APPENDIX A – Need and Alternatives Analysis

WEC Energy Group ("WEC" or "the Company"), and its subsidiaries Wisconsin Public Service Corporation ("WPSC") and Wisconsin Electric Power Company, doing business as We Energies, ("Wisconsin Electric") have long been leaders in providing safe and reliable energy to their Wisconsin customers.

Over the past two decades, WEC has prioritized a measured and methodical transition to clean energy. By converting the Valley Power Plant to clean natural gas, installing Wisconsin's largest wind energy facilities, constructing the first utility-scale solar fields and utility-scale battery project in Wisconsin, testing hydrogen blending in reciprocating internal combustion engine ("RICE") generators, retiring multiple coal plants, and testing new long-duration organic batteries, WEC has consistently demonstrated and continues to prove, that providing safe, reliable energy need not come at the expense of the environment. By leveraging technological advancements in power generation, WEC has maintained and will continue to maintain world-class reliability, promotes fuel diversity, and advance sustainability all at once.

As explained in this Appendix, WEC is continuing to transform its generation fleet to ensure reliability and resiliency in the face of evolving regional energy market resource adequacy rules established by the Midcontinent Independent System Operator ("MISO"), manage substantial load growth, and ensure compliance with proposed US Environmental Protection Agency ("USEPA") rules. WEC proposes to continue to transform its generation fleet while carefully and prudently ensuring the reliability of each hour of the year with needed dispatchable, highly flexible, and fast-ramping generation capacity fueled principally with clean natural gas.

Generation Reshaping Plan: Need

At a high level, WEC's continuing Generation Reshaping Plan ("GRP") efforts will include adding resources to:

- ✓ Maintain and enhance system reliability.
- ✓ Comply with recently implemented and anticipated future MISO resource adequacy construct and resource accreditation changes.
- ✓ Meet substantial new load growth in the Company's Service Territory.
- ✓ Ensure compliance with the proposed federal regulations (USEPA Clean Air Act Rule modifications.
- ✓ Support the state of Wisconsin's vision for carbon reduction, by meeting or exceeding WEC's previously-identified 80 percent carbon reduction goal by the end of 2030, relative to 2005 emission levels.

Regional Transmission Operators ("RTOs") and the North American Electric Reliability Corporation ("NERC") have increasingly expressed deep and growing concerns regarding the changing composition of the United States' generation portfolio and the impact that, absent new dispatchable generation being placed in service, the pace of this change will have on reliability throughout the country. Moving from a grid that relies on large, dispatchable baseload central generating plants to one with more dispersed intermittent (and non-dispatchable) and energy-limited resources is greatly increasing the risk that sufficient generation capacity will not be available in all seasons and during all hours. As NERC President and CEO Jim Robb recently highlighted the planning and reliability challenges the transition to a cleaner energy future presents in testimony before the Federal Energy Regulatory Commission's ("FERC") at its 2023 Reliability Technical Conference (Docket No. AD23-9-000):

> *NERC is concerned that the pace of change is overtaking the reliability needs of the system. Unless reliability and resilience are appropriately prioritized, current trends indicate the potential for more frequent and more serious long duration reliability disruptions, including the possibility of national consequence events.*
>
> *. . . [W]e must shift focus from planning for solely "capacity on peak" to "energy 24x7" due to the changing fuel mix. Further, we need to better understand the impact on the [bulk power system] from the dynamic performance associated with inverter-based resources . . . and distributed energy resources . . . These understandings can then be balanced against the potential for demand side management – both energy efficiency and demand response – to support reliability and resilience*.

In addition, MISO CEO John Bear noted in his update letter to the Edison Electric Institute ("EEI") members' CEOs in July of 2023:

> *Energy adequacy is a growing concern. This is in fact already illuminated in challenging operating situations, including the recent weather events of Uri and Elliot and this summer's heat.*

Mr. Bear was sounding the alarm even louder in a February, 2024 "Response to the Reliability Imperative" report, in which he said:

> *There are immediate and serious challenges to the reliability of our region's electric grid, and the entire industry — utilities, states and MISO — must work together and move faster to address them.*
>
> *MISO and its utility and state partners have been deeply engaged on these challenges for years, and we have made important progress. But the region's generating fleet is changing even faster and more profoundly than we anticipated, so we all must act with more urgency and resolve.*
>
> …
>
> *However, the transition that is underway to get to a decarbonized end state is posing material, adverse challenges to electric reliability. A key risk is that many existing "dispatchable" resources that can be turned on and off and adjusted as needed are being replaced with weather-dependent resources such as wind and solar that have materially different characteristics and capabilities. While wind and solar produce needed clean energy, they lack certain key reliability attributes that are needed to keep the grid reliable every hour of the year. Although several emerging technologies may someday change that calculus, they are not yet proven at grid scale. Meanwhile, efforts to build new dispatchable resources face headwinds from government regulations and policies, as well as prevailing investment criteria for financing new energy projects.* ***Until new technologies become viable, we will continue to need dispatchable resources for reliability purposes****. But fleet change is not the only challenge we face. Extreme weather events have become more frequent and severe. Supply chain and permitting issues beyond MISO's control are delaying many new reliability critical generation projects that are*

> *otherwise fully approved. Large single-site load additions, such as energy-intensive production facilities or data centers, may not be reliably served with existing or planned resources. Incremental load growth due to electric vehicles and other aspects of electrification is exerting new pressure on the grid. And neighboring grid systems are becoming more interdependent and reliant on each other, highlighting the need for more interregional planning ….*

To address these concerns, MISO has been moving rapidly to incentivize market participants to replace fully-dispatchable plants that are scheduled to retire in the near term with resources that have the characteristics needed to maintain grid reliability – in particular dispatchability and quick ramp rates. These changes can be seen in day ahead and real time energy market operations (via the introduction of new products, such as MISO's proposed system attributes discussed later in this document), evolution in the resource adequacy construct and accreditation rules and infrastructure development via transmission planning.

In addition to the market rules evolving to ensure reliability for a changing grid, WEC must also plan for additional load growth. WEC forecasts substantial load growth over at least the next five years in Wisconsin Electric's southeast Wisconsin service territory – particularly what has become known as the I-94 corridor between Milwaukee, Wisconsin and the Illinois border. The anticipated load growth is shown in Figures 3 and 4 further below. To manage this load growth WEC needs to ensure its generation portfolio can provide the capacity and energy to meet MISO load-serving obligations and to serve all customers reliably, safely, and economically.

In addition to managing the evolving rule changes in the MISO markets and load growth, WEC also needs to understand and prepare for future risks and trends which may impact generation portfolio planning decisions both today and in the future. On May 11, 2023, the USEPA proposed new greenhouse gas ("GHG") emission limits and guidelines for new and existing fossil fuel power plants. USEPA issued a proposed rule under section 111 of the Clean Air Act, which directs the USEPA to set standards based on the application of the "best system of emission reduction" ("BSER") that is adequately demonstrated, and considers cost, energy requirements, and other factors. Depending upon the final requirements that are identified as BSER as well as the timeframes allowed for compliance, WEC will need to carefully test and prove out fuel diversity investments of existing resources.

The USEPA GHG rule, which was finalized in the spring of 2024, provides insight into the real challenges the industry will face and the likely future risks associated with relying on baseload fossil-fueled generation. All the steps needed to ensure compliance with the rules will need to occur in less than a decade. Understanding and preparing now for the impact of these rules is critical to making prudent investment decisions about assets that have a 30-year or longer life. In addition, to be able to comply with the proposed GHG rules' timeframes, WEC must quickly take action to prudently place new generation resources into service to maintain reliability, particularly when considering potential delays due to supply chain challenges, limited labor availability, planning, permitting and regulatory approval timelines, and recently-encountered construction delays.

WEC's GRP: Objectives

The objectives of WEC's GRP are to maintain reliability, customer affordability, and safety at Wisconsin Electric and WPSC while transitioning the fleet to become more baseload renewable. The plan balances the following five key objectives:

- ✓ **Maintaining Reliability:** Ensuring compliance with evolving market rules and managing NERC grid reliability concerns. Given these factors, WEC will continue to design, operate, and maintain state-of-the-art generation resources to provide a safe, reliable, economical, and stable flow of electricity to serve the demand of Wisconsin homes and businesses in every hour of every season.

- ✓ **Ensuring Resiliency:** Maintaining and improving a diverse generation portfolio that provides Essential Reliability Services[1] to prepare for, withstand, and recover from significant disruptions.

- ✓ **Minimizing Environmental Impact*:*** Ensuring alignment with Governor Evers' Climate Change Task Force recommendations regarding generation CO_2 reductions and preparing for USEPA GHG rules. This will position WEC to achieve 80 percent carbon reduction by 2030 (and net carbon neutrality by 2050), as well as positioning WEC assets to comply with the revised $PM_{2.5}$ National Ambient Air Quality Standard.

- ✓ **Capturing Economic Value:** Harnessing market forces driving cost-competitive renewable and storage technology and maximizing efficiencies within WEC's own fleet, for the ultimate benefit of customers.

- ✓ **Managing Market Risk:** Recognizing that as technological advancements continue, geographic proximity of generating assets to customers' electricity consumption remains critical for ensuring that Wisconsin customers can depend on Wisconsin resources for their energy and, therefore, generation capacity needs.

Objectives 1 and 2: Maintaining Reliability and Ensuring Resiliency

In addition to economics, an optimal generation portfolio must balance other objectives to minimize customer risks. Reliability and resiliency are key aspects in the design and operation of an electric generation portfolio and have common goals:

- Keeping the power on during all hours;
- Minimizing the risk of outages;
- Withstanding disruptions and minimizing the impact of outages; and
- Quickly and efficiently restoring the system.

Reliability

As fully dispatchable resources continue to be retired and intermittent renewable resources are added, the risk of not having energy available at all hours and during all seasons is growing. As noted by MISO's CEO John Bear:

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[1] NERC has identified three features – dynamic voltage control, system inertia, and frequency response – as the "Essential Reliability Services" that are necessary to provide safety and stability to the grid.

These challenges all point to the ongoing need for ample, dependable levels of flexible, controllable and long-duration resources on the system.

To help manage this uncertainty and risk, generation portfolios need to evaluate the supply mix to ensure adequate amounts of dispatchable resources are available to fill the energy holes - even if they occur only for a handful of hours in a year - that have been experienced already and will continue to grow as the grid evolves to a carbon-free baseload supply mix.

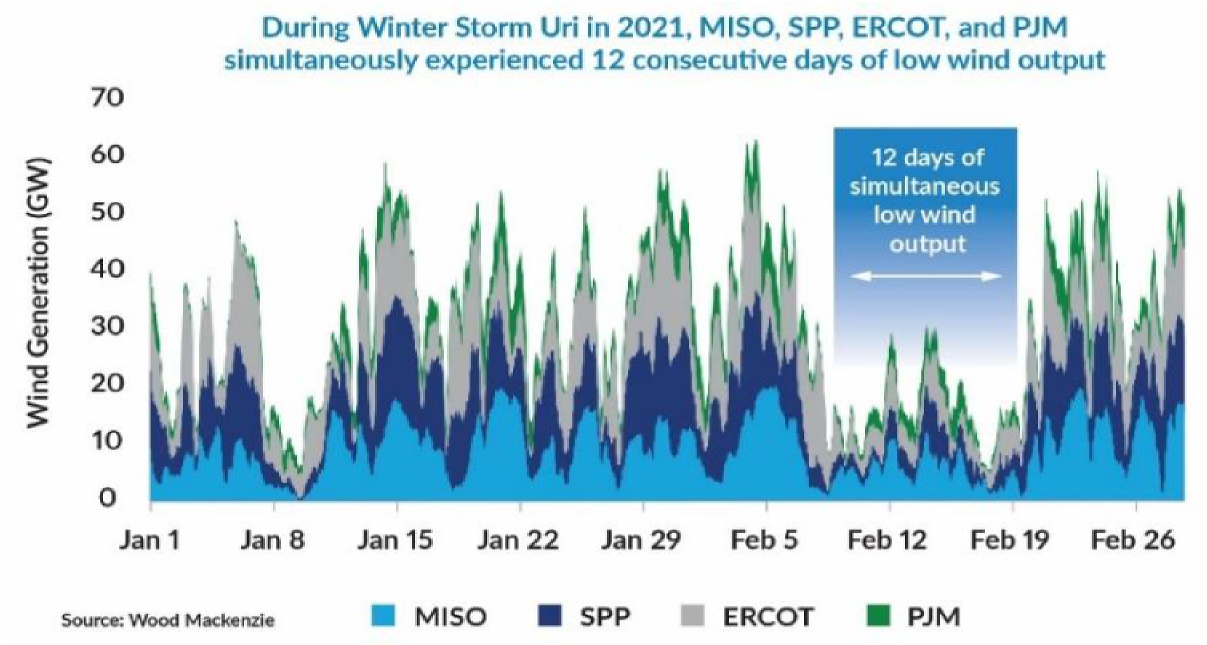
Although battery storage can be helpful in managing these risks, the technology is limited by the lack of commercial long (beyond 4 hours) duration batteries and the current grid following inverters used cannot provide the Essential Reliability Service of inertia support.[2] In addition, the cost of commercially available and proven battery storage has increased due to the competition with the auto industry for the component used to make batteries as well as supply chain limitations of rare earth metals. Finally, although battery storage may be dispatched for a limited period of time similar to a generation asset, it only stores power generated by other assets. Due to these limitations, to ensure 24/7 reliability to customers, battery storage must be supported by and augmented with dispatchable, clean generation resources, including those fueled by natural gas.

Together, the combination of batteries and dispatchable gas fueled generation will allow greater utilization of renewable resources. Natural gas generation and, to a lesser extent, batteries provide the fast-ramping capability necessary to reliably serve load and quickly and seamlessly offset energy production changes, either forecasted or unexpected, from renewable resources. While batteries and dispatchable gas-fueled resources both support this effort, they play very different and important roles. Batteries can help shift stored energy to a limited extent to different points in the day. However, only fully dispatchable gas plants can provide needed energy over days and even weeks when renewable energy generation resources are limited. As noted by MISO in January 2023:

Wind resources can also experience "fuel" availability challenges in the form of highly variable wind speeds correlated with weather patterns. The energy output of wind resources can fluctuate significantly on a day-to-day and even an hour-by-hour basis including multi-day periods of low wind output. The chart below illustrates how the MISO, Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), and PJM regions all experienced 12 consecutive days of low wind output during Winter Storm Uri in February 2021.

[2] Inertia refers to a kinetic property of the rotating mass of a synchronous generator. The importance of inertia to an electric grid is that it provides reliability and damping. It is needed in electric grid operations to instantaneously respond to grid disruptions to ensure that the output of electricity from the grid remains consistent and stable.

