PUBLIC SERVICE COMMISSION OF WISCONSIN

STRATEGIC ENERGY ASSESSMENT 2024-2030

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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 (i.e. resource adequacy);
- **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, in November 2023, 12 electric providers operating in Wisconsin[1] submitted to the Commission certain historical information through 2022—the full calendar year prior to submittal--and forecasted information from 2023 through 2030 on electric system operations.[2] 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 draft SEA 2030 was made available for public review and comment on June 27, 2024. Electric providers submitted updated information in August 2024. A public hearing was held on August 14, 2024, and the Commission approved the final SEA 2030 on November 7, 2024.

Electricity Generation in Wisconsin Today

Based on the data submitted to the Commission in November 2023 and updated in August 2024 through the SEA process, Wisconsin electric providers projected a decrease in peak electric demand of approximately 5 percent between 2023 and 2024 and an increase in demand of 14.8 percent from thereafter through 2030. The addition of new and expanding customer loads, such as a data center and transportation electrification, are placing upward pressure on Wisconsin's energy demands within this timeframe.

Wisconsin electric providers plan to provide electric generation capacity sufficient to meet projected customer demand, plus an additional reserve margin to ensure supplies are adequate if actual demand exceeds projections. Wisconsin providers' total aggregated capacity exceeds reserve requirements in both 2024 and 2025 and are expected to exceed the MISO seasonal requirements each season for both of those years.

Wisconsin electric providers seek to provide reliable electric supply by limiting both the frequency and duration of service outages. In 2022, the average customer of the state's five largest utilities experienced less than one outage per year, with an average duration of approximately 3 hours and 34 minutes.

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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 Wis. Admin. Code ch. PSC 111.

While coal made up the largest share of electricity generation in Wisconsin, the proportion of energy produced by coal decreased from approximately 54 percent in 2015 to 31 percent in 2023. Natural gas resources increased in generation share from 19 percent in 2015 to 36 percent in 2023 and wind resources increased from 6 percent in 2015 to 11 percent in 2023. Solar generation accounted for less than 0.1 percent of the generation mix in 2015 and increased to 2 percent in 2023.

Reduction of carbon dioxide (CO_2) emissions remains a 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 providers by 2050. Wisconsin electric providers reported CO_2 emission reductions of 41 percent in 2022 compared to the 2005 emission 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 2,700 MW of in-state generation by 2030. These planned retirements include two of the seven utility-scale coal facilities operating in Wisconsin as of 2024, Columbia and Oak Creek, which have a combined capacity of nearly 2400 MW. In June 2022, providers announced that they would delay previously reported retirement dates at both plants, due to concerns about maintaining resource adequacy in upcoming years associated with delays in construction of generation additions. Under these updated plans, full retirement of both plants may occur by 2026, with the Oak Creek units proposed to be replaced by natural gas fired combustion turbines in a docket currently under consideration by the Commission.

Wisconsin electric providers reported plans to add approximately 4,200 MW of new solar energy capacity, 2,500 MW of new natural gas capacity, and nearly 1,200 MW of new wind capacity by 2030. In addition, providers reported plans for approximately 900 MW of new energy storage capacity, most of which is paired with announced solar facilities. Providers also reported plans for ownership transfer of approximately 125 MW of existing natural gas capacity within the state.

If all additions and retirements are implemented as planned, coal will decline from 31 percent of Wisconsin generation in 2023 to 16 percent in 2030, natural gas will increase from 36 percent to 42 percent, wind will increase from 11 percent to 14 percent, and solar resource will increase from 2 percent to 12 percent. As planned, total CO_2 emissions will reach an 80 percent reduction in 2030 from 2005 baseline levels.

Utility regulatory agencies in over 35 states use Integrated Resource Planning (IRP) or other long-term planning processes to review providers' generation plans, and in some cases to exercise regulatory authority over final addition and retirement decisions. Wisconsin does not have an IRP requirement and does not approve retirement decisions, although it may review costs associated with retiring generators. The Commission's *Roadmap to Zero Carbon Investigation*, docket 5-EI-158, identified a need for more comprehensive utility resource decisions and greater transparency in the utility resource planning processes. IRP processes are typically established though legislative authorizations, which has not taken place in Wisconsin. 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 consideration.

Electric providers confirmed their own internal resource planning incorporated the four goals of adequacy, reliability, affordability, and environmental responsibility. Multiple providers also identified that their goals included maintaining a diverse set 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 resiliency. Providers affirmed that their announced additions and retirements were informed by modeling results assessed against those goals, stating that retirement of coal facilities and additional solar, wind, natural gas, and energy storage facilities were identified as the changes that supported emissions reduction, reliability and resiliency while limiting costs.

Commission staff conducted independent capacity expansion modeling under future scenarios that set different values for CO_2 emission reductions and growth in electric demand. In scenarios that assumed limited CO_2 emission reductions, the capacity expansion model predominantly selected natural gas resources to meet the needs identified by upcoming retirements and long-term load growth, due to the model's view of the reliability and resource adequacy advantages of natural gas. The model selected a larger share of renewable resources when using increased natural gas prices, however, it 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 emission reductions, at levels more closely consistent with the providers' emission reduction goals, the capacity expansion models selected a reduced share of natural gas resources and a larger share of renewable resources, including solar, battery storage, and wind. Additionally, for the more aggressive decarbonization scenario, modeling also identified the need for "flex" resources. "Flex" resources have the dispatchability of reciprocating internal combustion engine (RICE) units but have high fuel costs and zero carbon emissions. Equivalent technology could include reserved battery storage, traditional RICE units coupled with carbon capture and sequestration, RICE units powered by hydrogen and any combination of the previously mentioned technologies.

These planning considerations and cost assumptions may evolve over time if cost profiles for existing resources change, or if future technological developments such as long-duration energy storage 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 2021 and 2022 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 Focus programs showed a record high level of customer satisfaction. A 2021 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.[3] 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. A new study providing up-to-date analysis on Wisconsin's energy savings potential is currently in progress.

[3] 2021 Focus on Energy Efficiency Potential Study Report, Cadmus. Potential_Study_Report-FoE_Efficiency-2021.pdf

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 through 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 Midcontinent Independent System Operator, Inc. (MISO), the regional grid operator, calls upon them to reduce load, such as during Winter Storms Elliot and Uri.

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 emission reduction goals have driven increased renewable energy deployment above RPS requirements since 2013. 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 17,800 customer-owned renewable generation installations operating in 2023, with almost 300 MW capacity that equated to nearly 2 percent of total statewide electric capacity. Customer-owned solar, specifically, equated to nearly 1 percent of total statewide capacity in 2023. Customer-owned solar installations increased approximately 40 percent between 2021 and 2023. The Commission is reviewing the purchase rates and net metering framework associated with customer-owned generating systems in docket 5-EI-157, *Investigation of Parallel Generation Purchase Rates*, and updated the interconnection standards used to connect facilities to the electric grid in May 2024.[4]

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 in docket 5-EI-156, *Investigation of Electric Vehicle Policy and Regulation*, 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.[5] 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 electric providers and transmission owners participate in MISO's regional transmission system, which is an integrated electric grid across 15 states that supports long-distance transmission of electricity. Participating in MISO allows Wisconsin to access low-cost energy resources located in nearby states through wholesale electricity markets and affords an opportunity

[4] *See* Ch. PSC 119, Wis. Adm. Code.
[5] Order in Docket 5-EI-156

to access additional resources that providers may use to maintain adequate electric supply and increases reliability of electric service by pooling risk over a broader geographic footprint.

Due to increased transmission line development and construction costs, transmission expenses have significantly increased since 2005 and accounted for an increasing portion of electric providers' total operating expenses and customer bills. 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. Future transmission additions are expected to facilitate the delivery of low-cost and renewable energy resources.

MISO presented a complete analysis of the initial tranche of Long-Range Transmission Planning (LRTP) projects in April 2022, which were approved by the MISO Board in July 2022. Projects approved by the MISO Board 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 are required to receive Commission approval under state law prior to any construction occurring in the state.[6] The transmission line review process involves rigorous reporting and analysis, as well as opportunities for public participation. MISO is currently in the process of planning a second tranche of large-scale transmission project through LRTP process.

Resilience and Cybersecurity

Nationwide, electric providers and 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 plans to address energy-related challenges during emergency events. To expand its collaborative efforts on resilience, the Commission awarded financial assistance through its Critical Infrastructure Microgrid and Community Resilience Center grant program in docket 9705-FG-2020, to support innovative pre-disaster mitigation through microgrids and deployment of distributed energy resources. In June 2024, the Commission awarded $8.5 million from the Grid Resilience Program to enhance electric grid reliability in docket 9713-FG-2022.

Nationwide there is increased focus regarding the specific resilience threats associated with cyber security attacks. Commission staff have participated in cyber security 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

One of the Commission's key responsibilities as the utility regulator is to set rates so that customers receive reliable power at the lowest cost under applicable law, thus supporting affordable electric supply. In this process, the Commission also grants utilities a fair opportunity for recovery of and reasonable return on prudent investments. Total revenue requirements for Wisconsin's largest electric providers increased 1.01 percent per year between 2013 and 2022, driven primarily by

[6] Wis. Stat. § 196.491.

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 rates on average than the Midwest or national averages, but pay 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.

Bill Affordability

Low- and moderate-income residential customers often face challenges paying their utility bills, due to a higher energy burden, in which they must pay a larger percentage of their total income for service as compared to higher-income customers. The Commission has increased its efforts to assess energy burden, review affordability programs, 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 energy 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 the approach to measuring energy burden and ways to incorporate this information into Commission proceedings. The Commission opened investigation dockets[7] into ways to improve affordability for customers for four of Wisconsin's Investor-Owned Utilities (IOUs) and is working with utilities and stakeholders on exploring options to reduce energy burden for those most impacted.

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.[8] 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.[9] 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, the IRA Home Energy Rebate (HER) programs, and other programs.

[7] Dockets 5-UI-121, 6690-UI-101, 6680-UI-100 and 3270-UI-101
[8] See Wis. Admin. Code §§ PSC 113.0404, PSC 134.063.
[9] See Wis. Admin. Code §§ PSC 113.0505, PSC 134.13(5).

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 (i.e. resource adequacy);[10]
- **Reliable** electric supply that provides all customers access to electricity at all times, avoiding outages whenever possible;[11]
- **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 an ongoing generation transition that began in the 2010s. Providers have increased use of natural gas, wind, and solar generation and decreased 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 throughout the 2020s, as described in Chapter 2.

Defining Supply Needs

To ensure adequate electric supply, Wisconsin electric providers must procure enough total power to be able to meet forecasted seasonal peak demand, which is the highest level of electric demand that could occur at any point during a given year, plus a percent reserve margin. Prior to MISO's shift to a seasonal construct in fall 2022, which is further described below, providers were only required to procure enough total power to be able to meet an annual peak demand, which typically occurred in the summer. Regardless of the shift to a seasonal construct, an analysis of historical and annual peak demand provides general information on annual trends in customer demand.

As shown in Figure 1-1, annual peak demand in Wisconsin has varied between 13,000 and 15,500 megawatts (MW) since 2005 and, more recently, between 13,500 and 15,000 MW since 2018. Multiple factors influence year-by-year differences, including weather, economic conditions, and the addition and subtraction of significant customer loads.

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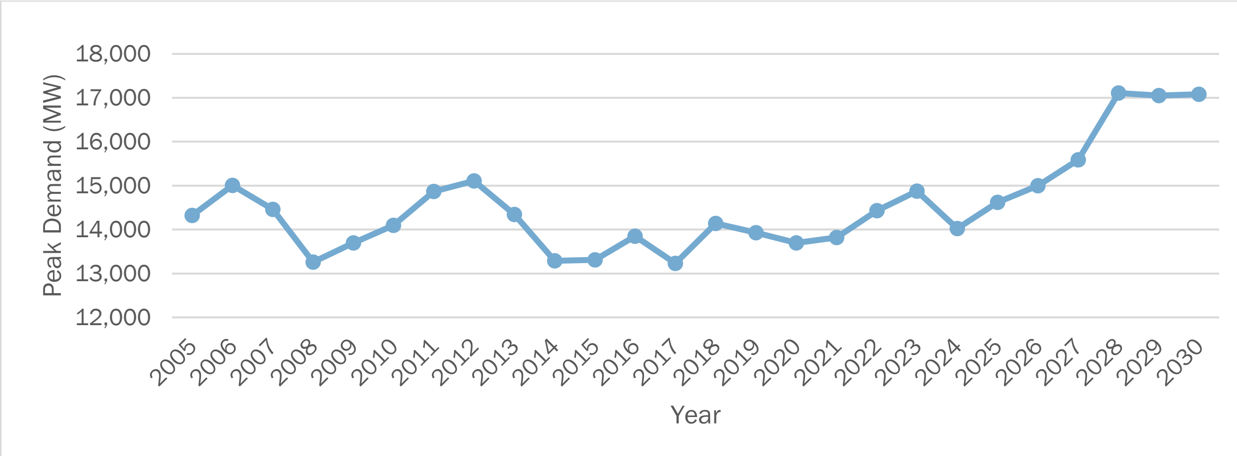
[10] Variations of this definition exist. The National Association of Regulatory Utility Commissioners define resource adequacy as a "measure of whether there are sufficient electric resources available to serve customer demand." pubs.naruc.org/pub/0CC6285D-A813-1819-5337-BC750CD704E3. MISO more specifically defines resource adequacy as the "ability of the bulk electric system to serve electricity demand while also providing enough excess supply to achieve a threshold level of grid reliability." MISO Draft Resource Accreditation Design White Paper628865.pdf (misoenergy.org).

[11] MISO's current Loss of Load Expectation is one-day loss of load in 10 years (0.1 day/year), which is not necessarily equal to 24 hours loss of load in 10 years (2.4 hours/year).

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



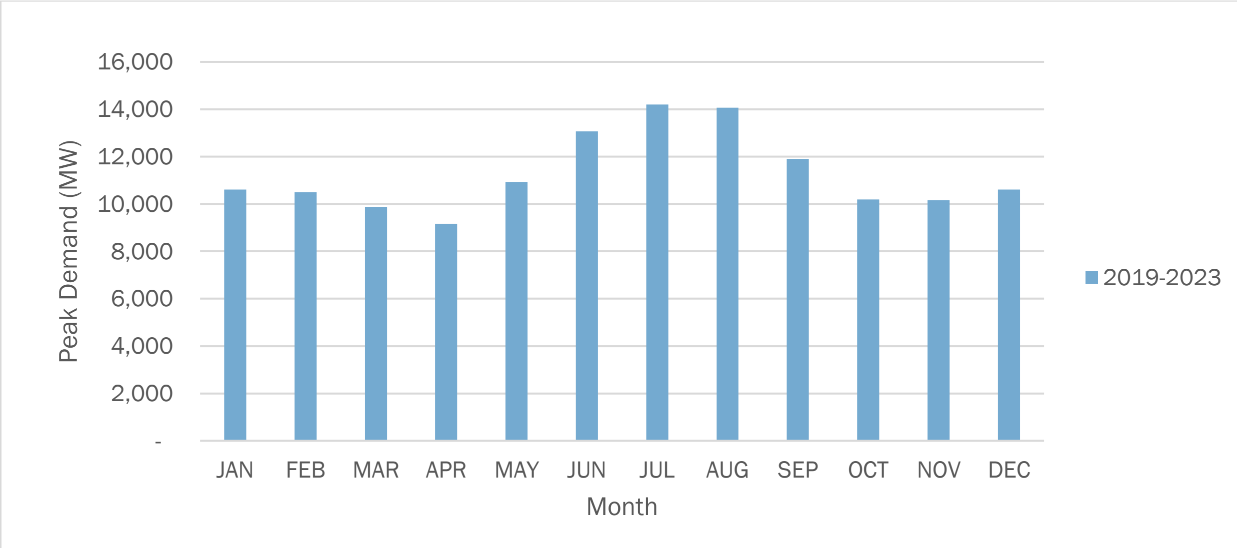
As shown in Table 1-1, providers reported a 4.43 percent increase in peak demand from 2021 to 2022 and a slightly smaller increase of 3.09 percent between 2022 and 2023. Annual forecasted demand submitted by electric providers in November 2023 and updated in August 2024 in response to SEA data requests demonstrates that electric demand is projected to increase in most future years from 2024 through 2028, before leveling off again in 2029 and 2030. The exception is for 2023 to 2024, where an approximate 5.73 percent decrease is forecasted. (More detailed projections can be found in Appendix A, Table A-1.) Multiple provisions of the IRA, including renewable energy tax credits and incentives for electric vehicles and electric appliances, may continue to influence projections of customer electric demand provided in future SEAs. Additionally, new and expanding customer loads, such as a data center and transportation electrification are placing upward pressure on Wisconsin's energy demands within this timeframe.

Table 1-1 Utility Reported Expected Maximum Annual Peak Demand, with Percent Change from Previous Year

Year	Maximum Annual Peak Demand (MW)	Percent Change From Previous Year (%)
2021	13,817	
2022	14,429	4.43%
2023	14,875	3.09%
2024	14,023	-5.73%
2025	14,621	4.26%
2026	14,996	2.57%
2027	15,590	3.96%
2028	17,108	9.74%
2029	17,053	-0.32%
2030	17,082	0.17%

As shown in Figure 1-2, peak demand for the years 2019 to 2023 occurred in the summer months of July and August, influenced largely by air conditioner use. Smaller peaks occurred in the winter, in part due to higher heating loads, fewer daylight hours and the use of holiday lighting.

Figure 1-2 Average NON-COINCIDENT Peak Demand per Month, 2019-2023



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 resources over and above projected peak levels to reduce the risk of inadequate supply if actual demand exceeds projections. This is known as a reserve margin.

Wisconsin electric providers generate and purchase energy supplies within the regional context of the MISO, which operates an integrated electric grid across Wisconsin and several other states. (See *Sources of Electricity* and the Transmission chapter for more information on MISO.) Wisconsin electric providers assess capacity supplies relative to MISO's Planning Reserve Margin (PRM), 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.[12] MISO calculates the PRM based on seasonal accredited capacity (SAC), which considers the total energy available from generation sources each season as well as the likelihood that conditions at any given time may include unit outages and other limitations on actual operating capacity. The SAC method also involves limits for generation resources that may exist during certain seasons and is one method by which MISO seeks to ensure the reliability of the bulk electric system. As this SAC method is new since the last publication of the SEA, MISO, state regulators, and electric providers are still acquiring a full understanding of the implications of the new method.

MISO's PRM under the new seasonal construct method is tabulated in Table 1-2 for years 2024 and 2025. Wisconsin providers' total aggregated capacity exceeds reserve requirements in both 2024 and 2025 and are expected to exceed the MISO seasonal requirements each season for both of those years. (More detailed reserve margin calculations, including projections for future years, can be found in Appendix A, Table A-2.) MISO's March 2023 planning resource auction confirmed that

[12] 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.

each Wisconsin electric provider would maintain sufficient capacity resources for all seasons in 2024 and 2025.[13] These resources are supported by established arrangements for providers to import capacity if needed to address shortfalls below MISO's PRM threshold.

Table 1-2 Wisconsin Aggregated Supply and Demand, MW

Year[14]	Season	2024	2025
Net Capacity[15]	Summer	16,574	17,569
Expected Demand[16]	Summer	13,984	13,986
WI Utilities' Planning Reserve Margin (PRMR) (MW)	Summer	15,163	15,234
Resources above PRMR (MW)	Summer	1,412	2,336
MISO Planning Reserve Margin (%) (UCAP)	Summer	9.0%	9.2%
Net Capacity	Fall	16,592	17,102
Expected Demand	Fall	11,721	11,792
WI Utilities' Planning Reserve Margin (PRMR) (MW)	Fall	13,529	13,629
Resources above PRMR (MW)	Fall	3,063	3,473
MISO Planning Reserve Margin (%) (UCAP)	Fall	14.2%	14.8%
Net Capacity	Winter	16,200	16,096
Expected Demand	Winter	10,260	10,671
WI Utilities' Planning Reserve Margin (PRMR) (MW)	Winter	13,095	13,523
Resources above PRMR (MW)	Winter	3,105	2,574
MISO Planning Reserve Margin (%) (UCAP)	Winter	27.4%	27.2%
Net Capacity	Spring	15,776	16,468
Expected Demand	Spring	10,770	10,774
WI Utilities' Planning Reserve Margin (PRMR) (MW)	Spring	13,518	13,549
Resources above PRMR (MW)	Spring	2,258	2,915
MISO Planning Reserve Margin (%) (UCAP)	Spring	26.7%	28.7%

Electric providers have stated their own internal resource planning seeks to meet minimum adequacy requirements, while avoiding building excess capacity that could increase costs to ratepayers. Historically, Wisconsin's energy supply has substantially exceeded reserve margin requirements, as shown in Table 1-3. The values in Table 1-3 represent the summer season's PRM and the summer of 2024 was added as a comparison—despite the move to the seasonal construct and SAC--since Wisconsin is still, overall, a summer peaking state.[17] Higher reserve margin values

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[13] Commission staff reviewed the results of the March 2023 MISO planning resource auction in docket 5-EI-2023.
[14] MISO Planning Years run from June 1 to May 31. Listed years represent the second calendar year in the planning year (i.e.,2024 is June 1, 2023-May 31, 2024).
[15] 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.
[16] Defined by MISO as coincident Load Serving Entity (LSE) peak to MISO peak gross of demand response net FullResponsibility Transaction (FRT).
[17] Due to the move to a SAC, yearly comparisons are no longer applicable; this table will be moved to the Appendix in future SEAs.

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. Low demand growth has continued; however, sources of supply have also started to decline due to recent retirements of generation facilities. This decline in traditional fossil fuel fired resources has been partially offset by an increase of non-dispatchable, renewable energy generation resources. (Chapter 2 outlines providers' announced future generation retirements and additions and assesses the project 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 2024

Planning Year	Final SEA 2014	Final SEA 2016	Final SEA 2018	Final SEA 2020	Final SEA 2022	Final SEA 2024*
2014	20.5					
2015	18.9					
2016	17.3	16.9				
2017	15.3	13.9				
2018	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	8.7	
2023			7.8	9.3	8.3	
2024			6.4	7.9	7.8	8.4

* The historic values in Table 1-3 represent the summer season's PRM and the summer of 2024 was added as a comparison—despite the move to the SAC--since Wisconsin is still, overall, a summer peaking state

Reliability

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

- **System Average Interruption Duration Index** (SAIDI), which identified the average number of total minutes a customer experiences electric outages during a year,[18]
- **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,[19] and
- **System Average Interruption Frequency Index** (SAIFI), which identifies the average number of outages a customer experiences during a year.[20]

The use of multiple metrics reflects that electric providers aim to limit both the frequency and duration of service outages. A provider experiencing many short outages in a year would have a high

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[18] SAIDI equals the annual sum of customer-minutes of interruption divided by the average number of customers servedduring the year.
[19] CAIDI equals the annual sum of customer-minutes of interruption divided by the annual number of customer interruptions.
[20] SAIFI equals the annual number of customer interruptions divided by the average number of customers served duringthe year.

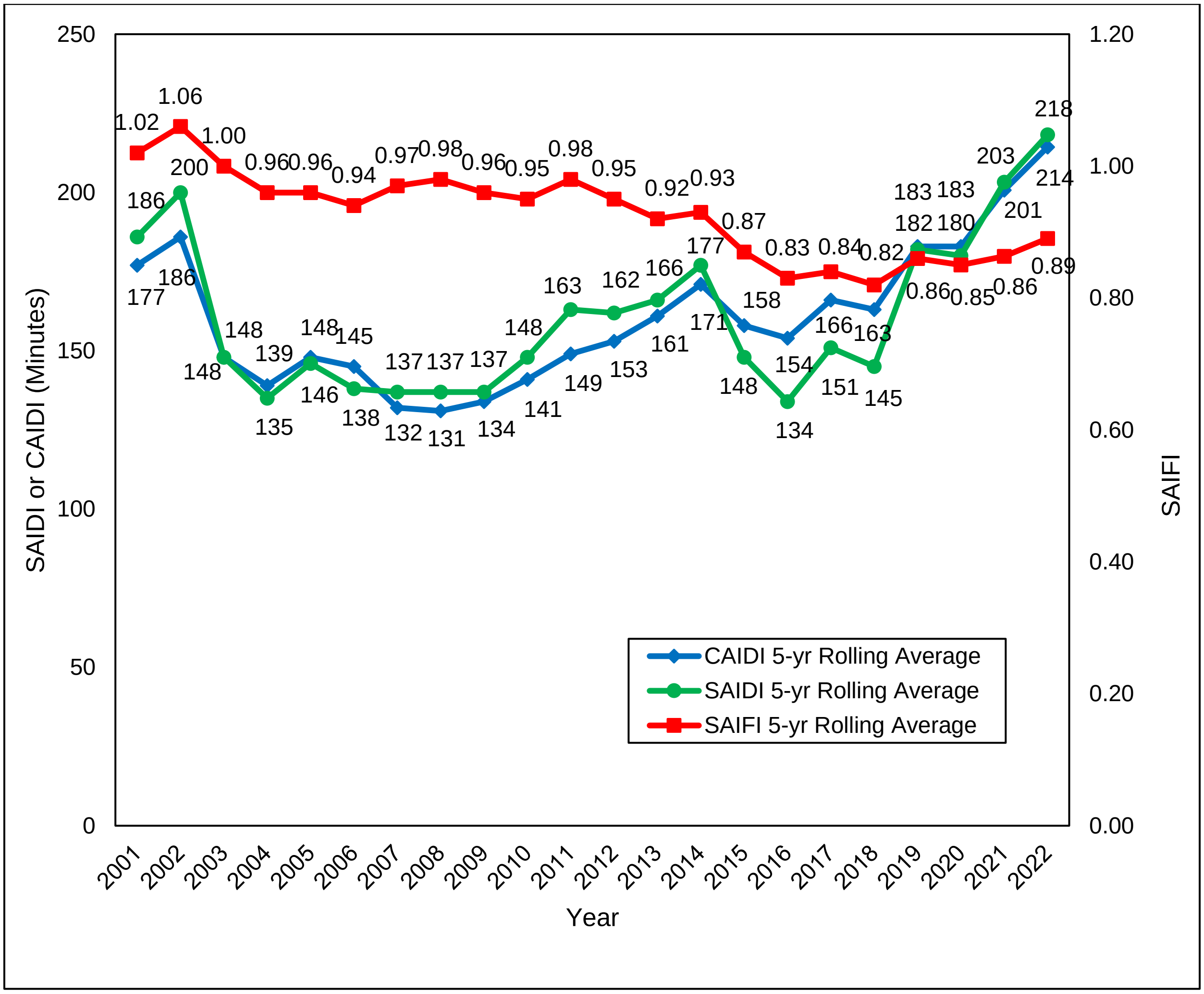
SAIFI value, but low SAIDI and CAIDI values. By contrast, a provider with few outages that take a long average time to restore would have high SAIDI and CAIDI values, but a low SAIFI value.

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 CAIDI since 2001 for the five largest IOUs subject to the reporting requirement. In 2022, the average customer of the five largest IOUs experienced less than one outage per year (SAIFI = 0.89), with an average duration per outage of three hours and 34 minutes (CAIDI = 214 minutes). The average frequency of outages has gradually declined over the past two decades, while the average outage duration has increased.

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.[21] Historically, these reports have indicated fallen branches and trees and equipment failures accounted for the largest share of outages. Providers have reported taking 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.[22]

[21] Wis. Admin. Code § PSC 113.0606. *See* dockets 5-GF-113 and 5-GF-2024.
[22] Responses to Data Request-PSC-Taylor-1, docket 5-GF-113.

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



Sources of Energy Supply

Wisconsin electric providers can meet their planning reserve (capacity) requirements by either owning and 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.[23]

Figure 1-4 depicts Wisconsin electric providers' in-state operating resources as of December 2022, including all owned generation facilities and large-scale merchant plants.[24] (For additional maps broken out by fuel type, see Appendix A, Figures A-1 through A-8.) While this map reflects most Wisconsin-providers owned and merchant resources, providers do also own or contract with

[23] 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 theprimary platforms for providers to meet supply needs, MISO also operates transmission rights and ancillary services markets to support grid operations.

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

generation facilities in other nearby states. For examples, providers received electricity supplies from several wind facilities in MISO region states west of Wisconsin, where windier conditions often support cost-effective production.

Figure 1-4 Electric Providers' Generation Resources in Wisconsin – December 2022

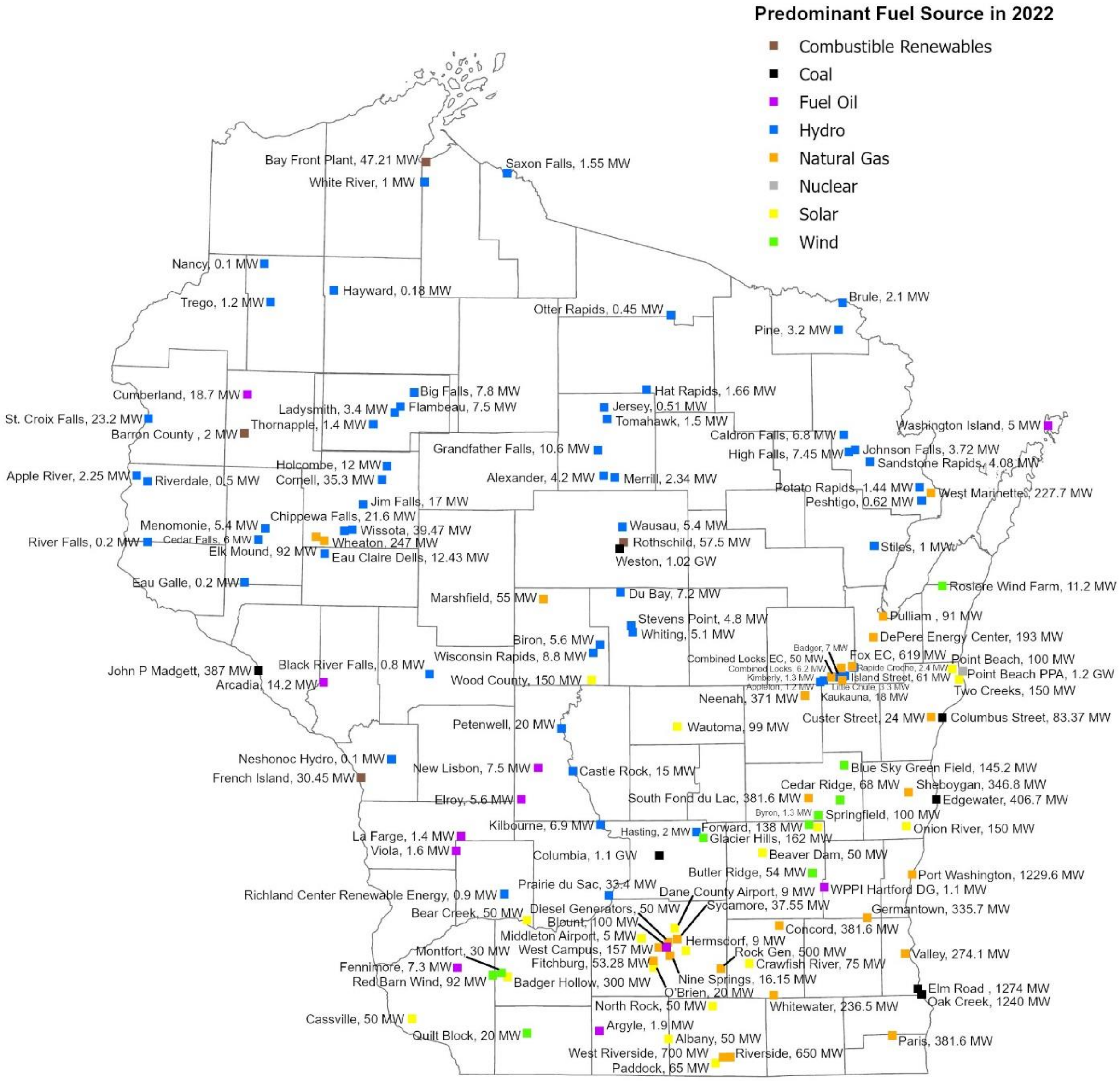
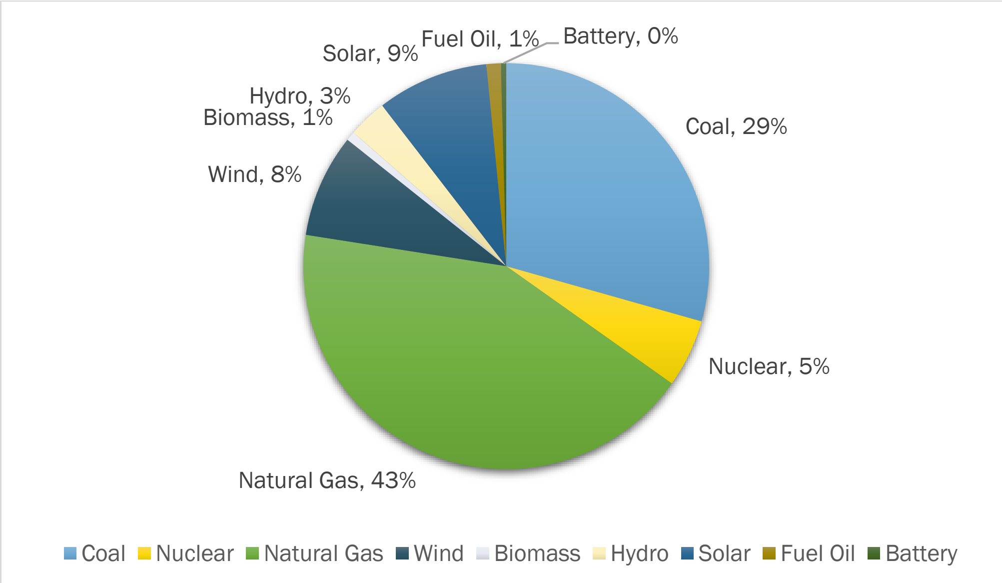


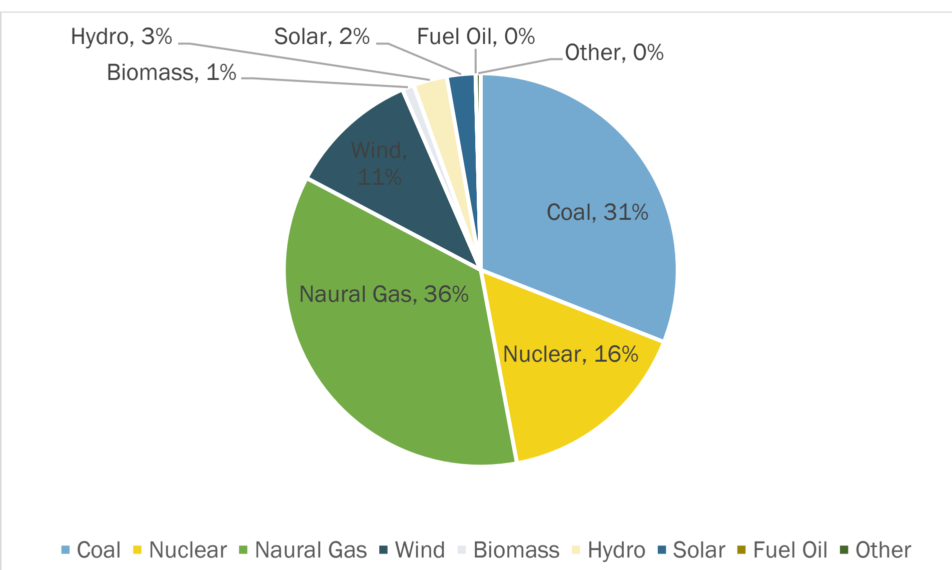
Figure 1-5 breaks down the total capacity of Wisconsin provider-owned generation and merchant plants by generation source, as of December 2023. Natural gas accounted for the largest share of total generation capacity at 43 percent, followed by coal at 29 percent. Zero-carbon energy sources accounted for approximately 25 percent of capacity; 9 percent from solar energy, 8 percent from wind energy, 5 percent from nuclear energy, and 3 percent from hydropower.

Figure 1-5 Wisconsin Electric Provider Capacity by Resource – December 2023



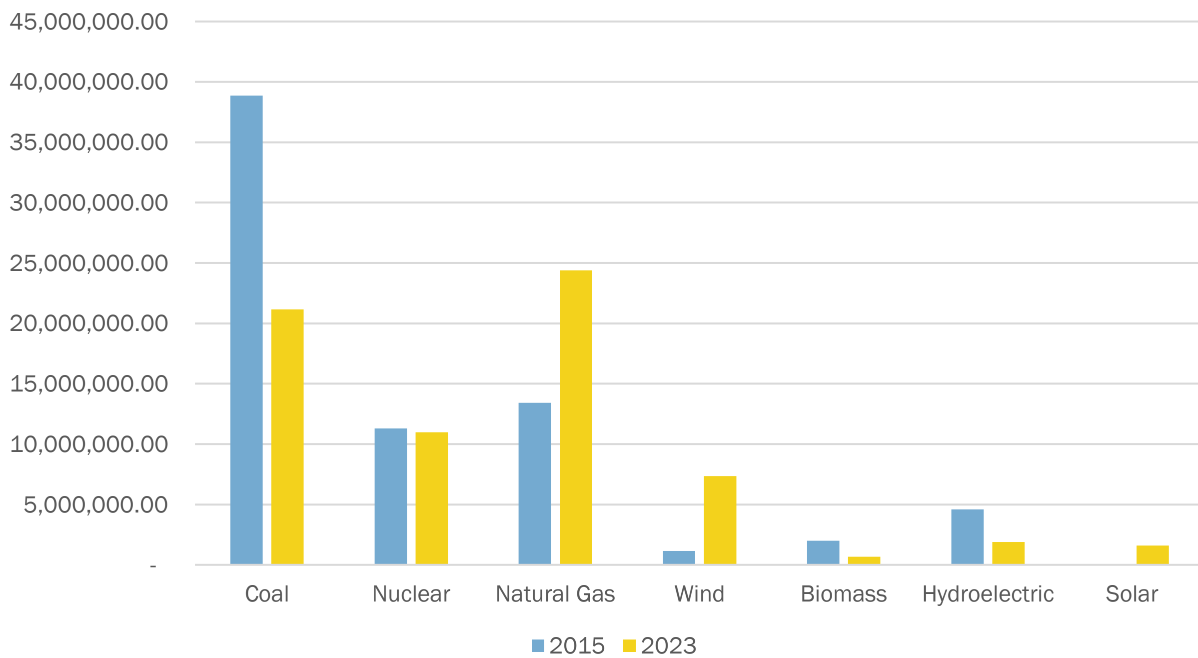
While Figure 1-5 depicts a resource type's share of total max capacity, Figure 1-6 depicts each resource type's total actual provider-owned energy generation during calendar year 2023. Different facilities operate with different "capacity factors," which are calculated based on the amount of total capacity used for energy production and the percentage of time during the year during which they operate. Coal and nuclear energy facilities typically operate on a consistent, ongoing basis; in 2023, coal facilities were near their share of energy generation at 31 percent, while nuclear energy facilities exceeded their share of energy generation with 16 percent of energy generation. Solar sources accounted for a smaller share of energy generation than capacity, due to comparatively lower average capacity factors.

Figure 1-6 Wisconsin Electric Provider Energy Generation by Resource – 2023



While coal still represents the most common source of electricity generation in Wisconsin during 2023, its share of total load has decreased in recent years. As shown in Figure 1-7, the energy produced from coal declined from approximately 38 million MWh 2015 to about 21 million MWh in 2023. Natural gas resources account for the largest corresponding increase in generation share, from about 13 million MWh in 2015 to 24 million in 2023. Wind resources also increased from about 1 million MWh to more than 7 million MWh. Solar generation accounted for nearly 2 million MWh of generation in 2023 after accounting for less than 1 million MWh in 2015.

Figure 1-7 Comparison of 2015 and 2023 Wisconsin Electric Provider Generation by Resource



Emissions

Reduction of 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 Evers issues Wisconsin Executive Order 38 in 2019, directing 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.

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 Energy, Inc.)	80%	100%
Madison Gas and Electric Company[25]	80%	100%
Wisconsin Electric Power Company (We Energies)	80%	100%
Wisconsin Power and Light Company (Alliant)	50%	100%
Wisconsin Public Service Corporation	80%	100%

Other electric providers have also announced their intent to reduce CO_2 emissions. For example, WPPI Energy (WPPI) has reported that it is targeting 100 percent CO_2 reduction by 2050 subject to its ability to maintain reliability and affordability. Dairyland Power Cooperative (DPC) has set a goal to achieve a 50 percent reduction by 2030 in its CO_2 intensity rate.[26, 27]

As it did for the SEA 2028, the Commission collected from all electric providers information on their progress achieving CO_2 reductions, compared to the 2005 emission levels commonly used as a baseline for calculating percentage reductions.[28] As shown in Table 1-5, reported emission reductions in 2023 ranged from 36-89 percent relative to 2005 emission levels. As outlined in individual providers' responses, methods for calculation emission reductions differ. For example, WP&L's goal applies to reductions from its owned generation, while Northern State 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.

[25] 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.
[26] The CO_2 intensity rate measures the amount of emissions per unit of energy generated (lbs. CO_2/MWh produced).
[27] 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 facilities.
[28] On July 8, 2024, Commission staff requested that utilities update all schedules to reflect actuals through December 2023. (PSC REF#: 507610.) MPU and WPL did not submit updated actual 2023 emissions data.

Table 1-5 Carbon Dioxide Reduction for 2022 and 2023 (% Compared to 2005 Carbon Dioxide Emissions)

Providers	2005 CO_2 Emissions (Million tons)	2022 CO_2 Emissions (Million tons)	2022 CO_2 Reduction (%)	2023 CO_2 Emissions (Million tons)	2023 CO_2 Reduction (%)	2030 CO_2 Reduction Goal (%)
Northen States Power Company-Wisconsin (Xcel Energy)	4.1	0.51	87.56%	0.45	89.0%	80%
Wisconsin Electric Power Company (WEPCO)	23.8	13.59	42.88%	14.59	38.7%	80%
Wisconsin Public Service Corporation	11.9	6.78	43.03%	6.18	48.1%	80%
WPPI	4.3	1.18	72.66%	1.19	72.2%	N/A
Wisconsin Power and Light Company (Alliant)	8.8	7.97	9.42%	-	-	50%
Madison Gas and Electric Company	3.4	1.68	50.66%	1.80	47.2%	80%
Dairyland Power Cooperative	4.4	3.80	13.66%	2.83	35.6%	N/A
Manitowoc Public Utilities	0.42	0.35	16%	-	-	N/A
All Providers	61.12	35.86	41.33%			

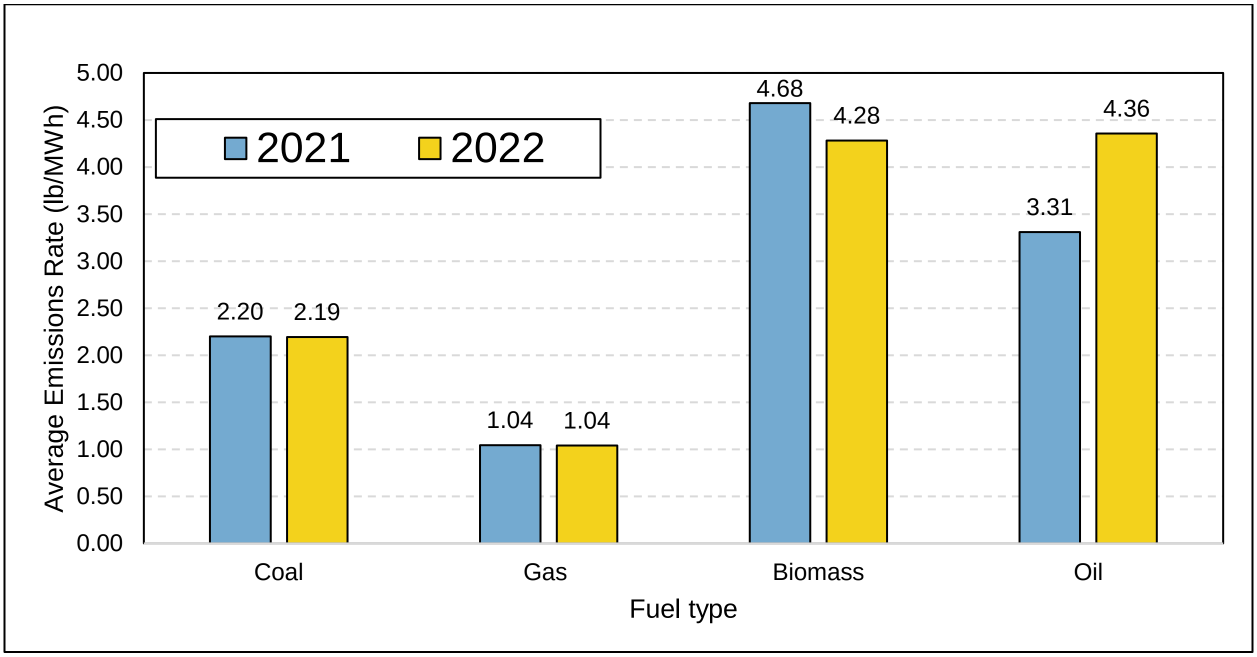
To provide further detail on emissions, electric providers submitted information on the CO_2 emissions for each generation facility owned by Wisconsin providers during 2021 and 2022. Total emissions of provider-owned facilities provided through this request did not match the total emissions reported for calculating percentage reductions above, in large part because many procure a substantial share of their total energy through purchased power and include emissions from those sources in calculating their emission reduction goals and outcomes.

