Public Service Commission of Wisconsin
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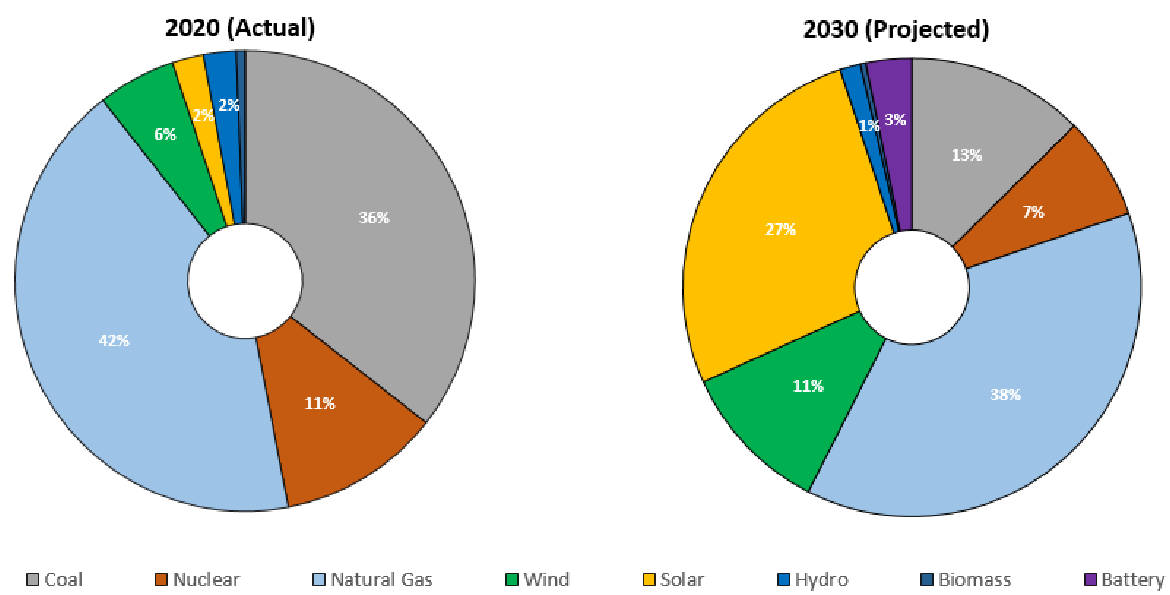
APPENDIX A – Supporting Need Case and Analysis

WEC Energy Group ("WEC"), and its subsidiaries Wisconsin Public Service Corporation ("WPSC") and Wisconsin Electric Power Company, doing business as We Energies, ("Wisconsin Electric")[1] have long been leaders in providing safe and reliable energy to their Wisconsin customers. Since 2005, Wisconsin Electric has been recognized thirteen times as the most reliable utility in the Midwest.

Over the same period, 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 that providing safe, reliable energy need not come at the expense of the environment. By leveraging technological advancements in power generation, WEC maintains world-class reliability, promotes fuel diversity, and advances sustainability all at once.

As explained in this Appendix, WEC is continuing to transform its generation fleet to ensure compliance with proposed US Environmental Protection Agency ("USEPA") rules, manage substantial load growth and ensure reliability and resiliency in the face of evolving regional energy market rules. As shown in Figure 1 below, WEC proposes to continue to transform its generation fleet to become baseload carbon free resources while carefully and prudently ensuring reliability with needed dispatchable generation capacity fueled principally with clean natural gas.

Figure 1 – WEC's Current and Projected Generating Capacity by Technology



[1] Collectively, Wisconsin Electric and WPSC are referred to as the "WEC Utilities."

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Generation Reshaping Plan: Need

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

- ✓ Comply with recently implemented and anticipated future Midcontinent Independent System Operator ("MISO") resource adequacy construct and resource accreditation changes.
- ✓ Ensure compliance with the proposed USEPA Clean Air Act rule modifications.
- ✓ Maintain and enhance system reliability.
- ✓ Meet substantial new load growth in the Company's Service Territory.
- ✓ Support the state of Wisconsin's vision for carbon reduction, by meeting or exceeding the WEC's 80 percent carbon reduction goal.

