PUBLIC SERVICE COMMISSION OF WISCONSIN

STRATEGIC ENERGY ASSESSMENT

2028-2034

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Strategic Energy Assessment 2028

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EXECUTIVE SUMMARY

Under Wis. Stat. § 196.491(2), the Public Service Commission of Wisconsin (Commission) prepares a biennial Strategic Energy Assessment (SEA) to evaluate Wisconsin's current and future electricity supply. The SEA provides this evaluation in the context of four primary goals maintained by Wisconsin electricity providers and the Commission:

- **Adequate** electric supply that maintains sufficient total power to meet customers' total electric demand;
- **Reliable** electric supply that provides all customers access to electricity at all times, avoiding outages whenever possible;
- **Affordable** electric supply that offers adequate and reliable energy at the lowest feasible cost for customers; and
- **Environmentally responsible** electric supply that minimizes the negative effects of electric generation on the natural environment.

As part of the biennial SEA process, electric providers operating in Wisconsin[1] must submit to the Commission specified historical and forecasted information on electric system operations, along with any additional information requested by the Commission.[2] All electric providers submitted that information for the SEA 2028 in November 2021, providing forecasted information through 2028. Commission staff analyzed the data submitted along with other information sources to develop the SEA as a comprehensive, public resource regarding Wisconsin's electric system. The Commission approved a draft SEA for comment in June 2022, and received feedback through a public hearing and written comments. This final SEA updates the draft to address questions and suggestions raised through comments. The final SEA also includes additional information on developments occurring since publication of the draft, including Commission actions, the passage of the federal Inflation Reduction Act, and announced plans to delay the previously reported dates of certain coal plant retirements and generation additions.

ELECTRICITY GENERATION IN WISCONSIN TODAY

As of November 2021, Wisconsin electric providers projected an increase in peak electric demand of approximately 3.5 percent between 2021 and 2022, as customer demand was expected to increase and economic conditions were expected to improve after the initial impacts of the COVID-19 pandemic. While providers projected limited annual demand growth between 2023 and 2028, the provisions of the recently enacted Inflation Reduction Act may influence updated projections of customer electric demand provided in future SEAs.

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[1] For purposes of the SEA, electric providers required to submit data include any entity who owns, operates, manages, or controls, or who expects to own, operate, manage, or control, electric generation capacity in Wisconsin greater than 5 megawatts (MW).

[2] Wis. Stat. § 196.491(2) and Admin. Code ch. PSC 111.

Wisconsin electric providers planned to procure electric generation capacity sufficient to meet projected customer demand, plus an additional "reserve margin" to ensure supplies are adequate if actual demand exceeds projections. Based on information submitted for the SEA, Wisconsin's projected capacity exceeded reserve margin requirements in both 2021 and 2022.

Wisconsin electric providers seek to provide reliable electric supply by limiting both the frequency and duration of service outages. In 2021, the average customer of the state's five largest utilities experienced less than one outage per year, with an average duration of approximately three hours and 21 minutes. Fallen branches and trees and equipment failures were the most frequently reported causes of outages reported to the Commission by all regulated electric providers.

While coal was the most common source of electricity generation in Wisconsin, the share of energy produced by coal decreased from approximately 54 percent in 2015 to 35 percent in 2020. Natural gas resources accounted for the largest corresponding increase in generation share, from 19 percent in 2015 to 33 percent in 2020. Wind resources also increased from 6 percent to 10 percent, and solar resources from 0.1 percent to 0.5 percent.

Reduction of carbon dioxide (CO_2) emissions has emerged as a leading priority for maintaining environmentally responsible electric service, due to the primary role of CO_2 emissions in contributing to climate change. Governor Tony Evers and each of Wisconsin's five largest electric providers have established goals to achieve 100 percent reductions in CO_2 emissions from electricity production by 2050. Wisconsin electric providers reported CO_2 emissions reductions of 40 percent in 2020, compared to the 2005 emissions levels commonly used as a baseline. Coal facilities accounted for more than 70 percent of CO_2 emissions from provider-owned facilities, driven by coal generation's status as the largest share of total in-state generation and its higher emissions rate compared to natural gas.

FUTURE ELECTRICITY GENERATION IN WISCONSIN

Wisconsin electric providers reported plans to retire approximately 3,300 MW of in-state generation by 2028. These planned retirements included three of the seven utility-scale coal facilities operating in Wisconsin as of 2022, which have a combined capacity of nearly 2,800 MW. In June 2022, providers announced that they would delay previously reported retirement dates at all three plants, due to concerns about maintaining reliability in upcoming years associated with delays in construction of generation additions. Under these updated plans, full retirement of all three plants would occur by 2026.

Wisconsin electric providers reported plans to add approximately 2,500 MW of new solar energy capacity, 400 MW of new natural gas capacity, and nearly 100 MW of new wind capacity by 2028. In addition, providers reported plans for approximately 500 MW of new battery energy storage capacity, all paired with announced solar facilities. Providers also reported plans for ownership transfers of approximately 850 MW of existing natural gas capacity within the state.

If all additions and retirements are implemented as planned, coal will decline from 35 percent of Wisconsin generation in 2020 to 21 percent in 2028, natural gas will increase from 33 percent to

34 percent, wind will increase from 10 percent to 13 percent, and solar resources will increase from 0.5 percent to 10 percent. As planned, total CO_2 emissions will reach a 58 percent reduction in 2028 from 2022 baseline levels.

The Commission's Roadmap to Zero Carbon investigation has identified a need for more comprehensive utility resource decisions and greater transparency in the utility resource planning processes. To support more transparent resource planning Commission staff preparing this SEA requested additional information from providers on their resource planning analysis associated with announced additions and retirements, and incorporated independent staff analysis on statewide resource planning considerations.

Electric providers confirmed that their resource planning accounted for the four goals of adequacy, reliability, affordability, and environmental responsibility. Multiple providers also identified that their goals included maintaining a diversity of generation sources located in Wisconsin and controlled by the providers, to support adequacy and reliability as well as pursue additional goals to maintain rate stability and support resilience. Providers affirmed that their announced additions and retirements had been informed by modeling results assessed against those goals, stating that retirement of coal facilities and addition of solar, wind, natural gas, and energy storage facilities were identified as the changes that supported emissions reduction, reliability, and resilience while limiting costs.

Commission staff conducted independent capacity expansion modeling under future scenarios that set different values for emissions reductions and growth in electric demand. In scenarios that assumed limited CO_2 emissions reductions, the capacity expansion model predominantly selected natural gas resources to meet the needs identified by upcoming retirements and long-term load growth, apparently due to the model's view of the reliability and resource adequacy advantages of natural gas. These results differed from the modeling outcomes and planned additions reported by providers, which included significantly larger shares of solar and battery storage. Updated analysis in summer 2022 found that the model selected a larger share of renewable resources under the increased natural gas prices experienced during 2022, but continued to select multiple natural gas units to help fill the capacity needs created by upcoming retirements.

In scenarios that assumed more aggressive CO_2 emissions reductions, at levels more closely consistent with providers' emissions reduction goals, capacity expansion models selected a reduced share of natural gas resources, and a larger share of renewable resources, including solar, battery storage, and wind. Modeling indicated that requiring rapid and complete emissions reduction by 2035 could be achieved by building a combination of renewable resources, but this scenario would require building substantially more facilities than needed to meet resource adequacy needs, at correspondingly higher costs, in order to maintain hour-to-hour reliability throughout the year. These planning considerations and cost assumptions may evolve over time if cost profiles for existing resources change, or if future technological developments support the emergence of other cost-competitive generation options.

CLEAN ENERGY PROGRAMS AND POLICIES

Focus on Energy (Focus), Wisconsin's statewide energy efficiency and renewable resource program, provides a portfolio of programs to help customers reduce their energy use. In 2020 and 2021 combined, Focus achieved energy savings equivalent to the amount of energy needed to power more than 1.4 million typical Wisconsin homes for a year, and reduced CO_2 emissions by 15.7 million tons. Evaluation of 2020 programs showed a record high level of customer satisfaction.

Wisconsin electric providers operate demand response programs that provide customers with incentives to reduce energy demand during peak periods, to support reliability and create financial savings for providers and customers. While demand response capacity available through these programs was equal to approximately 6 to 7 percent of Wisconsin's total peak demand between 2018 and 2021, a limited fraction of available capacity was dispatched during the period. Low dispatch rates reflect that demand response capacity is only utilized under specific conditions. For example, many providers' programs are only activated when the Midwest Independent System Operator, Inc. (MISO), the regional grid operator, calls upon them to reduce load, which did not occur between 2018 and 2021.

Historically, a primary driver for renewable resource development by Wisconsin electric providers has been compliance with the Renewable Portfolio Standard (RPS) law, which requires providers to provide at least 10 percent of electricity generation through renewable resources. Declining project costs, increasing customer interest, and the benefits of renewables in helping meet emissions reduction goals, have started driving increased renewable energy deployment above RPS requirements. In addition to constructing utility-scale renewable energy facilities, electric providers have also established programs for individual customers interested in procuring a larger share of their own energy use from renewables, including community solar programs and renewable rider programs for large customers.

Wisconsin had more than 11,500 customer-owned renewable generation installations operating in 2021, with capacity that equated to nearly 2 percent of statewide capacity. Customer-owned solar, specifically, equated to nearly 1 percent of total statewide capacity in 2021. Customer-owned solar installations increased nearly 40 percent between 2019 and 2020, accelerating beyond the consistent annual growth rate of 20 percent observed during the previous decade. The Commission is reviewing the purchase rates associated with customer-owned generating systems as well as the interconnection standards used to connect facilities to the electric grid.

Large-scale use of electric vehicles (EVs) could have significant implications for Wisconsin's electric system, by increasing total electric demand, modifying timing and location of energy use, and presenting new considerations for determining customer rates and service arrangements. The Commission issued an order in 2020 encouraging regulated utilities to submit pilot program proposals to explore EV-related issues, and providing regulatory clarity on the information providers must include in proposing pilots to the Commission. The Commission has approved multiple EV pilots, with conditions requiring robust accounting and reporting to identify cost impacts and provide insight to inform future program development.

ELECTRIC TRANSMISSION IN WISCONSIN

Wisconsin participates in MISO's regional transmission system, which operates an integrated electric grid across 15 states and supports long-distance transmission of electricity. Participating in MISO allows Wisconsin to access low-cost energy resources located in nearby states, and offers access to a wholesale market that providers may use to maintain adequate electric supply.

Due to increased transmission line development and construction, transmission expenses have significantly increased since 2005, and accounted for an increasing proportion of providers' total operating expenses. A key factor has been the implementation of MISO's Multi-Value Project (MVP) portfolio, a set of large-scale transmission projects approved by MISO in 2011 to alleviate congestion caused by rapid growth in wind generation.

MISO is currently in the process of planning a second portfolio of large-scale regional transmission projects through the Long Range Transmission Planning (LRTP) process. MISO presented completed analysis on an initial tranche of LRTP projects in April 2022, which were approved by the MISO Board in July 2022. Projects approved by the MISO Board will require transmission providers to design, plan, and seek regulatory approval as applicable in each state where the projects reside. High-voltage transmission lines going through Wisconsin will be required to receive Commission approval under state law.[3]

RESILIENCE AND CYBERSECURITY

Nationwide, electric providers and their regulators in recent years have increasingly focused on enhancing the electric system's resilience against "high impact, low frequency" (HILF) events, such as severe weather, that can result in lengthy service interruptions and significant recovery costs. The Commission's Office of Energy Innovation works with state emergency management staff to carry out planning exercises and develop improved plans for addressing energy-related challenges during emergency events. To expand its collaborative efforts on resilience, the Commission has awarded financial assistance through its Critical Infrastructure Microgrid and Community Resilience Center grant program to support innovative pre-disaster mitigation through microgrids and deployment of distributed energy resources.

Nationwide focus is also increasing regarding the specific resilience threats associated with cybersecurity attacks. Commission staff have participated in cybersecurity training and exercises to help identify information sharing mechanisms and define roles and responsibilities during cyber incidents. Electric providers and Commission staff have worked with state emergency management staff to add new cyber incident provisions to the Wisconsin Emergency Response Plan.

CUSTOMER RATES AND BILLS

The Commission uses its regulatory authority over customer rates to support affordable electric supply. Total revenue requirements for Wisconsin's largest electric providers increased 0.77 percent

[3] Wis. Stat. § 196.491.

per year between 2011 and 2020, driven primarily by increased costs for generation and distribution, which in turn was associated with continued provider investments in generation resources and distribution infrastructure.

National data shows that Wisconsin residential customers are charged higher average rates than Midwest or national averages, but also pay significantly less on their average monthly bills, due to lower average levels of energy use. Comparisons between states should be made cautiously due to differences in energy market conditions and regulatory frameworks.

Many Wisconsin providers offer innovative rate options designed to help customers exercise control over their costs and reduce their energy bills. 1.6 percent of Wisconsin residential, commercial, and industrial customers are enrolled in time-of-use rates that can reduce costs for both providers and customers by encouraging customers to shift their usage to hours of the day where energy supply costs are lower.

CUSTOMER AFFORDABILITY

Low- and moderate-income residential customers often face challenges paying their utility bills, due to a higher energy burden: they must pay a larger percentage of their total income for service. The Commission has significantly increased its efforts to assess energy burden, and to review and expand the options available to help customers address their affordability challenges.

To begin collecting more detailed and utility-specific information on energy burden, the Commission directed that large utilities provide detailed burden information in their annual reports to the Commission. Initial filings in 2021 affirmed that energy burden varied throughout geographic regions of the state and provided useful baseline information. The Commission issued updated instructions to collect more granular detail and provide a clearer picture of specific areas of the state with higher-than-average energy burden, and will continue to work with utilities to improve collection and analysis of energy burden data in future years. Commission staff are also working with national experts to further refine its underlying definitions and approach to measuring energy burden.

Regulated electric and natural gas utilities in Wisconsin are required to offer Deferred Payment Agreements to residential customers, allowing those customers to provide a down payment on unpaid bills and arrange an installment plan to pay the remaining balance.[4] The state's largest electric providers offer additional low-income assistance programs, many of which are arrears management programs that forgive portions of participants' overdue utility bills under certain conditions.[5] Electric providers and Commission staff also refer customers facing affordability challenges to available governmental community assistance programs, including state emergency assistance benefits administered by the Wisconsin Department of Administration and energy efficiency offerings available through Focus on Energy and other programs.

[4] *See* Wis. Admin. Code §§ PSC 113.0404, PSC 134.063.
[5] *See* Wis. Admin. Code §§ PSC 113.0505, PSC 134.13(5).

In 2020, the Commission opened an investigation to conduct ongoing review of appropriate steps to address safety, reliability, and affordability issues related to the COVID-19 pandemic. Information collected through the investigation demonstrated that residential customer arrears from unpaid bills increased from the first quarter of 2021 to the third quarter of 2021, likely due to the establishment of enhanced deferred payment agreements and arrears management programs; expanded communications efforts regarding financial assistance resources; and increased financial assistance available through federal legislation.

CHAPTER 1 – ELECTRICITY GENERATION IN WISCONSIN TODAY

Wisconsin electric providers must balance multiple goals to provide:

- **Adequate** electric supply that maintains sufficient total power to meet customers' total electric demand;
- **Reliable** electric supply that provides all customers access to electricity at all times, avoiding outages whenever possible;
- **Affordable** electric supply that offers adequate and reliable energy at the lowest feasible cost for customers; and
- **Environmentally responsible** electric supply that minimizes the negative effects of electric generation on the natural environment.

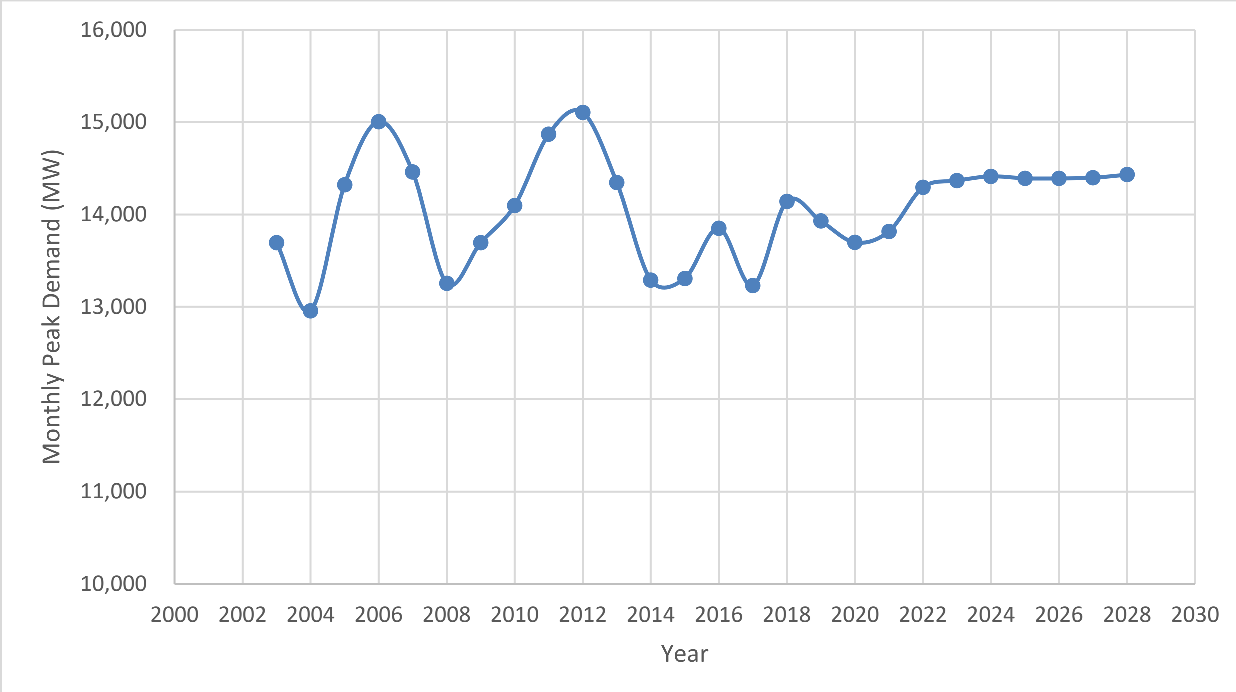
Wisconsin's current electric supply reflects a generation transition that began in the 2010s. Declining costs for natural gas, wind, and solar generation have encouraged providers to increase their use of those resources and decrease their use of higher-emission coal generation, with the goal of enhancing affordability and environmental responsibility while maintaining adequacy and reliability. This transition is projected to continue and accelerate in the 2020s, as outlined in Chapter 2.

DEFINING SUPPLY NEEDS

To ensure adequate electric supply, Wisconsin electric providers must procure enough total power to be able to meet the forecasted annual peak demand, the highest level of electric demand occurring at any point during a given year.

As shown in Figure 1-1, annual peak demand in Wisconsin has varied between 13,000 and 16,000 megawatts (MW) since 2003. Year-by-year differences can be influenced by multiple factors, including weather, economic conditions, and the addition and subtraction of significant customer loads.

Figure 1-1 Historical and Forecasted Maximum Monthly Peak Demand by Year, MW



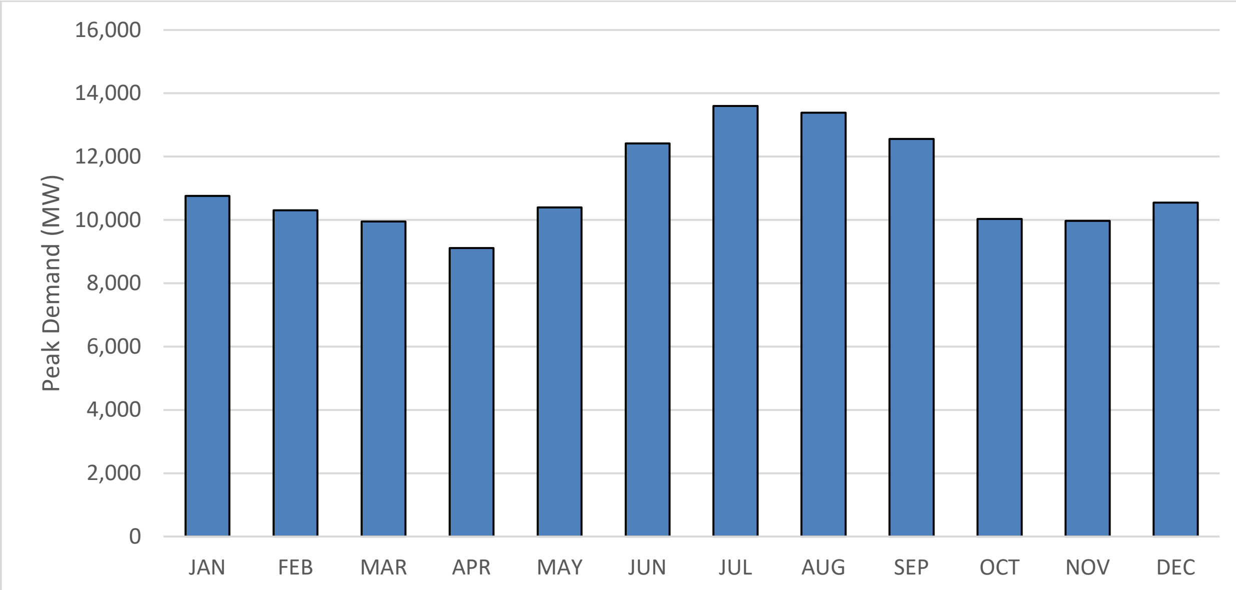
As shown in Table 1-1, providers reported a 0.9 percent increase in peak load from 2020 to 2021 and projected a larger increase of nearly 3.5 percent between 2021 and 2022, as customer demand was expected to increase and economic conditions were expected to improve after the initial impacts of the COVID-19 pandemic. Annual forecasted demand increased for the following six years at an average of 0.16 percent. (More detailed projections can be found in Appendix A, Table A-1.) These projections were submitted before passage of the federal Inflation Reduction Act (IRA) in August 2022. Multiple provisions of the IRA, including renewable energy tax credits and incentives for electric vehicles and electric appliances, may influence projections of customer electric demand provided in future SEAs.

Table 1-1 Expected Maximum Monthly Peak Loads, with Percentage Increases from Previous Year

Year	Maximum Monthly Peak Load (MW)	Percentage Change from Previous Year (%)
2020	13,698	
2021	13,817	0.87%
2022	14,293	3.44%
2023	14,366	0.51%
2024	14,413	0.32%
2025	14,392	-0.15%
2026	14,390	-0.01%
2027	14,398	0.05%
2028	14,431	0.23%

As shown in Figure 1-2, peak demand for the years 2015 to 2021 occurred in the summer months of July and August, influenced largely by the increase in air conditioner use. Smaller peaks occurred in the winter, in part due to higher heating loads and the use of holiday lighting.

Figure 1-2 Average Peak Demand per Month, 2015-2021



RESERVE MARGINS AND TOTAL REQUIRED ELECTRIC SUPPLY

Projections of peak energy demand serve as the foundation for determining the amount of electricity supply needed to meet customer demand. However, these projections may not match actual conditions, due to the variability of peak usage associated with weather and other factors. To account for these uncertainties, adequate supply must include a "reserve margin" over and above projected peak levels, to reduce the risk of inadequate supply if actual demand exceeds projections.

Wisconsin electric providers generate and purchase energy supplies within the regional context of the Midcontinent Independent System Operator, Inc. (MISO), which operates an integrated electric grid across Wisconsin and several other states. (See the Sources of Electricity section and Transmission chapter for more information on MISO.) Wisconsin electric providers therefore assess capacity supplies relative to MISO's Planning Reserve Margin, a value determined through statistical modeling designed to identify the amount of excess capacity necessary to minimize the probability of blackouts resulting from insufficient generation resources.[6] MISO calculates the Planning Reserve Margin based on aggregate Unforced Capacity (UCAP), which takes into account the total energy available from generation sources as well as the likelihood that conditions at any given time may include unit outages and other limitations on actual operating capacity.

[6] MISO conducts an annual Loss of Load Expectation study to determine a minimum planning reserve margin that would result in the MISO system experiencing a less than one-day loss of load (blackout) event every 10 years. *See* https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf.

MISO's Planning Reserve Margin was 9.4 percent for the 2021 planning cycle, and 8.7 percent for 2022,[7] requiring that Wisconsin electric providers maintain energy supplies that exceed projected peak electric demand by 9.4 percent in 2021, and 8.7 percent in 2022.[8] As shown in Table 1-2, Wisconsin providers' total aggregated capacity exceeded reserve requirements in both 2021 and 2022. (More detailed reserve margin calculations, including projections for future years, can be found in Appendix A, Table A-2.) MISO's planning resource auction, conducted in April 2021, confirmed that each Wisconsin electric provider would maintain sufficient capacity resources for 2022, supported by established arrangements for providers to import capacity if needed to address shortfalls below MISO's Planning Reserve Margin threshold.[9]

Table 1-2 Wisconsin Aggregated Supply and Demand, MW

Year[10]	2021	2022
Net Capacity[11]	**15,436**	**15,481**
Expected Demand[12]	**13,693**	**13,788**
UCAP Planning Reserve Margin[13]	**12.7%**	**12.3%**
MISO Reserve Margin Requirements	**9.4%**	**8.7%**

Electric providers' resource planning seeks to meet minimum adequacy requirements, while also seeking to avoid building excess capacity that could increase costs to ratepayers. Historically, Wisconsin's energy supply has more substantially exceeded reserve margin requirements, as shown in Table 1-3. Higher reserve margin values published in previous SEAs reflected large-scale construction of energy generation sources by Wisconsin electric providers in the 1990s and 2000s and low rates of demand growth. While relatively low demand growth has continued, sources of supply have also started to decline in scale, in part due to recent retirements of generation facilities. (Chapter 2 outlines

[7] MISO's decrease in the Planning Reserve Margin value, which continues in later planning years beyond 2022, reflects modeling enhancements, resource mix performance, and load factors. *See* https://cdn.misoenergy.org/20210907%20LOLEWG%20Item%2003%20PY%202022-23%20Preliminary%20LOLE%20Study%20Results586120.pdf

[8] The Commission has also historically set planning reserve margin guidelines for Wisconsin electric providers, to serve as a guideline for state-level planning and a reference for reporting to the Commission. The Commission most recently set a capacity planning reserve margin requirement in docket 5-EI-141. In its order of October 10, 2008 (PSC REF#: 102692), the Commission set a state-level planning guideline of 14.5 percent when considering generation needs beyond the current year. In the MISO auction completed in April 2022, Wisconsin utilities continued to meet this standard just as they had in April 2021. As described further in Chapter 2, FERC has recently approved MISO's proposal to move to a seasonal capacity framework that sets separate reserve margin requirements for spring, summer, fall and winter. Commission staff plan to collect more information from providers in late 2022 or early 2023 on reliability under the new seasonal construct, which can be used to assess how this new guidance comports with present Commission reliability standards.

[9] Commission staff are reviewing the results of the April 2022 MISO planning resource auction in docket 5-EI-2022.

[10] MISO Planning Years run from June 1 to May 31. Listed years represent the second calendar year in the planning year (i.e., 2021 is June 1, 2020-May 31, 2021).

[11] Net capacity numbers include projected future generation reported by utilities; whether and when those additions are implemented may vary based on factors including federal and state regulatory approvals and construction timelines.

[12] Defined by MISO as coincident Load Serving Entity (LSE) peak to MISO peak gross of demand response net Full Responsibility Transaction (FRT).

providers' announced future generation retirements and additions, and assesses the projected impacts of those plans on resource adequacy in future years.)

Table 1-3 Forecasted Reserve Margins from SEA (%); Forecasted Reserve in Installed Capacity through 2014 and UCAP through 2022

Planning Year	Final SEA 2012	Final SEA 2014	Final SEA 2016	Final SEA 2018	Final SEA 2020	Final SEA 2022
2009						
2010						
2011	6.6					
2012	7.3					
2013	21.9					
2014	15.8	20.5				
2015	15.8	18.9				
2016	13.0	17.3	16.9			
2017	11.6	15.3	13.9			
2018	13.3	13.7	13.7	12.0		
2019		14.3	16.4	5.9		
2020		13.8	15.5	8.2	10.2	
2021			14.7	9.0	8.7	
2022			13.6	9.2	7.5	12.7

RELIABILITY

All electric providers in the U.S. assess their reliability using three standard metrics defined by the Institute of Electric and Electronic Engineers:

- **System Average Interruption Duration Index (SAIDI)**, which identifies the average number of total minutes a customer experiences electric outages during a year;[14]
- **Customer Average Interruption Duration Index (CAIDI)**, which identifies the average number of minutes per customer outage, which reflects the length of time required for providers to restore service;[15] and
- **System Average Interruption Frequency Index (SAIFI)**, which identifies the average number of outages a customer experiences during a year.[16]

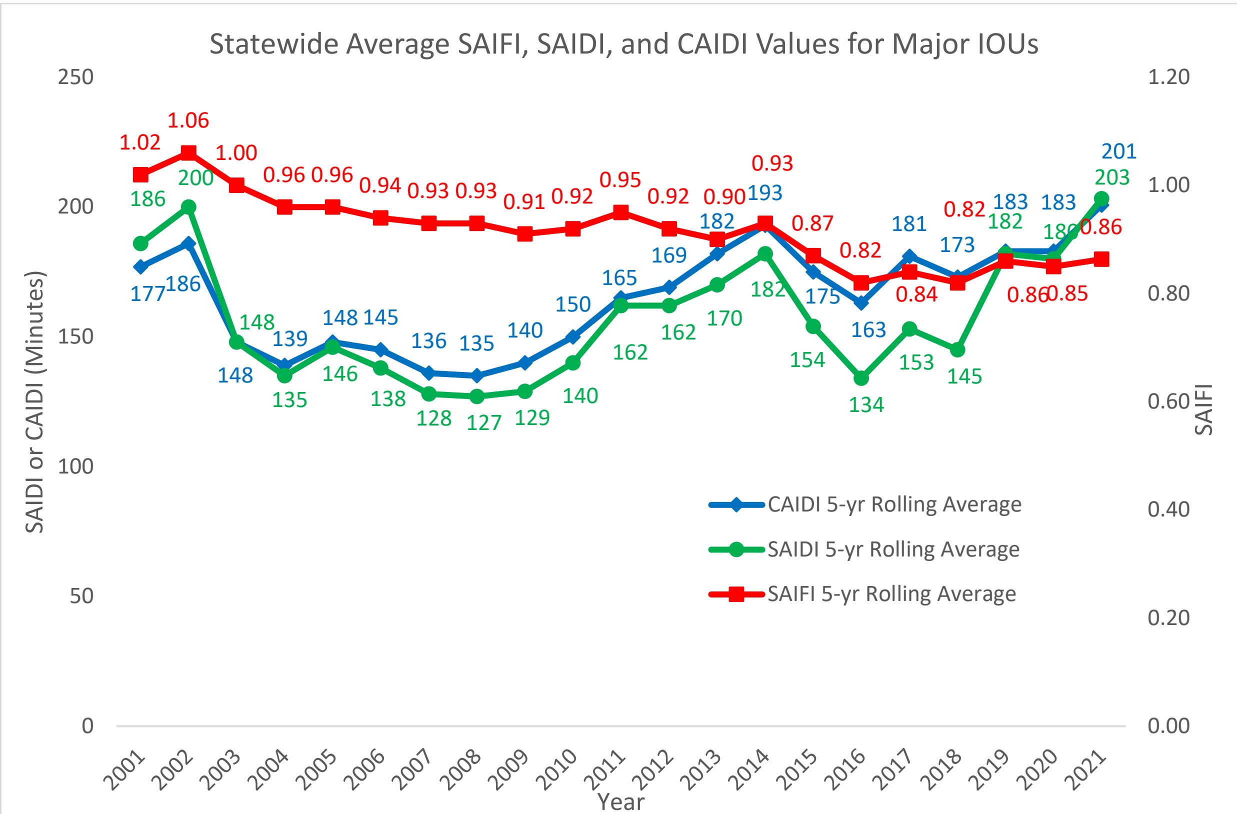
The use of multiple metrics reflects that providers want to limit both the frequency and duration of service outages. A provider experiencing many short outages in a year would have a high SAIFI value, but low SAIDI and CAIDI values. By contrast, a provider with few outages that take a long average time to restore would have high SAIDI and CAIDI values, but a low SAIFI value.

Electric providers with more than 100,000 customers must report annually to the Commission on their performance on those reliability metrics. Figure 1-3 shows combined SAIFI, SAIDI, and

[14] SAIDI equals the annual sum of customer-minutes of interruption divided by the average number of customers served during the year.
[15] CAIDI equals the annual sum of customer-minutes of interruption divided by the annual number of customer interruptions.
[16] SAIFI equals the annual number of customer interruptions divided by the average number of customers served during the year.

CAIDI since 2001 for the five largest investor-owned utilities (IOU) subject to the reporting requirement. In 2021, the average customer of those utilities experienced less than one outage per year (SAIFI=0.86), with an average duration per outage of three hours and 21 minutes (CAIDI=201 minutes). The average frequency of outages has gradually declined over the past two decades, while the average outage duration has increased.

Figure 1-3 Five-Year Rolling Average SAIFI, SAIDI, and CAIDI Values for Major IOUs

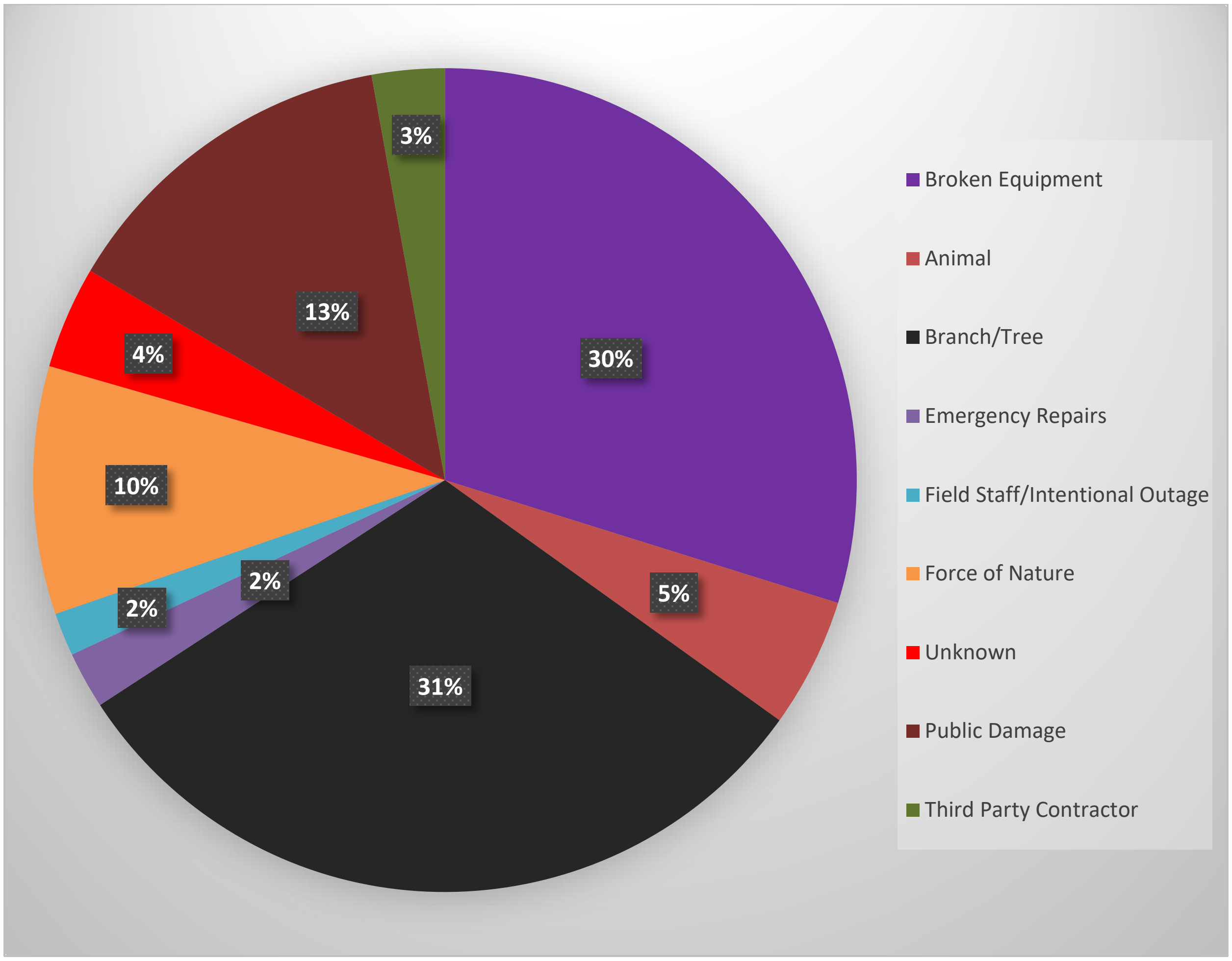


All electric utilities must file reports with the Commission documenting significant service interruptions and providing information on their location, duration, and, when known, the cause of the interruption.[17] Figure 1-4 shows the reported causes of all reported service interruptions in 2020 and 2021; fallen branches and trees and equipment failures accounted for the largest share of outages. In October 2021, providers reported taking ongoing steps to maintain high levels of reliability, including investing in equipment upgrades at locations with aging equipment or a history of reliability issues; seeking improvements to vegetation management practices that reduce the risk of outages from branches and trees; and placing an increasing amount of distribution infrastructure underground.[18]

[17] Wis. Admin. Code § PSC 113.0606. *See* docket 5-GF-113.

[18] Responses to Data Request-PSC-Taylor-1, docket 5-GF-113.

Figure 1-4 Causes of Service Interruptions Reported to the Commission, 2020-2021



SOURCES OF ENERGY SUPPLY

Wisconsin electric providers can procure energy by operating their own generation plants, entering into long-term purchased power agreements (PPA) with independently owned "merchant plants," or purchasing electricity from MISO's regional wholesale market, which operates a day-ahead market and a real time market.[19]

Figure 1-5 depicts Wisconsin electric providers' in-state operating resources as of December 2020, including all owned generation facilities and large-scale merchant plants.[20] (For additional maps

[19] Day-ahead markets permit providers to purchase energy one day in advance at binding prices, to procure energy as needed to meet anticipated demand. Real-time markets permit providers to purchase energy as needed during the operating day, at prices based on available supply and demand. While the day-ahead and real time markets serve as the primary platforms for providers to meet supply needs, MISO also operates transmission rights and ancillary services markets to support grid operations.

[20] For simplicity and clarity, the figure does not include merchant plants from which providers report less than 5 MW of capacity purchased.

broken out by fuel type, see Appendix A, Figures A-1 through A-7.) While this map reflects most Wisconsin providers' owned and merchant resources, providers do also own or contract with generation facilities in other nearby states. For example, providers receive electricity supplies from a number of wind facilities in MISO region states west of Wisconsin, where windier conditions often support cost-effective production.

Figure 1-5 Electric Providers' Generation Resources in Wisconsin – December 2020

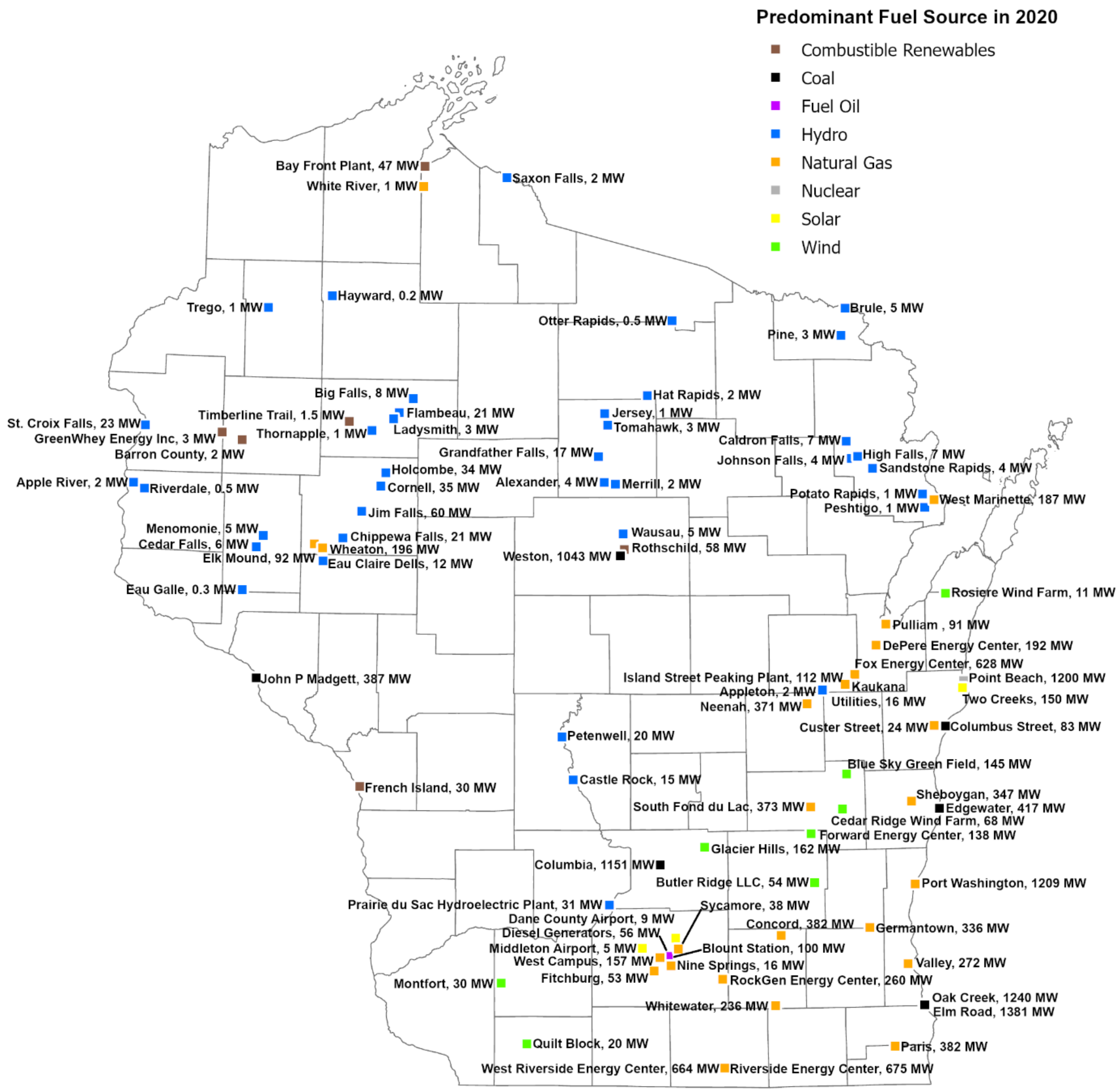


Figure 1-6 breaks down the total capacity of Wisconsin providers' owned generation and merchant plants by generation source, as of December 2020. Natural gas accounted for the largest share of total generation capacity at 45 percent, followed by coal at 33 percent. Zero-carbon energy sources accounted for approximately 20 percent of capacity: 9 percent from wind energy, 7 percent from nuclear energy, 3.5 percent from hydropower, and 1 percent from solar energy.

Figure 1-6 Wisconsin Electric Provider Capacity by Resource – December 2020

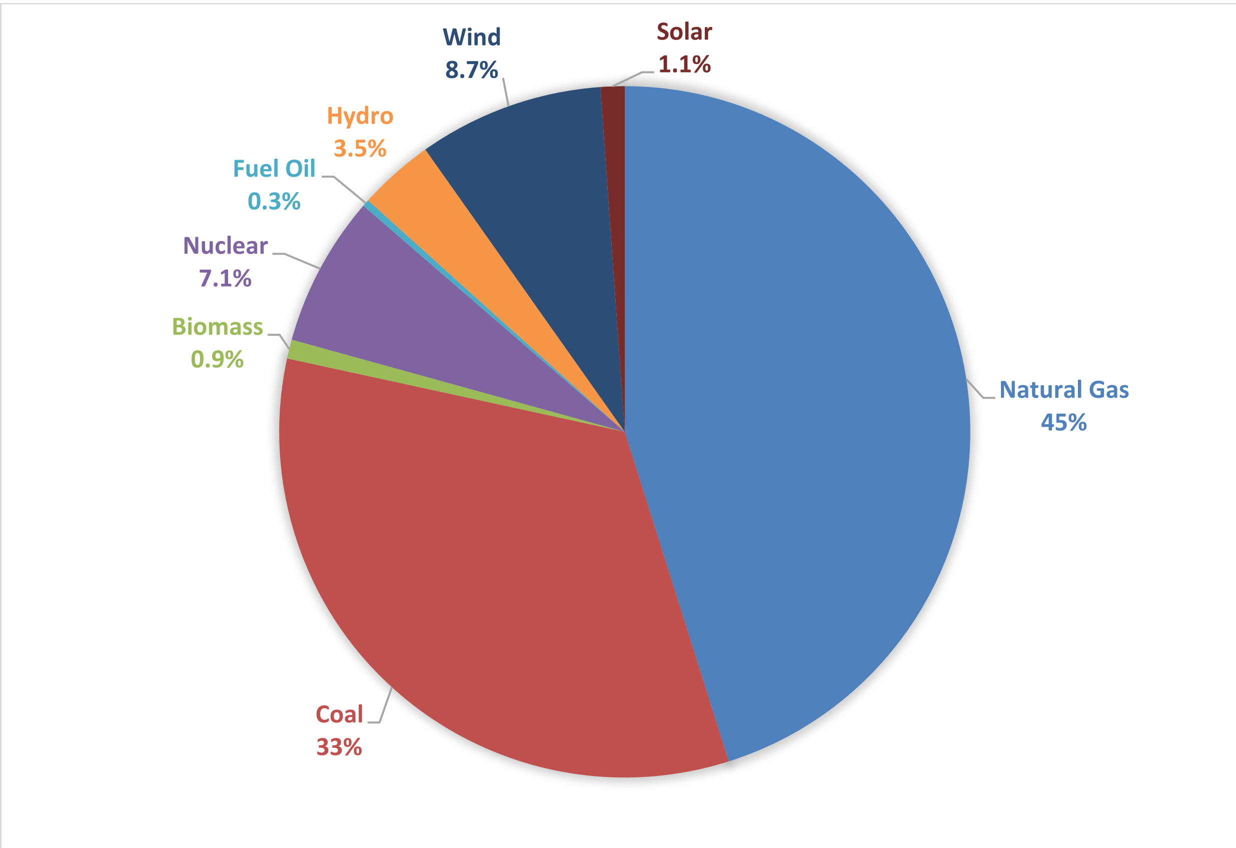
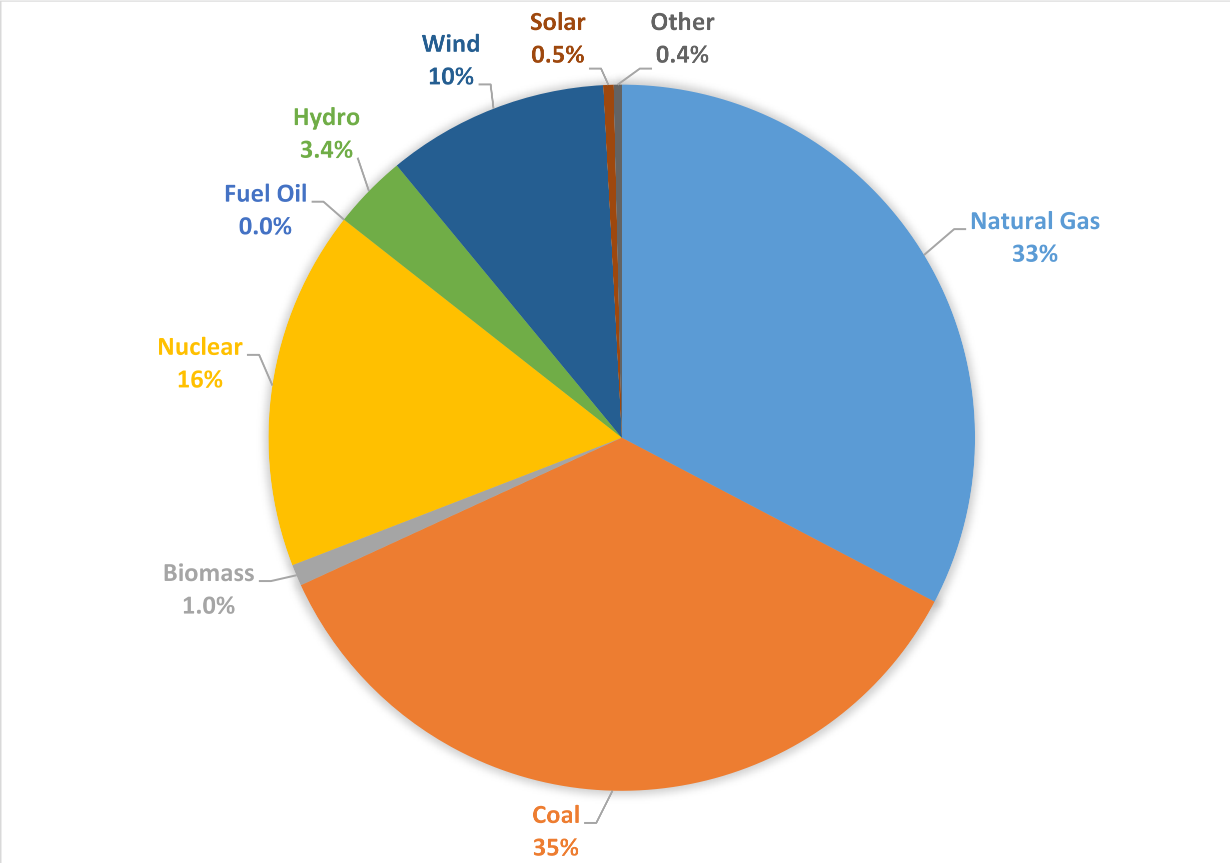


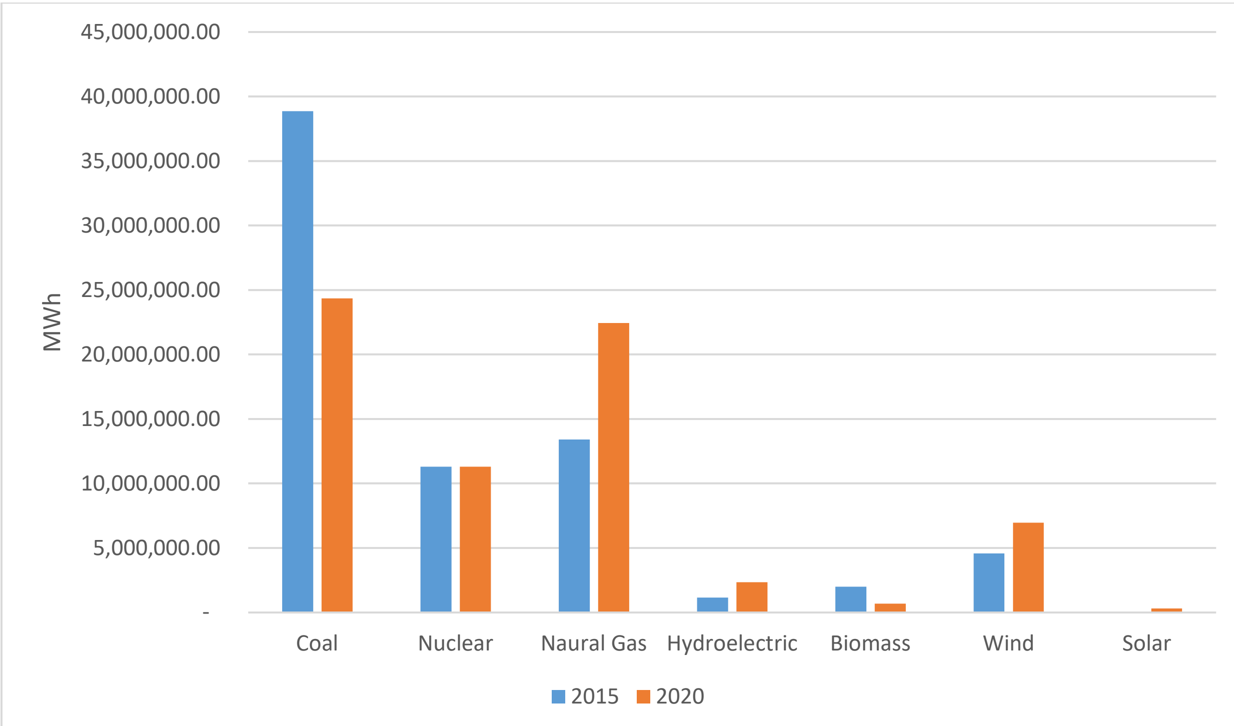
Figure 1-7 breaks down total owned and merchant energy generation by resource during calendar year 2020. Different facilities operate with different "capacity factors," which are calculated based on the amount of their total capacity used for energy production and the percentage of time during the year during which they operate. Because coal and nuclear energy facilities are typically operated on a consistent, ongoing basis, their share of energy generation exceeded their share of capacity in 2020, accounting for 35 percent and 16 percent of energy generation, respectively. Solar sources accounted for a smaller share of energy generation than capacity, due to comparatively low average capacity factors.