However, reviewing provider-owned facility CO_2 emissions can provide additional insight on provider emission 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 amounts of CO_2 emitted per unit of energy generated. As shown in Figure 1-8, CO_2 emissions rates differ significantly by fuel type.[29] Carbon dioxide emission rates from Wisconsin providers' natural gas facilities equaled approximately 47.4 percent of the emissions rates from coal facilities in 2022. Oil and biomass generation also have higher direct CO_2 emissions rates than natural gas, although their overall impact is limited because they account for a smaller share of total generation and total emissions. It should be noted that the emissions rates shown in Figure 1-8 do not account for externalities such as emissions

[29] 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, "GreenhouseGas 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.

associated with fuel extraction and procurement. There may be circumstances in which biomass is grown, harvested, and combusted in a carbon neutral fashion.[30]

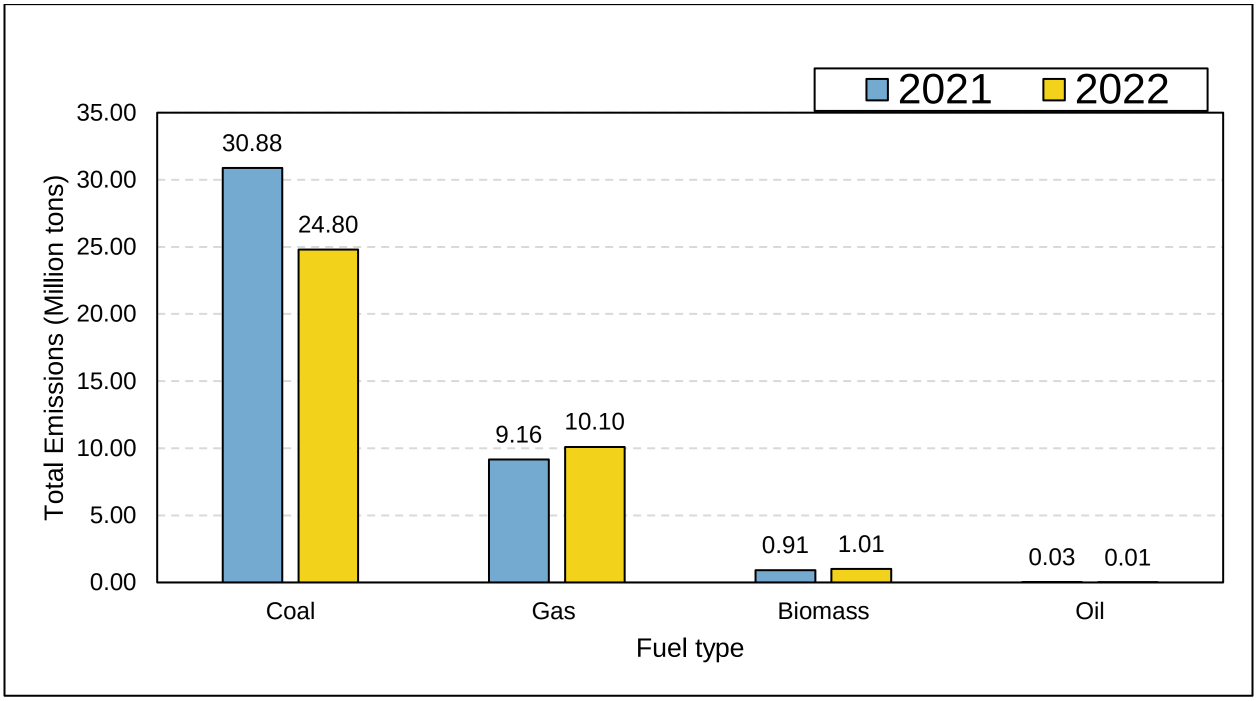
Figure 1-8 CO_2 Emissions Rates by Fuel Type at Provider-Owned Facilities, 2021-2022



As shown in Figure 1-9, coal facilities accounted for a majority of 2021 and 2022 CO_2 emissions from provider owned facilities, driven by its status as the largest share of total in-state generation (see Figure 1-6 above) and its higher emissions rate than natural gas. CO_2 emissions from coal facilities declined by 19.8 percent from 2021 to 2022, and overall CO_2 emissions declines by 12.4 percent, due to the continued progress by major electric providers in meeting their decarbonization goals with greater deployment of cleaner energy technology. As shown in Table 1-5, NSPW, WEPCO, WPSC, WPPI, and MGE have achieved a CO_2 reduction of greater than 40 percent in 2022 relative to 2005 emission levels. From 2021 to 2022, the total generation from coal facilities dropped by 19.4 percent while the total generation from gas facilities increased by 10.56 percent. Gas continues to substitute for coal as a highly dispatchable and reliable resource that meets baseline demand, while still representing a less carbon intensive alternative as indicated in Figure 1-8.

[30] Net emissions rates associated with biomass generation can vary significantly across individual facilities, depending on the specific biomaterial used and its source and production methods. *See* U.S. Environmental Protection Agency, "GreenhouseGas 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.

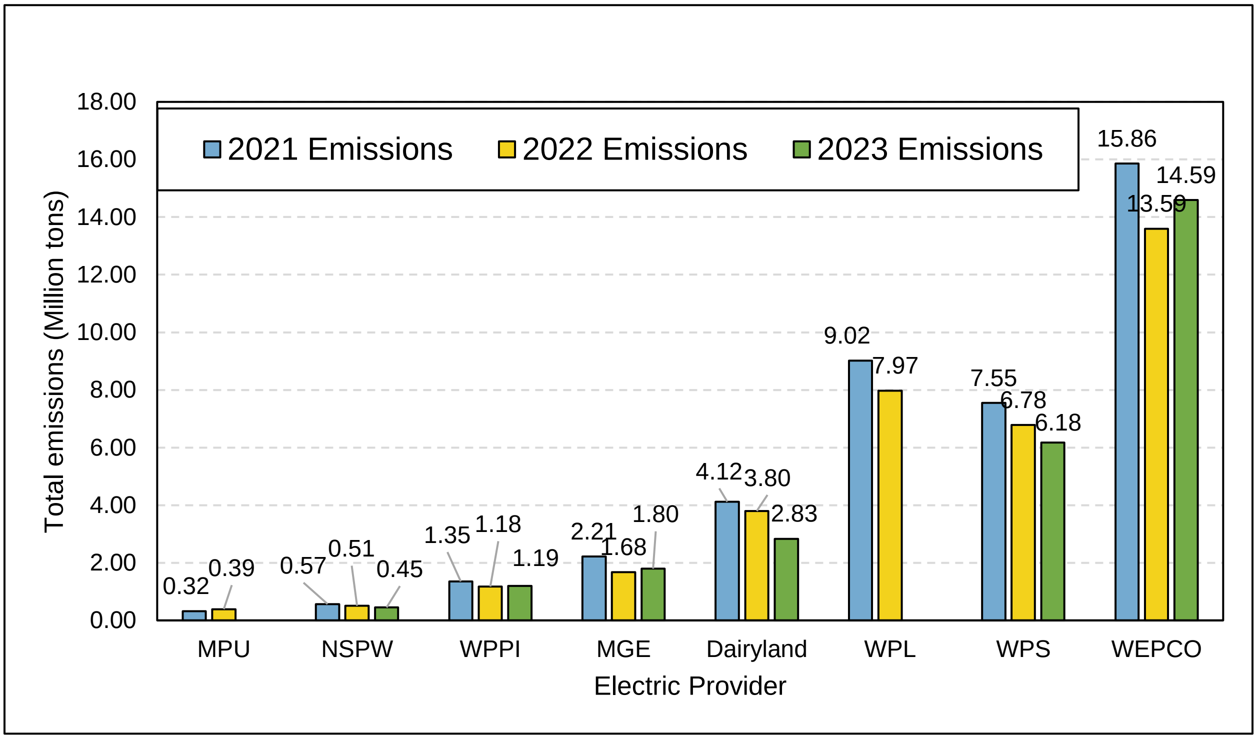
Figure 1-9 Total CO_2 Emissions by Fuel Type at Provider-Owned Facilities, 2021-2022[31]



As shown in Figure 1-10, providers' CO_2 emissions from owned facilities largely corresponded with providers' total share of generation in 2021 and 2022. WEPCO, WPSC, and WP&L together accounted for a significant majority of both generation and CO_2 emissions, over 78 percent in both 2021 and 2022. However, differences in emission rates also influence provider comparisons. All utilities experienced reduced emissions except Manitowoc Public Utilities. Appendix A includes more information on emission rates and individual facilities. As noted above, total emissions by provider may differ from calculations focused on provider-owned facilities, in part because several providers procure a substantial share of their total energy from purchased power.

[31] Updated 2023 actual emissions data was not provided by WP&L and MPU.

Figure 1-10 Total Emissions by Electric Providers in WI, 2021-2023[32]



While natural gas generation emits less CO_2 than coal generation, natural gas generation also emits methane. The IRA of 2022 included new charges on certain natural gas facilities for methane emissions, and the U.S. Environmental Protection Agency (EPA) has enacted rules to significantly reduce methane levels by 2023. Some of Wisconsin's largest electric providers have set net zero methane goals to include methane emitted from natural gas generation. NSPW has set a target for net zero natural gas emissions by 2050. MGE has a goal of net-zero methane emissions by 2035. WP&L seeks to achieve net-zero greenhouse gas emissions, including methane emissions, by 2050.

Chapter 2 – Future Electricity Generation in Wisconsin

Wisconsin electric providers' announced generation retirements and additions through 2030 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 energy storage, become increasingly cost-competitive, and the transition to zero-emission sources supports progress towards CO_2 and methane reduction goals. As the transition will require significant capital investments, presumably placing upward pressure on customer rates, future SEAs may consider the impact of construction in relation to the transition on the electric utilities' rate base. Considering the large-scale and rapid pace of generation changes, this chapter continues the SEA 2028's review of the utilities resource planning analyses 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.

[32] Updated 2023 actual emissions data was not provided by WP&L and MPU.

Generation Retirements and Additions

As shown in Table 2-1, Wisconsin electricity providers reported plans to retire approximately 2,700 MW of in-state generation by 2030. Providers plan to fully retire two of the seven utility-scale coal facilities currently operating in Wisconsin –Columbia and Oak Creek – which have a combined capacity of nearly 2,400 MW. Under the current plans, full retirement of both plants would occur by 2026. The Oak Creek coal units would be replaced by natural gas fired combustion turbine units in a docket currently under consideration by the Commission.

Table 2-1 Planned Utility-Owned or Leased Generation Capacity Retirement through 2030

Year	Name	Capacity (MW)	Fuel	Owner/Leaser
2024	Oak Creek 5, 6	299, 299	Coal	WEPCO
2025	Wheaton 1, 2, 3, 4, 6	56, 68, 56, 61, 70	Natural Gas and Fuel Oil	NSPW
2025	Oak Creek 7, 8	318, 324	Coal	WEPCO
2026	Columbia 1, 2	566, 565	Coal	WP&L, WPSC, MGE

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 is presented.[33] While no Wisconsin facilities larger than 100 MW have received SSR designations to date,[34] future retirements may be potentially foregone or delayed in response to findings that continued operation is needed.[35]

As shown in Table 2-2, Wisconsin electric providers reported plans to fuel switch approximately 1750 MW of electric generation from coal to alternative fuels by 2030. The major change would be from coal to natural gas at the Elm Road Generating Station facility, with the Edgewater Unit 5 also switching from coal to natural gas and an additional change from coal to biomass at the Lakefront Unit 9 station.

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

[34] The Lakefront Unit 9 received an SSR designation and is currently undergoing a switch from coal to biomass as a fuel source. https://cdn.misoenergy.org/20221111%20WTSTF%20Item%2002%20Attachment%20Y%20Submission%20for%20Lakefront%209626935.pdf

[35] 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.

Table 2-2 Planned Utility-Owned or Leased Generation Fuel Switches through 2030

Year	Name	Capacity (MW)	Previous Fuel	New Fuel	Owner/Leaser
2026	Lakefront 9	57	Coal	Biomass	MPU
2027	Elm Road 1, 2[36]	650, 650	Coal	Natural Gas	WEPCO
2028	Edgewater 5[37]	406	Coal	Natural Gas	WP&L

As shown in Table 2-3, Wisconsin providers reported plans to add approximately 4,200 MW of new solar energy capacity, 2,500 MW of new natural gas capacity, nearly 1,200 MW of new wind capacity, and approximately 900 MW of energy storage capacity by 2030.[38] Approximately 750 MW of that 900 MW of storage is expected to be paired with existing solar energy installations, while the remaining 150 MW would be “stand alone” storage or was not specified. Providers also reported plans to transfer ownership of approximately 125 MW of existing natural gas capacity within the state of Wisconsin.[39]

- WEPCO reported plans to add 1,971 MW of new solar capacity, 843 MW of new wind capacity, 1,315 MW of new natural gas capacity, and 476 MW of new energy storage capacity. It also has announced intentions to purchase an additional 100 MW of natural gas electric generation capacity at the existing West Riverside Generation facility.
- WPSC reported plans to add 1,042 MW of new solar capacity, 346 MW of wind electric generation capacity and 87 MW of energy storage capacity.
- WP&L has been authorized to construct 200 MW of new solar capacity at one site, while reporting plans to install 200 MW of natural gas upgrades at two existing natural gas electrical generation sites and add 274 MW of new energy storage capacity.
- MGE reported plans to add 234 MW of new solar capacity, 36 MW of new wind electric generation capacity, 141 MW of new natural gas capacity, and 113 MW of new energy storage capacity. It also has announced plans to purchase 25 MW of natural gas electric generation capacity at the existing West Riverside Generation facility.
- NSPW reported plans to add 600 MW of new solar capacity and 255 MW of new natural gas electric generation capacity.

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[36]MGE announces its intent to convert Elm Road Generating Station from Coal to Natural Gas Coal-Fired Generation - Madison Gas and Electric
[37]Alliant Energy announces its intent to convert Edgewater 5 to natural gas. Alliant Energy - Alliant Energy takes next step in the company’s energy transition.
[38] 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.
[39] 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);
- Saratoga Solar (9816-CE-100) (150 MW solar PV, 50 MW storage);
- Langdon Mills Solar (9818-CE-100) (200 MW solar, 50 MW storage); and
- Elk Creek Solar (9819-CE-100) (300 MW solar, 76 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 2-3 or subsequent analysis in this chapter assessing the effects of providers’ reported generation additions.

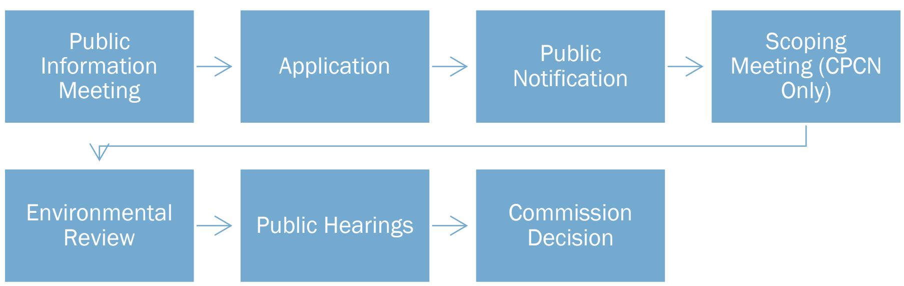
- DPC reported plans to add 149 MW of new solar capacity and 550 MW of new natural gas electric generation capacity.

Since planned additions were initially reported, 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 2-3. Additionally, a number of announced new facilities divide their total capacity between multiple providers through co-ownership arrangements, which are outlined in footnotes to Table 2-3.

There are two kinds of certificates that Wisconsin utilities or independent developers must obtain prior to constructing large electric or natural gas projects. The nature of the proposed project determines which certification is applicable to a specific proposal. A Certificate of Public Convenience and Necessity (CPCN) is required for proposed electric generation facilities of 100 or more MW and proposed high-voltage electric transmission lines of 100 kV or more. A Certificate of Authority (CA) is required for any construction project less than 100 MW that meets the review threshold based on size and cost of the project.[40]

As shown in Figure 2-1 and described below, there are numerous steps in the approval process for a construction case (there are additional protocols for wind siting projects).

Figure 2-1 Steps in a Construction Case



Before filing its application with the PSC, a developer, utility, or transmission company that wants to build a new construction project might host a **public information meeting**. The public can attend these meetings to learn about the preliminary design of a proposed project and give input directly to the applicant. After the public information meeting, the developer, utility, or transmission company officially kicks off the construction case when it files an **application**. This is when the PSC opens a docket for the construction case. Generally, an application includes information about the need, cost, size, and location of the proposed project. Applications for proposed power plants of 100 or more MW and proposed high-voltage electric transmission lines of 345 kV or more, must include information for two or more sites or routes, detailed engineering plans, plant costs (public utilities only), and a review of potential environmental and community impacts. Non-utility power plant applicants are exempt from a "needs" test and from demonstrating how their engineering specifications are better than available alternatives. Upon receiving the application, the PSC **notifies the public**. The PSC sends a public notification letter to all property owners on or near the potential sites, as well as local government officials, local libraries, the media, and other agencies and interested persons. This letter briefly describes the project; includes a map; identifies the level of

[40] CPCN process, including public participation opportunities, also applies to transmission dockets.

environmental review the project will require; lists places where copies of the application are available for review; and gives contact information for comments and questions.

The Commission often hosts project **scoping meetings** (*CPCN only*) to give the public a chance to learn about the proposed project, ask questions, and talk directly with the utility, Department of Natural Resources (DNR) staff, or Commission staff. Meetings may be held multiple times during the construction case. Commission staff completes an **environmental review** of the application, resulting in a PSC staff determination to prepare an Environmental Assessment (EA), prepare a more extensive Environmental Impact Statement (EIS), or take no further review. These documents are posted in the case file on the PSC website. Commission staff provides opportunities for the public to comment at various stages of it review and notifies the public when it is accepting such comments and how to file them. As a result of this process PSC staff may propose changes in project design or site location to protect the environment or an affected community. The DNR will also review an application for air, solid waste, water quality, and water discharge permits. When an application requires a permit from the DNR, Commission staff and the DNR cooperate in the environmental review process. The Commission **holds public hearings** on the application (and any final EIS) depending on the size and cost of the project and sends a Notice of Hearing to parties to the case, and landowners in the project area. At the hearings the PSC will receive “for the record” testimony and exhibits from parties to the case testimony and comment from members of the public. The Commission also accepts written comments from the public. After the hearing, the Commissioners review the record before making a **decision**. In an Open Meeting, the Commissioners will discuss the issues presented and vote either to approve or deny the proposal or approve the proposal with modifications or conditions. Following the Open Meeting, the PSC issues a written order and posts it to the docket.

As described above, this process has numerous opportunities for public participation, including opportunities for the public to subscribe to and follow the case online and to provide comments during open comment periods and for the official record. Certain individuals and organizations may also apply for party status as intervenors, which provides authority to file testimony and exhibits and appear at hearings and be available for cross-examinations and to ask questions to other parties. Intervenors may be eligible to apply for and received intervenor compensation. Additionally, all Commission meetings are available to attend in person on watch live or recorded on the Commission’s YouTube Channel.

Table 2-3 New Additions and Transfers of Utility-Owned or Leased Generation Capacity by Wisconsin ElectricProviders 2024 through 2030[41]

Year	Nameplate Capacity (MW)	Name	New or Existing Site	Owner/Leaser	Source	PSC Status and Docket Number	Recent Updates
2024	25[42]	West Riverside	Existing	MGE	Natural Gas	5-BS-273, approved	
2024	100[43]	West Riverside	Existing	WPSC	Natural Gas	5-BS-273, approved	
2024	200	Grant County Solar	New	WP&L	Solar	9804-CE-100, approved; 6680- CE-182, approved	
2024	75	Wood County Solar Storage	New	WP&L	Battery Storage	6680-CE-182 reopener, approved; 9803-CE-100 reopener, approved	
2024	6	MGE Solar 2024	New	MGE	Solar		
2025	200[44]	Paris Solar	New	WEPCO/WPSC/ MGE	Solar	9801-CE-100, approved; 5-BS-254, approved	
2025	110[45]	Paris Solar BESS	New	WEPCO/WPSC/ MGE	BatteryStorage	9801-CE-100, approved; 5-BS-254, approved	
2025	100	Grant County Solar Storage	New	WP&L	Battery Storage	9804-CE-100 reopener, approved; 6680-CE-182 reopener, approved	
2025	255	Wheaton replacement	New	NSPW	NaturalGas	4220-CE-185, approved	
2025	99	Edgewater Battery Storage	New	WP&L	Battery Storage	6680-CE-184, approved	
2025	100	Neenah Generating Station upgrades	Existing	WP&L	Natural Gas	6680-CE-185, approved	

[41] WP&L did not identify any new resource additions or transfers of utility-owned or leased generating capacity in any year after 2024.
[42] Per agreement between WP&L and MGE reached in docket 6680-CE-176.
[43] Per agreement between WP&L and WPSC reached in docket 6680-CE-176.
[44] Ownership shares are proposed as 150 MW to WEPCO, 30 MW to WPSC, and 20 MW to MGE.
[45] 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
2025	100	Sheboygan Falls Generating Station upgrades	Existing	WP&L	Natural Gas	6680-CE-186, approved	
2025	250[46]	Darien Solar	New	WEPCO WPSC/MGE	Solar	9806-CE-100, approved; 5-BS-255, approved	
2025	75[47]	Darien Solar Storage	New	WEPCO/WPSC /MGE	Battery Storage	9806-CE-100 approved; 5-BS-255, approved	
2025	6	Strix Solar	New	MGE	Solar		
2026	300[48]	Koshkonong Solar	New	WEPCO/WPSC/ MGE	Solar	9811-CE-100, approved; 5-BS-258, approved	
2026	15	MGE Solar 2026	New	MGE	Solar		
2026	149	Badger State Solar	New	DPC	Solar	9800-CE-100, approved	
2026	49	MGE RICE 2026	New	MGE	Natural Gas		
2026	21	MGE Battery Storage 2026	New	MGE	Battery Storage		
2026	4	Backup Generator	New	MPU	Natural Gas		
2027	165[49]	Koshkonong Solar Storage	New	WEPCO/WPSC/ MGE	BatteryStorage	9811-CE-100, approved; 5-BS-258, approved	
2027	300[50]	High Noon Solar	New	WEPCO/WPSC/ MGE	Solar	9814-CE-100, approved; 5-BS-276 pending	Delayed from 2025

46 Ownership shares are proposed as 187.5 MW to WEPCO, 37.5 MW to WPSC, and 25 MW to MGE.
47 Ownership shares are proposed as 56.25 MW to WEPCO, 11.25 MW to WPSC, and 7.5 MW to MGE.
48 Ownership shares are proposed as 225 MW to WEPCO, 45 MW to WPSC, and 30 MW to MGE.
49 Ownership shares are proposed as 123.75 MW to WEPCO, 24.75 MW to WPSC, and 16.5 MW to MGE.
50 Ownership shares are proposed as 225 MW to WEPCO, 45 MW to WPSC, and 30 MW to MGE.

Year	Nameplate Capacity (MW)	Name	New or Existing Site	Owner/ Leaser	Source	PSC status and Docket Number	Recent Updates
2027	165[51]	High Noon Solar Storage	New	WEPCO/WPSC/ MGE	BatteryStorage	9814-CE-100, approved; 5-BS-276, pending	Delayed from 2025
2027	280	WEPCO Solar 2027	New	WEPCO	Solar		
2027	70	WPSC Solar 2027	New	WPSC	Solar		
2027	102	MGE Solar 2027	New	MGE	Solar		
2027	130	Paris RICE	New	WEPCO	Natural Gas	6630-CE-318, pending	
2027	1185	Oak Creek CTs	New	WEPCO	Natural Gas	6630-CE-317, pending	
2027	54	WEPCO Wind 2027	New	WEPCO	Wind		
2027	13.5	WPSC Wind 2027	New	WPSC	Wind		
2027	6	MGE Wind 2027	New	MGE	Wind		
2027	40	MGE Battery Storage 2027	New	MGE	Battery Storage		
2027	50	WEPCO Battery Storage 2027	New	WEPCO	Battery Storage		
2028	253	WEPCO Solar 2028	New	WEPCO	Solar		
2028	64	WPSC Solar 2028	New	WPSC	Solar		
2028	600	NSPW Solar 2028	New	NSPW	Solar		
2028	89	WEPCO Wind 2028	New	WEPCO	Wind		
2028	22	WPSC Wind 2028	New	WPSC	Wind		
2028	40	WEPCO Battery Storage 2028	New	WEPCO	Battery Storage		
2028	10	WPSC Battery Storage 2028	New	WPSC	Battery Storage		
2028	92	MGE Combustion Turbine 2028	New	MGE	Natural Gas		

[51] 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
2029	550[52]	Nemadji Trail Energy Center	New	DPC	Natural Gas	9698-CE-100, approved	Delayed[53]
2029	100	WEPCO Solar 2029	New	WEPCO	Solar		
2029	100	WPSC Solar 2029	New	WPSC	Solar		
2029	500	WEPCO Wind 2029	New	WEPCO	Wind		
2029	60	WPSC Wind 2029	New	WPSC	Wind		
2029	30	MGE Wind 2029	New	MGE	Wind		
2030	550	WEPCO Solar 2030	New	WEPCO	Solar		
2030	650	WPSC Solar 2030	New	WPSC	Solar		
2030	200	WEPCO Wind 2030	New	WEPCO	Wind		
2030	250	WPSC Wind 2030	New	WPSC	Wind		

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 May 2022 and May 2023 indicated that projected capacity levels throughout the MISO region are at risk of falling below the local reserve margin requirement in future years if further new capacity is not planned for, which could result in a need for providers to pursue other means to meet demand requirements, such as importing additional capacity via transmission. The 2023 survey identified a potential regional capacity shortfall beginning in 2026 for Summer and Winter due to planned coal retirements from Columbia, and Oak Creek, delayed from previous retirement plans for between 2023 and 2024.

Resource adequacy requirements were historically defined in terms of adequacy during peak demand periods in the summer, as discussed in Chapter 1. However, influenced by recent regional experience with resource adequacy and reliability challenges occurring throughout the year, MISO has begun using a seasonal resource adequacy construct (SAC, described in more detail in Chapter 1), which separates reserve margin requirements for summer, fall, winter and spring. MISO implemented the SAC in 2023, which required modification to resource adequacy reporting and assessment by providers and the Commission. The introduction of the SAC now means that capacity positions will be evaluated on a quarterly basis by MISO. Additionally, MISO has submitted proposals to FERC to implement a new Direct Loss-of-Load (DLOL) accreditation methodology, which may impact the types of resources utilities must procure to meet their planning reserve margin requirements and greenhouse gas reduction goals. This accreditation methodology has not been accounted for in this SEA due to its uncertain and pending nature.

[52] 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).
[53] Quarterly reports indicate that construction has not yet started on either the generation or interconnection facilities. (PSC REF# 510186.)

The projected seasonal positions of the state of Wisconsin for the years 2024 through 2030 have been tabulated in Table 2-4. As shown in Figures 2-2 a-d and Table 2-4, electric providers report seasonal projections of total capacity (taking into account project additions and retirements) that continue to remain at about MISO's projected PRM requirements, except for summer and winter 2026, which maybe reflective of substantial coal facility retirements projected for that year. While analysis earlier in 2022 had projected declining capacity levels in 2023 and 2024, providers now expect to increase capacity well above PRM requirements in those years, due to the continued operation of generation plants previously assumed to be retired,[54] as well as added generation additions that have recently received MISO-approved Generation Interconnection Agreements. The MISO Seasonal PRM is expected to stay relatively constant in future years for all seasons, except for summer; the summer PRM is projected to increase from 7.90% to 10.40%. The substantial difference between the current winter PRM (25.5%) and summer PRM (7.90%) is that there is less overall load in the winter, so the risk of one unit from the smaller pool of resources not being available leads to a reserve requirement that is proportionately larger. There is also a greater need for dispatchable units during winter season, as many of the non-dispatchable units (i.e. solar) are not highly operational during winter. Wisconsin utilities have included in future resource plans units that directly address the dispatchability issue of certain technology in winter and similar weather seasons. More detailed PRM calculations can be found in Appendix A, Table A-2.

In August 2023, the Commission opened a generic investigation into resource adequacy, docket 5-EI-161, *Investigation on the Commission's Own Motion to Review Resource Adequacy Standards and Requirements*. In this investigation the Commission will investigate current and ongoing resource adequacy initiatives, including a review of newer metrics and requirements by MISO and other states, regional transmission organizations or independent system operators, and other related entities, and review the impacts of the state level planning guideline of 14.5 percent established by the Commission's Order in docket 5-EI-141 and whether that guideline remains appropriate. Relevant to this discussion is that MISO will adopt the Reliability Based Demand Curve (RBDC) beginning in PY 2025-2026. The RBDC does not change how the PRM is set, however, the RBDC may result in an LSE having a marginally higher or lower requirement in a given season depending on the availability and value of surplus capacity in MISO's planning resource auction. The Commission will continue to monitor resource adequacy issues and seasonal variability to ensure sufficient PRM targets are appropriately met in future years.

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[54] Planned retirements were delayed due to new information gained through a dynamic planning process that reacts to changes in market conditions, the regulatory environment, customer needs and preferences, and ongoing changes to the regional transmission system and generation mix.

Table 2-4 Seasonal Wisconsin Aggregated Supply and Demand, MW

Summer							
Year[55]	2024	2025	2026	2027	2028	2029	2030
Net Capacity[56]	16,574	17,569	16,373	16,862	17,512	18,022	18,380
Expected Demand[57]	13,984	13,986	14,403	14,875	16,440	16,399	16,473
WI LSE's PRMR (MW)[58]	15,163	15,234	15,704	16,167	17,743	17,674	17,695
Resources above PRMR (MW)	1,412	2,336	669	695	-232	348	685
MISO Planning Reserve Margin (%)[59]	8.4%	8.9%	9.0%	8.7%	7.9%	7.8%	7.4%
Fall							
Year	2024	2025	2026	2027	2028	2029	2030
Net Capacity	16,592	17,102	16,089	16,448	17,524	18,006	17,817
Expected Demand	11,721	11,792	11,597	13,106	13,532	13,527	13,597
WI LSE's PRMR (MW)	13,529	13,629	13,430	15,147	15,515	15,426	15,457
Resources above PRMR (MW)	3,063	3,473	2,659	1,302	2,009	2,580	2,360
MISO Planning Reserve Margin (%)	15.4%	15.5%	15.6%	15.3%	14.2%	13.2%	12.7%
Winter							
Year	2024	2025	2026	2027	2028	2029	2030
Net Capacity	16,200	16,096	15,255	15,644	16,111	16,742	16,274
Expected Demand	10,260	10,671	10,891	12,402	12,765	12,835	12,913
WI LSE's PRMR (MW)	13,095	13,523	13,704	15,464	15,832	15,773	15,761
Resources above PRMR (MW)	3,105	2,574	1,551	180	279	970	513
MISO Planning Reserve Margin (%)	27.6%	26.7%	25.8%	24.7%	24.0%	22.9%	22.1%
Spring							
Year	2024	2025	2026	2027	2028	2029	2030
Net Capacity	15,776	16,468	16,392	16,661	17,469	17,277	17,608
Expected Demand	10,770	10,774	10,736	11,275	12,370	12,737	12,803
WI LSE's PRMR (MW)	13,518	13,549	13,549	14,218	15,809	16,267	16,286
Resources above PRMR (MW)	2,258	2,919	2,843	2,444	1,660	1,010	1,321
MISO Planning Reserve Margin (%)	25.5%	26.1%	26.7%	26.5%	28.4%	28.4%	27.8%

[55] MISO Planning Years (PY) run from June 1 to May 31. Listed years represent the correspond to the calendar year in which a season falls in (i.e. PY 2024-25 is Summer 2024, Fall 2024, Winter 2024, and Spring 2025).
[56] 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.
[57] Defined by MISO as coincident LSE peak to MISO peak gross of demand response net FRT.
[58] Equals (net capacity/expected demand) – 1.
[59] MISO's increase in the reserve margin value reflects modeling enhancements, resource mix performance, and load factors. See MISO One Voice Style Guide (misoenergy.org).

Figure 2-2a Wisconsin Net Capacity Compared to Planning Reserve Requirements for Summer

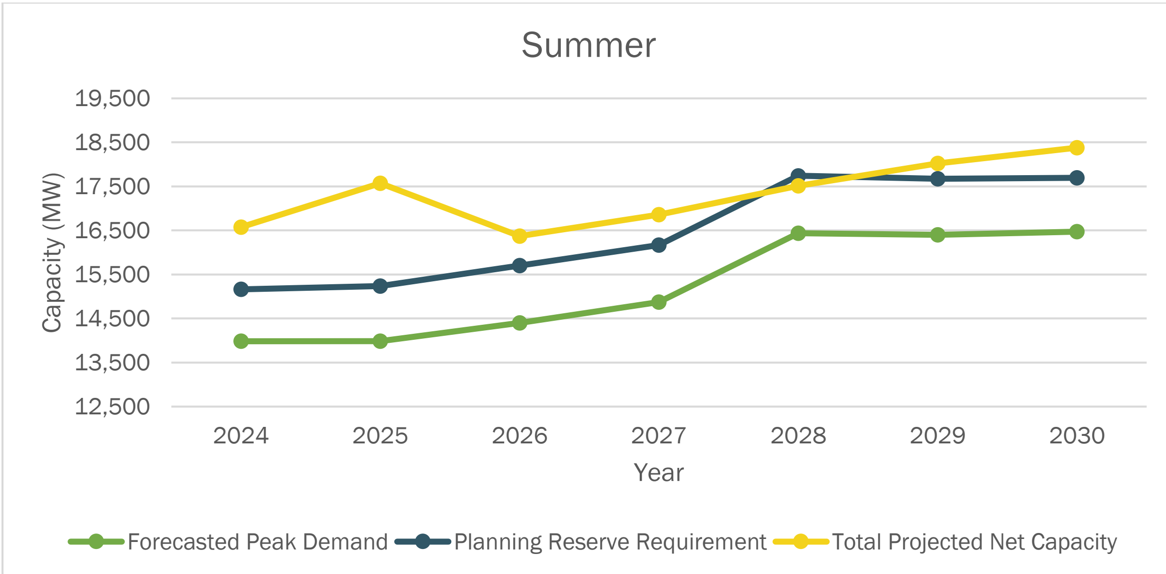


Figure 2-2b Wisconsin Net Capacity Compared to Planning Reserve Requirements for Autumn

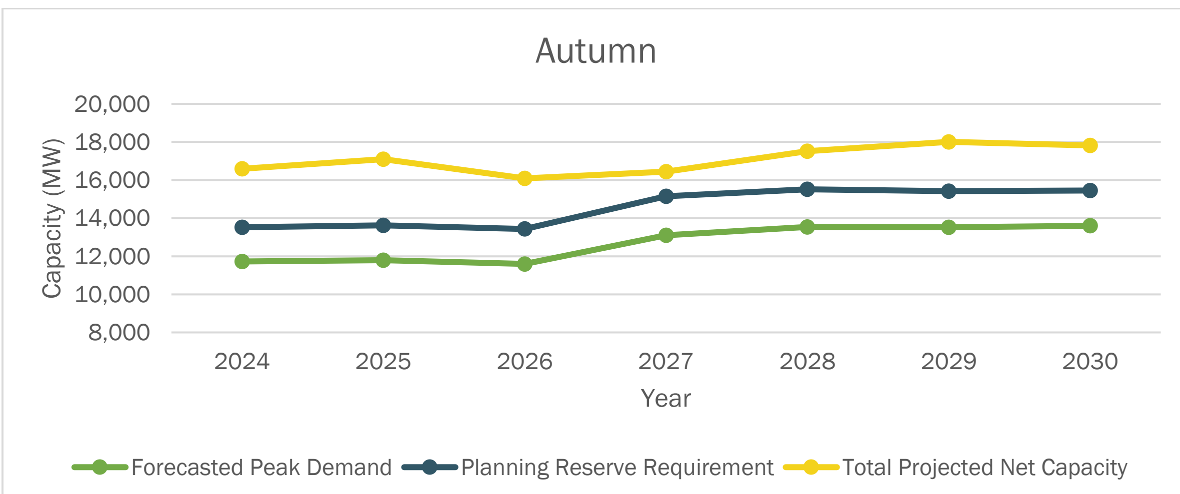


Figure 2-2c Wisconsin Net Capacity Compared to Planning Reserve Requirements for Winter

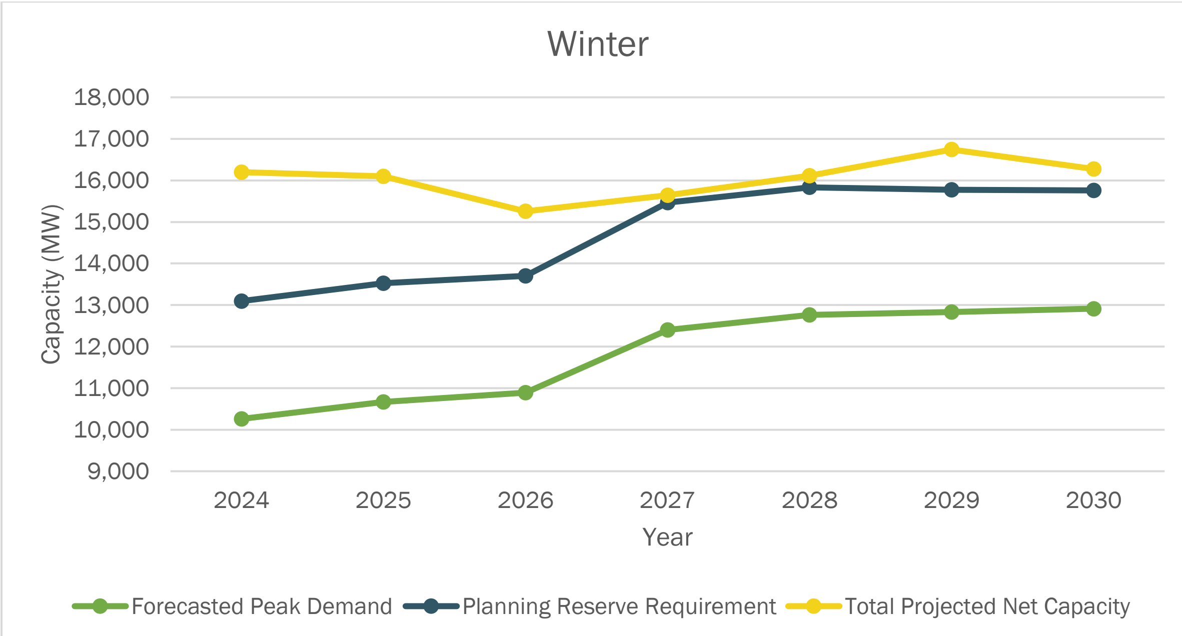
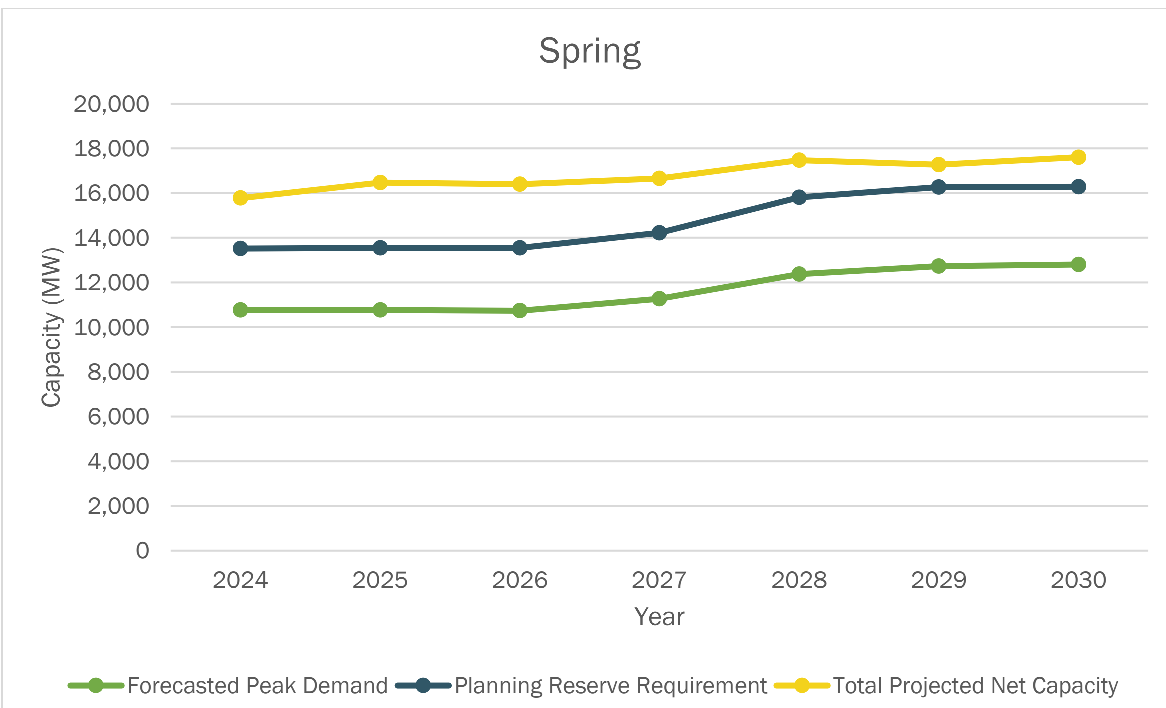


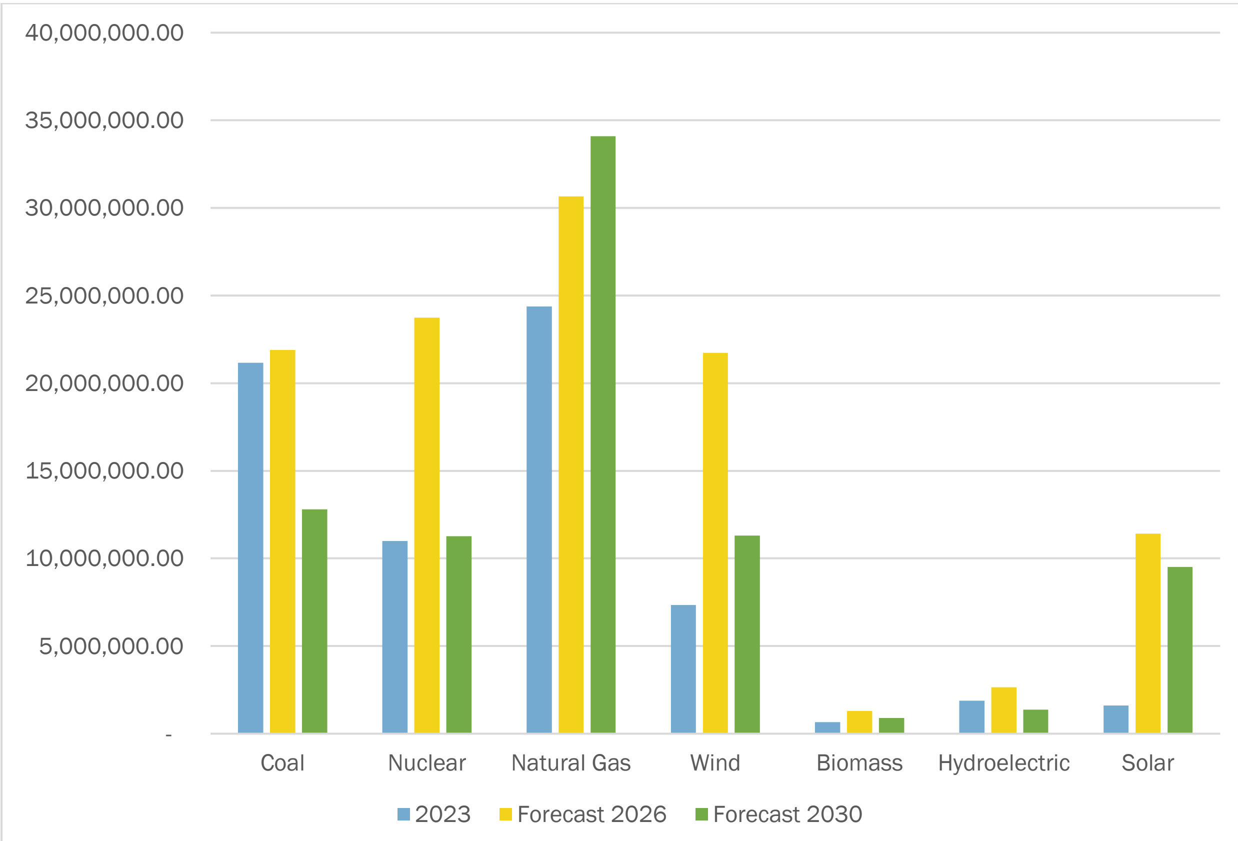
Figure 2-2d Wisconsin Net Capacity Compared to Planning Reserve Requirements for Spring



Effects on Sources of Energy Supply

As shown in Figure 2-3, if all additions and retirements are implemented as planned by electric providers, coal resources will decline from 31 percent of Wisconsin's generation to 16 percent in 2030, natural gas resources will increase from 36 percent to 42 percent, wind resources will increase from 11 percent to 14 percent, and solar resources will increase from 2 percent to 12 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 two plants will be fully retired by 2026, with another two fuel switching before 2030. The share of solar resources may increase further if Wisconsin providers choose to procure additional independently developed projects.

