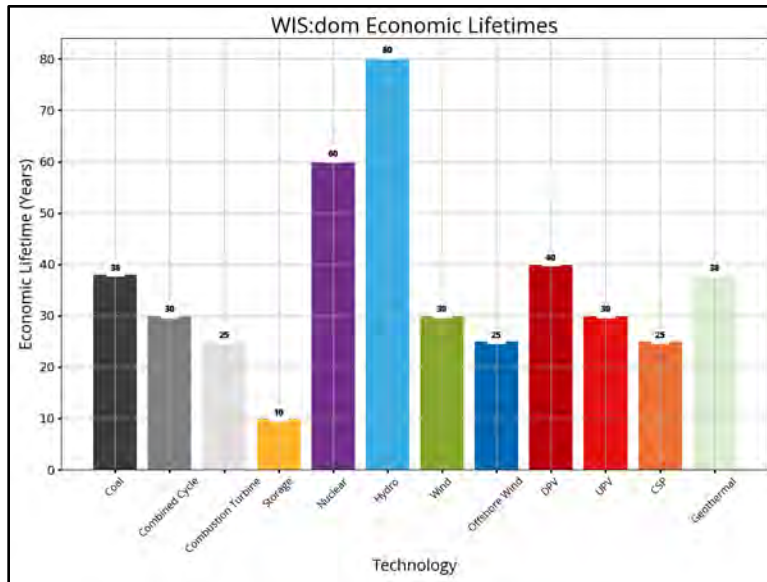


Figure 5.19: The economic lifetime for each generator type within WIS:dom-P in years. The economic lifetime means the time that the debt must be cleared from the units.

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.

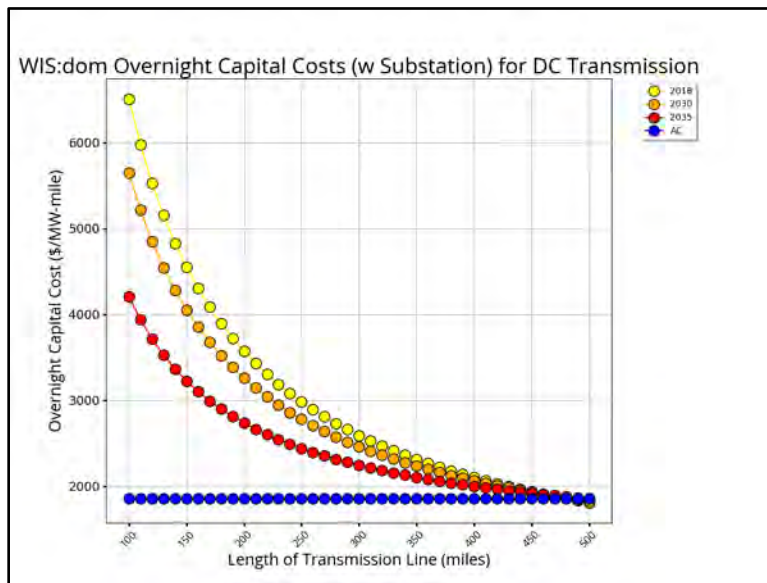


Figure 5.20: Shows the overnight capital cost of DC transmission in WIS:dom-P in real \$/MW-mile installed over various distances. Costs are shown for 2018, 2030 and 2050. The overnight capital cost of AC transmission (including substations) is also shown in blue. This is the same cost no matter the 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.

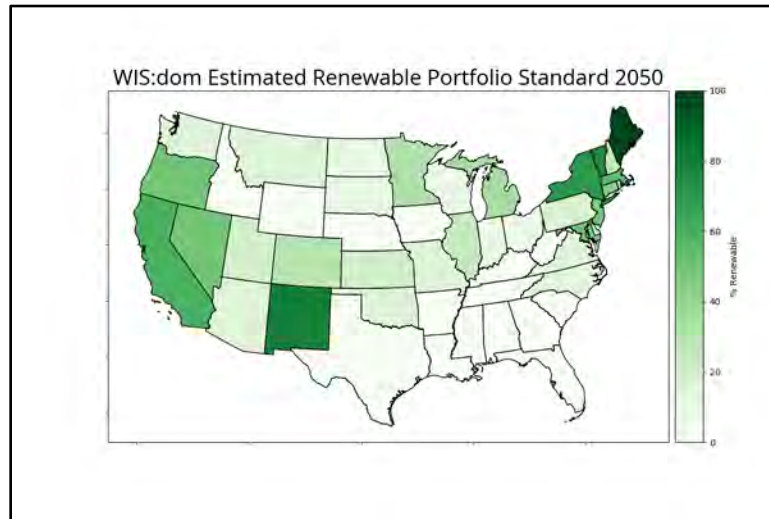


Figure 5.21: The Renewable Portfolio Standards percentage requirement of each state across the US.



Figure 5.22: The Clean Energy Mandate percentage requirements of each state across the US.





Figure 5.23: The Offshore Wind requirement in MW for each state across the US.



Figure 5.24: The Storage Mandates requirement in MW for each state across the US.



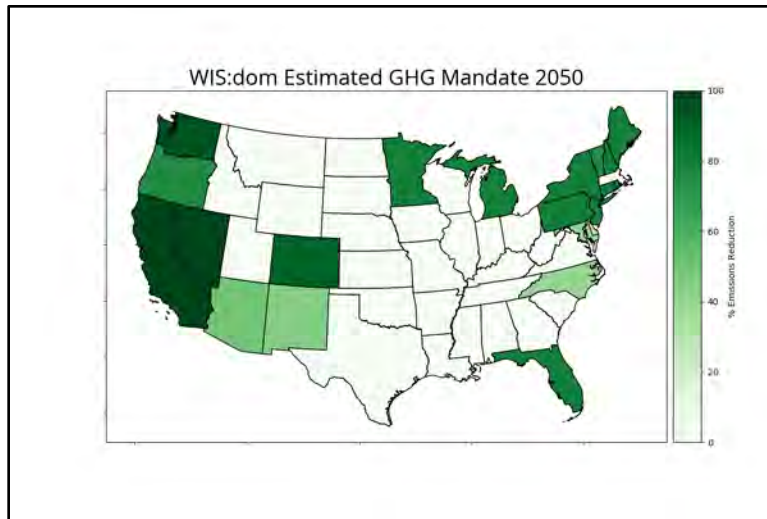


Figure 5.25: The GHG Emissions Reduction percentage requirement of each state across the US.

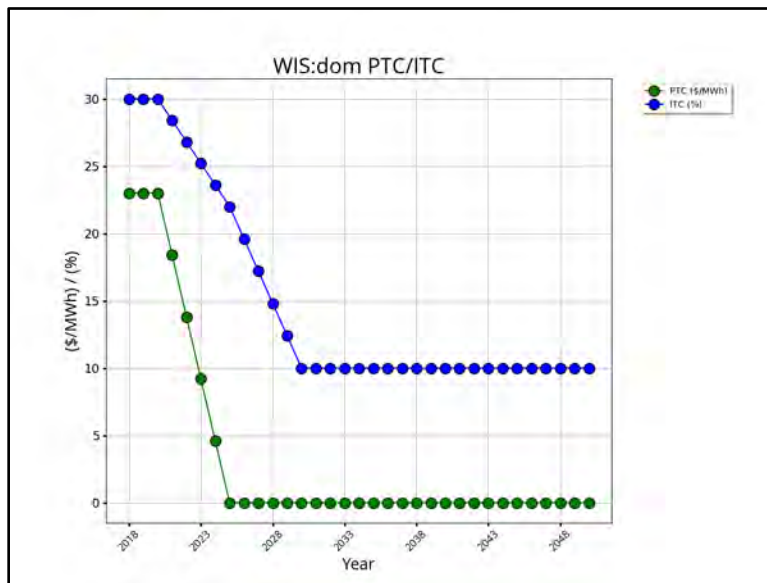


Figure 5.26: The Production Tax Credit subsidiary and the Investment Tax Credit. Note that for 2030 and beyond, the 10% ITC remaining is for utility scale projects only.