Figure 31 – Low Wind Output



This concern about energy availability has also been noted in NERC's 2022 Long Term Reliability Assessment ("LTRA"), where MISO is noted as a "high risk" area.[3] In addition, MISO identified growing reliability concerns in non-summer seasons caused by the shifting resource mix and system, fuel assurance and severe weather events.

> *Factors such as widespread retirements of conventional resources, lower reserve margins, more frequent and severe weather events, and increased reliance on emergency-only resources and weather-dependent renewables have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.*
>
> *Gas-fired resources are also subject to fuel-assurance risks because they rely on pipelines to deliver gas to them when they need it. However, because the gas pipeline system was largely built for home-heating and manufacturing purposes, gas power plants sometimes cannot procure all the fuel they need due to contractual issues related to delivery priorities. In the MISO region, this has historically occurred during extreme winter weather events that drive up home-heating needs for gas. Many gas generators in MISO do not have "firm" fuel-delivery contracts, opting instead for less costly "interruptible" pipeline service or a blend thereof. Only about 27% of the gas generation that responded to MISO's 2022-2023 Generator Winterization Survey indicated it had firm transport contracts in place for all of their supplies during the 2022-2023 winter season.*

[3] *2022 LTRA* at 5–6.

Resilience

Resilience is another growing concern for the electric grid and an important consideration in developing a prudent generation portfolio. Resilience is related to reliability: the grid cannot be resilient if it is not first reliable. Resilience encompasses additional concepts, including preparing for, operating through, and recovering from significant disruptions. Resilience concerns the grid's ability to withstand and recover from extreme or prolonged events.

NERC has identified three features – dynamic voltage control, system inertia, and frequency response – as the Essential Reliability Services that are necessary to provide safety and stability to the grid.

While batteries and associated grid-following inverter technology can provide dynamic voltage and frequency response, they simply cannot provide the Essential Service of inertia. Inertia refers to a kinetic property of the rotating mass of a traditional generator (*e.g.*, CT, CC, RICE engine, steam turbine, etc.). Inertia of an operating generator helps stabilize frequency on the transmission system during transient disturbances. Inertia mitigates frequency decline following a loss of generation and is extremely important to grid reliability as it provides reliability and frequency fluctuation damping.

According to NERC, inertia is needed to instantaneously respond to grid disruptions to ensure that the output of electricity from the grid remains consistent and stable. NERC has noted its concern that as traditional resources are replaced with inverter-based resources, system inertia and thus damping is reduced, making the risk of frequency swings higher. This is because inertia is a "mechanical attribute" that responds to unpredictable grid disturbances instantaneously and automatically because it is provided by generators that are already online and spinning, making the primary response necessary to prevent "cascading" outages that can have catastrophic consequences on the region.

Objective 3: Minimizing Environmental Impact

As noted above, WEC's stated goal for several years has been to reduce carbon emissions by 80 percent from 2005 levels by 2030. In April 2024, the USEPA finalized two Clean Air Act rules that established GHG performance standards for existing fossil fuel electric generating units and new simple and combined cycle combustion turbines. It is anticipated that USEPA will propose another rule in late 2024 to establish GHG performance standards for existing simple and combined cycle combustion turbines. The GHG rules require actions that are in alignment with WEC's 80 percent reduction goal. Meeting this goal for both existing and forecasted new load will require retiring or adding additional fuel diversity capability to coal units[4] and adding new capacity consisting of dispatchable natural gas generation, renewable generation and storage technology.

Starting in 2030, the GHG rules require more CO_2 emission control or reductions at coal-fueled power plants with plans to continue operation past 2031. Certain new units are subject to more stringent CO_2 requirements would be phased in over time. Therequirements vary by the type of unit (new or existing, combustion turbine or utility boiler, coal-fueled or natural gas-fueled), how frequently it operates (base load, intermediate load, or low load (peaking) and its planned operation after certain future dates.

Subcategories for various fossil fuel units include:

[4] Planned enhancements to the remaining coal-fueled units will allow these units to operate 100% using clean natural gas.

- Rules for existing coal-fueled units are based on retirement date and include natural gas co-firing, emission reductions, and/or emission control requirements.
- Rules for existing gas-fueled electric generating units (boilers) are based on operating capacity factors. State Implementation Plans (SIP) that are due in May 2026 will establish applicable CO_2 limits for units in each capacity factor subcategory using site-specific data, however USEPA did establish presumptively approvable limits as part of the final rule.
    - Note: If a coal plant is being repowered to a cleaner fuel source, such as natural gas, that transition needs to take place by December 31, 2029 to meet the definition of an existing gas-fueled electric steam generating unit ("EGU"). Coal may no longer be used in any capacity after that date.
- Combined heat and power units must meet one of the coal- or gas-fueled unit options or meet an exemption by limiting net electric sales to below the applicable threshold based on design capacity.
- New combined cycle combustion turbines are subject to CO_2 emission limits and must install carbon capture and sequestration (CCS) by January 1, 2032.
- New simple cycle combustion turbine ("CT") units with a capacity factor greater than 20 percent are subject to an output based CO_2 limit. New CT units with a capacity factor below 20 percent are limited to the use of clean fuels (natural gas and distillate oil).
- RICE units are not part of the rule, which exempts gas generating units under 25 MW.

If a coal plant is scheduled for retirement by 2032, the final rule would not require significant changes to the plant.

If a coal plant owner plans to continue to operate past 2032 but will retire the unit before 2039, the rule requires 40 percent natural gas co-firing and a 16 percent emission reduction starting on January 1, 2030. If a coal plant owner expects to operate a unit for an extended period of time (*i.e.*, beyond 2039), the rule requires that plant to install CCS by 2032.

New gas-fueled combustion turbine plants are allowed under the April 2024 rule, however if a company plans to operate a plant for a significant number of hours (*i.e.*, as baseload), USEPA requires that it install CCS by 2032. Prior to 2032, these units must comply with an output based CO_2 emission limit. New gas-fueled plants with a capacity factor between 20 and 40 percent (*i.e.*, intermediate load) are subject to an output based CO_2 limit but have no emission control requirements. New gas-fueled plants that limit their capacity factor to less than 20 percent (*i.e.*, low load or peaking units) are limited to the use of clean fuels, which includes natural gas and no. 1 and 2 distillate fuel oils.

Table 1 below summarizes the structure of the final April 2024 USEPA rule and notes the anticipated future rulemaking for existing simple and combined cycle combustion turbines.

Table 1 – Final USEPA GHG Rule (April 25, 2024)

Source Category	Best System of Emission Reduction (BSER) and Resulting Performance Standards			
	Through Dec. 31, 2029	Jan. 1, 2030 - Dec. 31, 2031 (2030)	Jan. 1, 2032 - Dec. 31, 2038 (2032)	Jan. 1, 2039 and beyond (2039)
111(d) - Existing Steam EGUs (coal-fired)				
Retire by 12/31/2031	No applicable standards	Routine operations/no emissions increase	**Unit Retired**	
Medium-term (Retire by 12/31/2038)	No applicable standards	40% natural gas co-firing based on heat input, 16% emission reduction beginning 1/1/2030		**Unit Retired**
Long-term (Retire after 1/1/2039)	No applicable standards		CCS at 90% capture efficiency, 88.4% emission reduction beginning 1/1/2032	
111(d) - Existing Steam EGUs (gas-fired)				
Base load (CF >45%)	No applicable standards	Meet definition of gas-fired unit; "Routine Efficient Operation" and limit of 1,400 lbs CO2/MWh-gross		
Intermediate load (CF 8% to ≤45%)	No applicable standards	Meet definition of gas-fired unit; "Routine Efficient Operation" and limit of 1,600 lbs CO2/MWh-gross		
Low load (CF <8%)	No applicable standards	Meet definition of gas-fired unit; "Routine Efficient Operation" and limit of 130 lb CO2/MMBtu (heat input)		
111(d) - Existing Combined Heat & Power				
Meet one of EGU options above	*See options listed above for Existing Steam EGUs (gas-fired)*			
Output limit exemption	No applicable standards	Exempt if limit on annual net-electric sales to no more than 219,000 MWh or [design efficiency x potential annual electric output], whichever is greater		
111(b)- New or Reconstructed NGCC				
Base Load (CF >40%)	High efficient generation with best O&M practices; Units≥2,000 MMBtu/hr = 800 lb CO2/MWh-gross; Units<2,000 MMBtu/hr = 800 - 900 lb CO2/MWh-gross		CCS at 90% capture rate 100 lb CO2/MWh-gross	
111(b) - New or Reconstructed CTs				
Intermediate Load (CF 20% to 40%)	Efficient design and best O&M practices; 1,170 lb CO2/MWh-gross			
Low Load (CF <20%)	Use of Clean Fuels (NG, Fuel Oil 1 & 2); 20% annual CF restriction; 120 lb CO2/MMBtu NG only; <160 lb CO2/MMBtu Fuel oil/mix			
Future Rulemaking				
111(d) - Existing NGCC & CTs				
Existing simple and combined cycle units were removed from the scope of the rule. Future rulemaking for these units is expected in late 2024.				

Notes:
• State Implementation Plan (SIP) must be submitted to EPA within 2 years of date rule is published in Federal Register.

The final GHG rules for fossil fuel electric generating units and new simple and combined cycle combustion turbines was issued April 25, 2024 and published in the Federal Register on May 9, 2024. State implementation plans required under the rule for existing electric generating units are due to USEPA by May 11, 2026.

Existing simple and combined cycle combustion turbines are not subject to the April 2024 rules. In March 2024, USEPA opened a non-regulatory docket and released framing questions to gather input on the regulation of existing turbines in the power sector. A proposed rulemaking for these units is expected in late 2024. EPA has indicated that this new proposal is likely to be multi-pollutant in nature, focusing on GHG emissions, as well as criteria (NOx) and hazardous air pollutants (formaldehyde) emissions.

The GRP will also position WEC to comply with the 2024 $PM_{2.5}$ standards. On February 7, 2024, the USEPA issued a final rule that lowers the primary annual NAAQS $PM_{2.5}$ emission standard from 12 micrograms per cubic meter (µg/m^3) to 9 µg/m^3. The new standards will require Wisconsin to develop additional requirements to reduce $PM_{2.5}$ emissions. The retirements and conversions of existing solid fuel units will reduce these emissions and position WEC to comply with any additional emission requirements.

Objective 4: Capturing Economic Value

Technology advancements and increased scale in US development of renewable generation should continue lowering primary cost inputs, thereby leading to lower production costs. This will increase efficiency, making renewables more cost-effective compared to traditional electric generation resources. In addition to declining technology costs, the Inflation Reduction Act provides a favorable tax credit environment, which also contributes to the increasing cost-competitiveness of renewable resources.

Until now, the ability to lower carbon emissions without using renewable technologies has been limited. However, CCS is rapidly evolving into a proven technology that may be a technically feasible option for both baseload gas and coal units and has been included in WEC's economic evaluation.

Traditional nuclear, while a proven technology, involves uncertainty in timing and cost. New small modular nuclear technology is promising but is still not commercially available.

Objective 5: Managing Market Risk

Since the first generating plants were constructed one important consideration in site selection was ensuring generating facilities were located close to a utility's native load. While transmission infrastructure and electric markets have helped to broaden this view, geographic proximity of generation to a utility's load is still an important risk mitigation tool for customers. In the context of resource adequacy, a significant percentage of a utility's capacity needed to meet demand requirements must be in the same zone as the demand it serves. Local generation helps insulate a utility's customers from market risks due to both evolving market structure and congestion or curtailments caused by transmission system constraints and is fundamental to WEC's portfolio planning.

MISO rapidly implemented the seasonal construct for resource adequacy planning starting with Planning Year 2023-2024 and continues to plan for significant changes in the coming years, which will impact generation resource's capacity accreditation as well as the amount of capacity required to meet customer needs. Table 2 below outlines the current resource adequacy rules and expected changes:

APPENDIX A – Need and Alternatives Analysis

Table 2 – MISO Rule Changes

<table>
<tr><td colspan="6">Anticipated Resource Adequacy Construct Changes and Impacts</td></tr>
<tr><td>PY2023-2024</td><td>PY2024-2025</td><td>PY2025-2026</td><td>PY2026-2027</td><td>PY2027-2028</td><td>PY2028-2029</td></tr>
<tr><td colspan="6">Implement Seasonal Construct</td></tr>
<tr><td colspan="6">Thermal Unit Accreditation Change: Schedule 53
Accreditation based on performance during tight hours[5].
Final seasonal accredited capacity is based on a market wide determinant.</td></tr>
<tr><td colspan="6">Capacity Replacement Noncompliance Charge:
Significant penalties assessed to units that clear the auction, have planned outages > 31 days in a season and do not replace the cleared capacity.
May result in higher clearing prices during traditional outage seasons.
May result in inadequate capacity during traditional outage seasons.</td></tr>
<tr><td></td><td>Schedule 53 ISAC weighting shifts by 10%</td><td colspan="4">Schedule 53 ISAC weighting shifts by another 10%</td></tr>
<tr><td></td><td></td><td colspan="4">MISO Implements Reliability Based Demand Curve (“RDBC”).
Annual price could reach 4 times cost of new entry (“CONE”) ($480K/MW-Year)
Auction will clear capacity beyond vertical demand curve.
Opt out provisions undetermined but projections are that market participant will need to obtain up to 5% excess capacity to meet obligation. Penalties for noncompliance will be steep.
Current simulations indicate RDBC clears 3% more than current level.
Implications for seasonal construct are unknown.
Solar accreditation changes possible due to shift in tight hours.</td></tr>
<tr><td></td><td></td><td colspan="3"></td><td>Direct Loss of Load (“DLOL”) accreditation of resources.
Resource accreditation more reliant on how the pool of resources performs.
Significant reduction in accreditation is expected.
Interplay with RDBC unknown.</td></tr>
</table>

MISO has also introduced an initiative to review system attributes to ensure the grid continues to perform adequately and reliably as the electric energy landscape continues to evolve. This initiative will encompass concepts such as energy assurance, availability, fuel assurance, ramp capability, voltage stability, and rapid start-up. While MISO has just recently initiated this work, WEC expects the system attributes evaluation and proposed outcomes to impact resource accreditation and reserve margin requirements, energy and ancillary market products and requirements, and generation interconnection requirements. In sum, the system attributes initiative adds complexity and risk considerations to WEC's resource planning.

As noted in prior filings, because Wisconsin Electric is currently summer peaking utilities, the GRP was initially designed to ensure the summer peaks were met. Designing the GRP in this manner provided a robust design and solid foundation to deal with future market changes. As these rules have evolved and further developed, the forecasted firm load requirements have significantly increased, impacting WEC's evaluation of the most effective and cost efficient way to adapt under these circumstances. These changes are incorporated into the planning and analysis of this and future proposed projects through the GRP.