Various Regional Transmission Operators ("RTOs") and the North American Electric Reliability Corporation ("NERC") have expressed deep and growing concerns regarding the changing composition of the United States' generation portfolio and the pace of this change. 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 noted in the Federal Energy Regulatory Commission's ("FERC") 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 priori zed, current trends indicate the potential for more frequent and more serious long dura on 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.*

To address this concern, 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 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 the chart below. To manage this load growth WEC needs to ensure its portfolio can provide the capacity and energy to serve all customers reliably and safely.

Figure 2 – Peak Demand Growth

[redacted]

In addition to managing the ever-evolving rule changes in the MISO markets and load growth, WEC also needs to understand 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. WEC will also need to carefully test and prove out fuel conversions of existing resources.

The new USEPA GHG rule, which is expected to be finalized in the spring of 2024, provides insight into real constraints 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 the impact of these rules is critical to making prudent investment decisions about assets that have a 25 year, or longer, life. In addition, to be able to comply with the proposed GHG rules' timeframes, WEC must quickly take action to 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 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 baseload renewable. The plan balances the following five key objectives:

- ✓ **Minimizing Environmental Impact***:* Ensuring alignment with the Governor's Climate Change Task Force recommendations regarding generation CO_2 reductions and preparing for proposed USEPA GHG rules. This will allow WEC to achieve 80 percent carbon reduction by 2030 (and net carbon neutrality by 2050).

- ✓ **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 remains critical for ensuring that Wisconsin customers can depend on Wisconsin resources for their energy needs.

- ✓ **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 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 to prepare for, withstand, and recover from significant disruptions.

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Objective 1: 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. Since this goal was established, the USEPA has issued a proposed Clean Air Act GHG rule, which is expected to be finalized in the spring of 2024. The rule would 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 repowering coal units and adding new capacity consisting of dispatchable natural gas, renewable and storage technology.

Starting in 2030, the proposed rule would generally require more CO_2 emission control at fossil fuel power plants with high capacity factors and plans to continue operation. Increasingly more stringent CO_2 requirements would be phased in over time. The proposed requirements 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:

- Rules for existing coal-fueled units are based on retirement date as well as limitations to capacity factor or natural gas co-firing.
- Existing natural gas-fueled units would need to limit capacity factor by 2030.
    - Note: If a coal plant is being repowered to a cleaner fuel source, such as natural gas, that transition would need to take place by January 1, 2027 to meet the definition of an existing gas-fired electric steam generating unit ("EGU").
- Existing combined cycle ("CC") units would need to use hydrogen by 2032 or install carbon capture with sequestration ("CCS") by 2035.
- New combined cycle units would have requirements for installation of CCS or use hydrogen for fuel.
- New simple cycle combustion turbine ("CT") units would need to have a capacity factor below 20 percent and use clean fuels.
- RICE units currently are not part of the proposed rule.

If a coal plant owner expects to operate the plant for a long time (*i.e.*, beyond 2040), the rule would require those plants to sequester carbon by 2030. But if a company plans to continue to operate a coal plant *until* 2035 or 2040, then USEPA proposes standards based on how much it will run or what fuels it uses. If a coal plant is scheduled for retirement by 2032, the rule would not require significant changes to the plant.

New gas-fueled power plants would be allowed under the rule, but if a company plans to operate a plant for significant hours (*i.e.*, as baseload), USEPA proposes that it must install CCS by 2035. Alternatively, the rule would allow a compliance pathway for units planning on using hydrogen. USEPA proposes a tailored approaches for units that will not be operating a lot. For existing natural gas CC plants, USEPA proposes a standard only for the large baseload units (greater than 300 MW and operating more than 50 percent of the time). In other words, the CC plant cannot operate over a 50 percent capacity factor without either CCS or burning 30 percent hydrogen.

Table 1 below summarizes the structure of the proposed USEPA rule.