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.



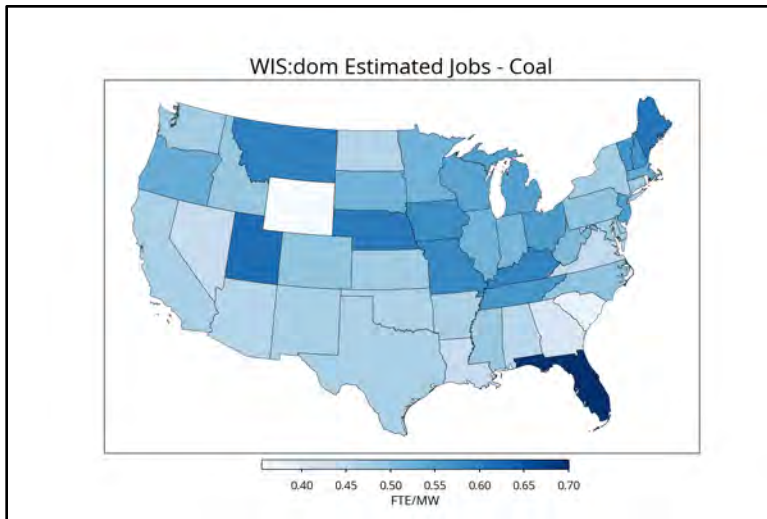


Figure 5.27: Employment per MW available from Coal.

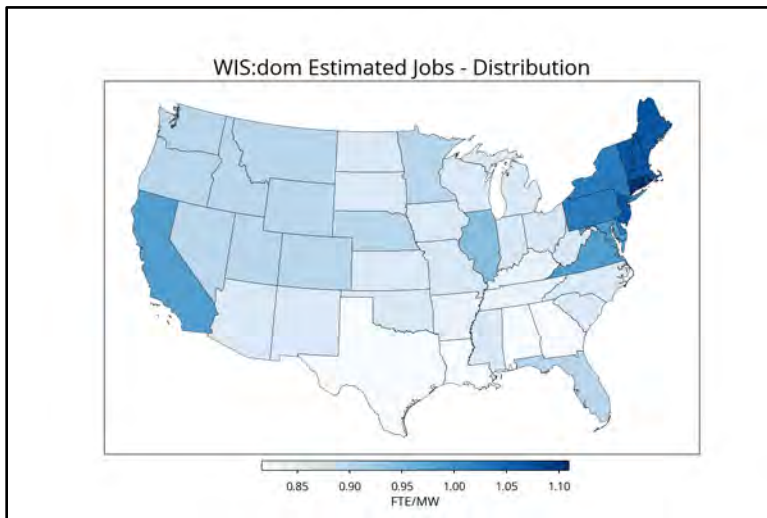


Figure 5.28: Employment per MW available from Distribution.

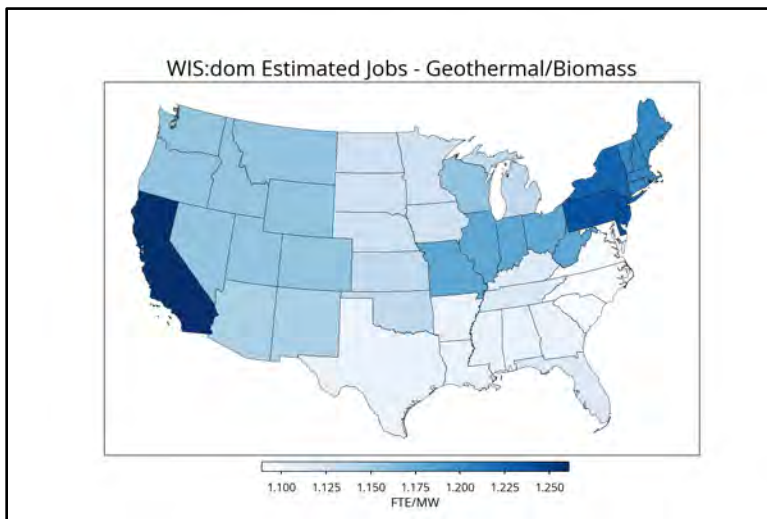


Figure 5.29: Employment per MW available from Geothermal and Biomass.



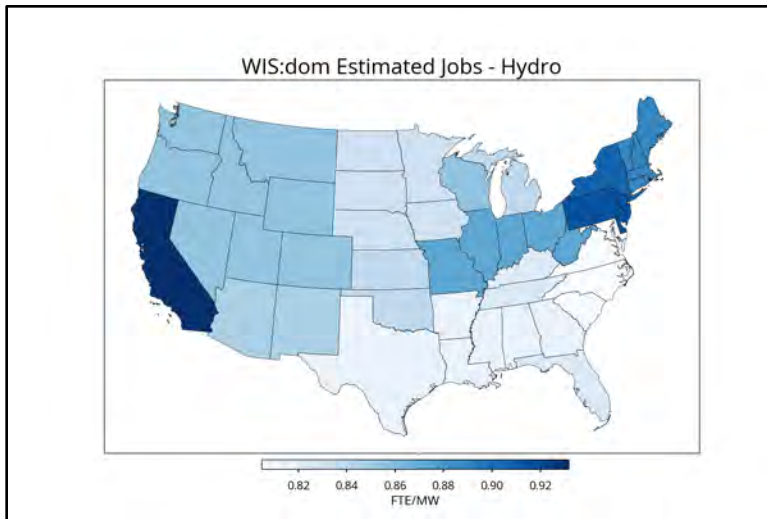


Figure 5.30: Employment per MW available from Hydro.

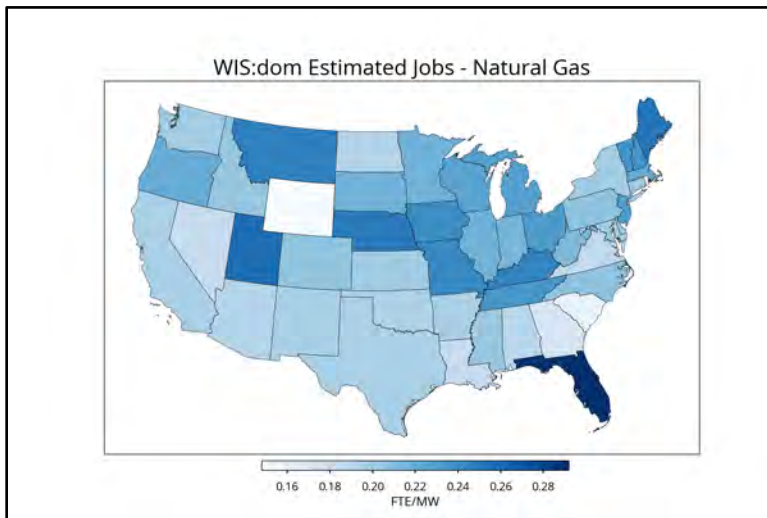


Figure 5.31: Employment per MW available from Natural Gas.