Figure 2-3 Generation Comparison by Resource - 2023, 2026, and 2030



Effects on Emissions

As shown in Table 2-5, providers project that announced additions and retirements will help drive additional reductions in CO_2 between 2022 and 2030. Projected emissions for 2024 show a CO_2 emissions reduction from all major providers of 43% relative to 2005 baseline levels. Manitowoc Public Utilities (MPU) was the only utility to report an increasing trend between these two years. MPU's resource planning does not include carbon reduction goals. MPU is proposing to decrease carbon intensity, but through a fuel switch that would increase capacity factors and therefore increase direct emissions. By 2030, the statewide CO_2 emissions reduction is projected to be 71.9% relative to 2005 baseline levels. Appendix B, Figure B-1 provides more details on projections by years, which are influenced by the currently anticipated timing of generation retirements and additions.

Table 2-5 Projected Carbon Dioxide Reductions from Owned Generation in 2024 and 2030 by Utility

Utility	2024 CO_2 Emissions (Million metric tons)	2024 CO_2 Reduction (% from 2005)	2030 CO_2 Emissions (Million metric tons)	2030 CO_2 Reduction (% from 2005)
WP&L	8.64	2%	3.81	57%
WEC Energy Group[60]	18.5	55%	*8.22*	*80%*
WEPCO	11.6	-	*5.15*	-
WPSC	6.9	-	*3.06*	-
DPC	4.14	3% increase	2.79	30%
WPPI	1.87	53%	1.66	58%
NSPW	1.9	53%	0.5	87%
MPU	0.35	16%	0.54	30% increase
MG&E	1.84	42%	0.64	82%
All Providers	37.24	43.59%	18.55	71.90%

As included in Table 1-5, NSPW, WEPCO, WPS, and MGE all stated a carbon reduction goal of 80% by 2030 relative to 2005 emission levels. Based on their SEA data request responses, reflected in Table 2-5, each of those providers anticipates meeting or surpassing that expectation, with NSPW projected to achieve the greatest reduction of 87%. WP&L had stated a carbon reduction goal of 50% by 2030, and according to its projections, will surpass that goal by 7%. As shown earlier in Tables 2-1, 2-2 and 2-3, electric providers anticipate meeting their goals by retiring existing coal-fired power plants, fuel switching from coal to cleaner fuels at other power plants and adding renewable resources to generation portfolios.

Resource Planning in Wisconsin

Utility resource decisions balance the goals of adequacy, reliability, affordability, and environmental responsibility, and effective resource planning is especially important during a period of rapid change. In response to the Commission's initial request for input on priorities in its *Roadmap to Zero Carbon Investigation*, docket 5-EI-158, commenters highlighted interest in establishing enhanced and more transparent utility resource planning processes. Commissions in numerous 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. Wisconsin does not have an IRP requirement and does not approve retirement decisions, although it may review costs associated with retiring generators. While some *Roadmap* commenters identified those other states as models for effective resource planning, IRP processes are typically established though legislative authorizations, which has not taken place in Wisconsin. In response to commenters' suggestion and in absence of an IRP process, Commission staff preparing this SEA requested additional information from providers related to their resource planning analysis associated with

[60] WEC Energy Group comprises WEPCO and WPSC. WEC did not provide emissions projections for years past 2024 but indicated that it anticipated being on target to meet its reduction goals. It also did not provide a breakdown of responsibility for its two subsidiaries after 2024, so the 2024 share was projected forward for subsequent years.

announced additions and retirements. Second, this SEA includes independent Commission staff analysis on statewide resource planning considerations, following up and expanding on similar considerations presented in the last SEA.

Provider Resource Planning

The resource planning information requested for this SEA covered content commonly addressed in detailed resource plans, including IRPs conducted in other states. Staff directed electric providers in Wisconsin that own more than 5 MW of generation to submit supplemental information on three broad topics, including carbon reduction activities, reliability impacts of potential unit retirements, and utility resource planning. The utility resource planning information requested responses to the following items:

- A narrative describing the factors leading to additions and retirements;
- The analysis methods used to assess how different additions and retirements occur;
- The inputs and assumptions used in the analysis to set initial values for the models used and how those inputs were developed; and
- A description of the generation scenarios considered and a presentation of the results, including discussion of how the presented scenario was better than the alternatives.

Table 2-6 summarizes the responses from nine electric providers, submitted in November 2023. The amount of detail provided varied by respondent. Providers with few or no planned additions and retirements provided comparatively limited information. Some providers with operations in Minnesota provided references to where IRP documents could be found or provided a version of the IRP document to this docket, 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 2-6 Resource Planning Responses: November 2023

Provider	Response	Additional Responses/Notes
DPC	PSC REF#: 485070	PSC REF#: 485069
Great Lakes Utilities	PSC REF#: 485171	PSC REF#: 485170
Manitowoc Public Utility	PSC REF#: 482849	
NSPW	PSC REF#: 485422	
MGE	PSC REF#: 485375	
WEPCO	PSC REF#: 485300	Same information as WPSC filing
WP&L	PSC REF#: 485330	
WPSC	PSC REF#: 485308	Same information as WEPCO filing
WPPI	PSC REF#: 485414	

In the last SEA investigation (docket 5-ES-111), electric providers confirmed that their planning accounted for the four main goals of adequacy, reliability, affordability, and environmental responsibility. In response to the utility resource planning narrative for this SEA, the electric providers reaffirmed the same concepts, while providing additional considerations that were reviewed, and identified specific metrics used to assess performance on those goals. While no electric providers provided capacity expansion plan modeling results for this specific SEA, all providers have been performing some type of resource plan modeling for their individual needs, some with relative frequency due to the changing nature of the electric system landscape and shifting regulatory and policy priorities. Thus, all providers have some form of modeling pertaining to their respective future plans, some details of which have been shared for the purposes of analysis in this SEA.

Electric providers identified key goals in the establishment of their utility resource plans, including reduction of costs to customers, stability of electric rates, maintenance of generation reliability and flexibility, increasing system resiliency, and reduction of CO_2 emissions. Multiple providers discussed diversification of resources as a strategy to provide increased resiliency of their resource portfolios. All electric providers discussed the reduction or elimination of coal from their generation mix, with replacement by other resources with fewer emissions concerns, including fuel switches from coal to natural gas or biomass. Most providers have corporate goals or aspirations to eliminate CO_2 emissions from their systems by certain future dates, which assisted in the consideration of which resources may be retired and which were considered for addition. Electric providers also discussed large capital expenditures that otherwise may have been required to maintain the operability of aging generation resources, particularly when these avoided costs could be used to pursue newer technology options with potentially greater reliability and fewer emissions.

As part of the analysis of how resource additions and retirements are selected, the electric providers discussed differing levels of the use of software tools as part of the evaluation process. Traditionally, electric providers have used three types of modeling software to assess resources against their defined goals.

- **Capacity expansion models**, to identify the optimal portfolio of generating assets (or load reduction 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 modeling which are listed in Table 2-7. 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 2-7 Primary Resource Planning Models Used by Wisconsin Electric Providers

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

The providers' modeling analysis incorporated the goals outlined above, as well as other inputs identifying future conditions relevant to making generation choices. These inputs and assumptions were provided to these capacity expansion programs, with the goal of developing optimal resource plans for each electric provider.

Among the key inputs identified by the providers included load forecasts, pricing of fuel types such as natural gas and coal, expected market pricing for capacity and energy, capital and operating costs of new generator and storage technologies, flexibility and resiliency of resource portfolios, physical location of resources, and emissions, among other considerations. Some providers allowed these key inputs to randomly vary over a range of possible values to perform a more probabilistic analysis, generating hundreds or thousands of modeling runs before reviewing results. Some providers also discussed the implementation of the seasonal construct, evaluating how different resources are accredited in various seasons, with potentially different resource outcomes for the individual portfolios.

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, several providers reported running multiple scenarios that changed the values of key inputs, to assess the impacts of different conditions on model outcomes. The most common scenarios include 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. These modeling scenarios were among those independently performed by Commission staff for the entire state of Wisconsin, as discussed more below. Some providers specified that their goal was to select final resource options that performed strongly across multiple scenarios 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 previous modeling work as discussed in the last SEA (issued in docket 5-ES-111), with appropriate updates to reflect changes to the state's electrical transmission and distribution system, as well as factoring in legislative and regulatory changes at the state and federal level. WP&L's announced generation changes reflected the results of its updated Clean Energy Blueprint planning process, which emphasized the need for additional resources outside of the 1,089 MW of new solar generation that has largely been constructed and is in operation. The updated Clean Energy Blueprint identified a need for 275 MW of battery energy storage system (BESS), an expansion of natural gas capacity at the Neenah and Sheboygan Falls generation sites and the potential future addition of more wind, RICE units using blended natural gas and hydrogen fuel and the Edgewater and Columbia coal facilities, while balancing its goals of achieving carbon reduction, limiting costs, and supporting rate stability, reliability, and resource flexibility. These new resources also will reduce

WP&L's winter season constraints, which were identified as they considered the seasonal construct modality.

WEPCO and WPSC continue to indicate that their plans to retire coal units at Columbia and Oak Creek reflected that those plants had reached the end of their useful lives and continued operations would require significant additional costs in maintenance and potential environmental compliance despite announced delays to those retirements to ensure short term electric reliability. 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 over 20 years, across a variety of scenarios, compared to the alternative scenario of maintaining the existing generation fleet. Similar to WP&L, the WEPCO and WPSC plans have been updated to account for market developments and the potential for new loads coming into their service territories. A first tranche of construction and buy/sell authorizations have been reviewed and approved by the Commission, with a second grouping of projects expected, informed by the utilities' ongoing analysis.

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 showed it is implementing a successful approach for meeting carbon reduction goals while controlling costs. NSPW also received the Minnesota Commission's approval to extend the life of the Monticello nuclear energy facility. DPC reported on a "balanced and pragmatic" approach to its resource portfolio, including retirement of coal assets, additions of renewable and natural gas resources, and the importance of the development of the Commission-approved, but not yet constructed, Nemadji Trail Energy Center.

Commission Staff Resource Planning Analysis

In addition to directing that Commission staff collect resource planning narratives from individual providers in the SEA, the Commission directed Commission staff to conduct additional analysis in this SEA to provide an independent perspective that evaluates generation changes statewide and maintain consistency with the last SEA (issued in docket 5-ES-111). 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, emission reductions, and affordability under multiple scenarios.

Commission staff has historically used EGEAS to review generation expansion planning information provided as part of individual project applications, though in recent years other programs such as EnCompass, AURORA, and PLEXOS have been utilized by various utilities as a replacement for EGEAS.[61] Commission staff does not maintain 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 2023 MISO Transmission Expansion Planning (MTEP) and LRTP processes. (See Chapter 4 for more information on MTEP23 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

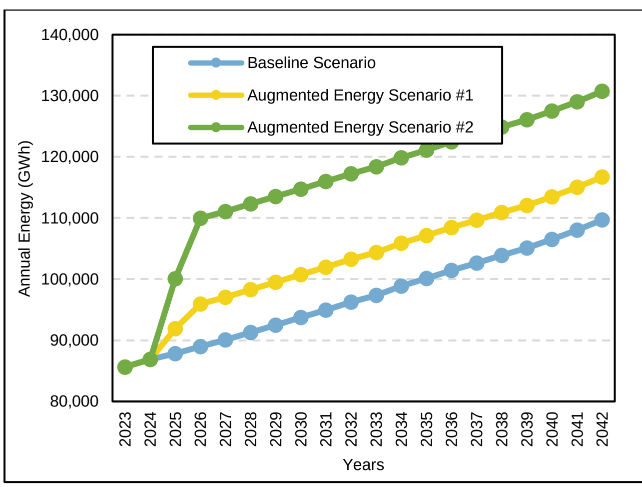
[61] The Commission will be transitioning to PLEXOS over the next couple of years, however for this SEA, all modeling was done in using EGEAS.

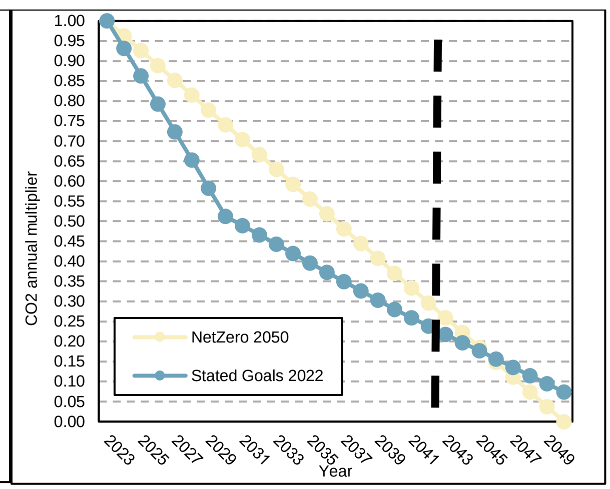
serving Wisconsin providers, and reducing the scale of general inputs, such as total energy use and peak demand, from regional to state level values.

EGEAS established resource adequacy and reliability as minimum baseline requirements. MISO's dataset defines resource adequacy as compliance with MISO's planning resource 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. Moreover, EGEAS is an annual model. Hence, Commission staff modeling concentrated around the summer season, which has historically been the constraining season for most electric providers in the state. Time limitations and the way the EGEAS model works did not allow for Commission staff to evaluate other seasons.

MISO's MTEP23 datasets support capacity expansion modeling through 2042, under a future scenario that set different values for emission reductions and growth in electric demand than was used in the previous SEA. Commission staff used the "refreshed" future scenarios upon which the MTEP21 futures were based. In particular, as shown in Figure 2-4, Commission staff used Future 2A which incorporated 100% of utility IRPs and announced state and utility goals within their respective timelines, which includes a minimum of 60% decarbonization assumption systemwide.[62] The Future 2A load was modified to Wisconsin's size within MISO. Future 2A utilizes an increase in electrification relative to pre-2019 trends and the previous future model portfolio, driving an approximate 0.8% annual energy growth rate. The electrification is driven by potential increases in the adoption of electric vehicles and electrification of end uses currently using other fuels, such as heating. The augmented energy scenarios represent a range of possible causes of load in excess of the F2A assumptions, including faster electrification in various sectors such as transportation and data center load. F2A load assumptions have been modified to Wisconsin's size within MISO. The EGEAS modeling software does not support spot additions of load, they are merely added to the system load requirements.

Figure 2-4 Assumed Load Growth and CO_2 Reductions





EGEAS' capacity expansion modeling under each future identified the lowest cost set of generation sources that serve customer load and meet adequacy and reliability standards, while achieving the

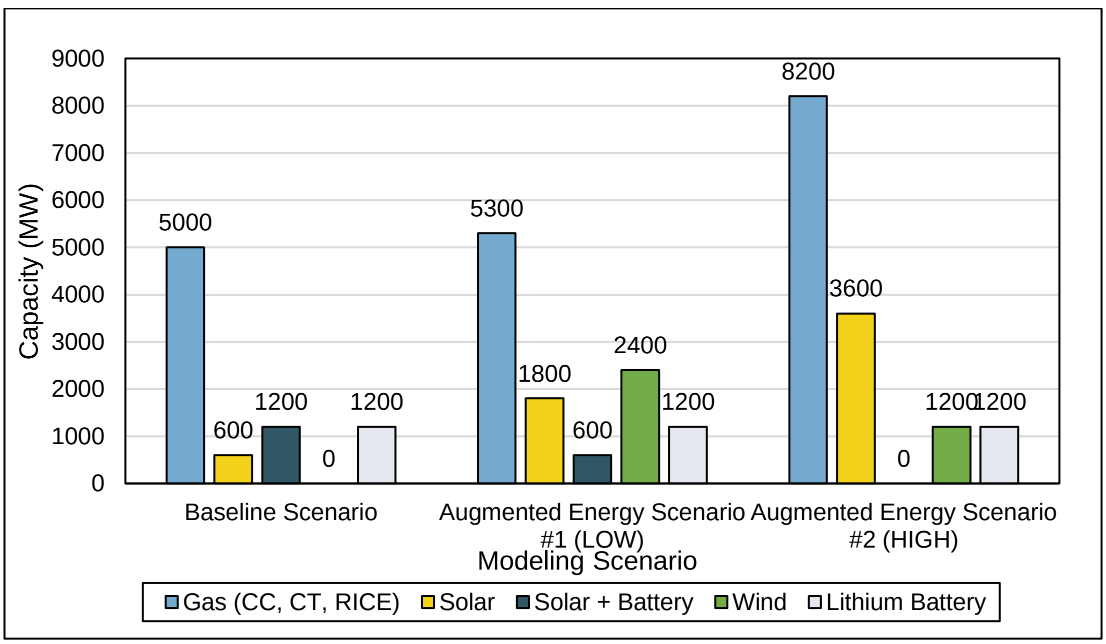
[62] Future 2A achieving 100% utility goals was first aggregated across the MISO footprint.

specified amount of CO2 reduction. These assessments are informed by assumptions regarding the relative costs of different generation sources, which staff confirmed to be consistent with cost assumptions used in other recent Commission dockets. The base assumptions were developed by MISO according to the documents provided in the footnote[63]. Selections also account for 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 during overnight hours. Generating plants available to the capacity expansion model utilized Wisconsin-specific generating characteristics, as the modeling was limited to in-state resources, which impact the selection of certain resources that may be constructed out-of-state with more favorable operating characteristics.

Since the Commission began drafting this SEA, the EPA enacted new greenhouse gas standards and guidelines for fossil fuel-fired power plants under the Clean Air Act, effective July 8, 2024.[64] These new standards may impact the cost assumptions used for new and existing natural gas plants by setting CO2 limits for newly constructed gas-fired combustion turbines and emission guidelines for existing coal, oil and gas-fired steam generating units. Also noteworthy is the EPA's new performance standards for new base load combustion turbines are based on using carbon capture and sequestration/storage.

Figure 2-5 illustrates the generation portfolio selected under each future. (More detailed results can be found in Appendix B: Tables B-1 through B-7, which identify all individual units selected by generation source and year.)

Figure 2-5 EGEAS Capacity Expansion Results - 2042



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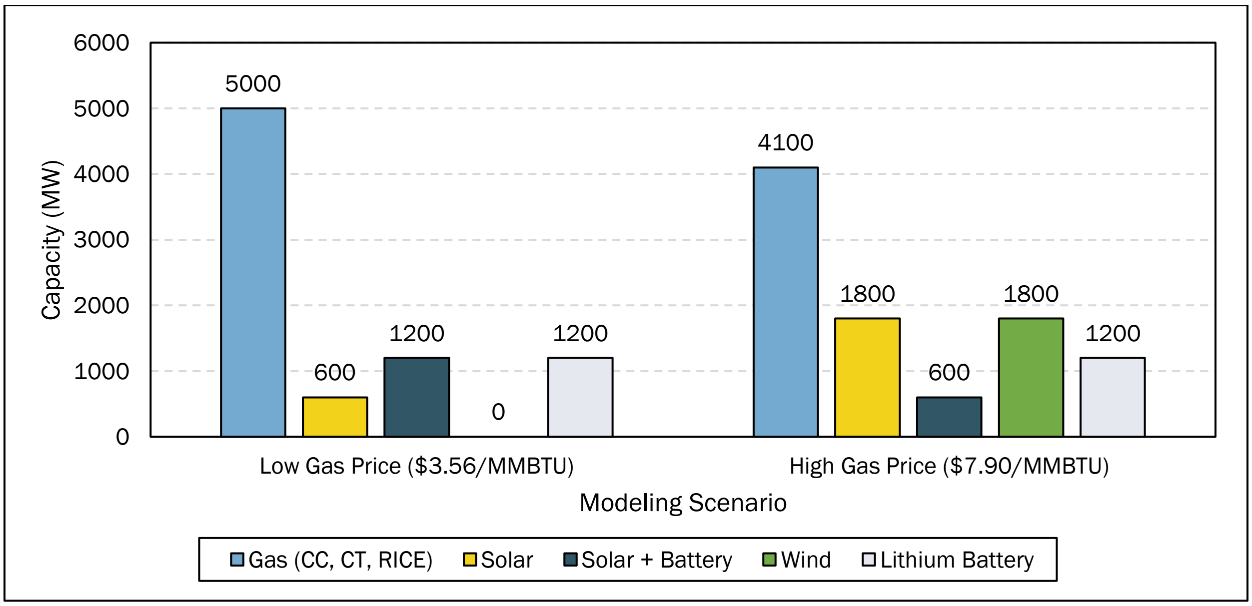
[63] The cost assumptions implemented by MISO are specified in the MISO Futures Report Series 1A (published in November 2023) and MISO Assumptions Book (published in September 2023). For more information, see the MTEP 21 MISO Futures Whitepaper, April 27, 2020. https://cdn.misoenergy.org/April%202021%20MISO%20Futures%20Report611694.pdf .
[64] These rules are currently being challenged in federal courts.

Commission staff's EGEAS modeling under Future 2A, including the base case and augmented load scenarios, predominately selected natural gas resources to meet the needs identified by upcoming retirements during the mid-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, as well as wind units in the augmented load scenarios run by staff. 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. However, the augmented load scenarios recognized the proportionate value of intermittent generation and battery storage as well, as in each case EGEAS selected 6,000 MW of these types of technology to completement the dispatchable gas generation.

Commission staff's EGEAS modeling also identified this advantage of robustness across a range of assumed natural gas prices. This modeling uses the baseline load growth. EGEAS selected a larger share of solar and battery resources under alternative natural gas price scenarios for Future 2A, 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 along a range of values as shown in Figure 2-6. Due to past volatility of natural gas prices, Commission staff modeled values across a broad starting gas cost range, which then escalated as time went on.[65] As may be expected, at a higher gas cost the dispatchable gas units are selected, but in a smaller amount compared to the lower gas cost runs. The difference is made up by renewable resources. Selection of individual units by year and generation source for these scenarios can be found in Appendix B, Tables B-4 and B-5.

Figure 2-6 EGEAS Capacity Expansion Modeling Results for Low and High Natural Gas Prices ($/MMBTU), 2042



[65] This low price scenario establishes a $3.56/MMBtu natural gas price at the beginning of the modeling period, with annual increasesover the modeling period consistent with the trends assumed for other scenarios. The high price scenario establishes a $7.90/MMBtu natural gas price at the beginning of the modeling period, with annualincreases over the modeling period consistent with the trends assumed for other scenarios.

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.[66]

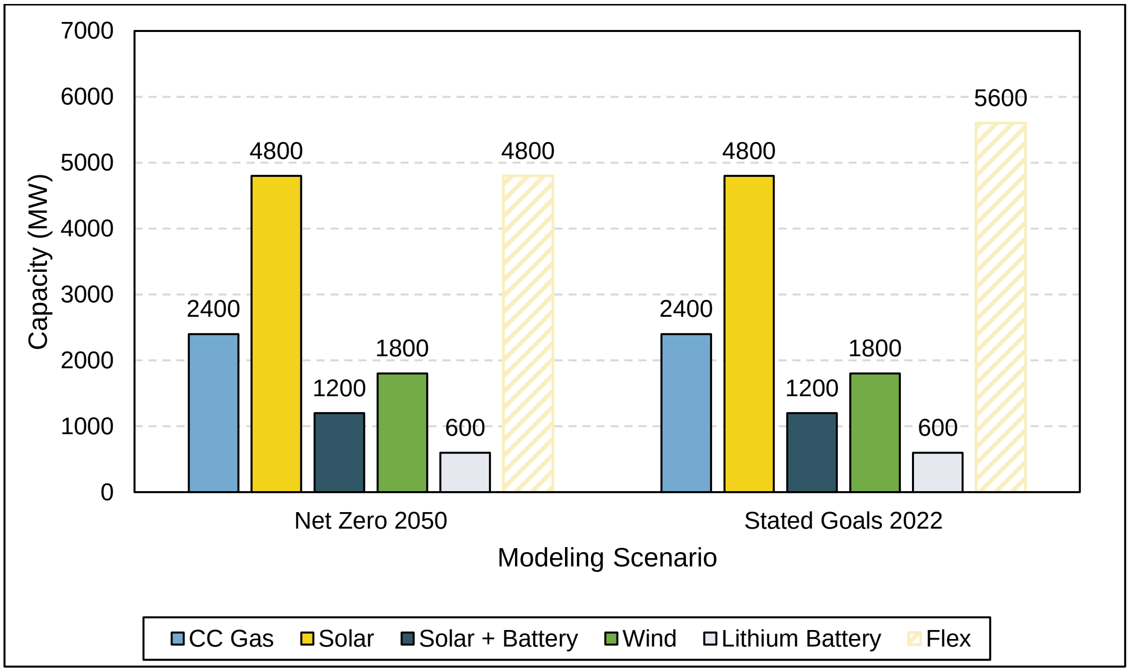
Figure 2-7 provides the results of the decarbonization sensitivities performed by Commission staff. In its modeling, MISO's Future 2A assumes CO_2 reductions based on aggregated goals from across MISO, including legislative and executive goals from the various states and stated goals of utilities within the footprint. In order to tailor the model to Wisconsin specific assumptions, Commission staff developed two alternative pathways that seek to reduce CO_2 to lower levels in different timeframes. The Net Zero by 2050 (NZ2050) sensitivity explores the Governor's vision of achieving zero emissions from electricity production in the state of Wisconsin by 2050. The State Goals (SG) sensitivities incorporates the state reduction goals of Wisconsin's largest utilities, including all utilities in Wisconsin which individually serve greater than 5 percent of the state's electrical load, projected from a 2022 baseline. Figure 2-3 on the right side, above, shows the annual carbon reduction as a fraction of 2023 carbon emissions in each year for the two sensitivities.

As outlined in Table 2-3, above, providers' announced expansion plans include a significant share of solar and battery storage. In order to ensure the EGEAS expansion results under decarbonization requirements were directionally consistent with utility expansion plans, the units identified in Table 2-3 were aggregated by class and placed into the model at appropriate years. As Figure 2-7 shows, the modeled buildout of natural gas combined cycle (CC), wind, solar, solar and battery hybrid, and lithium battery units are identical between the two decarbonization sensitivities. For these classes, the modeled buildout is the same as the aggregated utility-announced expansion plans.

Beyond those units, the EGEAS results identified the need for additional flexible ("Flex") units, a unit type uniquely selectable in the decarbonization sensitivity runs. Flex units have the dispatchability and other characteristics of RICE units, but with extremely high fuel costs (to ensure they only participate when absolutely needed) and without any carbon emissions. Equivalent technology could include, but would not be limited to, reserved battery storage, traditional RICE units coupled with carbon capture and sequestration, RICE units powered by hydrogen, and various combinations of those technologies.

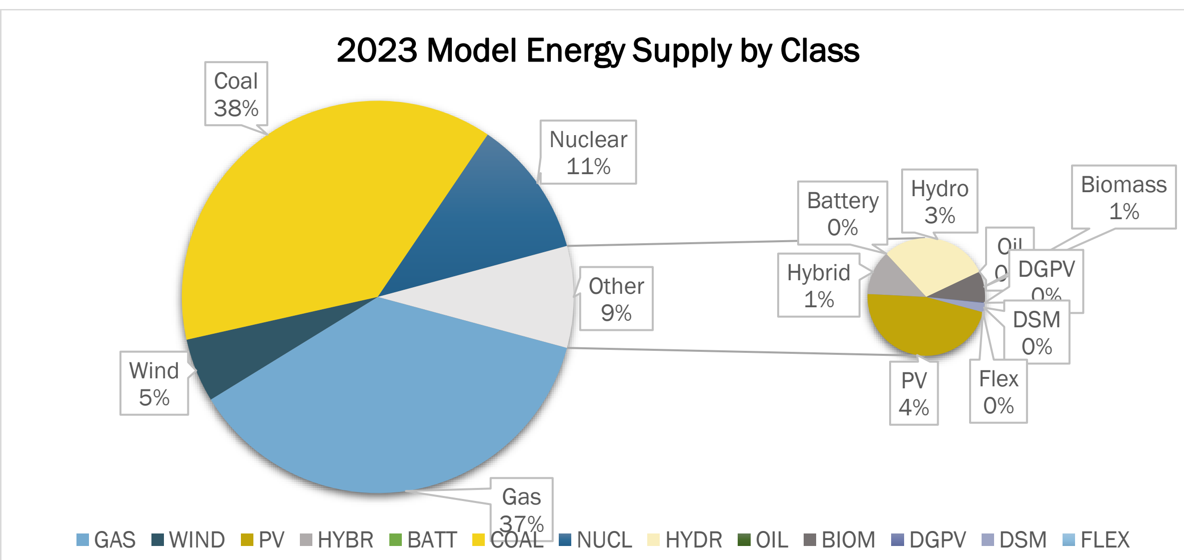
[66] Regional Resource Assessment: A Reliability Imperative Report. November 2021. https://cdn.misoenergy.org/2021%20Regional%20Resource%20Assessment%20Report606397.pdf.

Figure 2-7 EGEAS Capacity Expansion Results, Net Zero CO_2 Reduction by 2050 and Stated Goals in 2022



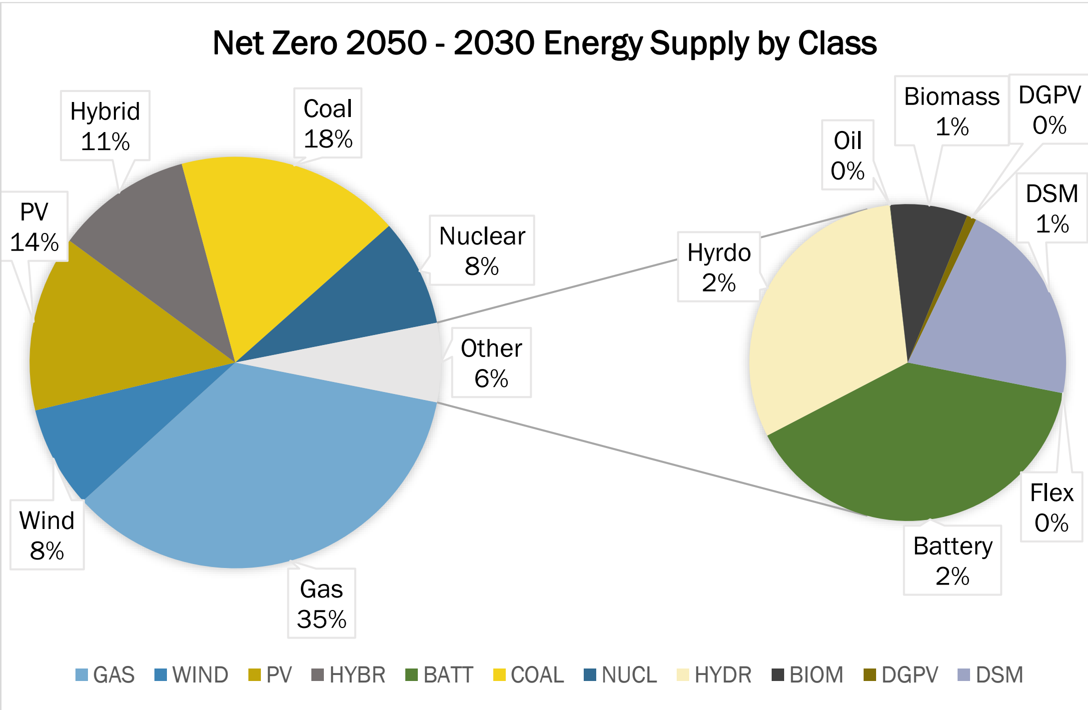
Given the significant buildout of the Flex unit type in both decarbonization sensitivities, it is important to examine the actual energy provided by resources of the various classes in these two runs. To start, Figure 2-8, below, shows the breakdown of energy generated by each unit class in the model, as of its start date of 2023. EGEAS outputs these values directly in GWh. These results have therefore been normalized to the total produced system energy in that year.

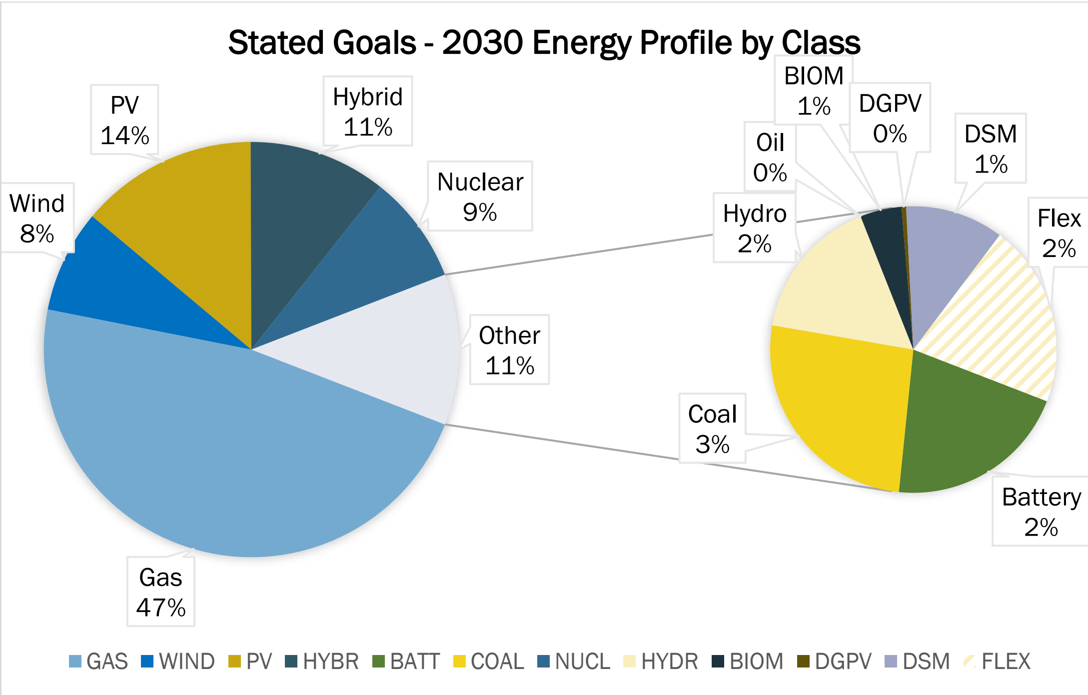
Figure 2-8 EGEAS 2023 Model Energy Production by Class



The 2023 model energy supply results set an important baseline – namely, that coal units provide a significant fraction (here, 38 percent) of the total energy generated in the state. Coal is followed by natural gas in the model, and thereafter by nuclear and wind. Solar PV and hybrid solar and battery units are collectively responsible for only 5 percent of the energy generated in the base year. These results for 2023 are directly comparable to the profiles for the year 2030 in both decarbonization runs, presented in Figure 2-9.[67]

Figure 2-9 EGEAS 2030 Energy Production by Class Across Two Decarbonization Sensitivities





[67] Commission staff will be doing a follow-up data request on 2022 and 2023 supply information during summer 2024 and will incorporate any updates into the final SEA.

As Figure 2-9 demonstrates, the energy profile for both decarbonization pathways differs significantly from the model baseline in 2023. Both decarbonization runs feature a significant increase in generation from solar PV and hybrid resources, which supply 25 percent of the energy generated in 2030 in both cases. Similarly, the percentage of energy generated by coal is lower in both cases, a result of curtailment of theoretical coal generation to ensure sufficient CO_2 reductions.

Although the two models featured identical buildout of new gas resources as shown in Figure 2-7, the generation of gas resources decreases from 2023 to 2030 when CO_2 is constrained according to the NZ2050 pathway but increases from 2023 to 2030 when CO_2 is constrained according to utility-stated goals. Figure 2-9 therefore demonstrates the meaningful distribution that must be made between the capacity of units built and the actual energy supplied by those units.

The best example of this distinction is the Flex resource class. Although the added capacity of this type exceeded all other classes in Figure 2-7, the class is responsible for a vanishingly small percentage of the energy generated in 2030 under NZ2050 constraints, and only 2 percent of the system energy under the SG pathway. As noted above, utility announced expansion plans form the backbone of the decarbonization sensitivities through 2030. Because Flex is not needed in 2030 under NZ2050 CO2 constraints, utility-announced expansion plans through 2030 appear compatible with the pathway to achieving net zero emissions by 2050. In contrast, Commission staff analysis shows that 2 percent of system energy would need to be served by highly dispatchable, carbon-free technology in 2030 for utilities to comply with their stated carbon commitments. 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 lithium-battery storage, or if future technological developments support the emergence of one or more of the Flex technologies identified above at a competitive cost.

Grid Inertia

The growing use of renewable resources such as solar and wind has raised questions about their effects on reliability. Commission staff has 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 American 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 rotational speed 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.[68] Because the inertia of an individual power plant is inherently tied to its physical properties[69], every power plant provides a different amount of inertia to the grid. As shown in Figures 2-10 and 2-11, natural gas plants in Wisconsin had both the highest installed capacity and provided 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.

Figure 2-10 Installed Capacity vs Grid Inertia, 2023

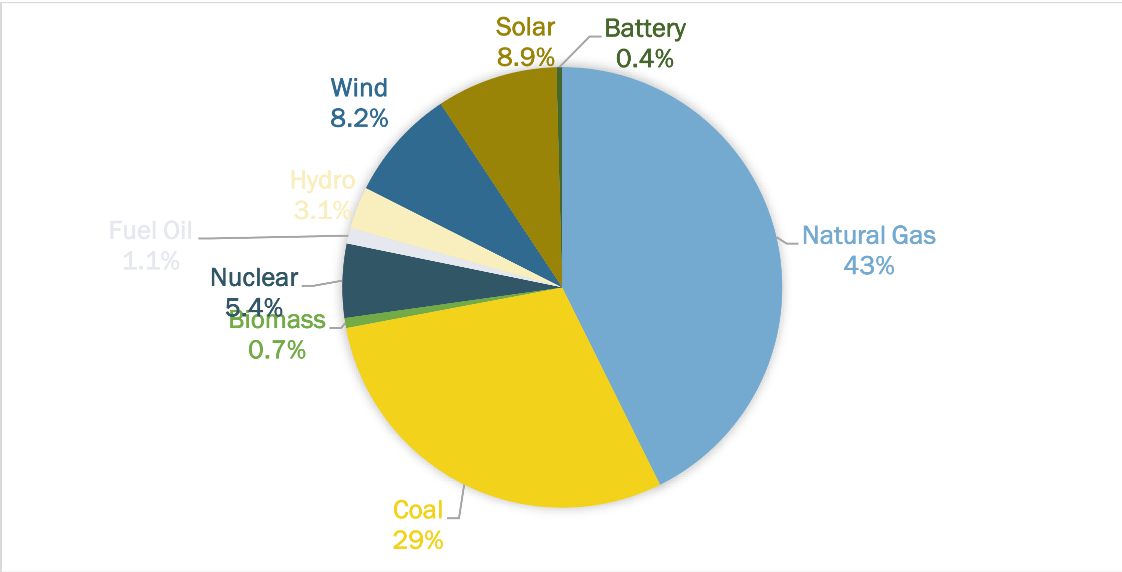
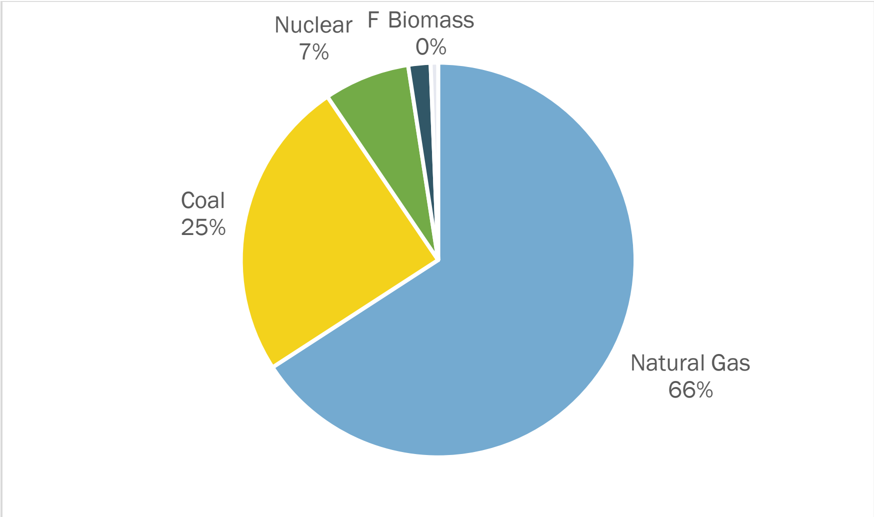


Figure 2-11 Inertia Provided by Each Type of Fuel, 2023



[68] The study focused on MISO Load Resource Zone 2, which encompasses most, but not all, of the grid operations within state borders.
[69] These physical properties include but are not limited to the generator's pole count and the angular mass of the rotorturbine shaft.

Commission staff calculated the inertia provided by each fuel type using publicly available inertia constants[70] and the installed MW capacity for each type of fuel as set out in Chapter 1, Figure 1-6. The referenced Institute of Physics Science article assigned hydroelectric, wind and solar an inertia constant of zero. As such, these resources do not appear in the inertia chart above. Commission staff believes that this issue needs to be revisited as grid-forming inverters replace the current generation of grid following invertors to see if the inertia constants change. The last SEA, issued in docket 5-ES-111, stated:[71]

> 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.

> There does not appear to be consensus relative to the amount of renewable penetration at which the grid stability becomes challenging. MISO's 2021 Renewable Integration Impact Study reported that "[f]requency response is stable up to 60 [percent] instantaneous renewable penetration," though increased integration complexity and ensuing challenges are anticipated after renewable penetration levels exceed 30 percent.[72]

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[70] https://iopscience.iop.org/article/10.1088/2516-1083/abf636/pdf.
[71] 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." https://www.nrel.gov/docs/fy20osti/73856.pdf.
[72] RIIA Executive Summary520053.pdf (misoenergy.org).

Chapter 3 – Clean Energy Programs and Policies

Energy Efficiency

Energy efficiency programs provide incentives and technical assistance to energy consumers to take steps to reduce energy use. In 1999, the Wisconsin State Legislature established Focus on Energy (Focus) as Wisconsin's statewide electric and natural gas efficiency and renewable resource program. Wisconsin Stat. § 196.374, repealed and recreated in 2005, requires IOUs to fund Focus through contributions equal to 1.2 percent of annual operating revenues from retail sales, and 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 can contribute these funds to Focus or administer their own programs. As of 2023, 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. Additionally, several IOUs and municipal utilities run voluntary energy efficiency programs that provide additional benefits to their customers beyond what Focus offers.[73]

Wisconsin Stat. § 196.374(2)(a)1. requires Focus to hire a third-party program administrator to operate Focus under a contract established by IOUs and approved by the Commission.[74] 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 2022 to establish contract priorities for the 2023-2026 time period through docket 5-FE-104, *Quadrennial Planning Process IV*.

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 includes separate portfolios of programs that 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, work with contractors to support energy efficient repairs and installations, and work with homebuilders to increase the energy efficiency of new homes. In docket 5-FE-104, *Quadrennial Planning Process IV*, the Commission set a Key Performance Indicated (KPI) for increasing the number of Tier II applications by six percent compared to those received during the prior quadrennium (Tier II customers fall between 60-80% of State Median Income.) Within Focus' non-residential portfolio, separate programs target the different efficiency opportunities for different types of customers, including small businesses, commercial customers, schools, and government facilities, agriculture customers, and large industrial facilities. In its Final Decision in docket 5-FE-104, the Commission set an overall KPI target of 31 percent of incentive spend for rural customers, which is proportional to the 31 percent of rural customers in the designated zip codes for 2023 and 2024. This applies to

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[74] The IOUs created a nonprofit board to fulfill its duties under Wis. Stat. § 196.374(2)(a)1. The nine-member board is called the Statewide Energy Efficiency and Renewables Administration (SEERA).

residential and nonresidential 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 can inform customers of Focus offerings and encourage participation. Some electric providers also fund and operate their own energy efficiency programs,[75] 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, which documents and explains the methods for calculating savings achieved from installing energy efficient measures. Savings calculations in the Technical Reference Manual 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 CY 2023, the Program Administrator achieved verified gross lifecycle savings equal to 50% of its quadrennial lifecycle therm savings goal, 24% of its lifecycle kWh savings goal, 27% of its kW savings goal, and 35% of the combined electric + gas (MMBtu) lifecycle savings goal. The program achieved its highest level of lifecycle therm savings since CY 2018 in CY 2023, with 390.7 million lifecycle therms saved. This result is in contrast to CY 2022 when lifecycle therm savings (254.7 lifecycle therms) were the lowest they had been since CY 2011. The year-over-year increase in therm savings is largely attributable to business customer projects delayed in CY 2021 and CY 2022 due to pandemic-related impacts (e.g., supply chain disruptions, staffing shortages) reaching completion in CY 2023. Also, the 2023 evaluation showed that the program maintained its record high level of customer satisfaction from 2022, achieving a portfolio average rating of 9.4 out of 10.

Focus' evaluators also evaluate 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 test that compares thebenefits 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 2023, Cadmus's cost-benefit analysis concluded that for every dollar spent, Focus' full portfolio of programs

[75] 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 contributingthose funds to Focus.