Table 1 – Proposed USEPA GHG Rule – Draft (06/09/2023)

	Proposed Best System of Emissions Reduction (BSER) and Resulting Performance Standards[1]				
	Through Dec. 31, 2029	Jan. 1, 2030 – Dec. 31, 2031	Jan. 1, 2032 – Dec. 31, 2034	Jan. 1, 2035 – Dec.31, 2039	2040 and beyond
111(d) – Existing Steam EGUs (coal-fired)*					
• Retire by 12/31/2031	No applicable standard	Routine operations/no emissions increases***	**Unit retired**		
• Retire 2032-2034	No applicable standard	20% annual capacity factor (CF) restriction***		**Unit retired**	
• Retire 2035-2039	No applicable standard	40% natural gas co-firing***			**Unit retired**
• Retire after 1/1/2040	No applicable standard	CCS at 90% capture rate***			
111(d) – Existing Steam EGUs (gas-fired)*					
• ≥45% Capacity Factor	No applicable standard	Routine efficient operations; 1,300 lb CO_2/MWh			
• <45% Capacity Factor[2]	No applicable standard	Routine efficient operations; 1,500 lb CO_2/MWh			
111(d) – Existing NGCC**					
• CCS option	1000 lb CO_2/MWh or current permit standard			CCS at 90% capture rate***	
• Hydrogen (H_2) option	1000 lb CO_2/MWh or current permit standard		30% hydrogen blending by volume (from 1/1/2032 until 1/1/2038)***		96% hydrogen blending by volume (after 1/1/2038)***
111(b) – New NGCC*[3]					
• Base load > 45-55%*** (CCS option)	Highly efficient generation/best O&M practices 770 lb CO_2/MWh for > 2,000 MMBTU/h Units 770-900 lb CO_2/MWh for < 2,000 MMBTU/h Units			CCS at 90% capture rate 90 lb CO_2/MWh	
• Base load > 45-55%*** (H_2 option)	Highly efficient generation/best O&M 770 lb CO_2/MWh for > 2,000 MMBTU/h Units 770-900 lb CO_2/MWh for < 2,000 MMBTU/h Units		30% hydrogen blending by volume 680 lb CO_2/MWh (until 1/1/2038)		96% hydrogen blending by volume 90 lb CO_2/MWh (after 1/1/2038)
111(b) – New CT*[2]					
• Intermediate – NGCC < 45-55% CF CT < 33-40% CF	Efficient operations 1,150 lb CO_2/MWh		30% hydrogen blending by volume 1,000 lb CO_2/MWh		
• Low Utilization (CT)***	Use of clean fuels (NG, Nos. 1 & 2 fuel oil); 20% annual CF restriction; 120-160 lb CO_2/MMBTU				

* **States set** emissions limits for existing units under Clean Air Act §111(d) that reflect EPA"s BSER. Under Clean Air Act §111(b), EPA sets emissions limits based on its BSER determination for new units.
** Only applies to NGCC units that are >300 MW with a capacity factor of ≥50%.
*** Actual CF restriction will be a unit-specific inquiry, based on design efficiency. States will set resulting performance standards using a unit-specific baseline emissions rate.

[1] A covered EGU is not required to use the technology identified as BSER, but instead to achieve an emissions rate equivalent to using the BSER. For existing units, the proposed regulations would allow states to authorize the use of various compliance flexibility tools to meet the standards (e.g., averaging, trading, banking, etc.).
[2] EPA does not propose a BSER or presumptive emissions rate for natural gas steam boilers that operate at capacity factors of less than 8%.
[3] New source standards are effective upon proposal, which is the date of *Federal Register* publication.

USEPA anticipates issuing a final rule in spring 2024. State implementation plans would be due 24 months after the final rule.

Objective 2: Capturing Economic Value

Technology advancements and increased scale in US development of renewable generation will continue to lower production costs. This will increase efficiency, making renewables 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 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 will 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 great uncertainty in timing and cost. New small modular nuclear technology is promising but is still not commercially available.