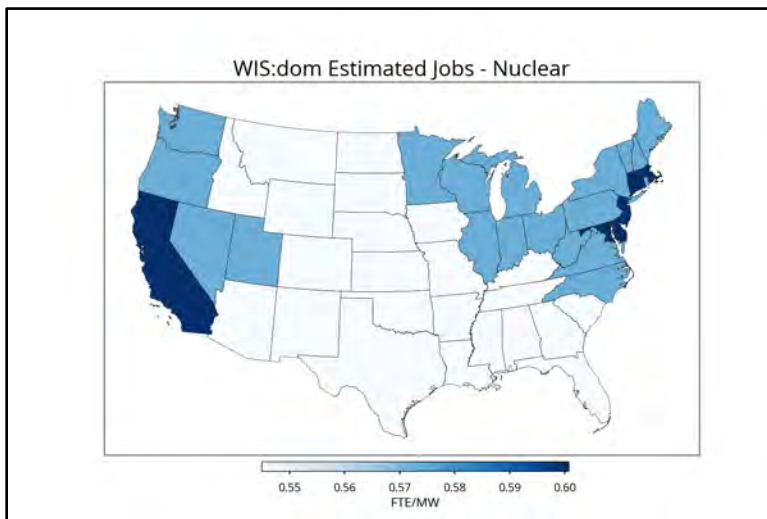


Figure 5.32: Employment per MW available from Nuclear.



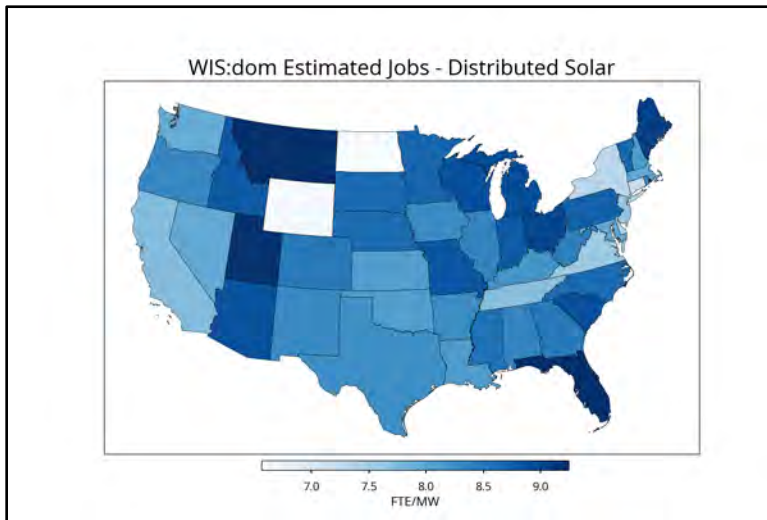


Figure 5.33a: Employment per MW available from Distributed Solar.

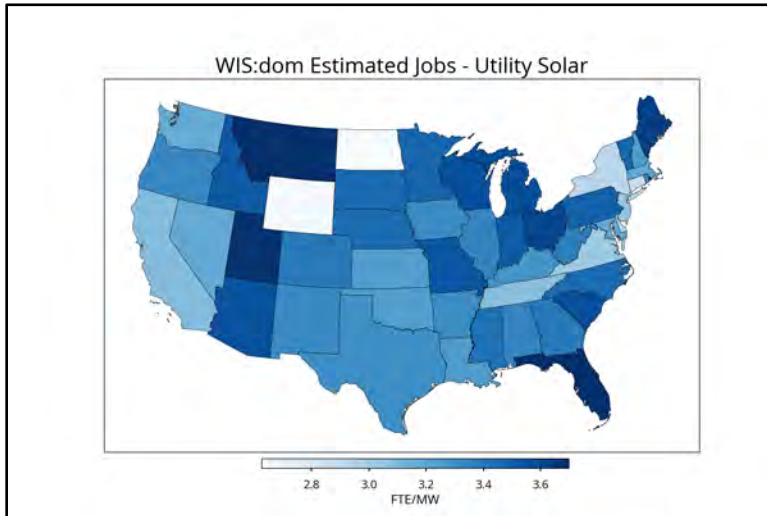


Figure 5.33b: Employment per MW available from Utility Solar.



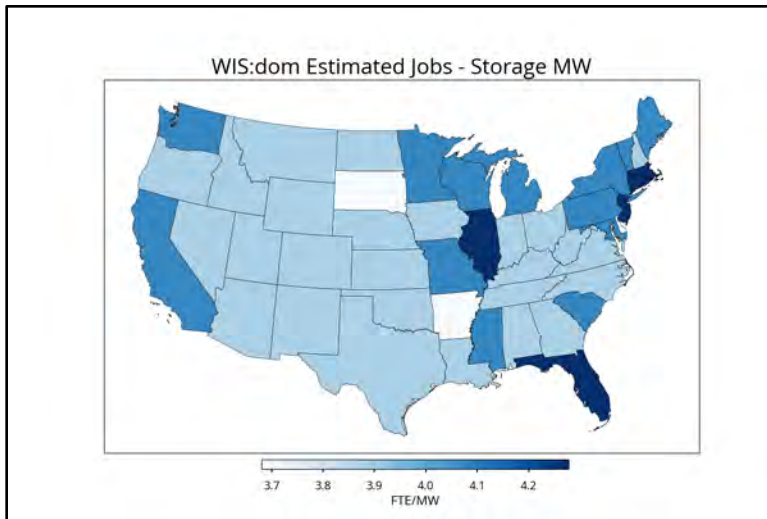


Figure 5.34: Employment per MW available from Storage MW.

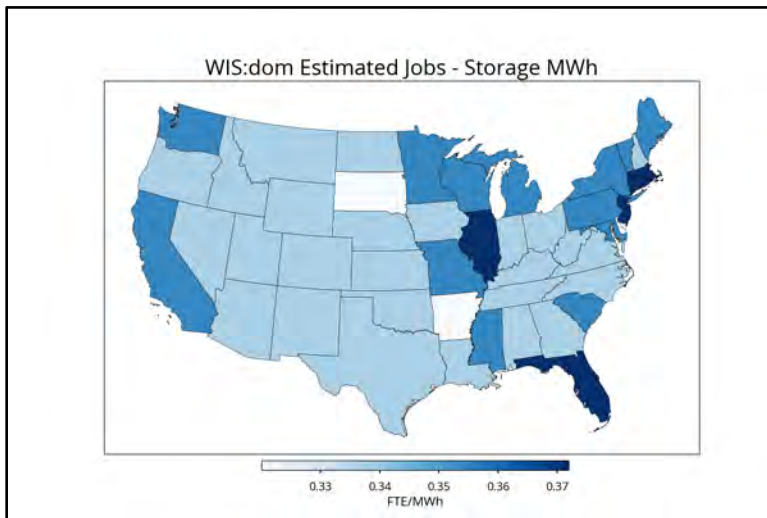


Figure 5.35: Employment per MWh available from Storage.