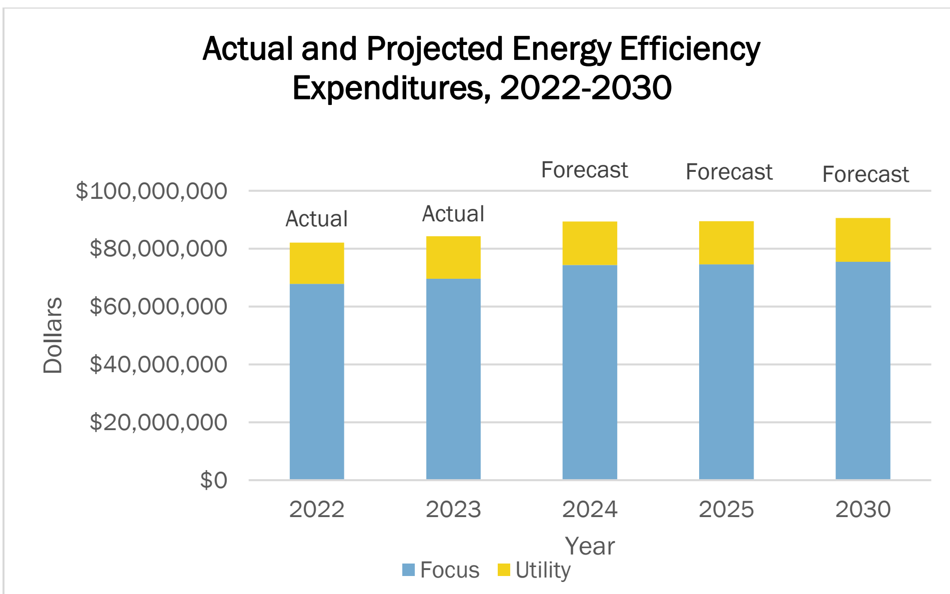
achieved $2.17 in life cycle benefits.[76] A national study of energy efficiency programs performed in 2018 found that Wisconsin ran the most cost-effective efficiency programs of any state in the country, achieving the highest rate of energy savings per dollar spent.[77]

Future Focus on Energy Spending and Outcomes

Annual IOU contributions to Focus are based on utility revenues, and therefore can vary. 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 from 2022 through 2030. (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.)

Commission staff calculates each IOU's required contribution based on a three-year rolling historical revenue average. IOUs project generally stable contribution levels between 2023 and 2030 with only slight increases over the period. Beginning in 2023, the historical calculation included 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.

Figure 3-1 Actual and Projected Annual Electric Energy Efficiency Expenditures 2022-2030[78]

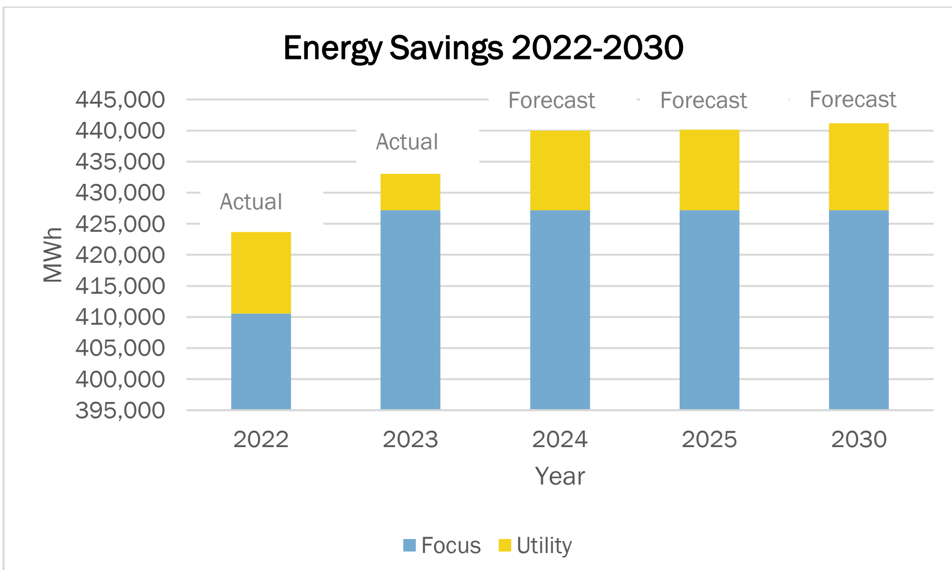


In docket 5-FE-104, *Quadrennial Planning Process IV*, (2023-2026), consistent with the approach used in planning for the 2019-2022 quadrennial period, the Commission authorized Cadmus to conduct a potential study projecting the amount of future energy efficiency savings Focus could

[76] For informational purposes, Cadmus also conducts an "expanded TRC" test which incorporates the economic benefits created by Focus. In 2023, the program evaluator's expanded TRC analysis found that when economic benefits are included, Focus achieved $4.08 in benefits for every $1.00 in costs.
[77] Report available at: http://www.swenergy.org/Data/Sites/1/media/lbnl-cse-report-june-2018.pdf.
[78] Aggregated electricity provider data responses, docket 5-ES-112; Focus on Energy 2022 Evaluation Report; IOU annual contributions calculated by Commission staff based on operating revenues reported in IOU PSC Annual Reports.

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[79], 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 historic levels in the 2023-2026 period. These potential estimates are reflected in Figure 3-2, which maintains electric savings estimates closely comparable to savings achieved in the 2019-2022 quadrennium. Energy savings from other utility programs are projected to remain stable through 2030; 2023 is an outlier year, mostly due to lower numbers reported by Dairyland. The 2021 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. A new study providing up-to-date analysis on Wisconsin's energy savings potential is currently in progress.

Figure 3-2 Actual and Projected First-Year Annual Energy Savings 2022-2030[80]



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 general topics and 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 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

[79] 2021 Focus on Energy Efficiency Potential Study Report, Cadmus. Potential_Study_Report-FoE_Efficiency-2021.pdf

[80] Sources: Aggregated electricity provider data responses, docket 5-ES-112; Focus on Energy 2022 Evaluation Report; PSC Docket 5-FE-104 Final Decision of November 14, 2022 (PSC REF#: 453081.).

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 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 peak natural gas use and winter electric peak use;
- identifying strategies to achieve greater demand savings;
- investigating opportunities to integrate the time-varying value of efficiency and renewables;
- playing a greater role in cost-effectively reducing carbon emissions;
- positioning the program to expand support of beneficial electrification statewide;
- assessing how the program can increase its long-term market transformationimpacts; and
- performing research and analysis to identify how Focus can improve service to underserved customers.

In the last phase of planning, the Commission established program goals, targets, and key performance indicators for the 2023-2026 quadrennial period. As part of this, the Commission implemented cost-effective benefits adder for low-income programs and work will remain ongoing throughout the quadrennium.

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. Historically, 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 ensure a cost-effective balance between demand and available supply.

A wide range of initiatives can be categorized as demand side management, including time-of-use rates, demand bidding, behavioral demand response, and timed water heating. In Wisconsin, electricity providers pursue demand response through two primary mechanisms: direct load control programs and interruptible load tariffs.[81]

- **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 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.

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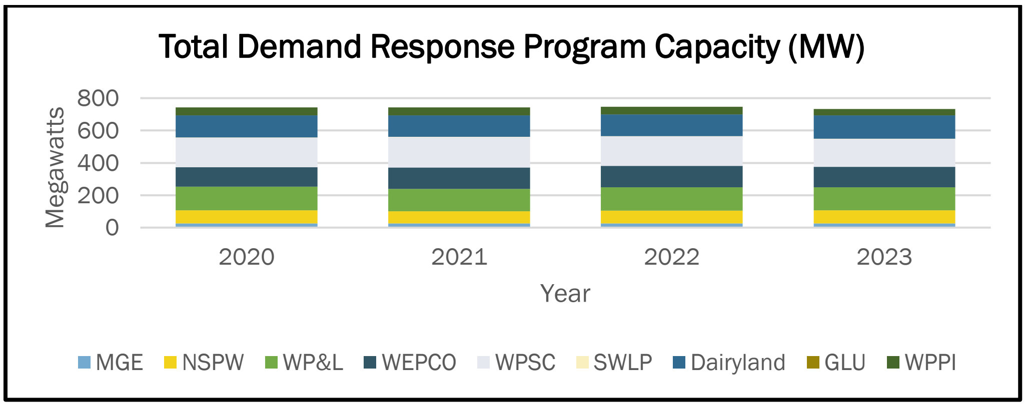
[81] '2019 Utility Demand Response Market Snapshot' by Smart Electric Power Alliance.

- **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 more than 130,000 customers enrolled in interruptible tariffs and direct load control programs, including more than 95,000 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.

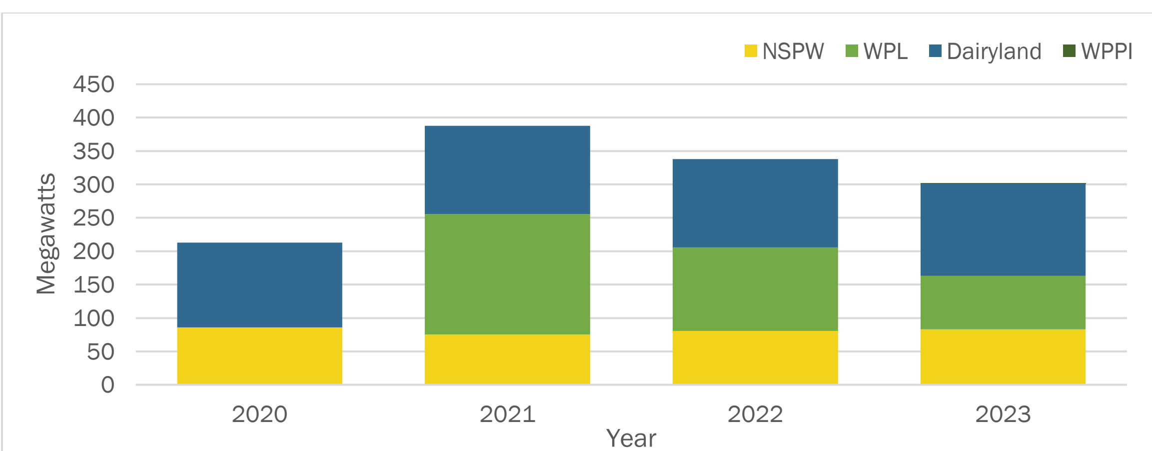
As shown in Figure 3-3, total demand response capacity available through those offerings ranged between 732 and 746 MW between 2020 and 2023, equal to approximately 5 percent of Wisconsin's total peak demand during the period. (See Chapter 1, Figure 1-1.) Interruptible tariffs accounted for approximately three quarters of available capacity in each year, and direct load control programs for the remaining one quarter.

Figure 3-3 Demand Response Capacity (MW) in Wisconsin by Provider, 2020-2023



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 13 to 42 percent of total interruptible load capacity and 84 to 93 percent of direct load control capacity was dispatched capacity by provider, and by individual demand response offerings available from each provider.

Figure 3-4 Demand Response Capacity (MW) Dispatched by Provider, 2020-2023



These dispatch rates largely reflect that demand response offerings are only utilized under specific programmatic conditions that varies by utility. Fewer events have been called in years where weather and grid conditions less frequently meet program criteria.

Another condition for interruptible load in Wisconsin to dispatch is whether MISO calls on it to deploy, as specified in many providers' interruptible load tariffs. In these cases, Wisconsin providers offer reduced rates to interruptible tariff participants in return for registering their demand response capabilities with MISO, most commonly as Load Modifying Resources (LMRs). MISO can obligate LMRs to respond in emergencies, and in return MISO credits the demand response capabilities of LMRs toward the providers' resource adequacy requirements. (See Chapter 2 for more discussion on resource adequacy.) Through a MISO and OMS data collection process, Wisconsin providers reported that an estimated 639 MW of demand response capacity in Wisconsin was registered with MISO in 2023. MISO has indicated a need to reform qualification criteria for its demand response programs which may impact participation in these programs in Wisconsin.

Although the implementation date for FERC Order 2222 in MISO is still years away, there may be more interest in aggregated DER, including aggregated demand response, as stakeholders prepare.[82] Through Order 2222, FERC ruled that aggregated DERs must be allowed to participate in wholesale markets. At present, FERC will allow states such as Wisconsin to continue prohibiting third-parties from aggregating demand response.[83] Therefore, aggregations of demand response that participate in MISO's markets under Order 2222 in Wisconsin would be facilitated by utilities, whereas third parties could organize DER aggregations that did not include demand response.

Gaining access to the MISO wholesale market may stimulate further interest in offering demand response resources in Wisconsin and the MISO footprint through the development of new program models or expanded programs with 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 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 Stat. § 196.378, repealed and recreated in 2005, requires each electric provider to increase the share of renewable energy resources it uses to serve retail customers to achieve a statewide goal for renewable resources to provide at least 10 percent of energy generation by 2015.[84]

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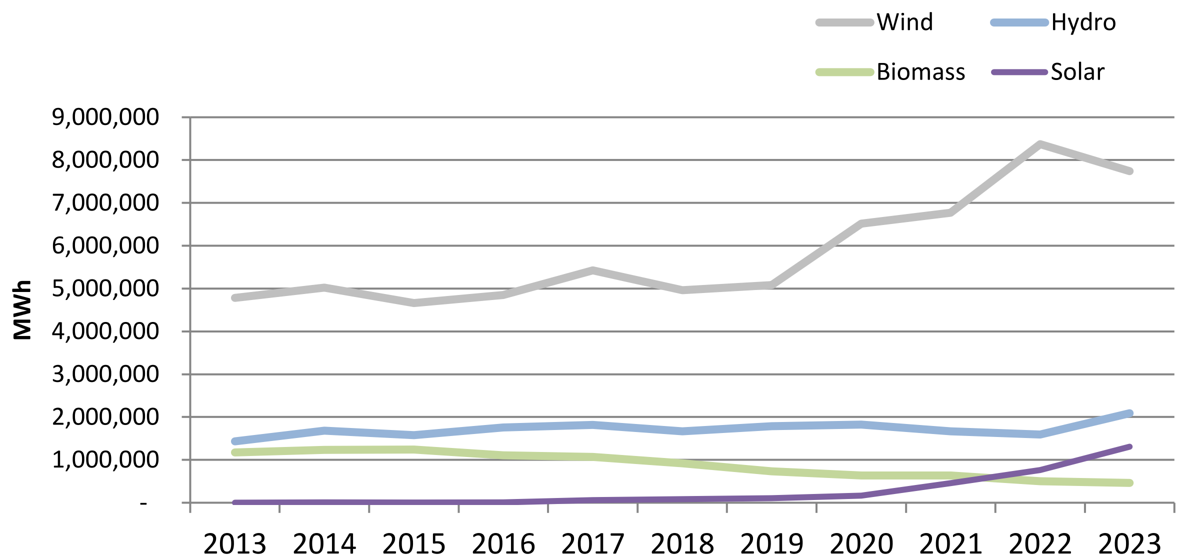
[82] *See* https://cdn.misoenergy.org/2022-04-14%20Docket%20No.%20ER22-1640-000624051.pdf.
[83] Wisconsin prohibits aggregated demand response in certain circumstances under 5-UI-116
[84] To achieve the statewide 10 percent standard, the RPS requires each electric provider to increase their percentage of renewables, relative to their 2001-2003 baseline, by 2 percent by 2010 and 6 percent by 2015.

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

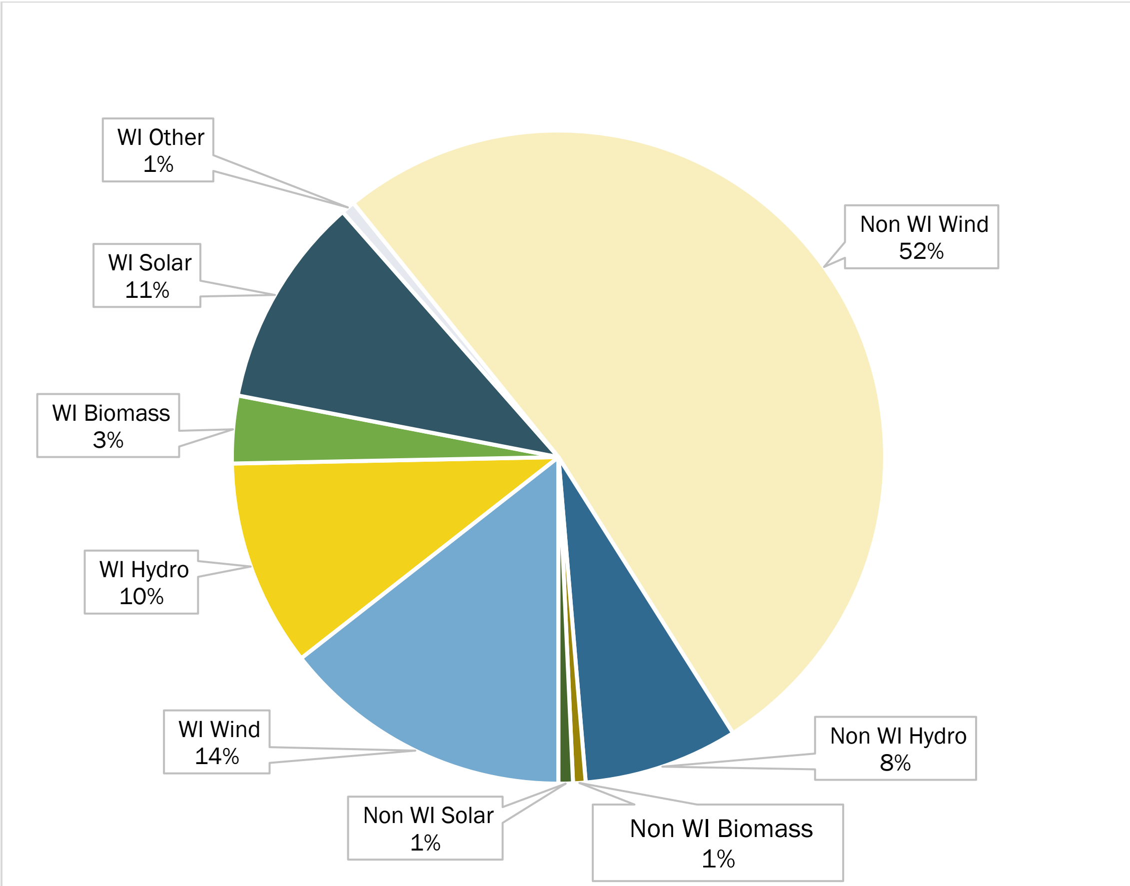
Figure 3-5 Renewable Energy by Resource 2013-2023



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 11.2 percent of total renewable generation deployed by electric providers in 2023, an increase from 6.8 percent in 2022. (These figures do not include solar generation used by individual customers, which is described in the Customer-Scale Renewables section below).

As discussed in Chapter 2, Wisconsin electric providers reported plans to add more than 7,600 MW of new electric capacity from renewable sources between 2024 and 2030, 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, emissionsreductions, 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 IRA may also encourage further deployment increases in future years.

Figure 3-6 2023 Renewable Energy by State and Resource



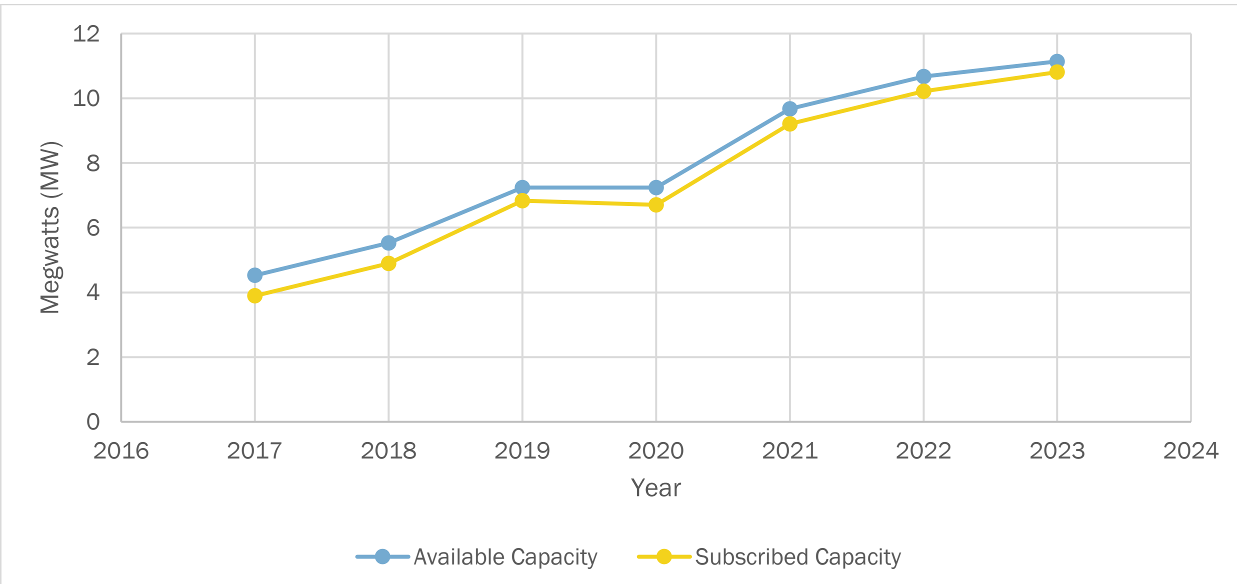
Electric Provider Solar Initiatives

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 MPU's 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.[85] This project was expanded from 1,000 kW to 1,500 kW in docket 3320-TE-115 in 2023.

As shown in Figure 3-7, total capacity offered by Wisconsin community solar programs has increased 146 percent from 2017 to 2023. In that time, customer subscriptions have increased from 86 percent of available capacity to 97 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 ongoing 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.[86]

Figure 3-7 Community Solar Capacity in Wisconsin



Five[87] 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 41.2 MW of solar capacity additions spanning 5 distinct projects[88].

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 for each SEA Commission staff has asked all electric providers in Wisconsin to report data on the number, type, and generation capacity of all non-utility DERs used by their customers, including historical data extending back to 2008.

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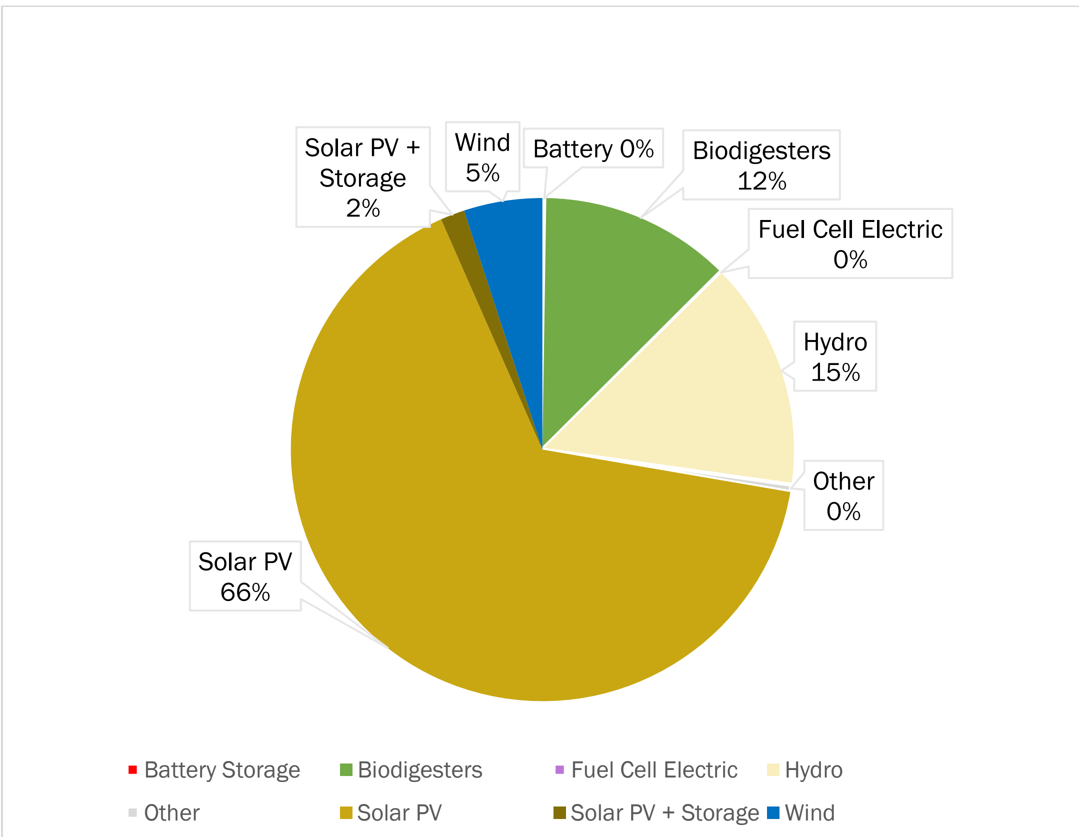
[85] Some DPC members also offer community solar options, but the Commission does not regulate or collect information on those programs.
[86] Both cooperatives are part of DPC so this will be reflected in future SEA reporting.
[87] MGE, NSPW, WEPCO, WP&L, and WPSC
[88] MOC, Morey, Dane County Airport, O'Brien, Hermsdorf

DERs are resources located on the distribution system and generally produce energy that is intended to be consumed on-site. Customer-owned DER data reported by utilities include all customer-owned generation, including generation from non-renewable sources. Non-renewable sources accounted for 17.14 percent of the total customer-owned DER capacity, including 9.98 MW (AC) from gas turbines and 52.96 MW (AC) from internal combustion, but the analysis below focuses on renewable customer-owned DERs.

Customer-owned renewable generation capacity in Wisconsin totaled 304.15 MW (AC) in 2023. The contribution of each resource type to that total is shown in Figure 3-8.[89] Customer-owned solar installations account for the largest share by source. At a total capacity of 200.84 MW (AC), customer-owned solar accounts for 66.03% percent of renewable DER capacity. Solar capacity increased over 20 percent from 157.56 MW (AC) in 2022 and 30 percent from 136.06 MW (AC) in 2021.

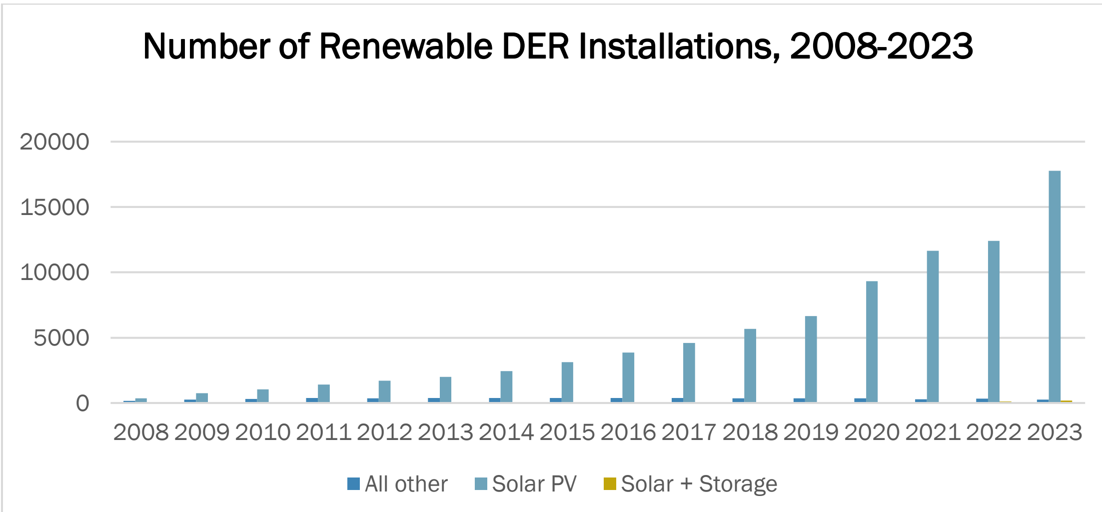
Figure 3-8 MW of Customer-Owned Renewables in Wisconsin (AC), 2023



[89] 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 the two definitions. We primarily report in AC for this analysis whereas past data sets have reported in DC or a mix of AC and DC converted values. In general, staff is seeking to move away from DC capacity reporting as AC capacity is more indicative of useful generation and impacts to the distribution system. The U.S. Energy Information Administration provides a range for this conversation between 1.13 to 1.30. As needed, staff filled in missing data where reported AC system capacity was not included and used an assumed conversion factor that DC capacity is 1.25 times the value of AC capacity, and vice versa for unreported DC values.

As shown in Figure 3-9, the number of customer-owned renewable installations increased from 528 in 2008 to 18,238 in 2023. The most common category of installation is solar, with 17,773 solar installations in the state as of 2023 (up from 12,404 reported solar installations in 2022). The next most common category of installation is solar *plus* storage, at 193 installations in 2023 (up from 115 total installations in 2022). Among other reasons, these installations are likely driven by investment and production tax credits available under the IRA that apply to customer-owned renewables.

Figure 3-9 Number of Renewable DER Installations (2008-2023)



As shown in Table 3-1, residential customers owned a large majority of total solar installations in 2023.[90] While most residential installations are small-capacity systems, commercial and industrial installations accounted for over half of total customer-owned solar capacity due to their more frequent deployment of larger systems.

Table 3-1 2023 Solar DER Snapshot by Customer Category

Category	Number of Installations	Capacity (MW-AC)
Residential	13,939	86.26
Commercial	1,816	74.01
Industrial	185	24.02
Cooperative	1,833	16.56
Total	17,773	196.96

There are also a growing number of solar *plus* storage installations, as shown in Table 3-2, particularly in the residential category. (See Appendix C, Figure C-1 for further information on all customer—owned renewable installations by customer class.)

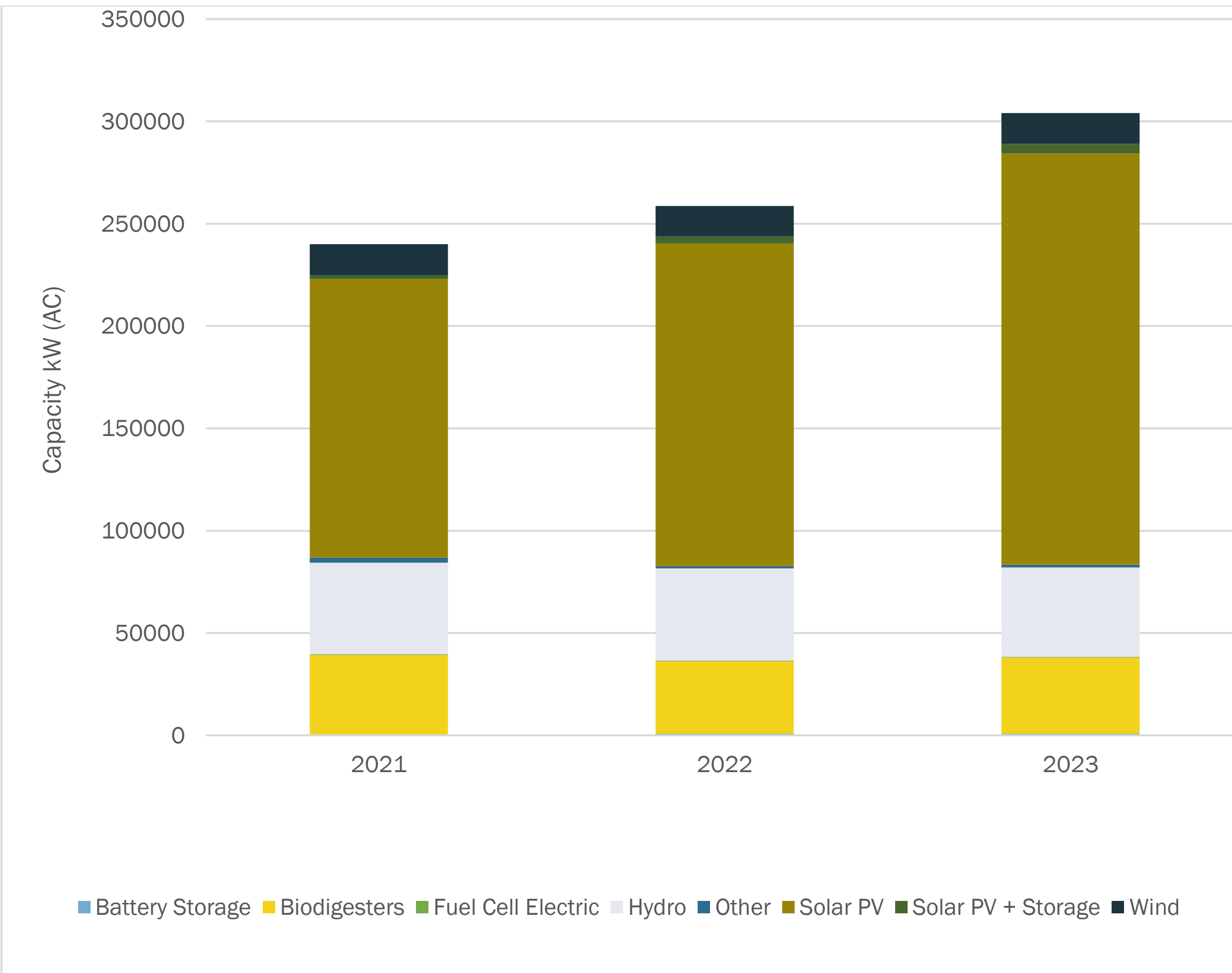
[90] DPC reports their systems under "cooperative" category, although most of those are also likely residential.

Table 3-2 2023 Solar Plus Storage DER Snapshot by Customer Category

Category	Number of Installations	Capacity (MW-AC)
Residential	153	1.74
Commercial	15	2.04
Industrial	1	0.21
Cooperative	21	0.68
Total	190	4.67

As shown in Figure 3-10, capacity from all customer-owned renewables was 304.15 MW (AC) in 2023. Total capacity increased from 2021 and 2022.

Figure 3-10 Installed Capacity kW-AC of Renewable DER Installations by Renewable Source, 2023



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 (usually under 20 kW) distributed energy resources—bill credits that match the retail rate charged to the customer, an arrangement termed "net metering." Other larger customers (usually over 20 kW) 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 docket 5-EI-157, *Investigation of Parallel Generation Purchase Rates*, to broadly examine the purchase rates associated with customer-owned DERs, also known as customer-owned generation systems (COGS). 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.[91] 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 customer-owned DERs. The Commission also directed MGE, NSPW, WEPCO, WP&L, and WPSC to propose updated purchase rates for large COGS.[92] Proposals were filed by all five IOUs in September 2021 and the Commission acted to approve updated buyback 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. The Commission received these studies, requested additional information from the utilities in early 2024, and is currently reviewing the submissions.

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, which typically affects small COGS. In February 2022, Commission staff issued a paper prepared by independent experts at the Regulatory Assistance Project (RAP) for public comment.[93] 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 ofstates throughout the country that have explored net metering reforms in recent years.

During the 2023 rate case proceedings, MGE and WP&L submitted proposals to revise their net metering programs for small COGs. The Commission did not authorize changes to the programs, but instead ordered Commission staff to investigate net metering under existing docket 5-EI-157. The Commission approved a second notice of investigation in March 2024 to provide notice to the public of the investigation and to provide a second opportunity to intervene.[94] Commission staff also prepared a memo requesting comments on the scope of the investigation.[95] The investigation is ongoing pending the results of a literature review and additional public comment, and subject to a future scoping determination by the Commission.

To receive buyback rates, customers must work with providers to interconnect their facilities to the broader electric grid. Interconnection standards and processes are found in Chapter PSC 119 of the Wisconsin Administrative Code. A revised PSC 119 took effect on May 1, 2024, after completion of a

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[91] Commission staff memorandum of December 18, 2020. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=401895
[92] Final decision of May 4, 2021. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=410850.
[93] John Shenot, Camille Kodoch, 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.
[94] Notice of Investigation - Second, Signed and Served 3/14/2024 - PSC REF#: 493957
[95] Cover Letter and Commission Memorandum for Comment - PSC REF#: 494461

rulemaking process that began in 2021; this was the first update of the rule since its initial promulgated in 2004. The revised rule includes new technologies and new technical standards and 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. Additionally, there is a new MISO process, the DER Affected System Study (AFS), which may impact some new DER interconnections. If a utility suspects a proposed DER interconnection may impact the transmission system, MISO and a transmission owner conduct a screening. Based on the screening results, a DER AFS study may be conducted. This process is associated with its own timelines and costs as determined by MISO.

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. The number of EVs registered in Wisconsin has more than doubled in the past two years from approximately 7,500 to 17,100,[96] and sales are expected to keep increasing. 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, *Investigation of Electric Vehicle Policy and Regulation*, to consider future policies andregulations 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.[97] 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.[98] MGE's five pilots address EV charging for residences, apartments and workplaces, fleets, and publicsites. Residential, apartment and workplace, and fleet charging pilots approved by the Commission in

[96] https://wisconsindot.gov/Documents/dmv/shared/rpt-25-fiscal-23.pdf.
[97] Order of December 23, 2020. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=402117.
[98] Commission Meeting Minutes of September 15, 2022. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=448345.

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.[99] 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.[100] The public charging program sets rates for charging sessions at the utility's network of charging stations, with rates varying based on charging speed and duration.[101]

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 willbe 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 periodsof 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 applied under docket 4220-TE-113 proposing limited modifications to its existing programs, as well as the creation of a new multifamily pilot. The Commission approved these programs in July 2023. NSPW also received approval for a public charging proposal included in its 2023 rate case proceedings.[102]

Robust accounting and reporting requirements have accompanied all approved pilot programs 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.

Further growth and developments are occurring outside of actions taken by or considered before the Commission. The Wisconsin Department of Transportation has been tasked with administering the funds available through the National Electric Vehicle Infrastructure (NEVI) program. In November 2021, the Bipartisan Infrastructure Law was signed, designating $7.5 billion to building out a national network of electric vehicle charging stations. The NEVI Program lays the groundwork for formula funding designation and use.

NEVI is specifically intended to build out the electric vehicle charging system along federally designated Alternative Fuel Corridors (AFCs). Currently, in Wisconsin these include five Interstates: I-90, I-94, I-43, I-41, and I-535; seven U.S. highways: US 53, US 151, parts of US 51, US 2 and US 141, and all of US 8 and US 41; one state highway: WIS 29.

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[99] Id.

[100] Order of December 29, 2020. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=%20402247

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

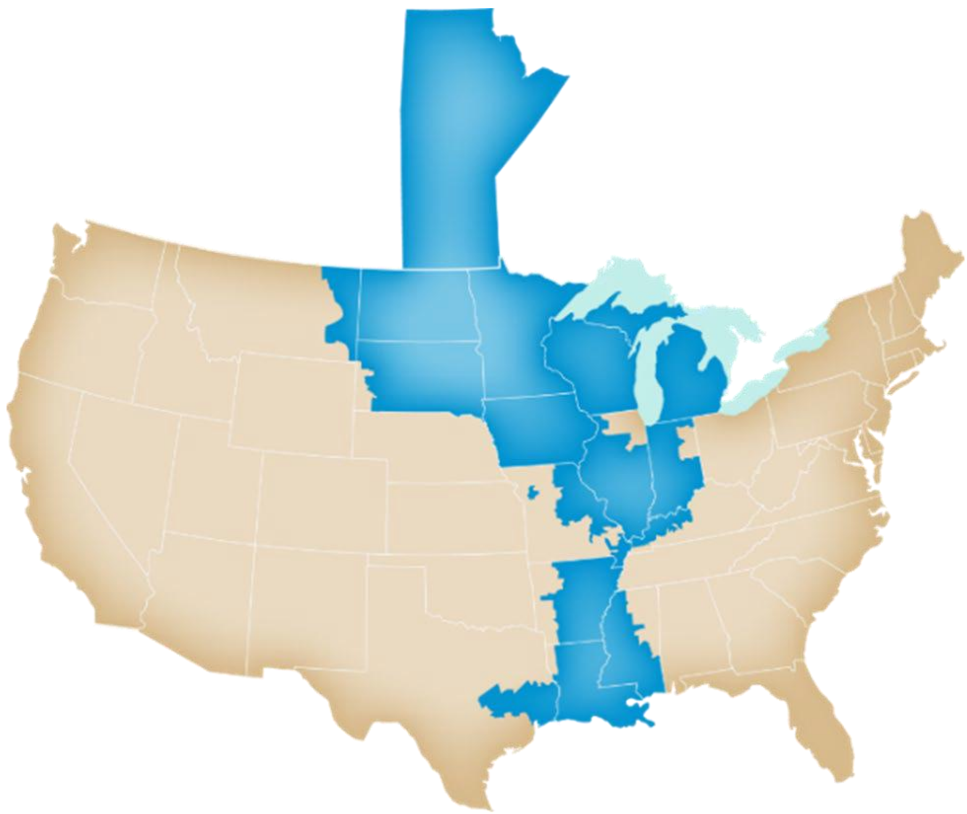
[102] Application of Northern States Power Company – Wisconsin for Approval of Electric Vehicle Programs. August 2, 2022. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=444518.

Fifty-three locations have been awarded over $23.3 million in federal funds through Round 1 of the Wisconsin Electric Vehicle Infrastructure (WEVI) Program.

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 Map of MISO Regional Transmission System



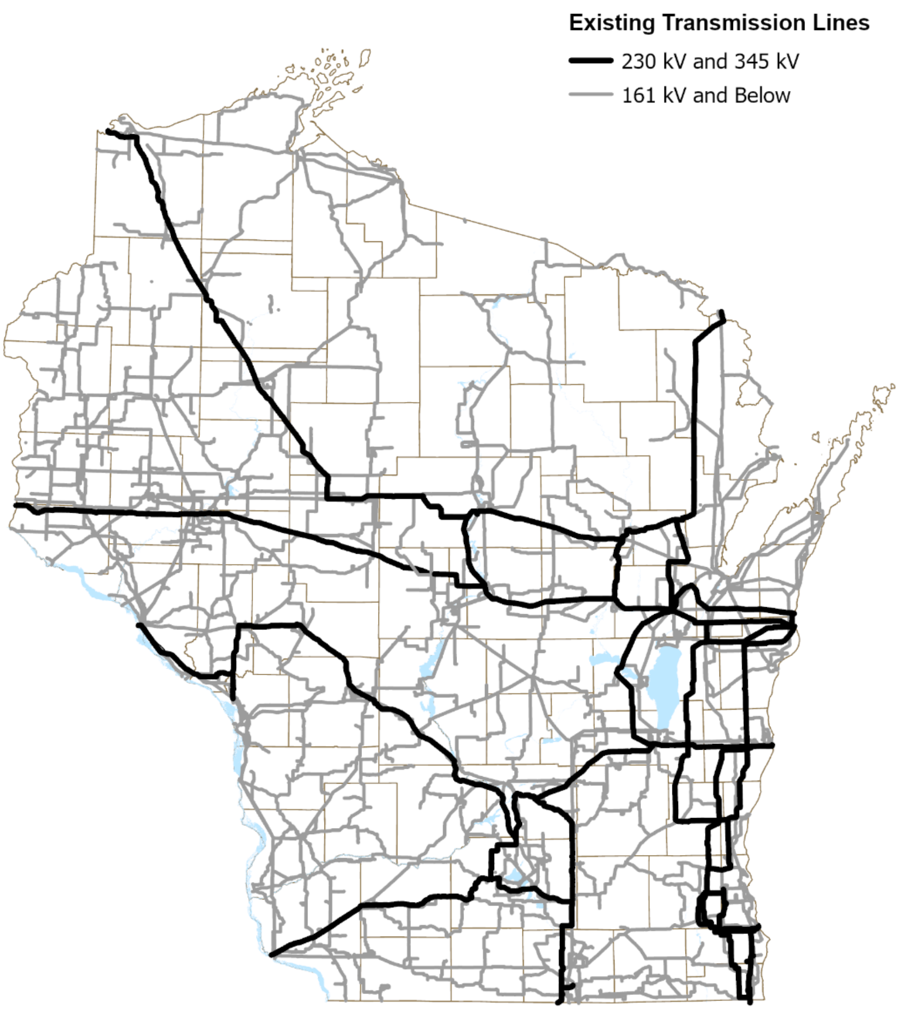
Participation in MISO helps Wisconsin's electric system access additional benefits within a larger regional context, including:

- Accessing less expensive wholesale energy and capacity resoruces available outside of Wisconsin'
- Reducing the generation capacity reserves any single provider may need to meet peak customer demand by taking advantage of more diverse supplies and load patterns;
- Offering access to a wholesale market with clear and predctable energy prices, which can allow providers access to energy resoruces and use price signals to guide their own investment decisions; and
- Managing the transmission grid to enhance region-wide reliability.[103]

[103] MISO states that these benefits currently result in more than $3-4.9 billion in annual cost savings across its region. *See* https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/ MISO does not provide benefit estimates by state.

Wisconsin had 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 volume of energy over longer distances, including to connect high-demand areas in Wisconsin with generation resources located in other states in the MISO region. The newest addition to this system is the 345 kV Cardinal-Hickory Creek transmission line, which completed construction and became completely operational in 2024, connecting the Dane County area to lower-cost renewable sources in Iowa.