Specifically, the market's growing concern regarding energy availability in winter (in particular because of the recently-experienced Winter Storms Uri and Elliot) drove MISO's most recent changes. These resource adequacy changes included using a 41 percent reserve margin (installed capacity or "ICAP") for winter in MISO's loss of load expectation ("LOLE") analysis. In addition, the accreditation of resources changed so that if units were not available during critical hours (no matter the cause) the capacity accreditation of that resource will be reduced for a three year period. In other words, if units cannot start due to cold weather, or do not have fuel available to run, or do not fully perform they face significant future accreditation risk. These changes are specifically intended to manage the winter reliability risk recently manifested in various markets, which could have significant cost and reliability implications for customers if not properly managed.

Another change that is impacting WEC's generation planning is expected MISO changes to its accreditation of intermittent resources over the next few years. This will more accurately reflect their contribution to reliability as greater amounts of these resources and batteries are added to the system. As an example, solar capacity is very effective at shaving the summer peak, but if too much is added it loses capacity value because the peak hour will shift and the renewable generation resource's availability no longer correspond with the tight hour for which a utility must plan to have adequate capacity. MISO recognized this impact in its recent LOLE study and its DLOL methodology will lower the solar capacity accreditation value in all seasons over time. In addition to wind and solar capacity accreditation values being lowered there are also concerns with capacity accreditation values associated with batteries, specifically in the winter and spring seasons in which battery accreditation is expected to decrease to 56 percent and 72 percent, respectively[6], from 100 percent. According to MISO, winter risk increases as electrification load grows and multiple events within a single day cause the DLOL of storage to drop in both winter and spring seasons. Preliminary studies within the system attributes initiative show that as additional risk factors are considered under the DLOL methodology, reserve margin requirements will increase across all four seasons. Especially pronounced is a potential 12 GW increase in the winter

[5] "Tight hours" are those hours where reserve capacity is diminished or not available.

[6] MISO Market Redefinition: Accreditation Reform presentation, November 7-8, 2023.

reserve margin requirement (unforced capacity or "UCAP") across MISO in 2028. This represents an increase of nearly 10 percent to the current winter reserve margin requirement of approximately 130 GW.

In addition, the RBDC as proposed by MISO and endorsed by the Organization of MISO States ("OMS") is intended to require more generation capacity to be cleared in the capacity auction beyond the reserve margin to provide a reliability "cushion." The RBDC has the potential to add 3 percent to 5 percent to the summer reserve margin requirements, increasing the typical summer reserve margin from 7 percent to at least 10 percent. This means an electric utility with a capacity requirement of 5,000 MW would need an additional 150 MW of accredited capacity within its generation portfolio to manage the cost risk exposure associated with this change.

The changes to market rules are specifically designed to ensure that utility systems with baseload renewables have enough dispatchable resources to fill the energy shortfalls that will exist at various times throughout the year when intermittent resources are not available. As mentioned previously, the outcomes of MISO's system attributes initiative are expected to dramatically impact the way utilities approach resource adequacy and the real-time energy and ancillary services market to maximize utilization of renewable resources while maintaining a high level of system reliability and resilience that electric customers expect and utilities are required to provide.

With a focus on ensuring energy assurance, reliability and resilience, WEC has taken these risks into account in its generation planning analysis by limiting reliance on the greater energy market, increasing its needed level of generation as well as analyzing its ability to meet energy requirements at all hours during all seasons.

Resource Planning Methodology

WEC used Energy Exemplar's PLEXOS market simulation software to evaluate each of its utility's optimal long-term expansion plan. PLEXOS is a proven power market simulation tool and is a leader in modeling flexibility, efficiency, simulation alternatives and advanced analysis. PLEXOS is a comprehensive production cost model with regional databases for conducting generation capacity expansion planning and is used by over 280 customers (utilities are the largest customer base).[7] The model provides the capability to solve the generation capacity expansion simultaneously with commitment and dispatch. PLEXOS accounts for all types of generation including storage resource options while optimizing generation capacity expansion. PLEXOS produces balanced portfolios of conventional, renewable and storage resources. WEC has used PLEXOS to analyze and support the approval of the following projects:

- Paris Solar and battery energy storage system ("BESS")
- Red Barn Wind
- Weston RICE
- Darien Solar and BESS
- Koshkonong Solar and BESS
- West Riverside Combined Cycle purchase options
- Whitewater Combined Cycle purchase
- High Noon and BESS

Due to the significant changes in the MISO resource adequacy construct discussed above, the resource planning process must also change. For many years, resource planning consisted of planning for the peak load (typically summer for most utilities) plus a prescribed reserve margin requirement based on the assumption that if a utility has adequate resources in the summer, it will have adequate resources in all months of the year. However, increased penetration of intermittent resources as well as physical operating characteristics of resources (*e.g.*, planned maintenance outages) drove the need for more granularity in the resource adequacy construct to ensure resources are available when needed. While the seasonal construct was just implemented with Planning Year 2023-2024, MISO continues to develop additional, significant changes that it hopes to implement as early as Planning Year 2025-2026. The inability to precisely forecast the impacts of these changes as their final contours are being developed makes the long term resource planning process challenging. To minimize risk to customers, what has become evident is the importance to have a resource plan that has the right mix of resources that allows a utility to serve its own customers every hour of the year without significant reliance on the MISO market. As a result, WEC has adjusted the development of its GRP to incorporate a balanced mix of resources as a physical hedge against the uncertainty elsewhere in the MISO market by including an adequate amount of local generation resources.

To accomplish this, WEC has developed a modified resource planning approach that incorporates traditional resource planning based on (1) capacity requirements utilizing a planning reserve margin

[7] Notable customers include AEP, Xcel Energy, Dominion, Southern California Edison, MISO, PJM, and California Independent System Operator.

("PRM") while also (2) providing a mix of resources that can meet energy needs 24 hours a day, 365 days a year when needed without having to rely on the broader MISO market for energy.

Capacity Assurance Resource Planning

Capacity assurance resource planning applies a reserve margin percent to the peak demand to determine the total capacity needed to adequately serve the expected demand. For example, if peak demand is 1,000 MW and there is a 10 percent PRM the total capacity needed to serve that load would be 1,100 MW. This has been the traditional approach to capacity resource planning.

In WEC's most recent prior filings for new resources, a 14.5 percent reserve margin above annual peak day demand was utilized in PLEXOS capacity expansion modeling. However, MISO has recently implemented a seasonal resource adequacy construct, as opposed to the historic annual resource adequacy construct, to better reflect intermittent characteristics of wind and solar, maintenance outages, and overall unit performance. As a result, instead of planning for a single peak day requirement Load Serving Entities ("LSEs") now need to plan for peak day requirements *in each season*. WEC's approach incorporates MISO's seasonal construct for Planning Year 2024/25 LOLE Report and the corresponding MISO PRM ICAP percentage requirements for each season, which are as high as 49.4 percent, as shown in Table 3 below.

Table 3 – Reserve Margins

MISO Planning Reserve Margin (PRM)	Summer 2024	Fall 2024	Winter 2024-2025	Spring 2025	Formula Key
MISO System Peak Demand (MW)	124,669	112,232	104,303	99,496	[A]
Installed Capacity (ICAP) (MW)	150,187	148,755	165,924	152,092	[B]
Unforced Capacity (UCAP) (MW)	139,444	136,572	143,201	138,251	[C]
Firm External Support ICAP (MW)	3,217	2,865	3,771	3,247	[D]
Firm External Support UCAP (MW)	3,052	2,758	3,613	3,105	[E]
Adjustment to ICAP [1d in 10yr] (MW)	(6,650)	(11,145)	(13,890)	(15,275)	[F]
Adjustment to UCAP [1d in 10yr] (MW)	(6,650)	(11,145)	(13,890)	(15,275)	[G]
ICAP PRM Requirement (PRMR) (MW)	146,754	140,475	155,805	140,064	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	135,846	128,185	132,925	126,081	[I] = [C]+[E]+[G]
MISO PRM ICAP	17.7%	25.2%	49.4%	40.8%	[J]=([H]-[A])/[A]
MISO PRM UCAP	9.0%	14.2%	27.4%	26.7%	[K]=([I]-[A])/[A]
LOLE Criteria (days/year)	0.1	0.01	0.01	0.01	

In addition to planning for capacity requirements for all seasons, WEC's methodology also assumes continued availability of lower cost energy from the broader MISO market to serve load as well as the market's availability to purchase excess generation when generation is greater than load. As has been the case for many years WEC utilities can purchase energy from the market when it is cost effective (in $/MWh) instead of operating an owned unit that may have a higher fuel cost, and sell energy into the market when the utility has excess generation compared to load.

WEC's capacity assurance resource planning methodology also takes into account the seasonal variation in the value of firm capacity for all generating resources. Since firm capacity is needed to meet MISO's PRM, wind and solar facilities' capacity value fluctuates drastically depending on the season. As more solar comes online the tight hours shift to later in the day when solar generation output is diminished or not available at all. As a result, over time, the solar firm capacity accreditation is expected to further decrease and battery accreditation is expected to change seasonally as MISO implements its DLOL capacity accreditation methodology. Table 4 below summarizes the approach WEC has taken to account for this concept in its modeling accompanying this application, based on MISO studies. Sensitivity runs are also performed that take a range of capacity accreditations into account, specifically for solar and battery resources.

Table 4 – Capacity Accreditation

	Solar				Wind				Battery			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
2024	70%	37%	1%	58%	16%	18%	29%	21%	100%	100%	100%	100%
2025	70%	37%	1%	58%	16%	18%	29%	21%	100%	100%	100%	100%
2026	70%	37%	1%	58%	16%	18%	29%	21%	100%	100%	100%	100%
2027	70%	37%	1%	58%	16%	18%	29%	21%	100%	100%	100%	100%
2028*	30%	25%	1%	12%	16%	18%	29%	21%	85%	73%	92%	100%
2029	30%	25%	1%	12%	16%	18%	29%	21%	85%	73%	92%	100%
2030	20%	25%	1%	12%	16%	18%	29%	21%	87%	85%	74%	86%
2031	20%	25%	1%	12%	16%	18%	29%	21%	87%	85%	74%	86%
2032+	20%	25%	1%	12%	16%	18%	29%	21%	89%	96%	56%	72%

**** DLOL estimates applied***

Energy Assurance Resource Planning

MISO's continued evolution of the resource adequacy construct has introduced more uncertainty in resource planning as the generation fleet transitions to more renewable technology. As such, the importance of having a balanced mix of energy resources that allows a utility to serve its customers regardless of any reliance on the market for energy has become increasingly evident. While recognizing that there will often be energy available to purchase from the market in the future, this approach provides a physical hedge for customers to *ensure* adequate resources will be available to meet energy requirements without impacting reliability.

Therefore, WEC uses the PLEXOS model to not solely focus on meeting capacity requirements, but to also ensure that energy requirements can be met with utility-owned generating resources on an hourly basis each year throughout the planning horizon. This methodology assumes an immediately decreased ability to purchase from and/or sell energy to the broader MISO market and that by 2029 there will not be any access to purchase or sell energy to the MISO market. Essentially, the difference from the capacity assurance methodology discussed above is that WEC's energy assurance resource planning does not rely on energy from the broader MISO market. The same capacity PRM requirements are met but, additionally, all energy requirements are met by WEC's generation portfolio. This assures the resource mix is adequate to always meet customer demand, regardless of conditions.

Modeling Assumptions

WEC has developed a comprehensive set of modeling assumptions designed to test the robustness of this next phase of its GRP, including the proposed Whitetail and Badger Hollow Wind (the "Project"). These assumptions reflect the latest available information regarding load growth, MISO's new seasonal capacity construct, and further upcoming changes in capacity accreditation for intermittent resources and USEPA's proposed GHG performance standards for fossil-based electric generating units. The following sections provide a detailed description of the modeling assumptions incorporated in the PLEXOS resource planning model simulations.

Planning Futures

A planning future is a set of planning uncertainties that represents a combination of events, requirements or conditions that may occur. Having a robust set of planning futures allows planners to compare the economic impacts of a resource plan to alternatives. WEC's analysis includes four planning futures incorporating varying assumptions for demand and energy growth, natural gas prices, general inflation and CO_2 cost, as described below in Table 5. For planning purposes WEC considers the "Continued Fleet Change" case to be its reference or "base" planning future.

Table 5 – Planning Futures

Category	Slow Economic Growth	Continued Fleet Change	Enhanced Decarbonization	High Economic Growth
Demand and Energy Growth	**Demand = 0.25% CAGR** **Energy = 0.29% CAGR** Stagnant economic factors with little to no growth in EV and electrification	**Demand = 0.60% CAGR** **Energy = 0.48% CAGR** Existing economic factors with small increases in EV penetration and electrification (2021 MTEP Future 1)	**Demand = 0.97% CAGR** **Energy = 1.09% CAGR** High penetration of EV and electrification drives energy growth rate (2021 MTEP Future 2)	**Demand = 1.41% CAGR** **Energy = 1.71% CAGR** An improved economy and high penetration of EV and electrification drives a high energy growth rate (2021 MTEP Future 3)
Natural Gas Prices	**Mid/High** 2023 AEO Low Economic Growth	**Mid** 2023 AEO Reference Case	**High** 2023 AEO Low Oil and Gas Supply	**Low** 2023 AEO High Oil and Gas Supply
General Inflation	**3.25%** 2023 AEO Low Economic Growth	**2.25%** 2023 AEO Reference Case	**2.00%** 2023 AEO Low Oil and Gas Supply	**2.45%** 2023 AEO High Oil and Gas Supply
CO_2 Penalty Price (2025)	**$20/ton**	**$30/ton**	**$40/ton**	**$30/ton**
Renewable Tax Credits	**IRA tax credits** Solar/Wind: 100% PTC Battery: 30% ITC	**IRA tax credits** Solar/Wind: 100% PTC Battery: 30% ITC	**IRA tax credits** Solar/Wind: 100% PTC Battery: 30% ITC	**IRA tax credits** Solar/Wind: 100% PTC Battery: 30% ITC

CO_2 pricing based on LAZARD's LCOE pricing update from April 2023, which includes a range of $20-$40/ton.
https://www.lazard.com/media/nltb551p/lazards-lcoeplus-april-2023.pdf
Compound Annual Growth Rate ("CAGR"), MISO Transmission Expansion Plan ("MTEP"), Annual Energy Outlook ("AEO"), Production Tax Credit ("PTC"), Investment Tax Credit ("ITC")

Study Period

The study period is 30-years (2023 to 2052), which lines up with the PLEXOS capacity expansion model planning horizon.

Discount Rate

The discount rate used in determining the net present value ("NPV") of the annual cost streams for the Whitetail and Badger Hollow Projects and alternatives is equal to the WEC utilities' average weighted average cost of capital ("WACC"). The WACC used in the evaluation is 7.17 for WPSC percent and 7.54 percent for Wisconsin Electric. The NPV values in the economic evaluation are expressed in 2023 dollars.