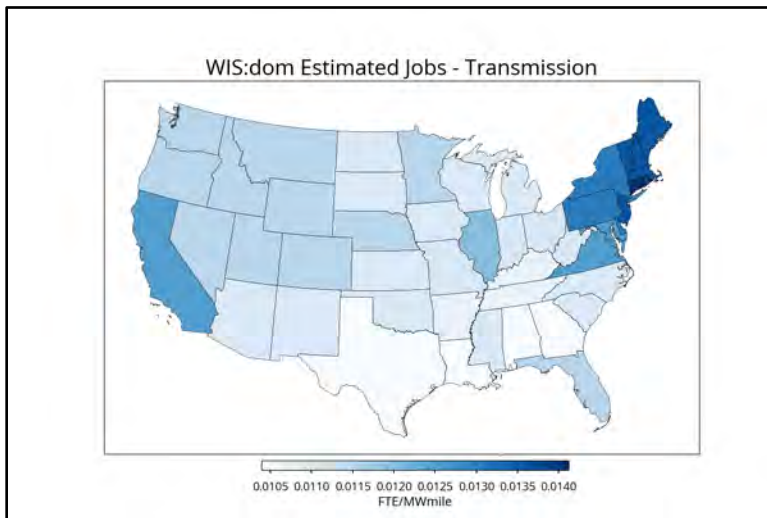


Figure 5.36: Employment per MW available from Transmission.



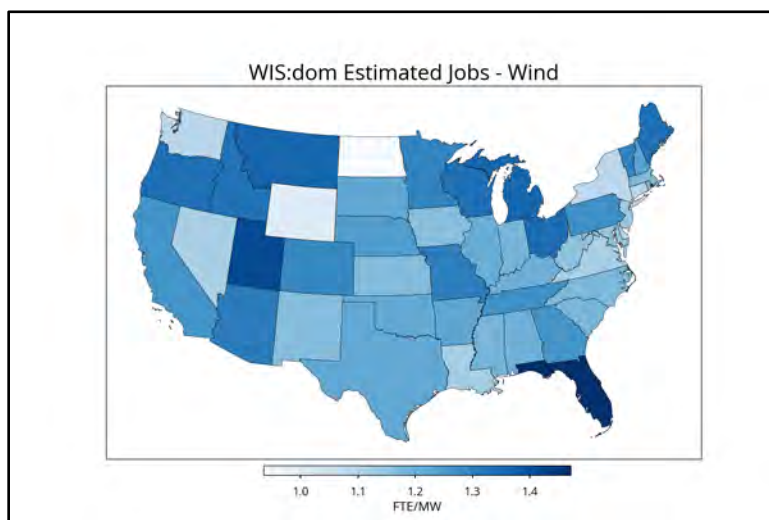


Figure 5.37: Employment per MW available from Wind.



5.4 Montana Weather Analysis

The present section will analyze the weather data specific to the state of Montana for this study. Where applicable, images and references will be also be given to the wider WECC region; Including Montana, California, Oregon, Washington, Idaho, Nevada, Utah, Arizona, Colorado and New Mexico. This section will provide some insight into how certain renewable sources are selected by the model. Figure 5.38a and Fig. 5.38b 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 5.38a shows a typical normalized load pattern. Figure 5.39b shows a normalized electrified load pattern for comparison.

Figure 5.38a and Fig. 5.38b show the solar resource is both higher in peak and longer in duration during the summer, reaching above over 60% capacity factor in those months for Montana. 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 over 30% 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. 5.38a for Montana shows a standard load pattern. It is much higher in the summer months than in the winter months. For Fig. 5.38b, an electrified load pattern is plotted for Montana. The electrified load is increased in many hours. The shape tends to “flatten out” throughout the day and remain at a more consistent level. The afternoon load peak shifts to the late evening hours. In winter, the early morning electrified load peak is higher than the late daytime peak for Montana. The observed increase in winter load is from electrification of space heating, water heating and transport, while the summer load is seen to lower in peak as increases in load due to electrification are offset by energy efficiency measures. 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.



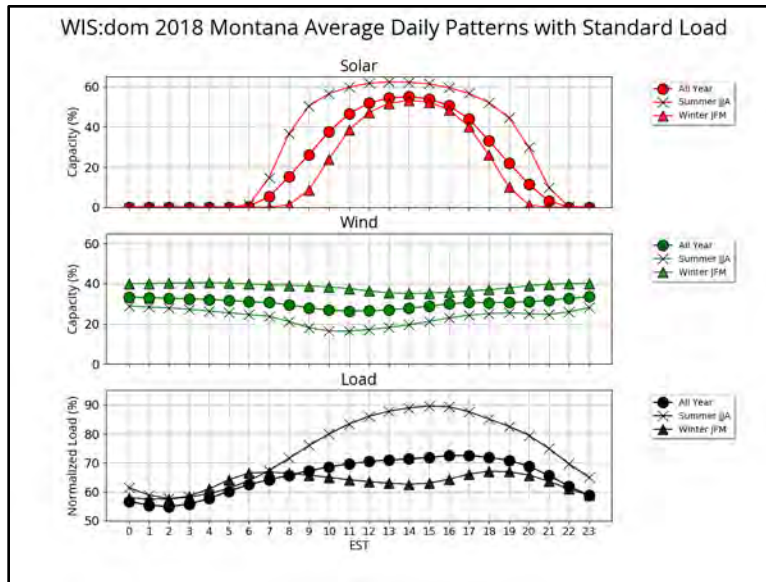


Figure 5.38a: The average solar (red) and wind (green) resource shown for the states in Montana alongside the corresponding load (black) by hour of the day (EST). The circles show the hourly averages for the entire 2018 year. The other two series look at the summer (JJA) and winter (JFM) months of 2018. This shows a normalized standard load pattern.

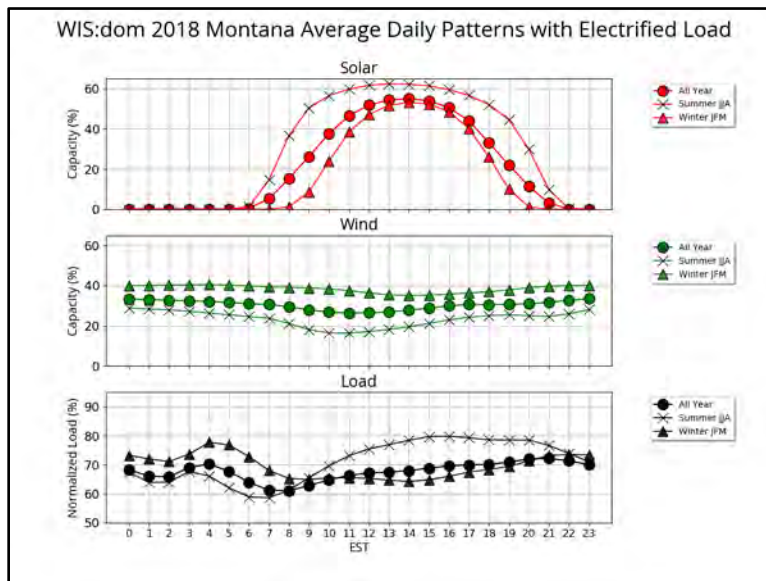


Figure 5.38b: The average solar (red) and wind (green) resource shown for the states in Montana alongside the corresponding load (black) by hour of the day (EST). The circles show the hourly averages for the entire 2018 year. The other two series look at the summer (JJA) and winter (JFM) months of 2018. This shows a normalized electrified load pattern.

The following Fig. 5.39a and Fig. 5.39b are similar to Fig. 5.38a and Fig. 5.38b; 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. Figure 5.39a shows a standard load scenario. Figure 5.39b displays an electrified load scenario. In Fig. 5.39a, 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 load. This observation along with the anti-correlated nature of wind and solar shows the viability of wind. In Fig. 5.39b, the load is electrified and stays more consistent throughout all hours, including at night with higher load. 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.