Objective 3: 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 and load is still an important risk mitigation tool. 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 insulates utilities' customers from market risks due to both evolving market structure and congestion or curtailments caused by transmission system issues 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 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:

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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[2].
• 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 steep.
• Current simulations indicated RDBC clears 3% more than current.
• 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>

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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 inquiry 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 at least resource accreditation and reserve margin requirements, energy and ancillary market products and requirements, and generation interconnection requirements. In sum, these initiatives add complexity and risk considerations to WEC's resource planning.

As noted in prior filings, because Wisconsin Electric and WPSC are currently summer peaking utilities, the GRP was 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.

Specifically, the market's growing concern regarding energy surety in winter (in particular because of 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 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, they face significant accreditation risk. These changes are specifically intended to manage winter reliability risk that has recently manifested in various markets, which could have significant cost and reliability implications for customers if not properly managed.

MISO is also expected to change the accreditation of intermittent resources over the next few years. This will more accurately reflect their contribution to reliability as greater amounts 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 no longer corresponds with the tight hour for which a utility must plan to have adequate capacity. MISO recognized this impact in its recent loss of load expectation ("LOLE") study and its DLOL methodology will lower the solar capacity value in all seasons over time. 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 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 allow 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

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

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 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 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.

Objectives 4 and 5: 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:

> *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.

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While battery storage can be helpful in managing these risks, the technology is limited by the lack of commercial long duration batteries and cannot provide inertia support.[3] 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. Due to these limitations, 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. Batteries and natural gas generation 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.*

[3] 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.

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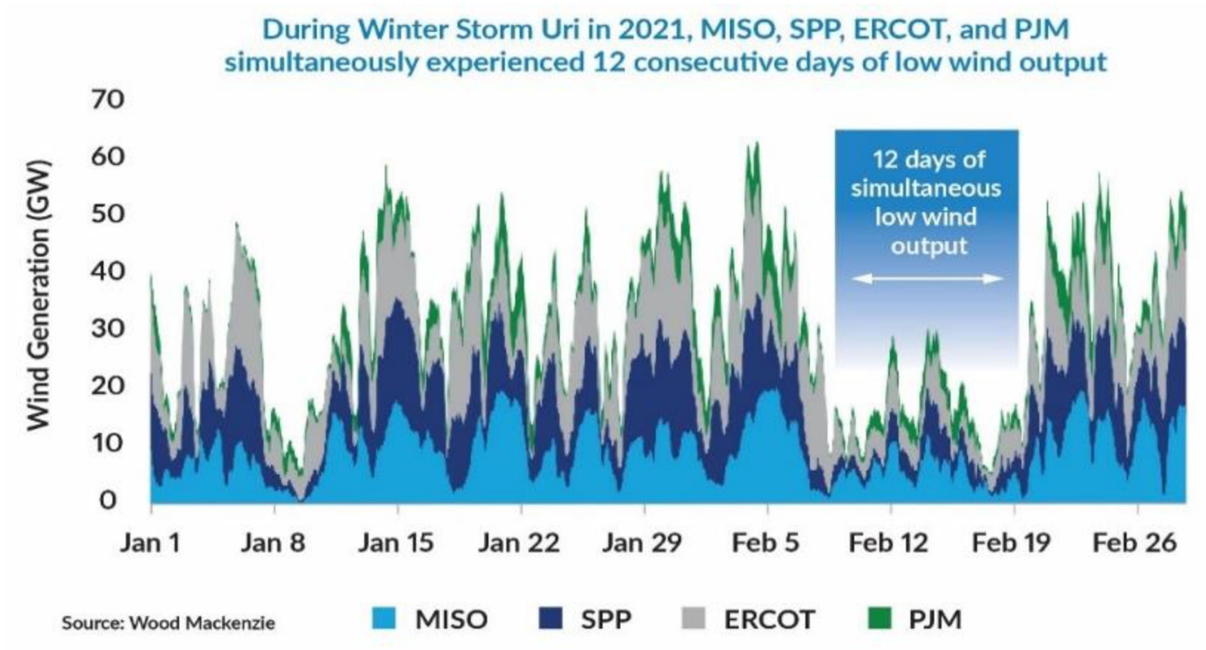
Fiigure 3 – Low Wind Output



This concern about energy surety has also been noted in NERC's 2022 Long Term Reliability Assessment ("LTRA"), where MISO is noted as a "high risk" area.[4] 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.*

[4] *2022 LTRA* at 5–6.