Demand and Energy Forecasts

The long term demand and energy forecasts for Wisconsin Electric and WPSC incorporate the varying growth rates identified in Table 5 above and apply them to an updated 2024 forecast developed in August 2023. All forecasts assume certain [redacted]. Wisconsin Electric's demand and energy forecasts include the assumed new load in the I-94 corridor starting in 2025. Total annual energy requirements for the I-94 corridor are assumed to start at approximately [redacted] MWh in 2025 growing to [redacted] MWh by 2029 and peak demand is assumed to grow from approximately [redacted] MW to almost [redacted] MW over the same time period. The figures below indicate the assumed demand and energy forecasts for the Continued Fleet Change planning future.

Figure 2 – Wisconsin Electric Energy

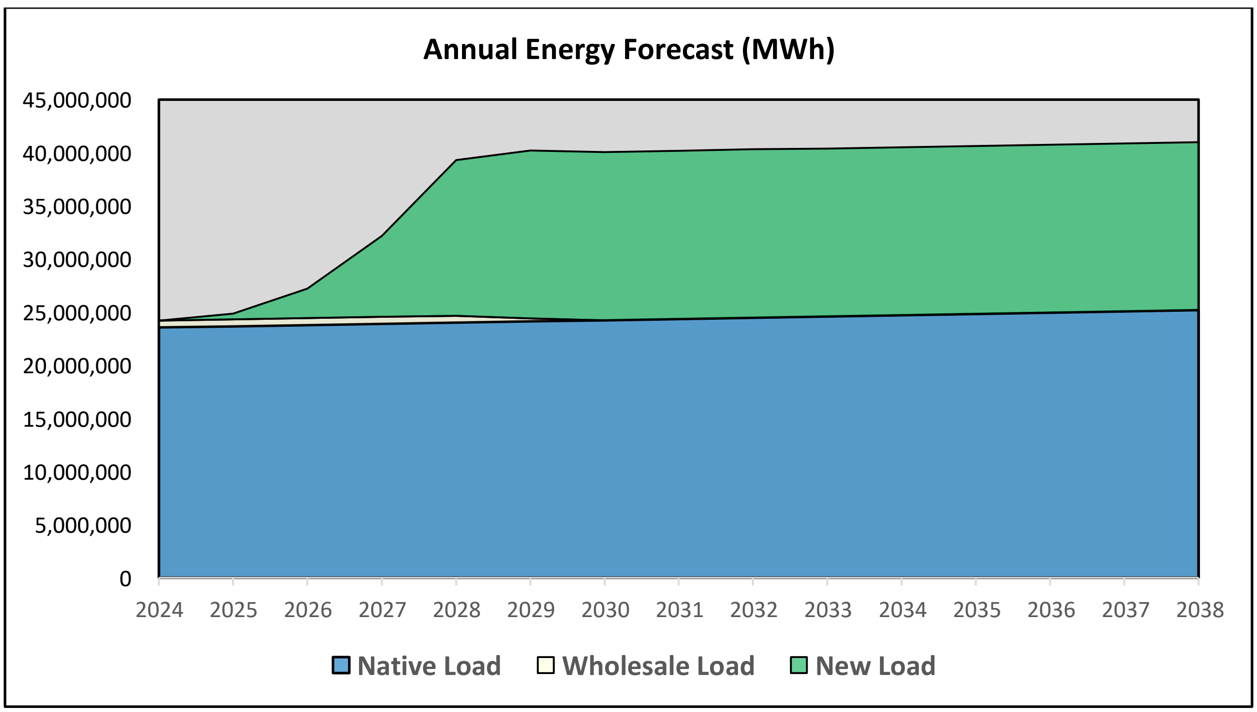


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Figure 3 – Wisconsin Electric Monthly Peak Demand

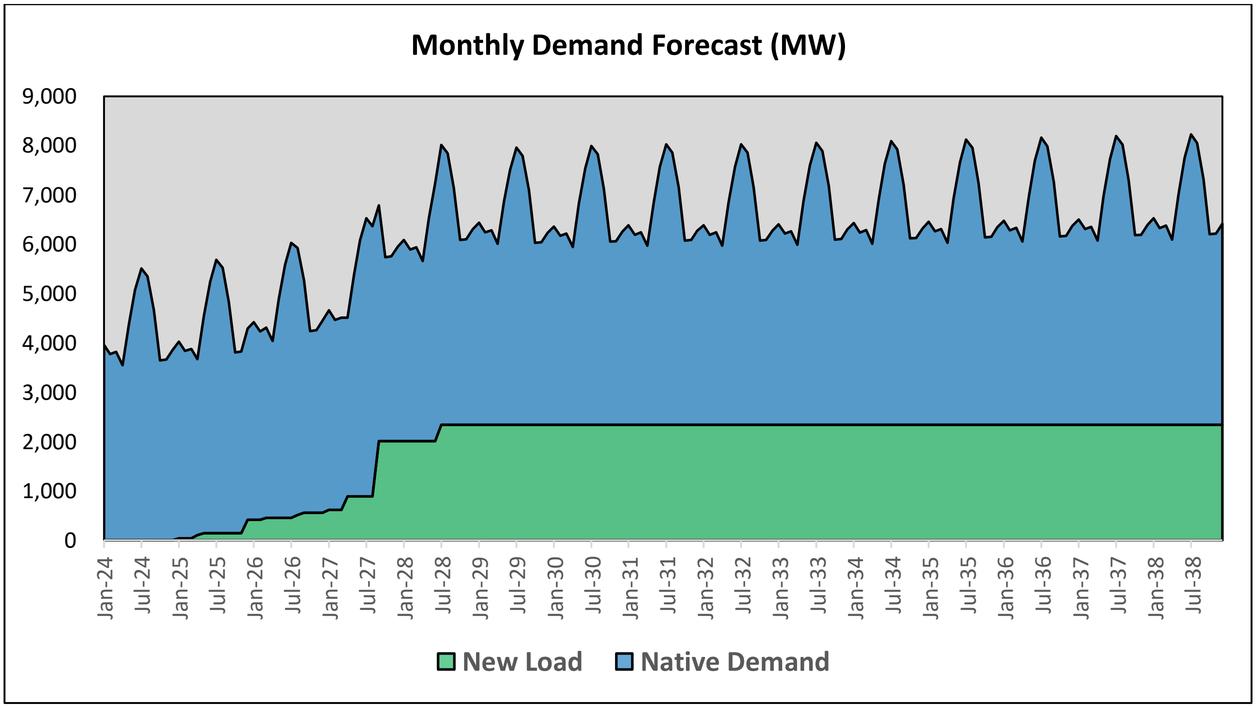


Figure 4 – WPSC Energy

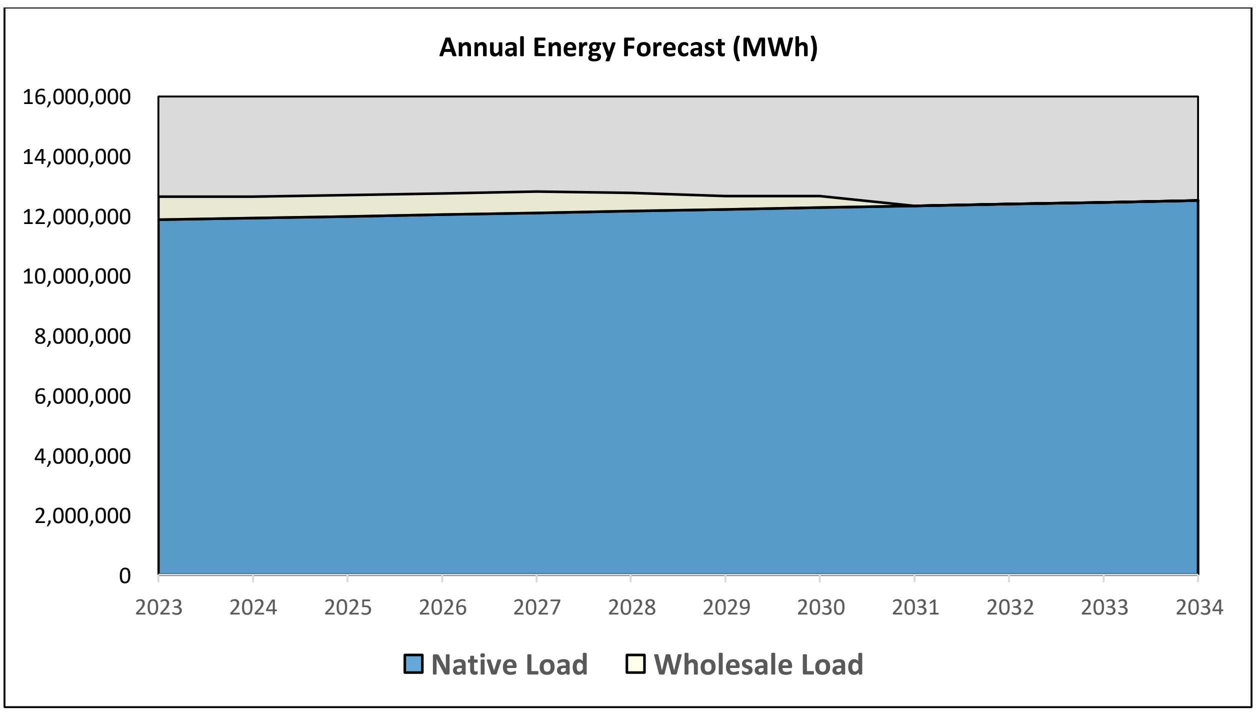
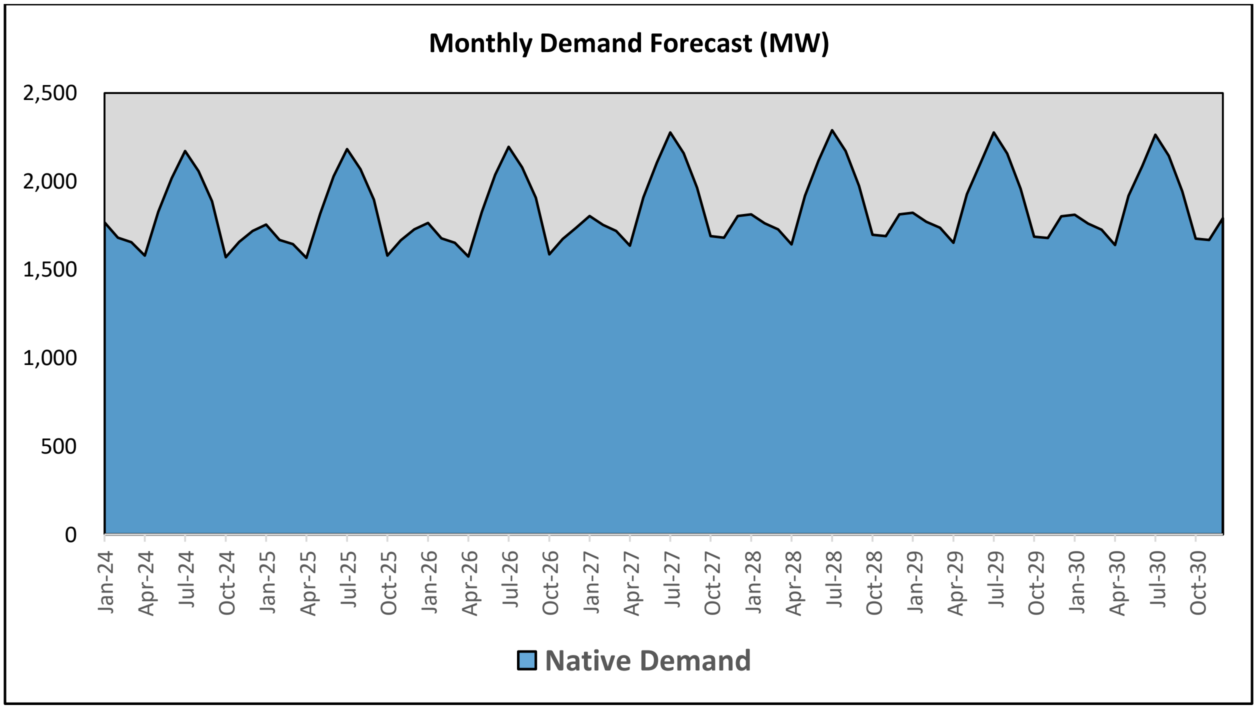


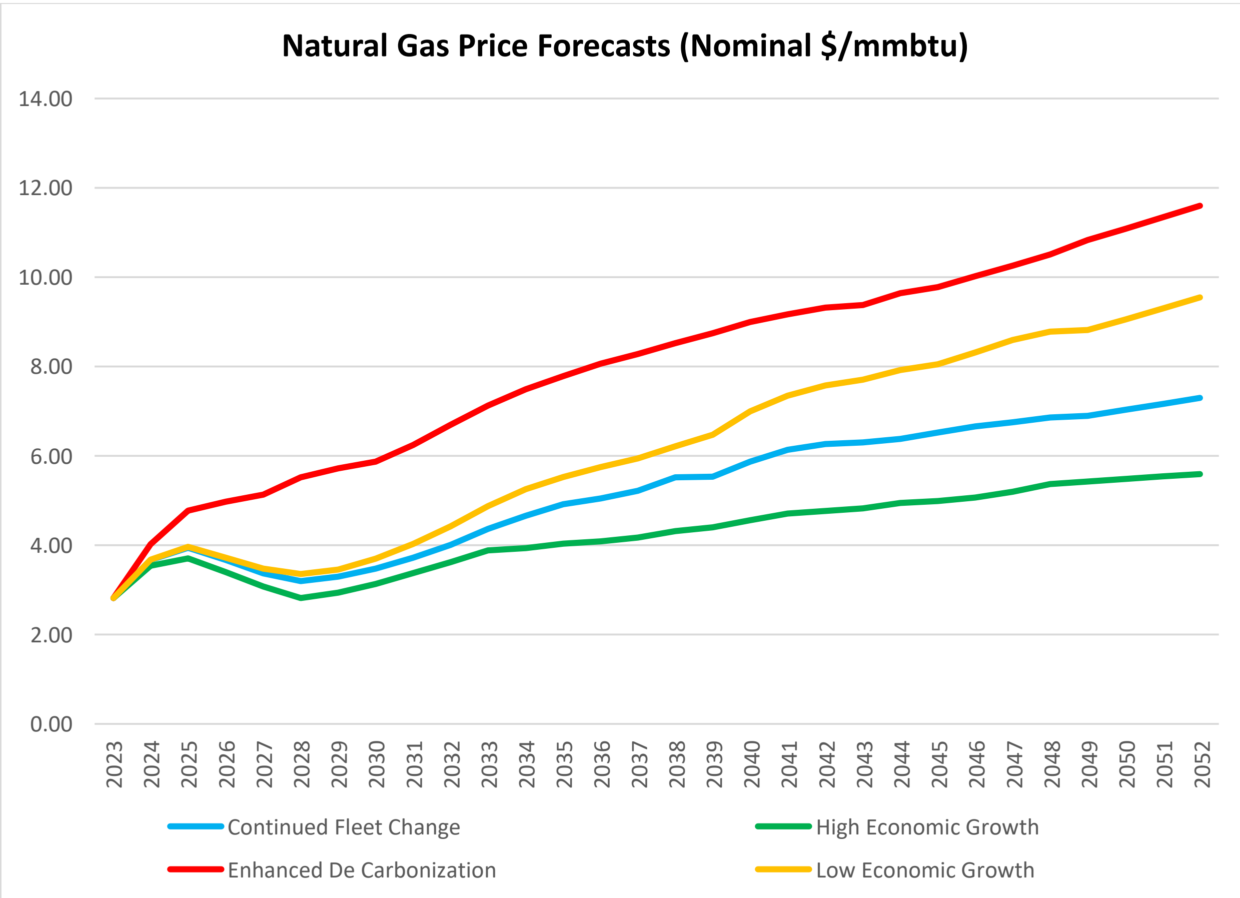
Figure 5 – WPSC Monthly Peak Demand



Natural Gas Prices

The natural gas price forecasts used in each of the planning futures are U.S. Energy Information Administration's ("EIA") 2023 Annual Energy Outlook ("AEO") scenarios, which are identified in Table 5 above. Figure 6 below shows the wide variation in gas prices used in the economic evaluation.