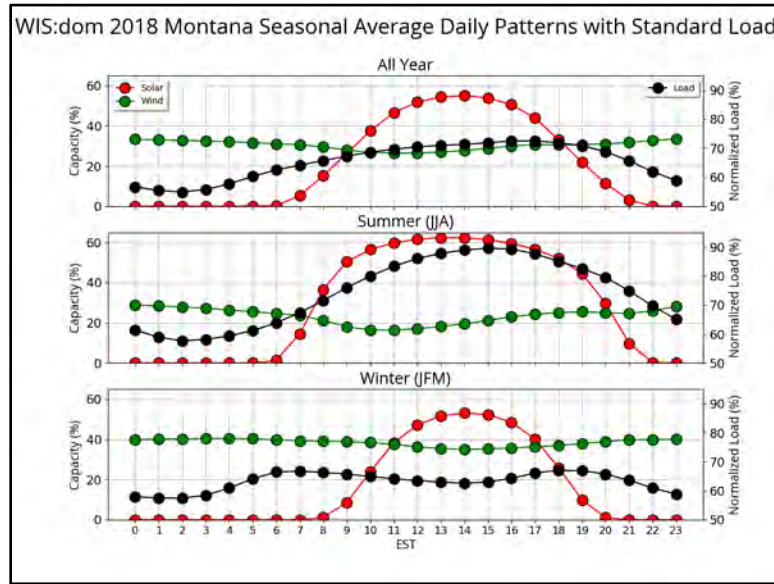


Figure 5.39a: The average solar (red) and wind (green) resource shown for the Montana states alongside the corresponding load (black) by hour of the day (EST). This is shown in seasonal groupings now; the entire 2018 year, the summer (JJA) of 2018 and winter (JFM) of 2018. This shows a normalized standard load.

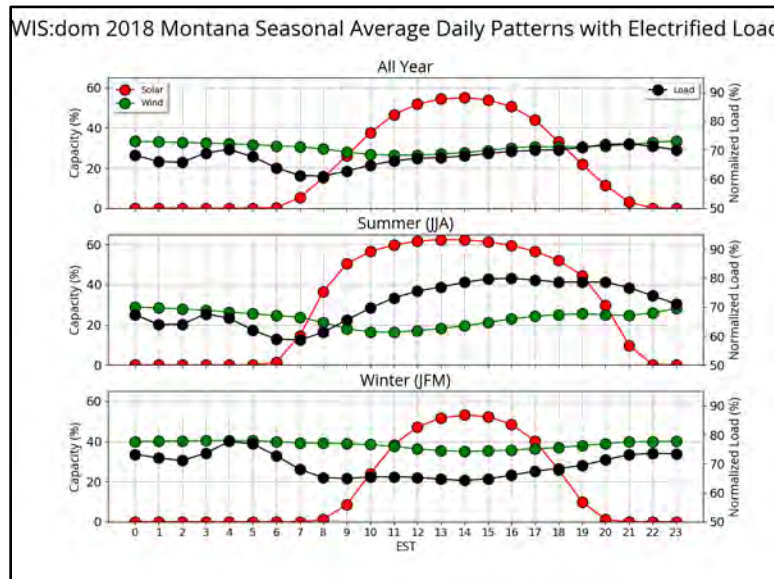


Figure 5.39b: The average solar (red) and wind (green) resource shown for the Montana states alongside the corresponding load (black) by hour of the day (EST). This is shown in seasonal groupings now; the entire 2018 year, the summer (JJA) of 2018 and winter (JFM) of 2018. This shows a normalized electrified load.



Figure 5.40 and Fig. 5.41 show the average diurnal solar and wind resources respectively throughout the day for Montana versus the same resource available over all the WECC states. The temporal solar patterns are similar between the two regions. This speaks to the large east to west geographic extent of Montana. However, the WECC solar average is much higher in daily average peak than Montana. The solar resource in the desert southwest is incredibly high. The wind in Montana on average is higher for all hours than the wind experienced in WECC. However, during the daytime hours is where Montana pulls apart from all of WECC. The daytime lull is not as pronounced in Montana as it is for WECC. At night, the two regions become more aligned in wind resource magnitude.

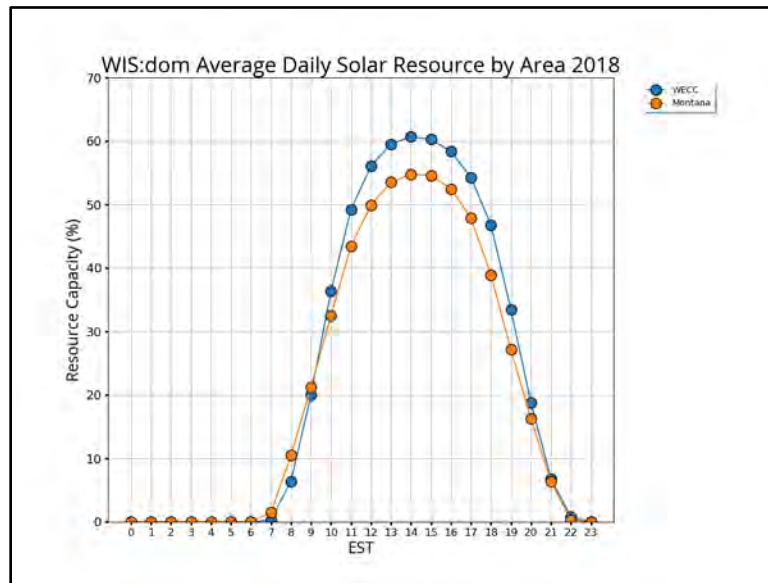


Figure 5.40: The 2018 average hourly solar resource capacity factors for modeled regions.

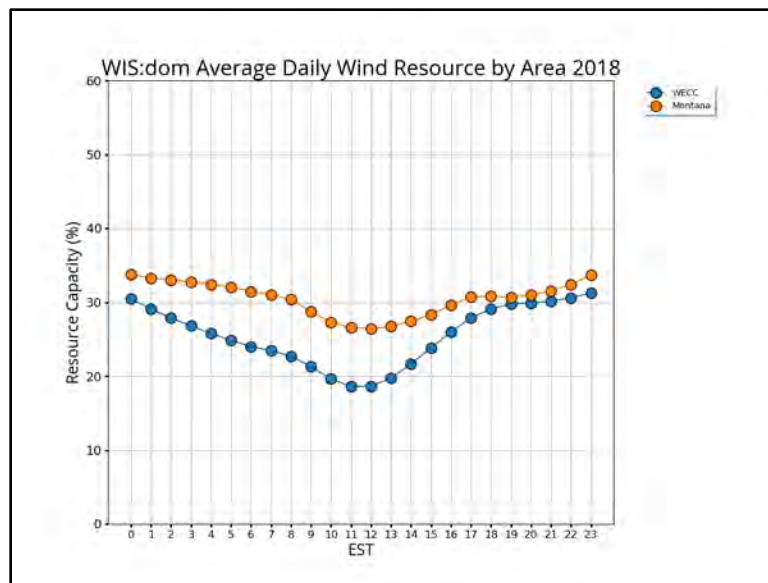


Figure 5.41: The 2018 average hourly wind resource capacity factors for modeled regions.