Figure 4-2 Existing High-Voltage Transmission Lines in Wisconsin



Historical Transmission Costs

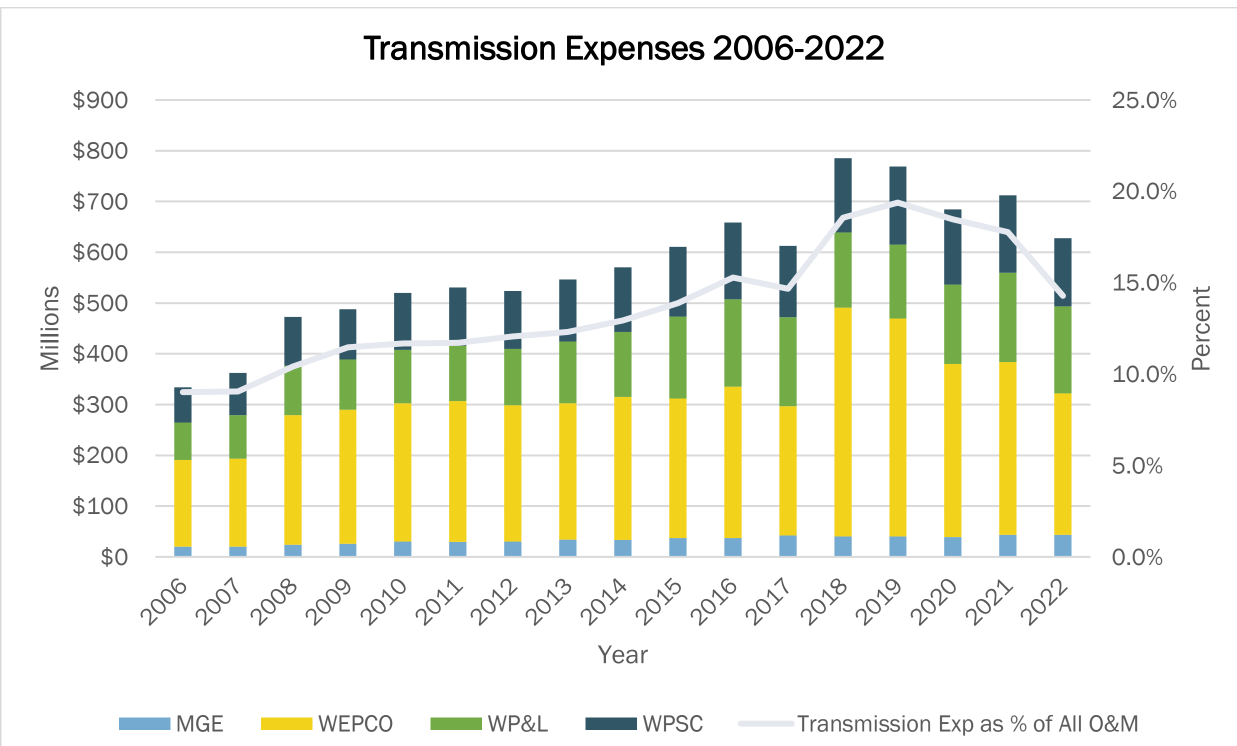
Transmission development and operation occurs collaboratively between MISO and individual providers within the region. Most Wisconsin electric providers do not own or operate their own high voltage transmission lines and associated infrastructure. These assets are owned by the American Transmission Company 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.[104]

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 2006-2022. Combined expenses from ATC and MISO payments increased from $334.1 million in 2006, to a high of $785.6 million in 2018, and have since decreased to $628.0 million in 2022.

Figure 4-3 Transmission Expenses, 2006-2022: MGE, WEPCO, WP&L, and WPSC

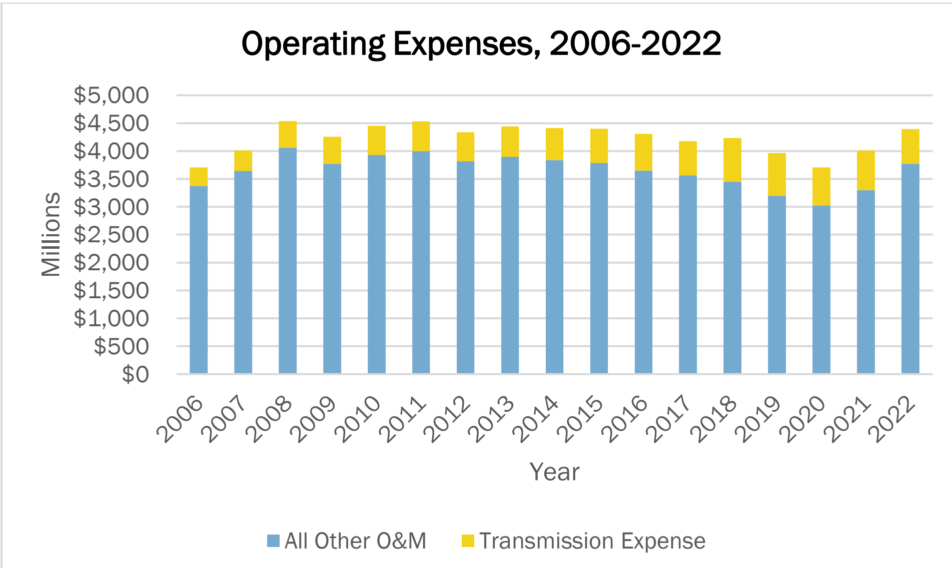


Transmission accounted for an increasing proportion of those electric providers' total operating expenses from 2018-2021, while decreasing in 2022. However, as shown in Figure 4-4, the total

[104] DPC also operates its own transmission system.

operating expenses paid by customers have remained comparatively stable, ranging from approximately $4.0 to $4.5 billion each year between 2007 and 2022, except for a low of $3.7 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, including 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.

Figure 4-4 Operating Expenses, 2006-2022: MGE, WEPCO, WP&L, and WPSC

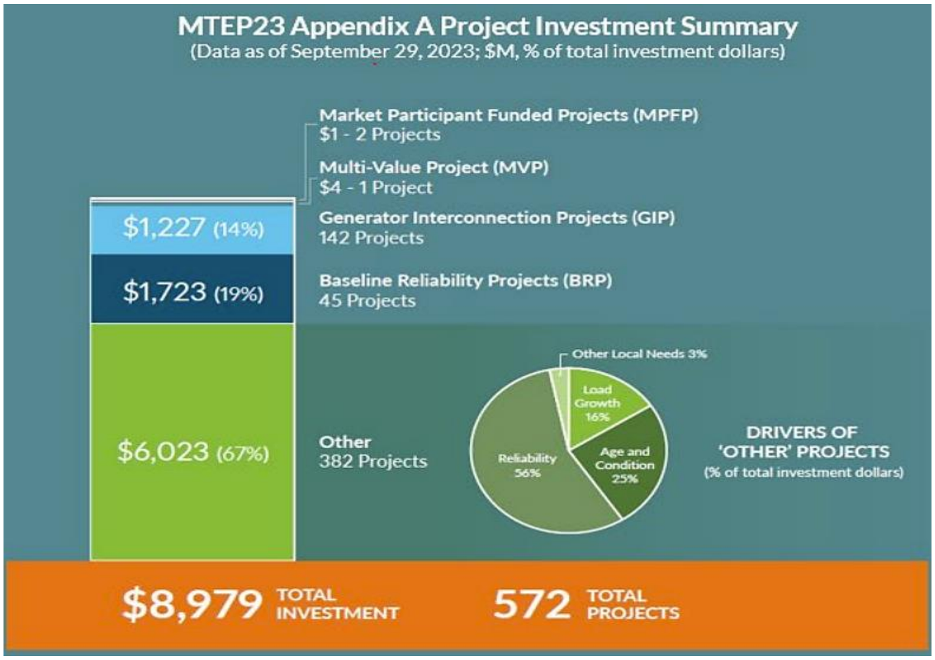


Increased transmission costs in Wisconsin over the past 15 years reflect increased transmission line development and construction costs. The annual MISO Transmission Expansion Planning (MTEP) process serves as a primary foundation for reviewing transmission needs and identifying and developing transmission 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, which resolve National Electric Reliability Corporation (NERC) standards to ensure the regional grid functions reliably;
- Generation interconnection projects (GIPs) to support the addition of new generation facilities in specific locations;
- Market efficiency projects (MEPs) to reduce transmission costs by reducing congestion on the transmission grid;
- “Other” projects that resolve specific, typically local issues like:
    - Local reliability projects to address localized transmission capacity needs within transmission owner service areas;
    - Age and condition updates to replace or enhance existing transmission infrastructure; and
    - Load growth projects to update the transmission system to meet increased demand at 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 2021. In the most recently completed planning cycle, MISO approved 572 MTEP23 projects totaling in almost $9 billion in costs across the entire regional footprint. As shown in Figure 4-5, local reliability projects accounted for the largest share of approved projects region-wide, followed by age and condition.

Figure 4-5 MISO MTEP23 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, $670.3 million in costs for 60 approved MTEP23 projects will be allocated to Wisconsin, with most costs allocated to age and condition updates.

Table 4-1 MTEP23 Projects in Wisconsin

Types of Projects	Estimated Costs	Number of Planned Projects
Baseline Reliability Projects	$74,200,000.00	3
Generator Interconnection Projects	$136,220,096.00	12
Other[105]	$459,904,000.00	45
Age and Condition	$268,050,000.00	27
Load Growth	$89,554,000.00	8
Other Local Needs	$11,600,000.00	2
Reliability	$90,700,000.00	8
Total	$670,324,096.00	60

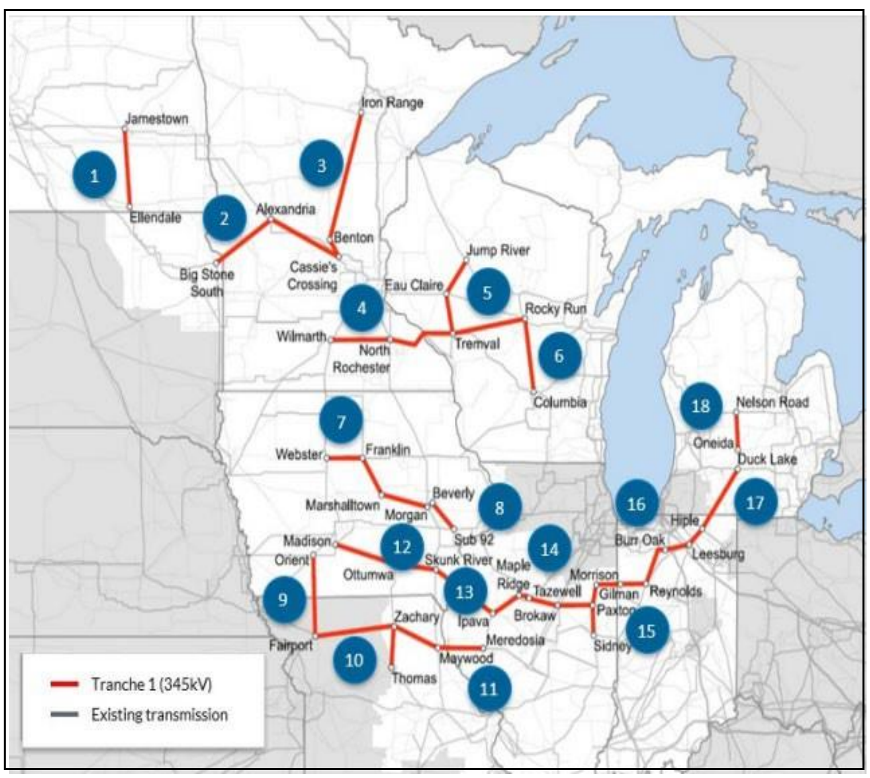
[105] The "Other" category includes Age and Condition, Load Growth, Other Local Needs, and Reliability Projects, whichare italicized in this Table to distinguish these as sub-categories.

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 additional groups of large-scale regional transmission projects through its 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. 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 resources and add a substantial amount of new resources at a variety of locations.

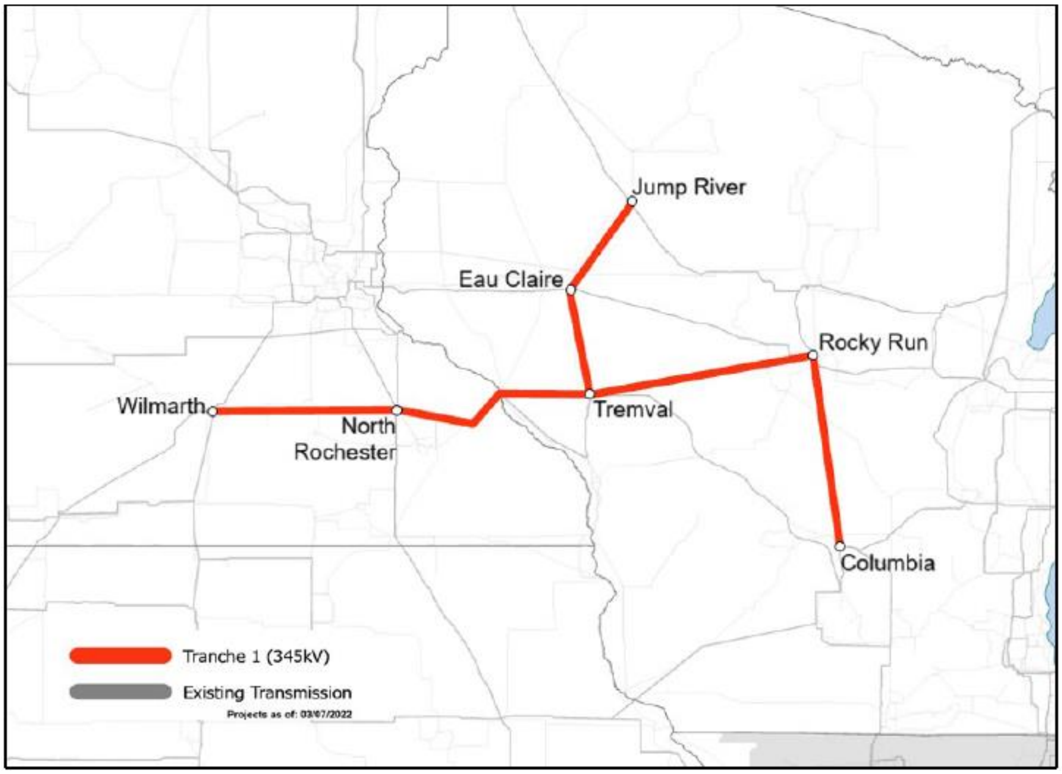
MISO indicates that four tranches of LRTP projects are planned to be pursued with Tranches 1 and 2 addressing reliability needs in the North/Central subregions, Tranche 3 addressing transmission needs in the South subregion, and Tranche 4 addressing the North/South interface limit. MISO approved the Tranche 1 projects shown in Figure 4-6 in July 2022 as an addendum to MTEP21. Tranche 2 planning is currently underway and the timing for MISO analysis and approval of Tranches 3 and 4 will be determined as Tranche 2 approaches MISO approval.

Figure 4-6 LRTP Tranche 1 Transmission Portfolio (MISO Midwest)



MISO reports that Tranche 1 represents a portfolio of least-regrets transmission projects aimed to ensure a reliable, resilient, and cost-effective transmission system as the region's generation resource mix continues to evolve. Total region-wide costs for the approved Tranche 1 projects are currently estimated at $10.3 billion.[106] Projects approved by MISO will require transmission providers to design, plan, and seek regulatory approvals in each state where the projects will reside. Under state law, projects sited in Wisconsin will be required to receive Commission approval. The transmission line review process involves rigorous reporting and analysis, as well as numerous opportunities for public participation, as described for construction cases (CA/CPCN) in Chapter 2. As shown in Figure 4-7, LRTP Tranche 1 projects four, five, and six from Figure 4-6, would be sited partially or completely in Wisconsin, subject to Commission approval.[107]

Figure 4-7 LRTP Tranche 1 Transmission Projects in Wisconsin



According to MISO, the Minnesota–Wisconsin series of projects, Tranche 1 projects four, five, and six, will work together to address related issues. MISO reports that the transmission system in southern Minnesota is the connection between significant wind and renewable resources in Minnesota and North and South Dakota, the regional load center of the Twin Cities, and load centers to the East and South. MISO estimates the projects will relieve transmission constraints around the Twin Cities metro area caused by high renewable flow toward and past the Twin Cities load center. For Wisconsin, MISO estimates the projects could add transfer capacity toward load centers in the

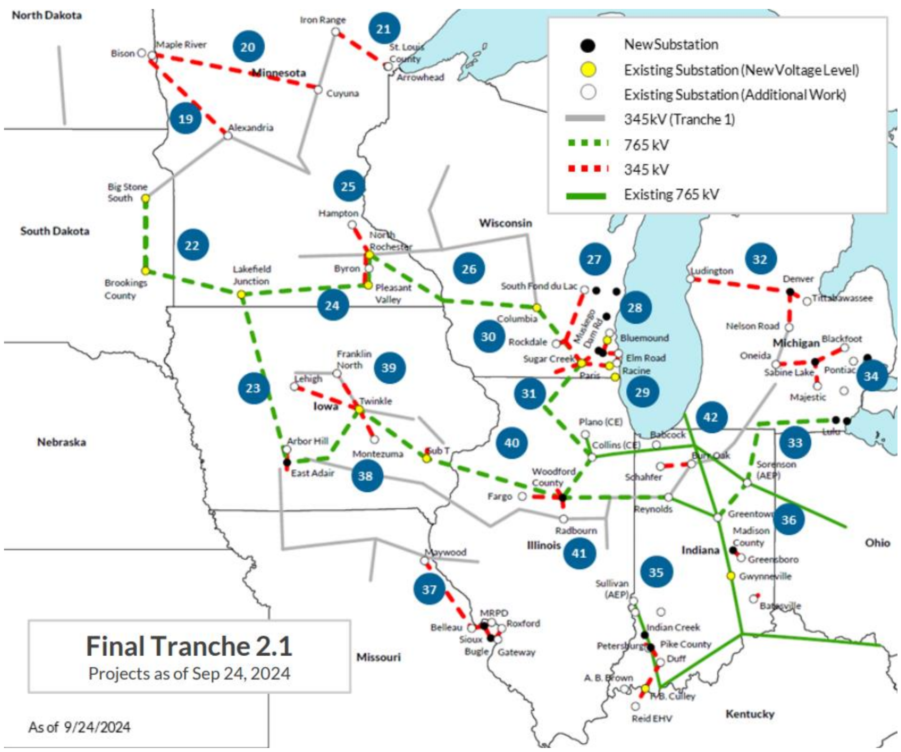
106 This estimate is based on "overnight costs" or is a simplistic estimate of project costs if they were constructed overnight without considering interest rates, lifespan, and other factors. See MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary, here: MTEP21 Addendum-LRTP Tranche 1 Report with Executive Summary

107 *See* dockets 1515-CE-103, 5-CE-157, and 5-CE-158.

state that could reduce transmission congestion and address thermal loading and transfer voltage stability.

The Tranche 2 planning efforts commenced in the fourth quarter of 2022 and are expected to be approved by the MISO BOD by the end of 2024 (as "Tranche 2.1"). Figure 4-8 shows the proposed portfolio of projects up for approval by the MISO Board of Directors as of September 2024.

Figure 4-8 MISO Proposed LRTP Tranche 2.1 Transmission Portfolio (MISO Midwest) (as of September 24 2024)



Throughout the LRTP analysis process, Commission staff has participated in MISO's public stakeholder processes that discuss the rationale for these projects and have worked with the OMS in reviewing the drivers and needs for these projects. This engagement will continue as MISO pursues analysis for all future LRTP tranches.[108]

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,

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

MISO proposed tariff revisions to modify the cost allocation methodology for LRTP projects in FERC Docket No. ER22-995.[109] FERC accepted the tariff revisions in May 2022.[110]

This tariff update modified 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 created two sub-regions of the MISO footprint, a MISO Midwest (North/Central) 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 sub-region,with exceptions for projects that provide demonstrated benefits to all of MISO. According to this method, the cost of the LRTP Tranche 1 and 2 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. In 2021, using MISO's forecastedenergy use for Wisconsin electrical providers and the predicted MUR for the Tranche 1 projects, Commission staff 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.

In addition to delegating power to coordinate transmission services to regional transmission owners and operators, FERC may issue Orders that impact transmission processes for MISO and other transmission providers. In 2024, FERC issued Order No. 1920 which requires transmission providers including MISO to adopt long-term regional and scenario-based planning. MISO's LRTP processes and cost allocation methods may already align with the requirements of Order No. 1920, however, it is possible that the Order will necessitate changes to how MISO conducts long-term planning in the future. MISO has not yet begun working with stakeholders on its plan to comply with Order No 1920. In addition to this Order, FERC issued an Advanced Notice of Proposed Rulemaking in 2024 on the Implementation on Dynamic Line Ratings (DLRs). DLRS are a prominent category of grid-enhancing technology. FERC's intention is for DLRs to improve overall grid performance and transmission efficiency, and as this issue progresses at FERC, there may be subsequent changes to MISO's processes.

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

[110] *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

The National Oceanic and Atmospheric Administration has found that the number of weather events with costs exceeding one billion dollars have continually increased, in part due to the effects of climate change. Nationwide, billion-dollar disasters averaged six per year in 2000-2009 and 12 per year from 2010-2019, and 22 per year from 2020-2023 with 22 events in 2020, 20 in 2021, 18 in 2022, and 28 in 2023.[111] Of those billion-dollar disasters, seven events in 2022 and six in 2023 impacted Wisconsin.[112] Enhanced national attention has also resulted from the February 2021 Winter Storm Uri, which generated record-low temperatures and snow and ice cover that caused widespread disruptions in utility service,[113] and the December 2022 Winter Storm Elliot, where 90.5 GW of unplanned generation unit outages—13 percent of the total winter generation resources available in the U.S. at that time—contributed to power outages for millions of electricity customers in the Eastern half of the country and resulted in the FERC and the North American Electric Reliability Corporation (NERC) recommendations to improve coordination among electric and natural gas infrastructure entities during extreme weather.[114]

As a result of increased, nationwide attention on "high impact, low frequency" (HILF) events that can result in lengthy service interruptions and significant recovery costs, electric providers and their regulators have heightened their focus on resilience. Resilience efforts attempt to prevent HILF events from occurring and support a swift recovery after an event occurs.

In FERC Docket No. AD18-7-000, FERC asked MISO and other regional transmission organizations to review the resilience of their systems. In its February 2021 Order in that docket, FERC concluded that the responsibility of resilience would be best addressed on a "case-by-case and region-by-region basis," in a way that dealt with the distinct threats posed by different regional weather events such as wildfires, hurricanes, and winter storms.[115] Consistent with this Order, the Commission has collaborated with other organizations within Wisconsin and the Midwest to enhance state-level planning and policy development on resilience issues.

State law places the primary responsibility for responding to large-scale emergencies—energy or otherwise—that exceed local capacities with the Department of Military Affairs, Division of Emergency Management (commonly known as Wisconsin Emergency Management [WEM]). Within the Commission, the Office of Energy Innovation (OEI) serves as a lead advisory agency to WEM in responding to energy-related emergencies. In this role during emergency situations, the OEI provides energy subject matter expertise and coordinates response and recovery with WEM and other state

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[111] National Oceanic and Atmospheric Administration, National Centers for Environmental Information. "Billion Dollar Weather and Climate Disasters." https://www.ncdc.noaa.gov/billions/time-series.
[112] National Oceanic and Atmospheric Administration, National Centers for Environmental Information. "Billion Dollar Weather and Climate Disasters." https://www.ncei.noaa.gov/access/billions/time-series/WI/cost.
[113] https://comptroller.texas.gov/economy/fiscal-notes/2021/oct/winter-storm-impact.php.
[114] FERC, NERC Final Report on Lessons from Winter Storm Elliott. November 2023. https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.
[115] FERC Order in Docket No. AD18-7-000, February 18, 2021. https://www.ferc.gov/media/e-3-ad18-7-000.

agencies, other state energy offices, private sector industry and organizations, and the federal government.

The OEI and WEM work together to carry out the OEI's federal requirement to maintain energy emergency plans that respond to supply disruptions. To align with the energy security planning elements of the federal Infrastructure Investment and Jobs Act (IIJA), also known as the Bipartisan Infrastructure Law, the OEI updated the Wisconsin Energy Security Plan in Fall 2022 and 2023.[116, 117] The OEI will submit further updates to the plan in Fall 2024. Additionally, in 2023 the OEI supported WEM in updating the Wisconsin Emergency Response Plan ESF-12 Energy and will continue to exercise and improve the plan under the plan's three-year cadence for making updates.[118]

WEM and the OEI regularly participate in planning and exercises at the local, state, regional, and national level, working with other actors to model planning and responses to HILF events. For example, in June 2022 the OEI hosted a Midwest regional energy emergency exercise, Shattered Cheddar, to explore the state's ability to prepare for and respond to a long-term power outage and subsequent fuel shortages resulting from an extreme event. The exercise included emergency management, state energy office, and utility commission personnel from Midwestern and other neighboring states, county and tribal emergency managers, utilities, and other public and private critical infrastructure owners and operators. The objectives of Shattered Cheddar included: examining state, local, tribal, and federal government roles and responsibilities, authorities, and actions that would be used during a regional event; reviewing communications procedures and reporting mechanisms; and identifying gaps in state energy security and response plans related to regional coordination, fuel coordination, and cybersecurity.

The OEI also supports ensuring a resilient grid infrastructure through implementation of related federal grants administration. Section 40101(d) of the IIJA established a five-year formula grant program, Preventing Outages and Enhancing the Resilience of the Grid, for States and Indian Tribes to enhance the reliability of the electric grid by supporting activities that reduce the likelihood, consequences of, and impacts to the electric grid from extreme weather, wildfire, and natural disaster. The OEI awarded the inaugural round of grant funding of $8.5 million in June 2024 to twelve electric cooperatives and four municipal electric utilities to support nineteen projects that invest in the modernization and hardening of Wisconsin's electric grid; reduce the frequency and duration of service interruptions; and increase the skilled workforce to support grid resiliency activities. OEI will award remaining funds in subsequent grant rounds.

Several other grant and technical assistance projects continue to contribute to energy resiliency and emergency planning in the state. Through four rounds of the Wisconsin Refueling Readiness Grant Program, state energy program formula funds have been made available for the installation of equipment and wiring to enable a swift connection of a generator at petroleum storage and fueling sites during a power outage. Following on its Statewide Assistance for Energy Resilience and Reliability (SAFER2) grant program, which was funded through a competitive U.S. DOE grant in 2019, the OEI dedicates staff time to coordinate statewide planning with local emergency management officials at the regional, tribal, county, and municipal levels. Lastly, the OEI Critical Infrastructure Microgrid and Community Resilience Center Pilot grant program focused on innovative pre-disaster

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[116] Infrastructure Investment and Jobs Act, Pub. L. No. 117-58 (2021), https://www.congress.gov/117/plaws/publ58/PLAW-117publ58.pdf
[117] 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.).
[118] https://wem.wi.gov/wisconsin-emergency-response-plan/

mitigation through critical infrastructure microgrids and other resilient building strategies, by studying the feasibility of the deployment of 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.[119] As a result of the interest in this pilot, the Commission included microgrid feasibility study and implementation projects as eligible activities beginning in the 2022 round of the OEI Energy Innovation Grant Program.

Cybersecurity

Concern with cybersecurity attacks that create energy outages or diminish service through attacks on the grid control networks used by system operators continue to be a national priority. With the changing landscape of energy distribution that not only includes typically utility-operated centralized power plants but also renewable energy generation, battery storage, and hybrid power plants, and the advancing electrification market, grid planners and operators face new security challenges. In March 2023 the Biden Administration issued a National Cybersecurity Strategy with objectives that seek to address cybersecurity regulation of and practices within critical infrastructure, including the electric and pipeline sectors.[120] The National Cybersecurity Strategy establishes the Cybersecurity and Infrastructure Security Agency (CISA) as the national coordinator that engages with Sector Risk Management Agencies, who in turn facilitate energy sector owners and operators to report, identify gaps, and prevent or mitigate the impacts of cyber incidents and threats. The National Cybersecurity Strategy also encourages regulators address investment in cybersecurity measures in ratemaking processes or other cost recovery mechanisms.

Several national organizations have established guidelines for cybersecurity within the energy industry. The National Institute of Standards and Technology (NIST) Cybersecurity Framework was developed following the 2013 presidential Executive Order 13636.[121,122] This Framework is voluntary and includes standards, guidelines, and activities to reduce the risk of cyber-attacks on critical infrastructure. The most-recent iteration of NIST's Framework, released February 2024, expands the scope of its application beyond critical infrastructure and engages in the practice of adoption the Framework internationally through International Organization for Standardization (ISO), and provides implementation examples, while retaining its format as a risk management reference document. Another guidance document, NERC's Critical Infrastructure Protection (CIP) Standards, includes requirements imposed on the bulk electric system (BES), those systems over 100 kV, to address cyber-related threats such as performing a risk assessment and analysis, firewalls and other controls, personnel training, physical security, incident reporting, and response recovery. Third, NARUC has developed with stakeholders a draft Cybersecurity Baselines for Electric Distribution Utilities and Distributed Energy Resources, which in its first phase intends to standardize cybersecurity risk and vulnerability management, mitigation, response, and recovery activities, and

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[119] Critical Infrastructure Microgrid and Community Resilience Center Pilot Grant Program interactive story map of applicants and project details. https://maps.psc.wi.gov/portal/apps/MapJournal/index.html?appid=011d448c66ef498e9011a160d37a2a1f&_gl=1*tdo vsj*_ga*OTMxNjg4OTcxLjE1OTExMDc0ODE.*_ga_MDKJWR1B6S*MTY0NjkzNzY4MS40Ni4xLjE2NDY5MzgzMTkuMA.

[120] White House National Cybersecurity Strategy. https://www.whitehouse.gov/wp-content/uploads/2023/03/National-Cybersecurity-Strategy-2023.pdf

[121] Executive Order 13636. https://obamawhitehouse.archives.gov/the-press-office/2013/02/12/executive-order-improving-critical-infrastructure-cybersecurity

[122] National Institute of Standards and Technology (NIST) Cybersecurity Framework. https://www.nist.gov/cyberframework

the second phase intends to provide guidance on implementing these baselines. NARUC has also collaborated with the National Association of State Energy Officials (NASEO) to create a Cybersecurity Advisory Team for State Solar (CATSS) to develop a roadmap and tools for implementing cybersecurity practices within grid-connected solar assets.

Within Wisconsin, WEM worked with state and local government officials and other owners of critical state infrastructure to add a Cyber Incident Response Plan to the Wisconsin Emergency Response Plan in 2015, and, informed by exercising the plan, WEM added a Cyber-Incident Response Annex to the Wisconsin Emergency Response Plan in 2021. The annex details cybersecurity response capabilities, including 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.

In March 2023 and April 2024, 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 and identifying 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.

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 would need to recover through customer rates to provide adequate and reliable service and an opportunity for a reasonable return. 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 adjusts 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.)

Two 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.)

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 through 2021.

One key reason sales have not returned to pre-2008 levels is 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 15 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), 2007-2022[123]

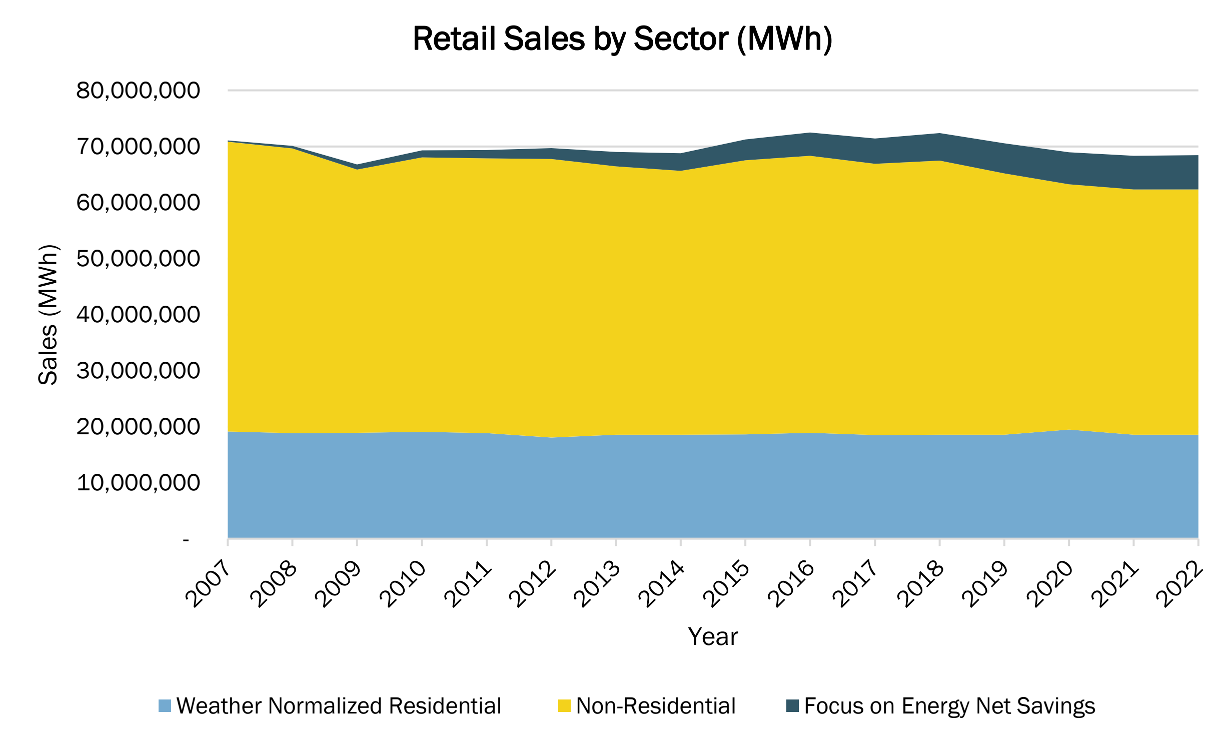

Table 6-1 Annual Growth Rates for Retail Electricity Sales (%)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Average Growth
Residential	0.9%	-1.1%	-4.3%	2.9%	0.0%	0.0%	1.7%	-2.2%	0.5%	-0.1%	4.9%	-4.7%	0.1%	-0.2%
Non-Residential	4.3%	0.1%	1.4%	-3.7%	-1.7%	4.0%	1.0%	-2.1%	1.0%	-4.6%	-6.2%	0.0%	0.0%	-1.1%
Total	3.3%	-0.3%	-0.2%	-1.9%	-1.2%	2.9%	1.2%	-2.1%	0.8%	-3.3%	-3.0%	-1%	0%	-0.8%
Total w/o Focus on Energy	3.8%	0.1%	0.5%	-1.0%	-0.3%	3.6%	1.7%	-1.5%	1.4%	-2.6%	-2.3%	-1%	0%	-0.2%

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 8 percent from 2007 through 2022. 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 90 percent from 2007 through 2022. (See Appendix D, Figures D-1 and D-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.

123 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.

Performance Based Regulation

As part of the State's 2022 Clean Energy Plan and the *Roadmap to Zero Carbon Investigation* in docket 5-EI-158, the PSCW is investigating Performance-Based Regulation (PBR) in Wisconsin. In states using PBR, utilities are incentivized to achieve performance objectives rather than prioritizing capital investment earnings in order to enhance shareholder value and impact the revenue requirement. These objectives and the metrics used to measure them tend to be based on customer-centric issues traditionally not prioritized by the current framework. The Commission is investigating the development of metrics related to goals to improve reliability, energy efficiency, and affordability. More details on the metrics related to those goals will be developed, and additional metrics may be considered, as work continues in the *Roadmap to Zero Carbon Investigation*.

Public Participation

The Commission encourages public participation in all its cases. How an individual or organization participates in a proceeding depends on their interest in the issues and the type of case. The easier and more common way to participate in a case is as a member of the public. Any person or organization can follow a case by tracking the filings in the case on the Commission's Case Management System, and, at the time and in the manner requested by the Commission, providing their opinion to the PSC either by attending a public hearing, or submitting a written comment for the record.

Alternatively, any person or organization that meets certain criteria may participate in a case as an intervenor. Those who have substantial interests that might be affected by a case can request to become a party through "intervention." Intervenors may qualify for compensation for some costs incurred while participating.

In 2022 and 2023, the Commission saw an increase in public engagement in generic investigations, construction and rate cases, including an increase in the number of intervenors seeking compensation. During this period, five different intervenors were awarded intervenor compensation for an average award of $34,896.

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. Declining usage may help avoid some costs, such as those associated with new power plant and transmission construction. However, many factors can influence costs, and declines or limited growth in customer usage can also increase the risk that customer rates need to be increased to absorb required fixed costs.

Revenue Requirements of Investor-Owned Utilities with Generation

Wisconsin's five largest IOUs,[124] which serve nearly 90 percent of the state's electric customers, provide most of the electric supply through utility-owned generation. Most of the revenue requirements for each of these "Major IOUs" comes from generation and distribution.

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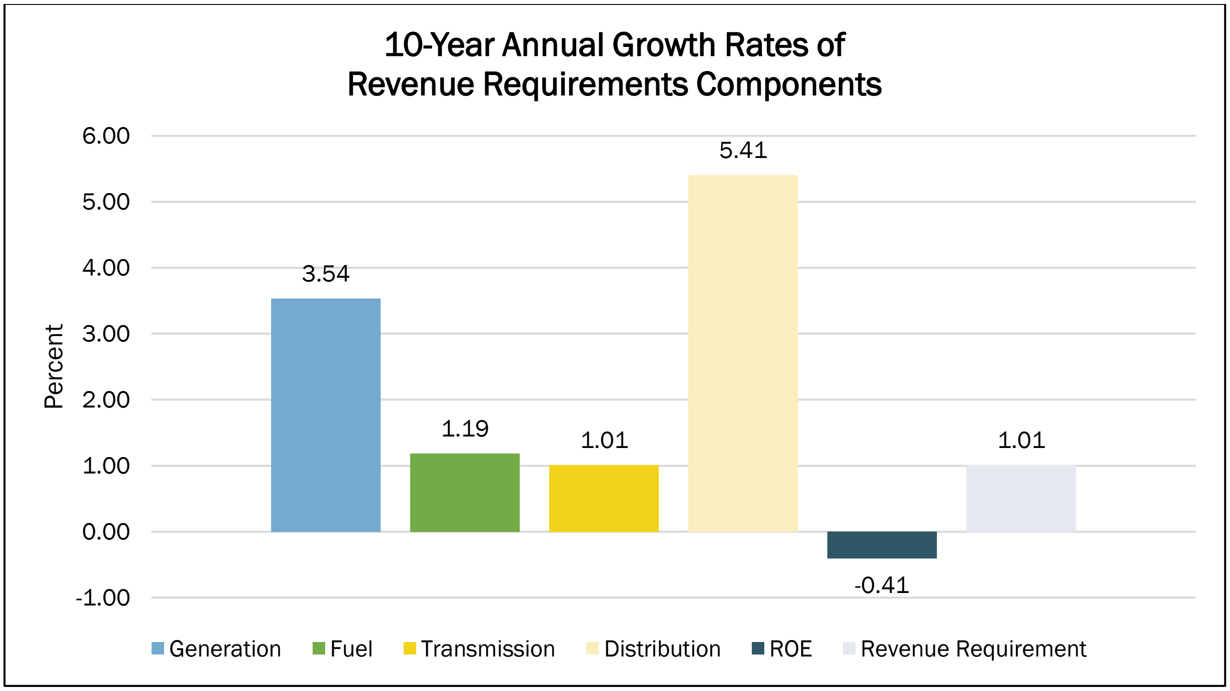
[124] MGE, NSPW, WEPCO, WP&L, and WPSC.

As shown in Figure 6-2, total revenue requirements for the Major IOUs increased 1.01 percent per year between 2013 and 2022. Of the revenue requirement components, the Commission has direct control over generation, return on equity (ROE), and distribution for large projects. Fuel costs and transmission rates are mostly outside the Commission's control and represent pass-through expenses.

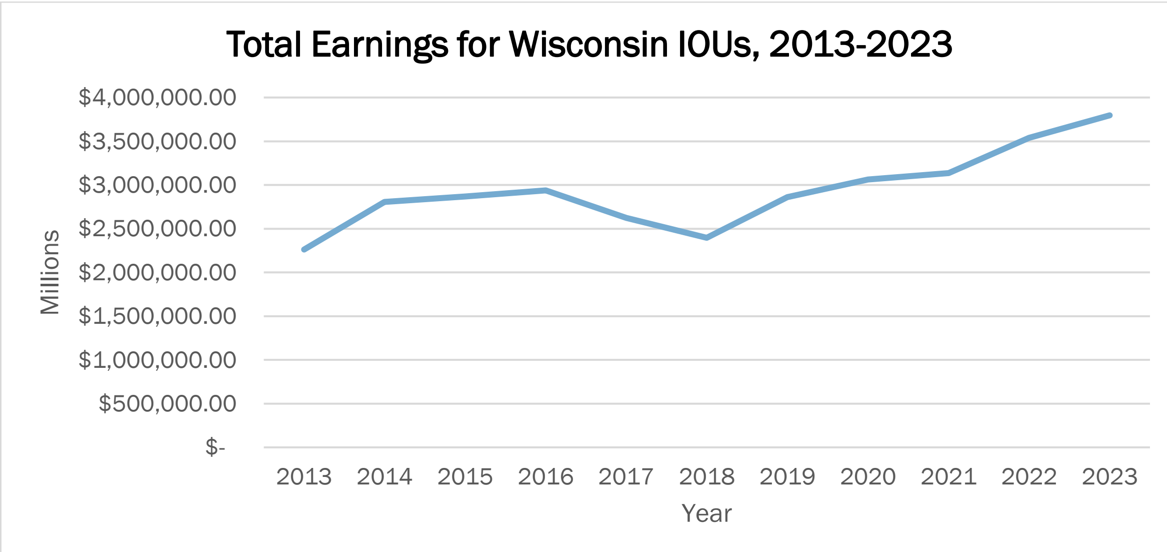
Figure 6-2 Ten-year Annual Growth Rate of Revenue Requirements Components—Major IOUs (%)



The increase in total revenue requirement between 2013 and 2022 was driven primarily by increasedcosts 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. Fuel and transmission costs also increased, as analyzed further in Chapter 2 and Chapter 4, respectively. Fuel costs began to increase due to increased natural gas prices during 2022 and due to changes in generation mix and market conditions. Investments in new generation may result in further increases in generation and distribution costs for new utility-owned generation. Revenue requirement increases were partially offset by decreases in IOU assets.

ROE is a metric set by the Commission in rate cases that derives a utility's profitability. Because expenses such as operations and maintenance and debt costs are passed through to customers, the ROE, which is a return on the capital owned by the utility, is the key variable used to set profit margins. ROE is set for each utility in a rate case proceeding. When setting an ROE, the Commission considers the requested ROE from the utility, any ROE recommendations by intervening parties, as well as an ROE recommendation produced by Commission staff. Given that ROE represents the utility profits, even a minor change can have a large effect on the revenue utilities are allowed to collect and the price customers pay. Changes in ROE effect the rates charged to customers and approximately half of the savings from a lower ROE go to residential customers. ROE has generally remained flat or trended down, due in part to low interest rates during this time period. However, as shown in Figure 6-3, a decrease in ROE does not mean a decrease in earnings; the total earnings for Wisconsin IOUs increased from about $2.25 million in 2013 to about 3.75 million in 2023.

Figure 6-3 Total Earnings for Wisconsin IOUs, 2013-2023



Effects of Tax Reform and Federal Funding on Investor-Owned Utilities

In December 2017, the federal Tax Cuts and Jobs Act (TCJA) implemented reforms to the federal tax code. Wisconsin IOUs 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. At this time, all IOUs have had a rate proceeding that incorporated the 21 percent tax rate or in the case of a few smaller IOUs have a rate proceeding currently in progress.

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 coming years.

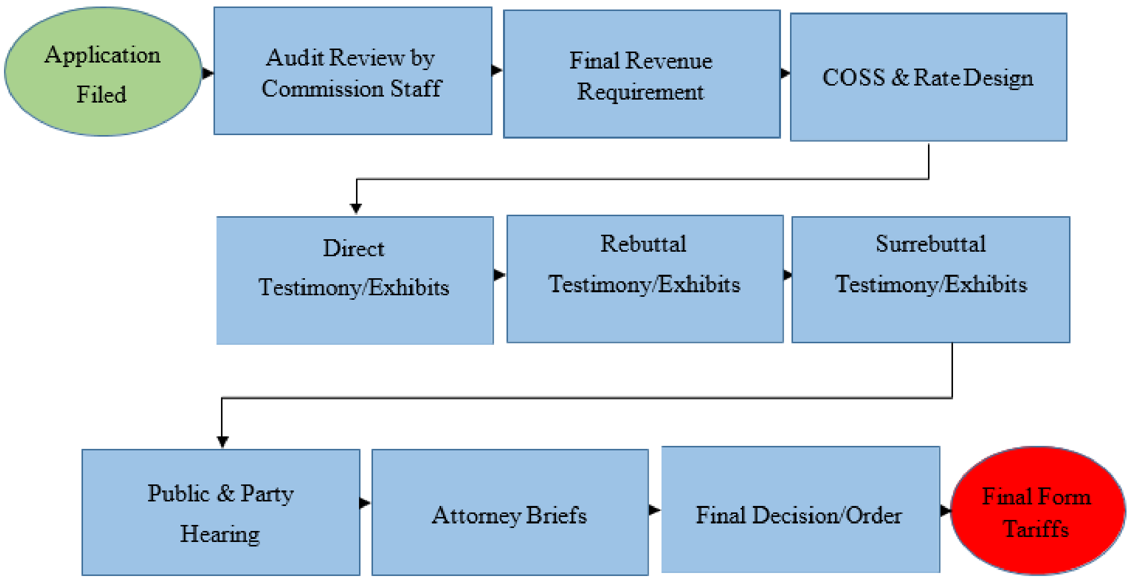
The IIJA, signed into law on November 15, 2021, IIJA includes approximately $65 billion in investments for clean energy projects. The IRA, signed into law on August 16, 2022, directing nearly $400 billion in federal funding to increase clean energy. This funding included provisions that provide direct benefits to end-use customers as well as tax credits and grants for larger clean energy projects. The Commission opened docket 5-UI-123, *Investigation on the Commission's Own Motion regarding Utility Application for and Receipt of Funding from the Infrastructure Investment Jobs Act of 2021 and Inflation Reduction Act of 2022*, to investigate utility application for and receipt of funding—including grants, rebates, loans and financing and tax credits--from IRA and the IIJA. Initial reports received indicate several utilities are making some efforts to pursue funding opportunities to enhance grid reliability and clean energy. While the specific customer impact is yet to be determined, funding received by Wisconsin utilities may reduce the cost of providing utility service to customers.