Figure 6 – Gas Prices



General Inflation

Each planning future has a unique general inflation rate that is used to escalate costs in the model simulation. The inflation rates used in each planning future are based on the embedded inflation rates used in AEO's natural gas price scenarios when comparing their forecasted prices in real dollars to nominal dollars. The following inflation rates are used for each planning future:

- Continued Fleet Change: 2.25 percent
- Slow Economic Growth: 3.25 percent
- Enhanced Decarbonization: 2.00 percent
- High Economic Growth: 2.45 percent

CO_2 Penalty Price

As mentioned above, one of GRP's main objectives is mitigating environmental impact. This objective ensures alignment with Governor Evers' Climate Change Task Force recommendations regarding CO_2 emission reductions, USEPA's proposed GHG rules, and WEC's 80 percent by 2030 reduction goal. As part of meeting this objective, similar to past economic evaluations, WEC utilized an estimated cost of carbon to design its generation portfolio.

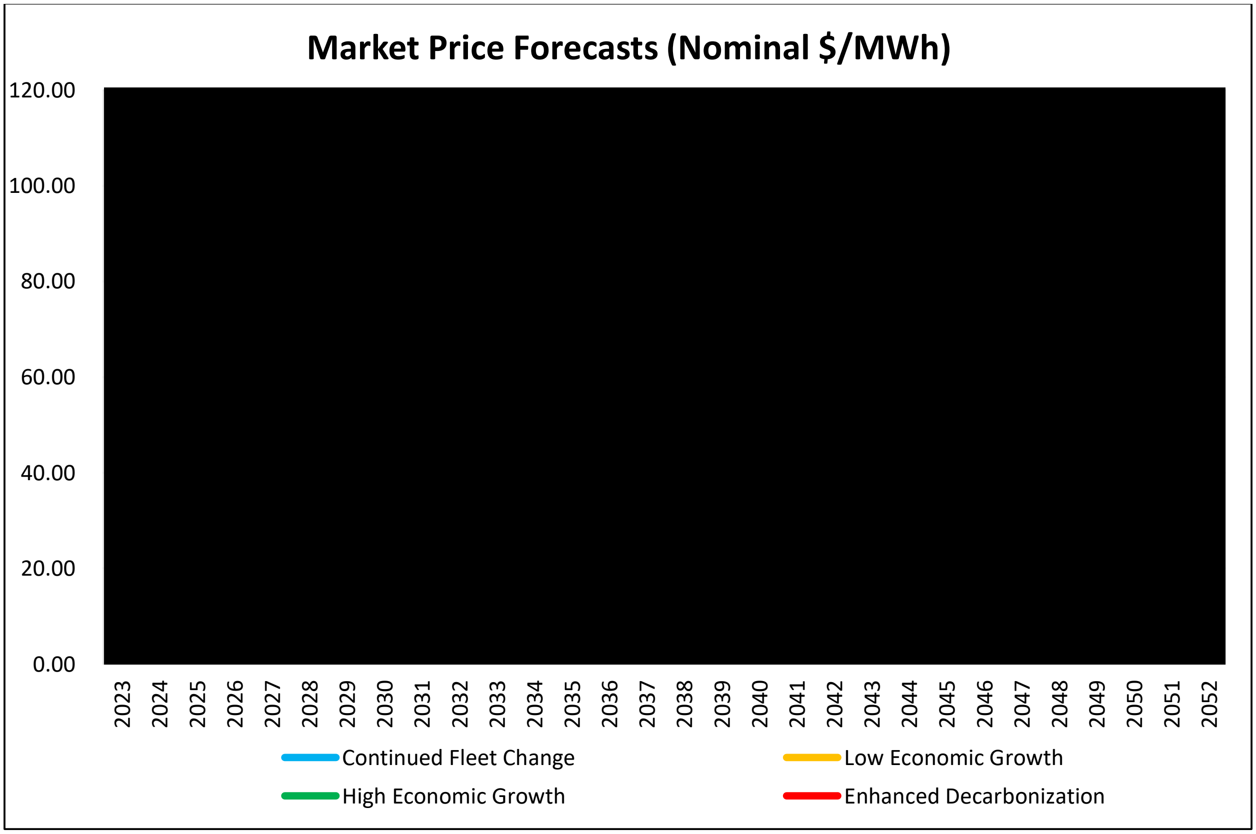
PLEXOS can optimize dispatch to meet CO_2 reduction level targets at the lowest system cost. Within the PLEXOS model, constraints are applied that optimize the combination of unit-generated CO_2 emissions and market-purchased energy CO_2 emissions. Market energy is assumed to have a CO_2 rate of 1,500 lb/MWh, which slowly decreases over time with a higher penetration of low carbon and carbon free resources. Within the model, the total CO_2 output is calculated as a combination of each utility's unit-specific output and net purchases. PLEXOS then solves to meet specified CO_2 reduction goals with a balanced approach to self-generation or market energy purchases. The utilization of market energy and its corresponding CO_2 is only applicable in Capacity Assurance resource planning. In the Energy Assurance resource planning all load is met with self-generation starting in 2029. The projected CO_2 cost is used as a dispatch adder to accomplish this goal, but the CO_2 reduction level is a soft constraint. That means any violation of this limit will incur a CO_2 cost penalty for each ton of CO_2 above the reduction level target but will only do so if the cost of that penalty has a lower overall cost than forcing the model to meet that constraint.

The carbon penalty price used in each planning future are based on LAZARD's April 2023 levelized cost of energy report, which ranges from $20/ton to $40/ton.

Market Prices

Forecasted locational marginal prices ("LMPs") were developed for each of the planning futures with the assumptions laid out in Table 5 on an hourly basis for MISO load zone 2 ("LRZ 2") covering Wisconsin and the upper peninsula of Michigan. A PLEXOS zonal model of the eastern interconnect was carved out specifically for the regions closest to LRZ 2 and utilized to develop the hourly market prices for each planning future. In addition to LRZ 2, this also includes MISO LRZ 1 (North Dakota, Minnesota and Western Wisconsin), LRZ 3 (Iowa) and PJM's ComEd region directly south of LRZ 2. These hourly prices were then utilized in the specific control area capacity expansion models for WPSC and Wisconsin Electric. A summary of the annual forecast LMPs is provided below in Figure 7.

Figure 7 – Market Prices



Tax Credits

The economic analysis assumes the latest guidance on tax credits for renewable projects based on the Inflation Reduction Act and the most current rates for PTCs.

- Solar = 100 percent PTC
- Wind = 100 percent PTC
- BESS = 30 percent ITC

In the PLEXOS model the tax credits are reflected as dollar-for-dollar reduction in capital costs, as shown in Table 6 below.

USEPA Rule Compliance

The economic model reflects different variations of greenhouse gas restrictions. Scenario 1 models the final USEPA GHG rule and further restrictions on existing natural gas units. The original proposed GHG rule included restrictions on existing natural gas units but were eventually removed from the final rule. However, USEPA has indicated it plans to implement a separate rule in the future for existing natural gas units. Scenario 2 assumes USEPA does not implement a separate rule for existing natural gas units is not implemented and the GHG rule only impacts new natural gas units and existing coal units. Scenario 3 assumes status quo, *i.e.*, the new GHG rule is vacated. Modeling these different scenarios provides a robust and thorough evaluation of potential variations of USEPA's GHG rule(s).

APPENDIX A – Need and Alternatives Analysis

Scenario 1: High GHG Restrictions (all new and existing units)

- Assumes further restrictions are imposed with a new rule addressing existing natural gas units.

- Elm Road Generating Station ("ERGS") and Weston 4 capability is enhanced to add flexibility to run on 100 percent natural gas beginning January 1, 2029 in order to comply with the 2030 deadline.

- All existing combined cycle units are constrained to a maximum 50 percent capacity factor starting January 1, 2030. Conservatively, the modeling also assumes Whitewater and RICE units would also be constrained to the same maximum capacity factor with an open question over whether this may have been an oversight in the original proposed rule but will be addressed in the new rule USEPA plans to implement for existing units.

- New simple cycle combustion turbines are constrained to a maximum 20 percent capacity factor beginning January 1, 2030.

- All new combined cycle units require CCS.

Scenario 2: Medium GHG Restrictions (new units and existing coal units only)

- Assumes the current final rule is not expanded further to address existing natural gas units.
- ERGS and Weston 4 capability is enhanced to add flexibility to run on 100 percent natural gas beginning January 1, 2029 in order to comply with the 2030 deadline.
- No restrictions on existing natural gas units or new RICE units.
- New simple cycle combustion turbines are constrained to a maximum 20 percent capacity factor beginning January 1, 2030.
- New combined cycle units require CCS.

Scenario 3: No GHG Restrictions

- Assumes the current USEPA GHG rule is vacated.
- Consistent with WEC's announced goal to eliminate coal as a fuel source by 2030, ERGS and Weston 4 capability is enhanced to add flexibility to run on 100 percent natural gas beginning January 1, 2029.
- No restrictions on existing natural gas units.
- No restrictions on new natural gas units. CCS is not required for new combined cycle units and new combustion turbines are not restricted to a max 20 percent capacity factor.

APPENDIX A – Need and Alternatives Analysis

Existing Units

The following assumptions are included in all modeling runs for Wisconsin Electric and WPSC.

Wisconsin Electric:

- Oak Creek units 5-6 retire May 31, 2024
- Oak Creek units 7-8 retire December 31, 2025
- [redacted]

ERGS capability is enhanced to add flexibility to run on 100 percent natural gas beginning January 1, 2029. Preliminary cost estimates of [redacted] per unit are included in the base model for natural gas retrofits.

WPSC:

- Columbia units 1-2 retire May 31, 2026
- Weston unit 3 retires December 31, 2031
- Weston unit 4 capability is enhanced to add flexibility to run on 100 percent natural gas beginning January 1, 2029. Preliminary cost estimate of [redacted] are included in the base model for natural gas retrofits.

New Units

New units, including those that have been recently commissioned, have full approval and those with applications pending before the Commission, are included in the base generation fleet for both utilities. This list includes the following projects:

Approved Projects:

- Paris Solar and BESS
- Darien Solar and BESS
- Koshkonong Solar and BESS

Projects Pending Approval:

- High Noon Solar and BESS
- Oak Creek CTs – Wisconsin Electric only
- Paris RICE – Wisconsin Electric only

New Projects (GRP Phase 2, Tranche 1 Filings)

- Badger Hollow Wind (111.6 MW): 1/1/2028
- Dawn Harvest Solar (150 MW) and Battery (50 MW): 10/1/2027 and 10/1/2027
- Good Oak Solar (98.4 MW): 1/1/2028
- Gristmill Solar (67 MW): 1/1/2028

- Saratoga Solar (150.3 MW) and Battery (50.3 MW): 6/1/2028 and 6/1/2028
- Ursa Solar (200 MW): 1/1/2027
- Whitetail Wind (67.2 MW): 1/1/2027

Generic New Units

The PLEXOS model also includes a list of alternatives that the model can select as part of the expansion optimization. Assumed costs for these technologies is based on a combination of EIA's 2023 AEO technology assessment, adjusted for inflation, as well as internal data based on recent estimates from vendors.

Wind units are all modeled with the same cost and performance characteristics used in WEC's other recent applications, such as 5-CE-316 (Paris RICE), 5-CE-317 (Oak Creek Combustion Turbines) and 5-BS-276 (High Noon Solar and BESS).

There are physical limitations to the amount of wind capacity that can be built in MISO LRZ 2 due to wind siting and set back rules and recently-increasing local opposition. As previously discussed, siting generating capacity in the same MISO load resource zone as the load requirements benefits customers. Long term, with further transmission improvements this may not be as critical but as the utility industry transitions to more renewable energy in the very near term it is extremely important to have generation near the load it is intended to serve. To account for this limitation of available wind resources PLEXOS was allowed to select up to 800 MW of wind capacity additions for Wisconsin Electric and up to 400 MW of wind capacity additions for WPSC before 2030. This amount also includes both Whitetail and Badger Hollow wind projects.

RICE and large frame Simple Cycle CTs (237 MW units) are modeled with the same cost and performance characteristics as Wisconsin Electric's proposed Paris RICE project and the OCCT Project, the except that additional transmission costs are included with the assumption these other generating facilities would be greenfield units. All gas technologies are assumed to need firm gas for fuel supply, due to MISO resource adequacy rule requirements. Given the currently-constrained interstate pipeline system this will require a pipeline expansion, construction of liquefied natural gas ("LNG") facilities, or both, depending on the anticipated duty cycle of the selected generation technology. Combined cycle units' firm rate is based on an estimated pipeline expansion cost ([redacted]/dekatherms ("Dth")/day) because these will operate as more baseload generation, and the firm rate for CT and RICE units, which will operate more like peaking units, is based on an equivalent cost for LNG ([redacted]/Dth/day).

Energy efficiency and demand response alternatives are also included as generic alternatives in the expansion plan. Assumed cost and penetration levels for energy efficiency and demand response are consistent with recent dockets, and adjusted for inflation, and assume similar cost increases as other technologies.