VCE investigated the wind and solar resources at different spatial granularities as well for the present analysis. This was performed for all the states within WECC to provide regional representation. Figure 5.42 and Fig. 5.43 show the average annual wind and solar resources throughout the day for each of the WECC states. Note that for those states where offshore potential sites are available, that data is included in the state wind resource average. Figure 5.44 and Fig 5.45 shows the average wind and solar resource for the 2018 weather year for each state. These four images combined show that Montana has some of the strongest wind resource in WECC, especially during the day. States like New Mexico and Colorado have higher wind capacity factors at night due to support from the low-level jet that forms over the Plains states. On the solar side, the desert southwest states dominate in resource magnitude. Montana is the second lowest state among the WECC states.

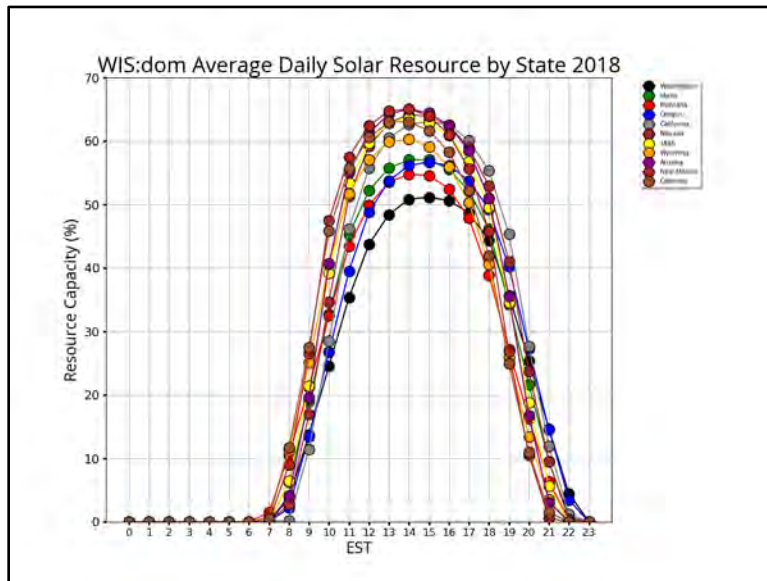


Figure 5.42: The 2018 average hourly solar resource capacity for each state modeled.

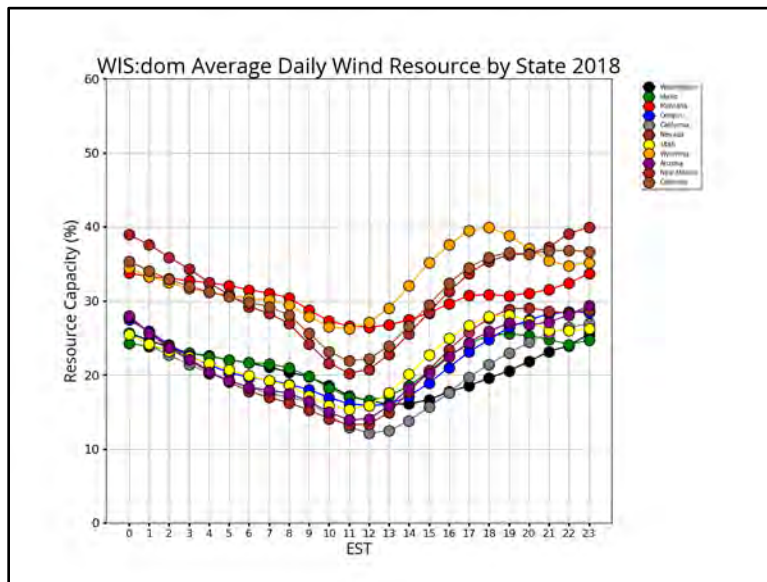


Figure 5.43: The 2018 average hourly wind resource capacity for each state modeled.



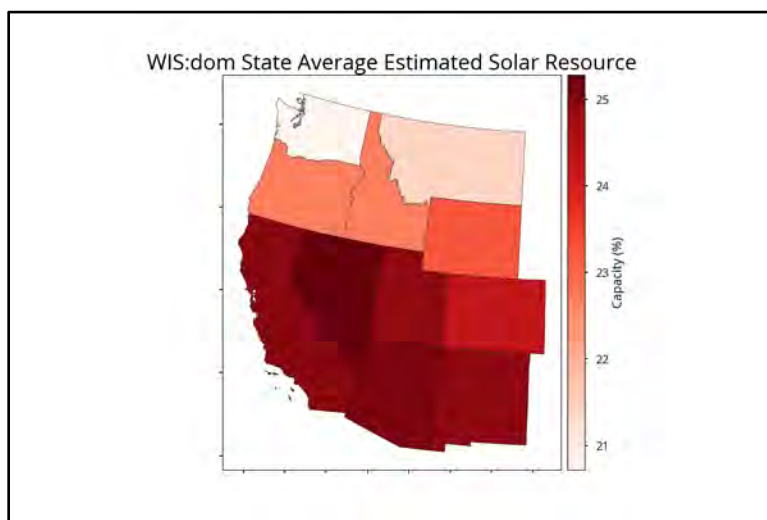


Figure 5.44: The average solar capacity factor (%) for 2018 by state in the Western US.

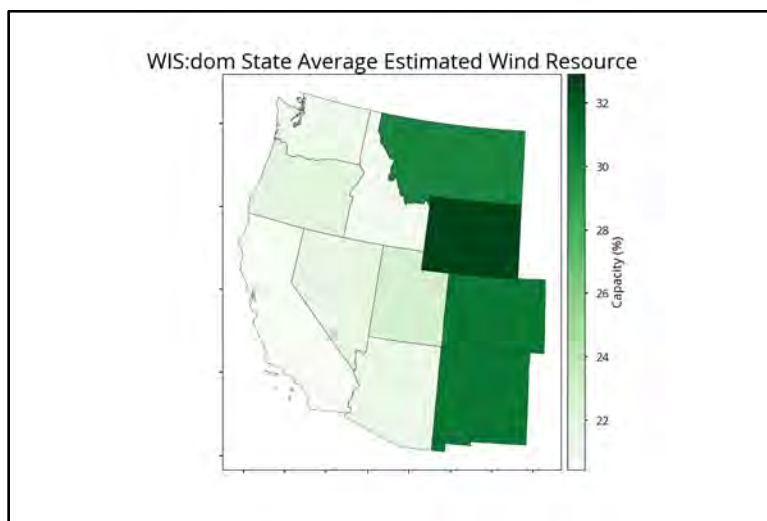


Figure 5.45: The average wind capacity factor (%) for 2018 by state in the Western US.

VCE utilizes the 3-km NOAA HRRR weather model as the raw inputs for the weather and power datasets. Figure 5.46 looks at the wind capacity resources at this granularity across the Western US. The plains along the Rocky Mountain Front Range show the highest wind power resource in the Western US. In general, wind power capacity factors decrease going from east to west looking at this half of the US. Strong pockets of high wind resource are observed in places such as the Tehachapi area of California and the Columbia River Gorge in the Pacific Northwest. Figure 5.47 shows that the solar resource is highest in the desert southwest. The solar power capacity factors generally decrease going north in the states considered. Nevada has the highest solar power capacity in 2018. Utah, Colorado, California, Arizona and New Mexico are not far below Nevada in terms of available solar resource. Southern California has very high solar capability as well. This decreases in northern California, so the state as a whole comes in slightly lower than the other southwest states. It is clear from Fig. 5.46 and Fig. 5.47 that the wind resources are far more



heterogenous than the solar resource, but that WECC as a whole has very good resource quality in both.