Figure 1-7 Wisconsin Electric Provider Generation by Resource – 2020



While coal still represented the most common source of electricity generation in Wisconsin during 2020, its share of total load has decreased in recent years. As shown in Figure 1-7, the share of energy produced from coal declined from approximately 54 percent in 2015 to 35 percent in 2020. Natural gas resources account for the largest corresponding increase in generation share, from 19 percent in 2015 to 33 percent in 2020. Wind resources also increased from 6 percent to 10 percent. Solar generation accounted for 0.5 percent of generation in 2020 after accounting for less than 0.1 percent in 2015.

Figure 1-8 Comparison of 2015 and 2020 Wisconsin Electric Provider Generation by Resource



EMISSIONS

Reduction of carbon dioxide (CO_2) emissions has emerged as a leading priority for maintaining environmentally responsible electric service, due to the primary role of CO_2 emissions in contributing to climate change. Wisconsin Executive Order 38, issued by Governor Evers in 2019, directed utilities and state agencies to work in partnership towards a goal of achieving 100 percent carbon-free electricity consumption in the state by 2050. As shown in Table 1-4, each of the state's five largest electric providers have announced goals to achieve 100 percent net CO_2 reductions by 2050, and set interim goals to achieve a specified percentage of those reductions by 2030. Several providers have also announced additional, complementary goals. For example, Wisconsin Electric Power Company (WEPCO) and Wisconsin Public Service Corporation (WPSC) have set goals to eliminate coal generation from their fleet by 2035, and Wisconsin Power and Light Company (WP&L) has set a goal to eliminate coal generation by 2040.

Table 1-4 Carbon Dioxide Reduction Goals of Wisconsin Electric Providers

Provider	2030 CO_2 Reduction Goal	2050 CO_2 Reduction Goal
Northern States Power Company-Wisconsin (Xcel)	80%	100%
Madison Gas and Electric Company[21]	80%	100%
Wisconsin Electric Power Company (We Energies)	80%	100%
Wisconsin Power and Light Company (Alliant)	50%	100%
Wisconsin Public Service Corporation	80%	100%

[21] MGE announced in February 2022 that it was updating its 2030 reduction goal to 80 percent, up from a previously announced goal of 40 percent.

Other electric providers have also announced their intent to reduce CO_2 emissions. For example, WPPI Energy reported that it is targeting 100 percent CO_2 reduction by 2050 subject to its ability to maintain reliability and affordability, and Dairyland Power Cooperative (DPC) has set a goal to achieve a 50 percent reduction by 2030 in its CO_2 intensity rate.[22]

As it did for the SEA 2026, the Commission collected from all electric providers information on their progress in achieving CO_2 reductions, compared to the 2005 emissions levels commonly used as a baseline for calculating percentage reductions. As shown in Table 1-5, reported emissions reductions in 2020 across all providers totaled 40 percent, with individual reductions ranging from 0 percent to 56 percent. As outlined in individual providers' responses, methods for calculating emissions reductions differ. For example, WP&L's goal applies to reductions from its owned generation, while Northern States Power Company-Wisconsin (NSPW) measures emissions from all electricity used to serve its customers, including purchased power. For providers that operate across multiple states, the figures in Table 1-5 reflect their reported Wisconsin share of emissions.

Table 1-5 Carbon Dioxide Reductions as of 2020 (% Compared to 2005 Carbon Dioxide Emissions)

Provider	2005 Emissions (Million tons)	2020 Emissions (Million tons)	2020 CO_2 Reduction	2030 CO_2 Reduction Goal
Northern States Power Company-Wisconsin (Xcel)	4.1	1.8	56%	80%
Wisconsin Electric Power Company (We Energies)	23.8	12.9	46%	80%
Wisconsin Public Service Corporation	11.9	6.5	46%	80%
WPPI Energy	4.3	2.4	44%	N/A
Wisconsin Power and Light Company (Alliant)	8.8	6.4	27%	50%
Madison Gas and Electric Company	3.4	2.5	26%	80%
Dairyland Power Cooperative	4.4	3.8	15%	N/A
Manitowoc Public Utilities	0.2	0.2	0%	N/A
All Providers	60.9	36.5	40%	

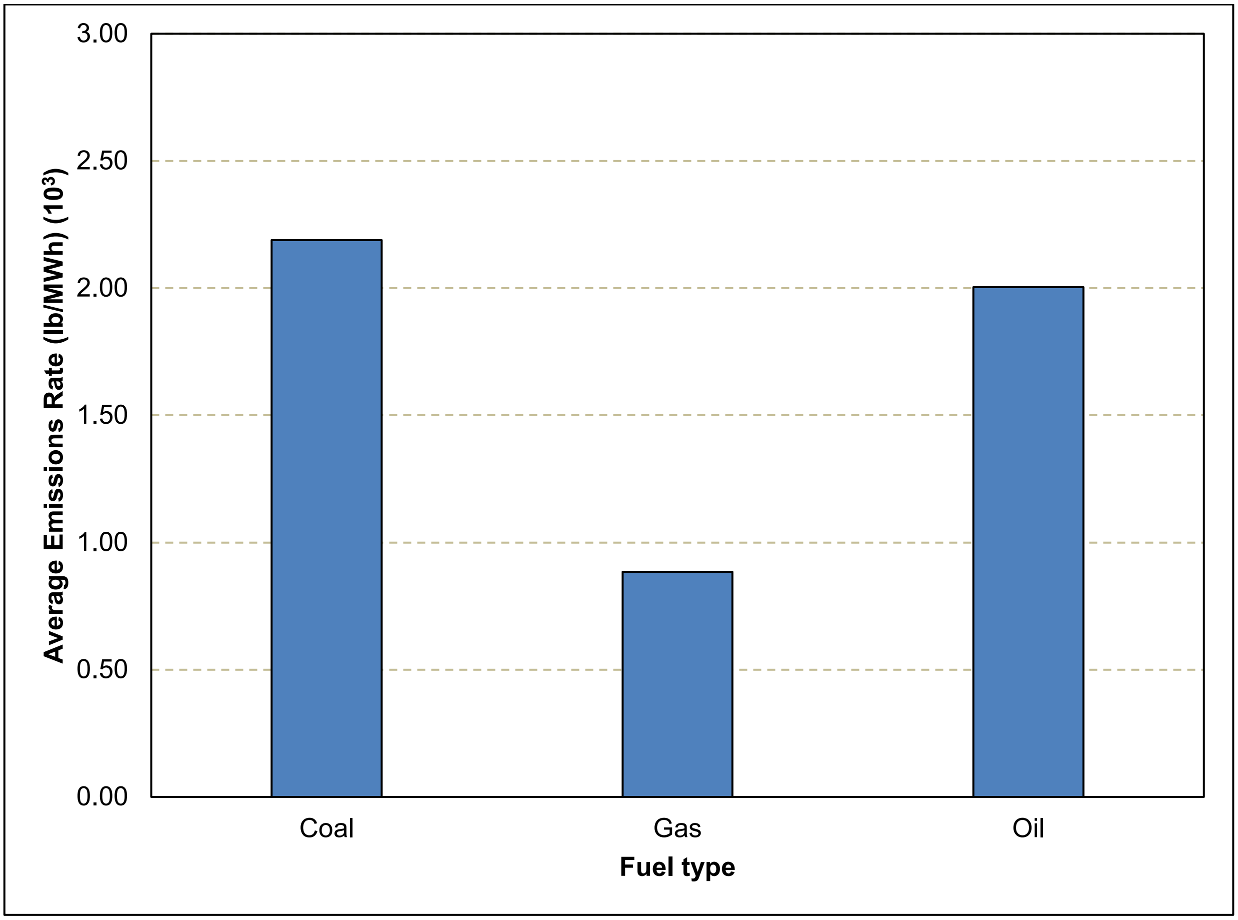
To provide further detail on emissions, the Commission expanded its SEA data request to include information on CO_2 emissions from each generation facility owned by Wisconsin providers during 2019 and 2020. Total emissions of provider-owned facilities provided through this request did not match the total emissions reported for calculating percentage reductions above, in large part because many providers procure a substantial share of their total energy through purchased power and include emissions from those sources in calculating their emissions reduction goals and outcomes. However, reviewing provider-owned facility CO_2 emissions can provide additional insight on provider emissions profiles.

Total emissions of provider-owned facilities reflect the combination of two factors: total electric generation at the facility, and the emissions rate, or the amount of CO_2 emitted per unit of energy generated. As shown in Figure 1-9, CO_2 emissions rates differ significantly by fuel type. Emissions rates from Wisconsin providers' natural gas facilities equal approximately 40 percent of the

[22] The CO_2 intensity rate measures the amount of emissions per unit of energy generated (lbs. CO_2/MWh produced).

emissions rates from coal facilities. Oil generation also has higher CO_2 emissions rates than natural gas, although its overall impact is limited because it accounts for a small share of total generation.[23]

Figure 1-9 Emissions Rates by Fuel Type at Provider-Owned Facilities, 2019-2020

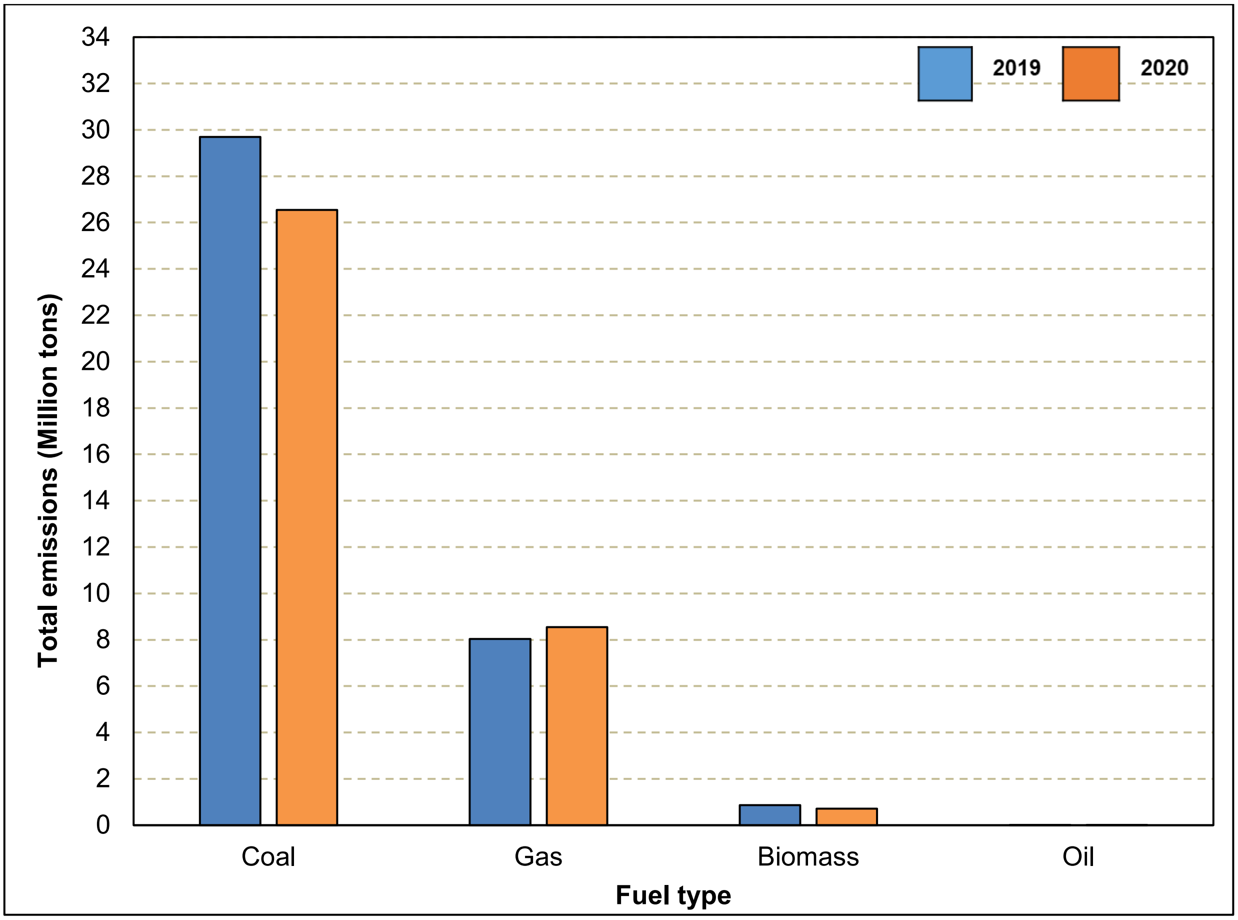


As shown in Figure 1-10, coal facilities accounted for more than 70 percent of CO_2 emissions from provider-owned facilities in both 2019 and 2020, driven by its status as the largest share of total in-state generation (see Figure 1-7 above) and its higher emissions rate than natural gas. CO_2 emissions from coal facilities declined more than 10 percent from 2019 from 2020, and overall CO_2 emissions declined more than 7 percent, due to decreased customer demand influenced by the COVID-19 pandemic and low natural gas prices that provided economic incentives for providers to increase their share of gas-fired generation. In light of subsequent increases in customer demand and natural gas prices, coal generation, coal-based CO_2 emissions, and total CO_2 emissions from Wisconsin

[23] Wisconsin providers also report emissions from a small number of biomass facilities. An average is not provided in Figure 1-9 because biomass emissions rates vary significantly across individual facilities, based on the source and production methods of the biomaterial used for generation. *See* U.S. Environmental Protection Agency, "Greenhouse Gas Inventory Guidance: Direct Emissions from Stationary Combustion Sources," Section 1.2. https://www.epa.gov/sites/default/files/2016-03/documents/stationaryemissions_3_2016.pdf.

facilities may increase from 2020 levels in 2021 and 2022, counterbalanced by the recent and upcoming facility retirements discussed in Chapter 2.

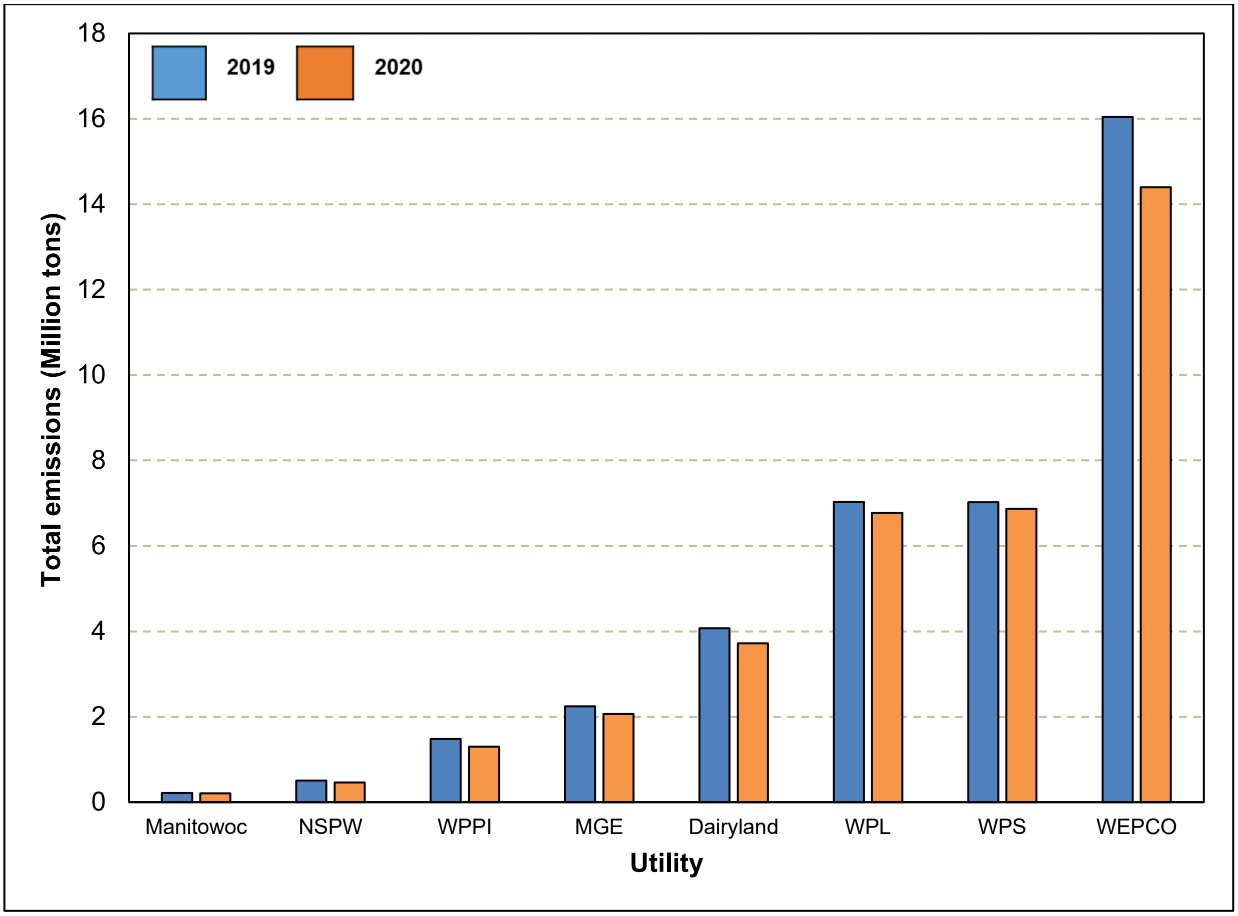
Figure 1-10 Total Emissions by Fuel Type at Provider-Owned Facilities, 2019-2020



As shown in Figure 1-11, providers' CO_2 emissions from owned facilities largely corresponded with providers' total share of generation in 2019 and 2020. WEPCO, WP&L, and WPSC together accounted for a significant majority of both generation and CO_2 emissions. However, differences in emissions rates also influence provider comparisons. Manitowoc Public Utilities, DPC, and WPPI Energy had the highest emissions rates from provider-owned facilities, influenced by their relative share of coal generation as well as differences in emissions rates between facilities of the same fuel type.[24] Appendix A includes more information on emissions rates at individual facilities. As noted above, total emissions by provider may differ from calculations focused on provider-owned facilities, in part because a number of providers procure substantial shares of total energy from purchased power.

[24] A primary influence on emissions rates at individual facilities is their generating efficiency, also known as heat rate: the amount of fuel energy consumed per unit of generation produced. Heat rate can vary considerably based on the size of the facility, the frequency (capacity factor) by which the facility runs, and the operating properties of individual facilities.

Figure 1-11 Total Emissions by Provider from Provider-Owned Facilities, 2019-2020



CHAPTER 2 – FUTURE ELECTRICITY GENERATION IN WISCONSIN

Wisconsin electric providers' announced generation retirements and additions through 2028 reflect an acceleration in the electric generation transition already underway. Providers cite increasing economic and environmental benefits as reasons to pursue the transition, as solar generation and other technologies, such as battery storage, become increasingly cost-competitive, and the transition to zero-emissions sources supports progress towards CO_2 reduction goals. In light of the large scale and rapid pace of generation changes, this chapter expands upon previous SEAs by reviewing in greater detail the utility resource planning analysis used to support announced additions and retirements, and providing Commission staff's independent analysis assessing the statewide impacts of generation changes on Wisconsin's electric system.

GENERATION RETIREMENTS AND ADDITIONS

As shown in Table 2-1, Wisconsin electricity providers report plans to retire approximately 3,300 MW of in-state generation by 2028. Providers plan to fully retire three of the seven utility-scale coal facilities currently operating in Wisconsin —Edgewater, Columbia, and Oak Creek – which have a combined capacity of nearly 2,800 MW. In June 2022, providers announced that they would delay previously reported retirement dates at all three plants, due to concerns about maintaining reliability in upcoming years associated with delays in construction of generation additions. Under these updated plans, full retirement of all three plants would occur by 2026.

Table 2-1 Planned Utility-Owned or Leased Generation Capacity Retirement through 2028

Year	Name	Capacity (MW)	Fuel	Owner/Leaser	Recent Updates
2023	Weston 2, 31, 32	75, 20, 58	Natural Gas	WPSC	
2024	West Marinette 31, 32	42, 42	Natural Gas	WPSC	
2024	Rosiere Wind Farm	11	Wind	MGE	
2024	Oak Creek 5, 6	299, 299	Coal	WEPCO	Delayed from 2023
2025	Wheaton 1, 2, 3, 4, 6	56, 68, 56, 61, 70	Natural Gas and Fuel Oil	NSPW	
2025	Edgewater 5	406	Coal	WP&L	Delayed from 2023
2025	Oak Creek 7, 8	318, 324	Coal	WEPCO	Delayed from 2024
2026	Columbia 1, 2	566, 565	Coal	WP&L, WPSC, MGE	Delayed from 2024 (Unit 1) and 2025 (Unit 2)

Providers must receive MISO approval to proceed with unit retirements. The generation retirement process at MISO begins when a provider submits an Attachment Y Notice to MISO requesting either to retire or suspend the operations of a unit. MISO then convenes a retirement study with the transmission owners to assess grid operations in the absence of the requested unit. If MISO's analysis concludes that retirement of the unit would not have negative effects on the reliability of the regional grid, it issues an approval of retirement or suspension to the provider. However, if MISO identifies reliability concerns, it designates the facility as a System Support Resource (SSR) which requires the facility to continue operating until a timely alternative to resolve the reliability issue is presented.[25] While no Wisconsin facilities have received SSR designations to date, future retirements could potentially be foregone or delayed in response to MISO findings that continued operation is needed.[26]

As shown in Table 2-2, Wisconsin providers reported plans to add approximately 2,500 MW of new solar energy capacity, 400 MW of new natural gas capacity, and nearly 100 MW of new wind capacity by 2028.[27] In addition, providers reported plans for approximately 500 MW of new battery energy storage system (BESS) capacity, all paired with announced solar facilities. Providers also reported plans for ownership transfers of approximately 850 MW of existing natural gas capacity within the state of Wisconsin.[28]

A number of announced new facilities divide their total capacity between multiple providers through co-ownership arrangements, which are outlined in footnotes to Table 2-2. Accounting for ownership shares, three providers account for more than 70 percent of total announced capacity additions and transfers: WEPCO, WPSC, and WP&L.

- WEPCO reported plans to add 888 MW of new solar capacity, 386 MW of new energy storage capacity, and 66 MW of new natural gas capacity. It also has announced intentions to purchase an additional 118 MW of natural gas electric generation capacity at the existing Whitewater Cogeneration Facility.
- WPSC reported plans to add 258 MW of new solar capacity, 83 MW of wind electric generation capacity, 77 MW of energy storage capacity, and 66 MW of new natural gas electric generation capacity. WPSC also reported plans to purchase ownership shares for 218 MW of existing natural gas capacity at the Whitewater Cogeneration and West Riverside facilities.

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[25] When alternatives are identified, MISO provides an assessment through its Open Access Same-Time Information System (OASIS).

[26] Providers who are considering a retirement or suspension may also opt to submit an Attachment Y2 form to MISO, which requests analysis of the potential adequacy and reliability effects and a nonbinding indication of whether an SSR designation would be considered. Providers who submit Attachment Y2 requests would still need to submit a subsequent Attachment Y Notice to receive formal approval to retire or suspend the facility.

[27] The figure for natural gas capacity does not include the ownership shares of out-of-state providers for 275 MW of the total capacity of the Nemadji Trail Energy Center.

[28] The Commission has approved or received construction authorization applications for multiple additional independent generation facilities in Wisconsin that are not included in this summary, including:

- Apple River Solar + Storage (Commission docket 9808-CE-100) (100 MW solar PV, 100 MW storage);
- Portage Solar (9810-CE-100) (250 MW solar PV);
- Northern Prairie Solar (9815-CE-100 (101 MW solar PV); and
- Saratoga Solar (9816-CE-100) (150 MW solar PV, 50 MW storage).

It is possible Wisconsin electric providers may eventually incorporate some or all of these facilities into their generation portfolios. However, it is not certain whether or when this may take place, and it is possible that these independent facilities may be deployed for other purposes, such as to supply private customers or providers located outside of Wisconsin. Due to this uncertainty, these facilities are not included in Table 2-2 or subsequent analysis in this chapter assessing the effects of providers' reported generation additions.

- WP&L has been authorized to construct 1,089 MW of new solar capacity at twelve sites.

Since planned additions were initially reported in November 2021, providers have announced delays in the completion date of multiple projects, due in part to supply constraints that have delayed materials procurement. Announced timing updates are identified in the rightmost column of Table 2-2.

Table 2-2 New Additions and Transfers of Utility-Owned or Leased Generation Capacity by Wisconsin Electric Providers 2021 through 2028

Year	Nameplate Capacity (MW)	Name	New or Existing Site	Owner/ Leaser	Source	PSC status and Docket Number	Recent Updates
2021	150[29]	Badger Hollow (phase 1)	New	WPSC/ MGE	Solar	5-BS-228, approved	
2022	8	Hermsdorf Solar	New	MGE	Solar	3270-CE-130, approved	
2022	489	Rock Gen 1-3	Existing	DPC	Natural Gas		
2022	0.5	Superior Solar	New	SWL&P	Solar		
2023[30]	74	Western Mustang	New	NSPW	Solar	4220-BS-100, approved	Delayed from 2022
2023	150[31]	Badger Hollow (phase 2)	New	WEPCO / MGE	Solar	5-BS-234, approved	
2023	92[32]	Red Barn Wind	New	WPSC / MGE	Wind	5-BS-256, approved	
2023	200[33]	Paris Solar	New	WEPCO / WPSC / MGE	Solar	9801-CE-100, approved; 5-BS-254, approved	
2023	110[34]	Paris Solar BESS	New	WEPCO / WPSC / MGE	Battery Storage	9801-CE-100, approved; 5-BS-254, approved	
2023	75	Crawfish River Solar	New	WP&L	Solar	6680-CE-182, approved	
2023	150	Onion River Solar	New	WP&L	Solar	9805-CE-100, approved; 6680-CE-182, approved	
2023	200	Grant County Solar	New	WP&L	Solar	9804-CE-100, approved; 6680-CE-182, approved	
2023	50	North Rock Solar	New	WP&L	Solar	6680-CE-182, approved	
2023	50	Albany Solar	New	WP&L	Solar	6680-CE-183, approved	
2023	50	Bear Creek Solar	New	WP&L	Solar	6680-CE-182, approved	Delayed from 2022

[29] Ownership is split with 100 MW to WPSC, 50 MW to MGE.
[30] This is the estimated year. Further updates may be provided at a later date.
[31] Ownership is split with 100 MW to WEPCO, 50 MW to MGE.
[32] Ownership shares are proposed as approximately 83 MW to WPSC, 9 MW to MGE.
[33] Ownership shares are proposed as 150 MW to WEPCO, 30 MW to WPSC, and 20 MW to MGE.
[34] Ownership shares are proposed as 82.5 MW to WEPCO, 16.5 MW to WPSC, and 11 MW to MGE.

Year	Nameplate Capacity (MW)	Name	New or Existing Site	Owner/ Leaser	Source	PSC status and Docket Number	Recent Updates
2023	150	Wood County Solar	New	WP&L	Solar	6680-CE-182, approved; 9803-CE-100, approved	Delayed from 2022
2023	50	Beaver Dam Solar	New	WP&L	Solar	6680-CE-183, approved	
2023	50	Cassville Solar	New	WP&L	Solar	6680-CE-183, approved	
2023	65	Paddock Solar	New	WP&L	Solar	6680-CE-183, approved	
2023	100	Springfield Solar	New	WP&L	Solar	9807-CE-100, approved; 6680-CE-183, approved	
2023	99	Wautoma Solar	New	WP&L	Solar	6680-CE-183, approved	
2023	132[35]	Weston RICE	New	WPSC/ WEPCO	Natural Gas	5-CE-153, approved	
2023	236[36]	Whitewater Cogeneration Facility	Existing	WPSC/WEPCO	Natural Gas	5-BS-264, pending	
2023	25[37]	West Riverside	Existing	MGE	Natural Gas	5-BS-265, pending	
2023	100[38]	West Riverside	Existing	WPSC	Natural Gas	5-BS-265, pending	
2024	250[39]	Darien Solar	New	WEPCO / WPSC / MGE	Solar	9806-CE-100, approved; 5-BS-255, pending	
2024	75[40]	Darien Solar Storage	New	WEPCO / WPSC / MGE	Battery Storage	9806-CE-100 approved; 5-BS-255, pending	
2025	300[41]	Koshkonong Solar	New	WEPCO / WPSC / MGE	Solar	9811-CE-100,approved; 5-BS-258, pending	
2025	165[42]	Koshkonong Solar Storage	New	WEPCO / WPSC / MGE	Battery Storage	9811-CE-100, approved; 5-BS-258, pending	
2025	Unknown	Wheaton replacement	New	NSPW	Natural Gas		
2026	300[43]	Solar 6	New	WEPCO / WPSC / MGE	Solar	9814-CE-100, pending	Delayed from 2025
2026	165[44]	Battery 6	New	WEPCO / WPSC / MGE	Battery Storage	9814-CE-100, pending	Delayed from 2025

[35] Ownership shares are proposed as approximately 66 MW to WPSC and 66 MW to WEPCO.
[36] Ownership shares are proposed as approximately 118 MW to WPSC and 118 MW to WEPCO.
[37] Per agreement between WP&L and MGE reached in docket 6680-CE-176. An additional 25 MW may be optioned at a future date.
[38] Per agreement between WP&L and WPSC reached in docket 6680-CE-176. An additional 100 MW may be optioned at a future date.
[39] Ownership shares are proposed as 187.5 MW to WEPCO, 37.5 MW to WPSC, and 25 MW to MGE.
[40] Ownership shares are proposed as 56.25 MW to WEPCO, 11.25 MW to WPSC, and 7.5 MW to MGE.
[41] Ownership shares are proposed as 225 MW to WEPCO, 45 MW to WPSC, and 30 MW to MGE.
[42] Ownership shares are proposed as 123.75 MW to WEPCO, 24.75 MW to WPSC, and 16.5 MW to MGE.
[43] Ownership shares are proposed as 225 MW to WEPCO, 45 MW to WPSC, and 30 MW to MGE.
[44] Ownership shares are proposed as 123.75 MW to WEPCO, 24.75 MW to WPSC, and 16.5 MW to MGE.

Year	Nameplate Capacity (MW)	Name	New or Existing Site	Owner/ Leaser	Source	PSC status and Docket Number	Recent Updates
2027	550[45]	Nemadji Trail Energy Center	New	DPC	Natural Gas	9698-CE-100, approved	

Effects on Resource Adequacy

Achieving ongoing compliance with reserve margin requirements will be significantly influenced by providers' additions and retirements. Electric providers' responses to the MISO and Organization of MISO States (OMS) Resource Adequacy Surveys conducted in June 2021 and June 2022 indicated that projected capacity levels throughout the MISO region are at risk of falling below the local reserve margin in future years if planned capacity is not implemented, which could result in a need for providers to pursue other means to meet demand requirements, such as importing additional capacity. The 2022 survey identified a potential regional capacity shortfall beginning in 2023, but noted that the shortfall could be addressed through further action by participating providers. Wisconsin providers' announced plant retirement delays occurred shortly after the 2022 survey results were published.

As shown in Figure 2-1 and Table 2-3, electric providers report annual projections of total capacity (taking into account projected additions and retirements) that continue to remain above MISO's projected reserve margin requirements. While analysis earlier in 2022 had projected declining capacity levels in 2023 and 2024, providers now expect to increase their capacity well above reserve margin requirements in those years, due to the continued operation of plants previously assumed to be retired, as well added credit for generation additions that have recently received MISO-approved Generator Interconnection Agreements. MISO's reserve margin requirements are also projected to decrease in future years, from 8.7 percent in 2022 to 7.0 percent by 2028.[46] More detailed reserve margin calculations can be found in Appendix A, Table A-2. The Commission will continue to monitor resource adequacy issues to ensure sufficient reserve margin targets are met in future years.

Table 2-3 Wisconsin Aggregated Supply and Demand, MW

Year[47]	2021	2022	2023	2024	2025	2026	2027	2028
Net Capacity[48]	15,436	15,481	16,464	16,342	16,482	15,457	15,624	15,729
Expected Demand[49]	13,693	13,788	13,768	13,796	13,826	13,852	13,852	13,885
UCAP Planning Reserve Margin[50]	12.73%	12.28%	19.58%	18.46%	19.21%	11.59%	12.79%	13.28%
MISO Reserve Margin Requirements	9.4%	8.7%	8.3%	7.8%	7.4%	7.5%	7.5%	7.0%

45 Ownership shares are proposed as 50 percent to DPC, 30 percent to Basin Electric Power Cooperative, and 20 percent to Minnesota Power (d/b/a ALLETE, Inc.).

46 MISO's decrease in the reserve margin value reflects modeling enhancements, resource mix performance, and load factors. See https://cdn.misoenergy.org/20210907%20LOLEWG%20Item%2003%20PY%202022-23%20Preliminary%20LOLE%20Study%20Results586120.pdf.

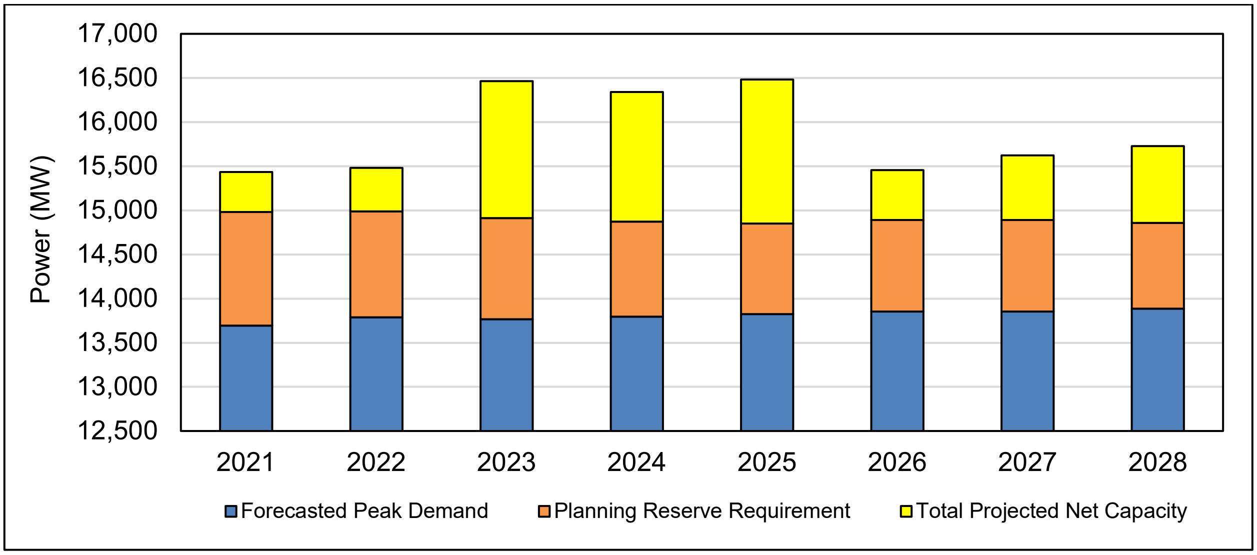
47 MISO Planning Years run from June 1 to May 31. Listed years represent the second calendar year in the planning year (i.e., 2021 is June 1, 2020-May 31, 2021).

48 Net capacity numbers include projected future generation reported by utilities; whether and when those additions are implemented may vary based on multiple factors, including federal and state regulatory approvals and construction timelines.

49 Defined by MISO as coincident LSE peak to MISO peak gross of demand response net FRT.

50 Equals (net capacity/expected demand) – 1.

Figure 2-1 Wisconsin Net Capacity Compared to Planning Reserve Requirements



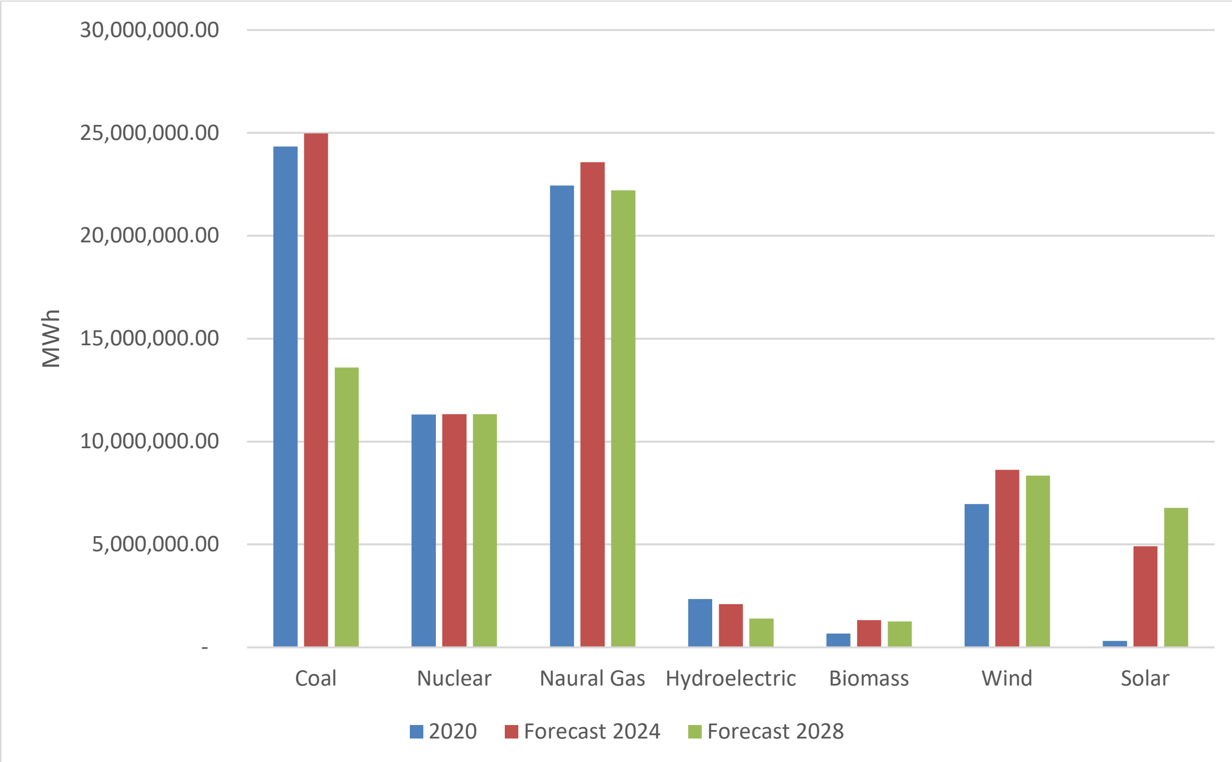
Resource adequacy requirements have historically been defined in terms of adequacy during peak demand periods in the summer, as discussed in Chapter 1. However, influenced by recent regional experiences with resource adequacy and reliability challenges occurring throughout the year, MISO filed a proposal with the Federal Energy Regulatory Commission (FERC) to begin using a seasonal resource adequacy construct, which would set four separate reserve margin requirements for winter, spring, summer and fall. FERC approved MISO's proposal in August 2022.[51] MISO plans to begin implementing the seasonal construct beginning in 2023, which will require modification to resource adequacy reporting and assessment by providers and the Commission.

Effects on Sources of Energy Supply

As shown in Figure 2-2, if all additions and retirements are implemented as planned by electric providers, coal will decline from 35 percent of Wisconsin's generation to 21 percent in 2028, natural gas will increase from 33 percent to 34 percent, wind resources will increase from 10 percent to 13 percent, and solar resources will increase from 0.5 percent to 10 percent. The recently announced delays in coal plant retirement dates would maintain coal generation near current levels through 2024, but providers continue to anticipate that all three plants will be fully retired by 2028. The share of solar resources may increase further if Wisconsin providers choose to procure additional independently developed projects.

[51] *Order Accepting Proposed Tariff Revisions Subject to Condition*, 180 FERC ¶ 61,141 (2022), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220831-3093.

Figure 2-2 Generation Comparison by Resource - 2020, 2024, and 2028



Effects on Emissions

As shown in Table 2-4, providers project that announced additions and retirements will help drive additional reductions in CO_2 between 2020 and 2028. As of July 2022, total CO_2 emissions reductions from all providers are projected to drop by 58 percent in 2028 compared to 2005 baseline levels. Appendix B, Figure B-1 provides more details on provider projections by year, which are influenced by the currently anticipated timing of generation retirements and additions.

Table 2-4 Projected Carbon Dioxide Reductions by 2028

Provider	2020 Emissions (Million tons)	2020 CO_2 Reduction	Projected 2028 Emissions (Million tons)	2028 CO_2 Reduction	2030 CO_2 Reduction Goal
Northern States Power Company-Wisconsin (Xcel)	1.8	56%	0.9	78%	80%
Madison Gas and Electric Company	2.5	26%	1.0	70%	80%
Wisconsin Public Service Corporation	6.5	46%	4.3	64%	80%
Wisconsin Power and Light Company (Alliant)	6.4	27%	3.3	62%	50%
Wisconsin Electric Power Company (We Energies)	12.9	46%	10.6	55%	80%
WPPI Energy	2.4	44%	2.3	46%	N/A
Dairyland Power Cooperative	3.8	15%	3.2	29%	N/A
Manitowoc Public Utilities	0.2	0%	0.2	0%	N/A
All Providers	36.5	40%	25.8	58%	

WP&L projects emissions reductions by 2028 that would exceed its announced 2030 CO_2 reduction goal of 50 percent. MGE, NSPW, WEPCO, and WPSC projected additional reductions by 2028 that would progress towards but not meet their 2030 goals to achieve 80 percent CO_2 reductions. Total CO_2 emissions reductions may exceed these projections if further additions of low-carbon generation or retirements of fossil fuel generation take place before 2028.

RESOURCE PLANNING IN WISCONSIN

In 2021, the Commission opened the "Roadmap to Zero Carbon" investigation in docket 5-EI-158 to gather information on how Wisconsin could best achieve the economic and environmental benefits of the generation transition. In response to the Commission's initial request for input on docket priorities, commenters most frequently highlighted interest in establishing enhanced and more transparent utility resource planning processes. Discussion of the issue through the Roadmap docket has highlighted the importance of thoroughly assessing how utility resource decisions balance the goals of adequacy, reliability, affordability, and environmental responsibility, and emphasized that effective resource planning is especially important during a period of rapid change.

Commissions in a number of other states use Integrated Resource Planning (IRP) processes to review providers' generation plans, and in some cases to exercise regulatory authority over final addition and retirement decisions. While some Roadmap commenters identified those other states as models for effective resource planning, IRP processes are typically established through legislative authorization, which has not taken place in Wisconsin. To support more transparent resource planning, the Commission sought to support enhanced resource planning within the SEA, in two ways. First, Commission staff preparing this SEA requested additional information from providers on their resource planning analysis associated with announced additions and retirements. Second, this SEA includes independent Commission staff analysis on statewide resource planning considerations.

Provider Resource Planning

The new resource planning information requested for this SEA covered content commonly addressed in detailed resource plans, including IRPs conducted in other states. Electric providers in Wisconsin that owned more than 5 MW of generation were directed to submit information on:

- The goals and standards set to guide planning decisions for additions and retirements;
- The analysis methods used to assess different resource options against the established goals and standards;
- The inputs and assumptions used in the analysis to define future electric system conditions, including the range of different scenarios used to account for the uncertainty of projecting future developments; and
- An explanation of how the resource analysis led the provider to identify the generation additions and retirements identified in the SEA, including a description of how the utility identified those decisions as superior to other potential generation options for meeting its planning goals and standards.

Table 2-5 summarizes the responses from nine electric providers, submitted in November 2021. The amount of detail provided varied by respondent. Providers with few or no planned additions and retirements provided comparatively limited information. NSPW and other providers with operations in Minnesota provided the IRP documents required by that state, noting that the analysis and findings were also relevant to their resource decisions in Wisconsin. Extensive submissions were provided by WEPCO, WPSC, and WP&L, consistent with their responsibility for the majority of announced additional generation capacity statewide.

Table 2-5 Resource Planning Responses: November 2021

Provider	Response	Additional Responses/Notes
DPC	PSC REF#: 425477	Minnesota IRP: PSC REF#: 425265
Great Lakes Utilities	PSC REF#: 424991	Minnesota IRP: PSC REF#: 424992
Manitowoc Public Utility	PSC REF#: 424988	IRP planned in 2022
NSPW	PSC REF#: 425535	Starting on p. 45; includes links to Minnesota IRP.
MGE	PSC REF#: 425579	
WEPCO	PSC REF#: 425537	Same information as WPSC filing
WP&L	PSC REF#: 426253	Starting on p. 41
WPSC	PSC REF#: 425528	Same information as WEPCO filing
WPPI Energy	PSC REF#: 426588	

Electric providers confirmed that their planning accounted for the four goals of adequacy, reliability, affordability, and environmental responsibility, and identified specific metrics used to assess performance on those goals:

- **Adequacy** was commonly defined as meeting the reserve requirements required by MISO and the Commission. (See "Reserve Margins and Total Required Electric Supply" section in Chapter 1.)
- **Reliability** was assessed by identifying available generation supply necessary to meet load during each hour of the year. Multiple providers reported that they assessed reliability in their planning based on maintaining a sufficient amount of "firm" and "dispatchable" generation that can be rapidly accessed to address supply needs, which would include natural gas generation resources and, for some utilities, battery storage.
- **Affordability** was commonly defined by calculating the net present value of the costs associated with a given set of generation additions and retirements (as well as any planned market purchases), under the assumption this value would reflect the costs passed along to customers, and comparing those costs to alternative resource mixes to identify lower-cost options.
- **Environmental responsibility** was defined in terms of compliance with the provider's CO_2 reduction goals, as well as any other established environmental goals.

Multiple providers also identified that their planning goals included maintaining a diversity of generation sources located in Wisconsin and controlled by the provider. Some providers stated that pursuing diversity of generation sources also supported the goals of adequacy and reliability, stating that MISO adequacy requirements require high levels of generation supply close to the utility territory, and that reliability could be threatened if the provider relied too heavily on generation imports from the regional grid for which availability cannot be assured. In addition, some providers stated that this emphasis on diversity of generation sources supported distinct goals to:

- **Maintain rate stability**, on the grounds that excessive reliance on a single type of generation, or on market purchases not controlled by the provider, could risk requiring customers to bear unanticipated cost increases associated with changes in future market conditions; and
- **Support resilience**, which WEPCO and WPSC tied to maintaining a diversity of sources and facility locations, as well as the use of RICE units which could support system recovery from disruptive events.

Electric providers reported using three types of modeling software packages to assess resource options against their defined goals.

- **Capacity expansion models**, to identify the optimal portfolio of generating assets (or load reductions such as energy efficiency) for a defined electric system to meet future demand and other goals incorporated into the model, such as those listed above.
- **Production cost models**, to assess the costs associated with generating the electric supply needed to meet demand for a defined generation portfolio during a defined time period, typically one year. Modeled costs include fuel used, fixed and variable operations and maintenance costs, transmission system losses and congestion, among others.
- **Dispatch models**, to identify the order in which generating assets will be deployed to meet electric demand and other defined goals.

Electric providers reported using a variety of different software packages to conduct their modeling, which are listed in Table 2-6. Historically, many providers have commonly used EGEAS, a capacity expansion model, and PROMOD, a production cost model. However, several providers have procured new modeling software in recent years that they report offers more detailed functionality and ease of use. For example, providers noted that PLEXOS and EnCompass offer the ability to conduct integrated capacity expansion and production cost modeling, and that EnCompass allows more detailed and effective reliability assessments by modeling system operations on an hour-by-hour basis.