Table 6 – Generic Units

	Technology	Operating Capacity (MW)	Capacity Factor (%)	Overnight Cost (2023$) ($/kW)	Equivalent IRA PTC/ITC ($/kW)	Total Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-year)	Firm Gas ($/kW-year)	Heat Rate (btu/kWh)
Common Units	Combined Cycle	418	varies	[redacted]						
	Combined Cycle w/ 90% CCS	377	varies	[redacted]						
	Combustion Turbine 1	105	varies	[redacted]						
	Combustion Turbine 2	237	varies	[redacted]						
	RICE - 7 unit site	128.8	varies	[redacted]						
WEPCO Specific Units	Wind	50	35%	[redacted]						
	Solar	50	23%	[redacted]						
	Battery	50	<16%	[redacted]						
	Energy Efficiency	14.5	52%	[redacted]						
	Demand Response	50	n/a	[redacted]						
WPS Specific Units	Wind	25	35%	[redacted]						
	Solar	25	23%	[redacted]						
	Battery	25	<16%	[redacted]						
	Energy Efficiency	6.6	52%	[redacted]						
	Demand Response	25	n/a	[redacted]						

Whitetail Wind and Badger Hollow Wind Modeling Inputs

Capital Costs

The project consists of an overall capacity of a 400.6 MW wind generation. Wisconsin Electric will own 80 percent, WPSC will own 10 percent and Madison Gas and Electric will hold the remaining 10 percent ownership of the wind generation. The commercial operation date of the Whitetail wind is forecasted to be July 2027, while for Badger Hollow wind is forecasted to be January 2028. However, for modeling purposes only Whitetail wind was assumed to be in-service January 2027. A breakdown of the capital cost estimates and ownership shares is shown below.

Table 7 – Capital Costs

Category (178.8 MW):		**Whitetail**	**Badger Hollow**	**Total**
Capacity	MW	**67.2**	**111.6**	**178.8**
Purchase Price	$M	[redacted]		
Owner's Costs				
Legal	$M			
Other	$M			
Total	$M			
Contingency	$M			
Total	$M	**221.2**	**355.7**	**576.9**
	$/kW	**3,292**	**3,187**	**3,227**
Equivalent 2023$	**$/kW**	**3,012**	**2,852**	**2,887**

Table 8 – Ownership Share

Category (MW):		**Whitetail**	**Badger Hollow**
Total	**MW**	**67.2**	**111.6**
Wisconsin Electric	%	80%	80%
WPSC	%	10%	10%
MGE	%	10%	10%

Whitetail and Badger Hollow Wind

The wind facilities are expected to have a combined installed capacity of 178.8 MW and [redacted] capacity factor. For firm capacity planning, WEC is assuming the annual accreditation values provided in Table 4 above with sensitivities performed to test the robustness and impact on economics associated with the long term uncertainty with wind accreditation.

As part of the recent Inflation Reduction Act solar generation is now eligible for PTCs. The economic analysis assumes these wind units receive 100 percent PTCs. As previously mentioned, the value of the PTC is modeled as an equivalent reduction to the capital cost based on overall net present value. The equivalent capital cost reduction associated with the wind PTC is [redacted]. As a result, the capital costs utilized in the PLEXOS modelhave been reduced from [redacted] to [redacted] for Whitetail wind and [redacted] to [redacted] for Badger Hollow wind.

Operating Costs

The levelized cost components by category for the Project included in the PLEXOS model, which includes both solar and BESS and are expressed in 2023 dollars, are as follows:

Table 9 – Annual Fixed Costs (2023$)

	Category (67.2 MW):	**$000/yr**	**$/kW-yr**
Whitetail	Base O&M	[redacted]	[redacted]
	Wind Spare Parts	[redacted]	[redacted]
	Substation Maintenance	[redacted]	[redacted]
	Vegetation Maintenance	[redacted]	[redacted]
	Land Royalties	[redacted]	[redacted]
	Insurance	[redacted]	[redacted]
	A&G	[redacted]	[redacted]
	CapEx	[redacted]	[redacted]
	Total (67.2 MW):	**2,144**	**31.9**

	Category (111.6 MW):	**$000/yr**	**$/kW-yr**
Badger Hollow	Base O&M	[redacted]	[redacted]
	Wind Spare Parts	[redacted]	[redacted]
	Substation Maintenance	[redacted]	[redacted]
	Vegetation Maintenance	[redacted]	[redacted]
	Land Royalties	[redacted]	[redacted]
	Insurance	[redacted]	[redacted]
	A&G	[redacted]	[redacted]
	CapEx	[redacted]	[redacted]
	Total (111.6 MW):	**3,478**	**31.2**

APPENDIX A – Need and Alternatives Analysis

Purchase Power Agreement ("PPA")

WEC and MGE did not pursue a PPA for a generation project of the same technology. They have not received any proposals from developers for such a PPA. As a result, the applicants do not have real-world information to perform any scenario or sensitivity analysis for a PPA.

Utility ownership of the Project provides significant benefits not available under a PPA. These benefits include ownership of the site and interconnection agreement, which provides the ability to repower or replace generation at the end of the useful life of the Project (*i.e.*, development rights), the ability to continue to operate the Project after it has been fully depreciated (*i.e.*, residual value), the ability to derive additional value through incorporation of technological advancements and cost reductions during the life of the Project, and avoidance of additional costs to utility customers due to the effect of debt-equivalent PPAs on utility balance sheets and capital structures.

Project development rights include land rights, permits, and interconnection agreements. The land agreement terms allow the Project to operate for more than 30 years (e.g. solar leases commonly have an initial term of 25 or 30 years with one or more extension periods). The permits and interconnection agreements do not have definitive end dates. Each of these development rights have intrinsic value that is expected to increase over time as the renewable generation market continues to mature and transmission interconnection rights become more difficult to obtain. For example, it is possible to amend generator interconnection agreements to allow additional facilities to use the same point of interconnection (*e.g.*, through the surplus interconnection process) without the need for significant additional transmission investment. Also, ownership of the interconnection agreement allows the point of interconnection to be repurposed for a new source of supply when the existing generation facilities are retired. The total value of development rights is reflected in the Project purchase price and accounts for a portion of the margin the developer will earn when the Engineering Procurement and Construction Agreement is executed at closing.

In addition to the interconnection value, the residual value can be significant. The Project will continue to generate power well after it has been fully depreciated (after 30 years). Continuing to operate the Project once it has been fully depreciated through the end of the term of the land leases (year 50) would result in significant residual value as the Project will continue to generate energy and provide capacity with only operating and maintenance costs to cover.

Technological advancements are expected to continue and may provide additional opportunities for further development and deployment of these technologies at the Project site, as well as additional net benefits to customers (where benefits to customers exceed costs).

Ownership also allows applicants to optimize the physical and market value of the Project in ways that a PPA would not. PPAs will impose a level of rigidity upon the operation of a facility. Ownership provides full operational control and flexibility to capture maximum customer benefit. These opportunities may be unforeseen when a project is initially developed or placed in service (when a PPA would be negotiated) but may emerge over time due to changes in fuel prices, market conditions, policy, and new technologies.

Ownership also allows for market optimization. A portion of expected output can be sold in the day ahead market while the residual is sold in the real- time market. The day ahead/real time offer strategy depends on availability and economics of the entire fleet as well as the load conditions. The determination of participation in the two markets may change hourly to extract the most value at the lowest risk to customers. Utility-wide financial transmission rights ("FTRs"), which can change monthly, also impact the day ahead/real time strategy.

Developers typically purchase insurance on a project level and pass the cost through to the utility or off-taker through PPAs. Utilities, on the other hand, procure insurance on a much larger portfolio of assets. Therefore, utility ownership would typically result in lower insurance costs.

Warranty terms are negotiated with equipment suppliers and construction contractors. As such, warranty costs are similar for a developer and a utility.

While fixing costs in PPAs can provide some ratepayer protection in replacement power costs or reduced exposure due to catastrophic equipment failure, they are limited and come at an incremental cost. Counterparties will not take on significant purchase power cost exposure and catastrophic risks would be accounted for in increased O&M costs and/or a more restrictive operational profile. In addition, given the modular nature and generally large footprint of renewable resources – particularly solar generation facilities – catastrophic failures of the entire facility would be extremely rare.

Economic Evaluation

WEC undertook a robust evaluation of the quantitative benefits the Project provides the WEC Utilities' customers. As part of the evaluation, WEC tested its primary assumptions to understand their overall impact on the results. This type of evaluation studies how different values of an independent variable (referred to as planning assumptions, scenarios or sensitivities) affect a project's economics. The base planning assumptions for each planning future and sensitivities incorporated in the economic model are summarized in Attachment 1 to this Appendix. The economic evaluation is comprised of a Scenario Analysis and a Sensitivity Analysis, which are described in more detail below. In Attachment 1 the specific model runs performed in the matrix are identified with an "x". As such, the sensitivity analysis model runs in Attachment 1 only include an "x" for the Continued Fleet Change (Base) planning future for both Capacity and Energy Assurance planning.

Resource Planning Methodology: As discussed above, WEC's modeling examined both Capacity Assurance and Energy Assurance across modeled scenarios and sensitivities. The specific outcomes for each methodology are discussed in detail below. Each defined scenario or sensitivity set of runs includes three modeling runs that were developed to provide the economic impact of the Project as follows:

1. The first case assumes Dawn Harvest solar & battery are in-service 2028
2. The second case assumes Dawn Harvest solar and battery are not included in the resource mix. All generic units are available to be selected (except solar and battery until 2029)

Scenario Analysis: A scenario analysis assesses the effect of changing multiple input variables or assumptions to define a specific planning future that could reasonably occur. As discussed above, each of the planning futures was evaluated using Capacity and Energy Assurance resource planning. In addition, the different variations of the USEPA GHG rule previously described were included as part of the scenario analysis. This results in a total of 48 model runs for both Wisconsin Electric and WPSC.

- **Continued Fleet Change (Base Future)**
    - Scenario 1 GHG Rule – High Restrictions
    - Scenario 2 GHG Rule – Medium Restrictions
    - Scenario 3 GHG Rule – No Restrictions
- **Slow Economic Growth**
    - Scenario 1 GHG Rule – High Restrictions
    - Scenario 2 GHG Rule – Medium Restrictions
- **Enhanced Decarbonization**
    - Scenario 1 GHG Rule – High Restrictions
- **High Economic Growth**
    - Scenario 2 GHG Rule – Medium Restrictions
    - Scenario 3 GHG Rule – No Restrictions

Sensitivity Analysis: A sensitivity analysis examines the effect of changing a single variable at a time. For the Continued Fleet Change (Base) Case planning future WEC studied the effect of nine sensitivities for Wisconsin Electric and six for WPSC, which are described in more detail below, resulting in 54 and 36 runs, respectively.

- **10% Summer Solar Capacity Accreditation:** Solar summer accreditation stays at 10 percent for the whole planning horizon. There are not additional changes to the baseline assumptions for winter, spring and fall accreditation values.
- **50% Summer Solar Capacity Accreditation:** Solar summer accreditation stays at 50 percent for the whole planning horizon. There are not additional changes to the baseline assumptions for winter, spring and fall accreditation values.
- **Battery Capacity Accreditation:** Similar to solar capacity accreditations, there is significant uncertainty about the capacity value of batteries with higher penetrations over time. This sensitivity aims to bookend the capacity value by assuming batteries maintain 100 percent ICAP capacity accreditation in all seasons over the entire study period.
- **Limited Wind Availability**: As discussed above, there are physical limitations to the amount of wind capacity that is available in MISO LRZ 2. This sensitivity reduces the amount of wind capacity the model can select prior to 2030 to 50 percent of the baseline assumptions. The base analysis in PLEXOS assumes up to 800 MW of wind capacity for Wisconsin Electric and up to 400 MW of wind capacity for WPSC prior to 2030.
- **25% Decreased/Increased Capital Costs:** Sensitivities were performed to examine a plus and minus 25 percent change in building costs for all solar, wind and battery technologies, including Dawn Harvest.
- **Low/ High New Load Estimates (WEPCO Only)**: Total annual energy requirements for the I-94 corridor are assumed to start at approximately [redacted] MWh in 2025 growing to [redacted] MWh by 2029 and peak demand is assumed to grow from approximately [redacted] MW to almost [redacted] MW over the same time period. Sensitivities were performed on the level of new load by changing requirements by plus and minus 50 percent for both capacity and energy.
- [redacted] Sensitivities were performed to examine the effects of the economics of the Project assuming [redacted]

Case Identification: Naming conventions are consistent for Scenario Analyses and Sensitivity Analyses. A matrix of modeling runs is included in Attachment 1 to this Appendix. Table 10 below is an example of one of the sets of model runs performed that can be used to help identify each model run.

Table 10 – Example of Model Run Identification

Case ID		Case Description	Capacity Assurance Resource Planning				Energy Assurance Resource Planning			
			Continued Fleet Change	Slow Economic Growth	Enhanced Decarbonization	High Economic Growth	Continued Fleet Change	Slow Economic Growth	Enhanced Decarbonization	High Economic Growth
			A	B	C	D	E	F	G	H
Scenario 1 GHG Rule: High Restrictions	Case 1	All new project candidates are in-service	x	x	x		x	x	x	
	Case 2	**Badger Hollow Wind** removed. All generics available to be selected, except generic wind as a replacement.	x	x	x		x	x	x	
	Case 3	**Dawn Harvest Solar and Battery** removed. All generics available to be selected, except generic solar and battery as a replacement.	x	x	x		x	x	x	
	Case 4	**Good Oak Solar** removed. All generics available to be selected, except generic solar as a replacement.	x	x	x		x	x	x	
	Case 5	**Gristmill Solar** removed. All generics available to be selected, except generic solar as a replacement.	x	x	x		x	x	x	
	Case 6	**Saratoga Solar and Battery** removed. All generics available to be selected, except generic solar and battery as a replacement.	x	x	x		x	x	x	
	Case 7	**Ursa Solar** removed. All generics available to be selected, except generic solar as a replacement.	x	x	x		x	x	x	
	Case 8	**Whitetail Wind** removed. All generics available to be selected, except generic wind as a replacement.	x	x	x		x	x	x	

The matrix shown in Table 11 is set up to help identify each specific model run. The columns include the Case ID, Case Description (a narrative description of the specific scenarios), and the specific planning future modeled in either Capacity Assurance (identified with a letter "A"-"D") or Energy Assurance resource planning (identified with a letter "E"-"H"). Within Table 11 there are a total of 48 model runs, each identified by an "X." Below are two examples of how the matrix identifies each specific model run:

1. **Case 1E**: The Case ID indicates high GHG restrictions are included and the model run is identified as Case 1, which assumes Dawn Harvest solar and battery are in-service in 2027. The "E" is indicates the model run was performed assuming the Continued Fleet Change planning future and optimized using Energy Assurance resource planning.
2. **Case 3B**: The Case ID indicates high GHG restrictions are included and the model run is identified as Case 3, which assumes Dawn Harvest solar and battery are <u>not</u> included in the resource mix but all generic units are available to be selected, with the exception of generic solar and battery until 2029 . The "B" indicates the model run was performed assuming the Slow Economic Growth planning future and optimized using Capacity Assurance resource planning.