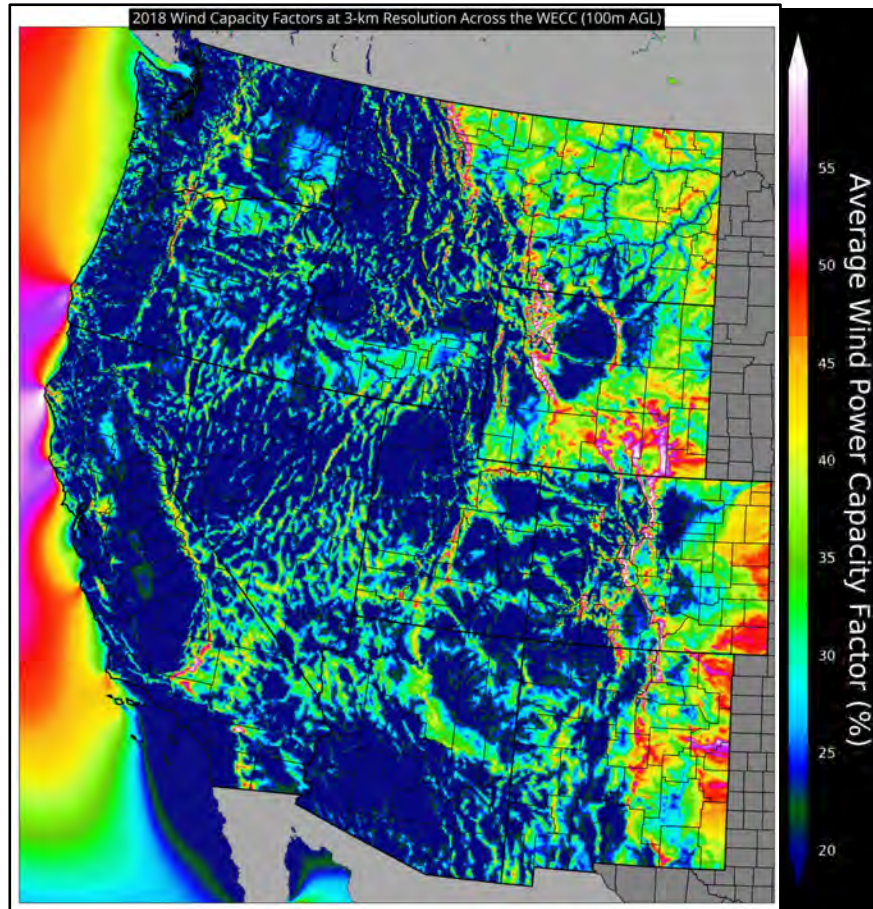


Figure 5.46: The 3-km 100-meter wind resource across the Western US in 2018.



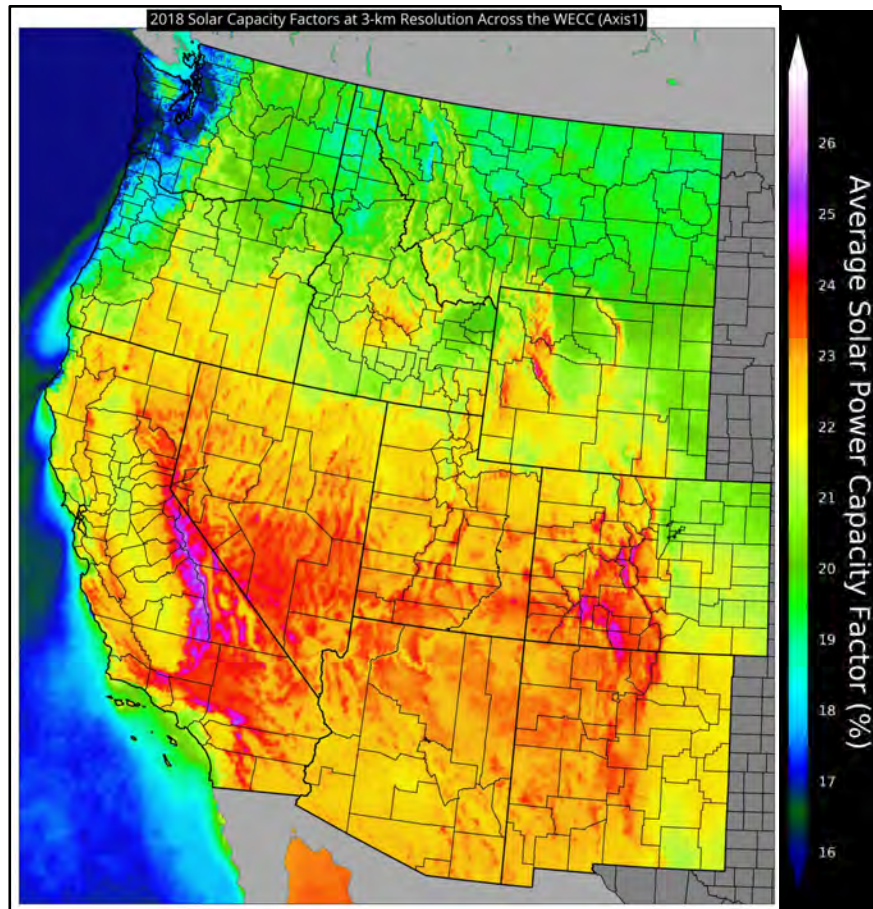


Figure 5.47: The 3-km latitude-tilted solar resource across the Western US in 2018.

VCE analyzed a day of high wind during 2018 in Montana. Figure 5.48, reproduced from the NOAA weather archives, shows a surface weather analysis in February 2018. An occluded winter system in Canada came across the northern Rocky Mountains and brought strong winds and pressure gradients both before and after frontal passage. Further, strong leeside downslope winds developed along the Montana front range. Figure 5.49a shows a time series view of the wind and solar resources alongside a normalized standard load in Montana during this high wind event just described. Wind capacity factors in Montana reach almost 90% at their peak during this period. Figure 5.49b shows the same weather data against a normalized electrified load. The early morning peak in the electrified load is apparent. The higher nighttime load is supported by the wind resource that maintains itself throughout all hours of the day during this period.



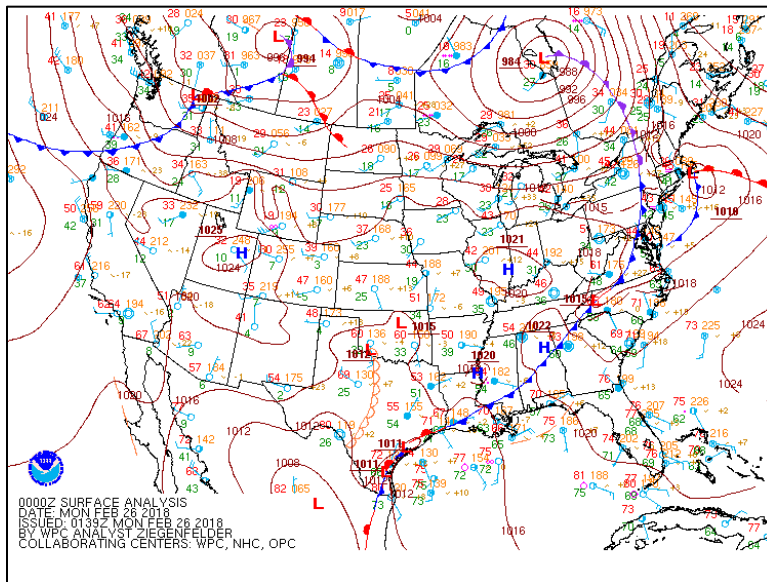


Figure 5.48: Surface Weather Analysis Plot from February 26th, 2018 at 00 UTC. This surface plot is provided from NOAA's Weather Prediction Center Archives (https://www.wpc.ncep.noaa.gov/archives/web_pages/sfc/sfc_archive.php).