Table 2-6 Primary Resource Planning Models Used by Wisconsin Electric Providers

Provider	Response
DPC	EnCompass
NSPW	Strategist; EnCompass
MGE	EGEAS
WEPCO	PLEXOS
WP&L	AURORA
WPSC	PLEXOS

The providers' modeling analysis incorporated the goals and metrics outlined above, as well as other inputs identifying future conditions relevant to making generation choices. Additional inputs commonly noted by providers included forecasted customer demand, market conditions such as natural gas prices and potential environmental regulations, assumed lifetimes and operational needs for the provider's existing generation sources, and projected costs for the different generation sources a provider may consider for new additions. No provider responses addressed in detail the Commission's request to identify their methods and inputs for modeling their existing renewable energy offerings.

After defining inputs, the providers ran models to identify the retirement and addition choices that performed best on their goals and metrics. Given that many key inputs were projections of future conditions, a number of providers reported running multiple scenarios that changed the values of key inputs, to assess the impacts of different conditions on model outcomes. The most commonly noted scenarios included alternative projected natural gas cost values, alternative forecasts of customer demand, and scenarios that assumed additional costs that could be associated with more stringent future environmental regulations. Some providers specified that their goal was to select final resource options that performed strongly across multiple scenarios, in order to identify resource decisions that could be expected to perform well on the provider's goals even if future conditions varied from the provider's primary set of projections.

Providers affirmed that their announced additions and retirements had been guided by the results of their modeling work. WP&L's announced generation changes reflected the results of its Clean Energy Blueprint planning process, which stated that modeling across five separate future scenarios consistently identified the retirement of the Edgewater and Columbia coal facilities, and the addition of 1,089 MW in new solar generation, as the preferred actions for balancing its goals of achieving carbon reduction, limiting costs, and supporting rate stability, reliability, and resource flexibility.

WEPCO and WPSC stated that their choices to retire coal units at Columbia and Oak Creek reflected that those plants had reached their end of their useful lives and continued operations would require significant additional costs in maintenance and potential environmental compliance. Those providers reported that modeling analysis for new additions to replace the retired coal capacity identified a mix of resources, including solar and storage units that could take advantage of cost declines to perform well on affordability metrics, as well as some gas-fired generation that would help the portfolio achieve resource diversity of resilience. WEPCO and WPSC report that their proposed generation additions would save customers up to $1 billion in costs, across a variety of scenarios, compared to the alternative scenario of maintaining the existing generation fleet. It is not clear how these proposed additions may compare to other alternative generation options beyond the status quo.

While WP&L, WEPCO, and WPSC accounted for the largest share of planned retirements and additions, reports from other utilities struck similar themes. For example, NSPW reported that modeling for its Minnesota IRP affirmed coal retirements and replacement with solar as well as wind was a successful approach for meeting carbon reduction goals while controlling costs. DPC reported that its announced coal plant retirements—including the recently completed retirement of the Genoa plant—and its mix of proposed renewable and natural gas additions would establish a "balanced portfolio" that achieved emissions reductions while maintaining gas resources for reliability and rate stability.

Commission Staff Resource Planning Analysis

In addition to directing that Commission staff collect resource planning information from individual providers in the Roadmap docket, the Commission directed Commission staff to conduct additional analysis in the SEA, to provide an independent perspective that evaluates generation changes statewide. With available time and resources, Commission staff focused on conducting capacity expansion modeling through EGEAS, and comparing the generation additions the model identifies to achieve adequacy, reliability, emissions reduction, and affordability under multiple scenarios.

Commission staff have historically used EGEAS to review generation expansion planning information provided as part of individual project applications. They have not maintained a general statewide EGEAS dataset, which can take substantial time to construct and validate. As an alternative, staff requested and received regional EGEAS datasets maintained by MISO for modeling associated with its 2021 MISO Transmission Expansion Planning (MTEP) process. (See Chapter 4 for more information on MTEP21 and its potential impacts on Wisconsin.) Commission staff then narrowed down the regional data to Wisconsin-specific data, through steps that included reducing active facilities to those operated by or serving Wisconsin providers, and reducing the scale of general inputs, such as total energy use and peak demand, from regional to state-level values. Commission staff also updated information on anticipated generation changes during the analysis period to reflect all retirements reported by the SEA, as well as additions approved to date by the Commission. Additions announced by providers but not yet approved by the Commission were not incorporated in the model, which allowed for comparison between the results of this independent modeling and the modeling outcomes reported by providers above.

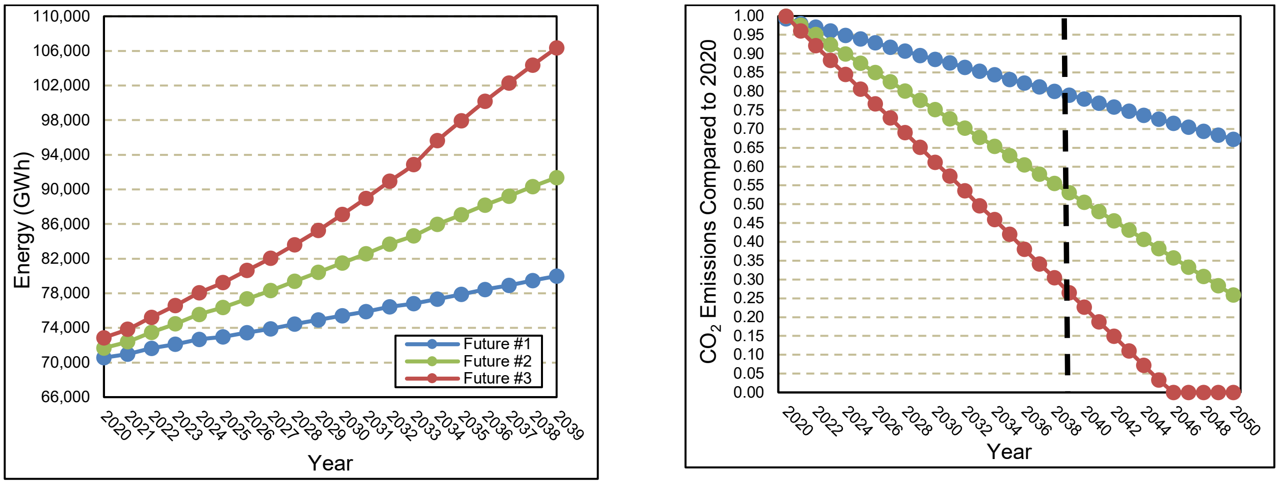
EGEAS establishes resource adequacy and reliability as minimum baseline requirements. MISO's dataset defines resource adequacy as compliance with MISO's planning reserve margin requirements, which are described in Chapter 1. Reliability is addressed through modeling parameters that identify the likelihood of potential outages or performance issues at existing plants, and assess whether customer demand could be met even if these issues occur. EGEAS modeling results only identify outcomes for which these resource adequacy and reliability requirements can be met.

MISO's MTEP21 datasets support capacity expansion modeling through 2039, under three future scenarios that set different values for emissions reductions and growth in electric demand.

- **Future 1** assumes annual CO_2 reductions from electric generation that reach 40 percent by 2039, relative to 2005 levels, and load growth of 0.5 percent per year throughout the period- figures roughly consistent with near-term conditions in Wisconsin.
- **Future 2** assumes CO_2 reductions of 60 percent by 2039 and load growth of 1.1 percent per year, driven by potential increases in the adoption of electric vehicles and electrification of end uses currently using other fuels, such as heating.
- **Future 3** assumes CO_2 reductions of 80 percent by 2039 and load growth of 1.7 percent per year, associated with a more rapid transition than Futures 1 and 2 towards zero-carbon generation, electric vehicle adoption, and electrification.

Figure 2-3 illustrates the emissions reductions and load growth trends in each future.[52]

Figure 2-3 Assumed Load Growth and CO_2 Reductions, Futures 1-3

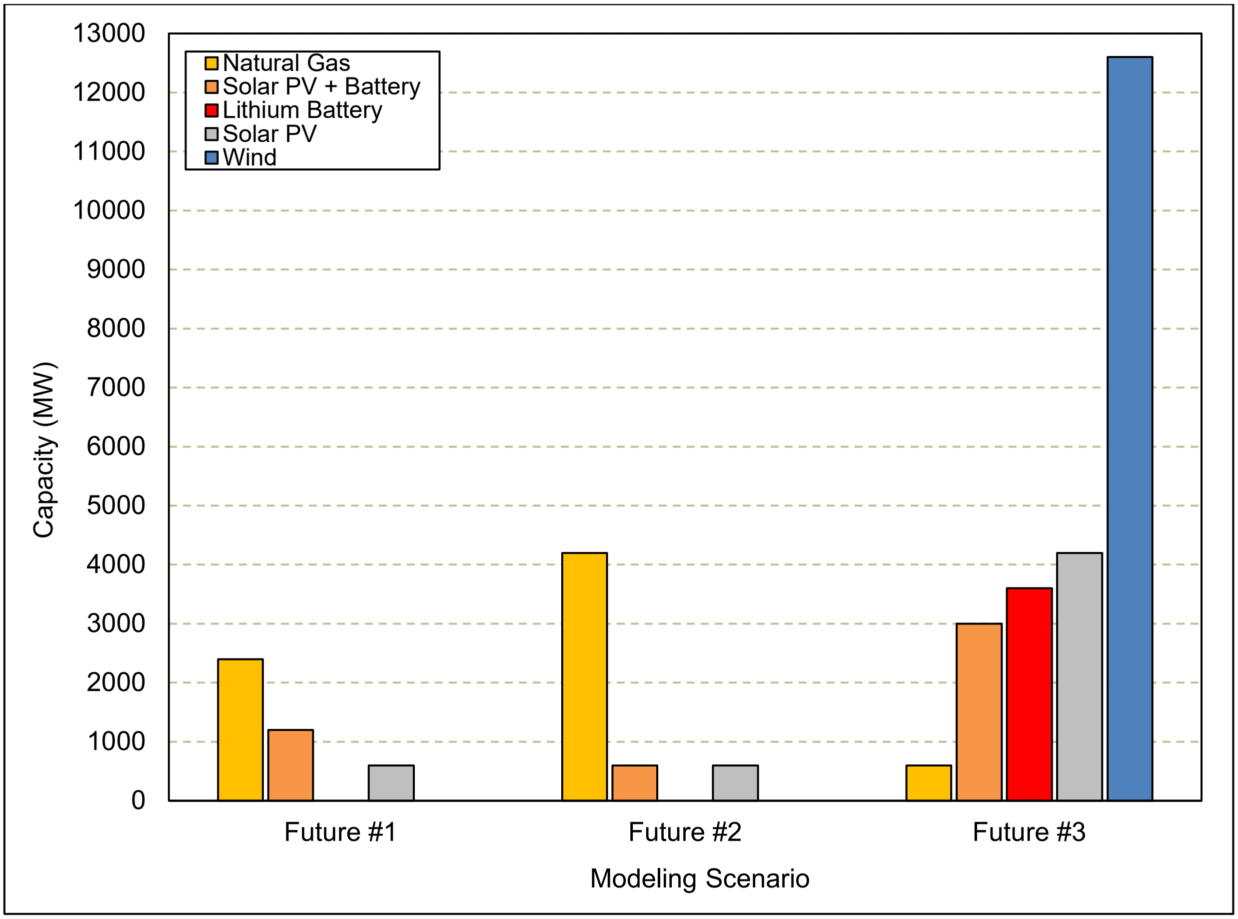


EGEAS' capacity expansion modeling under each future identifies the lowest-cost set of generation sources that serve customer load and meet adequacy and reliability standards, while achieving the specified amount of CO_2 reduction. These assessments are informed by assumptions regarding the relative cost of different generation sources, which staff confirmed to be consistent with cost assumptions used in other recent Commission dockets. Selections also take into account the different reliability and adequacy properties of different generation sources. For example, EGEAS assesses overall resource adequacy and reliability requirements against the intermittent characteristics of solar and wind generation, with solar available during daylight hours and wind often reaching its highest generation levels during overnight hours.

Figure 2-4 illustrates the generation portfolio selected under each future. (More detailed results can be found in Appendix B; Tables B-1 through B-3 identify all individual units selected by generation source and year.)

[52] For more information, see the MTEP 21 MISO Futures Whitepaper, April 27, 2020. https://cdn.misoenergy.org/20200427%20MTEP%20Futures%20Item%2002b%20Futures%20White%20Paper443656.pdf.

Figure 2-4 EGEAS Capacity Expansion Modeling Results, Futures 1-3



Commission staff's EGEAS modeling under Futures 1 and 2 predominantly selected natural gas resources to meet the needs identified by upcoming retirements during the 2020s, as well as longer-term needs created by load growth. A limited amount of solar and hybrid solar and battery storage units were also selected. These results were apparently driven by the model's view of the reliability and resource adequacy advantages of natural gas, which can be deployed at any time, without the intermittent properties of solar and wind. EGEAS identified that this property allowed a limited number of natural gas plants to meet adequacy and reliability requirements, at lower cost than alternative options that would require greater capital costs to construct a larger number of facilities using other generation sources.

Commission staff's EGEAS modeling also identified this advantage as robust across a range of assumed natural gas prices. EGEAS selected a larger share of solar and battery resources under alternative natural gas price scenarios for Futures 1 and 2, but also continued to select multiple natural gas units to help fill the capacity needs created by upcoming retirements, at natural gas prices that fall between historical values and 2022 values (Figure 2-5), as well as updated modeling conducted in summer 2022 at natural gas prices slightly above the highest levels experienced during 2022 (Figure 2-6). Selection of individual units by year and generation source for these scenarios can be found in Appendix B, Tables B-5, B-6, B-7, and B-8.

Figure 2-5 EGEAS Capacity Expansion Modeling Results, $6/MMBTU Natural Gas Price Scenario,[53] Futures 1-2

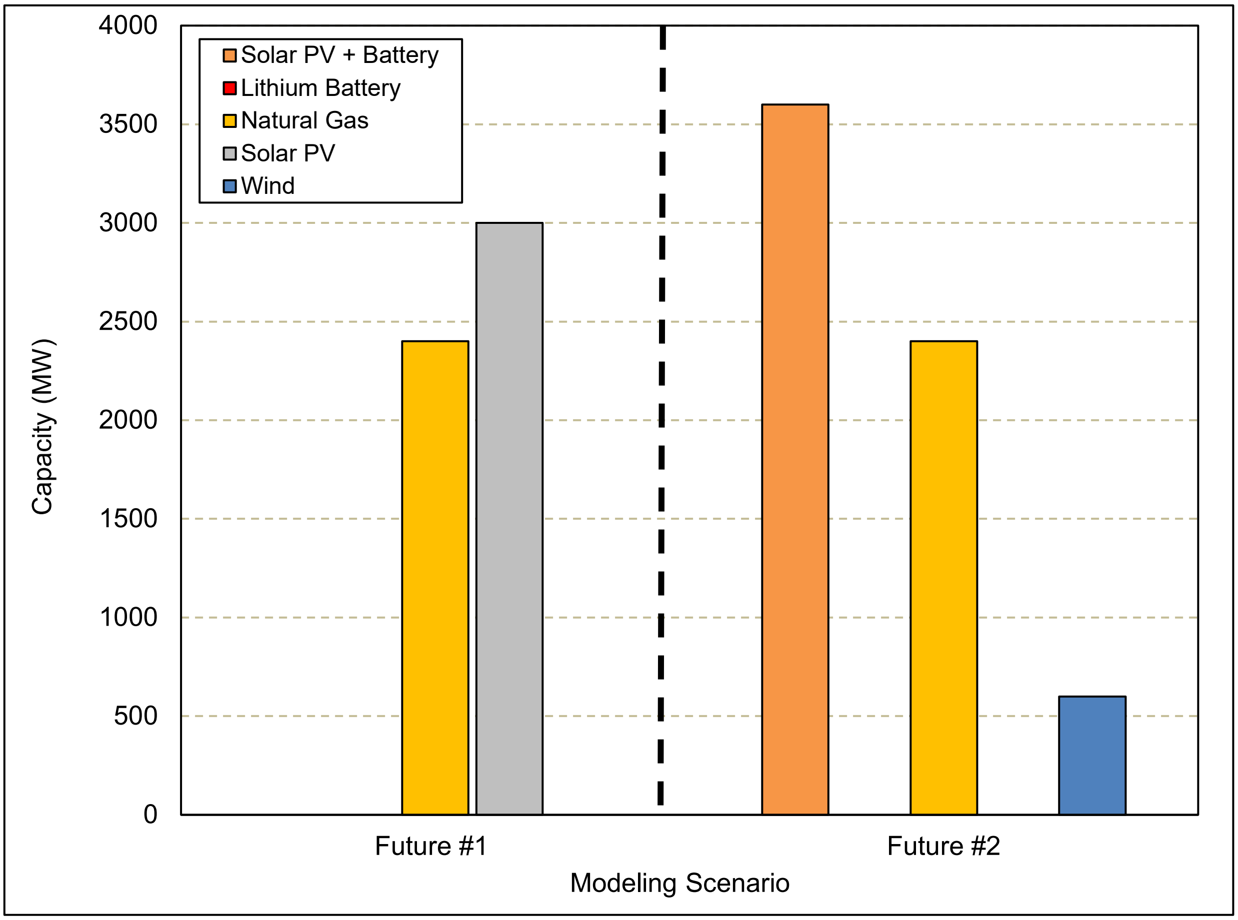
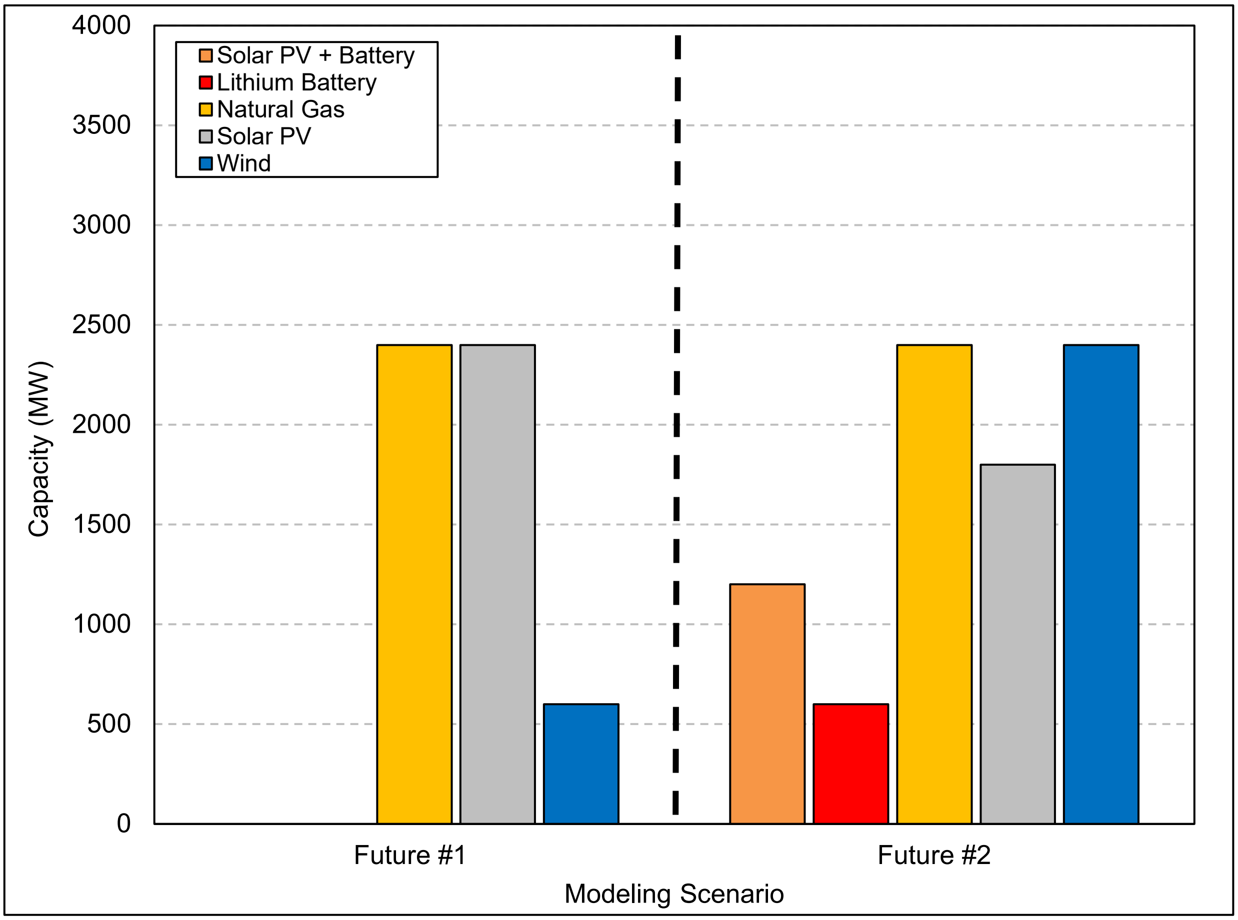


Figure 2-6 EGEAS Capacity Expansion Modeling Results, $10/MMBtu Natural Gas Price Scenario,[54] Futures 1-2



These findings are conceptually consistent with MISO's own recent modeling as part of its Regional Resource Assessment (RRA), which assessed potential future generation changes based on announced plans and policy goals across all states in the MISO region. The RRA's modeling identified a significant share of natural gas additions region-wide, but also suggested that those additions could be operated much less frequently—in other words, at a lower capacity factor—than current natural gas plants, to maintain the resource adequacy and reliability advantages of natural gas facilities while minimizing costs and emissions.[55]

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[53] This scenario establishes a $6/MMBtu natural gas price at the beginning of the modeling period, with annual increases over the modeling period consistent with the trends assumed for other scenarios.

[54] This scenario establishes a $10/MMBtu natural gas price at the beginning of the modeling period, with annual increases over the modeling period consistent with the trends assumed for other scenarios.

[55] Regional Resource Assessment: A Reliability Imperative Report. November 2021. https://cdn.misoenergy.org/2021%20Regional%20Resource%20Assessment%20Report606397.pdf.

It is important to note that these results for Futures 1 and 2 differ from the modeling outcomes and planned additions reported by providers. As outlined in Table 2-2 above, providers' announced plans include significantly larger shares of solar and battery storage. These differences demonstrate that the use of different models, and differing approaches to defining planning goals and metrics, can result in different resource planning results.

One factor that likely informed these differences was CO_2 reduction goals. While Futures 1 and 2 assume comparatively limited reductions from current levels, Future 3 requires more aggressive CO_2 reductions that are more closely consistent with achievement of the 2030 and 2050 goals announced by many Wisconsin providers. EGEAS modeling results for Future 3 continued to identify some natural gas additions to meet near-term resource needs in the 2020s, but also identified a much larger share of renewable resources. Driven in large part by higher assumed annual load growth, as well as lower capacity factors for wind and solar resources, EGEAS also identified a need to construct nearly four times more total capacity in Future 3 than in Futures 1 and 2. While the modeling results in Figure 2-4 reflected the lowest-cost generation mix available under the scenario, these higher total capacity and energy needs would also be expected to increase total costs relative to lower-growth futures.

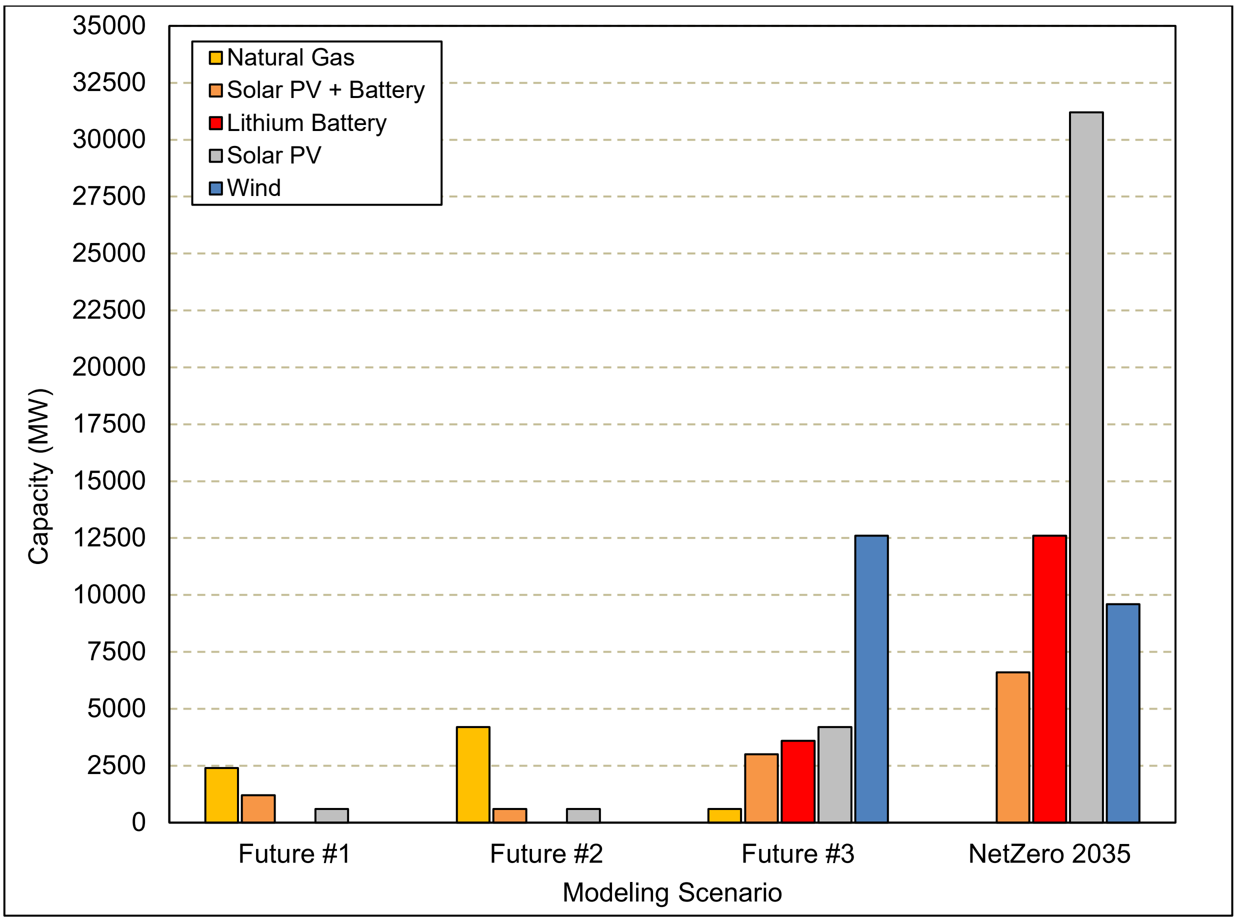
EGEAS modeling for Future 3 selected a greater share of solar and battery power, but also identified wind power additions to meet more than half of these increased needs. Two factors appeared to primarily account for the emphasis on wind. First, EGEAS identified wind as having reliability advantages due to its generation profile. Wind availability during overnight hours may more closely align with the assumed timing of the significant load increases under Future 3, particularly if increased electric vehicle charging largely occurred overnight as well. Second, the model assumed that Wisconsin providers may be able to procure wind from other states in the MISO region west of Wisconsin, where windier weather conditions allow for more cost-effective production. However, implementing the magnitude of increases required for Future 3 would likely require deployment of additional regional transmission resources. (See Chapter 4 for more discussion of Wisconsin's current transmission system and future transmission planning.) Some providers may also view out-of-state wind procurement differently than this general statewide EGEAS model, in light of their reported planning goals to maintain a large share of generation in or near their service territory.[56]

Future 3 selects a reduced share of natural gas resources, but still selects some facilities to address near-term capacity needs, consistent with Future 3's allowance for limited CO_2 emissions at the end of its modeling period in 2039. To model the impacts of more aggressive decarbonization, Commission staff also modeled an alternative scenario requiring 100 percent emissions reductions by 2035. As shown in Figure 2-7, this "Net Zero 2035" scenario does eliminate natural gas entirely, in favor of a combination of solar, battery storage, hybrid solar and storage, and wind. (See

[56] Different models and modeling approaches may also identify different generation mixes. For example, modeling of decarbonization-related scenarios conducted by the Clean Energy Planners and submitted as a comment to the draft SEA identified a larger share of solar and combined solar and battery, and a smaller share of wind energy, than staff's Future 3 EGEAS results. (PSC REF#: 446159 at 3.)

Appendix B, Table B-4 for selections of individual units by year and generation source.) EGEAS also identified a need to construct 2.5 times more total capacity than Future 3 and 10 times more total capacity than Futures 1 and 2—substantially more than needed to meet minimum resource adequacy requirements—in order to maintain hour-to-hour reliability throughout the year. Under present conditions, this would likely require commensurate increases in total costs for facility construction and operation. These planning considerations and cost assumptions may evolve over time if further cost reductions can be achieved for existing resources such as solar and lithium-battery storage, or if future technological developments support the emergence of other cost-competitive generation options such as small-scale nuclear generation, hydrogen, or long-duration storage.

Figure 2-7 EGEAS Capacity Expansion Modeling Results, Future 3 and Net Zero CO_2 Reduction by 2035



GRID INERTIA

The growing use of renewable resources such as solar and wind has raised questions about their effects on reliability. Commission staff have reviewed the emerging concern that the effects of renewable deployment limit the ability of the grid to maintain stable electrical frequencies, and thereby protect against outages, through grid inertia.

The electric grid in North America operates at a nominal frequency of 60 Hz. If the frequency falls outside of a narrow range surrounding 60 Hz, grid operators may need to reduce load on the system, and potentially cause outages for certain customers, to protect utility equipment from damage. Nearly all coal, natural gas, nuclear, hydroelectric, and geothermal power plants use spinning turbine machinery coupled with synchronous generators to generate electricity. These synchronous generators operate at 60 Hz frequency and their rotational speed is directly proportional to its electrical frequency. Great care is taken to maintain the speed of the rotor at a desired value.

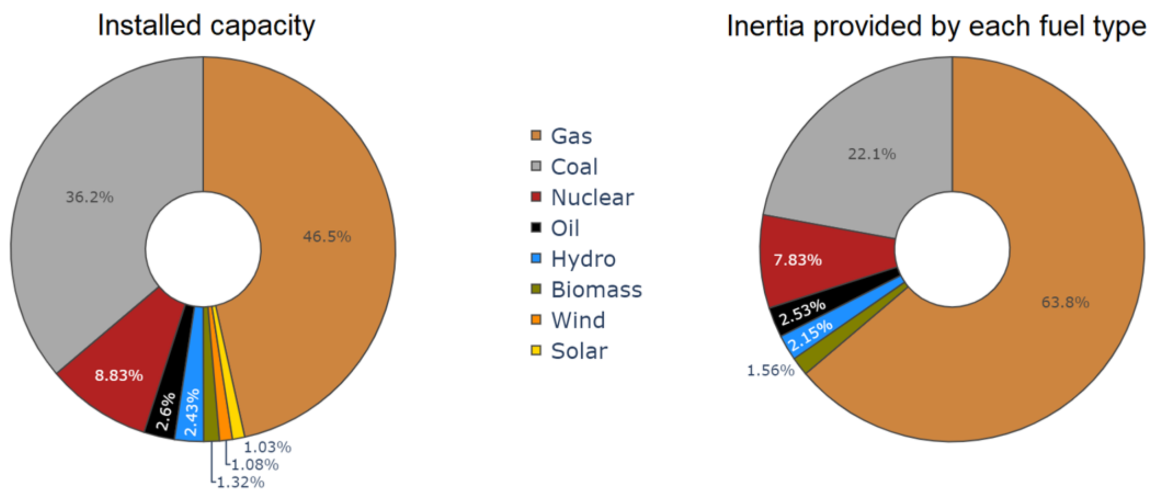
Because synchronous generator rotors are heavy and spin very rapidly, their momentum helps keep their rotational speed steady in the event of momentary disruptions in plant generation, and minimizes the chance that frequency-related outages will result from those disruptions. This grid inertia effect is strengthened when many synchronous generators are operating in parallel across the grid. While operators have historically relied on large-scale grid inertia to help maintain stable grid frequencies, the increasing deployment of solar and wind facilities that do not use synchronous generators has raised questions about whether the corresponding decreases in grid inertia present reliability risks.

To study grid inertia risks in Wisconsin, Commission staff conducted analysis to quantify the inertia currently provided by individual generators in Wisconsin.[57] Because the inertia of an individual power plant is inherently tied to its physical properties,[58] every power plant provides a different amount of inertia to the grid. As shown in Figure 2-8, natural gas plants in Wisconsin provide the most inertia per MW on average, accounting for less than half of installed capacity but more than 60 percent of total grid inertia. At the total capacity levels provided by all generators studied, the grid inertia identified could offset a disruption of several seconds, using only the energy stored in the momentum of the generators.

[57] The study focused on MISO Load Resource Zone 2, which encompasses most, but not all, of the grid operations within state borders.

[58] These physical properties include but are not limited to the generator's pole count and the angular mass of the rotor turbine shaft.

Figure 2-8 Installed Capacity and Grid Inertia by Fuel Type



Using this information, Commission staff calculated the effects on grid inertia from replacing synchronous-generator plants with solar and wind resources. The results suggested that, with no other significant changes to grid operations, the grid would be able to maintain a stable electrical frequency, in the event of unplanned generator outages, for renewable penetration levels of up to 70 percent. Above the 70 percent threshold, grid operators would need to consider a range of additional options for maintaining frequency stability, which could include demand response, operational changes for renewable and synchronous generators, or the deployment of new technologies such as grid-forming inverters.[59]

[59] Further discussion of these considerations can be found in a 2020 National Renewable Energy Laboratory report, "Inertia and the Power Grid: A Guide Without the Spin." Accessed September 2022 at https://www.nrel.gov/docs/fy20osti/73856.pdf.

CHAPTER 3 – CLEAN ENERGY PROGRAMS AND POLICIES

ENERGY EFFICIENCY

Energy efficiency programs provide incentives and technical assistance to residents and businesses to take steps to reduce energy use. Since 1999, state law has established Focus on Energy (Focus) as Wisconsin's statewide electric and natural gas efficiency and renewable resource program. Under 2005 Wisconsin Act 141 (Act 141), IOUs are required to fund Focus through contributions equal to 1.2 percent of annual operating revenues from retail sales. Act 141 also requires municipal utilities and retail electric cooperatives to collect an average of $8 per meter annually for energy efficiency programs. Municipal utilities and cooperatives have the option to contribute these funds to Focus or administer their own programs. As of 2022, all IOUs and municipal utilities participate in Focus. Of the 24 electric cooperatives in the state, 13 run their own programs while 11 participate in Focus. Several investor-owned and municipal utilities run voluntary energy efficiency programs that provide additional benefits to their customers beyond what Focus offers.[60]

Act 141 requires Focus to be operated by a third-party program administrator, under a contract established by IOUs and approved by the Commission.[61] APTIM has served as the third-party program administrator since 2011. Program administrator contracts are established on a 4-year basis, after the Commission completes a quadrennial planning process to determine program goals, policies, and priorities for the upcoming contract period. The Commission approved updated program goals in 2018, to establish contract priorities for the 2019-2022 time period. During 2022, the Commission is conducting the fourth Quadrennial Planning Process which will set program goals, policies, and priorities for the 2023-2026 time period.

Focus on Energy Programs

Focus offers a portfolio of programs that match energy efficiency products and services to appropriate customer segments, ensuring customers throughout the state have an equivalent opportunity to receive the benefits of the programs.

Focus on Energy includes separate portfolios of programs to target residential and nonresidential customers. To meet the differing needs of residential customers, separate residential programs ship energy-efficient products directly to customers free of charge, operate an online marketplace where customers can purchase energy efficient products which are then shipped to their home, offer retail discounts on efficient lighting and appliances, work with contractors to support energy efficient repairs and installations, and work with homebuilders to increase the energy efficiency of new homes. Within Focus' non-residential portfolio, separate programs target the differing efficiency opportunities for different types of customers, including small businesses, commercial customers,

[60] A voluntary energy efficiency program is run by the electricity provider with funding that is above and beyond what the electricity provider is required to collect pursuant to Wis. Stat. § 196.374.

[61] The IOUs created a nonprofit board to fulfill its duties under Act 141. The nine-member board is called the Statewide Energy Efficiency and Renewables Administration (SEERA).

schools and government facilities, agriculture customers, and large industrial facilities. As part of the 2018 Quadrennial Planning process, the Commission also allocated $8 million in annual funding to provide enhanced program offerings to rural residential, agricultural, and industrial customers. (More specific information on program offerings can be found at www.focusonenergy.com.)

While Focus accounts for the largest share of energy efficiency activity in the state, all electric providers in the state provide some degree of additional energy efficiency services. These services include educational and marketing activities, which do not have quantifiable savings of their own but can help increase Focus savings by informing customers of Focus offerings and encouraging participation. Some electric providers also fund and operate their own energy efficiency programs,[62] although, as shown below, spending and savings from those programs remain small relative to Focus' statewide activities.

Focus on Energy Outcomes

Independent program evaluators, led by the Cadmus Group (Cadmus), perform research and analysis to validate the energy savings from Focus programs. Cadmus works with program staff to manage Focus' Technical Reference Manual (TRM), which documents and explains the methods for calculating savings achieved from installing energy efficient measures. Savings calculations in the TRM take into consideration the lifecycle savings achieved as participants continue to use their efficient products and services for many years after implementation. Evaluators also seek to validate the amount of net savings that can be attributed to the influence of Focus programs, excluding the savings from "free-rider" participants who would have taken the same actions without Focus' support.

While energy-efficient products can reduce both energy use and total energy demand for customers, the Commission's quadrennial planning decisions have directed Focus to place primary priority on achieving savings in energy use. Demand savings are still tracked by the program, but are a secondary priority for Focus programs to achieve. In 2020 and 2021 combined, Focus achieved total life cycle verified net savings of 149.8 million MMBtu, the equivalent of the amount of energy to power more than 1.4 million typical Wisconsin homes for a year. These life cycle savings are estimated to reduce CO_2 emissions by about 15.7 million tons during the lifetime of the projects installed.

Focus' evaluators also validate whether the program meets its Commission requirement to operate cost-effectively, and achieve benefits in excess of costs. As directed by the Commission, Focus measures cost-effectiveness using a Modified Total Resource Cost (MTRC) test that compares the benefits from reduced energy use and emissions to the costs of program administration, program implementation, and the higher costs of energy-efficient products to participants. For 2021, Cadmus's cost-benefit analysis concluded that for every dollar spent, Focus' full portfolio of

[62] NPSW, WEPCO, WP&L, WPSC, and WPPI Energy all operate Commission-approved "voluntary programs," using utility funds that are in addition to the funds they contribute to Focus. Some cooperatives associated with DPC use the $8.00 per meter they are required to collect for energy efficiency to operate their own programs instead of contributing those funds to Focus.

programs achieved $2.35 in life cycle benefits.[63] A national study of energy efficiency programs performed in 2018 found that Wisconsin ran the most cost-effective efficiency programs of any state in the country, achieving the highest rate of energy savings per dollar spent.[64]

Future Focus on Energy Spending and Outcomes

Annual IOU contributions to Focus are based on utility revenues, and therefore can vary based on weather conditions and other influences on revenue levels. Commission decisions on program offerings can also impact Focus' available funding and annual expenditures. Figure 3-1 shows Focus' actual and projected energy efficiency expenditures through 2028. (Figure 3-1 only addresses Focus' electric activities and excludes spending associated with natural gas efficiency, which annually accounts for approximately $20 million in additional program activity.) Focus' 2020 expenditures are lower than future projections largely due to the impacts of COVID-19, which temporarily reduced program spending due to project delays and supply chain disruptions.

Commission staff calculate each IOU's required contribution based on a three-year rolling historical revenue average. IOUs project generally stable contribution levels between 2023 and 2028, with only slight increases over the five-year period. Beginning in 2023, the historical calculation will include utility revenues from 2020, when the COVID-19 pandemic began. The revenue impacts from 2020 are projected to have minimal impact on electric contributions, while reduced natural gas revenues will lead to a modest reduction in total IOU Focus contributions. Spending on additional utility programs are projected to remain stable.

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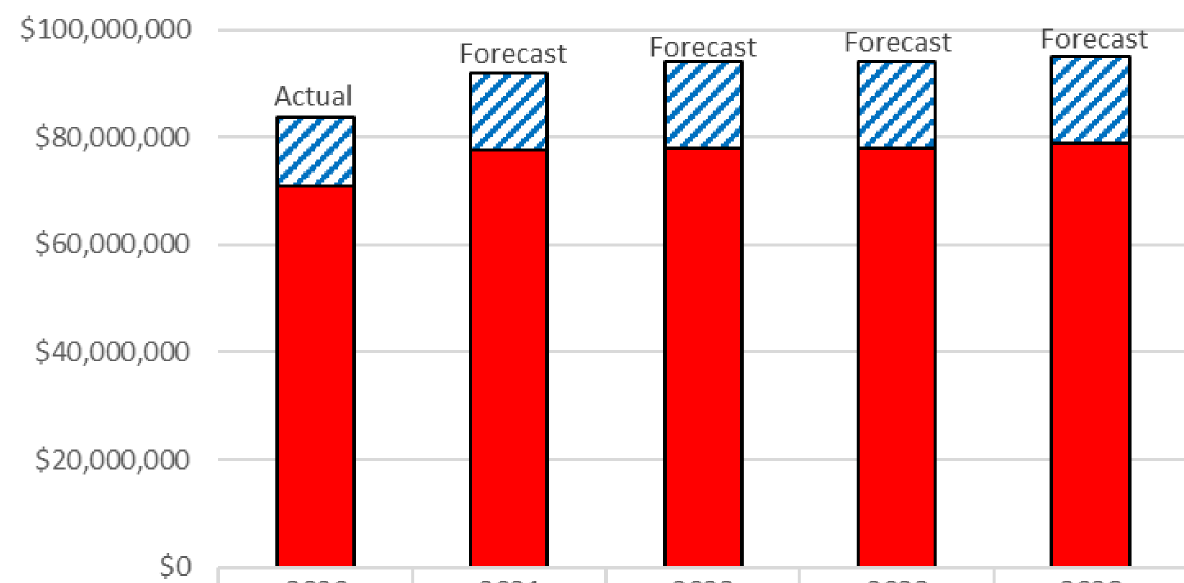
63 For informational purposes, Cadmus also conducts an "expanded TRC" test which incorporates the economic benefits created by Focus. In 2021, the program evaluator's expanded TRC analysis found that Focus created net economic benefits of more than $507 million and achieved $4.14 in benefits for every $1.00 in costs.

64 Report available at: http://www.swenergy.org/Data/Sites/1/media/lbnl-cse-report-june-2018.pdf.

Figure 3-1 Actual and Projected Annual Electric Energy Efficiency Expenditures 2020-2028[65]



	2020	2021	2022	2023	2028
Utility	$12,551,169	$14,303,600	$16,308,816	$16,142,842	$16,277,752
Focus	$71,047,862	$77,560,000	$77,880,000	$78,050,000	$78,890,000

Beginning in 2020, the Focus program deployed a restructured portfolio intended to simplify and enhance the customer experience, reduce administrative costs, and target opportunities for increased energy savings. The reorganization was intended to help support Focus' ability to maintain overall program savings levels with reduced funding, while also maintaining cost-effectiveness and improved service to rural customers. Evaluation of 2021 programs showed a record high level of customer satisfaction, achieving a portfolio average rating of 9.5 out of 10.

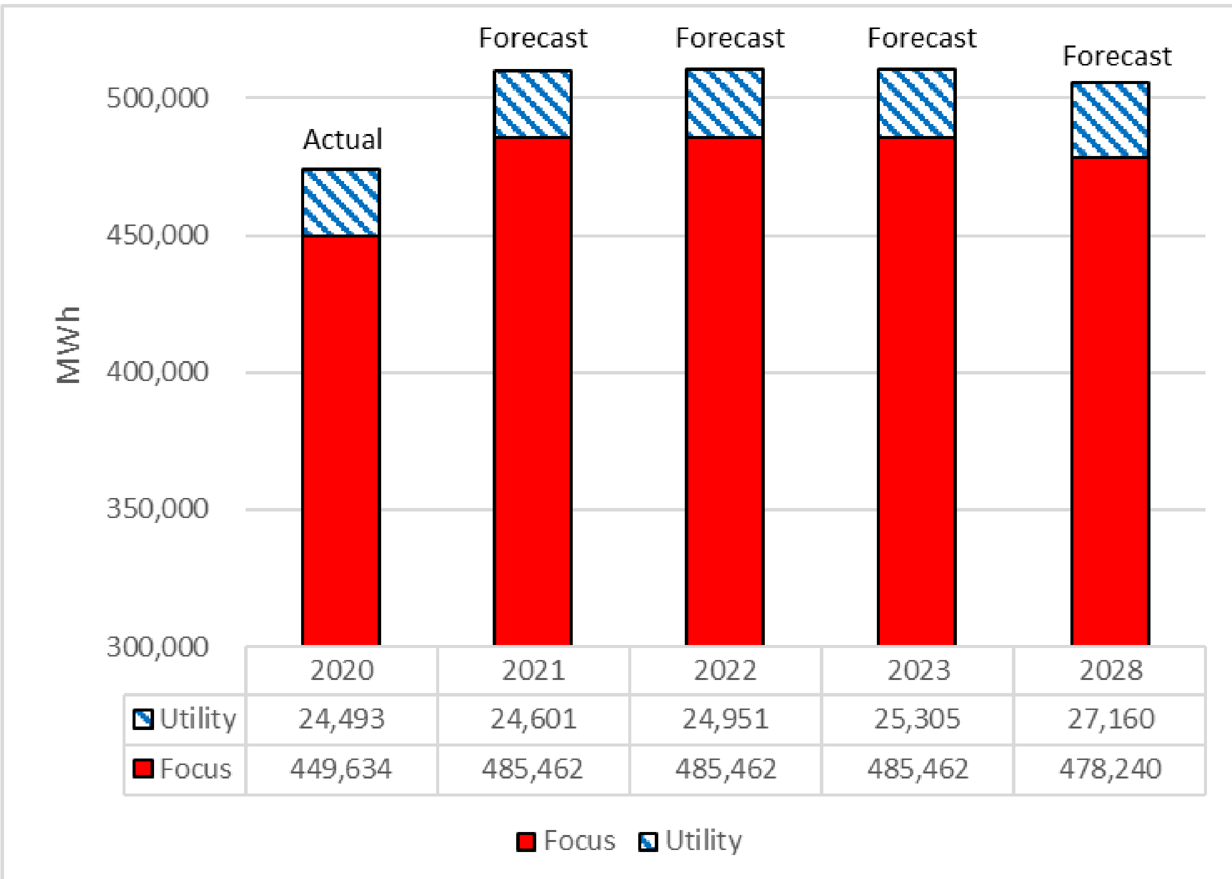
In 2020, the Commission opened a docket to initiate planning for the next Focus quadrennial period (Quadrennial Planning Process IV, 2023-2026) in docket 5-FE-104. Consistent with the approach used in planning for the 2019-2022 quadrennial period, the Commission authorized Cadmus to conduct a potential study projecting the amount of future energy efficiency savings Focus could achieve. Results of this study serve to inform the Commission's determination of savings goals for the 2023-2026 quadrennial period and beyond. The final study, completed in 2021, used data on customers' existing energy use practices and available efficient technologies to assess energy savings potential under a variety of scenarios, including a "current policy" scenario that maintained Focus' existing funding level and program policies.

The potential study concluded that under current program policies, including funding levels, Focus is positioned to achieve electric energy savings consistent with historical levels in the 2023-2026

[65]Aggregated electricity provider data responses, docket 5-ES-111; Focus on Energy 2020 Evaluation Report; Focus on Energy 2019 to 2022 Program Administration Contract.

period. These potential estimates are reflected in Figure 3-2, which maintains electric savings estimates closely comparable to savings achieved thus far in the 2019-2022 quadrennium. Projected energy savings from other utility programs are projected to remain stable through 2028. The 2021 Potential Study also analyzed cost-effective savings potential under alternative funding scenarios, and concluded that there are significant cost-effective energy savings that can be achieved beyond what current program funding will support. The study found that doubling program funding from current levels would increase electric savings potential by 48 percent—and natural gas savings by 171 percent—relative to the savings attainable at current funding levels.

Figure 3-2 Actual and Projected First-Year Annual Energy Savings 2020-2028[66]



	2020	2021	2022	2023	2028
Utility	24,493	24,601	24,951	25,305	27,160
Focus	449,634	485,462	485,462	485,462	478,240

In late 2021, the Commission approved Quadrennial Planning Process IV scope topics and decided to conduct planning using a phased approach. During its first phase of planning in April 2022, the Commission made decisions on a number of general topics. These initial decisions directed the program to maintain an emphasis on traditional energy savings in the 2023-2026 period, while also performing research and exploring emerging opportunities for the program to address implications

[66] Sources: Aggregated electricity provider data responses, docket 5-ES-111; Focus on Energy 2020 Evaluation Report; 2021 Focus on Energy Energy Efficiency Potential Study.

of energy efficiency and renewable resource programs related to decarbonization and customer affordability.

The second phase of planning decisions occurred in August 2022. The Commission directed Focus to maintain several established program policies, including emphasizing energy use savings over demand reductions, emphasizing near-term savings while maintaining secondary emphasis on market transformation, allocating funding to business and residential customers consistent with their contributions to the program, and maintaining established approaches for calculating program cost-effectiveness. The Commission also directed Focus to explore several new initiatives during the 2023-2026 Quadrennial Period, in order to operationalize the Commission's priorities from the first phase of planning and identify how Focus can adapt to new opportunities presented by changes in markets and technologies. New initiatives include:

- beginning to track demand impacts on natural gas use and winter electric use;
- identifying strategies to achieve greater demand savings;
- investigating opportunities to integrate the time-varying value of efficiency and renewables;
- assessing how the program can increase its long-term market transformation impacts; and
- performing research and analysis to identify how Focus can improve service to underserved customers.

In the last phase of planning, scheduled for fall 2022, the Commission will establish program goals, targets and key performance indicators for the 2023-2026 quadrennial period.