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 6-4 summarizes the rate case process[125] that is followed by all electric providers regulated by the Commission, including all investor-owned and municipal electric utilities.[126]

Figure 6-4 Rate Case Process



Before an electric utility can change 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 audits** 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 adjust the proposed revenue requirement to more accurately reflect projected costs and establish a **final revenue requirement** that will be used to determine rates.

[125] See also the Commission Proceedings webpage: https://psc.wi.gov/Pages/Regulatory/GuideToPSCProceedings.aspx.
[126] The rates of retail electric cooperatives are not regulated by the Commission. Uncontested municipal rate cases follow a simplified process.

Commission staff then uses 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.[127]

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 involvedin 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 utilities and parties to resolve some or all of the issues usually addressed by the Commission during contested rate cases. Based upon a proposed utility rate settlement agreement, the process described above may be modified 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 determine whether to approve the proposed settlement agreement.

A trend away from fully litigated IOU rate case proceedings and towards partial or full settlement agreements began in the early 2010s. That trend accelerated after passage of the 2018 settlement legislation, however after the 2022 rate case proceedings where the Commission did not fully accept a settlement agreement, 2023 saw 5 fully contested rate cases (3 full and 2 reopeners). For those utilities and intervenors interested in pursuing a settlement, the process remains available as a tool.

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

[127] The COSS model applies many assumptions about how to classify and allocate utility costs assumed in the revenuerequirement. Utilities, Commission staff, and other rate case participants may reference best practices documented bythe 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.

costs they create by including several different types of charges designed to recover different aspectsof 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 thecustomer'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 informedby 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 duringthe 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 2023. For municipal utilities, the median customer charge was $10.00 per month and the median energy charge was 10.16 cents per kilowatt-hour (kWh). IOUs had a median customer charge of $13.00 per month and a median energy charge of 13.09 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.[128]

Table 6-2 Wisconsin Electric IOU Bill Components for Residential Customers, 2023

Summary Statistics	Energy (cents/kWh)*	Customer Charge ($/month)
Minimum	9.10	$8.50
25th Percentile	11.98	$11.00
Median	13.09	$13.00
Average	13.21	$12.79
75th Percentile	13.91	$14.79
Maximum	16.63	$17.67

* 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, 2023

Summary Statistics	Energy (cents/kWh)	Customer Charge ($/month)*
Minimum	4.65	$5.00
25th Percentile	9.50	$5.00
Median	10.16	$10.00
Average	10.19	$9.92
75th Percentile	11.10	$12.00
Maximum	14.27	$16.00

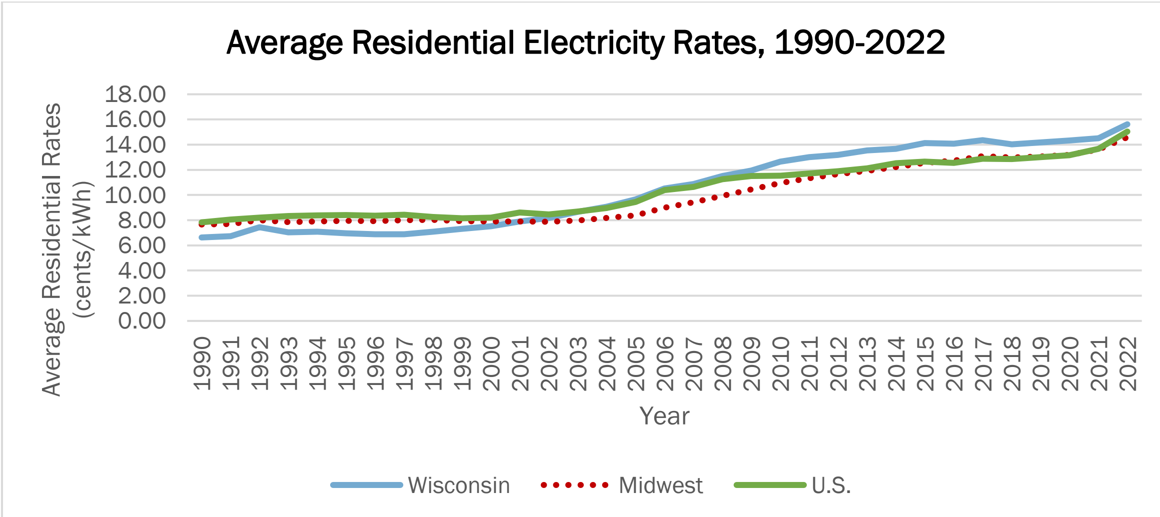
* Note: Customer charge data is for single-phase customers only.

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.[129] Based on an overall, sales-weighted average of all electric utilities within each state, Wisconsin's average 2022 residential energy charges of approximately 15.5 cents/kWh exceed national and Midwest averages of approximately 14.5 cents/kWh. As shown in Figure 6-5, Wisconsin's average rates have exceeded national and Midwest averages for nearly two decades. Appendix D, Table D-1 provides more detailed comparisons, including charges for each individual Midwest state.

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

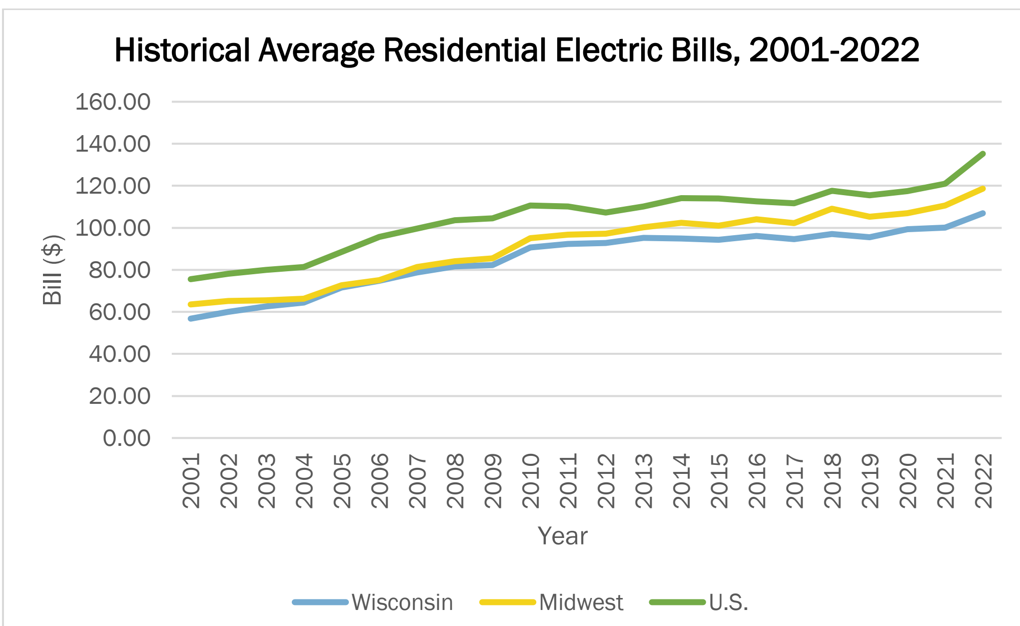
[129] For this analysis, Midwest states include Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Ohio, and Wisconsin.

Figure 6-5 Average Residential Electricity Rates (1990-2022)[130]



While customer rate levels are higher, EIA data shown in Figure 6-6 demonstrates that average monthly electric bills in Wisconsin have remained consistently lower than other states during the past decade. Wisconsin's average 2022 bill of $106.94 compares to Midwest average bills of $118.65 and national average bills of $135.25. (See Appendix D, Figure D-3 for more detailed comparisons of average bills by census region.)

Figure 6-6 Historical Comparison of Average Monthly Residential Electric Bills (2001-2022)[131]

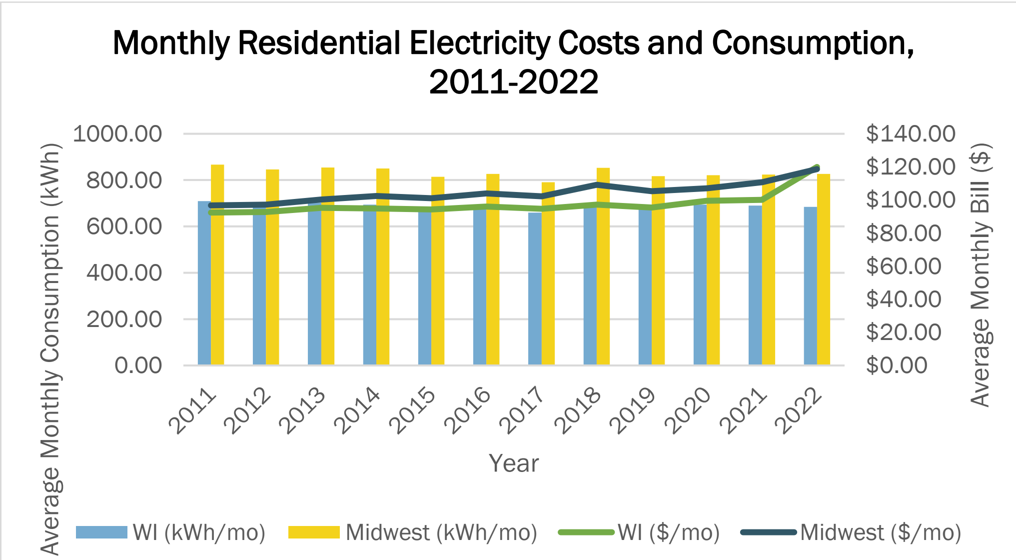


130 U.S. Energy Information Administration, Electricity Sales, Revenue, and Average Prices (Table 5A). Issued October 7, 2021. Accessed March 22, 2022 at: https://www.eia.gov/electricity/sales_revenue_price/.

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

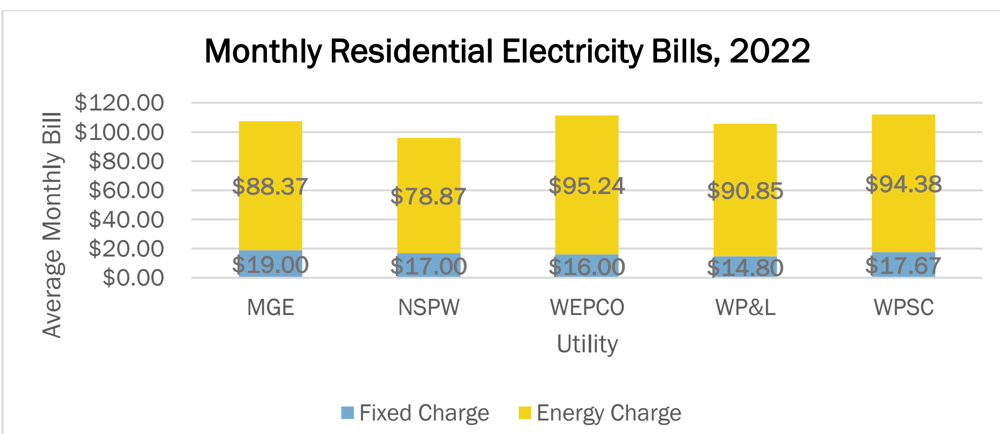
Wisconsin's lower bills reflect significantly lower average levels of electricity use. As shown in Figure 6-7, Wisconsin customers used an average of 684.5 kWh per month in 2022, compared to 827.41 kWh per month across other Midwest states. This usage difference has been present throughout the 2010s.

Figure 6-7 Monthly Residential Electricity Costs and Consumption in Wisconsin and the Midwest (2011-2022)



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 2022 ranged from $50 to $100 per month.[132] Figure 6-8 illustrates total 2022 residential bills at average usage levels for Wisconsin's five largest IOUs.

Figure 6-8 2022 Monthly Residential Electricity Bills for WI's Largest IOUs, at Average Levels of Energy Use



132 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.

Non-Residential Customers

Based on national EIA data, Wisconsin's average 2022 energy rate for commercial customers of 11.85 cents per kWh is below the national average of 12.41 cents per kWh and the Midwest regional average of 11.42 cents per kWh (additional data can be found in Appendix D, Table D-2). On the contrary, Wisconsin's average 2022 energy rate for industrial customers of 8.49 cents per kWh exceeds the national average of 8.32 cents/kWh and the Midwest regional average of 8.18 cents per kWh (Appendix D, Table D-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 9 cents per kWh, average customer charges of $49.60 per month, and demand charges of $7.66 per kW in 2023. (More details on the analysis can be found in Appendix D, Figures D-6 and Table D-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, 2023

Summary	Energy Charge(cents/kWh)	Distribution Demand ($/kW)	Billable Demand ($/kW)	Customer Charge ($/month)*
Minimum	5.42	$0.25	$5.00	$20.00
25th Percentile	8.41	$1.25	$7.00	$40.00
Median	9.21	$1.50	$7.63	$50.00
Average	9.29	$1.38	$7.66	$49.60
75th Percentile	10.12	$1.50	$8.50	$50.00
Maximum	12.38	$2.25	$11.25	$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 most customers in Wisconsin pay 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.

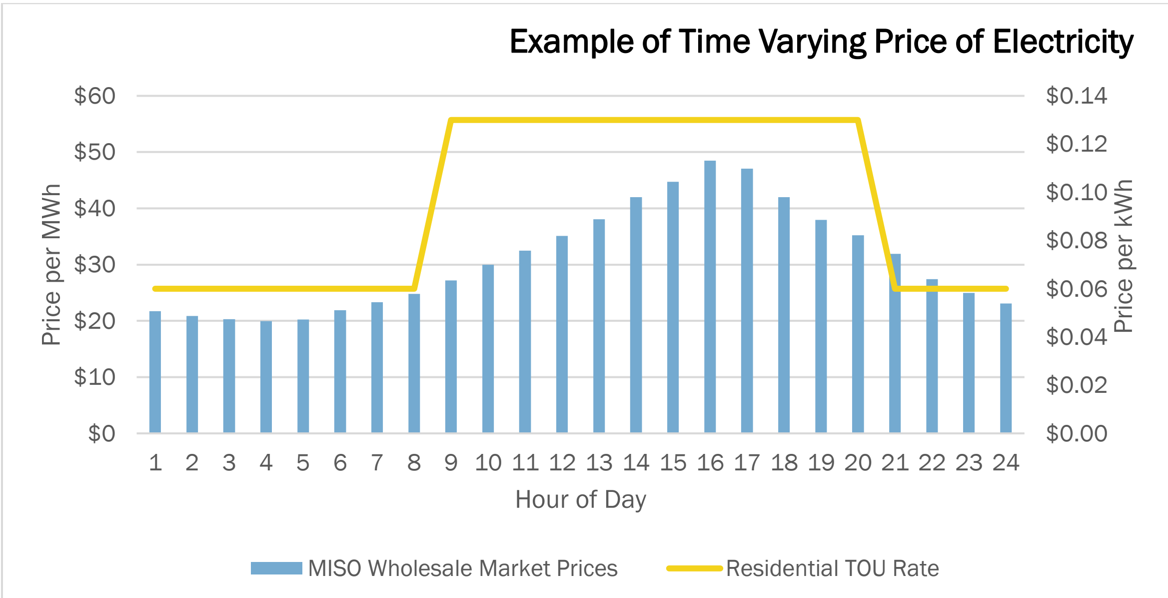
Residential Time-of-Use Rates

A total of 76 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.[133] By setting higher energy charges during

[133] 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

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 can reduce their total energy costs and pass savings along to customers through lower off-peak energy charges.

Figure 6-9 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 37,500 electric utility customers, or 1.52 percent of all residential customers, are currently enrolled in TOU rates.

Table 6-5 Enrollment in Standard and TOU Rates for 2022

Residential Rate Class	Total Enrollment	Percent of Total
Standard Rate	2,446,314	98.48%
TOU Rate	37,778	1.52%

The increasing use of new technologies in future years could help increase customers' ability to control their energy use and benefit from 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 EV 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.)

purchase from a different wholesale provider, as well as the costs a generation-owning utility would face for operating its own plants.

Real-Time Pricing for Commercial and Industrial Customers

Thirty-eight (38) 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. Like 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 receive 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 end this service.

As shown in Table 6-6, 121 commercial and industrial customers were enrolled in real-time pricing rates in 2022, an enrollment rate of 6.94 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	6,694	98.18%
Incremental Load (NLMP/EDR)	3	0.04%
Real-Time Pricing (RTMP)	121	1.77%

Chapter 7 – Bill Affordability

Low-income residential customers can often face challenges in paying their utility bills. By paying the same rates as all customers, but with more limited financial resources, those 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 increased its efforts over the last four years to assess energy burden and to review and expand the options available to help customers address their affordability challenges.

Energy Burden

In February 2021, the Commission requested that all IOUs with at least 15,000 customers- including MGE, NSPW, WEPCO, WP&L, and WPS- provide detailed energy burden analysis on electricity, natural gas, and water costs in their annual reports to the Commission, beginning with the 2020 annual reports submitted in spring 2021. The Commission directed that submissions should provide energy burden data by assessing bills as a percentage of income by county. Initial submissions in the 2021 annual reports affirmed that energy burden can vary throughout geographic regions of the state. However, submissions also demonstrated limitations in using county-level data to fully assess geographic variation, since median calculations do not capture the significant differences in income and energy use that may be present across different municipalities and neighborhoods within a single county. Providers' initial reports also used differing sources to develop their estimates of income data, complicating the ability to make direct comparisons between submissions.

The Commission subsequently directed that the energy burden analysis provided by these utilities be done at the census tract level or census block level. A census tract is a statistical subdivision of a county that has approximately 4,000 inhabitants and is a commonly seen level of tracking energy burden and other socioeconomic characteristics. A census block is a smaller subdivision of area within a census tract and does not have a given population level. In 2022 and 2023, utilities began to incorporate reporting at the census tract or more detailed levels, however, data was reported with different characteristics and variables, making comparisons between years and between utilities challenging. In late 2023, the Commission developed a template energy burden reporting table and provided the utilities guidance on data sources to use in analysis and reporting for the 2024 annual reports and those going forward.

The Commission received a technical assistance award from the federal Department of Energy in December 2021 to expand its efforts to address energy burden through evaluation of definitions and potential sources of data.[134] The Commission also approved funding in its State Energy Program Annual Plan to hire a consultant to conduct an Energy Burden Action Study to research data sources and provide a basis for consistent and accessible energy burden metrics and reporting.[135] This Action Study will also develop an actionable plan for short and long-term deployment of energy burden metrics for consideration in Commission programs and processes. Work on the study is underway in 2024 and the summary of findings and information resources will assist in providing the Commission with actionable options and feasible, targeted strategies and goals to reduce energy burden and contribute to an affordable energy transition in Wisconsin.

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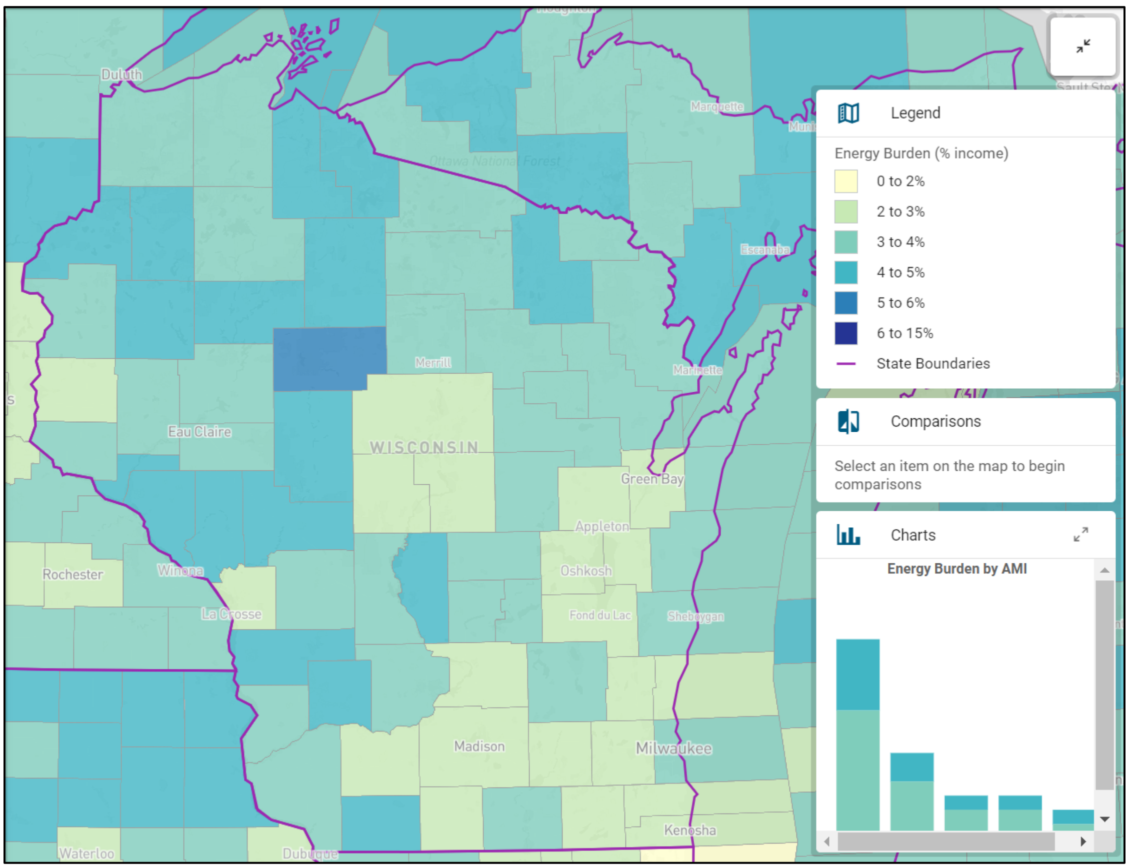
[134] "DOE Announces Technical Assistance for State Utility Regulators to Address Challenges Related to a Transforming Electric Grid." https://www.energy.gov/eere/articles/doe-announces-technical-assistance-state-utility-regulators-address-challenges.
[135] PSC REF# 464921 Final Decision approving Project Year 2023 State Energy Program Annual Plan

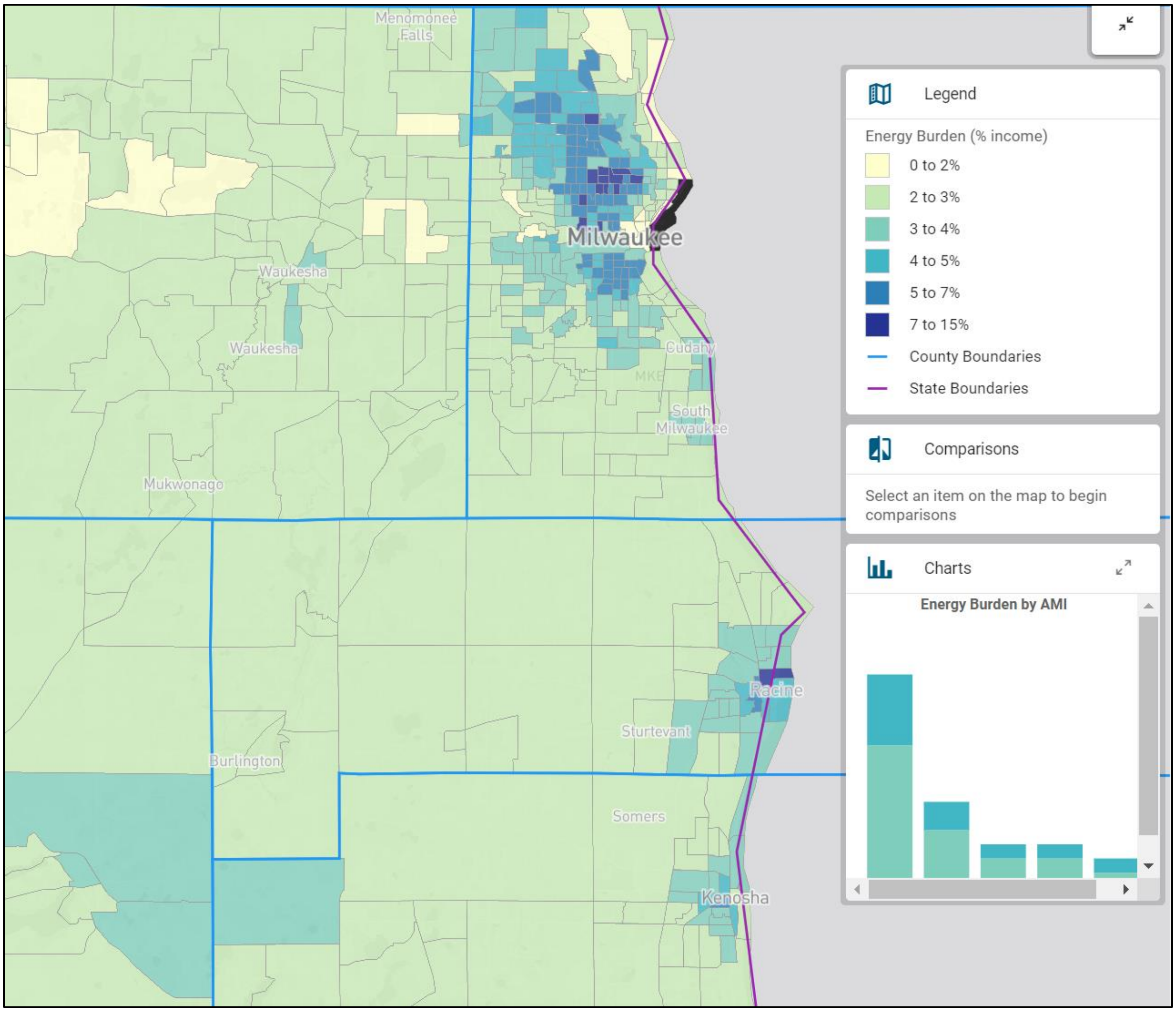
The topic of energy burden and affordability has been raised in recent rate cases before the Commission, as well as how to deploy federal funding programs through the IRA. There are existing tools that allow federal and state agencies, as well as organizations or members of the public to use to get a high-level understanding of energy burden using data from the American Census Survey. The online tool that is specific to evaluating energy burden is the Low-Income Energy Affordability Data (LEAD) tool[136] which can provide information at the national, state, county, city, or census tract level. Using this tool at different levels of geographic granularity demonstrates the effect on reported energy burdens. Figure 7-1 shows a county-wide evaluation of energy burden across Wisconsin, while Figure 7-2 shows a census-tract level evaluation of energy burden in southeast Wisconsin. The increased granularity of census tract level reporting shows census tracts that are over twice the energy burden levels seen when looking at county level data for parts of southeastern Wisconsin.

Figure 7-1 Wisconsin County-Level Evaluation of Energy Burden Levels (LEAD tool, Feb. 2024)



[136] https://www.energy.gov/scep/slsc/lead-tool

Figure 7- 2 Southeastern Wisconsin Energy Burden at Census-Tract Level (LEAD tool, Feb. 2024)



Through the work that comes out of the energy burden action study, stakeholder involvement in Commission dockets, and work done to deploy federal funds to disadvantaged communities, the Commission will continue to examine ways of evaluating energy burden experienced by customers.

Assisting Customers with Affordability Challenges

Wisconsin electric providers and the Commission help low-income customers manage their energy burden through multiple types of programs.

The Commission requires regulated electric utilities in Wisconsin to offer Deferred Payment Agreements (DPAs) to residential customers who are unable to pay their bill in full. DPAs allow 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 utilities are also required to offer residential customers budget billing options which help balance the seasonal spikes in usage and bills most customers experience by evenly distributing costs over a twelve-month period.

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

- 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 MG&E account.
- NSPW offers low-income customers flexible payment plans and arrears forgiveness of up to $400 per household.
- WP&L offers an Arrears Management Program to assist low-income customers who have received Wisconsin Home Energy Assistance Program funds by forgiving a portion of arrears each month that a participating customer pays their 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, Wisconsin Gas', and Wisconsin Public Service Corporation's Low Income Forgiveness Tool (LIFT) program requires participants to pay 50% of their budget installment each month. If the amount is paid, one twelfth of their arrears is forgiven each month.
- SWL&P offers an Arrears Management Program (AMP) that assists customers who receive Low-Income Energy Assistance (LIHEAP) benefit by matching the customer's subsequent payments until the balance is zero.

Electric providers and Commission Consumer Affairs staff also refer customers facing affordability challenges to multiple governmental and community assistance programs. Households with incomes of less than 60 percent of the state median income are eligible for federally funded energy assistance through the Wisconsin Home Energy Assistance Program and the Public Benefits Energy Assistance Program. These programs can help customers pay a portion of their electric bills and provide weatherization assistance that can help customers reduce energy costs. Many electric providers financially support the Keep Wisconsin Warm/Cool Fund (KWWF), a statewide, non-profit effort that provides preventative services and financial assistance in response to energy emergencies. Heat for Heroes assists 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 less energy-efficient lighting, appliances, and heating and cooling systems. Energy efficiency programs can also help low-income households reduce their energy bills. Focus, Wisconsin's statewide energy efficiency and renewable resource program, offers multiple program options that can benefit low-income customers. (See Chapter 3 for more information) Weatherization can also help low-income customers reduce their energy bills. 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.

In response to public and stakeholder interest in exploring opportunities to expand Focus' support for low-income customers, the Commission reviewed low-income offerings as part of its general updates of Focus policies and goals in the Quadrennial Planning Process in docket 5-FE-104, *Quadrennial Planning Process IV*. In its Final Decision, the Commission requested a review of options and approaches for a benefits adder to be applied to the cost-effectiveness analysis of Focus' programs and offerings targeting customers below 60 percent of statewide median income. Developing cost-effectiveness approaches that recognize the higher cost-to-serve low-income customers as well as the additional benefits associated with serving these customers is one way that regulators can encourage energy efficiency programs to engage with this population. The Commission subsequently determined[137] that the application of a 20 percent adder to the net benefits quantified in Focus' primary cost-effectiveness test for those programs and offerings targeting customers earning at or below 60 percent of statewide median income is reasonable and in the public interest.

Wisconsin's applications for $149 million in funding under the IRA HER programs, submitted to the U.S. DOE in May 2024, also propose multiple approaches to support delivery of rebates for energy efficiency and electrification projects to low- and moderate-income customers, including through reserving the majority of total rebate funding for those customers and offering higher maximum rebates to those customers to help address the financial barriers to participation they may face. Pending federal approval of Wisconsin's application, the IRA HER programs are expected to launch later in 2024.

In docket 5-UI-120, Investigation on the Commission's Own Motion to Ensure Safe, Reliable and Affordable Access to Utility Services During Declared Public Health Emergency for COVID-19, 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. Although the Commission discontinued the requirement to provide quarterly reporting on arrears and collection data through the docket when it closed in November of 2022, enhanced data collection will continue in future years through the addition of questions on residential arrears and disconnections on utility annual reports to the Commission.

Prior to disconnecting for nonpayment, utility providers must send customers a disconnection notice at least 10 calendar days prior to the day of the proposed disconnection. The notice must include the reason(s) for disconnection, a way to contact the utility to either pay the account balance, establish a payment arrangement, or inform the utility if there is a threat to health or safety, and inform the customer they may appeal to Commission staff if they have a dispute regarding the disconnection. A disconnection would occur if customers do not contact the utility or Commission staff to resolve the pending disconnection by the means provided in the disconnection notice within the timeframe provided in the disconnection notice. As Figures 7-3 and 7-4 indicate, actual disconnections occur in response to a small fraction of the disconnection notices received. Disconnections have increased between 2021-2023 as the COVID-related moratorium was lifted and utilities are returning to standard business collection practices.

[137] PSC REF#: 487366 Order 5-FE-104, Issued December 21, 2023.

Figure 7-3 Number of Residential Customers with Disconnection Notices and Disconnections, 2021 – 2023

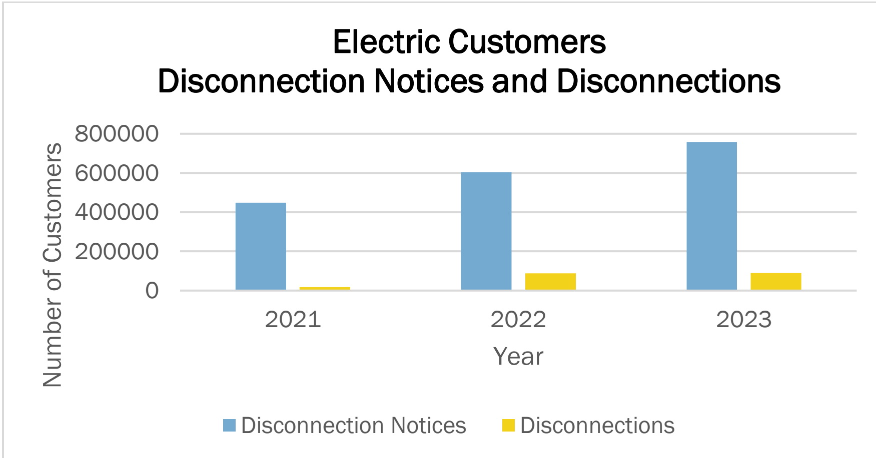
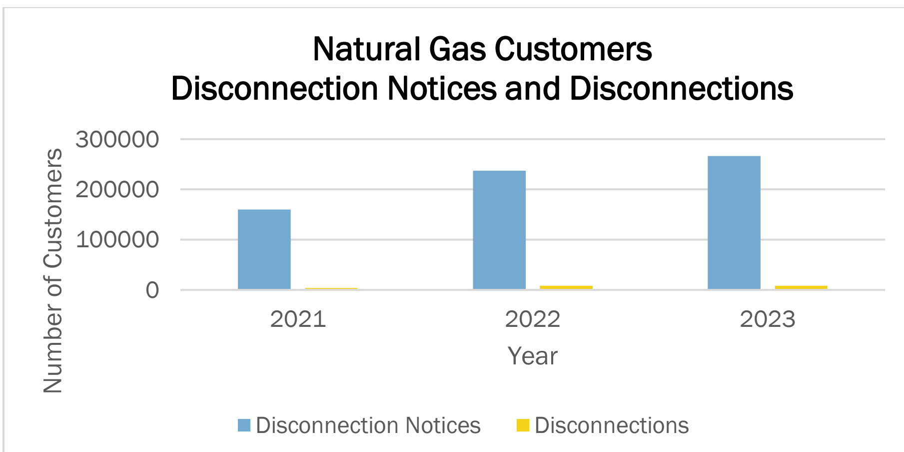


Figure 7-4 Number of Residential Natural Gas Customers with Disconnection Notices and Disconnections, 2020 – 2023



As shown in Figures 7-5 and 7-6, the data gathered under the annual reports demonstrated that the number of residential customer accounts with arrears have decreased since reaching a peak in 2020, for electric service as well as natural gas. The increase in financial assistance available to qualifying customers, utility establishment of enhanced DPAs and Arrearage Management Programs, and expanded communication efforts regarding financial resources likely all contributed to the decrease in the *number* of customers with arrears. However, the *amount* of arrears for electric customers did go up slightly from 2021 to 2022 and stayed fairly consistent between 2022 and 2023.

Figure 7-5 Number of Residential Customers with Arrears, 2020 – 2023

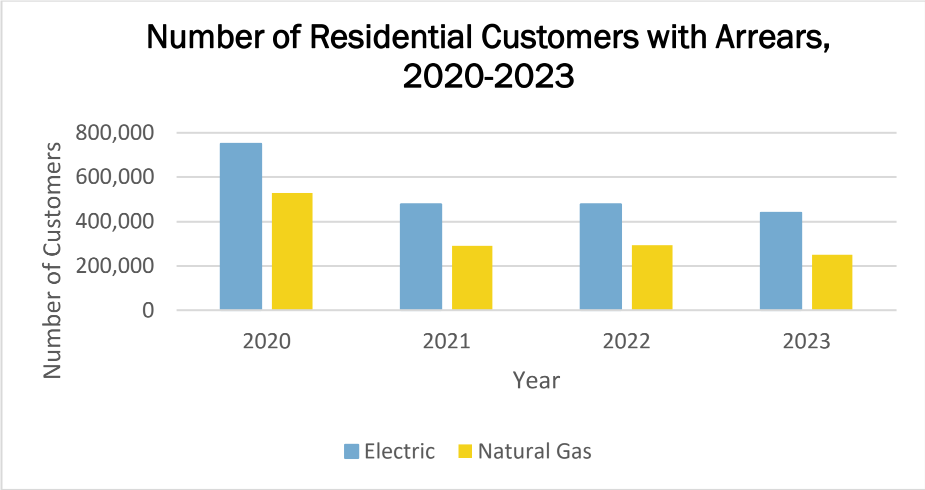
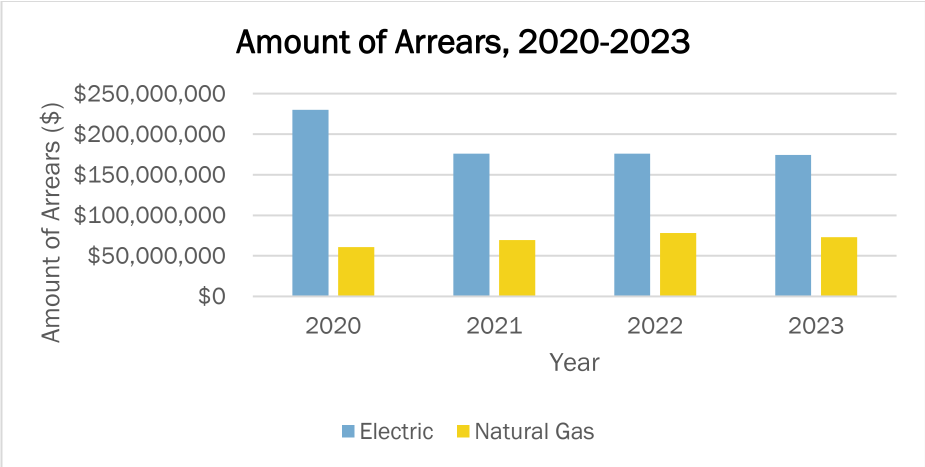


Figure 7-6 Residential Arrears Comparison by Year, 2020–2023



Affordability Investigation Dockets

Bill affordability has been a major concern for the public and intervenors in rate cases over the last several years. In response to these concerns, the Commission directed staff to open investigation dockets[138] related to bill affordability for four of the largest state utilities. In each docket, utilities, stakeholders, and Commission staff are working collaboratively to discuss options to address bill affordability issues and propose program elements that could address affordability challenges. Work on these investigation dockets is ongoing.

[138] Dockets 5-UI-121 (WEPCO) and 6690-UI-101 (WPSC) were opened in 2023. Dockets 6680-UI-100 (WP&L) and 3270-UI-101 (MGE) were opened in 2024.