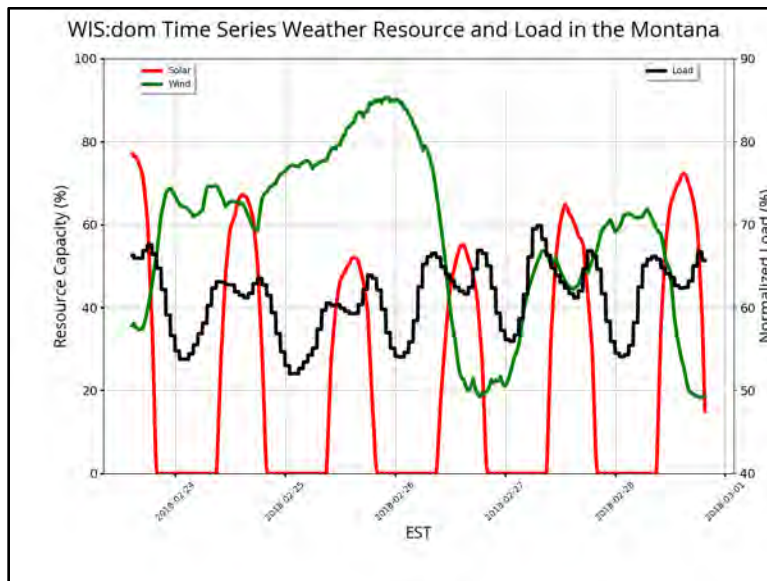


Figure 5.49a: A time series of the average solar (red) and wind (green) resources across Montana in April 2018. The standard load (black) is also plotted. This was one of the highest wind periods from 2018.



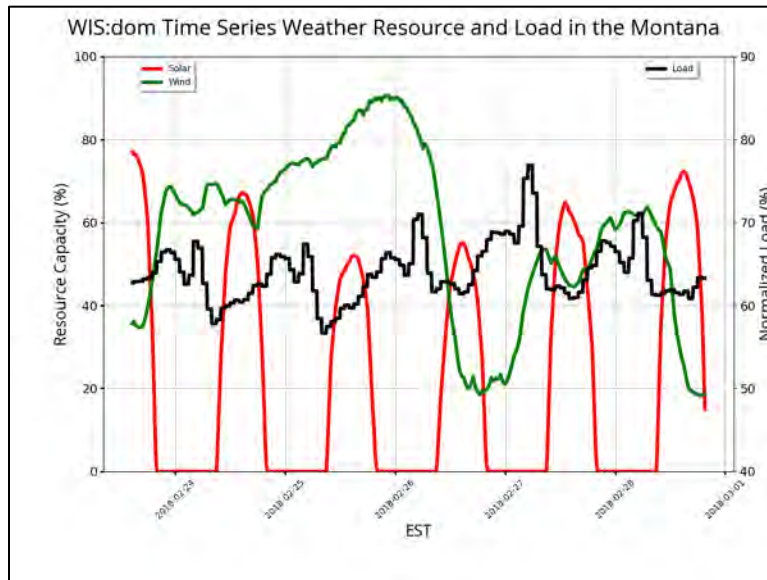


Figure 5.49b: A time series of the average solar (red) and wind (green) resources across Montana in April 2018. The electrified load (black) is also plotted. This was one of the highest wind periods from 2018.

The next figures (Fig. 5.50a and Fig. 5.50b) show a July week that had some of the lowest wind observed in 2018 for the state of Montana. A summer wind doldrum established itself for a few days. The diurnal nighttime increase in wind speed is still slightly apparent and many times the wind reaches 20% capacity as the sun is setting for the day. In Fig. 5.50a, it is shown that during the summer in Montana, the typical standard load is higher than the electrified load shown in Fig. 5.50b. This is due to advances in energy efficiency considered in an electrified scenario. In Fig. 5.50b, the nighttime wind increases help support the peak load that occurs later in the evening. Both figures distinctly show the anti-correlated nature of wind and solar and their ability to support load at different times throughout the day.

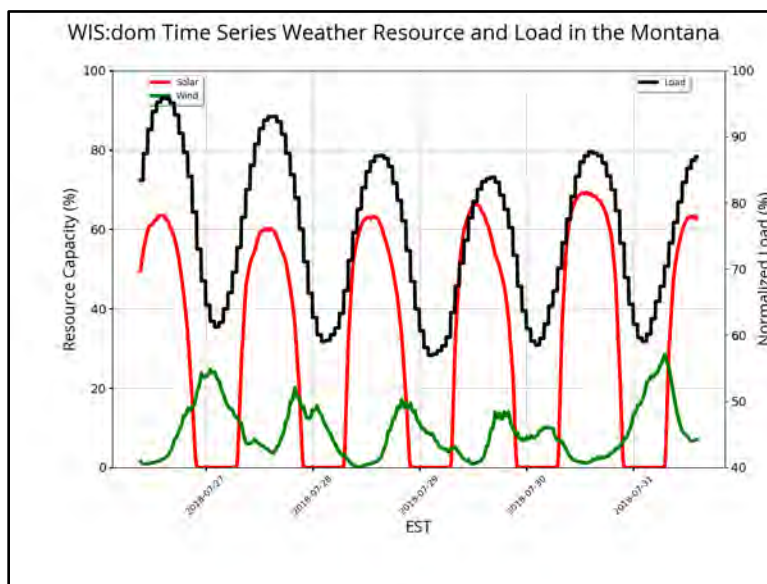


Figure 5.50a: A time series of the average solar (red) and wind (green) resources across Montana in September 2018. The standard load (black) is also plotted. This was one of the lowest wind periods from 2018.



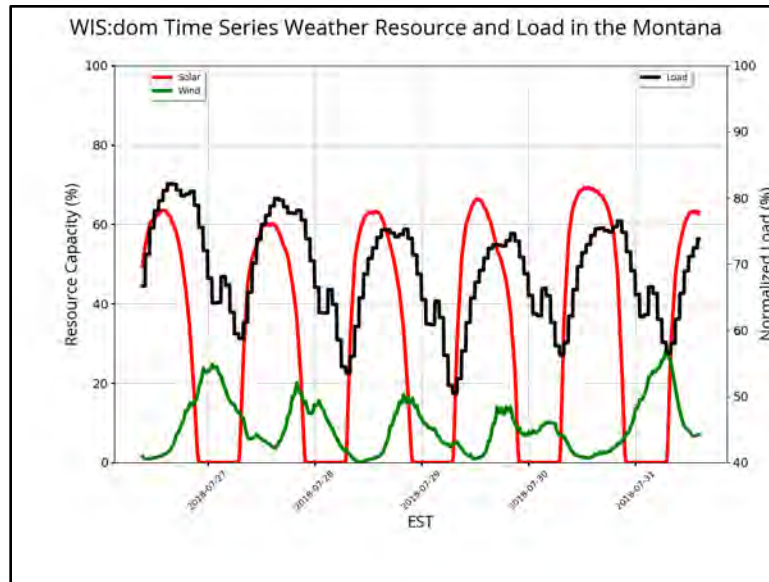


Figure 5.50b: A time series of the average solar (red) and wind (green) resources across Montana in September 2018. The electrified load (black) is also plotted. This was one of the lowest wind periods from 2018.