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Resiliency

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, coal plant, 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 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.

Resource Planning Methodology

WEC used Energy Exemplar's PLEXOS market simulation software to evaluate each 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).[5] 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

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

- Koshkonong Solar and BESS
- West Riverside Combined Cycle purchase options
- Whitewater Combined Cycle purchase

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 developed 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 resource planning approach that incorporates traditional resource planning based on (1) capacity requirements utilizing a planning reserve margin ("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 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.

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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 in to 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. Table 4 below summarizes the approach WEC has taken to account for this concept in its modeling accompanying this application, based on MISO studies.

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Table 4 – Capacity Accreditation

	Solar			
	Summer	Fall	Winter	Spring
2023	70%	37%	1%	58%
2024	70%	37%	1%	58%
2025	70%	37%	1%	58%
2026	70%	37%	1%	58%
2027	70%	37%	1%	58%
2028*	30%	25%	1%	12%
2029	30%	25%	1%	12%
2030+	20%	25%	1%	12%

**DLOL estimates applied*

	Wind			
	Summer	Fall	Winter	Spring
All Years	16%	18%	29%	21%

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 are 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 2026 there will 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 to rely on energy from the broader MISO market. The same capacity PRM requirements are met but 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.

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Modeling Assumptions

WEC has developed a comprehensive set of modeling assumptions designed to test the robustness of the next phase of its GRP, including the proposed High Noon solar and BESS facility ("High Noon" or 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 economics of impact 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")

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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 High Noon 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 WPS 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 WPS 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 forecast includes 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] growing to [redacted] and peak demand is assumed to grow from approximately [redacted] over the same time period. The figures below indicate the assumed demand and energy forecasts for both utilities for the Continued Fleet Change planning future.

Figure 4 – Wisconsin Electric Energy

[redacted]

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Figure 5 – Wisconsin Electric Monthly Peak Demand

[redacted]

Figure 6 – WPSC Energy

[redacted]

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Figure 7 – WPSC Monthly Peak Demand

[redacted]

Natural Gas Prices

Then natural gas price forecasts used in each of the planning futures are EIA's 2023 AEO scenarios, which are identified in Table 5 above. Figure 8 below shows the wide variation in gas prices used in the economic evaluation.