DEMAND RESPONSE

Demand response programs provide customers with incentives to reduce energy usage during peak periods, to support reliability and create financial savings for electric providers and customers. Traditionally, utilities deploy demand response programs primarily in the summer months, to control demand on very hot days where increased air conditioner use creates high demand. However, utilities may also use these programs for other circumstances, where they can help assure a cost-effective balance between demand and available supply.

A wide range of initiatives can be categorized under demand response, including time-of-use rates, demand bidding, behavioral demand response, and timed water heating. In Wisconsin, electricity providers have pursued demand response through two primary mechanisms: direct load control programs and interruptible load tariffs.[67]

- **Direct load control** gives electricity providers the ability to control the use of customer equipment, such as residential air conditioners, to reduce load on the system. In return, participating customers receive a financial incentive. While direct load control programs historically operated through remote shut-offs of participant

[67] '2019 Utility Demand Response Market Snapshot' by Smart Electric Power Alliance.

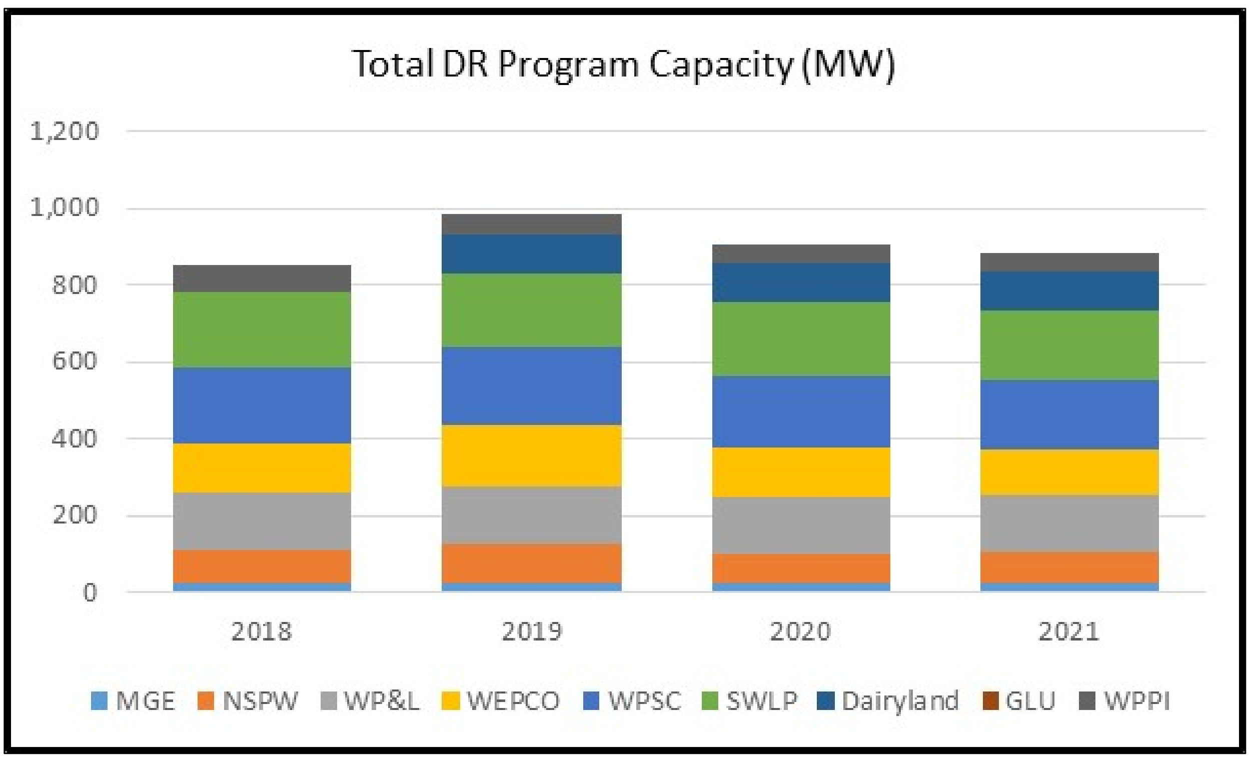
technologies, new program models control usage through customers' smart thermostats, using software to set thermostats at a higher temperature during peak demand periods, and in many cases, providing "pre-cooling" before peak demand hours to help customers remain comfortable during the event.

- **Interruptible tariffs** enable participating customers (typically industrial customers) to receive lower energy charges by agreeing to allow the electricity provider to interrupt load during periods of peak demand.

Wisconsin electric providers reported that more than 100,000 customers were enrolled in interruptible tariffs and direct load control programs, including more than 87,000 at DPC's member cooperatives. Appendix C provides more information on demand response participation by provider, and by individual demand response offerings available from each provider.

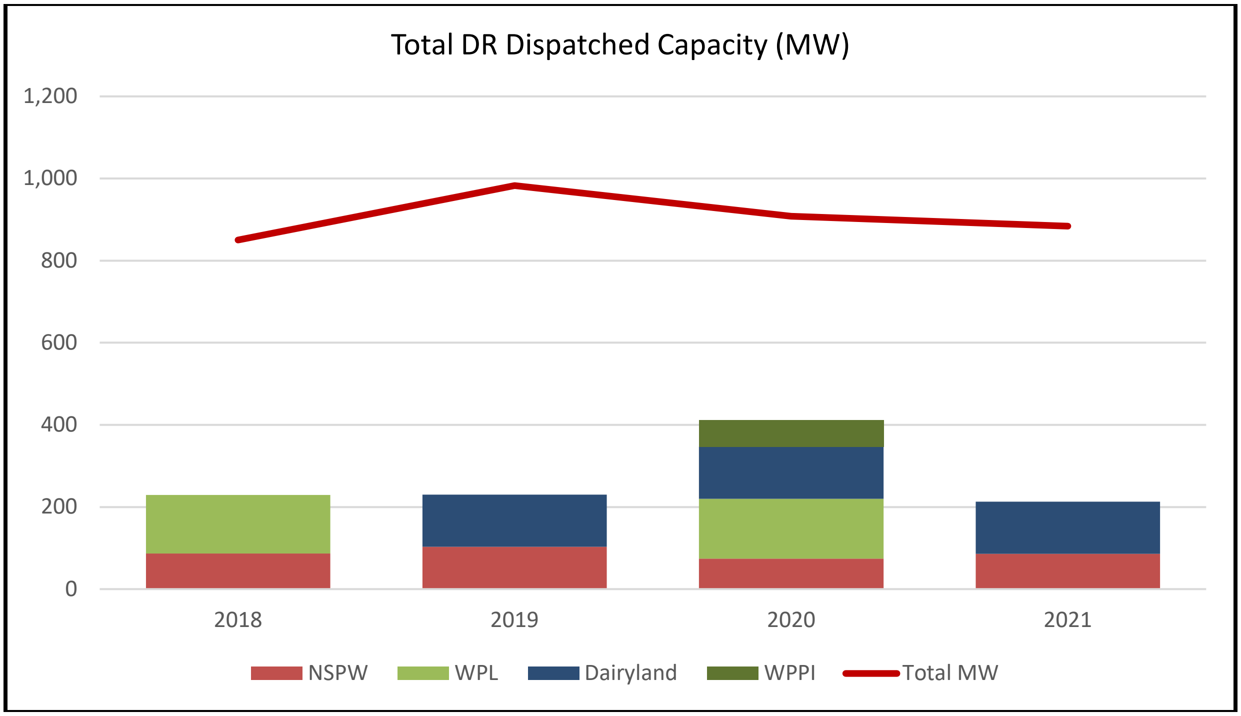
As shown in Figure 3-3, total demand response capacity available through those offerings ranged between 850 and 972 MW between 2018 and 2021, equal to approximately 6 to 7 percent of Wisconsin's total peak demand during the period. (See Chapter 1, Figure 1-1.) Interruptible tariffs accounted for approximately two-thirds of available capacity in each year, and direct load control programs for the remaining one-third.

Figure 3-3 Demand Response Capacity (MW) in Wisconsin by Provider, 2018-2021



As shown in Figure 3-4, Wisconsin providers dispatched a limited fraction of their available demand response capacity in recent years. While dispatch figures varied by program and provider, on a statewide basis 12 to 48 percent of total interruptible load capacity and 7 to 35 percent of direct load control capacity was dispatched annually between 2018 and 2021. Appendix C provides detailed summaries of total and dispatched capacity by provider, and by individual demand response offerings available from each provider.

Figure 3-4 Demand Response Capacity (MW) Dispatched by Provider, 2018-2021



These dispatch rates largely reflect that demand response offerings are only utilized under specific conditions. For example, the MGE Connect smart thermostat-based direct load control program will only adjust participant's thermostats if the utility's total system load exceeds 600 MW and the temperature is expected to be above 85 degrees. While MGE sets capacity on the assumption that 8-10 events may be called per year, fewer events have been called in years where weather and grid conditions less frequently meet program criteria.

Similarly, many providers' interruptible load tariffs are only activated when MISO calls upon them to reduce their load. Due to the absence of applicable MISO events, MGE, WEPCO, and WPSC reported that none of their combined capacity of approximately 250 MW was dispatched in any year between 2018 and 2021.

Under the arrangement described above, many Wisconsin providers register their interruptible tariff participants with MISO as Load Modifying Resources (LMR), which MISO can obligate to respond in regional emergencies, and thereby use to meet region-wide resource adequacy requirements and control the costs of meeting system peaks. (See Chapter 2 for more discussion on resource adequacy.) Wisconsin's largest electric providers reported an average 590 MW of demand response capacity from 2018 through 2020 that responds to MISO market signals, accounting for approximately 5 percent of MISO's total LMR capacity of more than 11,500 MW. MISO-registered LMR capacity, at both the state and regional level, is expected to decrease to some degree in future years as MISO implements planned changes to its methods for capacity calculation and accreditation.

At present, the substantial majority of regional MISO demand response activity occurs through LMR arrangements established by participating utilities.[68] However, implementation of FERC Order 2222 may lead to changes in MISO's demand response profile. Order 2222 will allow groups of small demand response resources, including non-utility resources, to aggregate into a single resource that will be allowed to participate in MISO's wholesale markets. Aggregations with a minimum combined capacity of 100 kW will be allowed to participate in the MISO markets as long as the resources do not also participate in utility-level demand response programs.

MISO submitted a filing outlining its plans for Order 2222 compliance to FERC in April 2022,[69] proposing full implementation by October 2029. MISO reported that full implementation is anticipated to take several years due to software upgrades and coordination between MISO, utilities, regulators, and other stakeholders. Gaining access to the MISO wholesale market may stimulate further deployment of demand response resources in Wisconsin and the MISO footprint, including through the development of new program models and partnerships between utilities, customers, project developers, and other market participants.

RENEWABLE ENERGY

Historically, a primary driver for utility-scale renewable resource development by Wisconsin electric providers has been compliance with Wisconsin's Renewable Portfolio Standard (RPS) law. However, declining project costs, combined with increasing customer interest, as well as the benefits of renewables in helping meet emissions reductions goals, have started driving increased renewable energy deployment above RPS requirements in recent years. Three separate factors have contributed to this increase: greater deployment of utility-scale renewable facilities, growth in provider offerings such as community solar programs, and increased installations of customer-owned renewables.

Renewable Portfolio Standard

Wisconsin's RPS law, 2005 Wisconsin Act 141, requires each electric provider to increase the share of renewable energy resources it uses to serve retail customers, in order to achieve a statewide goal for renewable resources to provide at least 10 percent of energy generation by 2015.[70]

Individual electric providers have met their requirements every year since 2006, and the statewide goal of 10 percent of electricity has been achieved every year since 2013. As shown in Figure 3-5,

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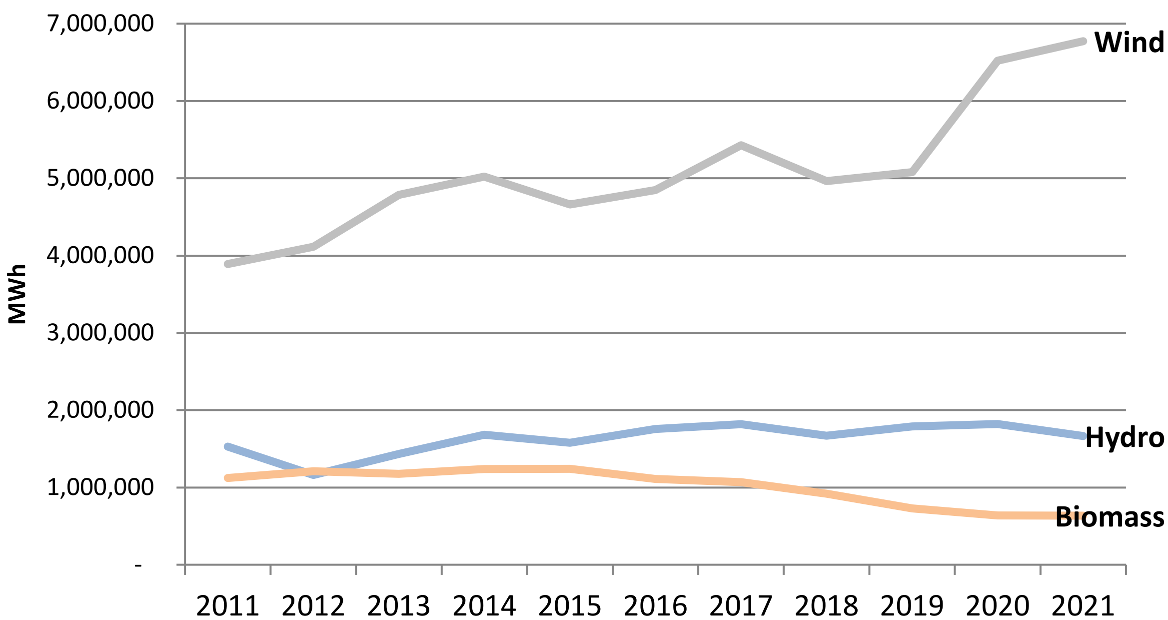
[68] During the 2018-2020 period MISO also maintained an additional 1,100 to 1,520 MW of demand response from two other categories: demand response resources (DRR) registered to respond to prices in MISO markets, and provide resources on short notice to avoid sudden increases in costs; and emergency demand response resources (EDR) which may also be called on in emergencies, but do not have the obligation of LMRs to respond during those events.

[69] *See* https://cdn.misoenergy.org/2022-04-14 Docket No. ER22-1640-000624051.pdf.

[70] To achieve the statewide 10 percent standard, the RPS requires each electric provider to increase their percentage of renewables, relative to their 2001-2003 baseline, by 2 percent by 2010 and 6 percent by 2015.

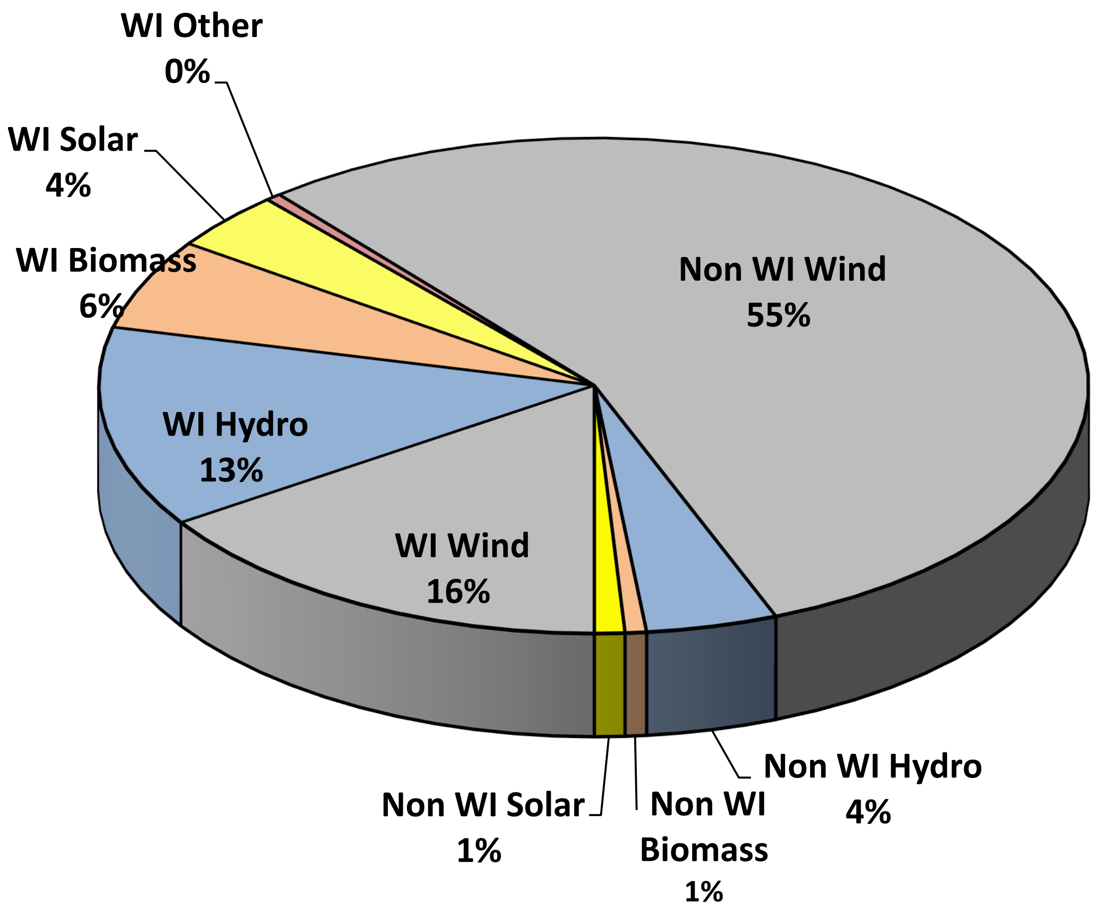
wind energy accounts for the largest share of renewable resources providers have deployed to comply with the RPS.

Figure 3-5 Renewable Energy by Resource 2011-2021



As shown in Figure 3-6, wind energy accounted for more than two-thirds of total renewable energy generation serving Wisconsin customers. Most of that wind energy, and more than half of Wisconsin's total renewable energy, is supplied through the transmission system from out-of-state facilities located west of Wisconsin, where more consistently windy weather conditions support cost-effective generation. Solar resources accounted for approximately 4.8 percent of total renewable generation deployed by electric providers in 2021, an increase from less than 2 percent in 2020. (These figures do not include solar generation used by individual customers, which is described in the Customer-Scale Renewables section below).

Figure 3-6 2021 Renewable Energy by State and Resource



As discussed in Chapter 2, Wisconsin electric providers reported plans to add more than 2,500 MW of new electric capacity from renewable sources between 2022 and 2028, nearly all from solar energy. These additions do not reflect required additions for RPS compliance; rather, providers reported that these planned additions reflect their preferred options, informed by resource planning analysis, to meet energy needs while balancing resource adequacy, reliability, affordability, emissions reductions, and other goals. If these additions are installed as planned, total renewable resources deployed in Wisconsin will continue to increase substantially beyond minimum RPS requirements. The investment tax credits and production tax credits for renewable resources available under the Inflation Reduction Act may also encourage further deployment increases in future years.

Electric Provider Solar Initiatives

Utility-scale solar construction projects increase the share of renewable generation provided to all customers. An increasing number of electric providers have also established programs for individual customers interested in procuring a larger share of their own energy use from renewables.

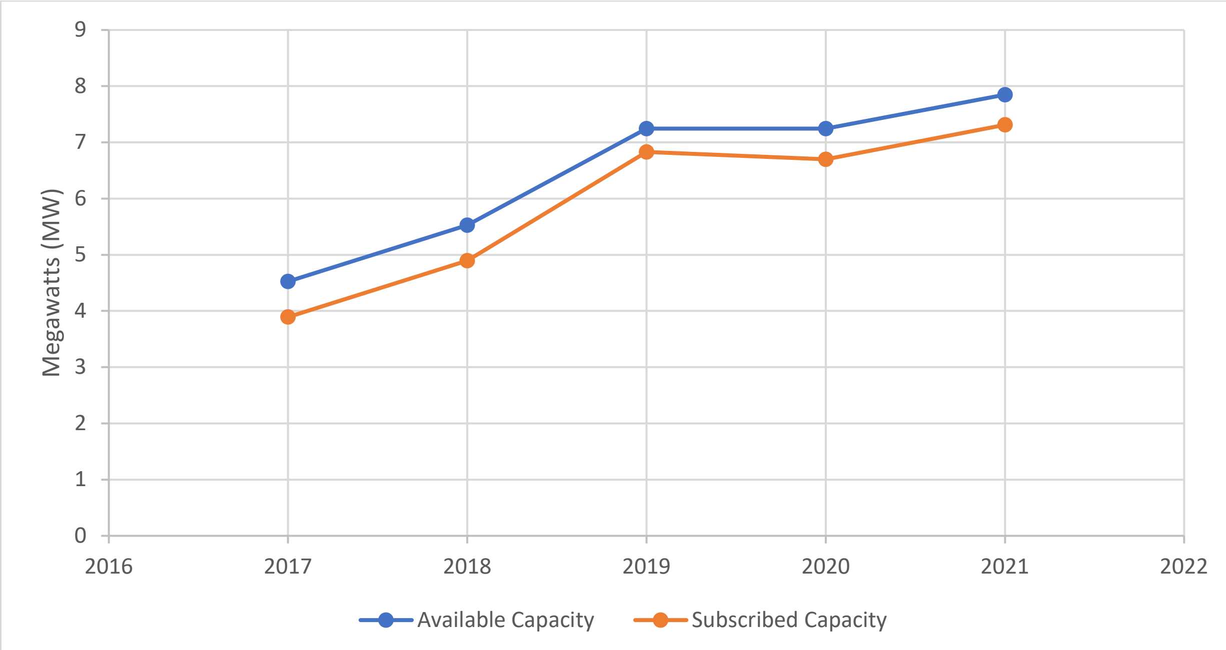
Community solar programs allow residential, and sometimes commercial, customers to subscribe to energy produced by solar facilities on the provider's system.

Most commonly, customers pay a subscription fee upfront, and then receive monthly bill credits to reflect the solar energy production associated with their subscription. Electric providers that offer this type of program structure include NSPW, WP&L, and the WPPI municipal members River Falls and New Richmond. MGE's Shared Solar program uses an alternative program structure under which customers can receive a guaranteed retail rate associated with the costs of the solar facilities for the duration of their participation. SWL&P's Community Solar Garden structure offers customers the option to pay upfront, through a flat monthly fee, or a guaranteed retail rate. In 2022, the Commission approved Manitowoc Public Utilities' application under docket 3320-TE-112 for a community solar program wherein customers would be charged monthly based on their share of the project's costs, and receive a monthly credit that reduces energy charges based on their share of energy produced by the solar facility.[71]

As shown in Figure 3-7, total capacity offered by Wisconsin community solar programs has increased 74 percent from 2017 to 2021. Customer subscriptions have consistently exceeded 85 percent of available capacity. Several providers report plans to add or expand programs, which if implemented would further increase total community solar capacity in the coming years. As another example of possible future expansion of community solar, the Wisconsin State Energy Office is currently pursuing an initiative with two electric cooperatives to increase the number of low- and moderate-income customers subscribing to new community solar projects.

[71] Some DPC members also offer community solar options, but the Commission does not regulate or collect information on those programs.

Figure 3-7 Community Solar Capacity in Wisconsin



Four electric providers also offer "renewable rider" programs for large customers to contract for a defined amount of utility-provided renewable resources for their use. The renewable rider uses a similar concept as Community Solar, but allows the electric provider to define larger portions of either distribution or transmission-interconnected renewable facilities for specific customers through individual contracts. For example, MGE's O'Brien solar field in Fitchburg, authorized in docket 3270-CE-129, provides 20 MW of capacity, serving seven customers. In total, MGE's renewable energy rider program has led to 37.5 MW of solar capacity additions spanning 4 distinct projects.

Customer-Owned Renewables

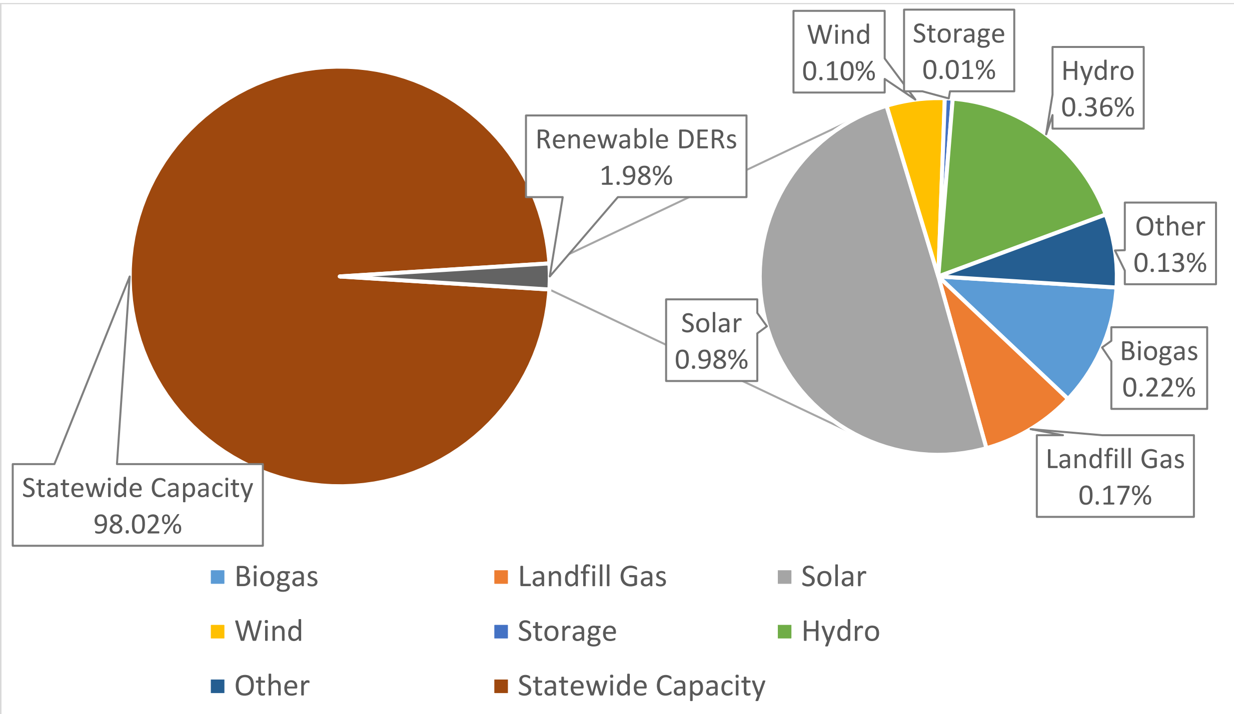
Customers may also procure renewable resources by installing their own sources of generation and reduce the amount of electricity they otherwise would have needed to purchase from their electric provider (or provide energy back to the grid). Starting in 2016, each SEA has asked all electric providers in Wisconsin to report data on the number, type, and generation capacity of all non-utility generation, or Distributed Energy Resources (DER), used by their customers, including historical data extending back to 2008. Customer-owned DER data reported by utilities include all customer-owned generation, including from non-renewable sources such as diesel-fueled generators. Since non-renewable sources account for less than 10 percent of total customer-owned DER capacity, the analysis below focuses on renewable customer-owned DERs.

Customer-owned renewable generation capacity in Wisconsin totaled 309 MW (DC) in 2021, which equates to 1.98 percent of total statewide capacity, as shown in Figure 3-8.[72] Customer-owned solar

[72] DER capacity data was requested under two different definitions: Direct Current (DC) and Alternating Current (AC). Some data provided included both DC and AC capacity, but some submitted data only identified capacity under one of

installations account for the largest share by source. At a total capacity of slightly more than 153 MW (DC), customer-owned solar accounts for nearly 50 percent of renewable DER capacity and equates to 0.98 percent of total statewide electric capacity. Solar capacity increased from 100 MW (DC) in 2019 to 153 MW (DC) in 2021, accounting for nearly all of the overall growth in renewable DER capacity during the two-year period.

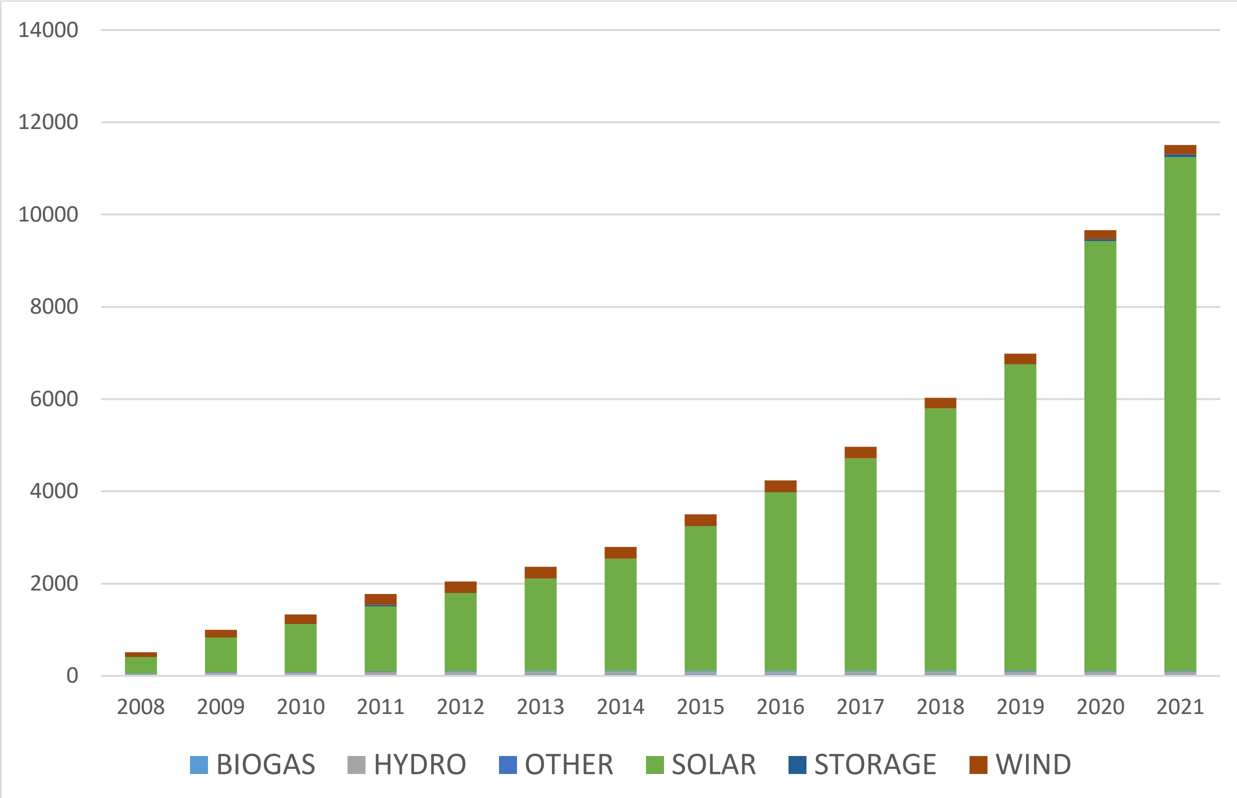
Figure 3-8 Capacity of Customer-Owned Renewables in Wisconsin, 2021



As shown in Figure 3-9, the number of customer-owned renewable installations increased from 528 in 2008 to 11,535 in 2021. The 11,140 solar installations reported in 2021 accounted for 95 percent of all customer-owned renewable installations in Wisconsin, and included nearly 4,500 new installations in 2020 and 2021. Solar installations and overall renewable installations increased nearly 40 percent between 2019 and 2020, accelerating beyond the consistent annual growth rate of approximately 20 percent observed during the previous decade. The growth rate was 19 percent between 2020 and 2021. The investment tax credits and production tax credits available under the Inflation Reduction Act will apply to customer-owned renewables and may influence growth rates in future years.

the two definitions. For purposes of reporting and analysis, staff filled in missing data using an assumed conversion factor that DC capacity is 1.25 times the value of AC capacity. Based on submitted data and conversions for missing data, total customer-owned renewable generation capacity was equivalent to 247 MW (AC) in 2021.

Figure 3-9 Number of Renewable DER Installations by Technology



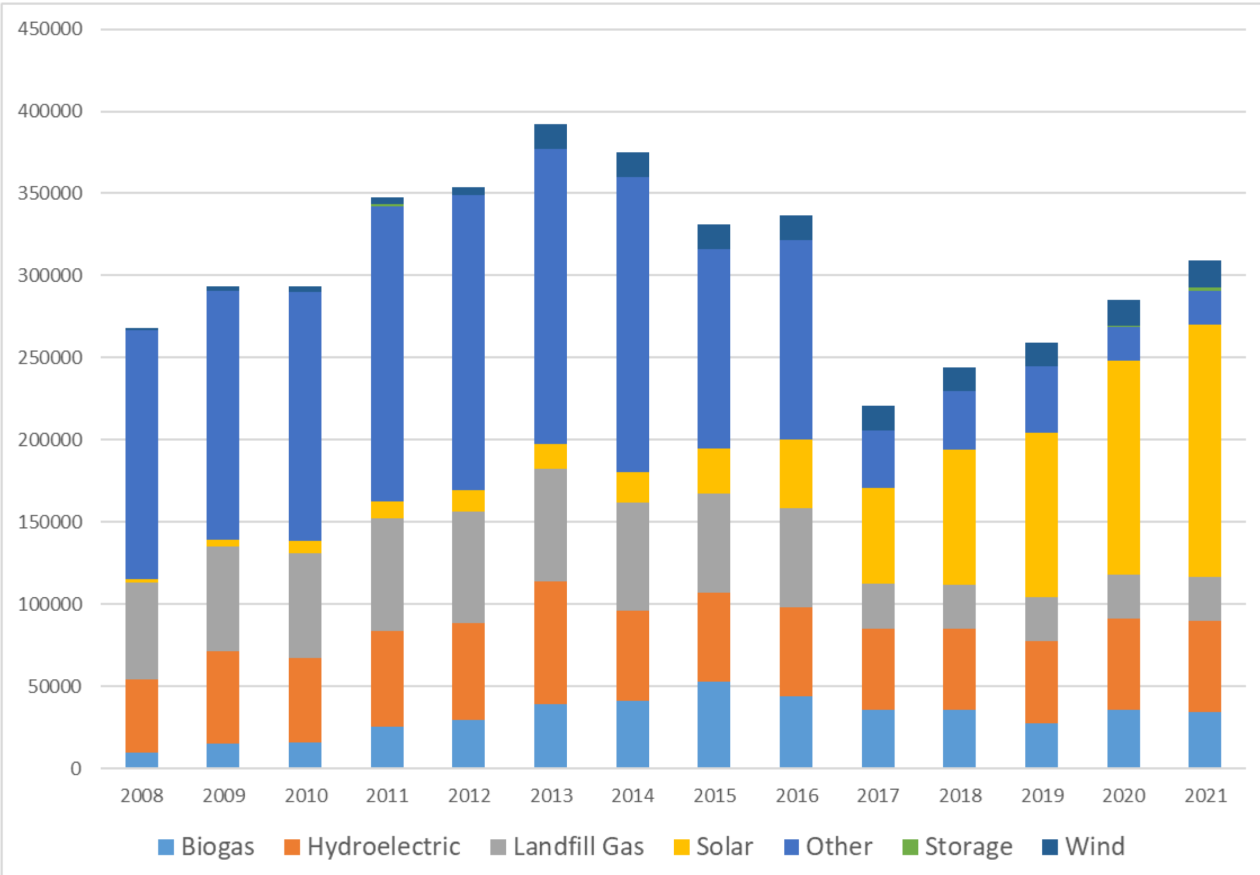
As shown in Table 3-1, residential customers owned a large majority of total solar installations in 2021, likely including most of the systems reported under the "Cooperative" category. While most residential installations are small-capacity systems, commercial and industrial installations accounted for at least half of total customer-owned solar capacity due to their more frequent deployment of larger systems. (See Appendix C, Figure C-1 for further information on all customer—owned renewable installations by customer class.)

Table 3-1 2021 Solar DER Snapshot by Customer Category

	Number of Installations	Capacity (MW-DC)
Residential	8,186	61
Commercial	1,422	53
Industrial	132	23
Cooperative	1,400	16
Total	**11,140**	**153**

As shown in Figure 3-10, capacity from all customer-owned renewables was 309 MW (DC) capacity in 2021. Total capacity has declined from levels in the early 2010s, driven by customer decisions to discontinue operation of a small number of very large DER installations, primarily in the industrial sector. Due to the combination of those retirements and the rapid growth in new solar installations, the solar share of total customer-owned renewable capacity increased from less than 8 percent in 2015 to 50 percent in 2021. Residential installations also increased from less than 10 percent of total capacity in 2019 to more than 20 percent in 2021 (see Appendix C, Figure C-2).

Figure 3-10 Installed Capacity kW-DC of Renewable DER Installations by Renewable Source



Eligible customers who own generation can receive bill credits for providing excess energy production from their generation back to their electric provider. Some providers offer certain customers—typically limited to those with small-capacity distributed energy resources—bill credits that match the retail rate charged to the customer, an arrangement often termed "net metering." Other customers receive lower rates based on the avoided cost to the provider associated with receiving energy from the customer's DER rather than from its own resources. Rates and eligibility thresholds for different buyback rate arrangements vary by provider.

In June 2020, the Commission opened an investigation in docket 5-EI-157 to broadly examine the purchase rates associated with customer-owned DERs. In December 2020, Commission staff released a memorandum summarizing current purchase rates offered by IOUs and municipal utilities and analyzing the methods used to calculate rate values.[73] Informed by that memorandum and commenter input, the Commission issued an Order in May 2021 establishing that avoided cost rates should be calculated under a standard conceptual framework, which uses utility-specific engineering and economic analysis to identify the avoided energy, capacity, and transmission costs avoided by

[73] Commission staff memorandum of December 18, 2020.
https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=401895

customer-owned DERs. The Commission also directed MGE, NSPW, WEPCO, WP&L, and WPSC to propose updated purchase rates.[74] Proposals were filed by all five IOUs in September 2021. The Commission acted to approve updated rates for all five utilities in 2022, which include modifications to the compensation customers received for avoided energy and capacity costs. The Commission also directed that MGE, WEPCO, WP&L, and WPSC pursue further study of avoided transmission costs and report back to the Commission on their findings in 2023.

As part of the same Order in docket 5-EI-157, the Commission directed the development of an informational paper on the determination of net metering rates. In February 2022, Commission staff issued a paper prepared by independent experts at the Regulatory Assistance Project (RAP).[75] RAP's paper emphasized that determination of purchase rates is informed by multiple, often-competing ratemaking principles and policy goals, and therefore requires a "balancing of priorities" in making final decisions. The paper also surveyed experiences in the growing number of states throughout the country that have explored net metering reforms in recent years. The Commission has solicited commenter input in response to the paper on whether current net metering rates in Wisconsin strike an appropriate balance, and on whether and how the Commission may wish to explore further net metering reforms. The Commission will draw on that input to consider options for further investigation of the issue later in 2022.

To receive purchase rates, customers must work with providers to interconnect their facilities to the broader electric grid. Interconnection standards and processes were established in Chapter PSC 119 of the Wisconsin Administrative Code, which has not been updated since it was first promulgated in 2004. In 2021, the Commission opened a rulemaking under docket 1-AC-256 to comprehensively update PSC 119. The rulemaking will focus on identifying rule changes that can address the impacts of new technologies and new technical standards, and identifying process updates that can help providers and customers achieve timely and well-informed processing of interconnection applications as the number of customer-owned facilities continues to increase. The Commission appointed an advisory committee—including providers, technology installers, customer advocates, and technical experts—to collaboratively identify recommendations for appropriate updates. The advisory committee delivered its recommendations in May 2022, which the Commission will use to develop proposed rule changes.

Electric Vehicles

Large-scale use of electric vehicles (EV) could have significant implications for Wisconsin's electric system, by increasing total electric demand, modifying timing and location of energy use, and presenting new considerations for determining customer rates and service arrangements. While fewer than 10,000 EVs were registered in Wisconsin in 2021, annual growth in EV sales continued

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[74] Final Decision of May 4, 2021. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=410850.

[75] John Shenot, Camille Kadoch, Carl Linvill and Jessica Shipley. "Ratemaking Principles and Net Metering Reform: Pathways for Wisconsin." Regulatory Assistance Project. Issued as an attachment to Commission staff memorandum of February 25, 2022. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=431687.

to increase,[76] and EV-related tax credits established and expanded in the recently enacted Inflation Reduction Act may further accelerate EV adoption. The Commission and electric providers are taking steps to research relevant issues and develop programming in order to be prepared to serve growing demand from customers with EVs.

In 2019, the Commission opened an investigation in docket 5-EI-156 to consider future policies and regulations related to EVs and their associated infrastructure. The investigation concluded that:

1. Barriers to EV adoption in Wisconsin included insufficient charging infrastructure, upfront costs of EVs and associated charging equipment, and limited customer awareness and education;
2. Commission and utility policies and regulations, such as electric rates and rate design, could significantly influence EV deployment;
3. The Commission could influence EV deployment by providing regulatory clarity; and
4. Pilot programs could help serve existing customers with EVs while preparing the Commission and utilities for future increases in EV deployment.

Informed by stakeholder feedback, the Commission issued an Order in December 2020 encouraging utilities to submit pilot program proposals that address identified barriers to EV adoption, serve customer needs, and explore EV-related issues. The Order also offered regulatory clarity by establishing a framework that set clear expectations for the information any provider must include in proposing EV pilots to the Commission.[77]

Multiple providers have received Commission approval for EV pilots serving residential, commercial, and fleet customers. To date, the Commission has approved MGE proposals for five pilot programs and one standard tariff offering. Under the Charge@Home program (which began as a pilot and was transitioned to a permanent offering in 2022), residential customers are charged a per-day fee for use of utility-provided charging equipment in addition to paying tariffed rates for energy use.[78]

MGE's five pilots address EV charging for residences, apartments and workplaces, fleets, and public sites. Residential, apartment and workplace, and fleet charging pilots approved by the Commission in September 2022 allow MGE to monitor and manage customer charging, in order to shift charging loads to off-peak times to support reliability and cost reductions.[79] A separate fleet program addresses cost barriers by offering commercial customers with meters dedicated to EV charging a discounted demand rate for up to five years.[80] The public charging program sets rates for charging

[76] https://wisconsindot.gov/Documents/dmv/shared/rpt-25-fiscal-21.pdf.
[77] Order of December 23, 2020. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=402117.
[78] Commission Meeting Minutes of September 15, 2022.
https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=448345.
[79] Id.
[80] Order of December 29, 2020. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=%20402247

sessions at the utility's network of charging stations, with rates varying based on charging speed and duration.[81]

In 2020, the Commission approved NSPW's proposal for residential and commercial pilots. Residential customers may contract with their utility to install an EV charger, the cost of which will be prepaid or paid in installments. Customers will also be enrolled in time-of-day (TOD) rates which establish lower rates for energy use during overnight hours and higher rates during hours of peak demand, providing economic incentives for customers to charge their vehicles during periods of low demand and help utilities avoid high costs associated with serving increased peak demand. NSPW's commercial program allows utilities to own and maintain "make-ready" EV charging infrastructure (which does not include the charger, but does include the wiring and equipment connecting the charger to the electric system) and allow customers to pay for new infrastructure extensions through monthly fees or demand charges. In 2021, WEPCO and WPSC were each approved to begin residential and commercial pilots designed similarly to the NSPW programs.

In August 2022, NSPW submitted an application under docket 4220-TE-113, currently under Commission review, that proposes limited modifications to its existing programs, as well as the creation of a new multifamily pilot. NSPW also provided preliminary information on a public charging proposal it expects to propose in its next rate case.[82]

Robust accounting and reporting requirements have accompanied all approved pilot programs, in order to identify cost impacts to the customer and the provider, and to provide insight to inform future program development. Data collection enables providers and the Commission to understand how customers' charging patterns align with electric system operations and existing rate designs, and can provide insight on how to address potential future increases in EV deployment while maintaining reliability and affordability. These findings may be used to continue to inform the development and review of future proposals before the Commission. In addition, these findings may help inform the Commission's ongoing engagement with statewide EV planning and initiatives, including interagency planning work to explore EV development opportunities under the federal Bipartisan Infrastructure Law.

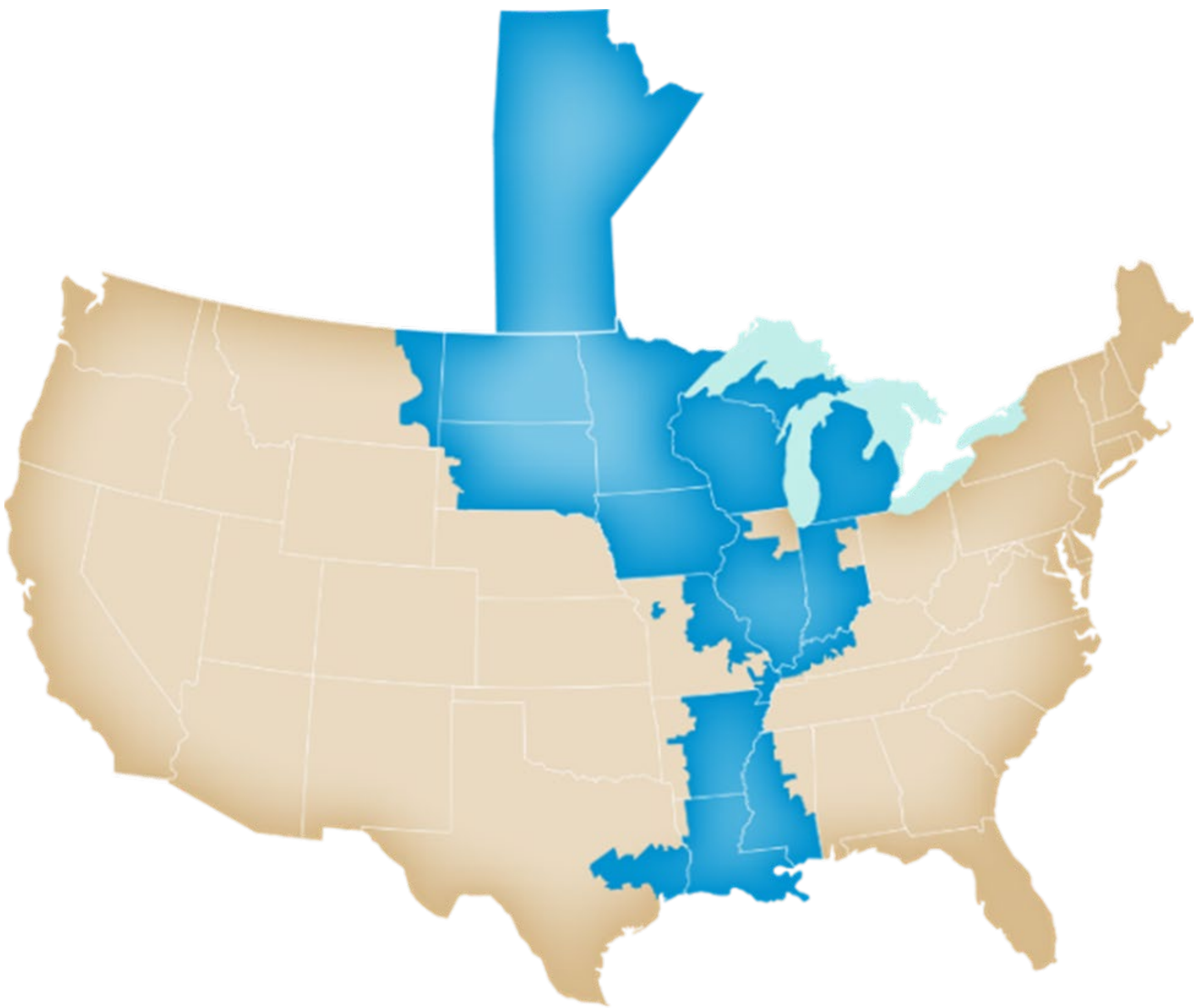
[81] Order of December 23, 2014. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=226563.

[82] Application of Northern States Power Company – Wisconsin for Approval of Electric Vehicle Programs. August 2, 2022. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=444518.

CHAPTER 4 – ELECTRIC TRANSMISSION IN WISCONSIN

Wisconsin electric providers are responsible for providing adequate and reliable service directly to customers, through their own distribution systems. In addition, high-voltage transmission lines are required to carry energy across long distances and deliver electricity to customers located far from generation resources. Wisconsin participates in the regional transmission system of MISO, which operates an integrated electric grid serving all or part of 15 states and one Canadian province, identified in Figure 4-1.