APPENDICES

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
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	9,667	9,825	10,429
2022	10,506	10,060	9,355	9,063	11,645	14,429	13,398	12,858	12,472	9,092	10,308	10,511
2023	10,154	10,027	9,295	9,161	11,091	12,399	13,508	14,875	13,016	10,761	9,889	9,965
Future												
2024	10,699	10,231	10,049	9,310	10,927	12,919	14,023	13,621	12,239	9,648	9,788	10,481
2025	11,230	10,717	10,488	9,834	11,470	13,519	14,621	14,182	12,783	10,225	10,458	11,343
2026	11,667	11,152	10,959	10,219	11,828	13,892	14,996	14,617	13,253	10,734	10,928	11,543
2027	11,984	11,504	11,259	10,763	12,411	14,470	15,590	15,152	14,845	12,368	12,464	13,144
2028	13,459	12,959	12,723	11,948	13,581	15,658	17,108	16,671	15,224	12,725	12,877	13,538
2029	13,828	13,346	13,108	12,328	13,957	15,914	17,053	16,614	15,179	12,632	12,793	13,482
2030	13,766	13,287	13,024	12,272	13,907	15,940	17,082	16,530	15,200	12,673	12,821	13,517

Table A-2 Seasonal Wisconsin Aggregated Supply and Demand

Report Line MISO Description Capacity (MW)	Summer Capacity 2024	2025	2026	2027	2028	2029	2030
High Certainty Resources (Existing Resource)	13,324	12,894	11,806	11,723	11,407	11,302	11,237
Low Certainty Resources (Existing Resource)	0	606	0	0	0	0	0
Behind the Meter (Existing Resource)	395	412	415	415	401	401	400
DRR plus Registered DSM (Existing Resource)	733	746	747	748	747	747	747
New Capacity DPP Signed GIA (New Resource)	615	1,046	1,372	1,414	1,094	1,094	1,094
New Capacity DPP GIA Phase (New Resource)	0	4	79	303	1,343	1,712	2,072
New Capacity DPP Phase 3 (New Resource)	58	58	68	68	218	218	218
New Capacity DPP Phase 2 (New Resource)	0	0	0	6	6	6	6
New Capacity DPP Phase 1 / Not Started (New Resource)	0	184	184	184	184	184	184
New Capacity Not in Interconnection Queue (New Resource)	23	257	269	552	616	855	873
New BTMG / NEW DR (New Resource)	16	65	115	172	157	196	236
RZ Internal Transfer- In (ZRC)	2,424	2,380	2,437	2,565	2,472	2,406	2,602
RZ Internal Transfer- Out (ZRC)	-1,334	-1,271	-1,307	-1,376	-1,221	-1,187	-1,384
External Resource Imports (Existing Resource)	321	187	187	87	87	87	87
Total Committed Net Capacity (MW) Includes DPP Signed GIA	16,478	17,002	15,658	15,577	14,988	14,851	14,791
Total Potential Net Capacity (MW)	16,574	17,569	16,373	16,862	17,512	18,022	18,380
Summer Demand							
Non-Coincident Peak gross of DR	14,500	14,546	15,186	15,671	16,320	16,678	16,822
Full Responsibility Transaction (FRT)	283	283	283	283	283	203	123
Zonal Coincident Factor	0.87	0.87	0.85	0.85	0.91	0.88	0.88
Coincident LSE Peak with Zonal Peak gross of DR	12,662	12,591	12,905	13,337	14,773	14,757	14,824
MISO Coincident Factor	0.96	0.96	0.95	0.95	1.01	0.98	0.98
Coincident LSE Peak to MISO Peak gross of DR	13,984	13,986	14,403	14,875	16,440	16,399	16,473

Summer Reserve Requirements							
Local Clearing Requirement (MW)	11,356	11,331	11,350	11,339	11,336	11,230	11,223
Planning Reserve Margin Requirement (MW)	15,163	15,234	15,704	16,167	17,743	17,674	17,695
MISO Planning Reserve Margin (%)	8.43%	8.92%	9.03%	8.68%	7.93%	7.78%	7.42%
Resources above Local Clearing Requirement	5,218	6,239	5,023	5,523	6,176	6,792	7,158
Resource above Planning Reserve Requirement	1,412	2,336	669	695	-232	348	685

Report Line MISO Description Capacity (MW)	Fall Capacity 2024	2025	2026	2027	2028	2029	2030
High Certainty Resources (Existing Resource)	13,468	12,907	11,887	11,788	11,534	11,512	11,433
Low Certainty Resources (Existing Resource)	0	614	0	0	0	0	0
Behind the Meter (Existing Resource)	334	366	366	366	360	360	360
DRR plus Registered DSM (Existing Resource)	715	718	719	721	720	720	720
New Capacity DPP Signed GIA (New Resource)	621	998	1,108	1,187	1,053	1,053	1,053
New Capacity DPP GIA Phase (New Resource)	0	4	79	303	1,522	1,787	2,087
New Capacity DPP Phase 3 (New Resource)	58	58	70	70	195	195	195
New Capacity DPP Phase 2 (New Resource)	0	0	0	7	7	7	7
New Capacity DPP Phase 1 / Not Started (New Resource)	0	0	170	170	170	170	170
New Capacity Not in Interconnection Queue (New Resource)	23	169	308	461	523	760	874
New BTMG / NEW DR (New Resource)	16	48	84	121	132	167	203
RZ Internal Transfer- In (ZRC)	2,335	2,304	2,400	2,454	2,412	2,351	1,939
RZ Internal Transfer- Out (ZRC)	-1,306	-1,279	-1,295	-1,295	-1,199	-1,172	-1,320
External Resource Imports (Existing Resource)	330	196	196	96	96	96	96
Total Committed Net Capacity (MW) Includes DPP Signed GIA	16,496	16,824	15,380	15,316	14,976	14,920	14,281
Total Potential Net Capacity (MW)	16,592	17,102	16,089	16,448	17,524	18,006	17,817
Fall Demand							
Non-Coincident Peak gross of DR	12,372	12,494	12,487	12,981	13,601	13,973	14,121
Full Responsibility Transaction (FRT)	283	283	283	283	283	203	123
Zonal Coincident Factor	0.87	0.86	0.84	0.92	0.91	0.88	0.88

Coincident LSE Peak with Zonal Peak gross of DR	10,782	10,779	10,529	11,941	12,322	12,312	12,372
MISO Coincident Factor	0.95	0.94	0.93	1.01	0.99	0.97	0.96
Coincident LSE Peak to MISO Peak gross of DR	11,721	11,792	11,597	13,106	13,532	13,527	13,597
Fall Reserve Requirements							
Local Clearing Requirement (MW)	9,184	9,141	8,813	8,756	8,604	8,603	8,836
Planning Reserve Margin Requirement (MW)	13,529	13,629	13,430	15,147	15,515	15,426	15,457
MISO Planning Reserve Margin (%)	15.43%	15.49%	15.63%	15.32%	14.17%	13.22%	12.73%
Resources above Local Clearing Requirement	7,407	7,962	7,276	7,692	8,920	9,403	8,981
Resource above Planning Reserve Requirement	3,063	3,473	2,659	1,302	2,009	2,580	2,360

Winter Capacity							
Report Line MISO Description Capacity (MW)	2024	2025	2026	2027	2028	2029	2030
High Certainty Resources (Existing Resource)	13,574	12,592	12,011	12,066	11,364	11,359	11,167
Low Certainty Resources (Existing Resource)	0	616	0	0	0	0	0
Behind the Meter (Existing Resource)	236	258	258	258	258	258	258
DRR plus Registered DSM (Existing Resource)	735	738	738	737	737	736	735
New Capacity DPP Signed GIA (New Resource)	178	296	428	455	447	447	447
New Capacity DPP GIA Phase (New Resource)	0	0	8	248	1,357	1,734	1,746
New Capacity DPP Phase 3 (New Resource)	6	6	25	25	30	30	30
New Capacity DPP Phase 2 (New Resource)	0	0	0	12	12	12	12
New Capacity DPP Phase 1 / Not Started (New Resource)	0	223	223	223	223	223	223
New Capacity Not in Interconnection Queue (New Resource)	74	111	240	338	391	608	878
New BTMG / NEW DR (New Resource)	2	7	7	9	9	11	14
RZ Internal Transfer- In (ZRC)	2,469	2,241	2,329	2,317	2,278	2,275	1,752
RZ Internal Transfer- Out (ZRC)	-1,348	-1,188	-1,208	-1,141	-1,090	-1,047	-1,084
External Resource Imports (Existing Resource)	275	196	196	96	96	96	96
Total Committed Net Capacity (MW) Includes DPP Signed GIA	16,119	15,750	14,752	14,788	14,089	14,124	13,372
Total Potential Net Capacity (MW)	16,200	16,096	15,255	15,644	16,111	16,742	16,274

Winter Demand							
Non-Coincident Peak Gross of DR	10,791	11,219	11,613	12,265	12,699	13,159	13,324
Full Responsibility Transaction (FRT)	252	252	252	252	252	182	112
Zonal Coincident Factor	0.86	0.85	0.84	0.91	0.90	0.87	0.87
Coincident LSE Peak with Zonal Peak Gross of DR	9,275	9,578	9,717	11,113	11,440	11,500	11,566
MISO Coincident Factor	0.95	0.95	0.94	1.01	1.01	0.98	0.97
Coincident LSE Peak to MISO Peak Gross of DR	10,260	10,671	10,891	12,402	12,765	12,835	12,913
Winter Reserve Requirements							
Local Clearing Requirement (MW)	8,790	9,923	9,904	9,912	9,876	9,775	9,762
Planning Reserve Margin Requirement (MW)	13,095	13,523	13,704	15,464	15,832	15,773	15,761
MISO Planning Reserve Margin (%)	27.64%	26.72%	25.84%	24.69%	24.03%	22.89%	22.06%
Resources above Local Clearing Requirement	7,410	6,173	5,351	5,732	6,235	6,968	6,512
Resource above Planning Reserve Requirement	3,105	2,574	1,551	180	279	970	513

Report Line MISO Description Capacity (MW)	Spring Capacity 2024	2025	2026	2027	2028	2029	2030
High Certainty Resources (Existing Resource)	13,400	12,617	12,151	11,665	11,245	11,109	11,005
Low Certainty Resources (Existing Resource)	0	529	0	0	0	0	0
Behind the Meter (Existing Resource)	401	411	421	421	421	403	403
DRR plus Registered DSM (Existing Resource)	717	731	737	743	749	750	752
New Capacity DPP Signed GIA (New Resource)	83	697	1,128	1,310	1,350	936	936
New Capacity DPP GIA Phase (New Resource)	0	4	79	303	1,280	1,658	1,935
New Capacity DPP Phase 3 (New Resource)	0	58	72	72	322	132	132
New Capacity DPP Phase 2 (New Resource)	0	0	0	8	8	8	8
New Capacity DPP Phase 1 / Not Started (New Resource)	0	0	174	174	174	174	174
New Capacity Not in Interconnection Queue (New Resource)	0	74	182	470	529	768	899
New BTMG / NEW DR (New Resource)	15	42	95	140	194	116	141
RZ Internal Transfer- In (ZRC)	2,344	2,407	2,414	2,524	2,515	2,290	2,310
RZ Internal Transfer- Out (ZRC)	-1,364	-1,283	-1,243	-1,350	-1,399	-1,149	-1,170
External Resource Imports (Existing Resource)	180	183	183	183	83	83	83
Total Committed Net Capacity (MW) Includes DPP Signed GIA	15,760	16,291	15,791	15,494	14,962	14,422	14,319
Total Potential Net Capacity (MW)	15,776	16,468	16,392	16,661	17,469	17,277	17,608
Spring Demand							
Non-Coincident Peak Gross of DR	11,321	11,404	11,368	12,131	12,673	13,061	13,191
Full Responsibility Transaction (FRT)	272	252	252	252	252	232	132
Zonal Coincident Factor	0.87	0.87	0.85	0.83	0.88	0.88	0.88
Coincident LSE Peak with Zonal Peak Gross of DR	9,821	9,869	9,643	10,127	11,158	11,492	11,551
MISO Coincident Factor	0.95	0.94	0.94	0.93	0.98	0.98	0.97
Coincident LSE Peak to MISO Peak Gross of DR	10,770	10,774	10,736	11,275	12,370	12,737	12,803

Spring Reserve Requirements							
Local Clearing Requirement (MW)	8,960	7,365	7,523	7,660	7,748	7,765	7,380
Planning Reserve Margin Requirement (MW)	13,518	13,549	13,549	14,218	15,809	16,267	16,286
MISO Planning Reserve Margin (%)	25.52%	26.10%	26.69%	26.49%	28.43%	28.37%	27.76%
Resources above Local Clearing Requirement	6,816	9,103	8,869	9,002	9,721	9,512	10,227
Resource above Planning Reserve Requirement	2,258	2,919	2,843	2,444	1,660	1,010	1,321

Figure A-1 Predominant Fossil Fuel Source in 2022 – Coal, Fuel Oil, Natural Gas

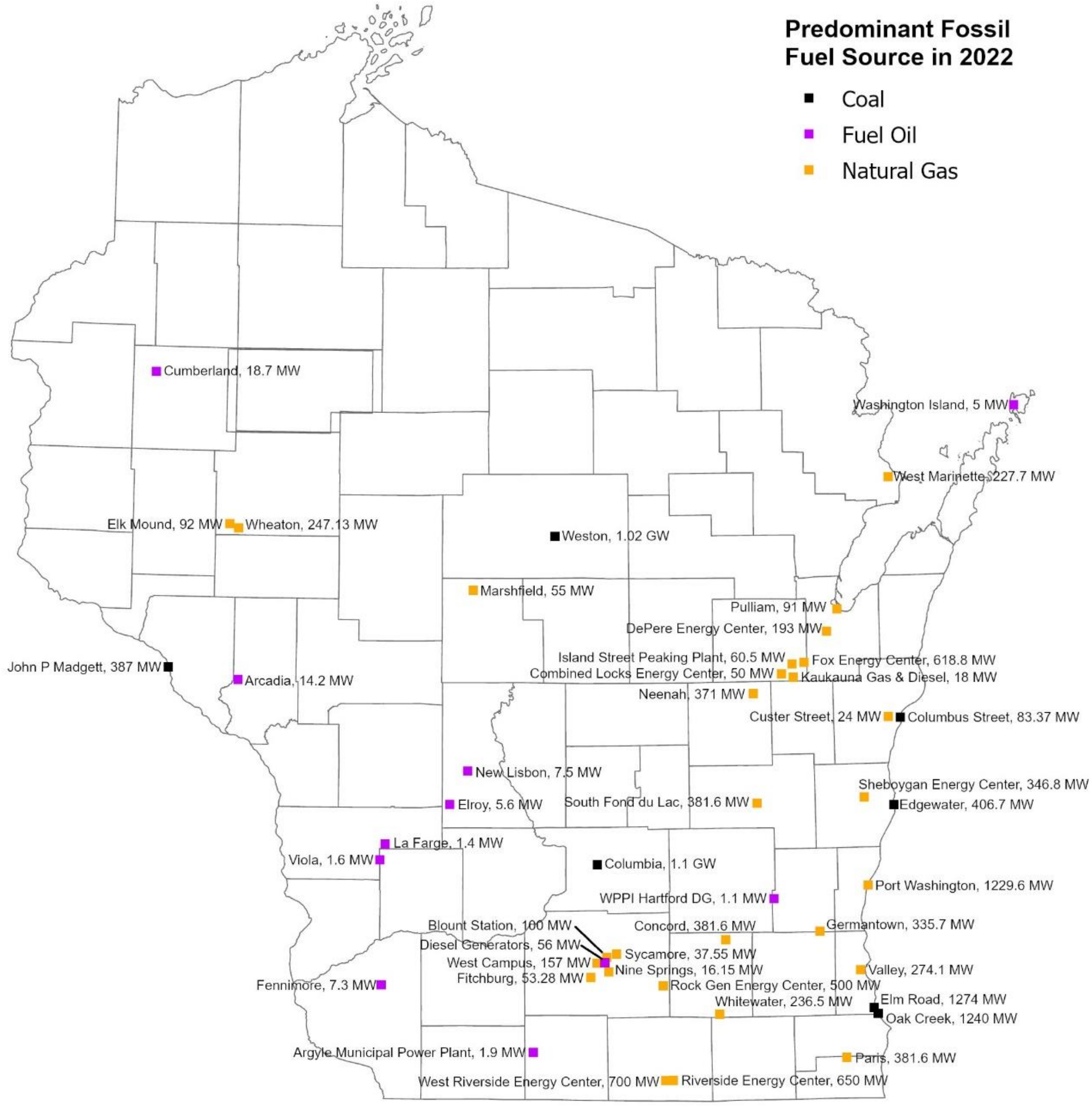


Figure A-2 Predominant Fossil Fuel Source in 2022 – Coal

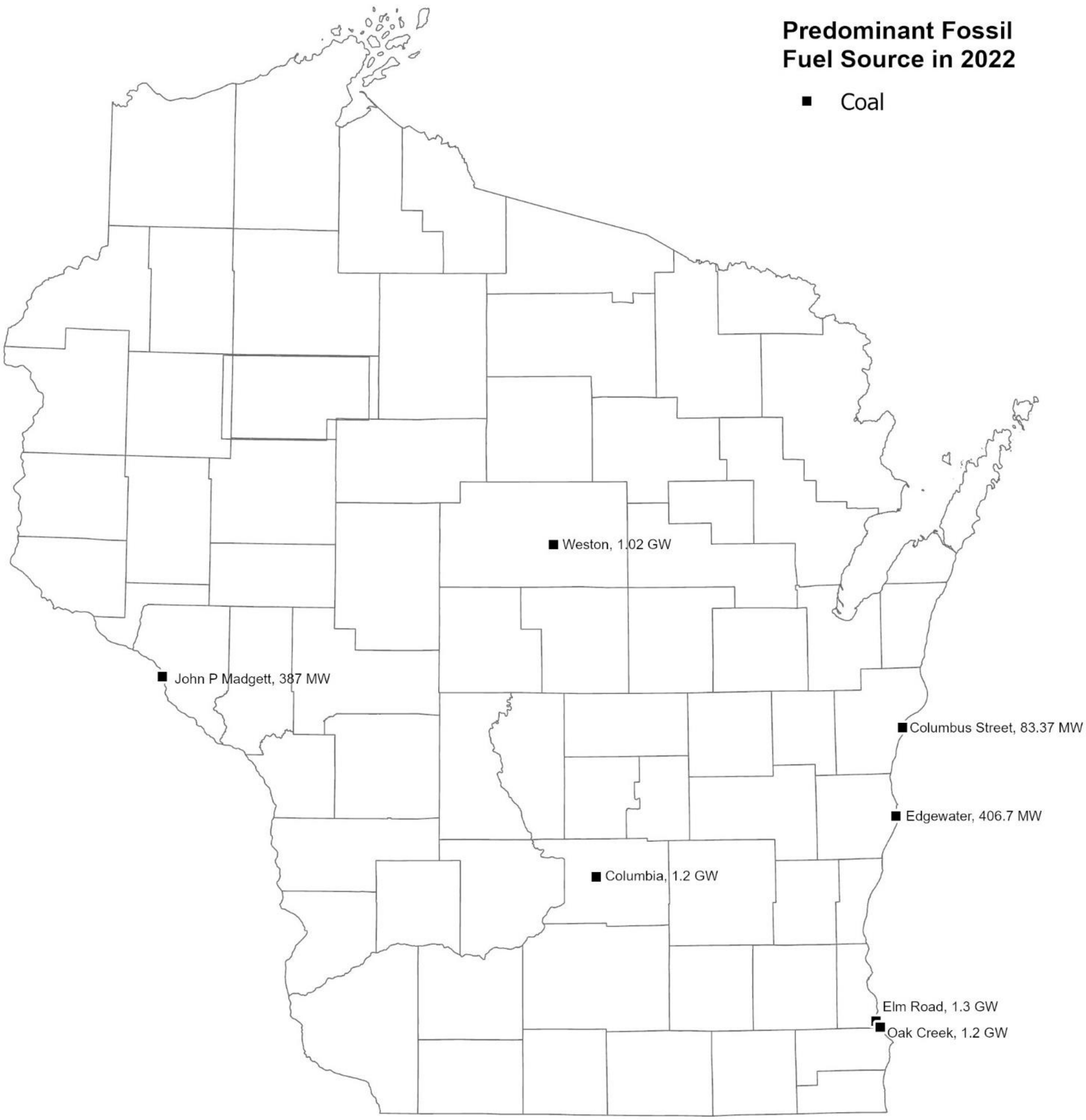


Figure A-3 Predominant Fossil Fuel Source in 2022 – Natural Gas

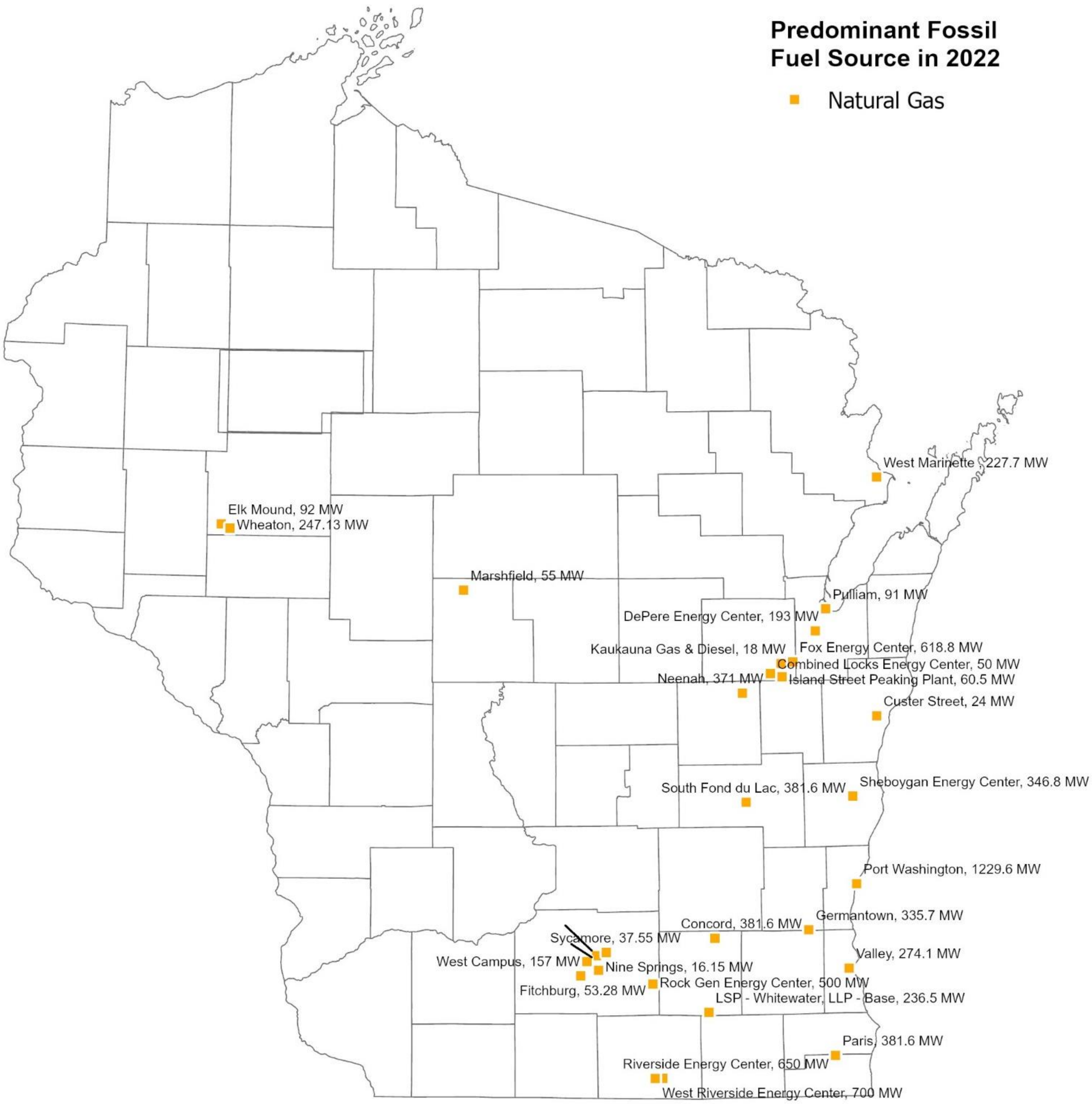


Figure A-4 Wisconsin Renewable Energy Generating Facilities –2022

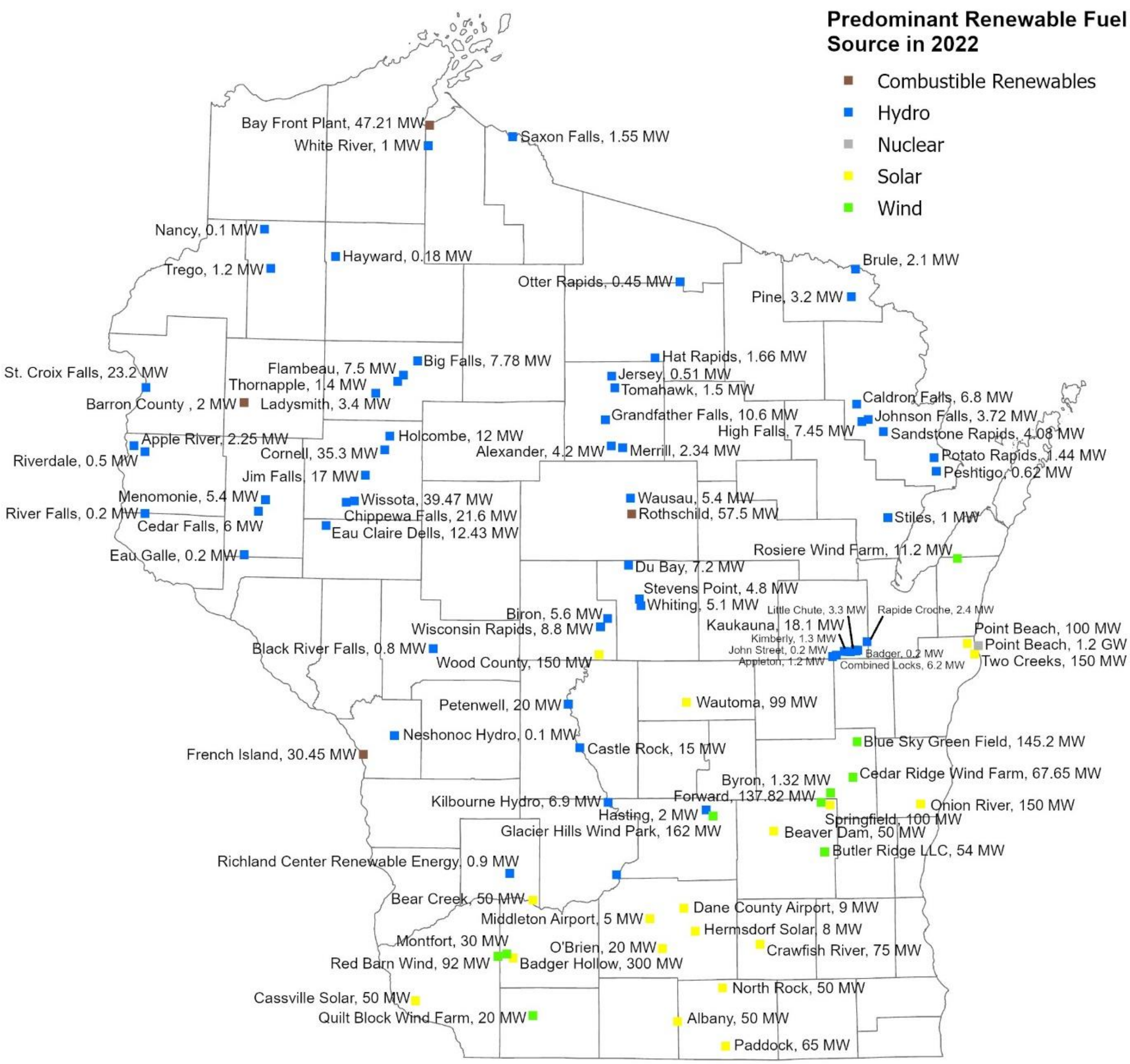


Figure A-5 Predominant Renewable Fuel Source in 2022 – Solar

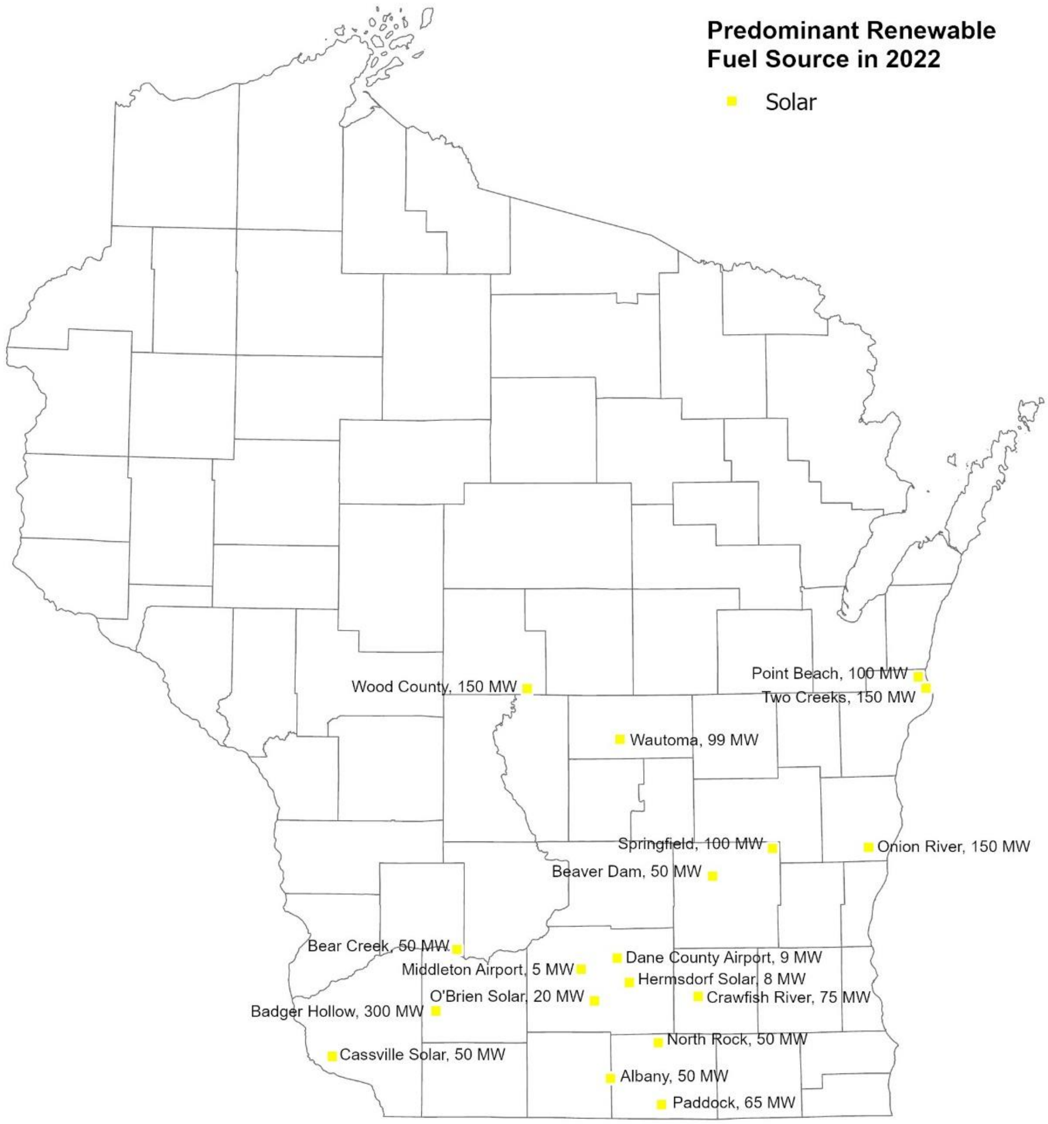


Figure A-6 Predominant Renewable Fuel Source in 2022 – Wind

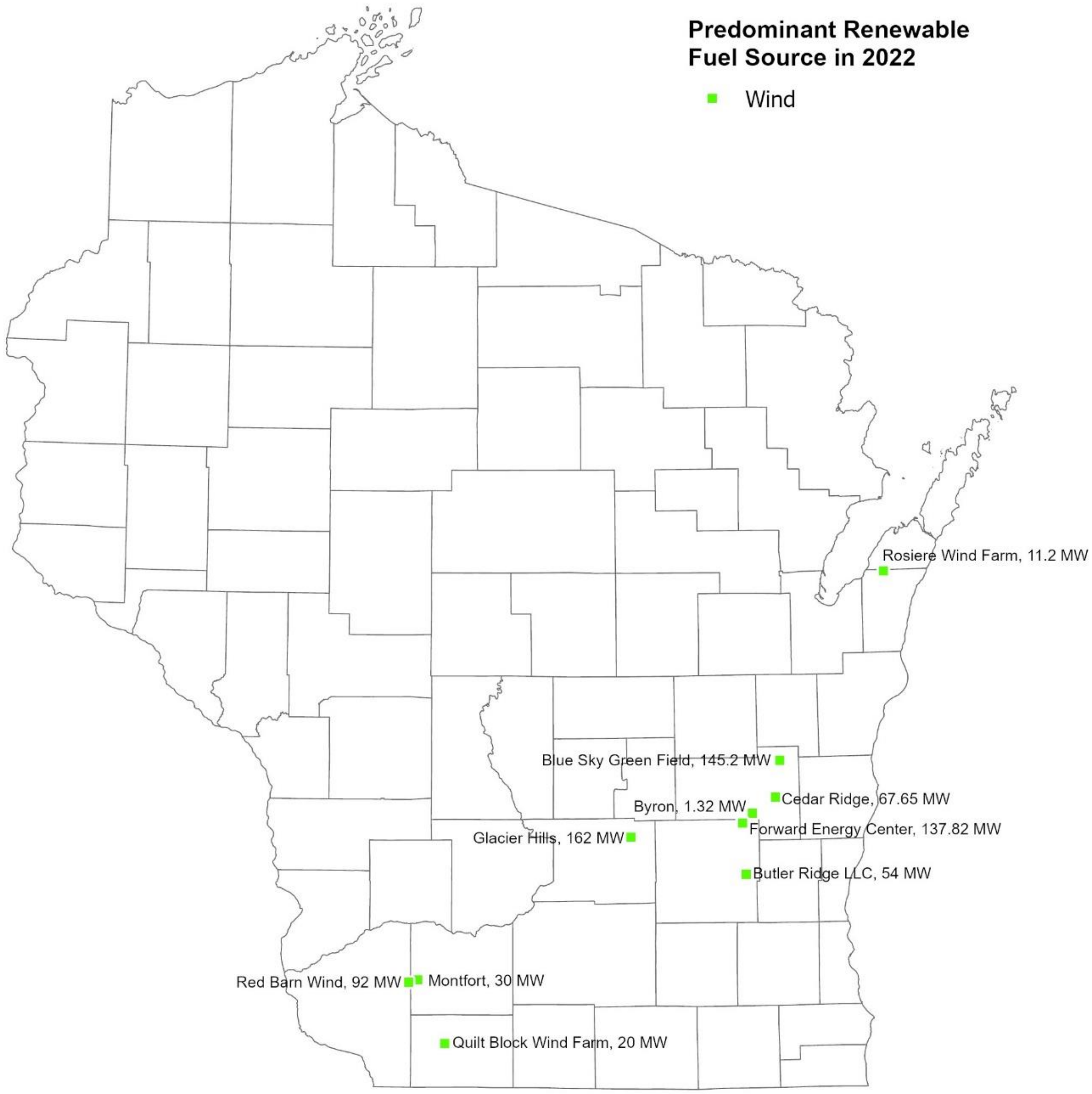


Figure A-7 Wisconsin Hydro Generating Facilities –2022

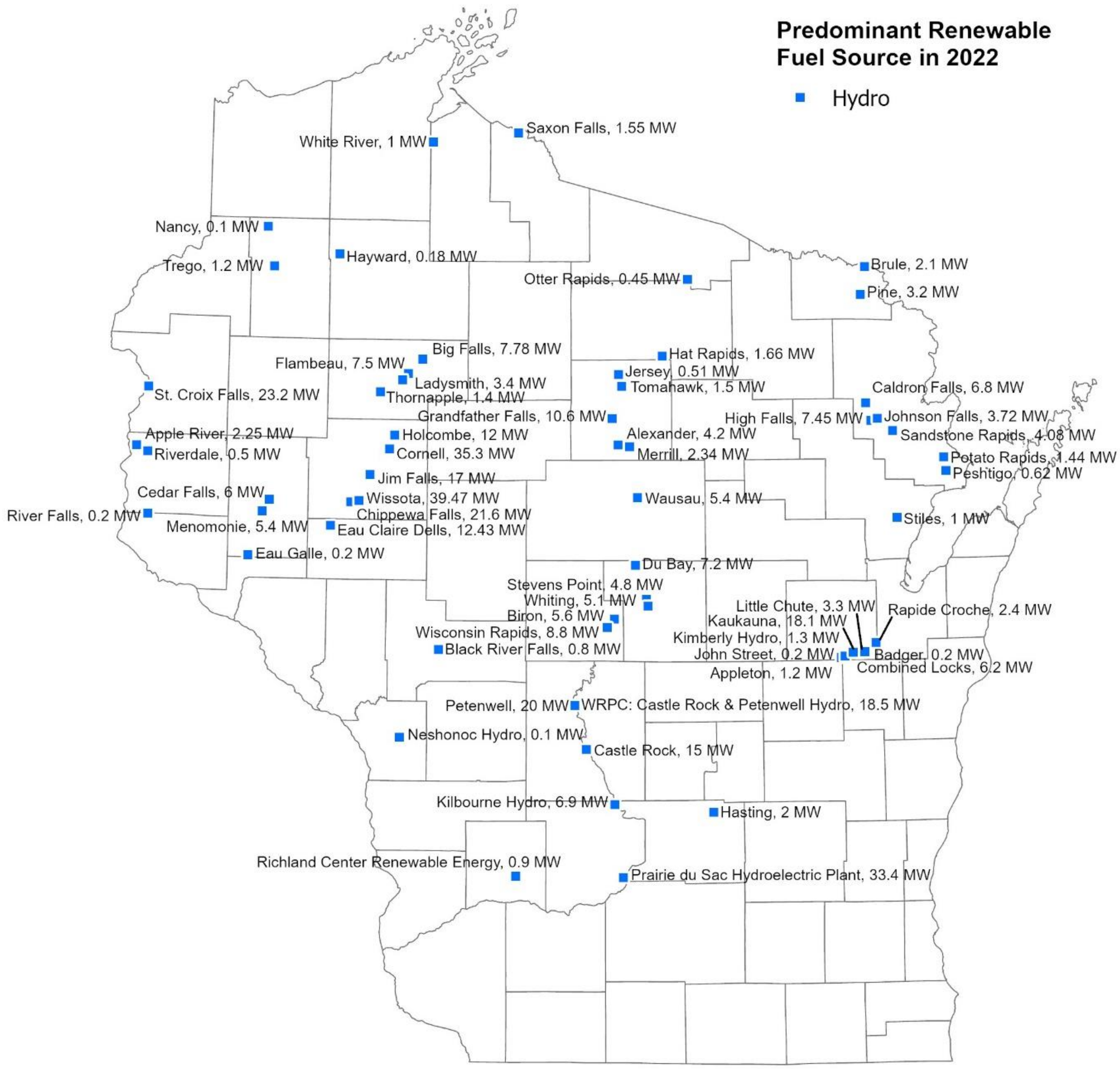


Figure A-8 Wisconsin Nuclear Generating Facilities –2022

Table A-3 Coal Generation Units by Total CO_2 Emissions, 2021, 2022, and 2023[139]

Unit name	2021 (Million tons)	Unit name	2022 (Million tons)	Unit name	2023 (Million tons)
Elm Road #2 (WEPCO)	6.51	Elm Road #2 (WEPCO)	4.88	Elm Road #2 (WEPCO)	5.40
Oak Creek #4 (WEPCO)	5.28	Oak Creek #4 (WEPCO)	4.17	Oak Creek #4 (WEPCO)	4.22
Edgewater #5 (WPL)	2.67	John P Madgett #1 (DPC)	2.48	Edgewater #5 (WPL)	-
Weston #4 (WPS Share)	2.30	Edgewater #5 (WPL)	2.24	Weston #4 (WPS Share)	1.96
John P Madgett #1 (Dairyland)	2.15	Weston #4 (WPS share)	2.12	John P Madgett #1 (DPC)	1.70
Columbia Energy Center #2 (WPL share)	1.87	Columbia Energy Center #1 (WPL share)	1.41	Columbia Energy Center #1 (WPL share)	-
Columbia Energy Center #1 (WPL share)	1.82	Weston #3 (WPS)	1.20	Columbia Energy Center #2 (WPL share)	-
Weston #3 (WPS share)	1.32	Columbia Energy Center #2 (WPL share)	1.20	Weston #4 (DPC Share)	0.72
Weston #4 (Dairyland share)	0.99	Weston #4 (Dairyland share)	0.87	Columbia #1 (WPS share)	0.70
Columbia #2 (WPS share)	0.98	Columbia #1 (WPS share)	0.79	Columbia #1 (WPS share)	0.70

139 For all WPL generation facilities, no 2023 emissions data was provided so the unit names in 2022 were assumed to have the same emissions amounts and rates for their placements in the 2023 columns.

Table A-4 Coal Generation Units by CO_2 emissions rate, 2021, 2022, and 2023[140]

Unit name	2021 (lb/kWh)	Unit name	2022 (lb/kWh)	Unit name	2023 (lb/kWh)
Columbus Street #9 (MPU)	2.75	Columbus Street #9 (MPU)	2.76	Columbus Street #9 (MPU)	-
John P Madgett #1 (Dairyland)	2.49	Oak Creek #4 (WEPCO)	2.44	John P Madgett #1 (Dairyland)	2.71
Columbia #1 (WPS share)	2.41	Columbia #1 (WPS)	2.43	Columbia #1 (WPS share)	2.42
Columbia #1 (MGE share)	2.38	Columbia #1 (MGE)	2.42	Columbia Energy Center #1 (WPL share)	-[141]
Columbia Energy Center #1 (WPL share)	2.37	Columbia #2 (MGE share)	2.42	Oak Creek #4 (WEPCO)	2.40
Oak Creek #4 (WEPCO)	2.36	Columbia Energy Center #1 (WPL share)	2.41	Columbia #1 (MGE share)	2.39
Columbia #2 (WPS)	2.33	Columbia #2 (WPS share)	2.41	Columbia #2 (MGE share)	2.39
Columbia #2 (MGE)	2.32	Columbia Energy Center #2 (WPL share)	2.39	Columbia Energy Center #2 (WPL share)	-
Columbia Energy Center #2 (WPL)	2.31	John P Madgett #1 (Dairyland)	2.36	Columbia #2 (WPS share)	2.36
Edgewater #5 (WPL)	2.31	Edgewater #5 (WPL)	2.31	Boswell Energy Center (WPPI)	-

140 For all MPU generation facilities, no 2023 emissions data was provided so the unit names in 2022 were assumed to have the same emissions amounts and rates for their placements in the 2023 columns.

141 For all WPL generation facilities, no 2023 emissions data was provided so the unit names in 2022 were assumed to have the same emissions amounts and rates for their placements in the 2023 columns.

Table A-5 Gas Generation Units by Total CO2 Emissions, 2021,2022, and 2023[142]

Unit name	2021 (Million tons)	Unit name	2022 (Million tons)	Unit name	2023 (Million tons)
Port Washington #2 (WEPCO)	2.92	Port Washington #2 (WEPCO)	3.16	Port Washington #2 (WEPCO)	3.47
Fox Energy Center #1 (WPS)	1.73	Fox Energy Center #1 (WPS)	1.77	Fox Energy Center #1 (WPS)	1.78
Riverside Energy Center #1 (WPL)	0.67	West Riverside Energy Center #1 (WPL)	0.72	West Riverside Energy Center #1 (WPL)	-
Riverside Energy Center #2 (WPL)	0.65	West Riverside Energy Center#2 (WPL)	0.66	West Riverside Energy Center#2 (WPL)	-
West Riverside Energy Center #1 (WPL)	0.46	Riverside Energy Center #1 (WPL)	0.58	Riverside Energy Center #1 (WPL)	-
Valley #2 (WEPCO)	0.44	Riverside Energy Center #2 (WPL)	0.53	Riverside Energy Center #2 (WPL)	-
West Riverside Energy Center #2 (WPL)	0.30	Valley #2 (WEPCO)	0.51	Valley #2 (WEPCO)	0.46
Neenah #2 (WPL)	0.16	Paris #4 (WEPCO)	0.20	Neenah #2 (WPL)	-
RockGen #1 (DPC)	0.16	West Campus (MGE)	0.19	West Campus (MGE)	0.17
West Campus (MGE)	0.16	Neenah #2 (WPL)	0.17	West Riverside Energy Center	0.16

[142] For all WPL generation facilities, no 2023 emissions data was provided so the unit names in 2022 were assumed to have the same emissions amounts and rates for their placements in the 2023 columns.

Table A-6 Gas Generation Units by CO_2 emissions rate, 2021, 2022, and 2023[143]

Unit name	2021 (lb/kWh)	Unit name	2022 (lb/kWh)	Unit Name	2023 (lb/kWh)
Blount Station (MGE)	3.18	Valley #2 (WEPCO)	2.28	Fitchburg units (MGE)	28.39
Nine Springs (MGE)	3.08	South Fond du Lac #1 (WPPI)	2.21	Sycamore units (MGE)	3.31
South Fond du Lac #1 (WPPI)	2.67	Germantown #5 (WEPCO)	2.11	Blount Station (MGE)	2.55
Germantown #5 (WEPCO)	2.57	Blount Station (MGE)	2.08	Valley #2 (WEPCO)	2.41
Valley #2 (WEPCO)	2.56	South Fond du Lac #4 (WPPI)	2.06	South Fond du Lac #3 (WPL)	-
South Fond du Lac #2 (WPL)	2.46	South Fond du Lac #3 (WPL)	2.01	South Fond du Lac #2 (WPL)	-
South Fond du Lac #3 (WPL)	2.31	South Fond du Lac #2 (WPL)	2.00	Wheaton #4 (NSPW)	1.93
South Fond du Lac #4 (WPPI)	2.24	West Marinette #31 (WPS)	1.89	Germantown #5 (WEPCO)	1.92
West Marinette #31 (WPS)	2.05	Custer Street (MPU)	1.85	West Marinette #31 (WPS)	1.83
West Marinette #32 (WPS)	1.99	Wheaton #4 (NSPW)	1.84	Nine Springs (MGE)	1.83

143 For all WPL generation facilities, no 2023 emissions data was provided so the unit names in 2022 were assumed to have the same emissions amounts and rates for their placements in the 2023 columns.