<u>Summary of Economic Analysis</u>

The overall need for capacity and energy for Wisconsin Electric and WPSC is greater than the Project's overall capacity and energy profile, indicating other resources are needed. However, WEC's robust modeling results demonstrate that the Project is part of the optimal resource mix across many different planning assumptions for Wisconsin Electric and WPSC. This analysis shows how the Project helps lay the foundation to meet additional capacity and energy needs for Wisconsin Electric and WPSC, which are different for each utility. The NPV savings in this analysis represent the proportion of the general NPV savings related to the Project. This calculation provides the specific NPV attributable to just the proposed Whitetail and Badger Hollow wind energy units.

With the significant near-term capacity and energy need, most notably for Wisconsin Electric, the Projects provide considerable quantitative and qualitative benefits to Wisconsin Electric and WPSC's customers in most scenarios and sensitivities analyzed. Not only does this confirm the Project is an appropriate resource to be added to their portfolio, but also shows that it complements other new resources, and alternatives. Resource planning is not a one-size-fits-all approach; it takes a diverse mix of resources to provide all of the benefits and reliability customers require. Whitetail wind and Badger Hollow wind are a part of that resource mix.

APPENDIX A – Need and Alternatives Analysis

Wisconsin Electric

The optimal resource mix in all scenarios and sensitivities performed includes a balanced and complementary mix of new resources, including Whitetail and Badger Hollow wind. The base models with all resources available and Whitetail wind in-service in 2027 and Badger Hollow wind in service in 2028, include up to **943 MW** of wind which is the physical limitation to the amount of wind capacity that can be built in MISO LRZ 2. This demonstrates that an alternative resource or a combination of alternative resources is not a lower cost alternative to the Project. However, to quantitatively show the value associated with the Project, the economic analyses compared it to an option where generic wind units are only available after 2028 and Whitetail is not available in 2027 and Badger Hollow in 2028.

Scenario Analysis:

- Whitetail wind provides approximately **$10 million** in NPV savings, ranging from a minimum savings of **-$11 million** (net cost) to a maximum savings of **$35 million**.
- Badger Hollow wind provides approximately **$14 million** in NPV savings, ranging from a minimum savings of **-$12 million** (net cost) to a maximum savings of **$64 million**.

Sensitivity Analysis:

- Whitetail wind provides approximately **$18 million** in NPV savings, ranging from a minimum savings of **-$4 million** (net cost) to a maximum savings of **$51 million**.
- Badger Hollow wind provides approximately **$25 million** in NPV savings, ranging from a minimum savings of **-$18 million** (net cost) to a maximum savings of **$86 million**.

WPSC

The optimal resource mix in all scenarios and sensitivities performed includes a balanced and complementary mix of new resources, including the Project. The base models with all resources available and Whitetail wind in-service in 2027 and Badger Hollow wind in service in 2028, include up to **468 MW** of wind which is the physical limitation to the amount of wind capacity that can be built in MISO LRZ 2. This demonstrates that an alternative resource or a combination of alternative resources is not a lower-cost alternative to the Project. Similarly to Wisconsin Electric, to quantitatively show the value associated with the Project, the economic analyses compared it to an option where generic wind units are only available after 2028 and Whitetail and Badger Hollow are inaccessible in 2027 and 2028, respectively.

Scenario Analysis:

- Whitetail wind provides approximately **$2 million** in NPV savings, ranging from a minimum savings of **$0 million** to a maximum savings of **$7 million**.
- Badger Hollow wind provides approximately **$3 million** in NPV savings, ranging from a minimum savings of **-$1 million** (net cost) to a maximum savings of **$12 million**.

Sensitivity Analysis:

- Whitetail wind provides approximately **$2 million** in NPV savings, ranging from a minimum savings of **$0 million** to a maximum savings of **$4 million**.
- Badger Hollow wind provides approximately **$4 million** in NPV savings, ranging from a minimum savings of **$1 million** to a maximum savings of **$7 million**.

Similar to Wisconsin Electric even though there are scenarios that show a net cost for the wind units in 2028, the lower cost alternative in that particular comparison, for the most part, is still selecting generic wind units in the 2029 to 2030 timeframe indicating more of a resource timing issue than a resource type issue.

Resource Mix

Wisconsin Electric

The optimal resource mix of new energy and capacity resources for case series 1, 9, and 17, which are reflective of the base runs assuming different variations of the USEPA GHG rule in the Continued Fleet Change planning future, are provided in Figure 7 below. The model runs indicate the addition of approximately **943 MW** of new wind capacity by the end of 2030 which is the physical limitation to the amount of wind capacity that can be built in MISO LRZ 2.

Figure 7 – Scenario Analysis New Resource Mix

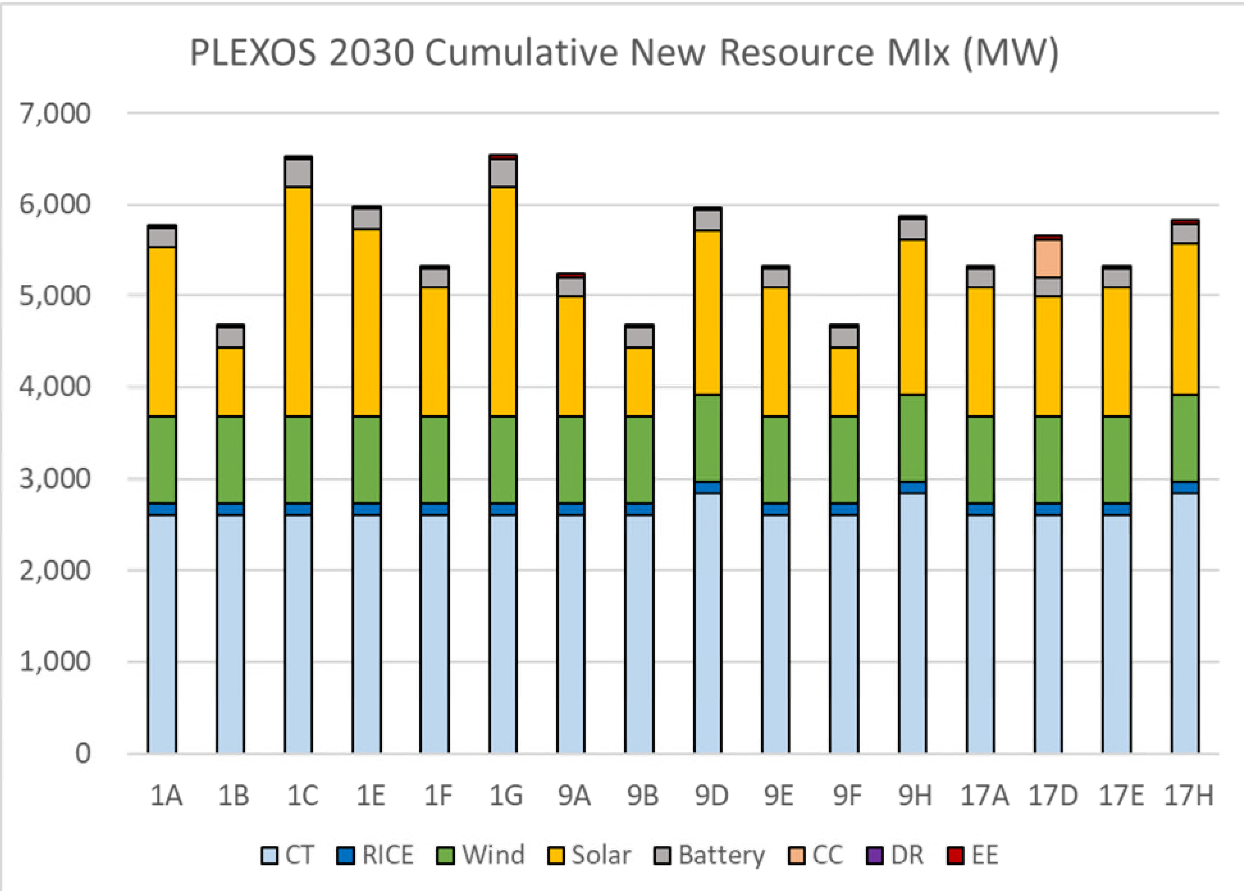
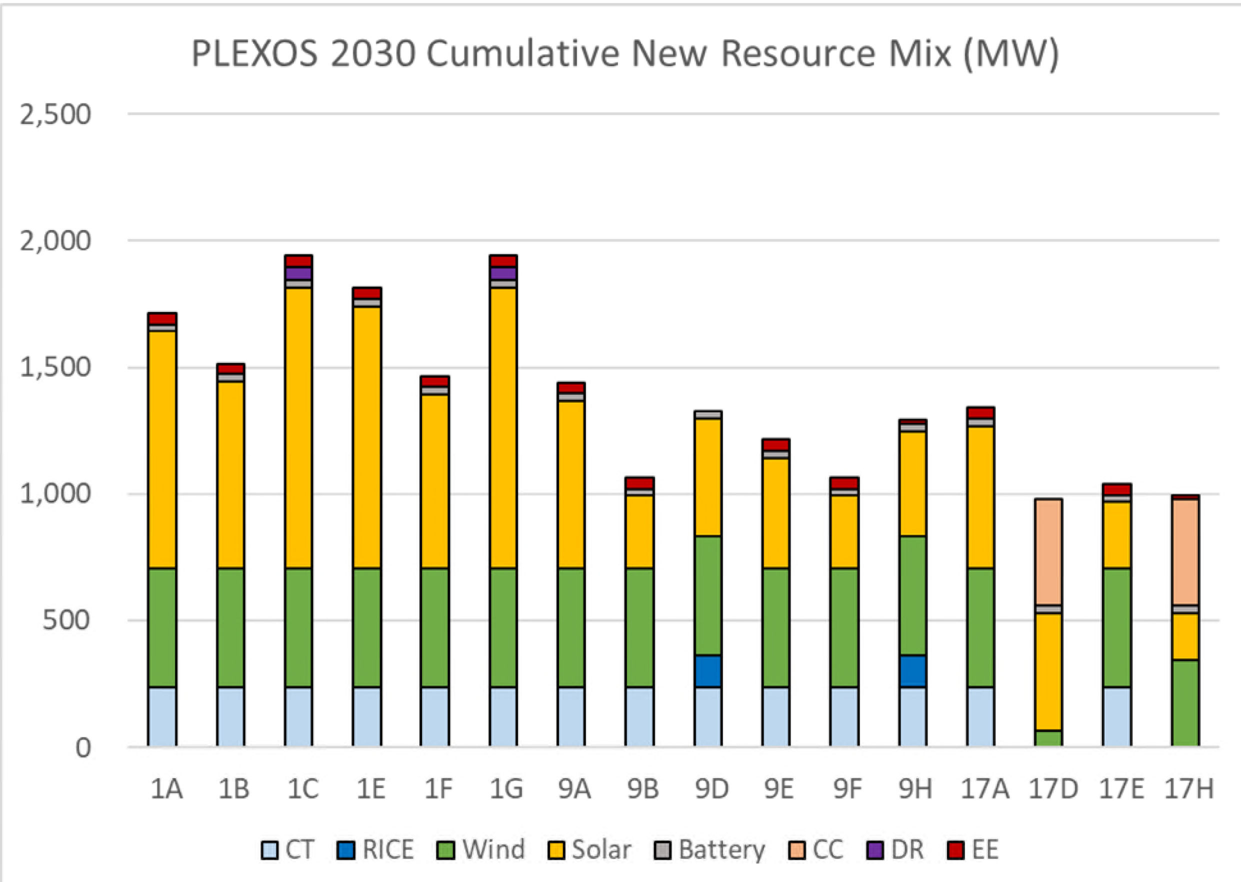


Figure 7 confirms the Project is a part of the low-cost plan in all runs and also shows a balanced and complementary mix of new resources is necessary to meet Wisconsin Electric's overall need. In addition, Figure 7 also reveals a common theme across all scenarios evaluated: the model consistently adds a balanced portfolio of new resources, such as wind, solar, batteries, CTs, RICE, and energy efficiency, to the resource mix.

WPSC

The optimal resource mix of new energy and capacity resources for case series 1, 9, and 17, which are reflective of the base runs assuming different variations of the USEPA GHG rule in the Continued Fleet Change planning future, are provided in Figure 8 below, which indicates a complementary and balanced mix of new resources. The model runs indicate the addition of approximately **435 MW** of new wind capacity (on average) by the end of 2030.

Figure 8 – Scenario Analysis New Resource Mix



Scenario Analysis Results

The Scenario Analysis examines the economic value of the Project against an equivalent amount of alternative resources in 2028 across a wide range of planning futures, including variations in potential GHG rule restrictions and two resource planning methods (Capacity and Energy Assurance).

Wisconsin Electric

The Scenario analysis confirms solar resources continue to be part of the low cost plan between 2027 and 2030. The average NPV savings attributed with Whitetail is approximately **$10 million**, with a minimum savings of **-$11 million** (net cost) and a maximum savings of **$35 million**. Similarly, the average NPV savings for badger Hollow wind is approximately **$14 million**, with a minimum savings of **-$12 million** (net cost) to a maximum savings of **$64 million**. Tables 11 and 12 below detail the NPV savings the Project provides compared to an equivalent capacity from alternative technologies in all the scenarios evaluated.

Planning Futures: The average NPV savings Whitetail and Badger Hollow wind provide in each Planning Future is as follows:

	Whitetail	Badger Hollow
Continued Fleet Change	12	18
Slow Economic Growth	5	4
Enhanced Decarbonization	35	62
High Economic Growth	(1)	(8)

USEPA GHG Scenarios: The average NPV savings Whitetail and Badger Hollow wind provide in each of the three potential GHG rule scenarios evaluated across the four planning futures above, is as follows:

	Whitetail	Badger Hollow
High Restrictions	21	33
Medium Restrictions	5	3
No Restrictions	(2)	(12)

Capacity/Energy Assurance: The average NPV savings Whitetail and Badger Hollow wind provide, when evaluated using Capacity and Energy Assurance resource planning methodologies across all four planning futures and with variations in the GHG rule, is as follows:

	Whitetail	Badger Hollow
Capacity Assurance	12	14
Energy Assurance	8	13

Table 11 and 12 summarize the NPV savings attributed to Whitetail and Badger Hollow wind compared to alternative resources for all the modeling runs performed in the Scenario analysis. For the most part the only scenarios in which each project provides a negative NPV savings is when it is assumed there will be no restrictions to greenhouse gases long term. Additional information and results can be found in Attachment 2 of this Appendix.