Figure 4-1 MISO Regional Transmission Map



Participation in MISO helps Wisconsin's electric system access additional benefits within a larger regional context, including:

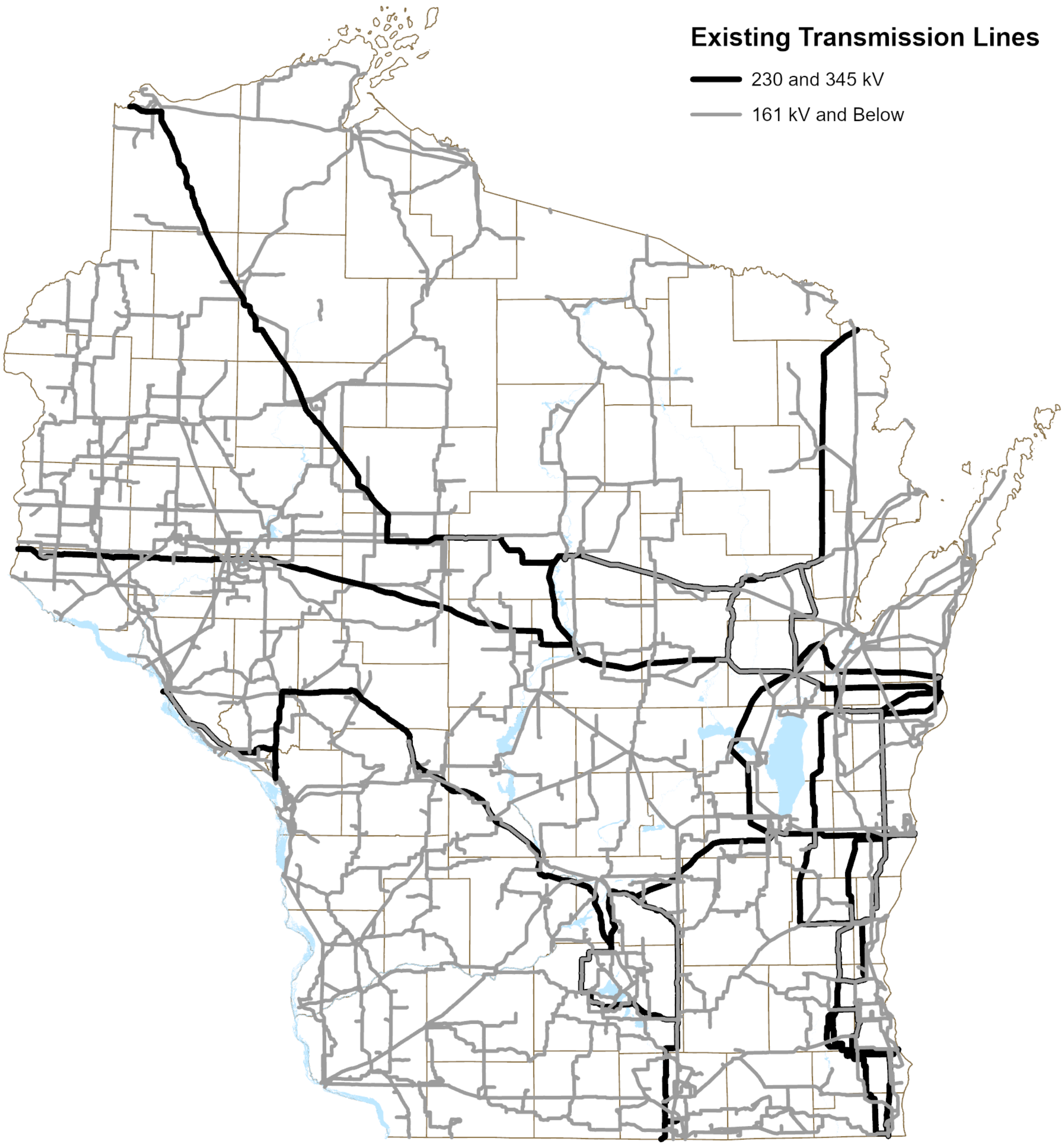
- Accessing less expensive wholesale energy and capacity resources available outside of Wisconsin;

- Reducing the generation capacity reserves any single provider may need to meet peak customer demand by taking advantage of access to more diverse suppliers;
- Offering access to a wholesale market with clear and predictable energy prices, which can allow providers access to energy resources and use price signals to guide their own investment decisions; and
- Managing the transmission grid to enhance region-wide reliability.[83]

Wisconsin has approximately 15,700 miles of high-voltage transmission lines in service, which are mapped in Figure 4-2. Transmission lines with higher-voltage ratings are designed to carry the largest volumes of energy over longer distances, including to connect high-demand areas in Wisconsin with generation resources located in other states in the MISO region.

[83] MISO states that these benefits currently result in more than $3 billion in annual cost savings across its region. *See* https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/. MISO does not provide benefit estimates by state.

Figure 4-2 Existing Transmission Lines



HISTORICAL TRANSMISSION COSTS

Transmission development and operations occurs collaboratively between MISO and individual providers within the region. Most Wisconsin electric providers do not own or operate their own high voltage transmission lines and associated infrastructure. These assets are owned by the American Transmission Company LLC (ATC), which builds and operates all transmission infrastructure in the territory of participating providers and participates in MISO planning and operations along with individual providers. NSPW operates transmission independently of ATC, because NSPW utilizes the transmission network owned by its parent company.[84]

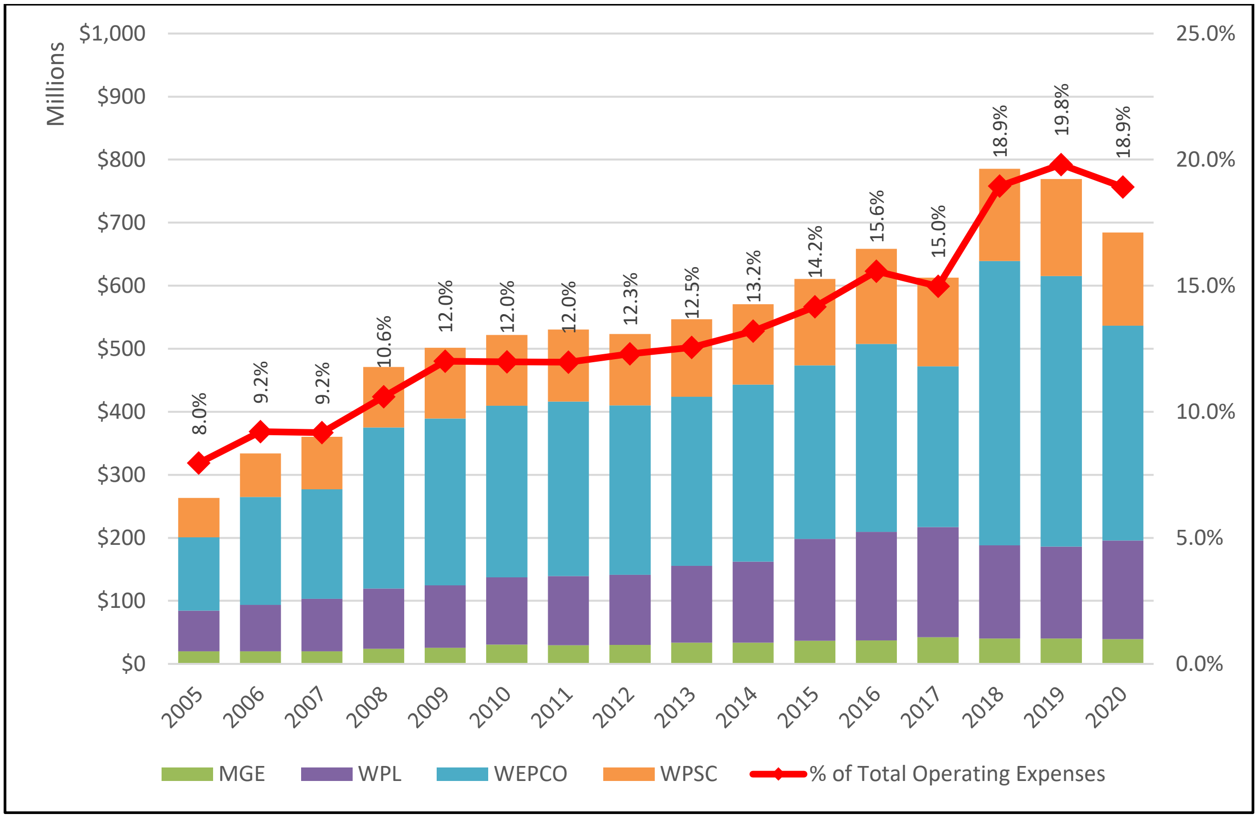
Three main regulatory bodies are involved in the recovery process of transmission costs: FERC, MISO, and the Commission. Federal law assigns the highest authority to FERC in interstate transmission regulation. FERC has delegated the power to coordinate transmission services to regional transmission owners and operators such as MISO and allows MISO to recover transmission costs according to its approved tariffs.

Under these rate structures, MISO facilitates payment for transmission services by Wisconsin electrical providers to ATC. Individual Wisconsin electric providers pay rates to MISO to cover transmission-related construction and operations expenses within their territory. MISO then distributes the revenue from electric providers to the appropriate transmission owners for their services. MISO also collects a charge from electric providers and transmission owners to cover the costs of its own planning and operations activities. The Commission reviews the costs regulated Wisconsin electric providers incur from MISO for these transmission services and approves recovery of costs through customer rates.

Figure 4-3 shows the transmission expenses reported by MGE, WEPCO, WP&L, and WPSC from 2005-2020. Combined expenses from ATC and MISO payments increased from $263.1 million in 2005 to $684.5 million in 2020.

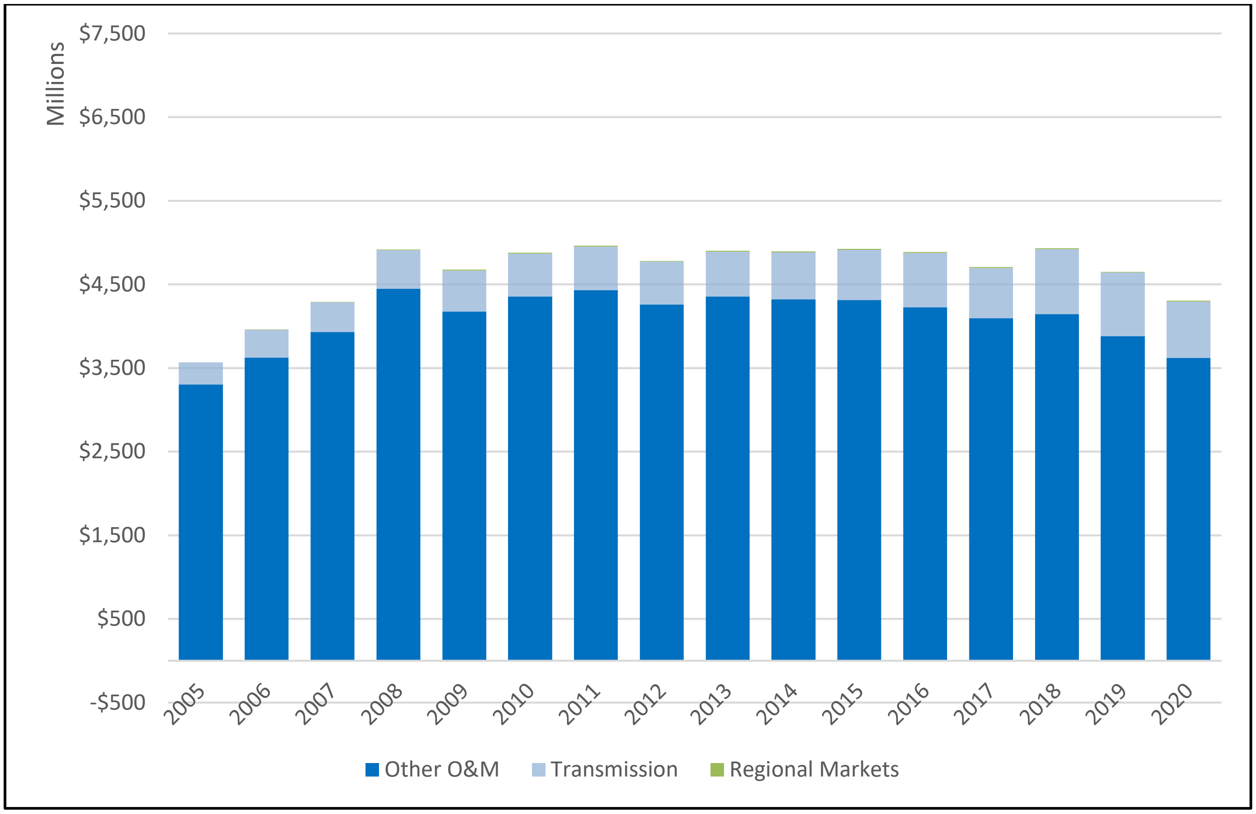
[84] DPC also operates its own transmission system.

Figure 4-3 Transmission Expenses, 2005-2020: MGE, WEPCO, WP&L, and WPSC



Transmission has also accounted for an increasing proportion of those electric providers' total operating expenses. However, as shown in Figure 4-4, the total operating expenses paid by customers have remained comparatively stable, ranging from $3.9 to $4.5 billion each year between 2008 and 2019 before decreasing to $3.6 billion in 2020 due to a decline in fuel costs associated with lower customer demand during the COVID-19 pandemic. Transmission expenses have been balanced by decreases in other operating expenses due to a variety of factors, which may include reduced fuel costs associated with the increased deployment of renewable generation; the decline in natural gas fuel prices during the 2010s; and decreases in the market energy prices providers must pay for purchased power. (See Figure D-1 in Appendix D for data on MISO market energy price trends.)

Figure 4-4 Operating Expenses, 2005-2020: MGE, WEPCO, WP&L, and WPSC



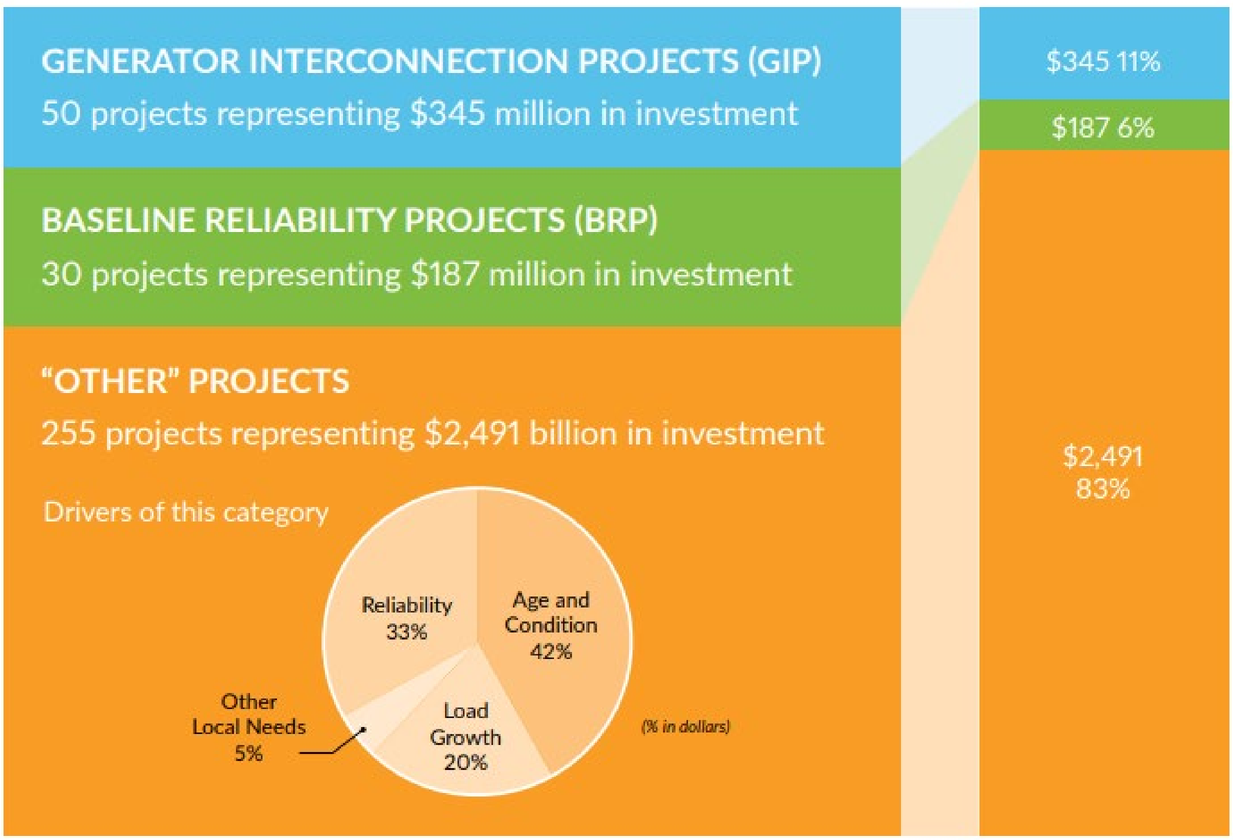
Increased transmission costs in Wisconsin over the past 15 years reflect increased transmission line development and construction. The annual MISO Transmission Expansion Planning (MTEP) process serves as a primary foundation for reviewing transmission needs and identifying and developing transmission infrastructure. MTEP focuses on identifying infrastructure sufficient to provide adequate energy delivery throughout the MISO region, meet national standards for maintaining service reliability, facilitate competitive regional energy markets, and support the policy goals of member states. Transmission projects identified and pursued through the MTEP process include:

- Baseline reliability projects to ensure adequate transmission is available throughout the regional grid. For example, a number of baseline reliability projects increase capacity to eliminate localized areas of transmission congestion where available energy exceeds transmission capacity, in order to reduce energy costs and minimize the risk of outages due to overheating or insufficient energy availability;
- Generation interconnection updates to support the addition of new generation facilities in specific locations;
- Reliability initiatives to address more localized transmission capacity needs within states;
- Market efficiency projects (MEP) to reduce transmission costs to customers by reducing congestion on the transmission grid;

- Age and condition updates to replace or enhance existing transmission infrastructure; and
- Load growth projects to update the transmission system to meet increased energy usage in specific locations.

On a region-wide basis, total costs from MTEP approved projects have steadily increased from $1 billion annually in 2010 to more than $3 billion each year since 2019. In the most recently completed planning cycle, the MISO Board of Directors approved 335 MTEP21 projects totaling $3.0 billion in costs across the entire regional footprint. As shown in Figure 4-5, age and condition updates accounted for the largest share of approved projects region-wide, followed by reliability initiatives.

Figure 4-5 MISO MTEP21 Snapshot (Footprint-wide)



Shares of MTEP-approved costs are allocated to Wisconsin and other individual states for projects located partially or entirely within their borders. As shown in Table 4-1, $314.4 million in costs for 27 approved MTEP 21 projects will be allocated to Wisconsin, with a majority of costs allocated to age and condition updates.

Table 4-1 MTEP21 Projects in Wisconsin[85]

Types of Projects	Estimated Costs	Number of Planned Projects
Baseline Reliability Projects	$1,777,603	1
Generator Interconnection Projects	$42,409,633	3
Other	$270,248,717	23
Age and Condition	$171,708,532	13
Load Growth	$50,891,407	4
Other Local Needs	$43,815,937	4
Reliability	$3,832,841	2
Total	$314,435,953	27

A key contributor to transmission cost increases throughout the past decade has been the implementation of MISO's Multi-Value Project (MVP) portfolio, a regional portfolio of large-scale transmission projects across the MISO footprint that were approved by MISO in 2011 to alleviate congestion caused by rapid growth in wind generation. The MVP projects had a total estimated cost of $5.1 billion, with costs for each individual project incorporated into annual MTEP portfolios and recovered through provider expenses once each project is put in service. Unlike other MTEP projects, the cost of each MVP is shared over the entire region that MISO has determined to benefit from the project. Transmission owners who have built an MVP provide MISO with financial information regarding the project's cost. MISO then uses the information from all the MVP-owners to calculate the MVP Usage Rate (MUR) charged to affected utilities to recover project costs.

MISO is currently in the process of planning a second portfolio of large-scale regional transmission projects, through the Long Range Transmission Planning (LRTP) process. Similar to providers' resource planning approaches (see Chapter 2), MISO and its stakeholders assess transmission needs under multiple scenarios that encompass a range of potential future economic, policy, and technology conditions. For MTEP21, MISO developed and applied a new set of three futures, which vary the speed and magnitude of future CO_2 reductions achieved throughout the region. The scenarios also vary the assumed amount of electric demand growth throughout the region, with more aggressive scenarios assuming that load growth accelerates due to increased electric demand associated with growing use of electric vehicles and conversions of gas-fired heating and other end-uses to electric sources. These futures were adapted to inform the resource planning conducted in Chapter 2, and more detail on futures design can be found there.[86]

For purposes of transmission planning, MISO has started developing "indicative roadmap[s]" identifying projects that address expected transmission capacity needs under each future.[87] MISO reports that identified LRTP projects are primarily meant to address system reliability needs throughout the MISO region, in light of plans across multiple states and utilities to retire existing

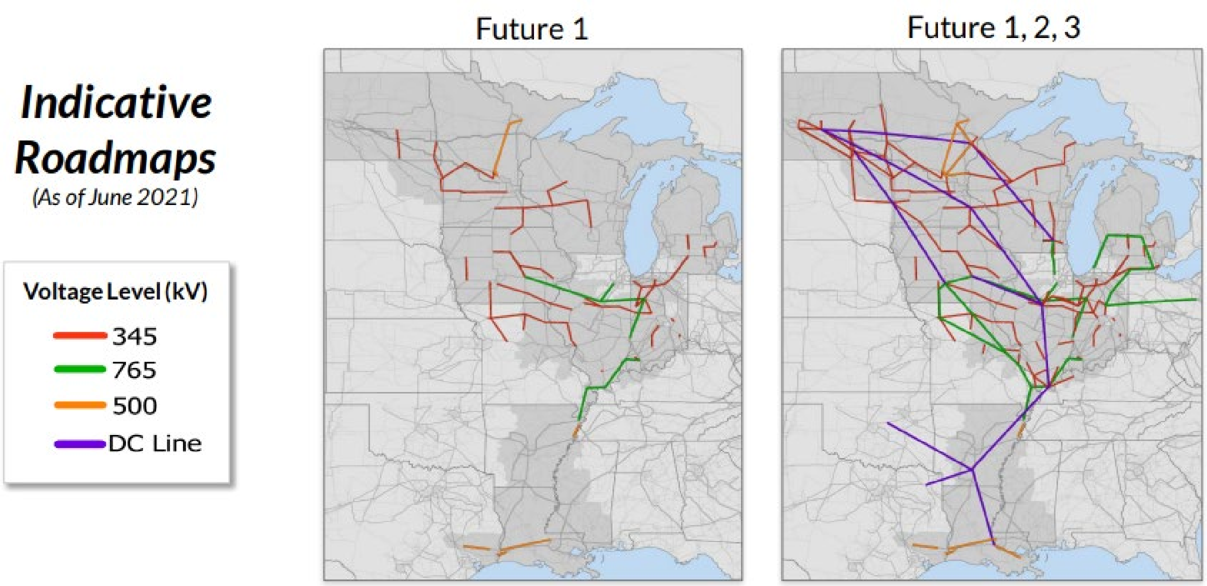
[85] The "Other" category includes Age and Condition, Load Growth, Other Local Needs, and Reliability Projects, which are italicized in this Table to distinguish these as sub-categories.

[86] See MISO Futures One-Pager https://cdn.misoenergy.org//MISO%20Futures%20One-Pager538214.pdf.

[87] Given the long development cycle for addressing regional needs and constraints on conducting robust, but timely analysis, MISO and its stakeholders plan using these Futures as formed in certain points in time, and continually discuss how the Futures or certain assumptions may need to be improved with each iteration of review as more accurate or the latest information is discovered.

resources and add a substantial amount of new resources at a variety of locations. Figure 4-6 illustrates two Roadmaps. The Roadmap for Future 1 assumes relatively limited future carbon reduction and load growth consistent with providers' currently announced plans, and identifies projects MISO believes will be needed to serve those announced plans. The second Roadmap identifies a more extensive set of projects that MISO has initially indicated could be supportive for achieving all futures combined, which assume continued and significant changes in the 2020s and 2030s that go beyond currently announced plans.[88]

Figure 4-6 MISO LRTP Indicative Roadmaps



In July 2022, the MISO Board of Directors approved all proposed Tranche 1 projects as shown in Figure 4-7. Total region-wide costs for the identified Tranche 1 projects are currently estimated at \$10.4 billion.[89] Projects approved by MISO will require transmission providers to design, plan, and seek regulatory approvals in each state where the projects will reside. Depending on size, transmission lines in Wisconsin will be required to receive Commission approval under state law. As shown in Figure 4-7, MISO is proposing that projects 4, 5, and 6 in LRTP Tranche 1 could be sited partially or completely in Wisconsin.

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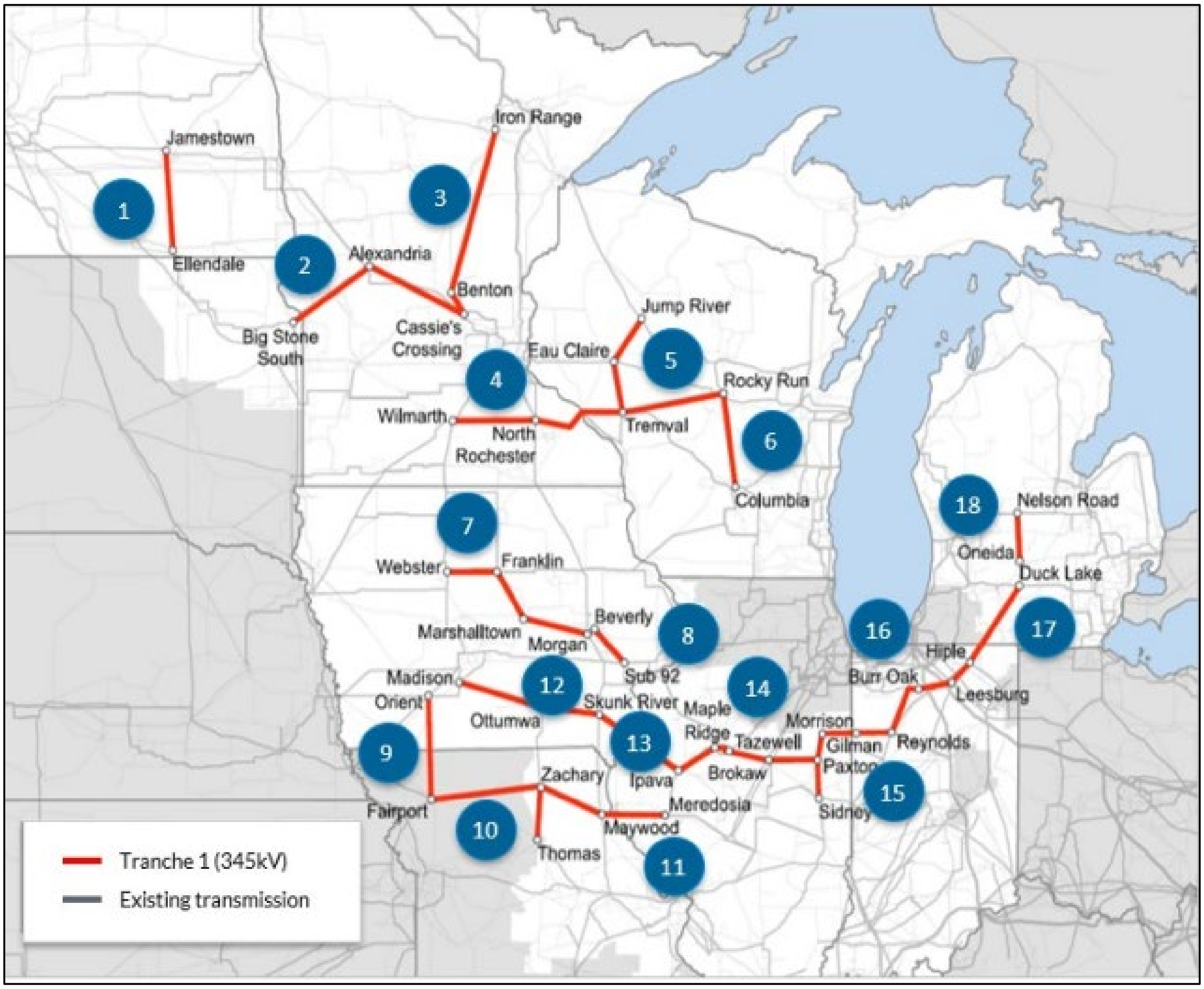
[88] See MTEP21 Executive Summary, page 12, here: https://cdn.misoenergy.org/MTEP21%20Full%20Report%20including%20Executive%20Summary611674.pdf.

[89] This estimate is based on "overnight costs" or is a simplistic estimate of project costs if they were constructed overnight without considering interest rates, lifespan, and other factors. See MTEP21 Report, under the MTEP 21 LRTP Tranche 1 Portfolio .zip file here: https://cdn.misoenergy.org/MTEP21%20LRTP%20Tranche%201%20Portfolio626133.zip. Initial cost estimates may change by the time of project construction based on a variety of factors.

MISO reports that this map illustrates proposed projects within the first of four planned "tranches" or groups of projects.

Figure 4-7 LRTP Tranche 1 Transmission Portfolio (MISO Midwest)



MISO reports that the map in Figure 4-7 illustrates proposed projects within the first of four planned tranches of projects. After the MISO Board of Directors' decision on Tranche 1, further analysis is expected to assess additional infrastructure needs, guided by the combined future roadmap in Figure 4-6. Throughout the analysis process, Commission staff have participated in MISO's public stakeholder processes that discuss the rationale for these projects and have worked with OMS in reviewing the drivers and needs for these projects. This engagement will continue as MISO pursues analysis on future LRTP tranches.[90]

[90] Future analysis of LRTP tranches may also be influenced by transmission-related provisions of the Inflation Reduction Act, which include grants and loans for project analysis, siting, and development.

The potential additional costs associated with future LRTP projects have inspired enhanced attention to methods for allocating costs among individual states and regions in MISO. In February 2022, MISO proposed tariff revisions to modify the cost allocation methodology for LRTP projects in FERC Docket No. ER22-995.[91] FERC accepted the tariff revisions in May 2022.[92]

This tariff update modifies the cost allocation method historically used for MVP projects, which allocated costs to all users importing and exporting from MISO through an energy charge called the MVP Usage Rate (MUR). The tariff update will create two sub-regions of the MISO footprint, a MISO Midwest sub-region that includes 11 states, including Wisconsin, and a MISO South sub-region that includes MISO's territory in the Southern states of Arkansas, Louisiana, Mississippi, and Texas. MISO will allocate costs for projects in each sub-region only to customers in that region, with exceptions for projects that provide demonstrated benefits to all of MISO. According to this method, the cost of the LRTP Tranche 1 projects would be shared amongst utilities in the Midwest sub-region using an MUR charge.

MISO calculates the MUR for each year of the project's life by dividing the annual revenue requirement of the projects by the total energy use of all the utilities located in the benefited region. MISO then charges each utility this rate based on their total energy usage. Using MISO's forecasted energy use for Wisconsin electrical providers and the predicted MUR for the Tranche 1 projects, Commission staff have preliminary estimated that Wisconsin electric providers would pay about **$195.91 million** for these projects in the first year of service, if the projects are approved for siting in each respective state. The costs allocated to the Wisconsin electric providers would amount to 15.95 percent of the total charges MISO collects annually for these projects. Like other transmission expenses, the Commission will review regulated providers' recovery of those costs in future rate reviews.

Some stakeholders hoped that MISO would propose a methodology that allocated costs more directly for these types of transmission projects to the various beneficiaries (identified via benefit analysis) rather than to an entire sub-region. MISO and its stakeholders have agreed to continue discussing this issue over the next two years, while moving forward with planning for currently-identified transmission needs.

[91] The MISO Transmission Owners, which include Wisconsin utilities ATC, Northwestern Wisconsin Electric Company, and NSPW (Xcel Energy), co-filed this proposal with MISO.

[92] *See Order Accepting Tariff Revisions*, 179 FERC ¶ 61,124 (2022), https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20220518-3037.

CHAPTER 5 – RESILIENCE AND CYBERSECURITY

RESILIENCE

Nationwide, electric providers and their regulators have increasingly focused on resilience, as a result of increasing attention to "high impact, low frequency" (HILF) events that can result in lengthy service interruptions and significant recovery costs. Resilience efforts focus on both taking steps to prevent HILF events from occurring and developing plans and resources to support efficient recovery after an event occurs.

Focus on resilience has increased in recent years, as attention has increased to the scope and scale of HILF events. Tracking by the National Oceanic and Atmospheric Administration has found that weather events resulting in more than $1 billion in costs have continually increased in frequency, in part due to the effects of climate change. Nationwide, billion-dollar disasters averaging six per year in 2000-2009 and 12 per year from 2010-2019, before reaching historic highs of 22 events in 2020 and 20 events in 2021.[93] Seven events in 2020 and 2021 impacted Wisconsin and surrounding areas, including the August 2020 Midwest derecho and the August 2021 high winds event.[94] Enhanced national attention has also resulted from Winter Storm Uri, which in February 2021 generated record-low temperatures and snow and ice cover that caused widespread disruptions in utility service - particularly in the state of Texas, where more than two-thirds of residents experienced power outages.[95]

The U.S. Department of Energy (DOE) initiated formal federal policy development on resilience by issuing a Notice of Proposed Rulemaking on the issue in September 2017. National policy effort has since shifted to FERC, which ended DOE's rulemaking in 2018 and created in its place FERC Docket AD 18-7, under which MISO and other regional transmission organizations were asked to review the resilience of their systems. In 2021, FERC concluded that the "paramount responsibility of resilience would be best addressed on a "case-by-case and region-by-region basis," consistent with the different threats posed by different regional weather events such as wildfires, hurricanes, and winter storms.[96] Consistent with this approach, the Commission has collaborated with other organizations within Wisconsin to enhance state-level planning and policy development on resilience issues.

State law places the primary responsibility for responding to large-scale emergencies that exceed local capacities with the Wisconsin Division of Emergency Management (WEM) within the Department of Military Affairs. The Commission's Office of Energy Innovation (OEI) contains the

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93 National Oceanic and Atmospheric Administration, National Centers for Environmental Information. "Billion Dollar Weather and Climate Disasters." https://www.ncdc.noaa.gov/billions/time-series.
94 National Oceanic and Atmospheric Administration, National Centers for Environmental Information. "Billion Dollar Weather and Climate Disasters." https://www.ncdc.noaa.gov/billions/events/WI/2020-2021.
95 https://comptroller.texas.gov/economy/fiscal-notes/2021/oct/winter-storm-impact.php.
96 FERC Order in Docket AD 18-7-00, February 18, 2021. https://www.ferc.gov/media/e-3-ad18-7-000.

state's designated state energy office, which serves as a lead advisory agency to WEM, and the two agencies work together to carry out OEI's federal requirement to develop energy emergency plans that respond to supply disruptions. Commission personnel also play roles in energy assurance coordination, by sharing information with other state agencies, the federal government, and other state governments during emergency situations.

WEM and OEI regularly participate in planning exercises at the state, regional and national level, working with other actors to model planning and responses to HILF events. In 2018, WEM hosted a three-day "Dark Sky" event which modeled a long-term power outage and incorporated considerations related to cybersecurity and fuel shortages. The exercise included over 1,600 participants from over 240 agencies and departments spanning the local, county, state, federal, and private sector including Commission staff, four investor-owned utilities, municipal electric utilities, water utilities, healthcare, law enforcement, and nonprofit partners. The exercise identified several specific recommendations to improve resilience planning, such as increasing the deployment of fueling infrastructure available during outages to support vehicles involved in recovery operations. After the Dark Sky Exercise, OEI and WEM finalized a Petroleum Shortage Contingency Plan, with measures specific to long-term power outage planning, and integrated the plan into the Wisconsin Emergency Response Plan.[97] OEI has proposed energy security grant programs to the Commission informed by Dark Sky findings. For example, Wisconsin's Refueling Readiness (WRR) program provides grants for automatic transfer switches for fueling locations, to support fuel access for first responder vehicles during a long-term power outage.

OEI is further promoting collaborative resilience planning through its Statewide Assistance for Energy Resilience and Reliability (SAFER2) grant program, which focuses on enhancing coordinated statewide planning with local emergency management officials at the regional, tribal, county, and municipal levels. Grant funds have supported meetings and training exercises to gather enhanced information on critical energy infrastructure, clarified specific roles and responsibilities within a collaborative framework, and developed planning templates for specific types of HILF events. In April 2022, the SAFER2 team hosted an energy emergency tabletop exercise for executives to bring the lessons learned from local and tribal planning to state agency leadership.

To further explore the state's ability to prepare for and respond to a long-term power outage and follow up to the findings from Dark Sky, OEI hosted a Midwest regional energy emergency exercise entitled "Shattered Cheddar" in June 2022. The exercise included states from around the region, county and tribal emergency managers, utilities, and other public and private critical infrastructure owners and operators. Objectives of Shattered Cheddar included: identifying gaps in state energy security and response plans related to regional coordination, fuel coordination, and cybersecurity; examining state, local, tribal, and federal government roles and responsibilities, authorities, and actions that would be used during a regional event; and reviewing communications procedures and reporting mechanisms. Consistent with the energy security planning requirements outlined in the

[97] https://wem.wi.gov/wisconsin-emergency-response-plan/

federal Bipartisan Infrastructure Law,[98] OEI will inform the 2022 update of the Wisconsin Energy Security Plan[99] with the lessons detailed in the after action report from Shattered Cheddar. The Energy Security Plan was delivered to US DOE in fall 2022. OEI and WEM will continue to exercise and improve the plan, providing updates on a three year cycle, complimenting the update cycle of the Wisconsin Emergency Response Plan (WERP) led by WEM.

To expand its collaborative efforts on resilience, OEI is implementing a pilot grant program to provide financial support for innovative pre-disaster hazard mitigation. The OEI Critical Infrastructure Microgrid and Community Resilience Center (CIMCRC) Pilot grant program focuses on innovative pre-disaster mitigation through critical infrastructure microgrids and other resilient building strategies, by studying the feasibility of the deployment of distributed energy resources (DERs), including battery storage, and grid-interactive controls. In October 2021, 15 grants were awarded to political subdivisions, school districts, tribal governments, utilities and nonprofits. An interactive story map of the applicants, with details on individual projects, can be found on the OEI website.[100]

In July 2021, the Commission approved NSPW's resilience service pilot program, under docket 4220-TE-106. To mitigate the high upfront costs that may present a barrier to industrial or commercial customers seeking to install their own resiliency assets, NSPW will establish 10-year service agreements with participants for the installation, operation, and maintenance of resiliency service assets such as solar photovoltaic arrays, diesel or gas-fired back-up generators, combined heat and power units, battery energy storage systems, and system controls.

CYBERSECURITY

Nationwide attention has also increased regarding the specific resilience threats associated with cybersecurity attacks, which could create outages or diminish service through attacks on the grid control networks used by system operators. In 2018, the U.S. DOE released a Multiyear Plan for Energy Cybersecurity which identifies goals to strengthen cybersecurity preparedness, coordinate event responses, and enhance research and development on cyber-resilience.[101] In the same year, DOE also established an Office of Cybersecurity, Energy Security, and Emergency Response (CESER) to coordinate cybersecurity issues and provide training and support to state and local officials.

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[98] Sec. 40108. State energy security plans https://www.congress.gov/bill/117th-congress/house-bill/3684/text which amends Part D of title III of the Energy Policy and Conservation Act (42 U.S.C. 6321 et. seq.).

[99] PSC Energy Security (wi.gov) formerly referred to as the Wisconsin Energy Assurance Plan.

[100] Critical Infrastructure Microgrid and Community Resilience Center Pilot Grant Program Story Map. https://maps.psc.wi.gov/portal/apps/MapJournal/index.html?appid=011d448c66ef498e9011a160d37a2a1f&_gl=1*tdovsj*_ga*OTMxNjg4OTcxLjE1OTExMDc0ODE.*_ga_MDKJWR1B6S*MTY0NjkzNzY4MS40Ni4xLjE2NDY5MzgzMTkuMA.

[101] U.S. Department of Energy. Multiyear Plan for Energy Sector Cybersecurity. March 2018. https://www.energy.gov/sites/prod/files/2018/05/f51/DOE%20Multiyear%20Plan%20for%20Energy%20Sector%20Cybersecurity%20_0.pdf. Accessed on March 18, 2020.

Concern with cybersecurity attacks that could impose resilience threats continue to be a national priority. In January 2022 the Biden Administration signed a National Security Memorandum to improve the cybersecurity of critical infrastructure including the electric and pipeline sectors.[102] The National Security Memorandum establishes voluntary cybersecurity goals for owners and operators of critical infrastructure and establish further collaboration with federal agencies for reporting and mitigation of cyber incidents and threats.

In September 2020, Commission staff participated in cybersecurity training provided by the National Association of Regulatory Utility Commissioners (NARUC). The training focused on the national frameworks in use to help manage cybersecurity risk including National Institute of Standards and Technology's Cybersecurity Framework and North American Electric Reliability Corporation's Critical Infrastructure Protection standards. The training also identified a range of cybersecurity approaches potentially available to electric providers and regulators, including participation in both tabletop and full-scale cybersecurity exercises, consideration of risk mitigation tools such as insurance, and familiarity with the impacts of ransomware.

In December 2020, Wisconsin was one of four states to participate, along with federal agencies and energy sector representatives, in the DOE CESER's Liberty Eclipse exercise to support the Multiyear Plan for Energy Cybersecurity. The scenario included a multi-country cyber-attack on electricity infrastructure compounded by physical attacks on oil and natural gas infrastructure in select regions of the US. Exercise objectives included confirming the intelligence and information sharing mechanisms between the federal interagency and energy sector partners during a cybersecurity incident as well as promulgating a greater awareness of specific roles and responsibilities of the attendees (from both government and industry) during a significant cyber incident.

In 2015, representatives of Wisconsin electric providers worked with state and local government officials and other owners of critical state infrastructure to add a Cyber Incident component to the Wisconsin Emergency Response Plan, including provisions to limit the impacts of cyberattacks and maintain critical services. The Dark Sky exercise, mentioned above, served as a test of the Cyber Incident Response Plan by incorporating cyberattack scenarios on electric utility infrastructure. Informed in part by the Dark Sky experience, WEM added a new Cyber-Incident Response Annex to the Wisconsin Emergency Response Plan in 2021. The confidential annex outlines a more detailed set of cybersecurity response capabilities, including more detailed specification of state agency roles and responsibilities and provisions for the deployment of Cyber Response Teams when events occur. The annex also establishes cybersecurity incident threat levels, and identifies distinct response actions for each threat level.

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[102] The White House. Memorandum on Improving the Cybersecurity of National Security, Department of Defense, and Intelligence Community Systems. January 19, 2022. https://www.whitehouse.gov/briefing-room/presidential-actions/2022/01/19/memorandum-on-improving-the-cybersecurity-of-national-security-department-of-defense-and-intelligence-community-systems/

CHAPTER 6 – CUSTOMER RATES AND BILLS

The Commission uses its regulatory authority over customer rates to support affordable electric supply. Rate regulation seeks to identify prices that minimize costs for customers while still permitting providers to recover from customers the funds needed to offset operating costs and make a reasonable profit to support future operations. Many electric providers also work, under Commission regulation, to develop new and innovative rates and programs to meet customers' evolving needs and cost-effectively serve specific types of customers.

UTILITY COST DRIVERS

One of the first steps in the rate setting process is for electric providers to propose a *revenue requirement,* the total amount of money a utility needs to recover through customer rates to provide adequate and reliable service. Revenue requirements are developed based on historical costs, as well as forecasts of future growth in customer energy use and the future costs of providing service. The revenue requirement also includes a return on equity on the assets used to provide service, such as generation plants, which each provider uses to pay interest on money it borrows and to compensate investors. Commission staff audits each provider's proposed revenue requirement and makes adjustments as appropriate to establish a requirement that will recover costs and provide utilities with a reasonable return, while maintaining the lowest feasible cost to customers. (See the Determining Customer Rates section below for more details on the rate case process.)

Three key trends have influenced revenue requirement levels for providers across Wisconsin in recent years. First, customer sales growth has remained limited throughout the past decade. Second, electric providers are still considering significant investments to meet electric supply needs, driven by capacity needs and the economic and environmental factors supporting the increased pursuit of new generation. (See Chapters 1 and 2.) Third, application of the cost savings from 2017's federal tax reform has reduced utility costs in recent cases.

Trends in Customer Sales

In 2008 and 2009, Wisconsin electricity sales fell in response to a recession, and have not reached pre-2008 levels at any time since. As shown in Figure 6-1 and Table 6-1, a post-recession rebound in sales was followed by a period of limited growth between 2010 and 2018 and year over year declines in 2019 and 2020.

One key reason sales have not returned to pre-2008 levels has been the growth in energy efficiency statewide. After incorporating total net energy savings recorded by Focus statewide programs since 2007, Figure 6-1 and Table 6-1 show that, in the absence of those reductions in energy use, annual growth rates would have been higher in each of the past 14 years, with total efficiency savings increasing throughout the period. Using Focus savings also serves as a conservative estimate of energy efficiency impacts, since many customers may also be taking additional energy-efficient actions outside of the program.

Figure 6-1 Retail Sales of Electricity, by Sector (MWh)[103]

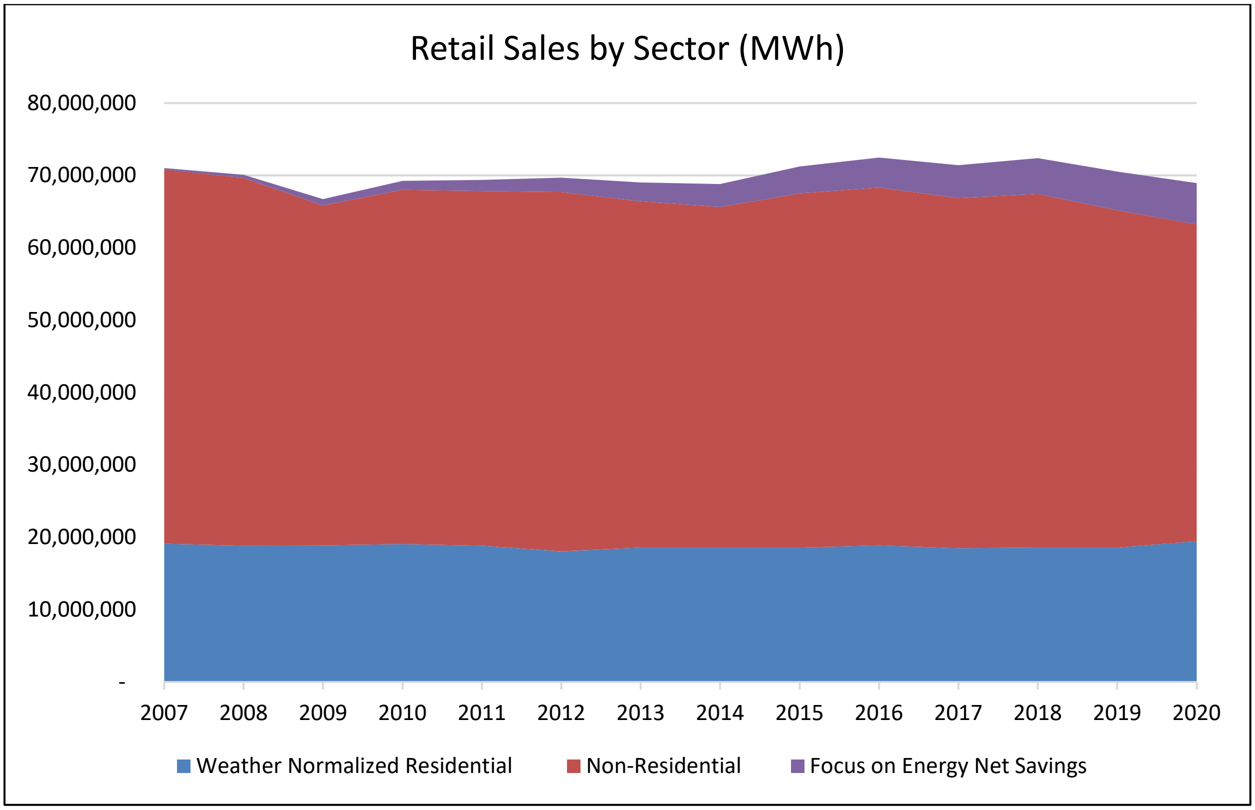


Table 6-1 Annual Growth Rates for Retail Electricity Sales (%)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Average Growth
Residential	-1.4%	-0.4%	0.9%	-1.1%	-4.3%	-2.9%	0.0%	0.0%	1.7%	-2.2%	.05%	-0.1%	4.9%	0.2%
Non-Residential	-1.8%	-7.6%	4.3%	0.1%	1.4%	-3.7%	-1.7%	4.0%	1.0%	-2.1%	1.0%	-4.6%	-6.2%	-1.2%
Total	**-1.7%**	**-5.4%**	**3.3%**	**-0.3%**	**-0.2%**	**-1.9%**	**-1.2%**	**2.9%**	**1.2%**	**-2.1%**	**0.8%**	**-3.3%**	**-3.0%**	**-0.8%**
Total w/o Focus on Energy	**-1.3%**	**-4.8%**	**3.8%**	**0.1%**	**0.5%**	**-1.0%**	**-0.3%**	**3.6%**	**1.7%**	**-1.5%**	**1.4%**	**-2.6%**	**-2.3%**	**-2.6%**

Usage by customer provides another measure of the effects of energy efficiency on overall sales. Weather-normalized average electricity use per customer for residential customers declined 7 percent from 2007 through 2019, before increasing nearly 5 percent in 2020, likely due to the effects of the COVID-19 pandemic. Average energy intensity in dollars per unit of energy, the metric commonly used to assess the more widely varying population of non-residential customers, increased more than 60 percent from 2007 through 2020. (See Appendix E, Figures E-1 and E-2 for illustration of these trends.) The effects of these per-customer trends have been partially offset by an increase in the number of total customers served, but not at sufficient levels for total sales to reach their pre-2008 levels.

[103] Source: Utility annual reports filed with the Commission; Focus on Energy. For this analysis, weather-normalized sales for residential customers are used to remove data outliers from unusual weather events such as the polar vortex of 2014.

The onset of the COVID-19 pandemic contributed to a 3 percent decrease in electric sales in 2020. As noted in Chapter 1 (Table 1-1), Wisconsin electric providers project that demand will rebound in 2021 and 2022, as customer use increases and economic conditions improve, before an expected return to minimal annual growth rates later in the decade.

Sources of Utility Costs

Declining usage trends, such as those described above, can benefit individual customers by helping them reduce their energy bills. However, electric providers must still bear the costs of providing adequate and reliable service to all customers. While many factors can influence those costs, declines or limited growth in customer usage may increase the risk that customer rates need to be increased to absorb required costs.