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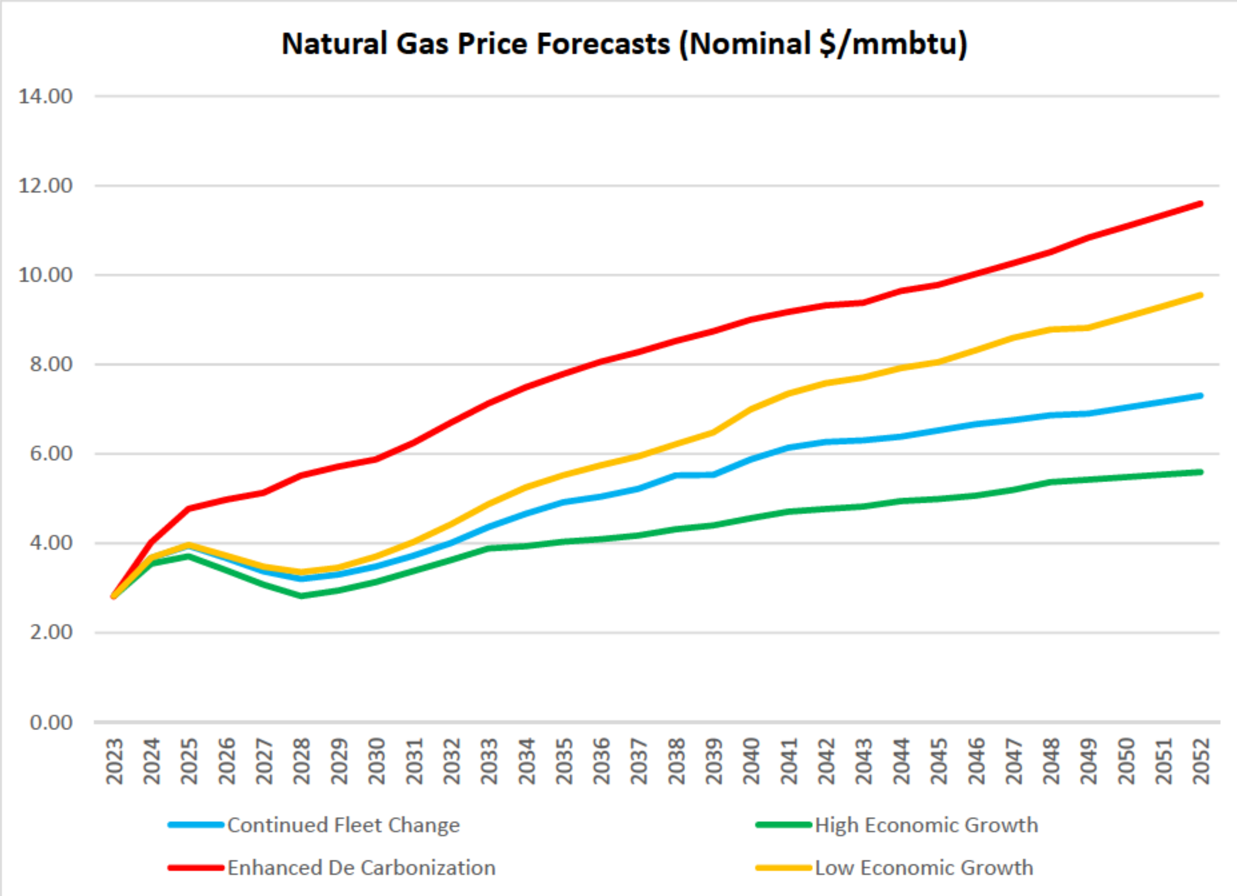
Figure 8 – Gas Prices



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 the Governor's Climate Change Task Force 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.

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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. 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

Assumed 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 9.

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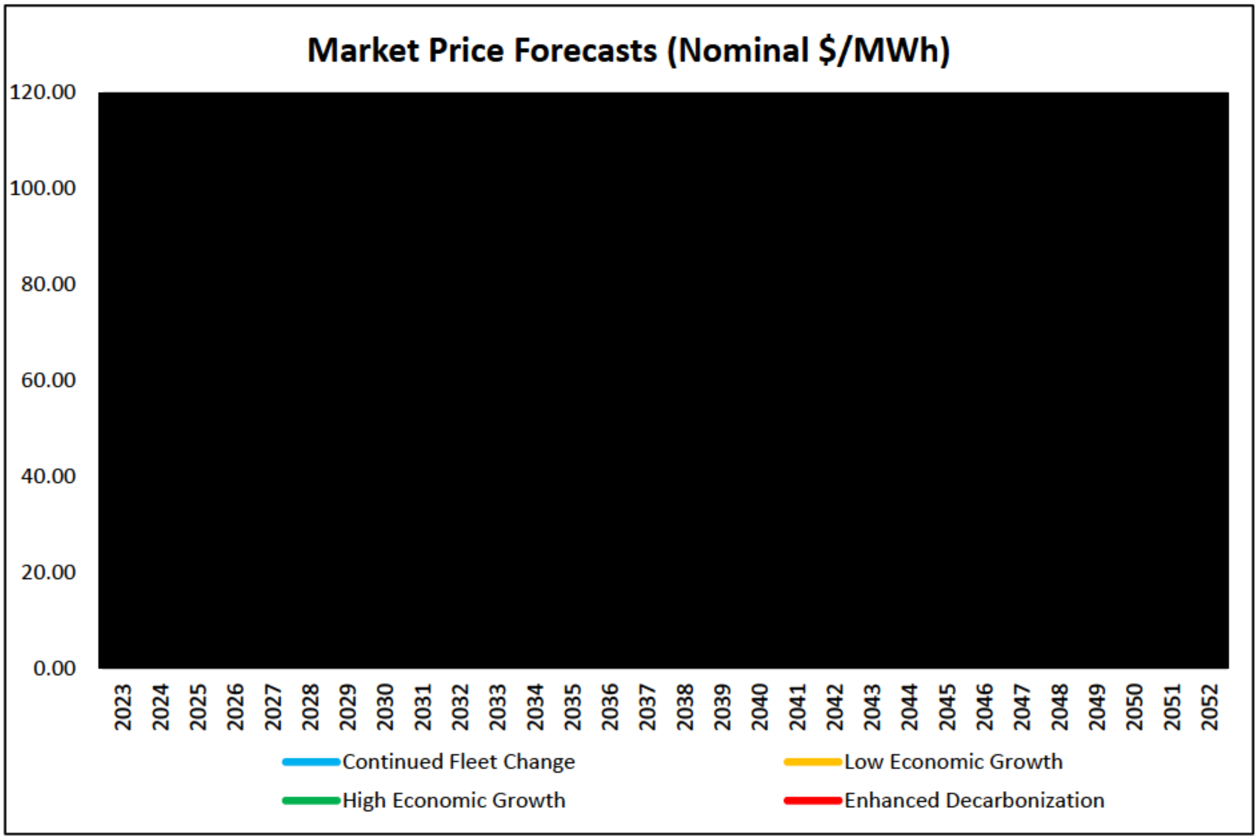
Figure 9 – Market Prices