Table 11 – Whitetail Scenario Analysis NPV Results ($Millions)

Planning Future	GHG Rule Assumptions	Resource Planning Methodology	Case IDs	NPV Savings
Continued Fleet Change	High Restrictions	Capacity Assurance	1A vs 8A	**21**
		Energy Assurance	1E vs 8E	**19**
	Medium Restrictions	Capacity Assurance	9A vs 16A	**14**
		Energy Assurance	9E vs 16E	**16**
	No Restrictions	Capacity Assurance	17A vs 24A	**11**
		Energy Assurance	17E vs 24E	**(11)**
Slow Economic Growth	High Restrictions	Capacity Assurance	1B vs 8B	**11**
		Energy Assurance	1F vs 8F	**8**
	Medium Restrictions	Capacity Assurance	9B vs 16B	**1**
		Energy Assurance	9F vs 16F	**1**
Enhanced Decarbonization	High Restrictions	Capacity Assurance	1C vs 8C	**35**
		Energy Assurance	1G vs 8G	**35**
High Economic Growth	Medium Restrictions	Capacity Assurance	9D vs 16D	**2**
		Energy Assurance	9H vs 16H	**(1)**
	No Restrictions	Capacity Assurance	17D vs 24D	**(3)**
		Energy Assurance	17H vs 24H	**(2)**
			Average	**10**
			Minimum	**(11)**
			Maximum	**35**

Table 12 –Badger Hollow Scenario Analysis NPV Results ($Millions)

Planning Future	GHG Rule Assumptions	Resource Planning Methodology	Case IDs	NPV Savings
Continued Fleet Change	High Restrictions	Capacity Assurance	1A vs 2A	**27**
		Energy Assurance	1E vs 2E	**25**
	Medium Restrictions	Capacity Assurance	9A vs 10A	**16**
		Energy Assurance	9E vs 10E	**15**
	No Restrictions	Capacity Assurance	17A vs 18A	**15**
		Energy Assurance	17E vs 18E	**12**
Slow Economic Growth	High Restrictions	Capacity Assurance	1B vs 2B	**12**
		Energy Assurance	1F vs 2F	**8**
	Medium Restrictions	Capacity Assurance	9B vs 10B	**(2)**
		Energy Assurance	9F vs 10F	**(1)**
Enhanced Decarbonization	High Restrictions	Capacity Assurance	1C vs 2C	**59**
		Energy Assurance	1G vs 2G	**64**
High Economic Growth	Medium Restrictions	Capacity Assurance	9D vs 10D	**(5)**
		Energy Assurance	9H vs 10H	**(5)**
	No Restrictions	Capacity Assurance	17D vs 18D	**(12)**
		Energy Assurance	17H vs 18H	**(11)**
			Average	**14**
			Minimum	**(12)**
			Maximum	**64**

WPSC

The primary finding of the scenario analysis confirms wind resources continue to be part of the low cost plan between 2027 and 2030. Since WPSC is receiving a 10 percent ownership share in each of the facilities the overall ratio of the NPV savings, i.e. the percent directly attributed to the each project, are much smaller given the overall capacity of each project. As a result, the NPV savings attributed to each specific project appear modest because they are a small percentage of a larger savings wind facilities provide when including the additional generic wind resources that are optimally selected. However, it shows that wind projects like Whitetail and Badger Hollow continue to be cost effective, which is supported in the results below and the optimal resource mix chart above. The average NPV savings attributed with Whitetail is approximately **$2 million**, with a minimum savings of **$0 million** and a maximum savings of **$7 million**. Similarly, the average NPV savings for Badger Hollow wind is approximately **$3 million**, with a minimum savings of **-$1 million** to a maximum savings of **$12 million**.

Planning Futures: The average NPV savings Whitetail and Badger Hollow wind provide in each Planning Future is as follows:

	Whitetail	Badger Hollow
Continued Fleet Change	2	3
Slow Economic Growth	1	2
Enhanced Decarbonization	6	11
High Economic Growth	0	0

USEPA GHG Scenarios: The average NPV savings Whitetail and Badger Hollow wind provide in each of the three potential GHG rule scenarios evaluated across the four planning futures above, is as follows:

	Whitetail	Badger Hollow
High Restrictions	3	6
Medium Restrictions	1	2
No Restrictions	0	0

Capacity/Energy Assurance: The average NPV savings Whitetail and Badger Hollow wind when evaluated using Capacity and Energy Assurance resource planning methodologies across all four planning futures and with variations in the GHG rule, is as follows:

	Whitetail	Badger Hollow
Capacity Assurance	2	3
Energy Assurance	2	3

Tables 13 and 14 summarize the NPV savings attributed to Whitetail and Badger Hollow wind compared to alternative resources for all the modeling runs performed in the Scenario analysis. The results also confirm wind resources are a part of WPSC's low cost plan, only in the High Economic Growth does it indicate there would be a negative NPV savings with Badger Hollow wind. However, the model does select a combined of **400 MW** of generic wind in 2029 and 2030 indicating the need for solar is based more on timing and is needed prior 2030. Additional information and results can be found in Attachment 3 of this Appendix.

Table 13 – Whitetail Scenario Analysis NPV Results ($Millions)

Planning Future	GHG Rule Assumptions	Resource Planning Methodology	Case IDs	NPV Savings
Continued Fleet Change	High Restrictions	Capacity Assurance	1A vs 8A	**3**
		Energy Assurance	1E vs 8E	**2**
	Medium Restrictions	Capacity Assurance	9A vs 16A	**2**
		Energy Assurance	9E vs 16E	**1**
	No Restrictions	Capacity Assurance	17A vs 24A	**2**
		Energy Assurance	17E vs 24E	**2**
Slow Economic Growth	High Restrictions	Capacity Assurance	1B vs 8B	**2**
		Energy Assurance	1F vs 8F	**2**
	Medium Restrictions	Capacity Assurance	9B vs 16B	**1**
		Energy Assurance	9F vs 16F	**1**
Enhanced Decarbonization	High Restrictions	Capacity Assurance	1C vs 8C	**7**
		Energy Assurance	1G vs 8G	**6**
High Economic Growth	Medium Restrictions	Capacity Assurance	9D vs 16D	**0**
		Energy Assurance	9H vs 16H	**0**
	No Restrictions	Capacity Assurance	17D vs 24D	**0**
		Energy Assurance	17H vs 24H	**0**
			Average	**2**
			Minimum	**0**
			Maximum	**7**

Table 14 – Badger Hollow Scenario Analysis NPV Results ($Millions)

Planning Future	GHG Rule Assumptions	Resource Planning Methodology	Case IDs	NPV Savings
Continued Fleet Change	High Restrictions	Capacity Assurance	1A vs 2A	**4**
		Energy Assurance	1E vs 2E	**4**
	Medium Restrictions	Capacity Assurance	9A vs 10A	**3**
		Energy Assurance	9E vs 10E	**3**
	No Restrictions	Capacity Assurance	17A vs 18A	**3**
		Energy Assurance	17E vs 18E	**3**
Slow Economic Growth	High Restrictions	Capacity Assurance	1B vs 2B	**2**
		Energy Assurance	1F vs 2F	**3**
	Medium Restrictions	Capacity Assurance	9B vs 10B	**2**
		Energy Assurance	9F vs 10F	**2**
Enhanced Decarbonization	High Restrictions	Capacity Assurance	1C vs 2C	**12**
		Energy Assurance	1G vs 2G	**9**
High Economic Growth	Medium Restrictions	Capacity Assurance	9D vs 10D	**(1)**
		Energy Assurance	9H vs 10H	**0**
	No Restrictions	Capacity Assurance	17D vs 18D	**0**
		Energy Assurance	17H vs 18H	**0**
			Average	**3**
			Minimum	**(1)**
			Maximum	**12**

Sensitivity Analysis Results

The Sensitivity Analysis examines the effect of changing just one variable at a time. The sensitivities were evaluated using both Capacity Assurance and Energy Assurance resource planning while utilizing the Continued Fleet Change planning future and high GHG rule restrictions (Scenario 1). Stress testing different variables did not result in a lower cost solution, which reaffirms Dawn Harvest solar and battery will provide economic savings to customers.

Wisconsin Electric

The sensitivity analysis for Wisconsin Electric includes eight separate sensitivities, as described above. The results of that analysis are as follows:

- **Solar Capacity Accreditation (summer):** There were two individual sensitivities performed regarding the solar summer accreditation. On the high end it was assumed the summer accreditation would remain at 50 percent over the study period and on the low end it would only attribute 10 percent capacity accreditation over the study period. Regardless of the accreditation value for solar, both wind resources like Whitetail and Badger Hollow continue to provide NPV savings.

- **Battery Capacity Accreditation:** The NPV savings the Project provides positive when assuming batteries will have 100 percent capacity accreditation in all seasons throughout the study period. The average NPV savings are **$6 million** for Whitetail wind and **$6 million** for Badger Hollow wind.

- **Limited Wind Availability:** Assuming a less optimistic amount of Wisconsin wind availability by 2030 increases the value of the wind projects. The average NPV savings are approximately **$30 million** for Whitetail wind and approximately **$37 million** for Badger Hollow wind.

- **Wind Capital Costs:** Increasing and decreasing wind capital costs 25 percent provides strong NPV savings. The resulting NPV savings range from **$21** to **$35 million** for Badger Hollow wind and **$16 to 25 million** for Whitetail wind.

- **WEPCO New Load Estimates:** The Project shows strong economic value in Energy Assurance methodology when compared to alternative resources even with when the new load estimate is increased 50 percent. Of the cases that show negative savings, generic wind units are still built in the 2029-2030 time frame up to the amount of wind capacity that can be built in MISO LRZ 2, **600 MW**, indicating the need for wind is based more on timing and is needed prior to 2030.

- [redacted] Regardless of the assumption pertaining to the [redacted] Whitetail and Badger Hollow wind continue to provide NPV benefits in both capacity and energy assurance scenarios

Table 15 – Whitetail Sensitivity Analysis NPV Results ($Millions)

Sensitivity	Resource Planning Methodology	Case IDs	NPV Savings
50% Solar Accreditation	Capacity Assurance	25A vs 32A	**29**
	Energy Assurance	25E vs 32E	**21**
High New Load	Capacity Assurance	33A vs 40A	**(4)**
	Energy Assurance	33E vs 40E	**25**
Low New Load	Capacity Assurance	41A vs 48A	**0**
	Energy Assurance	41E vs 48E	**3**
Limited Wind Availability	Capacity Assurance	49A vs 56A	**30**
	Energy Assurance	49E vs 56E	**30**
100% Battery Accreditation	Capacity Assurance	57A vs 64A	**5**
	Energy Assurance	57E vs 64E	**6**

10% Summer Solar Accreditation	Capacity Assurance	65A vs 72A	**8**
	Energy Assurance	65E vs 72E	**9**
25% Increased Capital Cost	Capacity Assurance	73A vs 80A	**16**
	Energy Assurance	73E vs 80E	**24**
25% Decreased Capital Cost	Capacity Assurance	81A vs 88A	**25**
	Energy Assurance	81E vs 88E	**25**
Point Beach PPA	Capacity Assurance	89A vs 96A	**21**
	Energy Assurance	89E vs 96E	**51**

Table 16 – Badger Hollow Sensitivity Analysis NPV Results ($Millions)

Sensitivity	Resource Planning Methodology	Case IDs	NPV Savings
50% Solar Accreditation	Capacity Assurance	25A vs 26A	**40**
	Energy Assurance	25E vs 26E	**38**
High New Load	Capacity Assurance	33A vs 34A	**(18)**
	Energy Assurance	33E vs 34E	**34**
Low New Load	Capacity Assurance	41A vs 42A	**(1)**
	Energy Assurance	41E vs 42E	**(16)**
Limited Wind Availability	Capacity Assurance	49A vs 50A	**35**
	Energy Assurance	49E vs 50E	**38**
100% Battery Accreditation	Capacity Assurance	57A vs 58A	**5**
	Energy Assurance	57E vs 58E	**8**
10% Summer Solar Accreditation	Capacity Assurance	65A vs 66A	**27**
	Energy Assurance	65E vs 66E	**29**
25% Increased Capital Cost	Capacity Assurance	73A vs 74A	**21**
	Energy Assurance	73E vs 74E	**32**
25% Decreased Capital Cost	Capacity Assurance	81A vs 82A	**35**
	Energy Assurance	81E vs 82E	**35**
Point Beach PPA	Capacity Assurance	89A vs 90A	**29**
	Energy Assurance	89E vs 90E	**86**

WPSC

The sensitivity analysis for WPSC includes six separate sensitivities, as described above. The Sensitivity analysis results are consistent with the results of the Scenario analysis in which wind resources continue to be part of the low cost plan between 2027 and 2030 regardless of the sensitivity performed. Overall, the NPV savings are consistent for both Whitetail and Badger Hollow wind projects and are further summarized in Tables 17 and 18.

Table 17 – Whitetail Sensitivity Analysis NPV Results ($Millions)

Sensitivity	Resource Planning Methodology	Case IDs	NPV Savings
50% Solar Accreditation	Capacity Assurance	25A vs 32A	**4**
	Energy Assurance	25E vs 32E	**3**
Limited Wind Availability	Capacity Assurance	49A vs 56A	**2**
	Energy Assurance	49E vs 56E	**1**
100% Battery Accreditation	Capacity Assurance	57A vs 64A	**3**
	Energy Assurance	57E vs 64E	**3**
10% Summer Solar Accreditation	Capacity Assurance	65A vs 72A	**1**
	Energy Assurance	65E vs 72E	**2**
25% Increased Capital Cost	Capacity Assurance	73A vs 80A	**1**
	Energy Assurance	73E vs 80E	**0**
25% Decreased Capital Cost	Capacity Assurance	81A vs 88A	**4**
	Energy Assurance	81E vs 88E	**3**

Table 18 – Badger Hollow Sensitivity Analysis NPV Results ($Millions)

Sensitivity	Resource Planning Methodology	Case IDs	NPV Savings
50% Solar Accreditation	Capacity Assurance	25A vs 26A	**6**
	Energy Assurance	25E vs 26E	**5**
Limited Wind Availability	Capacity Assurance	49A vs 50A	**2**
	Energy Assurance	49E vs 50E	**2**
100% Battery Accreditation	Capacity Assurance	57A vs 58A	**4**
	Energy Assurance	57E vs 58E	**3**

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10% Summer Solar Accreditation	Capacity Assurance	65A vs 66A	**2**
	Energy Assurance	65E vs 66E	**3**

25% Increased Capital Cost	Capacity Assurance	73A vs 74A	**2**
	Energy Assurance	73E vs 74E	**1**

25% Decreased Capital Cost	Capacity Assurance	81A vs 82A	**7**
	Energy Assurance	81E vs 82E	**7**