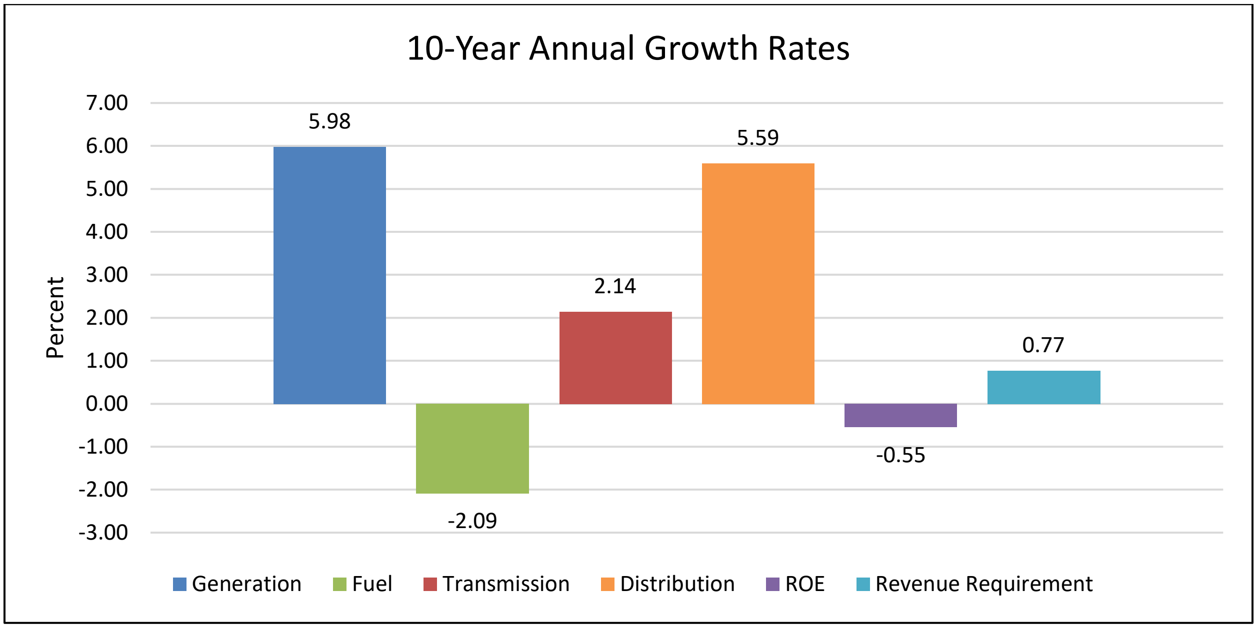
Major Investor-Owned Utilities with Generation

Wisconsin's five largest IOUs,[104] who serve nearly 90 percent of the state's electric customers, provide most of the electric supply through utility-owned generation. The majority of the revenue requirements for each of these "Major IOUs" comes from generation, distribution, and transmission.

As shown in Figure 6-2, total revenue requirements for the Major IOUs increased 0.77 percent per yearbetween 2011 and 2020. Of the revenue requirement components, the Commission has direct control over generation, return on equity, and distribution for large projects. Fuel costs and transmission rates are mostly outside the Commission's control and represent pass-through expenses.

[104] MGE, NSPW, WEPCO, WP&L, and WPSC.

Figure 6-2 **Ten-year Annual Growth Rate of Revenue Requirements Components—Major IOUs (%)**



The increase in total revenue requirement between 2011 and 2020 was driven primarily by increased costs for generation and distribution, associated with continued provider investments in generation resources and distribution system infrastructure. Total impacts from those investments on the revenue requirement reflect the amount of annual depreciation value from historical investments authorized by the Commission in rate proceedings. Transmission costs also increased, as analyzed further in Chapter 4. These increases were partially offset by decreases in fuel costs and return on equity for IOU assets. Return on equity is set for each utility in their rate proceeding, but have generally remained flat or trended down, due in part to low interest rates during this time period.

Fuel costs declined primarily due to decreasing natural gas costs during the period, as well as the increased utilization of generating resources that incur no fuel costs, such as wind and solar. It should be noted that a variety of factors have driven significant increases in natural gas fuel costs in 2022, well above typical levels during the 2011-2020 analysis period. Fuel costs may continue to decline in future years as providers make further investments in wind and solar resources, but may also face increases due to changes in generation mix and market conditions, such as if the increased natural gas prices experienced during 2022 continue over a longer period. Investments in new generation may result in further increases in generation and distribution costs for new utility-owned generation.

Effects of Tax Reform on Investor-Owned Utilities

In December 2017, the federal Tax Cuts and Jobs Act (TCJA) implemented reforms to the federal tax code. Wisconsin investor-owned utilities (IOU) are impacted by the TCJA's reduction of the corporate income tax rate to a flat rate of 21 percent, in place of a graduated structure with a maximum rate of 35 percent.[105]

The rates the Commission approved prior to 2018 for each IOU included the previously higher tax rate. As a result, IOUs began over-collecting tax revenue under those rates when the legislation took effect in 2018. To address these over-collections, the Commission opened docket 5-AF-101 to review collections by all IOUs, reduce each IOUs' 2019 rates to account for the reform, and identify how each utility will return to customers the funds over-collected in 2018.

A total of $110.3 million was directly refunded to customers in 2018, 2019, and 2020, reflecting savings from utilities' 2018 tax expense. An additional $541.7 million is in the process of being returned to customers through rate cases. These funds represent income taxes collected in previous accounting periods that will not be paid to the IRS due to the reduction in the corporate tax rate, and can be applied to reduce customer rates. In docket 5-AF-101, the Commission ordered that all IOUs must file a rate case by 2021 to ensure customers receive these benefits in a timely fashion. The major IOUs and several small IOUs have completed rate updates that incorporated the 21 percent tax rate. A few small IOUs received filing extensions until 2022 due to the COVID-19 pandemic.

Nearly $1.5 billion in additional tax reform savings, previously collected in customer rates, will continue to be applied to reduce future costs based on utility assets, such as owned power plants. Under federal tax law, these balances cannot be returned to customers any faster than the asset depreciates over its average remaining life. Given the long-lived nature of large utility capital investments, these balances will be gradually applied to reduce revenue requirements in each rate case over the next several years.

DETERMINING CUSTOMER RATES

Customer rates are established by each electric provider to generate sufficient revenue to recover their costs. Ratemaking processes are intended to simulate for monopoly utilities the conditions of a free market; when rates are designed properly, the rate structure should signal to all different types of customers the actual cost of providing them reliable service and electricity.

Figure 6-3 summarizes the rate case process[106] that is followed by all electric providers regulated by the Commission, including all investor-owned and municipal electric utilities.[107]

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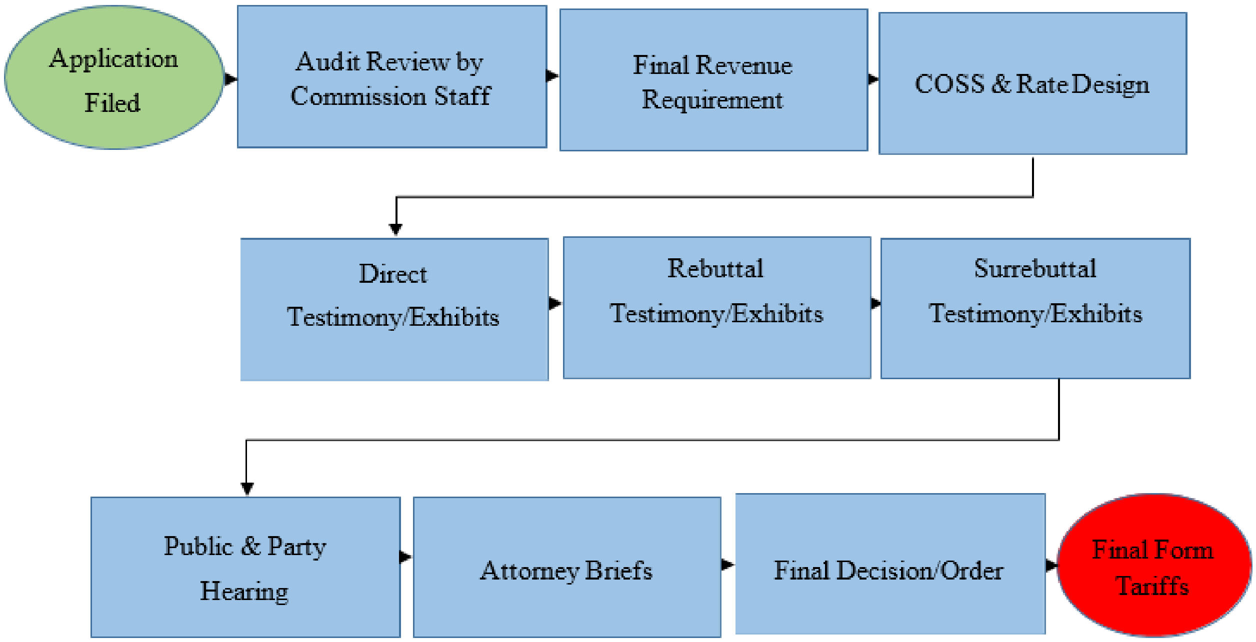
[105] See Sec. 13001 at: https://www.congress.gov/bill/115th-congress/house-bill/1.

[106] See also the Commission Proceedings webpage: https://psc.wi.gov/Pages/Regulatory/GuideToPSCProceedings.aspx.

[107] The rates of retail electric cooperatives are not regulated by the Commission. Uncontested municipal rate cases follow a simplified process.

Figure 6-3 Rate Case Process



Before an electric utility can raise its customer rates, it must file an **application** with the Commission. The application proposes rates for a forward-looking test year, typically the first year of service the rates are expected to be in effect. Since this test year is usually either the current year or the year after the application is filed, the provider submits forecasts of the revenue requirement it projects it will need to cover its expenses and return on investment in that year and subsequent years, and proposes customer rates to allocate that revenue requirement among its customers.

As the first step in application review, **Commission staff audit** the utility's revenue requirement by reviewing the application's forecasts and proposals and requesting additional information as needed. Commission staff analysis may focus on determination of values for key cost drivers such as asset depreciation, operations and maintenance costs, labor costs, rate of return, and sales forecasts. Based on audit findings, Commission staff may make adjustments to the proposed revenue requirement to more accurately reflect projected costs, and establish a **final revenue requirement** that will be used to determine rates.

Commission staff then use the final revenue requirement to review the utility's proposed **rate design**. Rate design analysis begins with a **cost-of-service study (COSS)** that seeks to meet the goal of charging actual costs to customers by estimating the allocation of utility costs among different customer classes, such as residential, commercial, industrial, and agricultural classes.[108]

[108] The COSS model applies many assumptions about how to classify, and allocate utility costs assumed in the revenue requirement. Utilities, Commission staff, and other rate case participants may reference best practices documented by the National Association of Regulatory Utility Commissioners (NARUC) COSS Manual, as well as other external references, and the practices used by the Commission and the utility in previous rate cases.

Utilities may submit one or more COSS models in their application, and Commission staff may design one or more additional models of their own. Using the COSS models, alternative rate designs can be proposed by the utility, Commission staff, and other parties to fully recover the costs allocated to each class. (See the Components of Customer Rates section below for more detail on rate designs.)

Audit and rate design findings are then used as core evidence in a **rate case proceeding** that creates a record of evidence for Commissioners to evaluate, and allows many opportunities for public input. The proceeding includes:

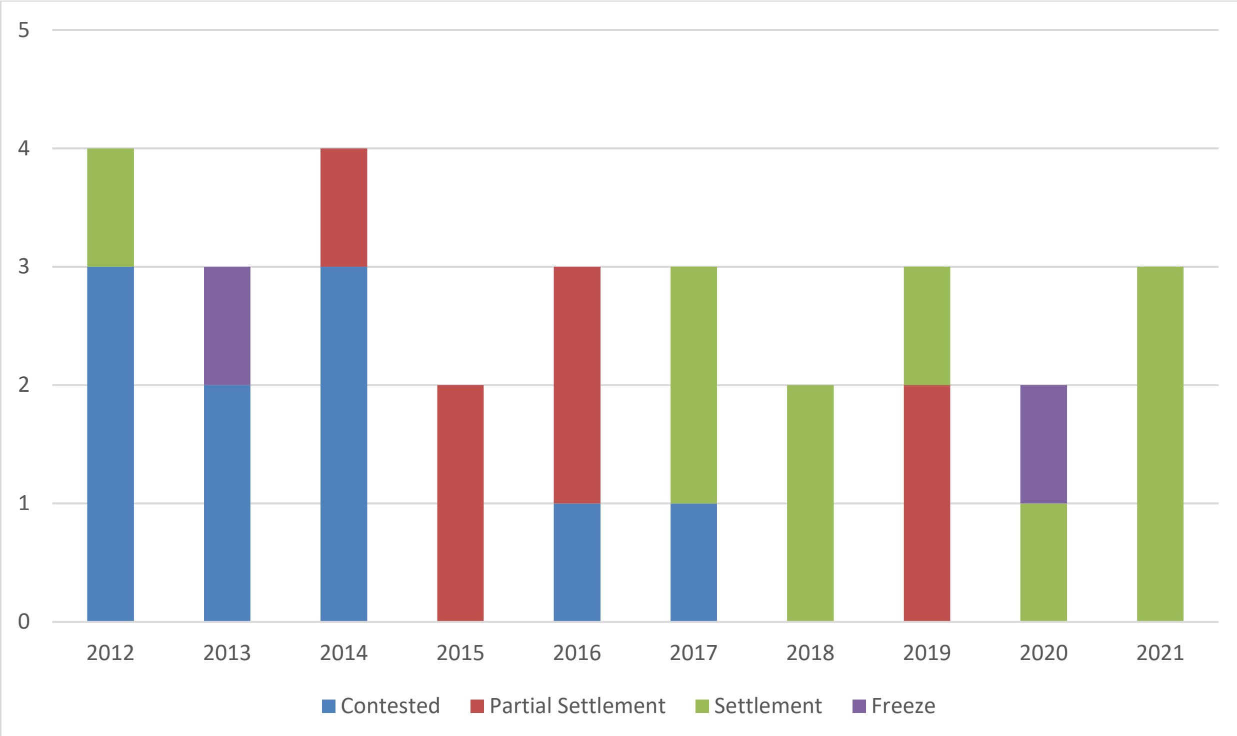
- Submission of case evidence, including **testimony and exhibits** that summarize the audit and rate design work;
- Opportunities for **rebuttal and surrebuttal** testimony to initial evidence, which may be submitted by the utility and Commission staff as well as by other interested parties;
- At least one **public and party hearing** to receive testimony from all interested parties, including members of the public; and
- **Attorney briefs** to summarize the final positions of the applicant and other parties involved in the proceeding.

Commissioners then review the full record created by the rate case proceeding and issue a final decision approving, denying, or approving with modifications the proposed rates. As applicable, a final approval will also select from among the alternative decision options provided by the utility, staff, and other parties for decisions on specific components of the revenue requirement and rate design.

Wisconsin Stat. § 196.026, enacted in 2018, allows for the opportunity for utilities and parties to agree upon a resolution of some or all of the issues usually addressed by the Commission during full contested rate cases. Based upon a proposed utility rate settlement agreement, the rate case process described above may be modified in order for the Commission to gather and examine evidence related to the proposed settlement agreement, ensure settlement agreement conditions listed under Wis. Stat. § 196.026 are met, and make a determination on whether to approve the proposed settlement agreement. While the timing of settlement arrangements can vary, settlements to date have typically resolved some or all issues in advance of the later steps in the rate case process. To approve a settlement agreement, the Commission must find that parties to a docket have been given a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement, and that the public interest is adequately represented by the parties who entered into the settlement agreement. The Commission must also find that the settlement agreement represents a fair and reasonable resolution to the docket, is supported by substantial evidence on the record as a whole, and complies with applicable law, including that any rates resulting from the settlement agreement are just and reasonable.

As shown in Figure 6-4, a trend away from fully litigated IOU rate case proceedings and towards partial or full settlement agreements had already begun in the early 2010s, and that trend has accelerated since passage of the 2018 settlement legislation.

Figure 6-4 **Resolution of Investor-Owned Utility Rate Cases, 2012-2021**



Components of Customer Rates

As described above, COSS are designed to assign to different customers the total amount of costs required to serve their customer class. Rates are designed to further link customer charges with the costs they create by including several different types of charges designed to recover different aspects of service costs.

All customers receive a **customer charge, or fixed charge**, of a flat amount per day or per month, regardless of how much energy they use. These charges are designed to reflect the minimum service utilities must provide to serve customers regardless of energy usage level. COSS studies seek to estimate these costs for each customer class, and then calculate the customer charges to recover those costs.

All customers also receive an **energy charge** per unit of electricity (kilowatt-hour) they use. These charges reflect the incremental costs associated with producing the next additional unit of energy a customer might need to use. For a customer of a utility that owns power plant generation, these costs are informed by the fuel costs and other costs needed to operate the plant. For utilities that do not own generating units, energy charges are informed by the per unit energy costs they use to purchase wholesale energy.

Demand charges are typically only charged to larger non-residential customers, such as commercial and industrial customers. Residential and small commercial customers have these demand costs embedded in energy charges instead. Demand may be measured using one of two separate methods.

- *Distribution (or customer) demand* reflects the distribution infrastructure costs associated with the customer's peak load use. The utility calculates a distribution demand charge by measuring the customer's highest usage level in a month, and then assigning a demand charge informed by the costs of the infrastructure needed to provide that volume of energy to the customer.
- *Coincident, or "billable", demand* reflects the costs to the utility of serving large customers during the utility's peak energy usage hours. Coincident demand charges reflect the service costs associated with making the generation, transmission, and distribution investments needed to provide adequate energy supply and transmission during system peaks.

Customer bills may also include **adjustments** to align customer charges with the variable costs of certain resources. IOUs that own generation units must provide fuel credits to customers when actual fuel costs are lower than forecasted in the utility's previous rate case, or fuel surcharges to recover costs higher than forecasted. IOUs submit annual fuel plans to the Commission, which approves the amount of the fuel credit or surcharge provided to customers in the following year. Customers of municipal utilities receive credits or surcharges under the power cost adjustment clause (PCAC), which accounts for deviations from the municipal utility's forecasted costs of purchasing wholesale power.

Finally, other charges and credits may appear on the customer's bill if authorized by the Commission or state law. A recent example is the refunds associated with the 2018 tax reform (see the Utility Cost Drivers section above).

CURRENT RATES AND BILLS

Charges paid by utility customers reflect two inputs: the utility's Commission-approved rates, and the amount of energy used by the customer, which determines their total amount of energy and demand charges.

Residential Customers

Residential customers of all electric providers are typically billed almost entirely through customer and energy charges. Tables 6-2 and 6-3 summarize residential rates for IOUs and municipal utilities, respectively, based on the Commission-approved tariffs in place during 2021. For municipal utilities, the median customer charge was $9.00/month and the median energy charge was 10.16 cents per kilowatt-hour (kWh). IOUs had a median customer charge of $11.00/month and a median energy charge of 11.98 cents/kWh. On average, IOUs charged higher rates compared to municipal utilities. Both tables also demonstrate that rates can vary based on the cost profiles of individual utilities, which can differ due to a wide variety of factors such as location, amount and condition of utility assets, and the mix of customers served.[109]

[109] Bill components for each provider can be found on the Commission website at: https://apps.psc.wi.gov/RATES/tariffs/default.aspx.

Table 6-2 Wisconsin Electric IOU Bill Components for Residential Customers, 2021

Summary Statistics	Energy (cents/kWh)*	Customer Charge ($/month)
Minimum	8.70	$8.00
25th Percentile	11.50	$10.50
Median	11.98	$11.00
Average	11.98	$13.24
75th Percentile	12.70	$16.25
Maximum	13.72	$21.00

** Note: Cents/kWh based on weighted average seasonal rates for MGE and NSPW.*

Table 6-3 Wisconsin Municipal Electric Utility Bill Components for Residential Customers, 2021

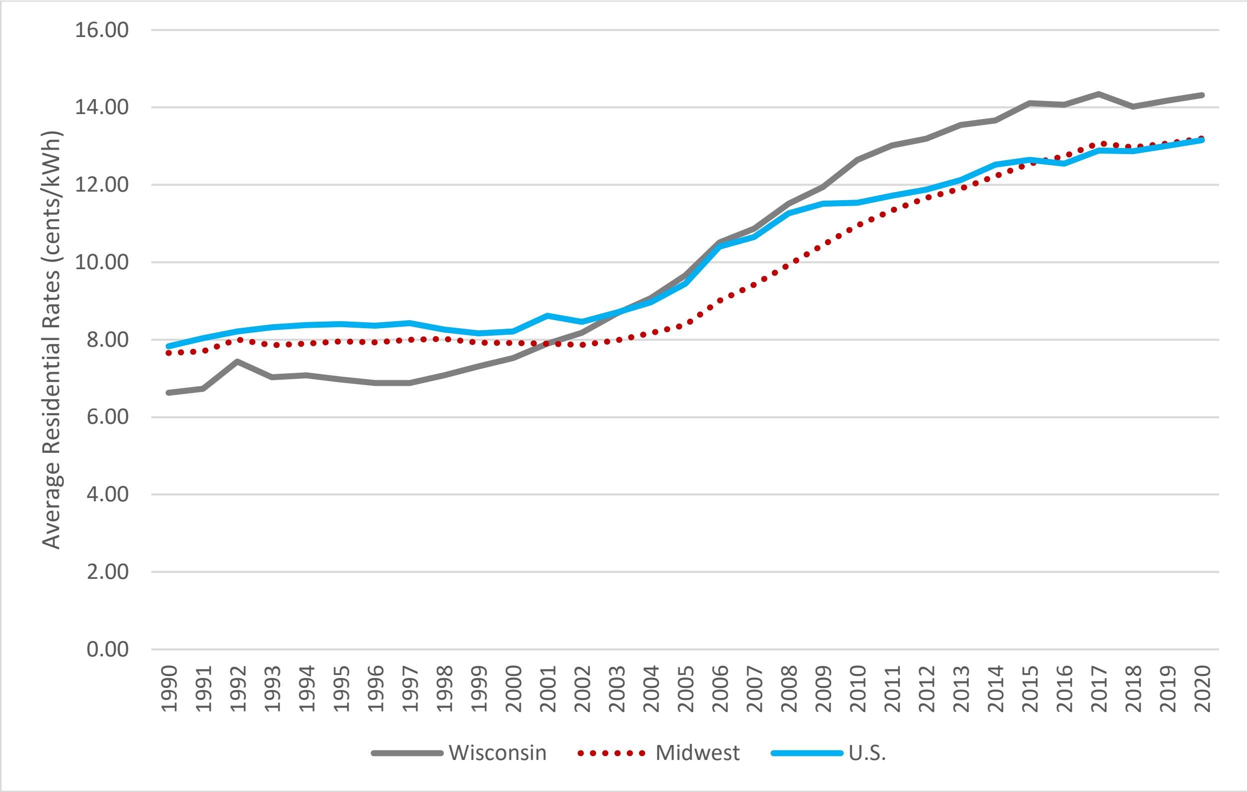
Summary Statistics	Energy (cents/kWh)	Customer Charge ($/month)*
Minimum	4.65	$5.00
25th Percentile	9.46	$5.00
Median	10.16	$9.00
Average	10.10	$9.21
75th Percentile	11.00	$11.00
Maximum	12.45	$16.00

** Note: Customer charge data is for single-phase customers only.*

National data collected by the EIA permits comparison of Wisconsin rate levels to other states and regions. While direct rate comparisons between states should be made cautiously due to differences in energy market conditions and regulatory structures, available data indicates Wisconsin's residential rates are higher than Midwest and national averages.[110] Based on an overall, sales-weighted average of all electric utilities within each state, Wisconsin's average 2020 residential energy charges of approximately 14 cents/kWh exceed national and Midwest averages of approximately 13 cents/kWh. As shown in Figure 6-6, Wisconsin's average rates have exceeded national and Midwest averages for nearly two decades. Appendix E, Table E-1 provides more detailed comparisons, including charges for each individual Midwest state.

[110] For this analysis, Midwest states include Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Ohio, and Wisconsin.

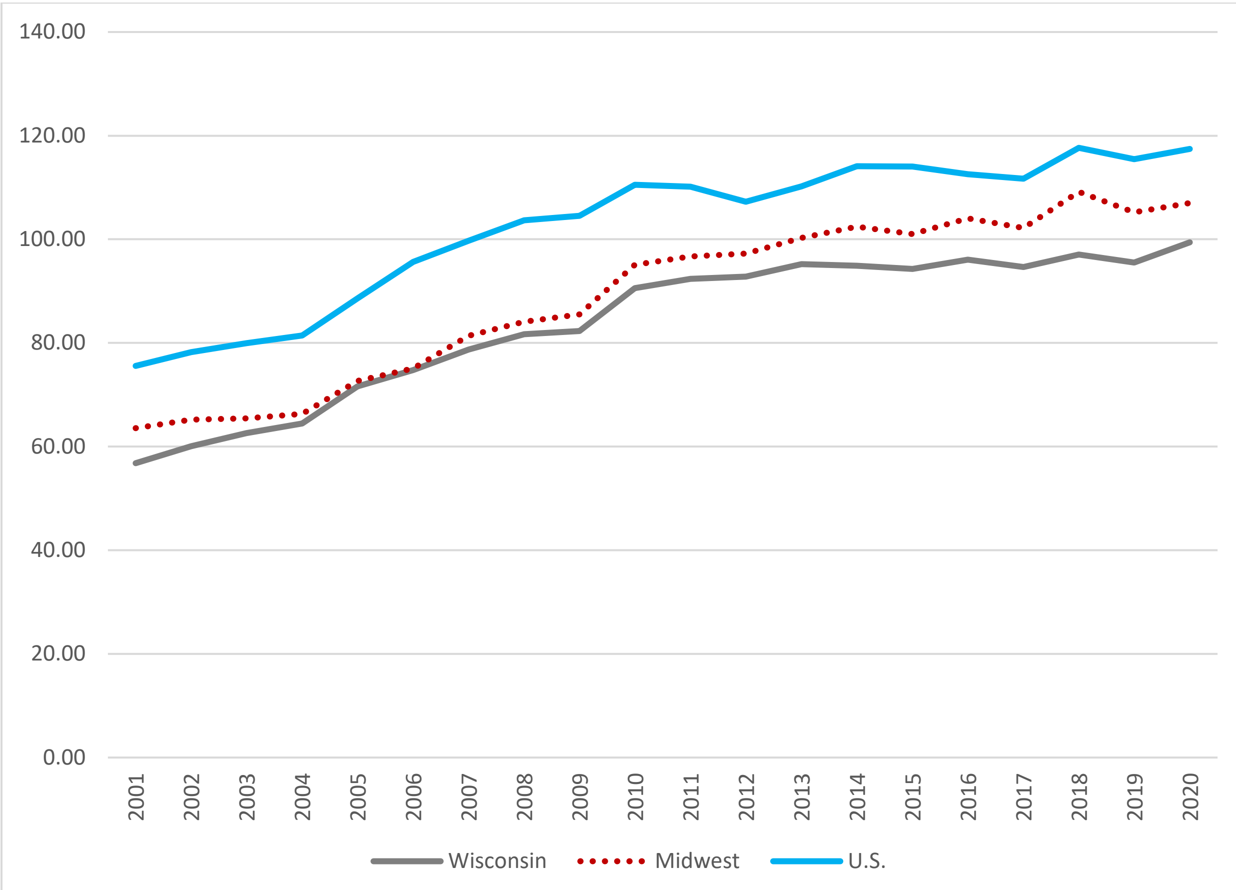
Figure 6-6 Average Residential Electricity Rates (1990-2020)[111]



While customer rate levels are higher, EIA data demonstrates that average monthly electric bills in Wisconsin have remained consistently lower than other states during the past decade. Wisconsin's average 2020 bill of $99.42 compares to Midwest average bills of $107.02 and national average bills of $117.46. (See Appendix E, Figure E-3 for more detailed comparisons of average bills by census region.)

[111] U.S. Energy Information Administration, Electricity Sales, Revenue, and Average Prices (Table 5A). Issued October 7, 2021. Accessed March 22, 2022 at: https://www.eia.gov/electricity/sales_revenue_price/.

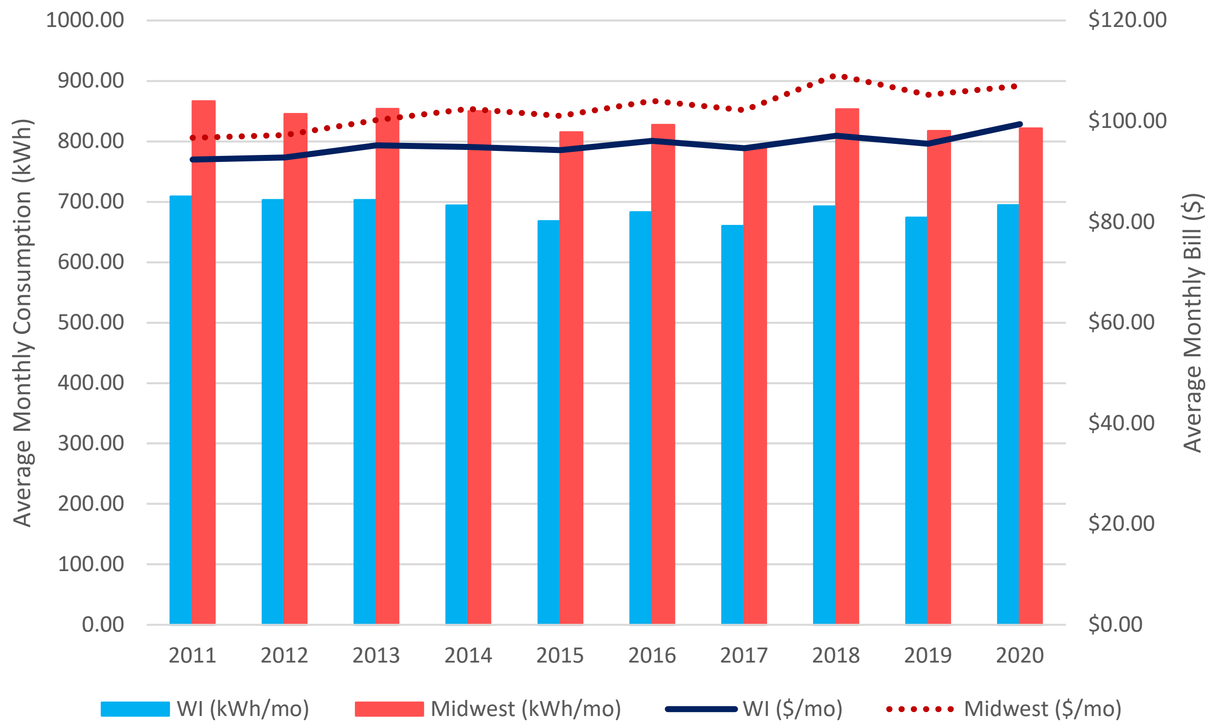
Figure 6-7 Historical Comparison of Average Monthly Residential Electric Bills (2001-2020)[112]



Wisconsin's lower bills reflect significantly lower average levels of electricity use. As shown in Figure 6-8, Wisconsin customers used an average of 694 kWh per month in 2020, compared to 821 kWh per month across other Midwest states. This usage difference has been present throughout the 2010s.

[112] See previous editions of Residential Average Monthly Bill by Census Division and State at: https://www.eia.gov/electricity/sales_revenue_price/.

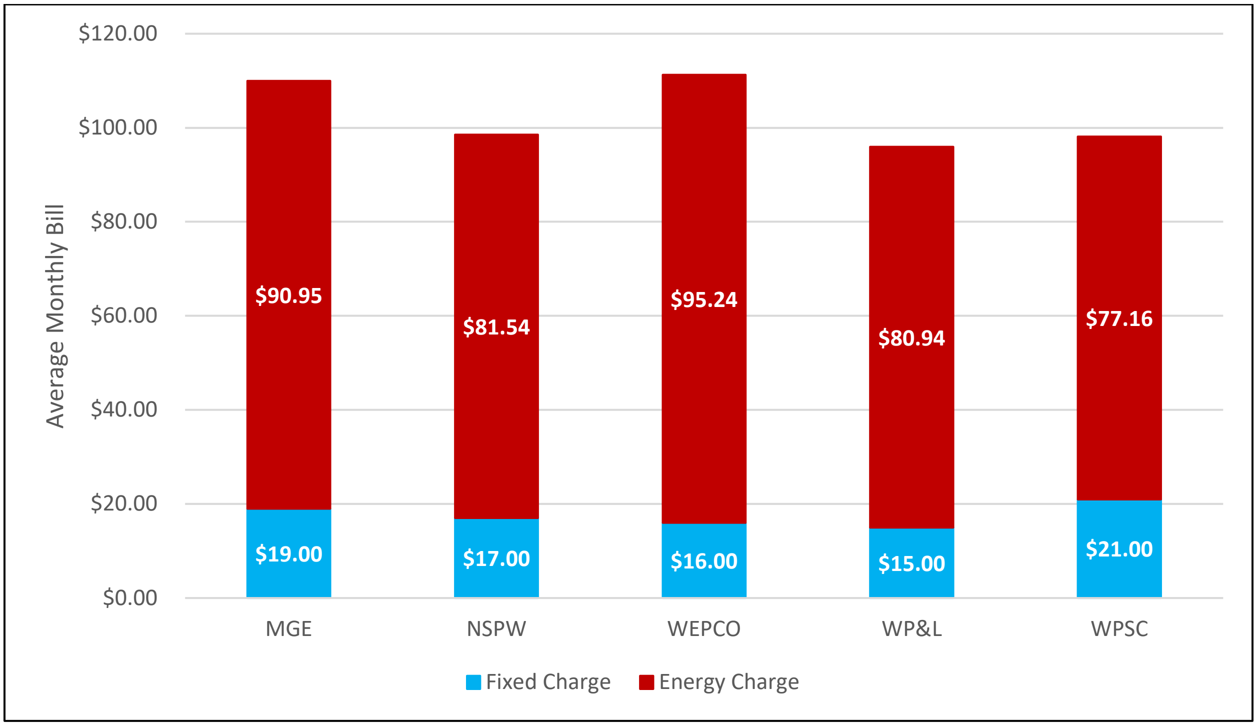
Figure 6-8 Monthly Residential Electricity Costs and Consumption in Wisconsin and the Midwest (2011-2020)



Bills received by individual customers will vary based on their utility and the amount of individual energy use. At average usage levels, residential customer electric bills for different utilities in 2020 ranged from $50 to $120 per month.[113] Figure 6-9 illustrates total 2020 residential bills at average usage levels for Wisconsin's five largest IOUs. Subsequent rate settlements have reduced NSPW and MGE fixed charges from the values illustrated in Figure 6-9, beginning in 2022.

[113] Residential electric bill comparisons by provider can be performed on the Commission's Residential Monthly Bill Comparison web tool at: https://apps.psc.wi.gov/RATES/electricbill/default.aspx.

Figure 6-9 **2020 Monthly Residential Electricity Bills for Wisconsin's Largest IOUs, at Average Levels of Energy Use**



Non-Residential Customers

Based on national EIA data, Wisconsin's average 2020 energy rate for commercial customers of 10.75 cents/kWh exceeds the national average of 10.59 cents/kWh the Midwest regional average of 10.21 cents/kWh (additional data can be found in Appendix E, Table E-2). Similarly, Wisconsin's average 2020 energy rate for industrial customers of 7.29 cents/kWh exceeds the national average of 6.67 cents/kWh and the Midwest regional average of 6.91 cents/kWh (Appendix E, Table E-3). However, drawing clear conclusions from rate and bill comparisons for non-residential customers is generally more difficult than for residential customers.

Reasonable comparisons can be made for municipal utility customers served under the Cp-1 rate schedule, which most municipal providers use to serve small and medium-sized commercial and industrial customers under a common rate structure. As shown in Table 6-4, municipal Cp-1 customers paid average energy charges of 7 cents/kWh, average customer charges of $45/month, and demand charges of $7 per kW in 2021. (More details on the analysis can be found in Appendix E, Figures E-6 and E-7 and Table E-4.) Similar comparisons of IOU rates, and of rates for larger municipal customers, cannot be made in simple terms due to greater variation in definitions of customer classes, in rate structures, and in methods for calculating charges, such as different definitions of peak periods used for demand charges.

Table 6-4 Municipal Utility Bill Components for Cp-1 Customers, 2021

Summary	Energy Charge (cents/kWh)	Distribution Demand ($/kW)	Billable Demand ($/kW)	Customer Charge ($/month)*
Minimum	3.00	$0.25	$5.00	$20.00
25th Percentile	6.29	$1.00	$6.50	$35.00
Median	6.88	$1.50	$7.25	$50.00
Average	6.89	$1.33	$7.19	$45.63
75th Percentile	7.74	$1.50	$8.00	$50.00
Maximum	9.00	$2.00	$9.79	$100.00

* *Note: Summary statistics include data from 68 municipal utilities that offer Cp-1 rates with a flat energy charge.*

Alternative Rate Options

While the substantial majority of customers in Wisconsin receive traditional rates, many Wisconsin electric providers offer additional, innovative rate options designed to help customers exercise control over their costs to reduce their energy bills.

Residential Time-of-Use Rates

A total of 75 electric providers in Wisconsin offer a time-of-use (TOU) rate option to residential customers, under which the customer's energy charge per kWh varies at different hours of the day. As shown in Figure 6-9, electric providers face higher costs for serving customers during peak afternoon hours of the day for multiple reasons, including the higher costs of operating peaking resources designed to provide power primarily during peak hours, and the greater availability of low-cost wind resources in the overnight hours.[114] By setting higher energy charges during higher-cost hours, TOU rates can encourage customers to move more of their energy usage to lower-cost hours. When TOU rates successfully shift usage, providers are able to reduce their total energy costs and pass savings along to customers through lower off-peak energy charges.

[114] Wholesale energy prices on the energy market are used for general illustration. While many providers do not buy electricity directly from this market, the price trends correspond with the prices a utility would pay to purchase from a different wholesale provider, as well as the costs a generation-owning utility would face for operating its own plants.

Figure 6-10 Illustrative Example of Time Varying Price of Electricity on an Average Summer Day in Wisconsin

All utilities with TOU rates offer them as optional alternatives in which customers may choose to enroll. This optional approach partially reflects concern over the impacts on customers with limited ability to shift the timing of their energy use. While many customers may benefit from TOU rates, mandatory TOU enrollment could cause bills to increase for those with high energy needs during on-peak hours. As shown in Table 6-5, approximately 39,000 customers of investor-owned and municipal electric utilities, or 1.6 percent of all residential customers, are currently enrolled in TOU rates. Total TOU enrollment has increased by approximately 5,000 customers since 2018.

Table 6-5 Enrollment in Standard and TOU Rates

Residential Rate Class	Total Enrollment	Percent of Total
Standard Rate	2,413,067	98.39%
TOU Rate	39,368	1.61%

The increasing use of new technologies in future years could help increase customers' ability to control their energy use, and accordingly enhance the benefits of enrolling in TOU rates. For example, installing smart thermostats and other smart appliances can make it easier for customers to shift the timing of energy use to off-peak periods. (See the Demand Response section for more information on the use of smart thermostats to control demand.) If electric vehicle use increases in the future, the use of charging equipment that allows customers to control charging time for vehicles could provide similar benefits. (See the Electric Vehicle section.)

Real-Time Pricing for Commercial and Industrial Customers

Twenty-six (26) Wisconsin electric providers offer "real-time pricing" rate options for commercial and industrial customers. These rate options typically incorporate wholesale prices for energy and demand, based on MISO's next-day electricity prices and transmission charges on demand, which serve as the primary influence on energy costs for customers with high energy use. Similar to TOU rates, these rate options are designed to account for the actual electricity prices faced by providers, to incent customers to modify their energy use and create potential shared cost savings for providers and customers.

Customer eligibility for real-time pricing depends on the type of rate options each provider offers. The most common option presently offered in Wisconsin is incremental load pricing, often labeled as a New Load Market Pricing (NLMP) rate or an Economic Development Rider (EDR). Incremental load pricing is only available to customers opening a new facility or expanding an existing facility. The additional electric load must also be substantial in size, typically greater than 400 kW of demand.

Incremental load enrollees are provided an incentive to control their energy use, and promote business growth, by receiving energy charges specific to their new load that vary each day based on day-ahead MISO market prices. Customers able to control the timing of their energy use can benefit by shifting energy use to days with lower day-ahead prices, and minimizing energy use on higher-priced days. New loads are typically eligible for incremental load enrollment for four years, before being placed on the standard rates.

Real Time Market Pricing (RTMP) enrollees are provided a similar incentive to NLMP/EDR enrollees to control their energy usage, but the pricing is applied to all consumption above a set level, rather than to new loads. Similar to NLMP/EDR customers, those who can control the timing of their energy use would be able to benefit the most from this type of rate. Enrollment on this rate generally begins with a multi-year contract that requires an advanced notice to the utility if the customer wishes to stop taking this type of service.

As shown in Table 6-6, 97 commercial and industrial customers were enrolled in real-time pricing rates in 2020, an enrollment rate of 1.5 percent. These enrollment levels reflect, in part, the restriction of eligibility to customers with large and (for NLMP) new loads. Moreover, eligible customers will only receive clear benefits if they are able to exercise significant control over their energy use; customers with less control over their load profile may not be able to achieve reduced costs through these rates.

Table 6-6 Enrollment in Incremental Load and Real-Time Pricing Rates

Industrial	Total Enrollment	Percent of Total
Standard Rate	6659	98.57%
Incremental Load (NLMP/EDR)	76	1.12%
Real-Time Pricing (RTMP)	21	0.31%

CHAPTER 7 – CUSTOMER AFFORDABILITY

Low- and moderate-income residential customers often face challenges paying their utility bills. By paying the same rates as other residential customers but with limited financial resources, these customers often face a higher energy burden: they must pay a larger percentage of their total income for the same amount of service. The Commission has significantly increased its efforts in recent years to assess energy burden, and to review and expand the options available to help customers address their affordability challenges.

ENERGY BURDEN

In 2021, Commission staff requested that students at the UW-Madison Robert M. La Follette School of Public Affairs conduct a research project assessing publicly available information on energy burden in Wisconsin.[115] The report used federal data to estimate that Wisconsin customers face an average energy burden- including both electric and gas expenditures- of 5.7 percent. The report also took advantage of the ability of federal data sources to provide data at the level of census tracts, a designation used to distinguish individual neighborhoods within counties and municipalities.[116] Census tract analysis confirmed significant variation in energy burden at the neighborhood level, illustrated for the Milwaukee area in Figure 7-1. Statewide analysis identified 18 neighborhoods throughout the state that face especially high burdens of 8 percent or more, including 11 predominantly Black and Hispanic neighborhoods in Milwaukee County, as well as rural areas in Menominee, Marinette, Clark, Burnett, and Adams Counties.

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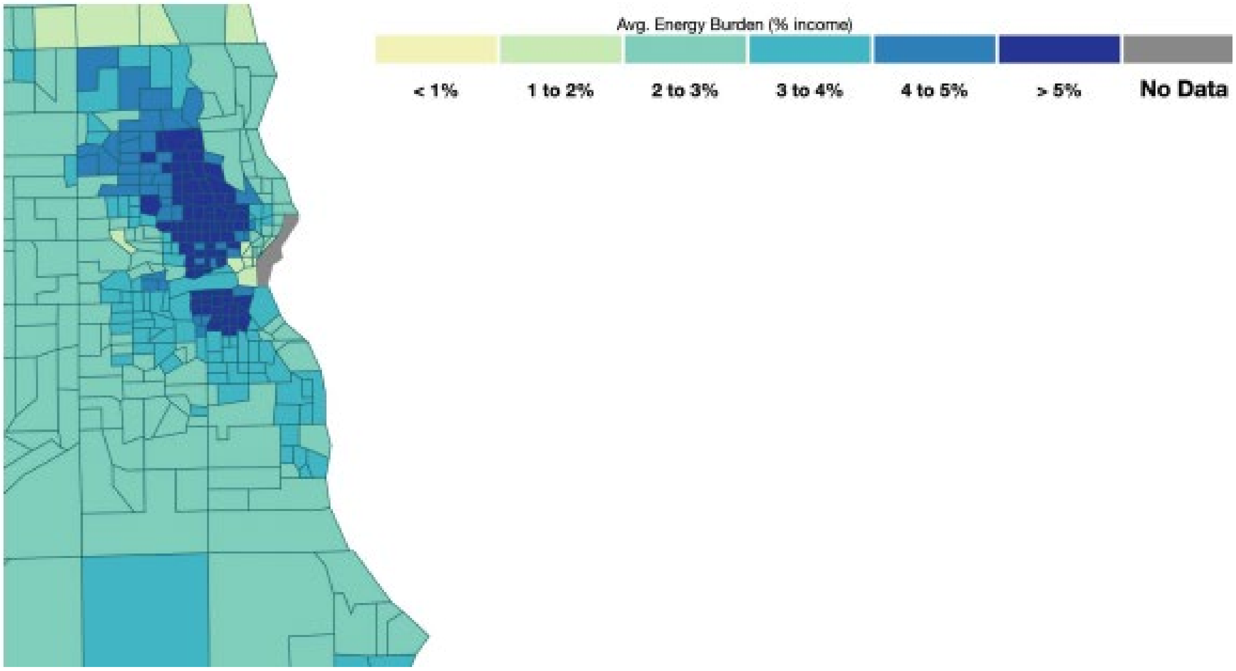
[115] Laura Downer, Sonny Leffin, Mitchell McFarlane, and Nicholas Schafer. "Addressing Energy Poverty in Wisconsin Communities." Accessible at https://lafollette.wisc.edu/images/publications/workshops/2021_PSC_Energy_report.pdf.

[116] Census tracts are defined to designate an area with approximately 4,000 residents, with boundaries drawn to reflect "visible and identifiable features" like municipal boundaries and major roadways. See https://www.census.gov/programs-surveys/geography/about/glossary.html.

Figure 7-1 Energy Burden by Census Tract in the Milwaukee Area



To begin collecting more detailed and utility-specific information on energy burden, the Commission directed that all utilities with at least 15,000 customers—including MGE, NSPW, Superior Water Light and Power Company (SWL&P), WEPCO, WP&L, and WPSC—provide detailed utility burden index analysis on electricity, natural gas, and water residential bills in their annual reports to the Commission, beginning with the 2020 annual reports submitted in spring 2021. The Commission directed utilities to provide a detailed household economic burden index analysis evaluating residential energy (electric and/or natural gas) and residential water utility customer bills as percentages of household income by county. The initial filings in 2021 affirmed that energy burden varies throughout geographic regions of the state and provided useful baseline information.[117]

To build upon this baseline, the Commission issued updated instructions for the 2021 annual reports due spring 2022. The updated instructions requested that utilities provide the summary results of a detailed household burden index analysis with a census block group or census tract level of resolution, or better. This level of granularity in the data is intended to provide a clearer picture of specific areas of the state with higher than average energy burden. While some utilities – including NSPW, SWL&P, and WP&L – provided census-tract level information, other utilities did not, limiting the ability to draw clear and consistent statewide conclusions from data submitted to

[117] *See* 2020 Annual Reports at https://apps.psc.wi.gov/ARS/annualReports/default.aspx.

date. Commission staff will continue to work with utilities to improve collection and analysis of energy burden data in future years.[118]

In addition, the Commission received a technical assistance award from the U.S. DOE in December 2021 to expand its efforts to assess energy burden.[119] Commission staff have started working with national experts during 2022 to further refine its underlying definitions and approach to measuring energy burden, by comprehensively documenting available data sources and analysis tools, and assessing alternative options for conducting energy burden calculations. Work under the grant will continue in late 2022 by using the initial findings to determine future practices for energy burden data collection and analysis, and identifying opportunities for energy burden data to more thoroughly inform Commission decision-making.

Assisting Customers with Affordability Challenges

Wisconsin electric and natural gas utilities, the Wisconsin Department of Administration (DOA), and the Commission work together to help low-income customers manage their energy burden through multiple types of programs.

Regulated electric and natural gas utilities in Wisconsin are required to offer Deferred Payment Agreements (DPA) to residential customers who are unable to pay their bill in full.[120] DPAs allow those customers to provide a down payment on their outstanding balance and arrange an installment plan to pay the remaining balance over a specified time period.

Regulated electric and natural gas utilities are also required to offer residential customers budget billing options that charge customers the same bill amount in all 12 months of the year, to help avoid the seasonal increases in energy charges most customers typically experience.[121]

The state's largest IOUs offer additional low-income assistance programs, many of which are designed as arrears management programs (AMP) that forgive portions of participants' overdue utility bills under certain conditions.[122]

- MGE offers the Low Income Case Management Arrearage Reduction Program (LICMARP). When a customer agrees to and completes a payment plan, a predetermined bill credit is applied to the customer's MGE account.
- NSPW also offers low-income customers flexible payment plans and arrears forgiveness of up to $600 per household.
- WPSC offers its Fresh Start Program, which provides flexible payment plans and grants arrears forgiveness of up to $600 per household and its Low Income Forgiveness Tool

[118] *Id.*
[119] "DOE Announces Technical Assistance for State Utility Regulators to Address Challenges Related to a Transforming Electric Grid." https://www.energy.gov/eere/articles/doe-announces-technical-assistance-state-utility-regulators-address-challenges.
[120] *See* Wis. Admin. Code §§ PSC 113.0404, PSC 134.063.
[121] *See* Wis. Admin. Code §§ PSC 113.0406(5), PSC 134.13(5).
[122] *See* Wis. Admin. Code § PSC 113.0505.

(LIFT) program. The LIFT program requires participants to pay 50 percent of their budget installment each month. If the amount is paid, one-twelfth of their arrears is forgiven each month.

- WP&L offers an Arrears Management Program to assist low-income customers who have received Wisconsin Home Energy Assistance Program (WHEAP) funds by forgiving a portion of arrears each month that a participating customer pays its bill.
- WP&L's Hometown Care Energy Fund provides financial assistance of up to $500 to qualifying customers to help pay their energy bills.
- WEPCO's LIFT program requires participants to pay 50 percent of their budget installment each month. If the amount is paid, one-twelfth of their arrears is forgiven each month.
- WEPCO also offers the Revised Low Income Program (RLIP) which requires participants to pay a portion of their budget installment. If the amount is paid, a portion of their arrears is forgiven. RLIP includes an extra coaching aspect for participants.
- SWL&P offers an AMP that assists customers who receive a WHEAP benefit by matching the customer's subsequent payments until the balance is zero.

Utilities and Commission Consumer Affairs staff also refer customers facing affordability challenges to multiple governmental and community assistance programs. Households that have incomes of less than 60 percent of the state median income, and meet other eligibility requirements, are eligible for energy assistance benefits through WHEAP at DOA. DOA also administers the Weatherization Assistance Program using both federal and state funds. These programs help customers pay a portion of their energy bills and also provide weatherization assistance to eligible homes that help reduce energy costs. Many state energy utilities also contribute funds to support the Keep Wisconsin Warm/Cool Fund (KWWF), a statewide, non-profit fund that provides preventative services and financial assistance in response to energy emergencies. Part of KWWF is the Heat for Heroes Program, which provides assistance to veterans facing service disconnections or other energy challenges. Customers may be able to find assistance through a variety of other local non-profits throughout Wisconsin, such as Aging and Disability Resource Centers, the Salvation Army, and local churches.