Appendix B (Chapter 2)

Figure B-1 Total Annual Emissions Forecast for Wisconsin Electric Providers, 2024-2030

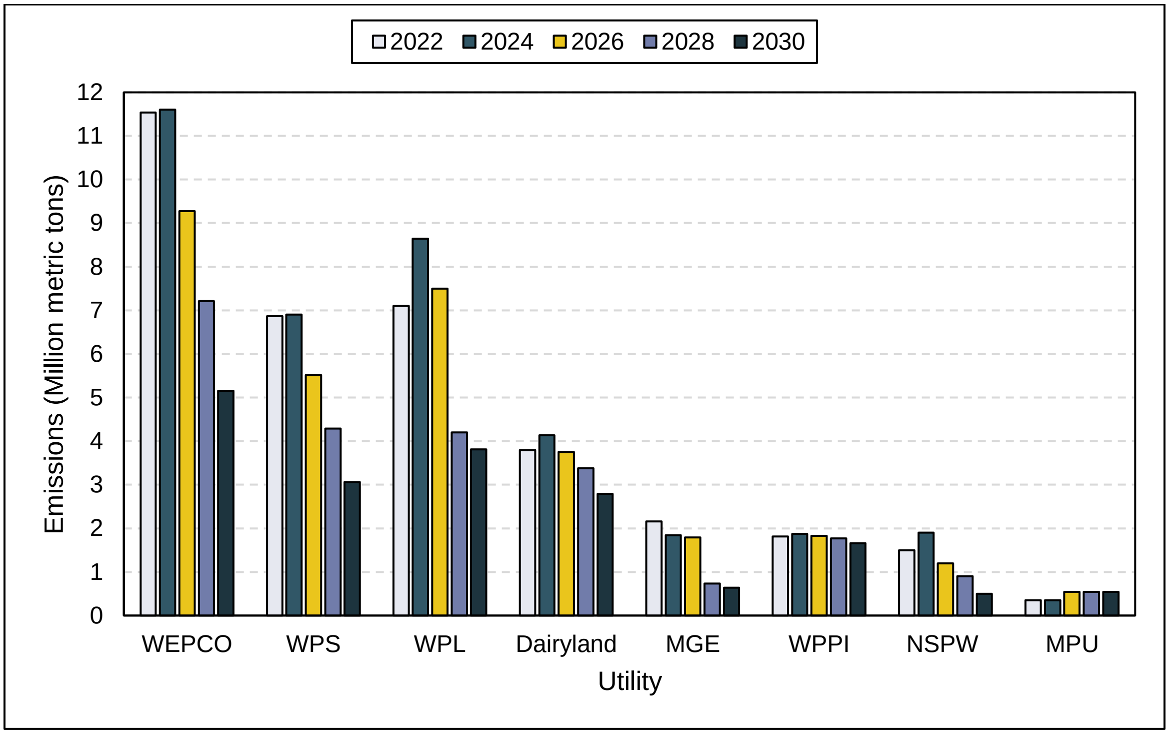


Table B-1 Annual Unit Selection for Baseline Scenario

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE	CI CPV	CI UPV	CIN LOW
2023	0	0	0	0	0	0	200	1.994	0.09	46.172
2024	0	0	0	0	0	0	0	2.138	0.081	48.651
2025	0	0	0	0	0	0	0	3.558	0.124	48.839
2026	600	0	0	0	0	0	0	5.461	0.189	46.473
2027	1200	0	0	0	0	0	0	7.315	0.289	43.132
2028	0	0	0	0	0	0	0	8.436	0.442	48.793
2029	0	0	0	0	0	0	0	8.938	0.675	45.248
2030	0	0	0	0	0	0	0	9.660	1.02	38.374
2031	600	0	0	0	0	0	0	11.102	1.516	33.215
2032	0	0	0	0	600	600	0	13.047	2.194	46.065
2033	0	0	0	0	0	0	0	14.880	3.052	38.806
2034	0	0	0	0	0	0	0	15.981	4.018	37.726
2035	0	0	0	0	0	0	0	16.030	4.932	33.606
2036	0	0	0	0	0	0	0	15.103	5.582	34.013
2037	600	0	0	0	0	0	0	13.573	5.786	32.74
2038	600	0	0	0	0	0	0	11.898	5.493	31.132
2039	0	0	0	600	600	600	0	10.444	4.805	27.387
2040	0	0	0	0	0	0	0	9.402	3.92	33.48
2041	600	0	0	0	0	0	0	8.804	3.034	23.632
2042	600	0	0	0	0	0	0	8.583	2.275	27.549
Total	4800	0	0	600	1200	1200	200	196.347	49.52	765.033

Table B-2 Annual Unit Selection for Augmented Energy Scenario #1

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE	CI CPV	CI UPV	CIN LOW
2023	0	0	0	0	0	0	200	1.994	0.09	46.172
2024	0	0	0	0	0	0	0	2.138	0.081	48.651
2025	600	0	0	0	0	0	0	3.558	0.124	48.839
2026	1200	0	0	0	0	0	0	5.461	0.189	46.473
2027	600	0	0	600	0	0	0	7.315	0.289	43.132
2028	0	0	0	0	0	0	0	8.436	0.442	48.793
2029	0	0	0	0	0	0	0	8.938	0.675	45.248
2030	0	0	0	0	0	0	0	9.660	1.02	38.374
2031	1200	0	0	0	0	0	0	11.102	1.516	33.215
2032	600	0	0	0	0	0	0	13.047	2.194	46.065
2033	0	0	600	0	0	0	0	14.880	3.052	38.806
2034	0	0	0	0	0	0	0	15.981	4.018	37.726
2035	0	0	1200	0	0	0	0	16.030	4.932	33.606
2036	0	0	600	0	0	600	0	15.103	5.582	34.013
2037	0	0	0	0	0	600	100	13.573	5.786	32.74
2038	0	0	0	0	600	0	0	11.898	5.493	31.132
2039	0	0	0	600	0	0	0	10.444	4.805	27.387
2040	0	0	0	0	0	0	100	9.402	3.92	33.48
2041	600	0	0	0	0	0	50	8.804	3.034	23.632
2042	0	0	0	600	0	0	50	8.583	2.275	27.549
Total	4800	0	2400	1800	600	1200	500	196.347	49.52	765.033

Table B-3 Annual Unit Selection for Augment Energy Scenario #2

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE	CI CPV	CI UPV	CIN LOW
2023	0	0	0	0	0	0	200	1.994	0.09	46.172
2024	0	0	0	0	0	0	0	2.138	0.081	48.651
2025	3000	0	0	0	0	0	200	3.558	0.124	48.839
2026	1200	0	0	0	0	0	0	5.461	0.189	46.473
2027	0	0	0	1800	0	0	0	7.315	0.289	43.132
2028	0	0	0	0	0	0	0	8.436	0.442	48.793
2029	0	0	0	0	0	0	0	8.938	0.675	45.248
2030	0	0	0	0	0	0	0	9.660	1.02	38.374
2031	1200	0	0	0	0	0	0	11.102	1.516	33.215
2032	0	0	0	0	0	600	0	13.047	2.194	46.065
2033	0	0	0	0	0	0	0	14.880	3.052	38.806
2034	0	0	0	0	0	0	0	15.981	4.018	37.726
2035	0	0	600	0	0	600	0	16.030	4.932	33.606
2036	0	0	600	0	0	0	0	15.103	5.582	34.013
2037	600	0	0	600	0	0	0	13.573	5.786	32.74
2038	600	0	0	0	0	0	0	11.898	5.493	31.132
2039	0	0	0	600	0	0	0	10.444	4.805	27.387
2040	0	0	0	0	0	0	0	9.402	3.92	33.48
2041	600	0	0	0	0	0	0	8.804	3.034	23.632
2042	600	0	0	600	0	0	0	8.583	2.275	27.549
Total	7800	0	1200	3600	0	1200	400	196.347	49.52	765.033

Table B-4 Annual Unit Selection for Low Gas Price (3.56 $/MMBTU)

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE	CI CPV	CI UPV	CIN LOW
2023	0	0	0	0	0	0	200	1.994	0.09	46.172
2024	0	0	0	0	0	0	0	2.138	0.081	48.651
2025	0	0	0	0	0	0	0	3.558	0.124	48.839
2026	600	0	0	0	0	0	0	5.461	0.189	46.473
2027	1200	0	0	0	0	0	0	7.315	0.289	43.132
2028	0	0	0	0	0	0	0	8.436	0.442	48.793
2029	0	0	0	0	0	0	0	8.938	0.675	45.248
2030	0	0	0	0	0	0	0	9.660	1.02	38.374
2031	600	0	0	0	0	0	0	11.102	1.516	33.215
2032	0	0	0	0	600	600	0	13.047	2.194	46.065
2033	0	0	0	0	0	0	0	14.880	3.052	38.806
2034	0	0	0	0	0	0	0	15.981	4.018	37.726
2035	0	0	0	0	0	0	0	16.030	4.932	33.606
2036	0	0	0	0	600	600	0	15.103	5.582	34.013
2037	600	0	0	0	0	0	0	13.573	5.786	32.74
2038	600	0	0	0	0	0	0	11.898	5.493	31.132
2039	0	0	0	600	0	0	0	10.444	4.805	27.387
2040	0	0	0	0	0	0	0	9.402	3.92	33.48
2041	600	0	0	0	0	0	0	8.804	3.034	23.632
2042	600	0	0	0	0	0	0	8.583	2.275	27.549
Total	4800	0	0	600	1200	1200	200	196.347	49.517	765.033

Table B-5 Annual Unit Selection for Low Gas Price (7.90 $/MMBTU)

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE	CI CPV	CI UPV	CIN LOW
2023	0	0	0	0	0	0	200	1.994	0.09	46.172
2024	0	0	0	0	0	0	0	2.138	0.081	48.651
2025	0	0	0	0	0	0	0	3.558	0.124	48.839
2026	600	0	0	0	0	0	0	5.461	0.189	46.473
2027	1200	0	0	0	0	0	0	7.315	0.289	43.132
2028	0	0	0	0	0	0	0	8.436	0.442	48.793
2029	0	0	0	0	0	0	0	8.938	0.675	45.248
2030	0	0	0	0	0	0	0	9.660	1.02	38.374
2031	600	0	0	0	0	0	0	11.102	1.516	33.215
2032	600	0	0	600	0	0	0	13.047	2.194	46.065
2033	0	0	0	0	0	0	0	14.880	3.052	38.806
2034	0	0	0	0	0	0	0	15.981	4.018	37.726
2035	0	0	600	0	0	0	0	16.030	4.932	33.606
2036	0	0	1200	0	0	600	0	15.103	5.582	34.013
2037	0	0	0	0	0	600	100	13.573	5.786	32.74
2038	0	0	0	600	0	0	50	11.898	5.493	31.132
2039	0	0	0	600	0	0	0	10.444	4.805	27.387
2040	0	0	0	0	0	0	100	9.402	3.92	33.48
2041	600	0	0	0	0	0	50	8.804	3.034	23.632
2042	0	0	0	0	600	0	0	8.583	2.275	27.549
Total	3600	0	1800	1800	600	1200	500	196.347	49.517	765.033

Table B-6 Annual Unit Selection for Net Zero by 2050

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE	CI CPV	CI UPV	CIN LOW
2023	0	0	0	0	0	0	400	1.994	0.09	46.172
2024	0	0	0	0	0	0	0	2.138	0.081	48.651
2025	600	0	0	0	0	0	0	3.558	0.124	48.839
2026	0	0	0	1200	0	0	0	5.461	0.189	46.473
2027	600	0	0	600	600	0	0	7.315	0.289	43.132
2028	1200	0	600	1800	600	600	0	8.436	0.442	48.793
2029	0	0	600	0	0	0	0	8.938	0.675	45.248
2030	0	0	600	1200	0	0	0	9.660	1.02	38.374
2031	0	0	0	0	0	0	0	11.102	1.516	33.215
2032	0	0	0	0	0	0	0	13.047	2.194	46.065
2033	0	0	0	0	0	0	0	14.880	3.052	38.806
2034	0	0	0	0	0	0	400	15.981	4.018	37.726
2035	0	0	0	0	0	0	400	16.030	4.932	33.606
2036	0	0	0	0	0	0	400	15.103	5.582	34.013
2037	0	0	0	0	0	0	800	13.573	5.786	32.74
2038	0	0	0	0	0	0	400	11.898	5.493	31.132
2039	0	0	0	0	0	0	400	10.444	4.805	27.387
2040	0	0	0	0	0	0	400	9.402	3.92	33.48
2041	0	0	0	0	0	0	800	8.804	3.034	23.632
2042	0	0	0	0	0	0	400	8.583	2.275	27.549
Total	2400	0	1800	4800	1200	600	4800	196.347	49.517	765.033

Table B-7 Annual Unit Selection for Stated Goals in 2022

Year\Tech	NEW CC	NEW CT	NEW WIND	NEW PV	NEW PVBAT	NEW LIBAT	NEW RICE	CI CPV	CI UPV	CIN LOW
2023	0	0	0	0	0	0	400	1.994	0.09	46.172
2024	0	0	0	0	0	0	0	2.138	0.081	48.651
2025	600	0	0	0	0	0	0	3.558	0.124	48.839
2026	0	0	0	1200	0	0	0	5.461	0.189	46.473
2027	600	0	0	600	600	0	0	7.315	0.289	43.132
2028	1200	0	600	1800	600	600	0	8.436	0.442	48.793
2029	0	0	600	0	0	0	0	8.938	0.675	45.248
2030	0	0	600	1200	0	0	400	9.660	1.02	38.374
2031	0	0	0	0	0	0	400	11.102	1.516	33.215
2032	0	0	0	0	0	0	400	13.047	2.194	46.065
2033	0	0	0	0	0	0	400	14.880	3.052	38.806
2034	0	0	0	0	0	0	400	15.981	4.018	37.726
2035	0	0	0	0	0	0	400	16.030	4.932	33.606
2036	0	0	0	0	0	0	400	15.103	5.582	34.013
2037	0	0	0	0	0	0	400	13.573	5.786	32.74
2038	0	0	0	0	0	0	400	11.898	5.493	31.132
2039	0	0	0	0	0	0	400	10.444	4.805	27.387
2040	0	0	0	0	0	0	400	9.402	3.92	33.48
2041	0	0	0	0	0	0	400	8.804	3.034	23.632
2042	0	0	0	0	0	0	400	8.583	2.275	27.549
Total	2400	0	1800	4800	1200	600	5600	196.347	49.517	765.033

Appendix C (Chapter 3)

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

Interruptible	2020	2021	2022	2023
MGE	7.8 / 0 (0%)	6 / 0 (0%)	6.1 / 0 (0%)	5.1 / 0 (0%)
NSPW	64.5 / 69.5 (107.8%)	57.9 / 57.9 (100%)	63 / 63 (100%)	65 / 65 (100%)
WP&L	146 / 0 (0%)	138 / 180 (130.4%)	143.7 / 125 (87%)	141 / 80 (56.7%)
WEPCO	96.8 / 0 (0%)	120.2 / 0 (0%)	97.2 / 0 (0%)	96.8 / 0 (0%)
WPSC	182 / 0 (0%)	206.7 / 0 (0%)	185.9 / 0 (0%)	182 / 0 (0%)
Dairyland	9.5 / 0 (0%)	7.1 / 5.1 (71.8%)	7.1 / 5.1 (71.8%)	7.4 / 0 (0%)
GLU	None	None	None	None
WPPI	48.8 / 0 (0%)	48.5 / 0 (0%)	48.3 / 0 (0%)	38.8 / 0.8 (2.1%)
WI Total	555.3 / 69.5 (12.5%)	584.4 / 243 (41.6%)	551.4 / 193.1 (35%)	536.1 / 145.8 (27.2%)
Direct Load Control	**2018**	**2019**	**2020**	**2021**
MGE	18.8 / 0 (0%)	19.6 / 1.8 (9.4%)	20.4 / 2.6 (12.5%)	20.9 / 3.9 (18.9%)
NSPW	16.3 / 16.3 (100%)	17.1 / 17.6 (102.8%)	15.6 / 17.7 (113.5%)	16.2 / 18.1 (111.7%)
SWLP	1.6 / 0 (0%)	1.4 / 0 (0%)	1.9 / 0 (0%)	1.7 / 0 (0%)
Dairyland	91 / 91 (100%)	91 / 91 (100%)	91 / 91.1 (100%)	91 / 98.1 (107.8%)
WI Total	127.7 / 107.3 (84%)	129.1 / 110.5 (85.6%)	128.9 / 111.3 (86.3%)	129.9 / 120.1 (92.5%)

Table C-2 Summary of Demand Response Activity by Provider

Entity	Summary of Demand Response Programs	2020	2021	2022	2023
MGE	MGE DR Capacity	26.6	25.6	26.6	26.1
MGE	MGE DR Capacity Dispatched	0.0	1.8	2.6	3.9
MGE	MGE DR Customers Enrolled	19	2,572	3,578	5,519
NSPW	NSPW DR Capacity	80.8	75.0	78.6	81.2
NSPW	NSPW DR Capacity Dispatched	85.8	75.5	80.7	83.1
NSPW	NSPW DR Customers Enrolled	21,286	22,342	22,130	22,793
WP&L	WPL DR Capacity	146.0	138.0	143.7	141.0
WP&L	WPL DR Capacity Dispatched	0.0	180.0	125.0	80.0
WP&L	WPL DR Customers Enrolled	127	125	5,621	10,117
WEPCO	WEPCO DR Capacity	120.3	132.2	132.3	127.7
WEPCO	WEPCO DR Capacity Dispatched	0.0	0.0	0.0	0.0
WEPCO	WEPCO DR Customers Enrolled	87	86	84	84
WPSC	WPSC DR Capacity	182.0	187.8	181.2	170.8
WPSC	WPSC DR Capacity Dispatched	0.0	0.0	0.0	0.0
WPSC	WPSC DR Customers Enrolled	50	50	46	46
SWL&P	SWLP DR Capacity	1.6	1.4	1.9	1.7
SWL&P	SWLP DR Capacity Dispatched	0.0	0.0	0.0	0.0
SWL&P	SWLP DR Customers Enrolled	169	169	165	164
Dairyland	Dairyland DR Capacity	136.5	134.1	134.2	145.5
Dairyland	Dairyland DR Capacity Dispatched	127.0	132.1	132.2	138.1
Dairyland	Dairyland DR Customers Enrolled	87,402	87,417	87,444	95,202
Entity	Summary of Demand Response Programs	2020	2021	2022	2023
GLU	GLU DR Capacity	0.0	0.0	0.0	0.0
GLU	GLU DR Capacity Dispatched	0.0	0.0	0.0	0.0
GLU	GLU DR Customers Enrolled	0.0	0.0	0.0	0.0
WPPI	WPPI DR Capacity	48.8	48.5	48.3	38.8
WPPI	WPPI DR Capacity Dispatched	0.0	0.0	0.0	0.8
WPPI	WPPI DR Customers Enrolled	12	12	12	12
WI	Total DR Capacity	742.5	742.7	746.6	732.7
WI	Total DR Capacity Dispatched	212.8	389.4	340.4	305.9
WI	Total DR Customers Enrolled	109,152	112,773	119,080	133,937

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

DR Program	DR Type	2020	2021	2022	2023
Is-3 Electric Interruptible Service	Interruptible Load	7.8	6.0	6.1	5.1
Is-4 Electric Interruptible Service	Direct Load Control	7.6	6.6	6.9	6.0
CP-1 C&I High Load Factor Direct Control Interruptible Service for Transmission Voltage	Direct Load Control	11.3	11.2	11.0	11.0
MGE Connect	Direct Load Control	0.0	1.8	2.6	3.9
MGE 4 Programs		26.6	25.6	26.6	26.1
Electric Rate Savings (commercial)	Interruptible Load	64.5	57.9	63.0	65.0
AC Rewards	Direct Load Control	0.0	1.1	1.7	2.1
Saver's Switch (Residential AC)	Direct Load Control	9.8	9.5	7.9	8.1
Saver's Switch (Residential Water Heaters)	Direct Load Control	0.3	0.3	0.3	0.3
Saver's Switch (Commercial)	Direct Load Control	6.2	6.2	5.7	5.7
NSPW 5 Programs		80.8	75.0	78.6	81.2
C&I Interruptible	Interruptible Load	146.0	138.0	138.0	131.0
Smart Hours Residential DLC	Interruptible Load	0.0	0.0	5.7	10.0
WP&L 2 Programs		146.0	138.0	143.7	141.0
Curtailable Service	Other	22.9	24.0	25.5	23.5
Seasonal Curtailable Service	Other	0.5	1.2	1.5	1.2
General Primary Combined Firm and Non-Firm Service	Interruptible Load	65.0	68.6	66.1	65.9
Real Time Pricing Rider	Interruptible Load	31.8	38.4	39.1	37.2
WEPCO 5 Programs		120.3	132.2	132.3	127.7
General Primary Interruptible	Interruptible Load	127.1	136.1	135.5	132.0
Real Time Market Pricing	Interruptible Load	54.9	51.7	45.6	38.8
WPSC 2 Programs		182.0	187.8	181.2	170.8

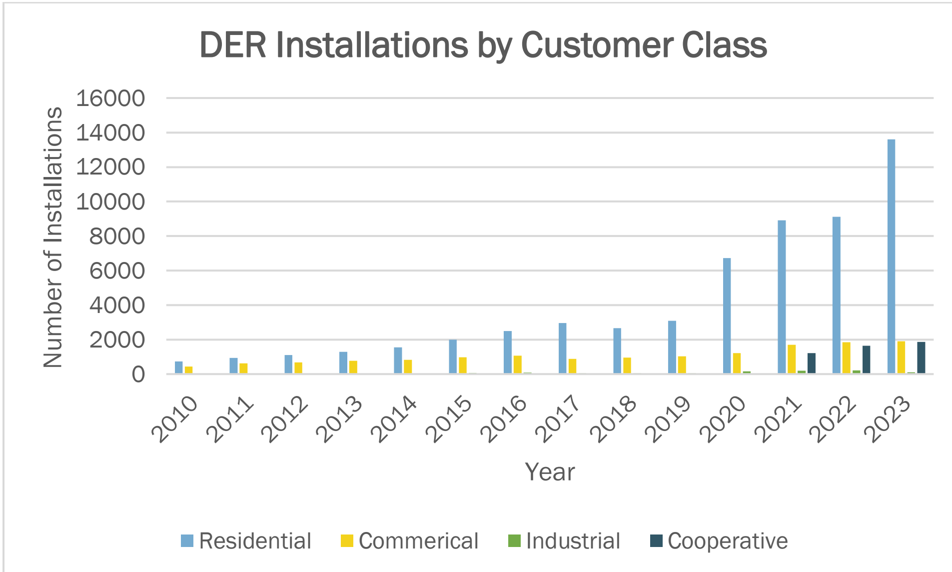
DR Program	DR Type	2020	2021	2022	2023
Controlled Space Heating	Direct Load Control	1.5	1.3	1.8	1.6
Controlled Water Heating	Direct Load Control	0.1	0.1	0.1	0.1
SWLP 2 Programs		1.6	1.4	1.9	1.7
Daily Thermal Storage	Direct Load Control	12.0	12.0	12.0	14.0
Bulk Interruptible	Interruptible Load	9.5	7.1	7.1	7.4
Residential DLC	Direct Load Control	74.0	74.0	74.0	79.0
C&I BTM Generators	Other	36.0	36.0	36.0	40.0
Agricultural DLC	Direct Load Control	5.0	5.0	5.0	5.0
Daily EV Charging	Direct Load Control	0.0	0.0	0.1	0.1
Dairyland 5 Programs		136.5	134.1	134.2	145.5
Large Customer Demand Response	Interruptible Load	48.8	48.5	48.3	38.8
WPPI 1 Programs		48.8	48.5	48.3	38.8
WI Total	Interruptible Load	555.3	552.3	554.6	531.2
WI Total	Direct Load Control	127.7	129.1	129.0	136.9
WI Total	Other	59.5	61.2	63.0	64.6
WI Total		742.5	742.7	746.6	732.7

Table C-4 Demand Response Enrolled Customers by Program

DR Program	DR Type	2020	2021	2022	2023
Is-3 Electric Interruptible Service	Interruptible Load	7	7	7	7
Is-4 Electric Interruptible Service	Direct Load Control	11	11	11	11
CP-1 C&I High Load Factor Direct Control Interruptible Service for Transmission Voltage	Direct Load Control	1	1	1	1
MGE Connect	Direct Load Control	0	2,553	3,559	5,500
MGE 4 Programs		19	2,572	3,578	5,519
Electric Rate Savings (commercial)	Interruptible Load	273	271	271	270
AC Rewards	Direct Load Control	182	1,074	1,410	1,829
Saver's Switch (Residential AC)	Direct Load Control	18,212	18,299	17,975	18,175
Saver's Switch (Residential Water Heaters)	Direct Load Control	1,551	1,634	1,384	1,404
Saver's Switch (Commercial)	Direct Load Control	1,068	1,064	1,090	1,115
NSPW 5 Programs		21,286	22,342	22,130	22,793
C&I Interruptible	Interruptible Load	127	125	121	117
Smart Hours Residential DLC	Direct Load Control	0	0	5,500	10,000
WP&L 2 Programs		127	125	5,621	10,117
Curtailable Service	Other	50	49	48	48
Seasonal Curtailable Service	Other	11	11	11	11
General Primary Combined Firm and Non-Firm Service	Interruptible Load	25	25	24	24
Real Time Pricing Rider	Interruptible Load	1	1	1	1
Electronics and Information Technology Manufacturing-Market Pricing Rate	Interruptible Load	0	0	0	0
WEPCO 5 Programs		87	86	84	84
General Primary Interruptible	Interruptible Load	42	42	38	38
Real Time Market Pricing	Interruptible Load	8	8	8	8
WPSC 2 Programs		100	100	92	92

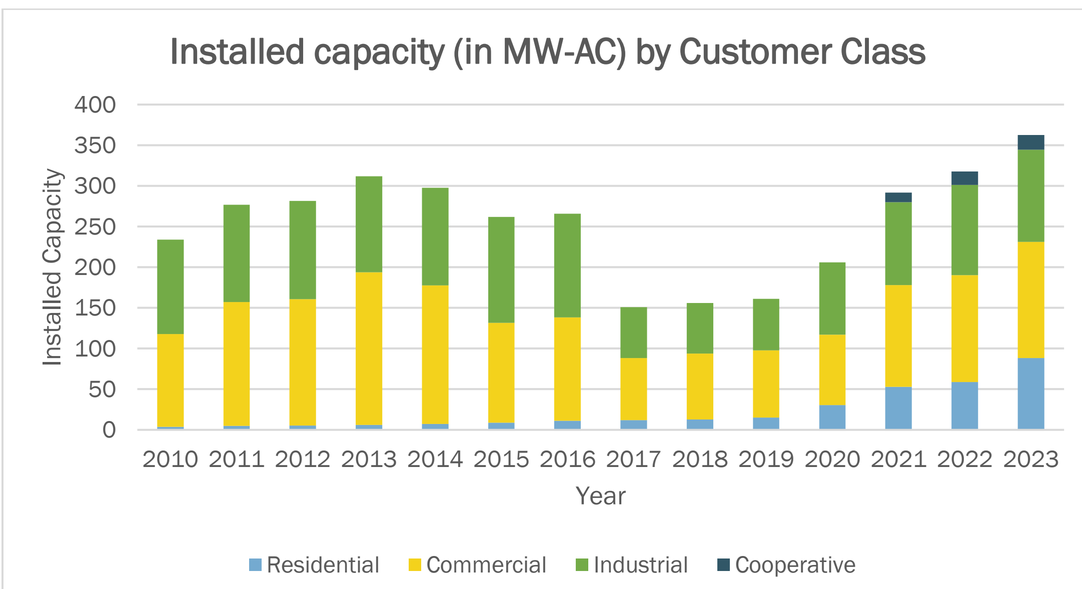
DR Program	DR Type	2020	2021	2022	2023
Controlled Space Heating	Direct Load Control	119	119	118	117
Controlled Water Heating	Direct Load Control	50	50	47	47
SWLP 2 Programs		388	387	378	376
Daily Thermal Storage	Direct Load Control	12,000	12,000	12,000	14,000
Bulk Interruptible	Interruptible Load	2	2	2	2
Residential DLC	Direct Load Control	74,373	74,373	74,373	80,000
C&I BTM Generators	Other	141	141	141	160
Agricultural DLC	Direct Load Control	828	828	828	840
Daily EV Charging	Direct Load Control	58	73	100	200
Dairyland 5 Programs		87,402	87,417	87,444	95,202
Large Customer Demand Response	Interruptible Load	12	12	12	12
WPPI 1 Programs		12	12	12	12
WI Total	Interruptible Load	497	493	484	479
WI Total	Direct Load Control	108,453	112,079	118,396	133,239
WI Total	Other	202	201	200	219
WI Total		109,152	112,773	119,080	133,937

Figure C-1 Distributed Energy Resources, Installations by Customer Class, 2010-2023



Note: Data on the cooperative category prior to 2021 is not shown.

Figure C-2 Installed Capacity in MW-AC by Customer Class



Note: In years prior to 2021, data was primarily reported in DC. This data was converted to AC for this chart with an assumed conversion factor that DC capacity is 1.25 times the value of AC capacity.

Appendix D (Chapter 6)

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

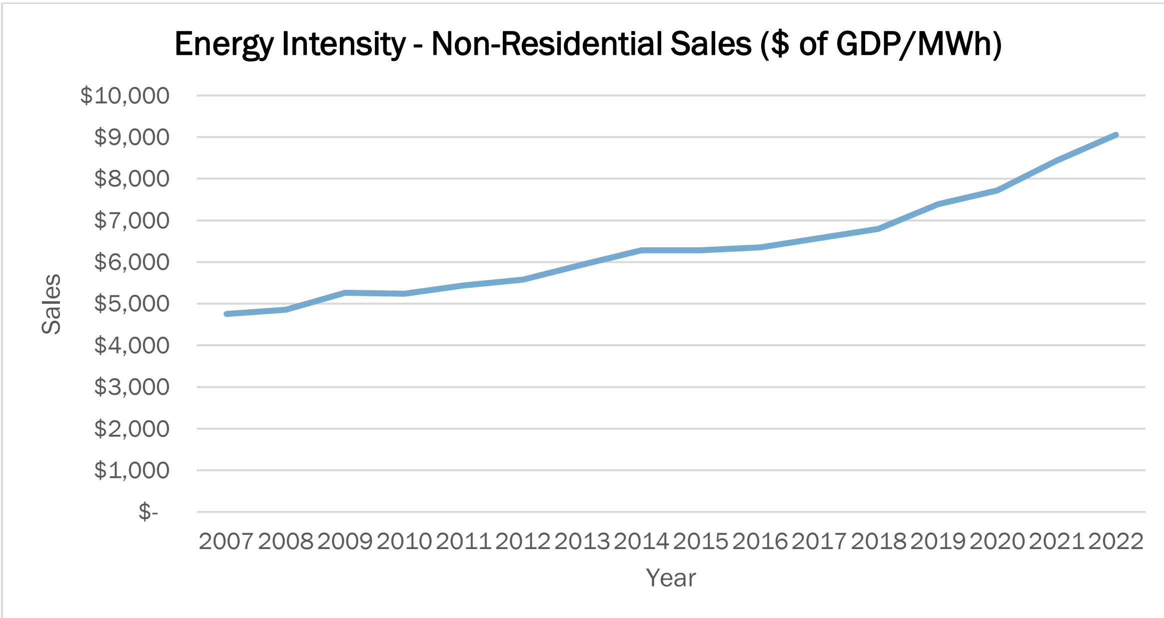


Figure D-2 Weather-Normalized Annual Use, per Residential Customer (kWh)

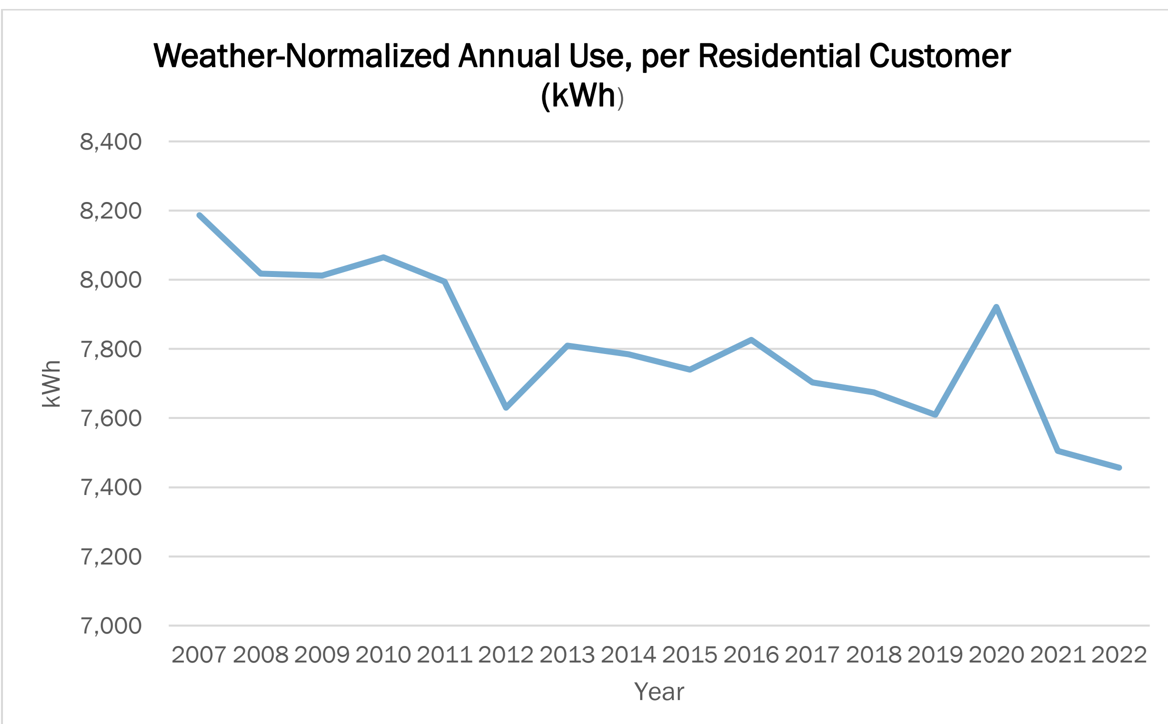


Table D-1 Residential Average Rates in the Midwest and U.S. (cents/kWh)

State	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Illinois	11.38	10.63	11.91	12.50	12.54	12.95	12.77	13.03	13.04	13.18	15.65
Indiana	10.53	10.99	11.46	11.57	11.79	12.29	12.26	12.58	12.83	13.37	14.59
Iowa	10.82	11.05	11.16	11.63	11.94	12.34	12.24	12.46	12.46	12.73	13.15
Michigan	14.13	14.59	14.46	14.42	15.22	15.40	15.45	15.74	16.26	17.54	17.86
Minnesota	11.35	11.81	12.01	12.12	12.67	13.04	13.14	13.04	13.17	13.50	14.25
Missouri	10.17	10.60	10.64	11.21	11.21	11.63	11.34	11.14	11.22	11.42	11.74
Ohio	11.76	12.01	12.50	12.80	12.47	12.63	12.56	12.38	12.29	12.77	13.85
Wisconsin	13.19	13.55	13.67	14.11	14.07	14.35	14.02	14.18	14.32	14.52	15.62
Midwest	11.67	11.90	12.23	12.55	12.74	13.08	12.97	13.07	13.20	13.63	14.59
U.S. Average	11.88	12.13	12.52	12.65	12.55	12.89	12.87	13.01	13.15	13.66	15.04

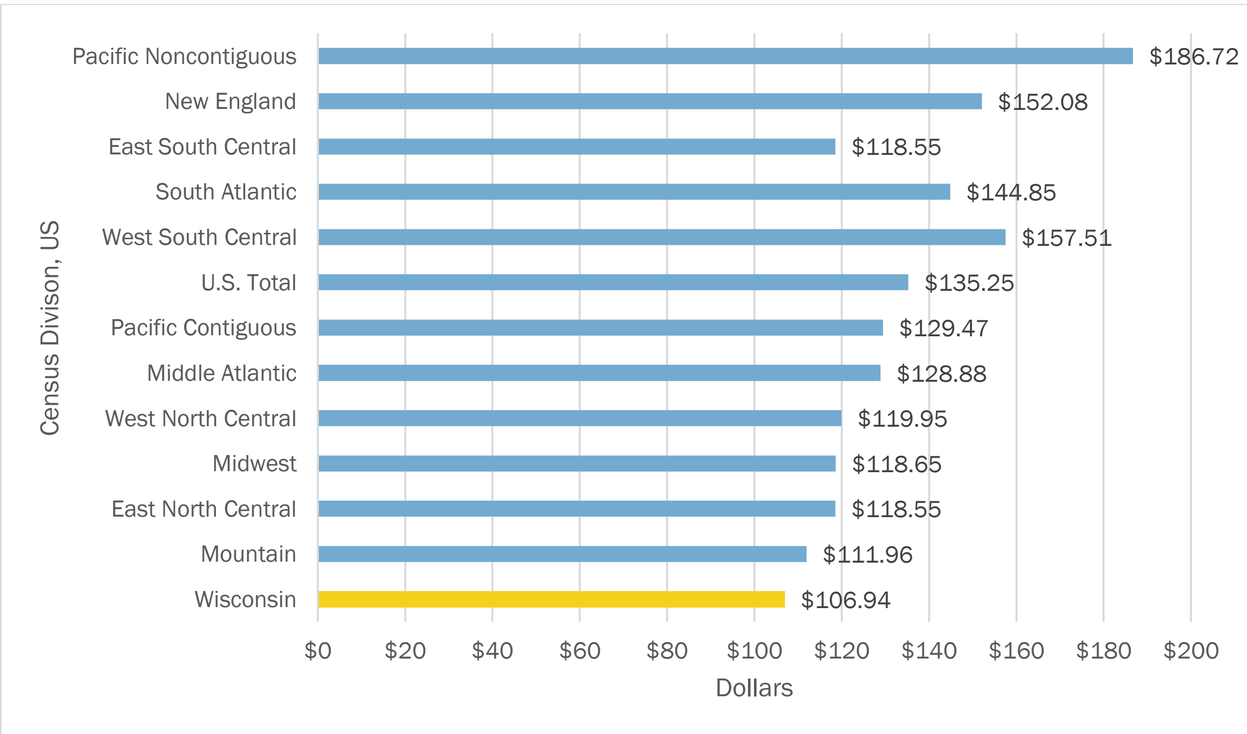
Table D-2 Commercial Average Rates in the Midwest and U.S. (cents/kWh)

State	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Illinois	7.99	8.14	9.26	9.02	9.02	9.09	9.12	9.08	9.15	9.65	11.32
Indiana	9.14	9.60	9.96	9.78	10.01	10.54	10.60	11.03	11.21	11.58	12.86
Iowa	8.01	8.44	8.67	8.92	9.17	9.46	9.68	9.99	9.96	10.17	10.55
Michigan	10.93	11.06	10.87	10.55	10.64	11.00	11.15	11.39	11.71	12.31	12.55
Minnesota	8.84	9.42	9.85	9.44	9.86	10.48	10.38	10.34	10.43	11.22	12.30
Missouri	8.20	8.80	8.90	9.16	9.26	9.47	9.40	9.07	8.93	9.17	9.55
Ohio	9.47	9.35	9.83	10.07	9.97	10.05	10.11	9.72	9.53	9.75	10.39
Wisconsin	10.51	10.74	10.77	10.89	10.77	10.87	10.67	10.72	10.75	10.95	11.85
Midwest	9.14	9.45	9.76	9.73	9.84	10.12	10.14	10.17	10.21	10.60	11.42
U.S. Average	10.09	10.26	10.74	10.64	10.43	10.66	10.67	10.68	10.59	11.22	12.41

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

State	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Illinois	5.80	5.94	6.85	6.67	6.51	6.47	6.80	6.52	6.70	7.30	8.57
Indiana	6.34	6.70	6.97	6.86	6.97	7.54	7.38	7.36	6.98	7.39	8.65
Iowa	5.30	5.62	5.71	5.90	6.05	6.21	6.45	6.60	6.43	6.63	7.06
Michigan	7.62	7.72	7.68	7.02	6.91	7.19	7.10	7.07	7.24	7.69	8.33
Minnesota	6.54	6.98	6.72	7.02	7.37	7.37	7.53	7.53	7.67	8.29	9.25
Missouri	5.89	6.29	6.36	6.44	7.12	7.33	7.22	7.11	6.84	7.11	7.67
Ohio	6.24	6.22	6.77	7.02	6.98	6.92	7.01	6.55	6.16	6.55	7.45
Wisconsin	7.34	7.40	7.52	7.58	7.49	7.49	7.33	7.31	7.29	7.63	8.49
Midwest	6.38	6.61	6.82	6.81	6.93	7.07	7.10	7.01	6.91	7.32	8.18
U.S. Average	6.67	6.89	7.1	6.91	6.76	6.88	6.92	6.81	6.67	7.18	8.32

Figure D-3 Average Monthly Residential Bills by Census Division (2022 EIA Data)[144]



[144] U.S. Energy Information Administration. 2022 Average Monthly Bill – Residential. https://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf. Accessed February 15, 2024.

Figure D-4 *2023 Distribution of Monthly Residential Electricity Bills for Municipal Utilities*[145]

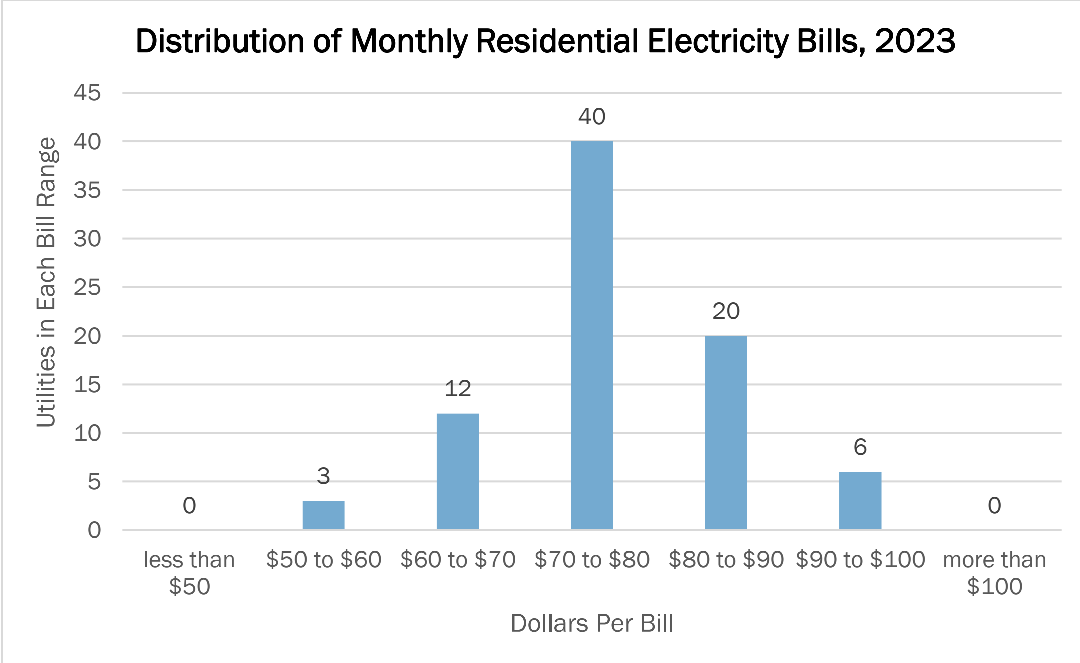
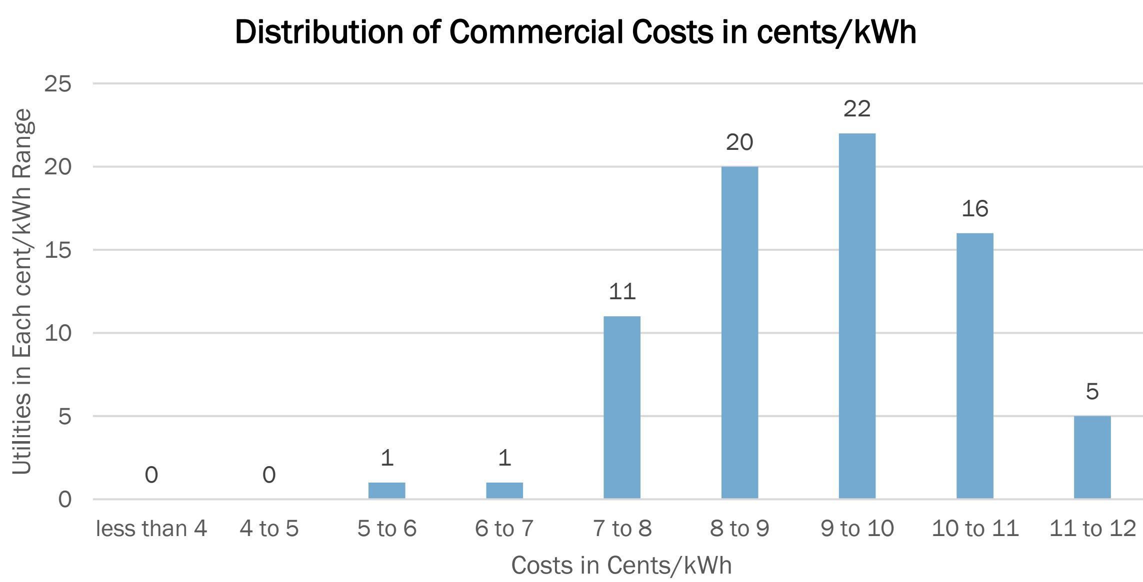


Figure D-5 *2023 Distribution of Commercial (CP-1) Costs in Cents/kWh for Municipal Utilities*[146]



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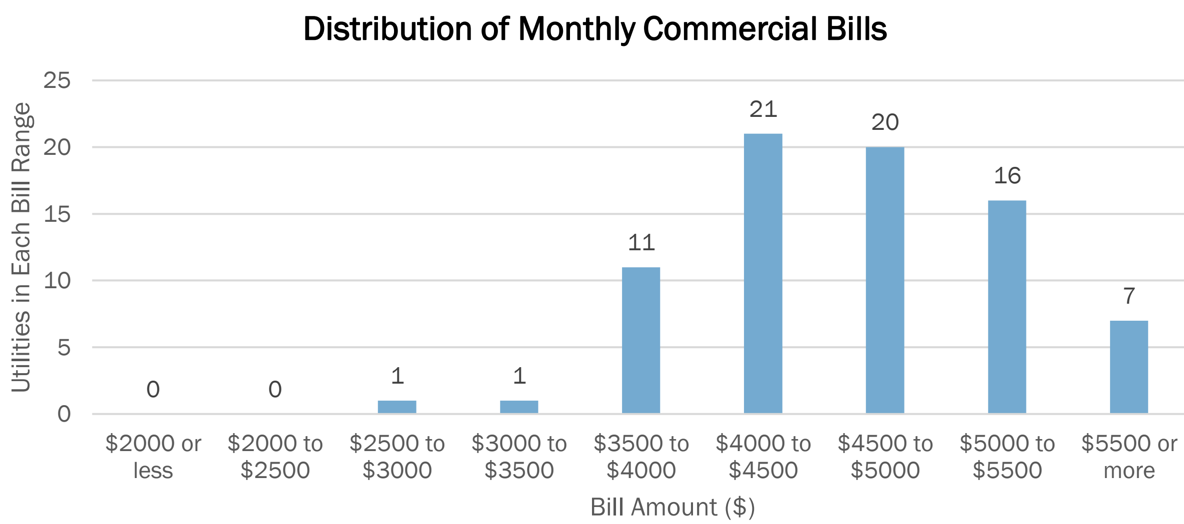
[145] Source: Major utility tariffs filed with the Commission, https://apps.psc.wi.gov/RATES/tariffs/default.aspx.
[146] Source: Major utility tariffs filed with the Commission, https://apps.psc.wi.gov/RATES/tariffs/default.aspx.

Figure D-6 Distribution of Monthly Commercial (CP-1) Bills for Municipal Utilities [147]



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 D-4 2023 Estimated Monthly Bill Data for Municipal Utility Cp-1 Customers

Summary	Total Cost (cents/kWh)*	Estimated Bill ($/month)*
Minimum	5.42	$2,710.00
25th Percentile	8.41	$4,205.00
Median	9.21	$4,605.00
Average	9.29	$4,644.70
75th Percentile	10.12	$5,060.00
Maximum	12.38	$6,190.00

* 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.

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

Acronyms and Initialisms

§	Section
AC	Alternating current
ATC	American Transmission Company LLC
Cadmus	Cadmus Group
ch.	Chapter
Commission	Public Service Commission of Wisconsin
CO2	Carbon Dioxide
COSS	Cost-of-Service Study
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
EPA	U.S. Environmental Protection Agency
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission
Focus	Focus on Energy
fps	Feet per second
GIP	Generator Interconnection Project
GW	Gigawatt
HER	Home Energy Rebate
Hz	Hertz
HILF	High impact, low frequency
ICAP	Installed Capacity
ICE	Improved Customer Experience
IEEE	Institute of Electric and Electronic Engineers
IMM	Independent market monitor
IOU	Investor-owned utility
IPL	Interstate Power and Light Company
IRP	Integrated Resource Planning
ITC	Investment Tax Credit
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
LRTP	Long Term Transmission Planning
LSE	Load Serving Entity
LTRA	Long-Term Resource Assessment
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
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
NLMP	New Load Market Pricing
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
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
SEA	Strategic Energy Assessment
SWL&P	Superior Water, Light and Power Company
TCJA	Tax Cuts and Jobs Act
TOU	Time-of-Use
TRC	Total Resource Cost
UCAP	Unforced Capacity
WEC	Wisconsin Energy Corporation
WEM	Wisconsin Emergency Management

WEPCO	Wisconsin Electric Power Company
WG	Wisconsin Gas LLC
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

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