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 compliance with the proposed USEPA GHG rule. This includes the following assumptions:

- Elm Road and Weston 4 are repowered to burn 100 percent natural gas beginning January 1, 2027. The requirement for converted coal to natural gas fueled boilers is January 1, 2030 but to qualify as a natural gas fired boiler there is a 3-year "look back" period. As a result, both units are assumed to be converted at the beginning of 2027 to comply with the proposed rule.

- 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 the Weston 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 proposed rule.

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

- All new combined cycle units require CCS.

Retirements

The following retirement dates are included in all modeling runs:

- Oak Creek units 5-6 retire May 31, 2024.
- Oak Creek units 7-8 retire December 31, 2025.
- Columbia units 1-2 retire May 31, 2026.
- Weston unit 3 retires December 31, 2031.

Approved Projects

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 Red Barn Wind Farm, Whitewater combined cycle, Weston RICE, Paris solar/BESS, Darien solar, Koshkonong solar, and both West Riverside 100 MW options.

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.

Solar and battery units are all modeled with the same cost and performance characteristics as High Noon. Doing so it removes potential confusion between High Noon versus a generic solar and/or BESS. The assumed capacity of the solar and BESS units is specifically sized according to the percent ownership each utility has of High Noon. For example, Wisconsin Electric would have a 75 percent ownership share of High Noon meaning it would have 225 MW of solar and 123.75 MW of battery capacity. To better align with this configuration a generic solar unit is assumed to be 112.5 MW and a generic battery unit is assumed to be 125 MW. Therefore, two solar units and one battery unit is equivalent to Wisconsin Electric's ownership share of High Noon for purposes of the model.

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 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

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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.

All gas technologies are assumed to need firm gas for fuel supply, due to MISO resource adequacy rule requirements. Given the current constrained interstate pipeline system this will require either a pipeline expansion or construction of liquified natural gas ("LNG") facilities 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] since these units are more baseload while CT units' firm rate is based on an equivalent cost for LNG ([redacted] since it is more of a peaking unit. Given the intermediate nature of RICE units, the firm rate is based on the composite average rates for CC and CT units.

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, including Docket No. 5-BS-258 (PSC REF#: 445244) and adjusted for inflation, and assume similar cost increases as other technologies.