One reason customers may experience a higher energy burden is because they live in residences with insufficient insulation and/or inefficient lighting, appliances, and heating and cooling systems. As a result, energy efficiency programs can also help low-income households reduce their energy bills on an ongoing basis. Focus on Energy, Wisconsin's statewide energy efficiency and renewable resource program, offers multiple program options that can benefit low-income customers. For example, all residential customers may register to receive a free kit of energy efficient products, including lighting, power strips, and low-flow showerheads, and may purchase program-discounted lighting and appliances at retail stores. Many low-income customers are also eligible for bonus incentives to help them conduct home energy audits and complete projects to replace heating and cooling appliances, and also to install insulation. Four Wisconsin electric providers—NSPW, WEPCO, WP&L, and WPSC—operate additional energy efficiency programs that provide enhanced financial support to low-income customers participating in Focus. The Inflation Reduction Act will provide additional tax incentives and rebates targeted towards low-income customers, including rebates for households with income below 150 percent of their local median income to reduce the costs of electric appliances, heat pumps, and insulation projects.

In response to public and stakeholder interest in exploring opportunities to expand Focus's support for low-income customers, the Commission is currently reviewing low-income offerings as part of its general Quadrennial Planning Process to update Focus goals in docket 5-FE-104. In April 2022, the Commission made initial decisions directing Focus to make additional efforts to coordinate with other weatherization programs, explore developing additional targeted pilot programming to serve low-income customers, engage with community stakeholders on how to reduce barriers to Focus participation, and develop key performance indicators (KPIs) for programs and offerings targeting income-qualified customers.

In August 2022, the Commission made additional Quadrennial Planning decisions directing the Focus Program Administrator to perform more research and analysis to better identify and serve underserved customers, with an emphasis on customers facing the highest energy burden as well as on small business. The Commission also directed further work to assess whether a benefits adder should be applied within Focus' cost-effectiveness test to better capture the value of programs and offerings targeting low-income customers. In October 2022, the Commission approved KPIs related to serving low-income and rural customers as part of the final phase in the Quadrennial Planning Process.

Economic conditions associated with the COVID-19 pandemic increased affordability concerns for many customers. At the onset of the pandemic in March 2020, the Commission directed utilities to take several steps to address safety and affordability concerns for the duration of the public health emergency, including:

- Prohibiting the disconnection of service to any customer unable to pay their bill;
- Prohibiting the charging of late fees for failure to pay a bill; and
- Requiring deferred payment agreements to be offered to all interested customers, including nonresidential customers.

The Commission also opened an investigation under docket 5-UI-120 to conduct ongoing review of appropriate steps to address safety, reliability, and affordability issues related to the pandemic.

As part of its investigation, the Commission required that all Wisconsin utilities supply information on changes to reported disconnection plans, disconnection notices, arrears balances and customers in arrears, DPAs and terms, and other collection activities such as deposits. All utilities were also ordered to submit a comprehensive plan to the Commission as to how the utility proposed to address the financial impacts of customer arrearages.

As documented in docket 5-UI-120, utilities implemented a number of different strategies to reduce customer arrears for low-income customers during the pandemic, including:

- Increased outreach and communication with customers to make them aware of payment offerings and assistance available through the utility, governmental, and community programs described above;

- Updated payment plan offerings with more flexible down payment amounts, extended repayment terms, due date extensions and individualized terms tailored to customer needs;
- Establishment of new Arrears Management Programs and expansions of existing forgiveness programs to increase assistance available to residential customers who have fallen behind on their bills.

In April 2021, the Commission directed utilities through docket 5-UI-120 to take several steps to continue to address safety, reliability and affordability concerns for the duration of the public health emergency, including:

- Requiring the offer of a DPA to any low-income residential customer who was unable to pay a bill in full, prior to disconnecting service, even if the terms of a previous DPA were unfulfilled;
- Remaining flexible when working with customers to establish a reasonable DPA;
- Requiring utilities seeking to disconnect residential service after April 15, 2021, to file a disconnection plan and any disconnection plan updates with the Commission prior to pursuing disconnections for non-payment of residential customers.

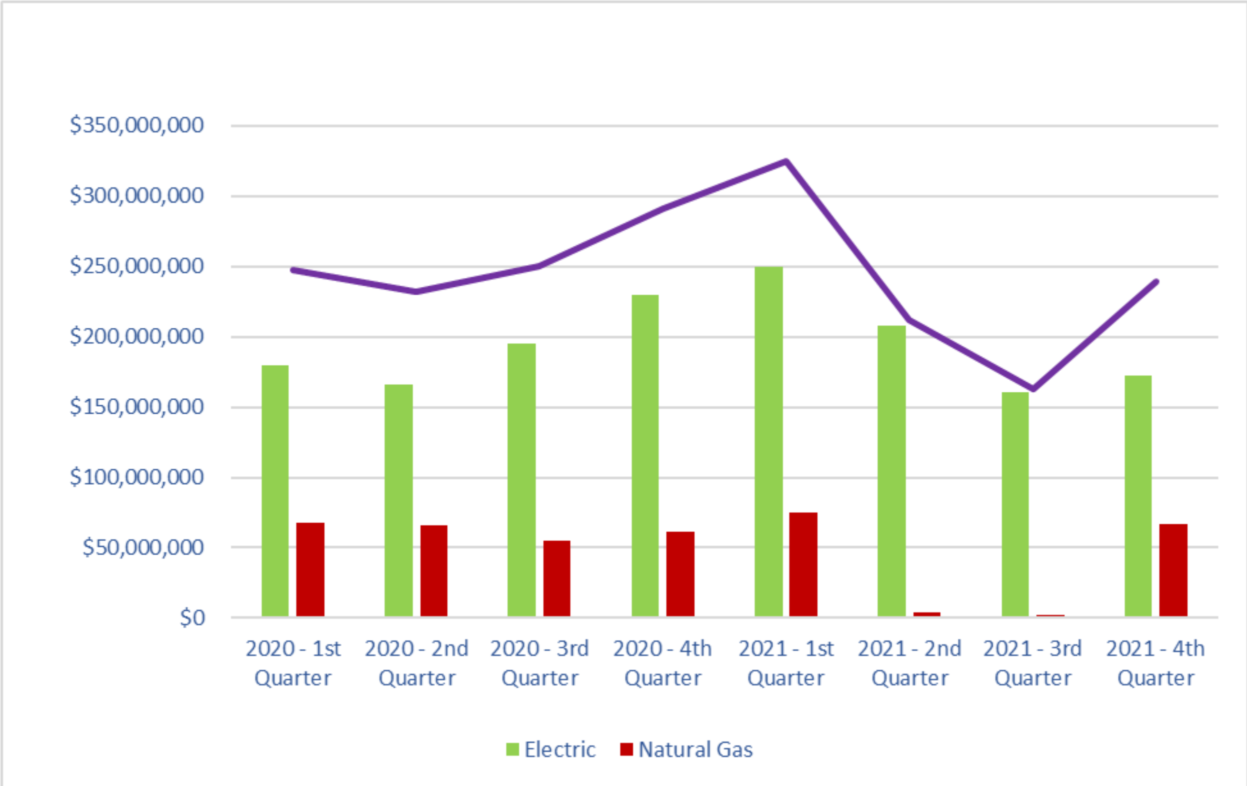
In December 2021, the Commission discontinued the requirements set in April, taking into consideration the additional financial assistance resources that became available to customers, such as the allocation of significant additional federal funds to low-income assistance programs in the state. The Commission also discontinued the requirement for utilities to provide quarterly reporting on arrears and collection data through the docket. However, enhanced data collection will continue through the addition of new questions related to residential arrears and disconnections on utility annual reports to the Commission.

As shown in Figure 7-2, the data gathered under docket 5-UI-120 and the 2021 Annual Reports demonstrated that residential customer arrears decreased from a peak in the first quarter of 2021, for electric service as well as natural gas, before increasing again in the fourth quarter of 2021. Likely contributors to the decrease in arrears include:

- utility establishment of enhanced DPAs and AMPs;
- expanded communication efforts regarding existing financial assistance resources; and
- increased financial assistance available through federal legislation, including the Wisconsin Emergency Rental Assistance Program, which offered customers financially impacted by the pandemic up to 12 months of financial support for rate payments and utility bills.

The increase in arrears during the fourth quarter likely reflects that utilities tend to receive fewer payments and DPA applications during the winter disconnection moratorium period from November 1 to April 15. The Commission will continue to monitor trends for 2022 and future years.

Figure 7-2 2020-2021 Residential Arrears Comparison by Quarter



APPENDIX A (Chapter 1)

Table A-1 Assessment of Electric Demand and Supply Conditions, Monthly Non-Coincident Peak Demands, MW

Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
HISTORICAL:												
2003	10,739	10,498	10,291	9,602	9,048	12,725	13,319	13,694	11,937	10,136	10,450	11,302
2004	10,924	10,384	10,091	9,400	10,273	12,486	12,958	12,437	12,161	9,902	10,557	11,478
2005	11,127	10,678	10,433	9,610	10,000	14,020	13,832	14,323	13,224	11,912	10,833	11,581
2006	10,622	10,556	10,174	9,550	11,527	12,559	15,006	14,507	11,060	10,320	10,909	11,553
2007	10,958	11,419	10,682	9,946	11,343	13,834	14,163	14,461	13,693	12,033	11,091	11,503
2008	11,249	11,167	10,437	9,899	9,583	12,283	13,256	12,883	13,111	10,216	10,279	11,438
2009	11,273	10,681	10,246	9,209	9,606	13,694	11,051	12,260	10,846	9,454	9,944	11,075
2010	10,671	10,226	9,611	9,030	12,490	12,495	13,069	14,098	11,662	9,608	10,170	11,101
2011	10,552	10,645	9,824	9,311	10,668	13,601	14,870	13,553	13,092	9,624	9,955	10,520
2012	10,614	10,020	9,779	9,005	10,394	13,974	15,105	13,439	12,927	9,681	10,186	10,475
2013	10,685	10,182	9,720	9,171	10,221	11,937	14,347	14,162	13,428	9,647	9,814	10,897
2014	11,299	10,656	10,272	9,150	10,117	11,793	13,290	12,270	11,255	9,339	10,403	10,514
2015	11,107	10,710	10,153	9,072	9,871	11,243	12,860	13,308	13,065	9,207	9,694	9,986
2016	10,755	10,139	9,659	9,049	10,190	12,500	13,730	13,851	13,030	9,695	9,574	10,900
2017	10,842	10,245	9,720	9,166	10,047	13,143	13,230	12,474	13,123	10,178	9,972	10,804
2018	10,977	10,414	9,674	9,375	12,739	14,143	13,655	13,373	13,118	10,357	10,155	10,220
2019	11,094	10,449	10,524	9,199	9,536	11,824	13,929	12,644	11,224	10,063	9,917	10,327
2020	9,979	9,945	9,115	8,340	10,951	12,748	13,698	13,669	10,259	9,060	9,463	9,964
2021	9,850	10,446	9,273	8,839	10,811	13,599	13,817	13,499	11,050			
FORECASTED:												
2021										9,667	9,825	10,429
2022	10,701	10,304	10,013	9,332	10,943	13,162	14,293	13,799	12,264	9,588	9,894	10,548
2023	10,709	10,354	10,042	9,377	11,012	13,246	14,366	13,876	12,344	9,655	9,955	10,614
2024	10,727	10,342	10,047	9,383	11,004	13,245	14,413	13,879	12,330	9,643	9,945	10,612
2025	10,702	10,330	10,024	9,362	10,977	13,260	14,392	13,907	12,336	9,646	9,946	10,608
2026	10,683	10,310	10,005	9,340	10,950	13,255	14,390	13,905	12,318	9,623	9,924	10,588
2027	10,677	10,298	9,997	9,328	10,938	13,255	14,398	13,914	12,313	9,615	9,916	10,582
2028	10,699	10,306	10,017	9,346	10,950	13,280	14,431	13,948	12,331	9,634	9,936	10,604

Table A-2 Wisconsin Aggregated Supply and Demand

Report Line MISO Description Capacity (MW)	2021	2022	2023	2024	2025	2026	2027	2028
High Certainty Resources	12,596	11,920	11,946	11,366	11,220	9,794	9,274	9,274
Low Certainty Resources	20	417	313	388	76	76	154	154
Behind the Meter	353	357	363	364	361	361	440	440
Demand Response Resources	832	818	826	826	827	828	830	831
New Capacity	2,342	2,759	3,842	4,265	4,984	5,457	6,179	6,301
Local Resource Zone (LRZ) Internal Transfer - In	2,311	1,893	2,064	2,216	2,406	2,461	2,517	2,528
LRZ Internal Transfer – Out	-920	-1,021	-1,056	-1,098	-1,086	-1,159	-1,254	-1,271
Net Imports	211	231	231	231	99	99	0	0
Committed Net Capacity (MW)	15,432	15,012	15,456	15,207	15,047	13,664	13,166	13,159
Potential Net Capacity (MW)	15,436	15,481	16,464	16,342	16,482	15,457	15,624	15,729
Demand (MW)								
Non-Coincident Load Serving Entities (LSE) Peak gross of DR	14,117	14,215	14,194	14,223	14,254	14,280	14,280	14,315
Full Responsibility Transactions	0	0	0	0	0	0	-13	12
Zonal Coincident Factor	0.96	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Coincident LSE Peak with Zonal Peak	13,452	13,691	13,693	13,745	13,775	13,801	13,814	13,847
MISO Coincident Factor	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Expected Demand: Coincident LSE Peak to MISO Peak	13,693	13,788	13,768	13,796	13,826	13,852	13,852	13,885
Reserve Requirement (MW)								
Local Clearing Requirement	14,186	14,299	14,350	14,402	14,441	14,483	14,526	14,579
Planning Reserve Requirement	14,980	14,988	14,911	14,872	14,849	14,891	14,891	14,857
UCAP Planning Reserve Margin	9.4%	8.7%	8.3%	7.8%	7.4%	7.5%	7.5%	7.0%
Resources above local clearing requirement	1,250	1,283	1,811	2,122	2,327	1,845	1,969	2,020
Resource above planning reserve requirement	456	594	1,250	1,652	1,919	1,437	1,604	1,742

Figure A-1 Wisconsin Fossil Fuel Generating Facilities – December 2020

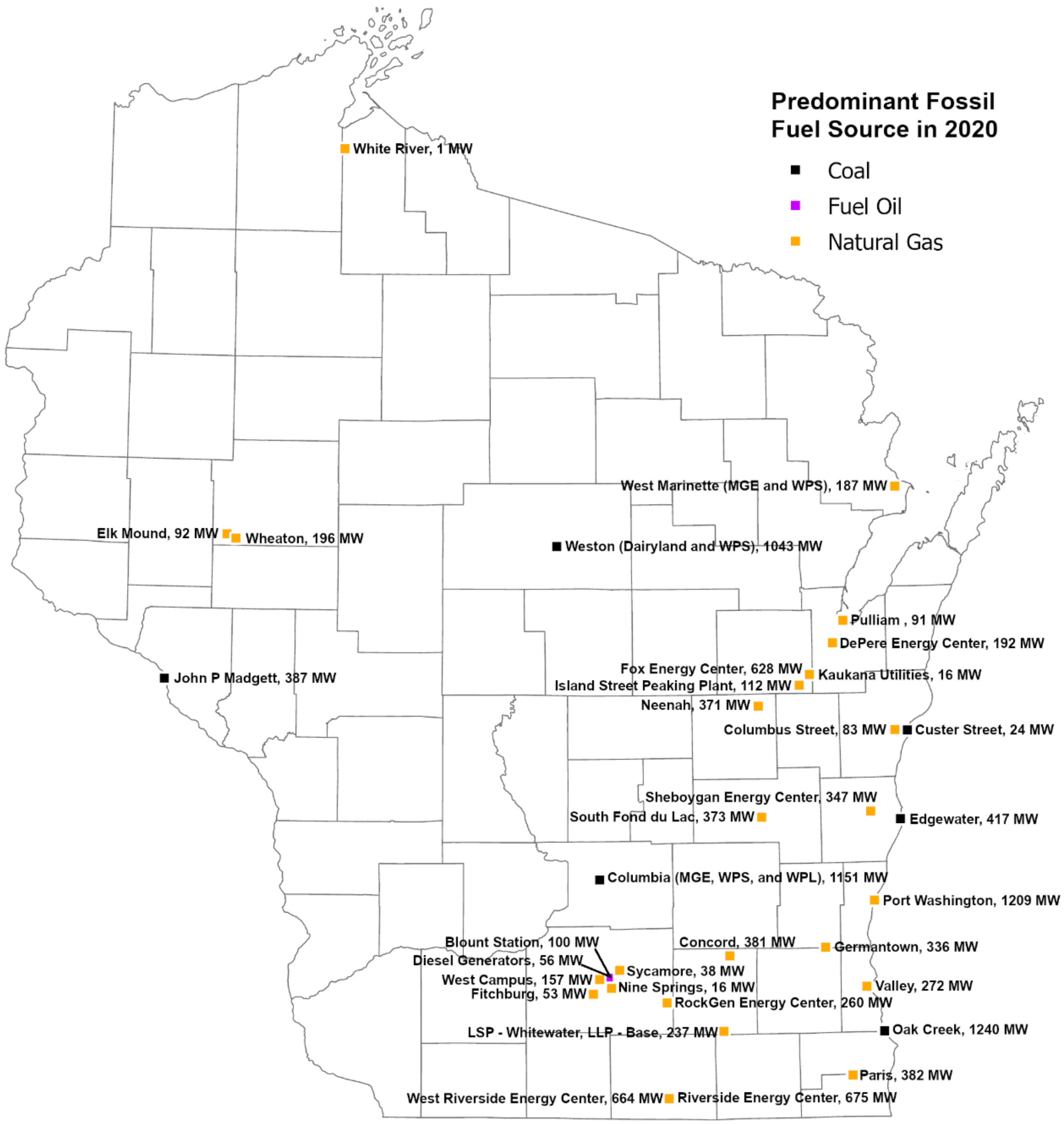


Figure A-2 Wisconsin Coal Generating Facilities – December 2020

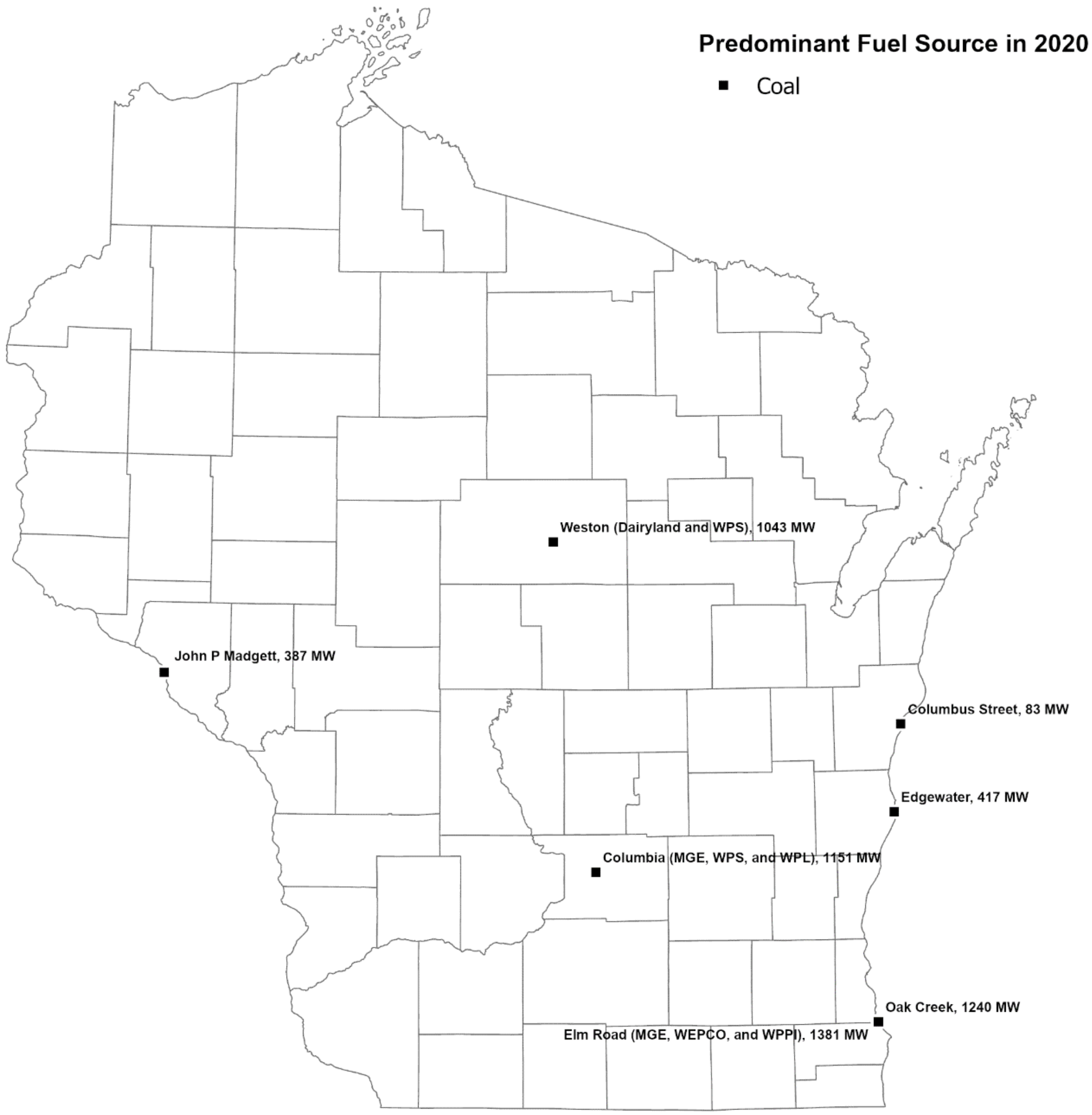


Figure A-3 Wisconsin Natural Gas Generating Facilities – December 2020

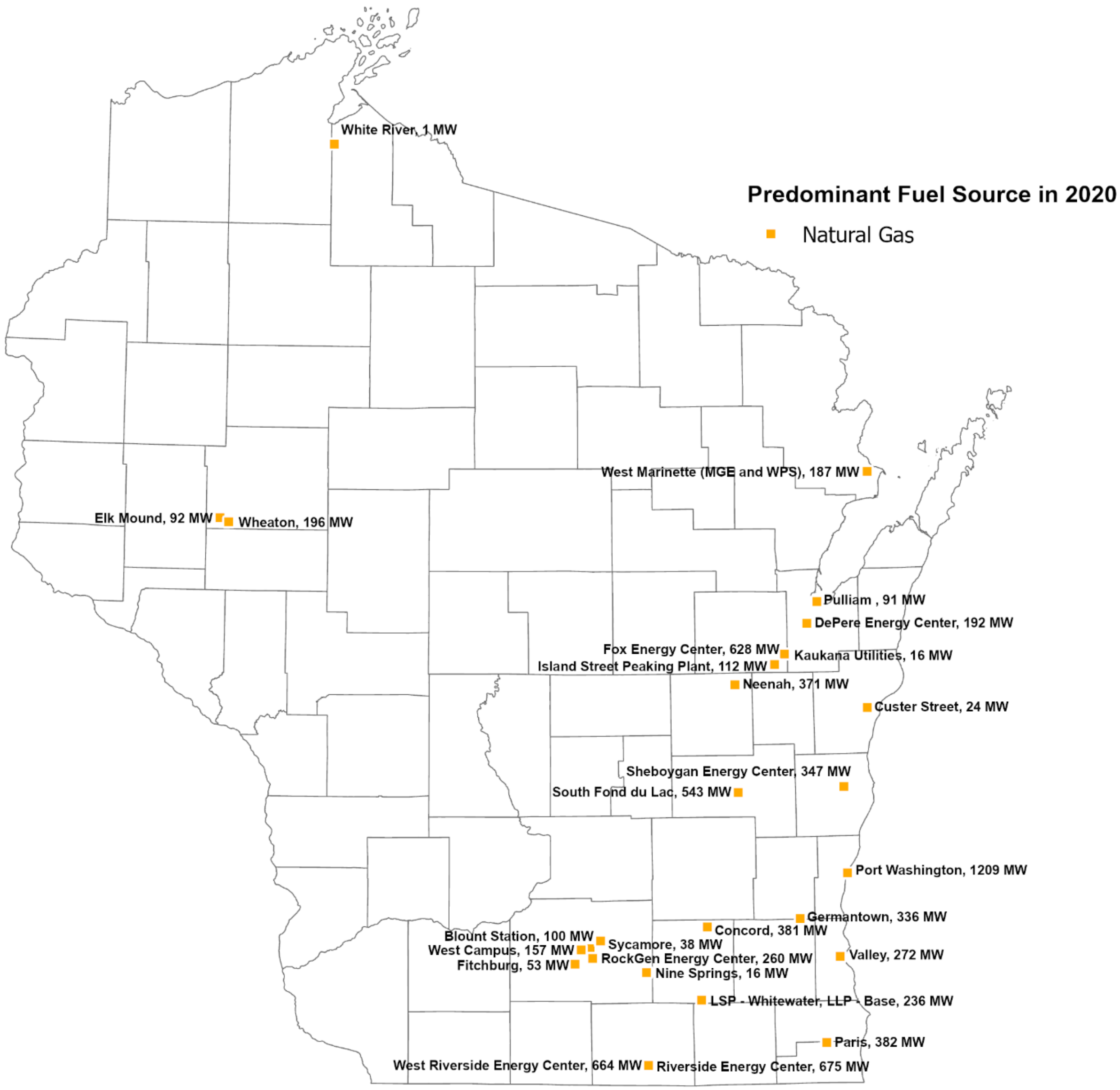


Figure A-4 Wisconsin Renewable Energy Generating Facilities – December 2020

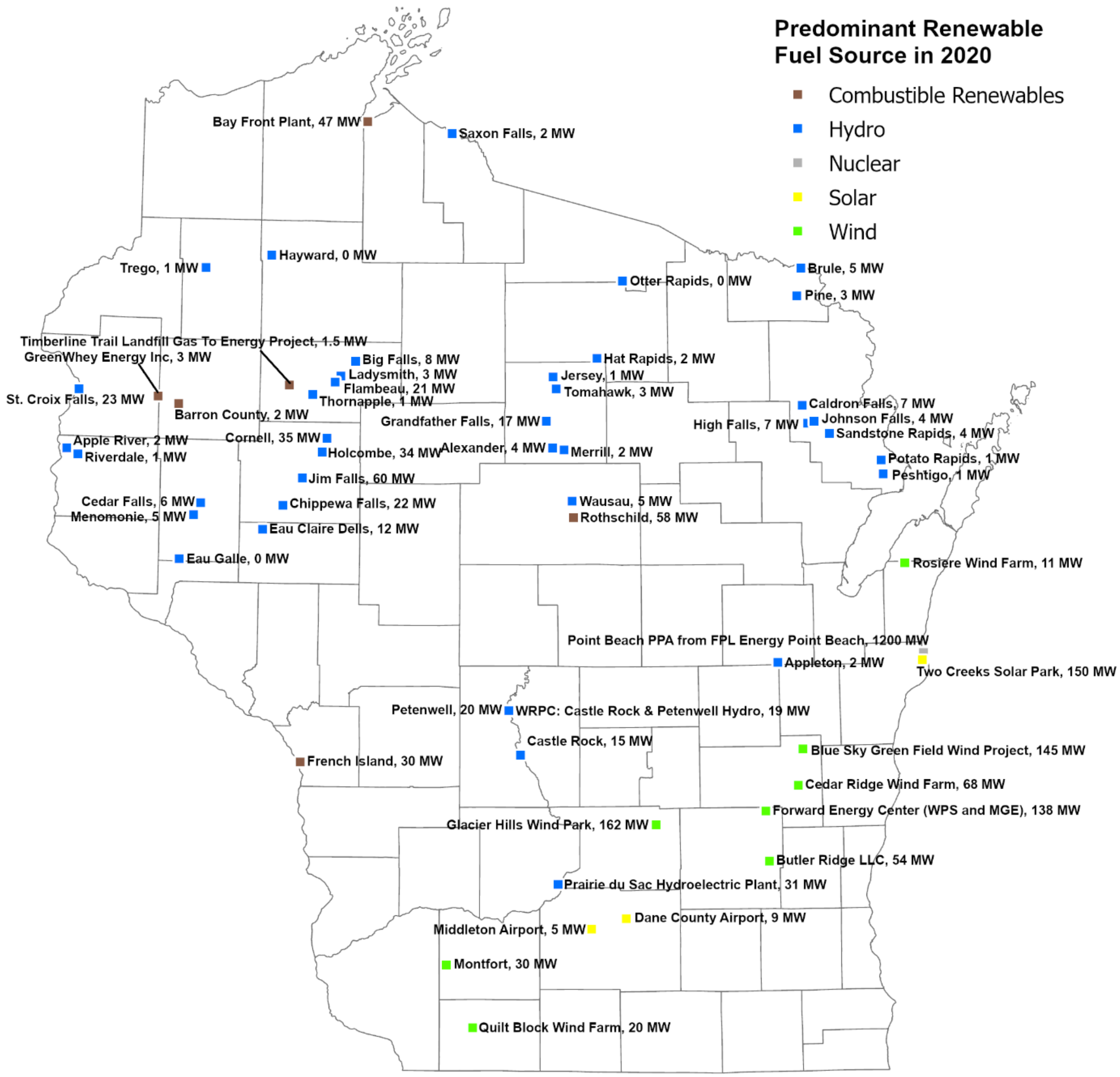


Figure A-5 Wisconsin Solar Generating Facilities – December 2020

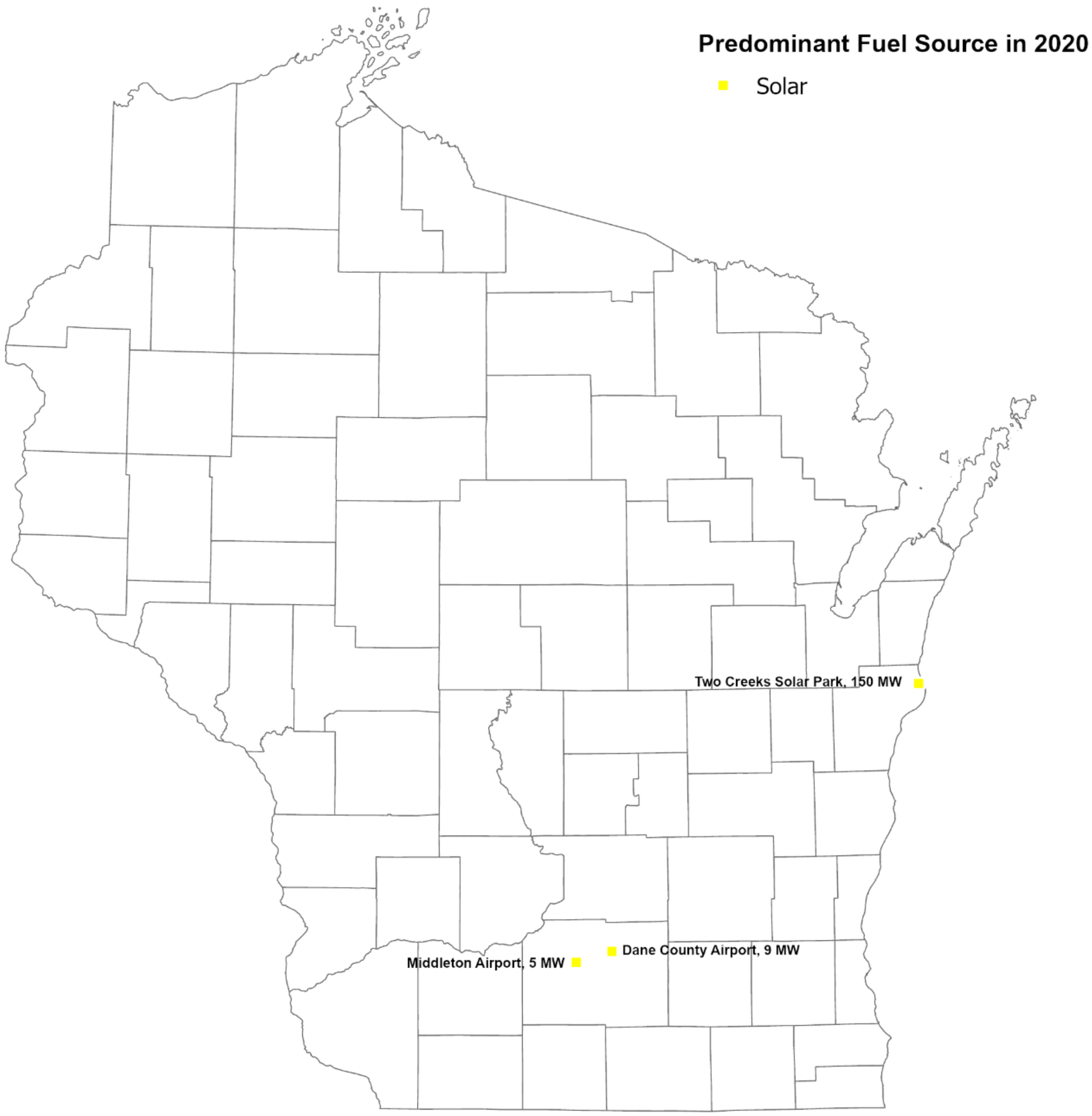


Figure A-6 Wisconsin Wind Generating Facilities – December 2020

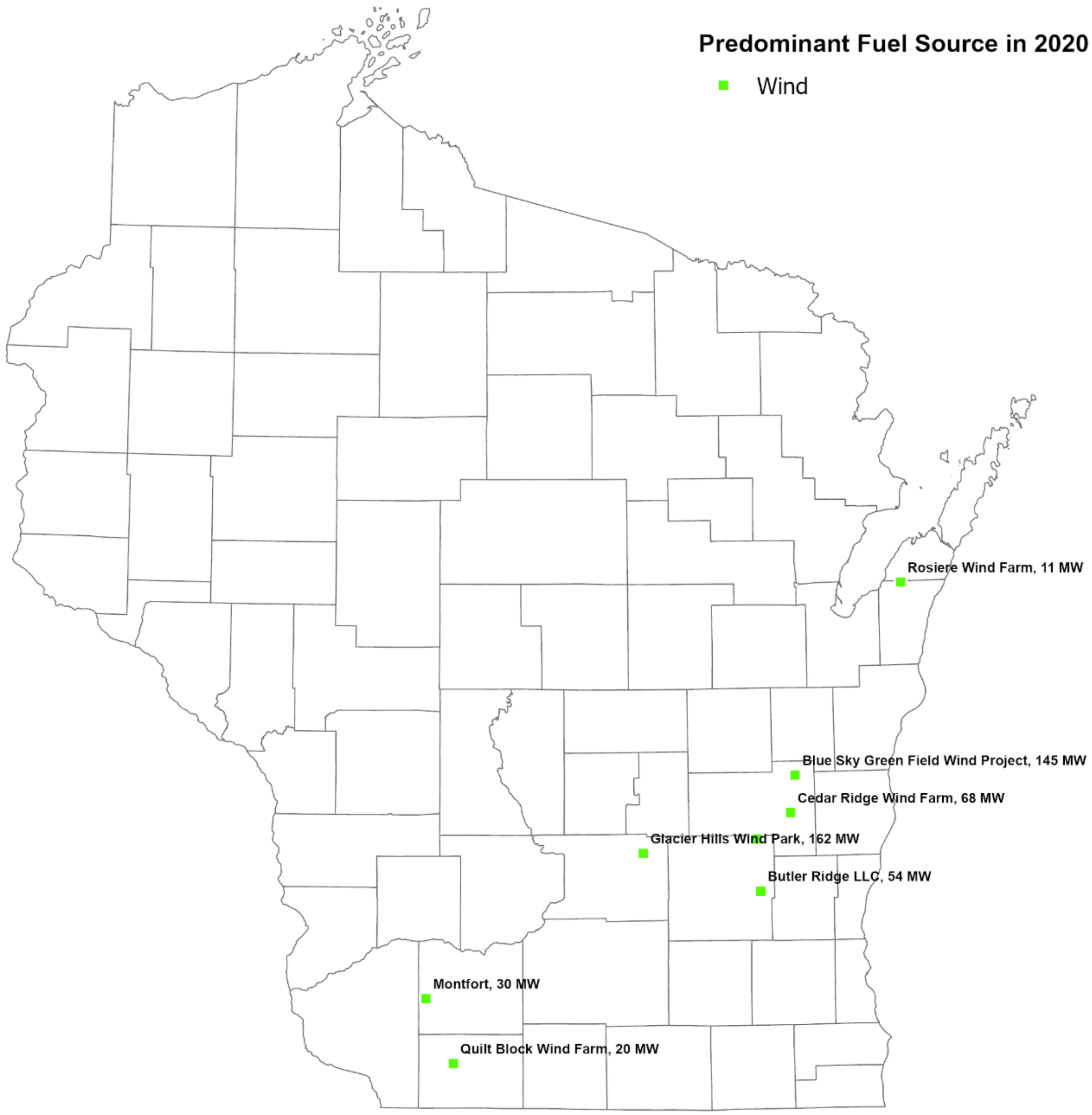


Figure A-7 Wisconsin Hydro Generating Facilities – December 2020

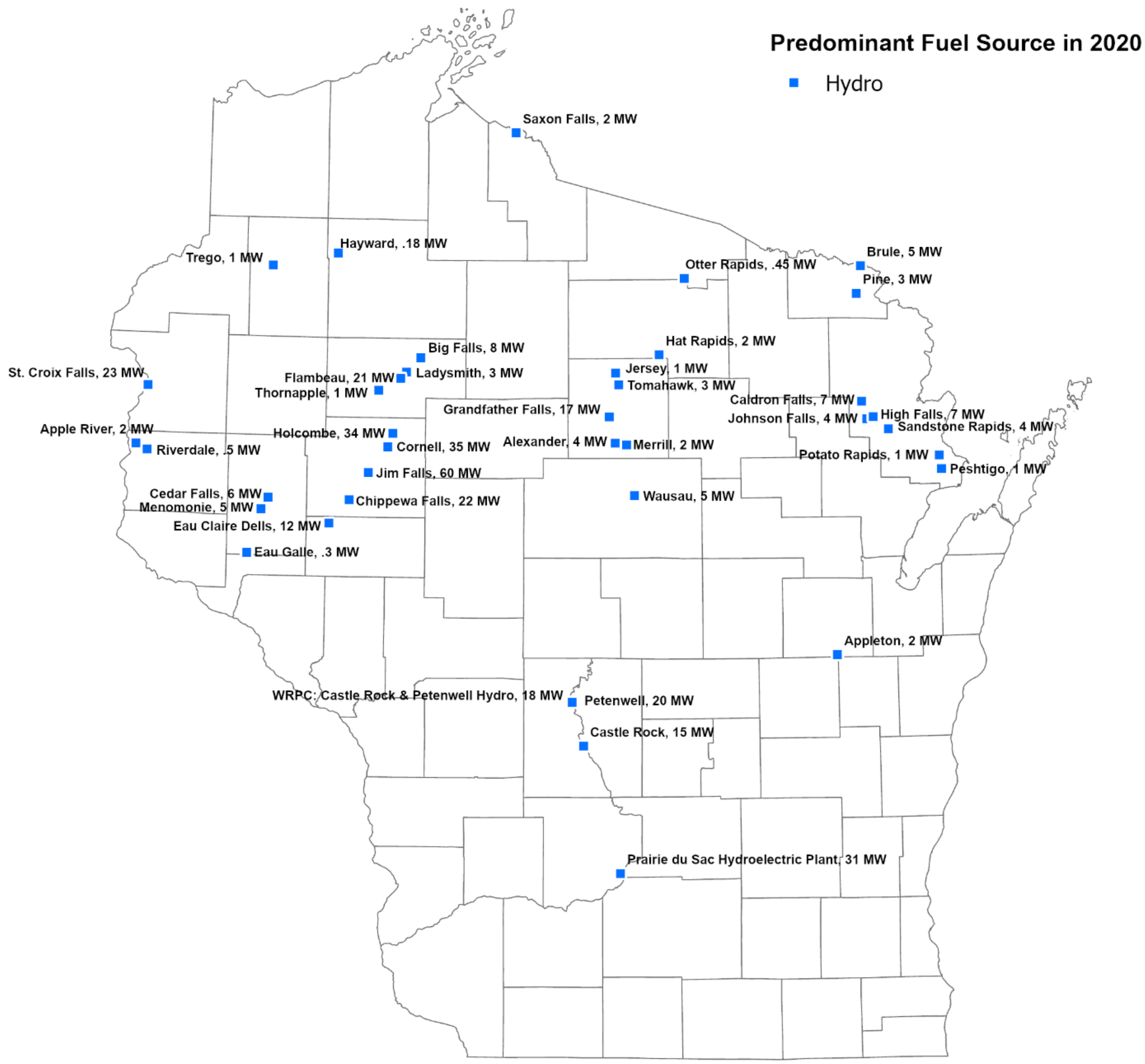


Table A-3 Coal Generation Units by Total CO_2 Emissions, 2019 and 2020

Unit name	2019 (Million tons)	Unit name	2020 (Million tons)
Elm Road #2 (WEPCO)	6.981	Elm Road #2 (WEPCO)	6.504
Oak Creek (WEPCO)	4.891	Oak Creek (WEPCO)	3.566
Weston - Unit: 04 (WPS Share)	2.236	Weston - Unit: 04 (WPS)	2.080
John P Madgett #1 (Dairyland)	1.932	Columbia Energy Center #1 (WPL)	1.886
Columbia 1 & 2 (WPS)	1.869	John P Madgett #1 (Dairyland)	1.847
Edgewater #5 (WPL)	1.658	Columbia 1 & 2 (WPS)	1.844
Columbia Energy Center #2 (WPL)	1.654	Columbia Energy Center #2 (WPL)	1.366
Columbia Energy Center #1 (WPL)	1.584	Edgewater #5 (WPL)	1.271
Genoa #3 (Dairyland)	1.373	Genoa #3 (Dairyland)	1.106
Weston #3 (WPS)	1.145	Weston #3 (WPS)	1.075

Table A-4 Coal Generation Units by CO_2 Emissions Rate, 2019 and 2020

Unit name	2019 (lb/kWh)	Unit name	2020 (lb/kWh)
Columbus Street #8 (Manitowoc)	5.804	Columbus Street #8 (Manitowoc)	3.900
Columbus Street #9 (Manitowoc)	3.080	Columbus Street #9 (Manitowoc)	2.890
John P Madgett #1 (Dairyland)	2.517	John P Madgett #1 (Dairyland)	2.589
Columbia #1 (MGE)	2.377	Boswell Energy Center #4 (WPPI)	2.402
Columbia Energy Center #1 (WPL)	2.371	Columbia #1 (MGE)	2.396
Oak Creek (WEPCO)	2.370	Columbia 1 & 2 (WPS)	2.390
Columbia 1 & 2 (WPS)	2.360	Columbia Energy Center #1 (WPL)	2.386
Columbia #2 (MGE)	2.343	Columbia #2 (MGE)	2.367
Columbia Energy Center #2 (WPL)	2.340	Genoa #3 (Dairyland)	2.364
Boswell Energy Center #4 (WPPI)	2.337	Oak Creek (WEPCO)	2.350

Table A-5 Natural Gas Generation Units by Total CO_2 Emissions, 2019 and 2020

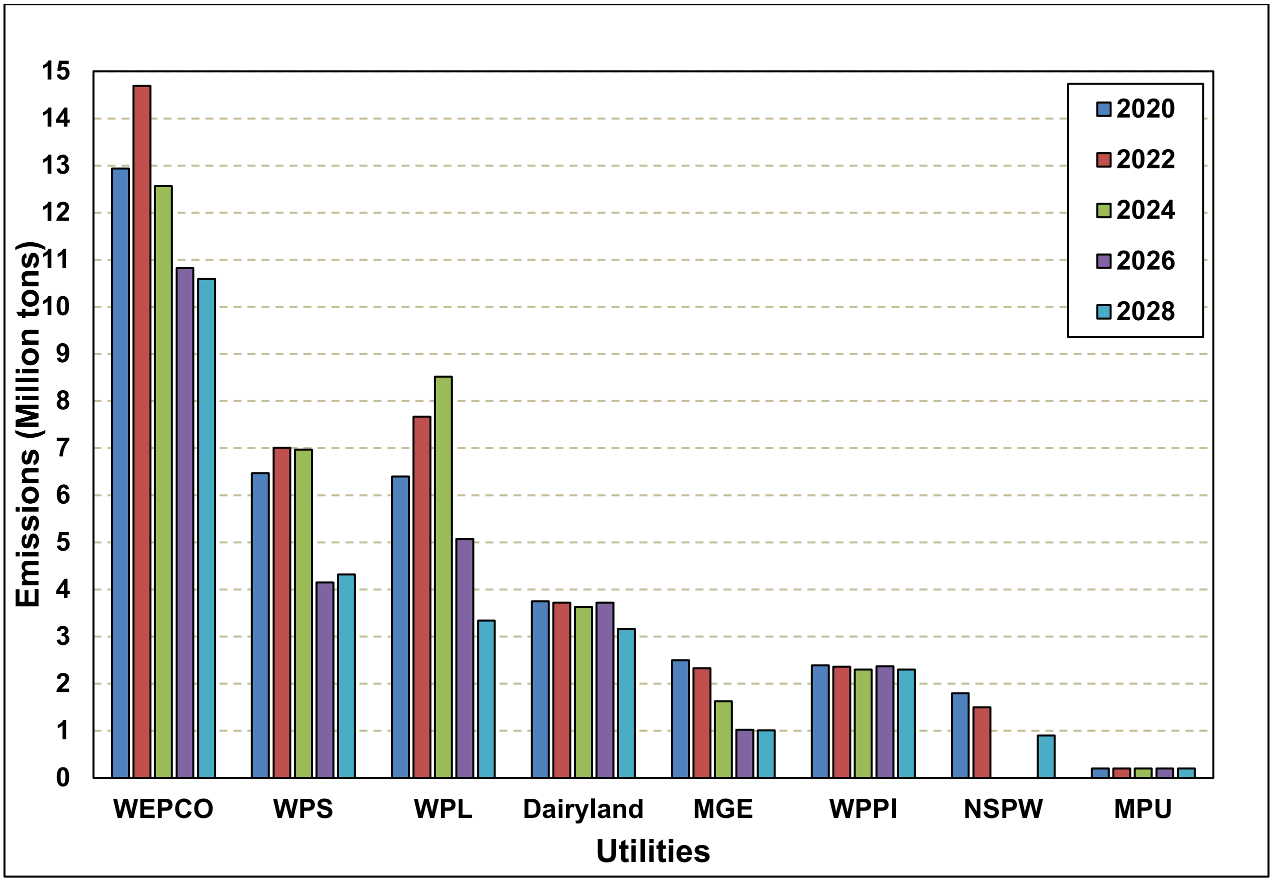
Unit name	2019 (Million tons)	Unit name	2020 (Million tons)
Port Washington #2 (WEPCO)	3.212	Port Washington #2 (WEPCO)	3.413
Fox Energy Center #1 (WPS)	1.617	Fox Energy Center #1 (WPS)	1.726
Riverside Energy Center #3 (WPL)	0.700	Valley #2 (WEPCO)	0.485
Riverside Energy Center #1 (WPL)	0.505	Riverside Energy Center #3 (WPL)	0.395
Riverside Energy Center #2 (WPL)	0.496	West Riverside #2 (WPL)	0.350
Valley #2 (WEPCO)	0.404	Riverside Energy Center #1 (WPL)	0.320
West Campus (MGE)	0.196	West Riverside #1 (WPL)	0.278
Sheboygan Energy Center #2 (WPL)	0.114	Riverside Energy Center #2 (WPL)	0.248
Neenah #2 (WPL)	0.107	West Campus (MGE)	0.225
Sheboygan Energy Center #1 (WPL)	0.106	Sheboygan Energy Center #1 (WPL)	0.202

Table A-6 Natural Gas Generation Units by Emissions Rate, 2019 and 2020

Unit name	2019 (lb/kWh)	Unit name	2020 (lb/kWh)
Weston W31;W32 #2 (WPS)	10.830	Weston W31;W32 #2 (WPS)	28.680
South Fond du Lac #1 (WPPI)	2.914	Germantown #5 (WEPCO)	2.630
South Fond du Lac #2 (WPL)	2.838	Elk Mound #2 (Dairyland)	2.560
South Fond du Lac #4 (WPPI)	2.600	Weston Unit 2 #1 (WPS)	2.550
Elk Mound #2 (Dairyland)	2.473	Valley #2 (WEPCO)	2.190
South Fond du Lac #3 (WPL)	2.414	Nine Springs (MGE)	2.115
Germantown #5 (WEPCO)	2.390	South Fond du Lac #2 (WPL)	2.010
Wheaton #1 (NSPW)	2.275	South Fond du Lac #1 (WPPI)	2.006
Valley #2 (WEPCO)	2.130	South Fond du Lac #3 (WPL)	1.995
Wheaton #2 (NSPW)	2.113	Elk Mound #1 (Dairyland)	1.979

APPENDIX B (Chapter 2)

Figure B-1 Total Annual Emissions Forecast for Wisconsin Electric Providers, 2022-2028



NSPW did not submit projections for years 2024 and 2026.

Table B-1 Annual Unit Selection – Future

Units\Years	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Natural Gas (Combined Cycle or Combustion Turbine)					1	1	1	1												
Wind																				
Solar PV																				1
Solar PV + Battery													1						1	
Lithium Battery																				

Table B-2 Annual Unit Selection – Future 2

Units\Years	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Natural Gas (Combined Cycle or Combustion Turbine)					2	1	1	1				1	1							
Wind																				
Solar PV																				1
Solar PV + Battery																			1	
Lithium Battery																				

Table B-3 Annual Unit Selection – Future 3

Units\Years	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Natural Gas (Combined Cycle or Combustion Turbine)					1															
Wind						1				1	1	2	1	2	2	3		6		2
Solar PV					1	1					1	1	2	1						
Solar PV + Battery					1	1										1	2			
Lithium Battery							1	1				1					2	1		

Table B-4 Annual Unit Selection – Net Zero by 2035

Units\Years	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Combined Cycle																				
Combustion Turbine																				
Wind										4	3	2	5			2				
Solar PV			1		1			2				3	5	12	12	10	2	2	1	1
Solar PV + Battery						2	3		1	2		1	2							
Lithium Battery					1					2		1	5	3	3	5				1

Table B-5 Annual Unit Selection – Future 1, Gas Price $6/MMBtu

Units\Years	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Natural Gas (Combined Cycle or Combustion Turbine					1	1	1	1												
Wind																				
Solar PV													2						2	1
Solar PV + Battery																				
Lithium Battery																				

Table B-6 Annual Unit Selection – Future 2, Gas Price $6/MMBtu

Units\Years	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Combined Cycle					2	1	1													
Combustion Turbine																				
Wind																				1
Solar PV																				
Solar PV + Battery								1				2	2						1	
Lithium Battery																				

Table B-7 Annual Unit Selection – Future 1, Gas Price $10/MMBtu

Units\Years	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Natural Gas (Combined Cycle or Combustion Turbine					1	1	1	1												
Wind																				1
Solar PV													2						2	
Solar PV + Battery																				
Lithium Battery																				

Table B-8 Annual Unit Selection – Future 2, Gas Price $10/MMBtu

Units\Years	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Natural Gas (Combined Cycle or Combustion Turbine)						1	1	1					1							
Wind					2	1												1		
Solar PV					1									1						1
Solar PV + Battery					1															1
Lithium Battery												1								

APPENDIX C (Chapter 3)

Table C-1 Total and Dispatched Demand Response Capacity (MW) by Provider

Interruptible	2018	2019	2020	2021
MGE	7.6 / 0 (0%)	7.5 / 0 (0%)	9.7 / 0 (0%)	7.8 / 0 (0%)
NSPW	70.4 / 70.4 (100%)	88.8 / 88.8 (100%)	58.1 / 58.1 (100%)	64.5 / 69.5 (107.8%)
WP&L	146 / 143 (97.9%)	146 / 0 (0%)	146 / 146 (100%)	146 / 0 (0%)
WEPCO	98.2 / 0 (0%)	120.2 / 0 (0%)	97.2 / 0 (0%)	96.8 / 0 (0%)
WPSC	197.3 / 0 (0%)	206.7 / 0 (0%)	185.9 / 0 (0%)	182 / 0 (0%)
SWL&P	None	None	None	None
DPC	None	9.5 / 0 (0%)	9.5 / 0 (0%)	9.5 / 0 (0%)
WPPI	66.9 / 0 (0%)	49.2 / 0 (0%)	50.1 / 64.6 (128.9%)	48.8 / 0 (0%)
WI Total	586.5 / 213.4 (36.4%)	627.8 / 88.8 (14.1%)	556.6 / 268.7 (48.3%)	555.3 / 69.5 (12.5%)

Direct Load Control	2018	2019	2020	2021
MGE	18.7 / 0 (0%)	18.6 / 0 (0%)	18.9 / 0 (0%)	18.8 / 0 (0%)
NSPW	16 / 16 (100%)	14.2 / 14.2 (100%)	15.9 / 15.9 (100%)	16.3 / 16.3 (100%)
WP&L	None	None	None	None
WEPCO	None	None	None	None
WPSC	None	None	None	None
SWL&P	199.5 / 0 (0%)	192.7 / 0 (0%)	193.8 / 0 (0%)	179.2 / 0 (0%)
DPC	None	91 / 91 (100%)	91 / 91 (100%)	91 / 91 (100%)
WPPI	None	None	None	None
WI Total	234.2 / 16 (6.8%)	316.4 / 105.2 (33.3%)	319.6 / 106.9 (33.5%)	305.4 / 107.3 (35.2%)

Table C-2 Summary of Demand Response Activity by Provider

Summary of Demand Response Programs	2018	2019	2020	2021	2022
MGE DR Capacity	26.3	26.0	28.6	26.6	29.1
MGE DR Capacity Dispatched	0.0	0.0	0.0	0.0	2.0
MGE DR Customers Enrolled	20	20	20	20	2,419
MGE DR Payments & Admin Costs	$713,415.4	$698,115.0	$804,827.2	$713,113.7	$827,975.5
NSPW DR Capacity	86.4	103.0	74.0	80.8	75.2
NSPW DR Capacity Dispatched	86.4	103.0	74.0	85.8	75.2
NSPW DR Customers Enrolled	21,202	21,541	22,157	21,286	22,258
NSPW DR Payments & Admin Costs	$1,439,290	$1,116,731	$1,224,206	$1,047,472	$1,108,800
WP&L DR Capacity	146.0	146.0	146.0	146.0	138.0
WP&L DR Capacity Dispatched	143.0	0.0	146.0	0.0	180.0
WP&L DR Customers Enrolled	130	130	130	130	130
WP&L DR Payments & Admin Costs	$12,000,000	$12,000,000	$12,000,000	$12,000,000	$12,000,000
WEPCO DR Capacity	127.7	158.7	128.9	120.3	136.9
WEPCO DR Capacity Dispatched	0.0	0.0	0.0	0.0	0.0
WEPCO DR Customers Enrolled	101	97	93	86	85
WEPCO DR Payments & Admin Costs	$0	$0	$0	$0	$0
WPSC DR Capacity	197.3	206.7	185.9	182.0	180.4
WPSC DR Capacity Dispatched	0.0	0.0	0.0	0.0	0.0
WPSC DR Customers Enrolled	49	49	48	50	50
WPSC DR Payments & Admin Costs	$0	$0	$0	$0	$0
SWL&P DR Capacity	199.5	192.7	193.8	179.2	173.6
SWL&P DR Capacity Dispatched	0.0	0.0	0.0	0.0	0.0
SWL&P DR Customers Enrolled	189	180	173	169	169
SWL&P DR Payments & Admin Costs	$0	$0	$0	$0	$0
DPC DR Capacity	0.0	100.5	100.5	100.5	98.1
DPC DR Capacity Dispatched	0.0	127.0	127.0	127.0	132.1
DPC DR Customers Enrolled	0	87,347	87,368	87,402	87,417
DPC DR Payments & Admin Costs	$0	$0	$0	$0	$0
GLU DR Capacity	0.0	0.0	0.0	0.0	0.0
GLU DR Capacity Dispatched	0.0	0.0	0.0	0.0	0.0
GLU DR Customers Enrolled	0	0	0	0	0
GLU DR Payments & Admin Costs	$0	$0	$0	$0	$0
WPPI DR Capacity	66.9	49.2	50.1	48.8	48.5
WPPI DR Capacity Dispatched	0.0	0.0	64.6	0.0	0.8
WPPI DR Customers Enrolled	10	11	11	12	12
WPPI DR Payments & Admin Costs	$2,463,161	$2,664,534	$2,663,298	$2,553,219	$3,077,506
Total DR Capacity	850.2	982.8	907.9	884.1	879.8
Total DR Capacity Dispatched	229.4	230.0	411.6	212.8	390.1
Total DR Customers Enrolled	21,701	109,375	110,000	109,155	112,540
Total DR Payments & Admin Costs	$16,615,867	$16,479,380	$16,692,331	$16,313,804	$17,014,281

Notes:

1) DPC reported 87,000 customers and 127 MW of dispatched capacity beginning 2019.

2) GLU reported no DR data for any years.

3) WEPCO and WPSC did not report DR payments or program admin costs for any year.

Table C-3 Demand Response Capacity (All Types) by Program

DR Program	DR Type	2018	2019	2020	2021	2022
Is-3 Electric Interruptible Service	Interruptible Load	7.6	7.5	9.7	7.8	8.4
Is-4 Electric Interruptible Service	Direct Load	7.7	7.6	7.6	7.6	7.2
CP-1 C&I High Load Factor Direct Control Interruptible Service for Transmission Voltage	Direct Load Control	11.0	11.0	11.3	11.3	11.2
MGE Connect	Direct Load	0.0	0.0	0.0	0.0	2.3
MGE 4 Programs		26.3	26.0	28.6	26.6	29.1
Electric Rate Savings (commercial)	Interruptible Load	70.4	88.8	58.1	64.5	57.9
AC Rewards	Direct Load	N/A	N/A	< 1	< 1	1.0
Saver's Switch (Residential AC)	Direct Load	7.5	7.5	9.3	9.8	10.0
Saver's Switch (Residential Water Heaters)	Direct Load	0.5	0.5	0.5	0.3	0.3
Saver's Switch (Commercial)	Direct Load	8.0	6.2	6.1	6.2	6.0
NSPW 5 Programs		86.4	103.0	74.0	80.8	75.2
C&I Interruptible	Interruptible Load	146.0	146.0	146.0	146.0	138.0
WP&L 2 Programs		146.0	146.0	146.0	146.0	138.0
Curtailable Service	Other	28.5	37.5	30.7	22.9	26.1
Seasonal Curtailable Service	Other	1.0	1.0	0.9	0.5	0.7
General Primary Combined Firm and Non-Firm Service	Interruptible Load	75.2	78.2	71.4	65.0	68.2
Real Time Pricing Rider	Interruptible Load	23.0	42.0	25.8	31.8	31.8
Electronics and Information Technology Manufacturing-Market Pricing Rate	Interruptible Load	0.0	0.0	0.0	0.0	10.0
WEPCO 5 Programs		127.7	158.7	128.9	120.3	136.9
General Primary Interruptible	Interruptible Load	142.7	145.3	134.1	127.1	128.7
Real Time Market Pricing	Interruptible Load	54.6	61.4	51.9	54.9	51.7
WPSC 2 Programs		197.3	206.7	185.9	182.0	180.4
Controlled Space Heating	Direct Load	181.0	179.0	181.0	168.0	163.0
Controlled Water Heating	Direct Load	18.5	13.7	12.8	11.2	10.6
SWL&P 2 Programs		199.5	192.7	193.8	179.2	173.6
Daily Thermal Storage	Direct Load Control	0.0	12.0	12.0	12.0	12.0
Bulk Interruptible	Interruptible Load	0.0	9.5	9.5	9.5	7.1
Residential DLC	Direct Load Control	0.0	74.0	74.0	74.0	74.0
Agricultural DLC	Direct Load Control	0.0	5.0	5.0	5.0	5.0
Daily EV Charging	Direct Load Control	0.0	0.0	0.0	0.0	0.0
DPC 5 Programs		0.0	100.5	100.5	100.5	98.1
Large Customer Demand Response	Interruptible Load	66.9	49.2	50.1	48.8	48.5
WPPI 1 Programs		66.9	49.2	50.1	48.8	48.5
WI Total	Interruptible Load	586.5	627.8	556.6	555.3	550.4
WI Total	Direct Load Control	234.2	316.4	319.6	305.4	302.6
WI Total	Other	29.5	38.5	31.7	23.4	26.8
WI Total		850.2	982.8	907.9	884.1	879.8

Table C-4 Demand Response Enrolled Customers by Program

DR Program	DR Type	2018	2019	2020	2021	2022
Is-3 Electric Interruptible Service	Interruptible	7	7	7	7	7
Is-4 Electric Interruptible Service	Direct Load	12	12	12	12	11
CP-1 C&I High Load Factor Direct Control Interruptible Service for Transmission Voltage	Direct Load	1	1	1	1	1
MGE Connect	Direct Load	0	0	0	0	2,400
MGE 4 Programs		20	20	20	20	2,419
Electric Rate Savings (commercial)	Interruptible	258	263	269	273	271
AC Rewards	Direct Load	0	0	58	182	912
Saver's Switch (Residential AC)	Direct Load	17,511	17,768	18,195	18,212	18,500
Saver's Switch (Residential Water Heaters)	Direct Load	2,513	2,555	2,585	1,551	1,500
Saver's Switch (Commercial)	Direct Load	920	955	1,050	1,068	1,075
NSPW 5 Programs		21,202	21,541	22,157	21,286	22,258
C&I Interruptible	Interruptible	130	130	130	130	130
WPL 2 Programs		130	130	130	130	130
Curtailable Service	Other	58	57	54	50	48
Seasonal Curtailable Service	Other	13	13	12	10	10
General Primary Combined Firm and Non-Firm Service	Interruptible	29	26	25	25	25
Real Time Pricing Rider	Interruptible Load	1	1	1	1	1
Electronics and Information Technology Manufacturing-Market Pricing Rate	Interruptible	0	0	0	0	1
WEPCO 5 Programs		101	97	93	86	85
General Primary Interruptible	Interruptible	43	41	40	42	42
Real Time Market Pricing	Interruptible	6	8	8	8	8
WPSC 2 Programs		49	49	48	50	50
Controlled Space Heating	Direct Load	128	123	120	119	119
Controlled Water Heating	Direct Load	61	57	53	50	50
2 Programs		189	180	173	169	169
Daily Thermal Storage	Direct Load	0	12,000	12,000	12,000	12,000
Bulk Interruptible	Interruptible	0	2	2	2	2
Residential DLC	Direct Load	0	74,373	74,373	74,373	74,373
C&I BTM Generators	Other	0	141	141	141	141
Agricultural DLC	Direct Load	0	828	828	828	828
Daily EV Charging	Direct Load	0	3	24	58	73
DPC 5 Programs		0	87,347	87,368	87,402	87,417
Large Customer Dmeand Response	Interruptible	10	11	11	12	12
WPPI 1 Programs		10	11	11	12	12
Large Customer Dmeand Response	Interruptible	484	489	493	500	499
WI Total	Direct Load	21,146	108,675	109,299	108,454	111,842
27 Programs		21,701	109,375	110,000	109,155	112,540

Figure C-1 DER Installations by Customer Class

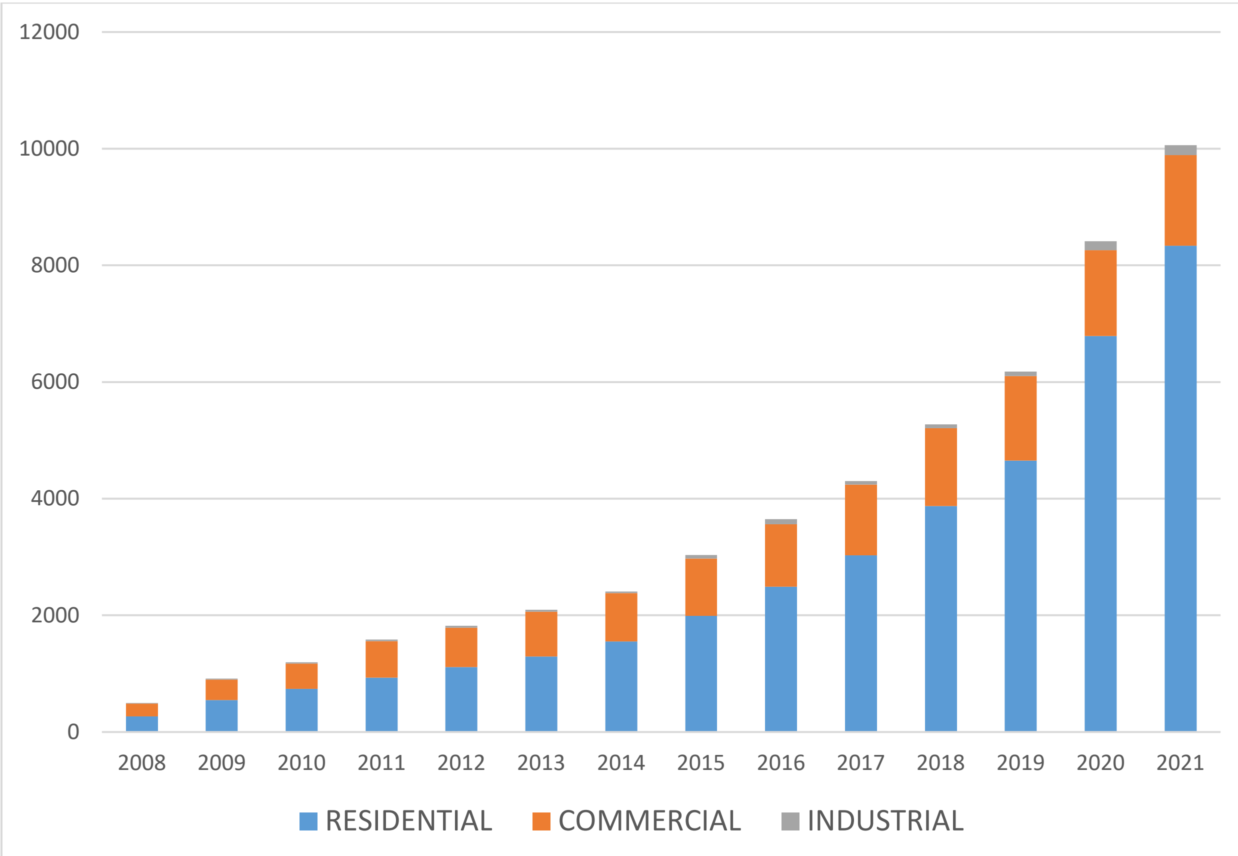
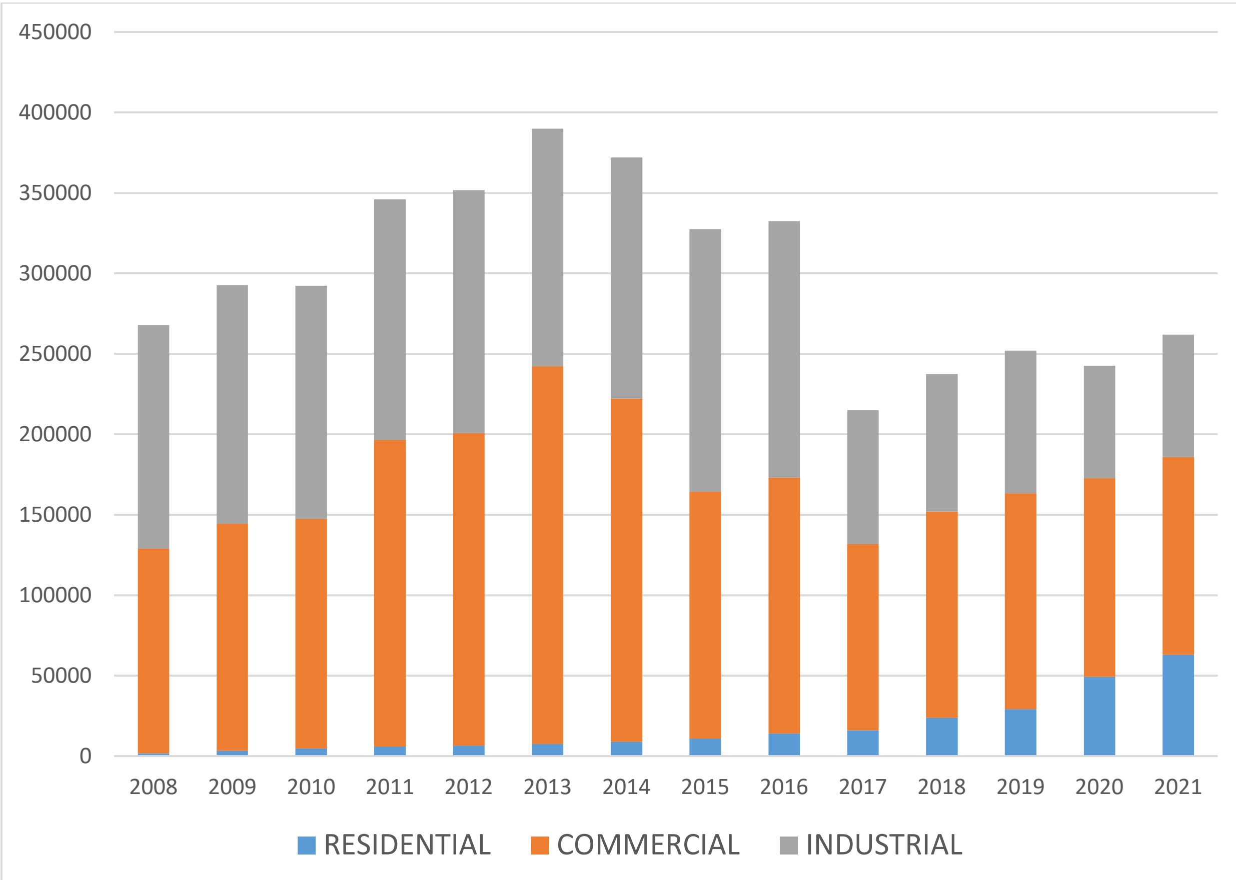
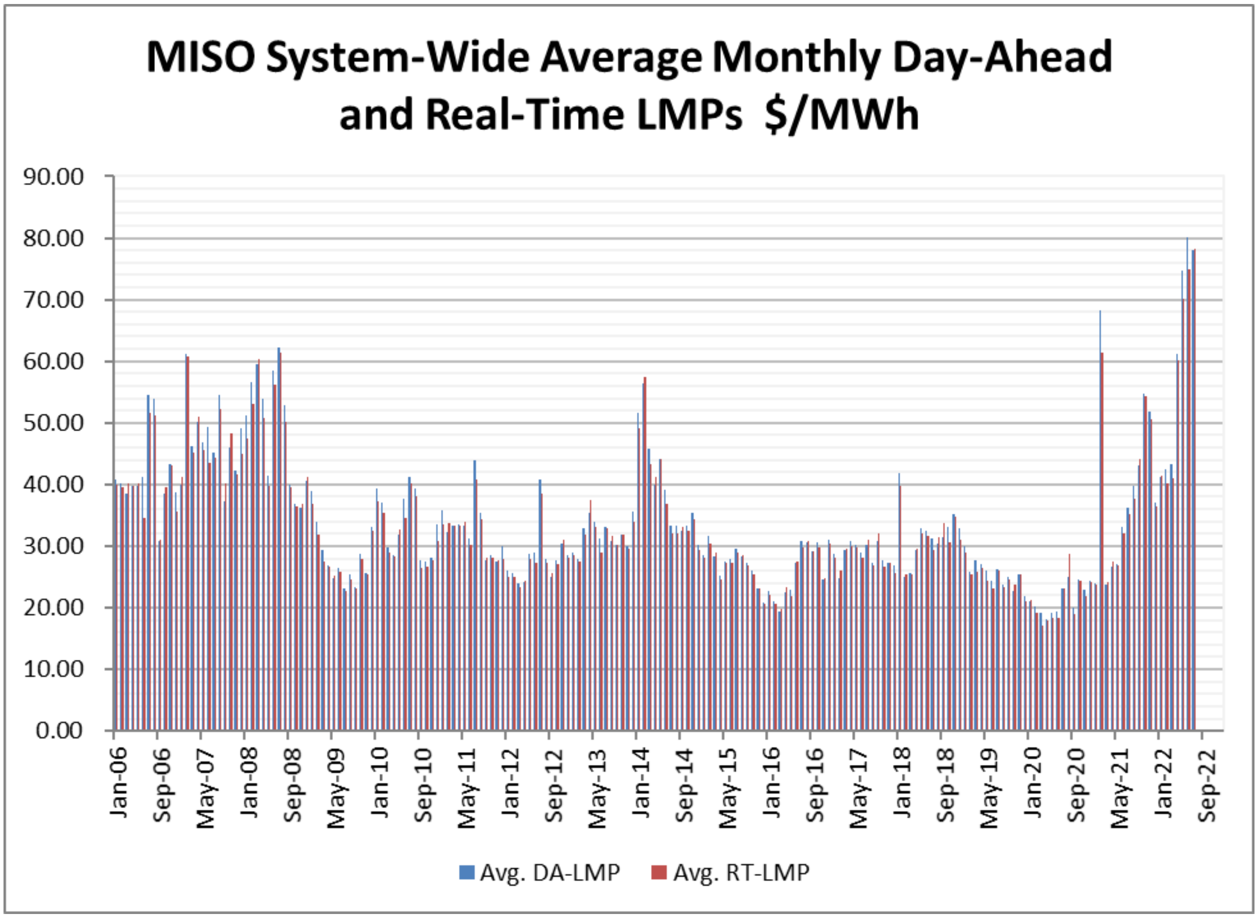


Figure C-2 Installed DER Capacity by Customer Class



APPENDIX D (Chapter 4)

Figure D-1 MISO System-Wide Average Monthly Day-Ahead and Real-Time LMPs, $/MWh



APPENDIX E (Chapter 6)

Figure E-1 Energy Intensity - Non-Residential Sales ($ of GDP/MWh)

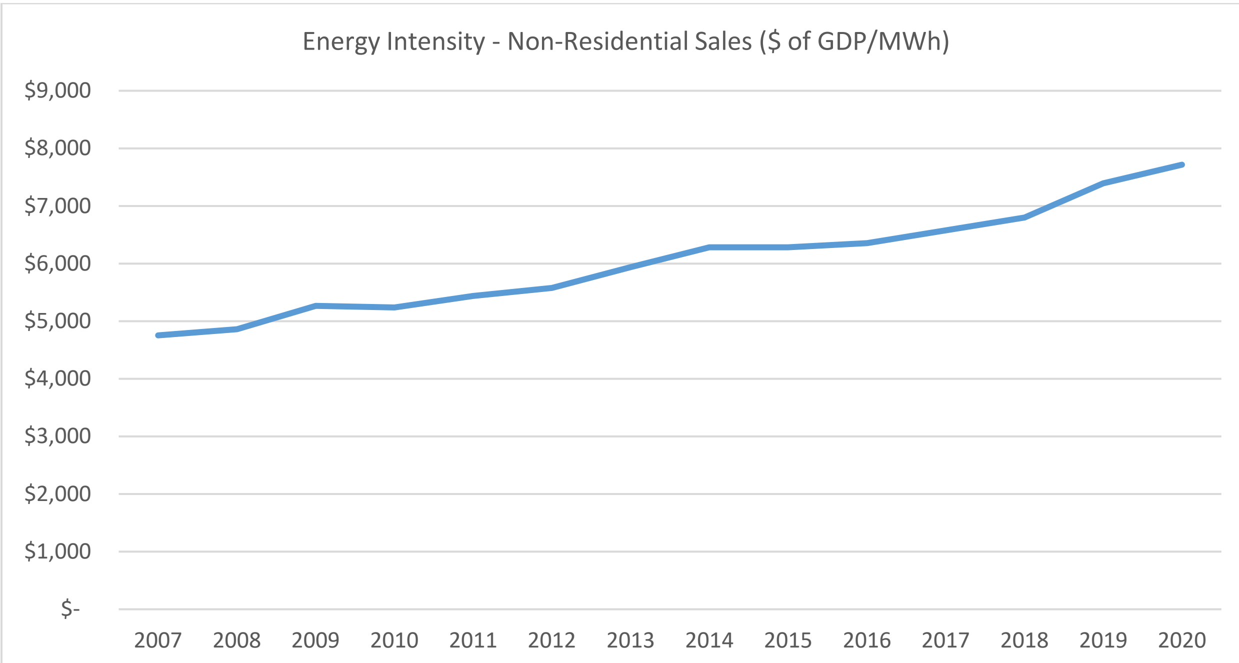


Figure E-2 Weather-Normalized Annual Use, per Residential Customer (kWh)

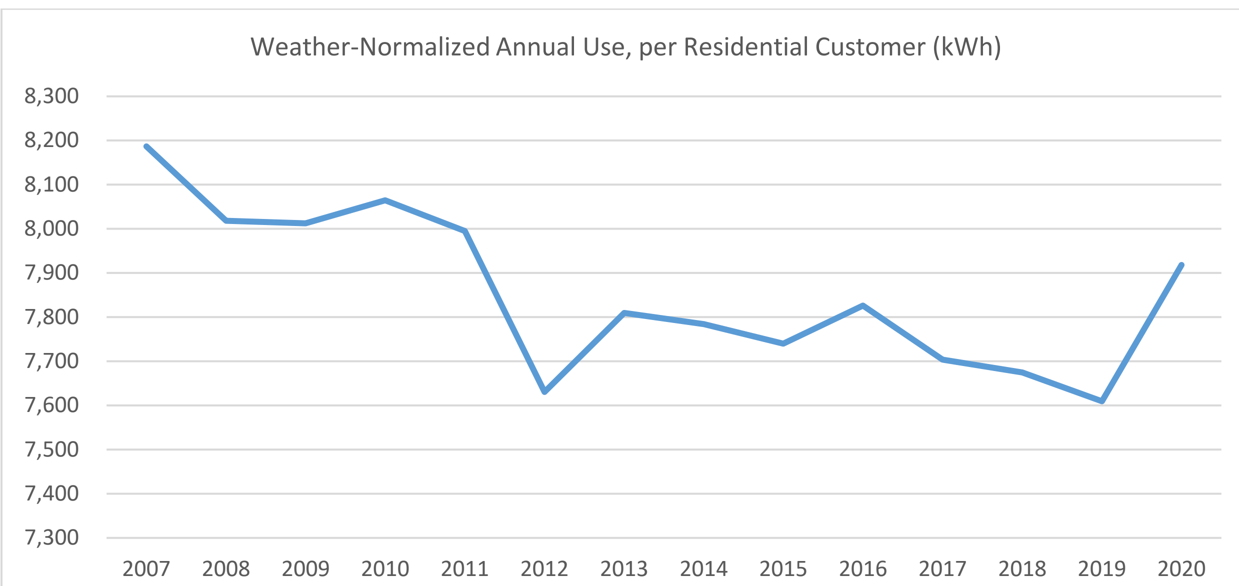


Table E-1 **Residential Average Rates in the Midwest and U.S. (cents/kWh)**

State	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Illinois	11.52	11.78	11.38	10.63	11.91	12.50	12.54	12.95	12.77	13.03	13.04
Indiana	9.56	10.06	10.53	10.99	11.46	11.57	11.79	12.29	12.26	12.58	12.83
Iowa	10.42	10.46	10.82	11.05	11.16	11.63	11.94	12.34	12.24	12.46	12.46
Michigan	12.46	13.27	14.13	14.59	14.46	14.42	15.22	15.40	15.45	15.74	16.26
Minnesota	10.59	10.96	11.35	11.81	12.01	12.12	12.67	13.04	13.14	13.04	13.17
Missouri	9.08	9.75	10.17	10.60	10.64	11.21	11.21	11.63	11.34	11.14	11.22
Ohio	11.32	11.42	11.76	12.01	12.50	12.80	12.47	12.63	12.56	12.38	12.29
Wisconsin	12.65	13.02	13.19	13.55	13.67	14.11	14.07	14.35	14.02	14.18	14.32
Midwest	10.95	11.34	11.67	11.90	12.23	12.55	12.74	13.08	12.97	13.07	13.20
U.S. Average	11.54	11.72	11.88	12.13	12.52	12.65	12.55	12.89	12.87	13.01	13.15

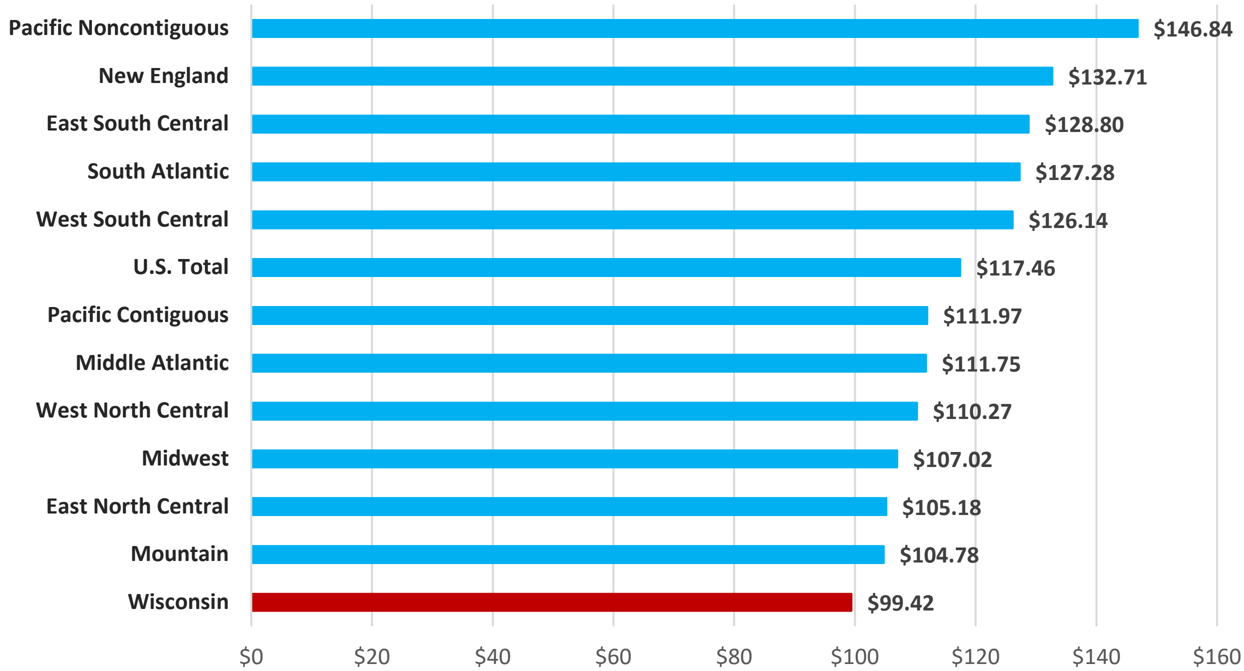
Table E-2 **Commercial Average Rates in the Midwest and U.S. (cents/kWh)**

State	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Illinois	8.88	8.64	7.99	8.14	9.26	9.02	9.02	9.09	9.12	9.08	9.15
Indiana	8.38	8.77	9.14	9.60	9.96	9.78	10.01	10.54	10.60	11.03	11.21
Iowa	7.91	7.85	8.01	8.44	8.67	8.92	9.17	9.46	9.68	9.99	9.96
Michigan	9.81	10.33	10.93	11.06	10.87	10.55	10.64	11.00	11.15	11.39	11.71
Minnesota	8.38	8.63	8.84	9.42	9.85	9.44	9.86	10.48	10.38	10.34	10.43
Missouri	7.50	8.04	8.20	8.80	8.90	9.16	9.26	9.47	9.40	9.07	8.93
Ohio	9.73	9.63	9.47	9.35	9.83	10.07	9.97	10.05	10.11	9.72	9.53
Wisconsin	9.98	10.42	10.51	10.74	10.77	10.89	10.77	10.87	10.67	10.72	10.75
Midwest	8.82	9.04	9.14	9.45	9.76	9.73	9.84	10.12	10.14	10.17	10.21
U.S. Average	10.19	10.24	10.09	10.26	10.74	10.64	10.43	10.66	10.67	10.68	10.59

Table E-3 **Industrial Average Rates in the Midwest and U.S. (cents/kWh)**

State	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Illinois	6.82	6.42	5.80	5.94	6.85	6.67	6.51	6.47	6.80	6.52	6.70
Indiana	5.87	6.17	6.34	6.70	6.97	6.86	6.97	7.54	7.38	7.36	6.98
Iowa	5.36	5.21	5.30	5.62	5.71	5.90	6.05	6.21	6.45	6.60	6.43
Michigan	7.08	7.32	7.62	7.72	7.68	7.02	6.91	7.19	7.10	7.07	7.24
Minnesota	6.29	6.47	6.54	6.98	6.72	7.02	7.37	7.37	7.53	7.53	7.67
Missouri	5.50	5.85	5.89	6.29	6.36	6.44	7.12	7.33	7.22	7.11	6.84
Ohio	6.40	6.12	6.24	6.22	6.77	7.02	6.98	6.92	7.01	6.55	6.16
Wisconsin	6.85	7.33	7.34	7.40	7.52	7.58	7.49	7.49	7.33	7.31	7.29
Midwest	6.27	6.36	6.38	6.61	6.82	6.81	6.93	7.07	7.10	7.01	6.91
U.S. Average	6.77	6.82	6.67	6.89	7.1	6.91	6.76	6.88	6.92	6.81	6.67

Figure E-3 **Average Monthly Residential Bills by Census Division (2020 EIA Data)**[123]



[123] U.S. Energy Information Administration. 2020 Average Monthly Bill – Residential. https://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf. Accessed March 20, 2022.

Figure E-4 **Distribution of Monthly Residential Electricity Bills for Municipal Utilities**[124]

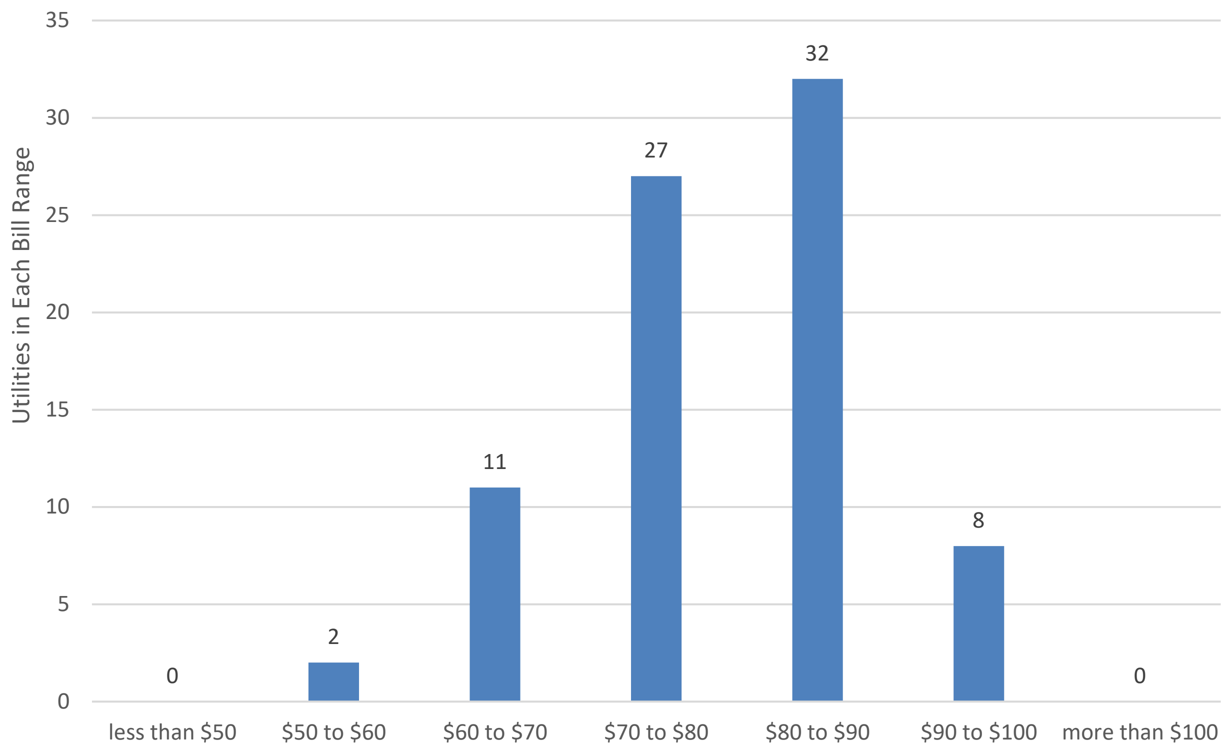
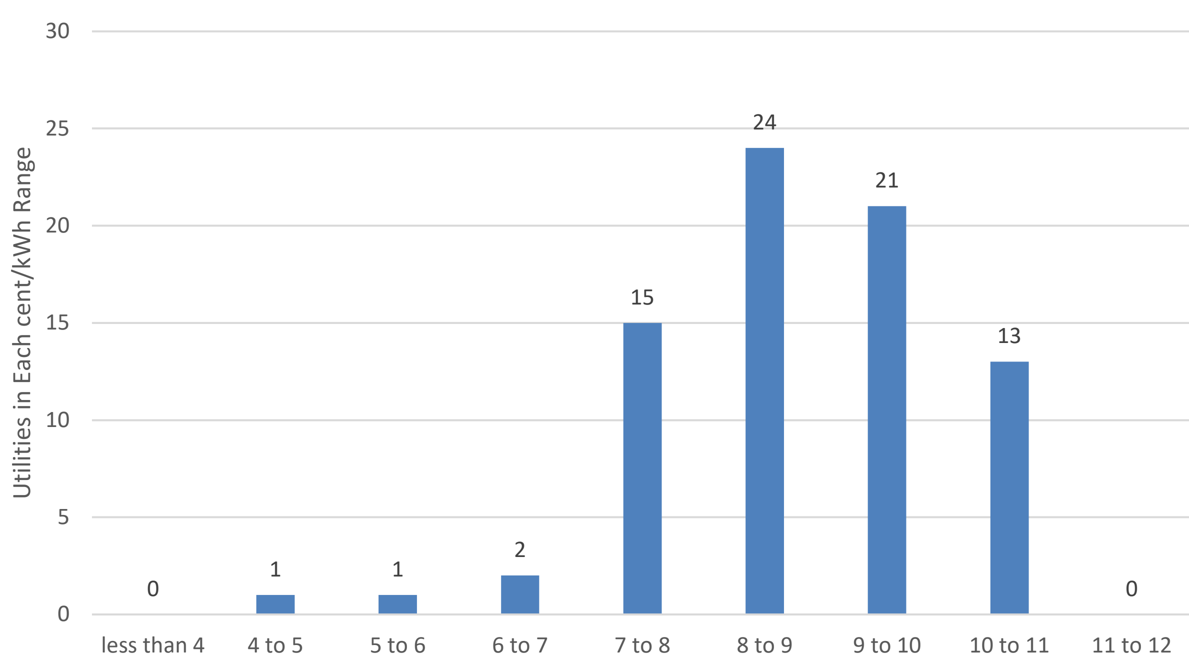


Figure E-5 **Distribution of Commercial (CP-1) Costs in cents/kWh for Municipal Utilities** [125]



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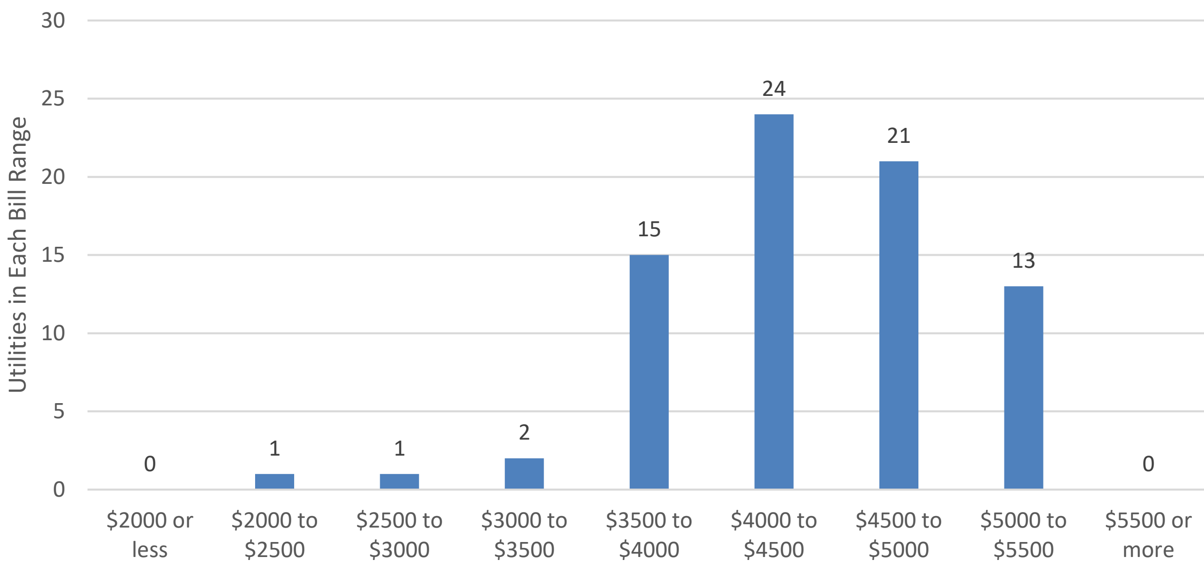
[124] Source: Major utility tariffs filed with the Commission, https://apps.psc.wi.gov/RATES/tariffs/default.aspx.

[125] Source: Major utility tariffs filed with the Commission, https://apps.psc.wi.gov/RATES/tariffs/default.aspx.

Figure E-6 **Distribution of Monthly Commercial (CP-1) Bills for Municipal Utilities**[126]



The monthly costs summarized in Figure C-5 and Figure C-6 are based on the following assumptions for commercial customers billed under the CP-1 tariff schedule:

- Monthly consumption of 50,000 kWh or 600,000 kWh/year (this represents an average load factor of 68.5 percent based on a peak load of 100 kW)
- Peak/Off-Peak split of 60 percent (peak) and 40 percent (off-peak)
- Monthly peak demand of 100 kW (typically CP-1 range is 50-200 kW)
- Municipal utilities with a CP-1 classification threshold below 50 kW are not included in the distribution plot shown in Figure C-6 (only one utility has a threshold below 100 kW and two others do not have a CP-1 schedule in their effective tariff).

Table E-4 **Estimated Monthly Bill Data for Municipal Utility Cp-1 Customers**

Summary	Total Cost (cents/kWh)*	Estimated Bill ($/month)*
Minimum	4.19	$2,095.00
25th Percentile	8.09	$4,045.00
Median	8.95	$4,475.00
Average	8.81	$4,403.25
75th Percentile	9.57	$4,785.00
Maximum	10.96	$5,480.00

** Note: The Total Cost (cents/kWh) is the sum of all bill components (monthly fixed charge, energy charge, distribution demand, and billable demand) divided by monthly energy use.*

[126] Source: Major utility tariffs filed with the Commission, https://apps.psc.wi.gov/RATES/tariffs/default.aspx.

ACRONYMS

§	Section
AC	Alternating current
AMI	Advanced metering infrastructure
AMP	Arrears management programs
AMR	Automated meter reading
APTIM	formerly Chicago Bridge and Iron
ATC	American Transmission Company LLC
BRP	Baseline Reliability Project
CAA	Clean Air Act
CAIAI	Customer Average Interruption Duration Index
Cadmus	Cadmus Group
CB&I	Chicago Bridge and Iron
CC&B	Customer Care and Billing System
CESER	Cybersecurity, Energy Security, and Emergency Response
ch.	Chapter
CIMCRC	Critical Infrastructure Microgrid and Community Resilience Center
CIS	Customer information systems
CME	Centuria Municipal Electric Utility
Commission	Public Service Commission of Wisconsin
CO_2	Carbon Dioxide
COSS	Cost-of-Service Study
CSAPR	Cross State Air Pollution Rule
DC	Direct current
DER	Distributed Energy Resources
DNR	Department of Natural Resources
DOA	Wisconsin Department of Administration
DOE	U.S. Department of Energy
DPA	Deferred Payment Agreements
DPC	Dairyland Power Cooperative
DRR	Demand response resources
EDR	Economic Development Rate
EDR	Emergency demand response
EIA	U.S. Energy Information Administration
ELG	Effluent Limitations Guideline
EPA	U.S. Environmental Protection Agency
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
Focus	Focus on Energy
fps	Feet per second
GIP	Generator Interconnection Project
GW	Gigawatt
Hz	Hertz

HILF	High impact, low frequency
ICAP	Installed Capacity
ICE	Improved Customer Experience
IEEE	Institute of Electric and Electronic Engineers
IGCC	Integrated Gasification Combined-Cycle
IMM	Independent market monitor
IOU	Investor-owned utility
IPL	Interstate Power and Light Company
IRP	Integrated Resource Planning
ITC	Investment Tax Credit
JOA	Joint Operating Agreement
kV	kilovolt
kW	Kilowatt
kWh	Kilowatt hour
KWWF	Keep Wisconsin Warm/Cool Fund
LICMARP	Low Income Case Management Arrearage Reduction Program
LIFT	Low Income Forgiveness Tool
LMP	Locational Marginal Pricing
LMR	Load Modifying Resources
LOLE	Loss of load expectations
LRTP	Long Term Transmission Planning
LRZ	Local Resource Zone
LSE	Load Serving Entity
LTRA	Long-Term Resource Assessment
MATS	Mercury and Air Toxics Standard
MEP	Market Efficiency Project
MGE	Madison Gas and Electric Company
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British thermal units
MTEP	MISO Transmission Expansion Plan
MTRC	Modified Total Resource Cost
MVP	Multi Value Project
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NEV	Neutral-to-earth voltage
NLMP	New Load Market Pricing
NO_X	Nitrogen oxides
NRC	Nuclear Regulatory Commission
NSPM	Northern States Power Company-Minnesota
NSPW	Northern States Power Company-Wisconsin
NWE	Northwestern Wisconsin Electric Company
OEI	Office of Energy Innovation
OMS	Organization of MISO States

PCAC	Power cost adjustment clause
PPA	Purchased power agreements
PRB	Power River Basin
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PTC	Production Tax Credit
PY	Planning Year
RAP	Regulatory Assistance Project
RER	Renewable Energy Rider
RIIA	Renewable Integration Impact Assessment
RLIP	Revised Low Income Program
ROW	Right-of-way
RPS	Renewable Portfolio Standard
RTMP	Real Time Market Pricing
RTO	Regional Transmission Organization
SAFER2	Statewide Assistance for Energy Resilience and Reliability
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCPC	Supercritical pulverized coal
SCR	Selective catalytic reduction
SEA	Strategic Energy Assessment
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
SWL&P	Superior Water, Light and Power Company
TCJA	Tax Cuts and Jobs Act
TMEP	Targeted Market Efficiency Projects
TOU	Time-of-Use
TRC	Total Resource Cost
TRM	Technical Reference Manual
UCAP	Unforced Capacity
VOC	Volatile organic compounds
WEC	Wisconsin Energy Corporation
WEM	Wisconsin Emergency Management
WEPCO	Wisconsin Electric Power Company
WERP	Wisconsin Emergency Response Plan
WG	Wisconsin Gas LLC
WHEAP	Wisconsin Home Energy Assistance Program
Wis. Admin. Code	Wisconsin Administrative Code
Wis. Stat.	Wisconsin Statutes
WP&L	Wisconsin Power and Light Company
WPPI	WPPI Energy
WPSC	Wisconsin Public Service Corporation
WRR	Wisconsin Refueling Readiness
Xcel	Xcel Energy, Inc.

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