Table 6 – Generic Units

	Technology	Utility	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	WE/WPS	418	varies	[redacted]						
	Combined Cycle w/ 90% CCS	WE/WPS	377	varies							
	Combustion Turbine 1	WE/WPS	105	varies							
	Combustion Turbine 2	WE/WPS	237	varies							
	RICE - 3 unit site	WE/WPS	55.2	varies							
	RICE - 7 unit site	WE/WPS	128.8	varies							
WEPCO Specific Units	Wind	WE	100	35%							
	Solar	WE	112.5	23%							
	Battery	WE	125	<16%							
	Energy Efficiency	WE	14.5	52%							
	Demand Response	WE	50	n/a							
WPS Specific Units	Wind	WPS	50	35%							
	Solar	WPS	45	23%							
	Battery	WPS	25	<16%							
	Energy Efficiency	WPS	6.6	52%							
	Demand Response	WPS	25	n/a							

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High Noon Solar and BESS Parameters

High Noon Purchase Price

High Noon consists of an overall capacity of a 300 MW solar generation and a 165 MW BESS facility. Wisconsin Electric will own 75 percent, WPSC will own 15 percent and Madison Gas and Electric will hold the remaining 10 percent ownership. The commercial operation date of the Project is assumed to be January 1, 2027 for purposes of the economic analysis. A breakdown of the capital cost estimates and ownership shares is shown below.

Table 7 – Capital Costs

Category (465 MW):		Solar	BESS	Total
Capacity	MW	300	165	465
Purchase Price	$M	[redacted]		
Owner's Costs				
Transmission	$M			
Legal	$M			
Other	$M			
Total	$M			
Contingency	$M			
Sub-Total	$M			
Sales Tax	$M			
Total	$M	640.1	341.0	981.1
	$/kW	2,134	2,067	2,110
Equivalent 2023$	$/kW	[redacted]	[redacted]	[redacted]

Table 8 – Ownership Share

Category (465 MW):		Solar	BESS	Total
Total	**MW**	**300.0**	**165.0**	**465.0**
Wisconsin Electric	MW	225.0	123.8	348.8
WPSC	MW	45.0	24.8	69.8
MGE	MW	30.0	16.5	46.5

High Noon Solar

The High Noon solar facility is expected to have an installed capacity of 300 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 solar accreditation. As with all solar facilities modeled in PLEXOS, a 0.05 percent annual degradation in output was modeled for High Noon solar.

As part of the recent Inflation Reduction Act solar generation is now eligible for PTCs. The economic analysis assumes High Noon solar receives 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 solar PTC is $[redacted]. As a result, the modeled capital cost for solar units in the model has been reduced from $[redacted] to $[redacted].

High Noon BESS

The High Noon BESS is expected to have an installed capacity of 165 MW and is expected to have a minimum of four hours of continuous discharge capability (660 MWh per day). Degradation occurs when batteries are charged and discharged, with higher degradation occurring with more utilization. The economic evaluation assumes one full cycle of operation per day. The expected degradation after one year with one full cycle per day is approximately 5.7 percent and then levels off after year four with approximately 2.0 percent degradation per year. Batteries typically have a useful life of 20 years. However, in the economic analysis the BESS facilities are modeled to remain in operation throughout the 30-year study period. To account for the extended life of the BESS the modeling includes extra costs for battery augmentation, *i.e.* repowering to maintain firm capacity, as discussed above, and inverter replacements. "Repowering" the BESS every two years with sufficient energy storage capacity to maintain a minimum of four hours of continuous discharge capability will allow WEC to fully utilize the interconnection and capture the BESS's full capacity value. This strategy also takes advantage of the anticipated capital cost curve for batteries, which is forecast to continue to decline in the coming years.

As part of the recent Inflation Reduction Act, BESS is now eligible for ITCs. The economic analysis assumes High Noon solar receives a 30 percent ITC. As with the solar facilities, the value of the ITC is modeled as an equivalent reduction to the capital cost based on overall net present value. The equivalent capital cost reduction associated with the solar PTC is [redacted]. As a result, the modeled capital cost for solar units in the model has been reduced from [redacted] to [redacted].

The High Noon BESS will allow energy arbitrage, meaning the batteries are charged when the market prices are low, store that energy until the batteries are eventually discharged when the cost of energy is higher. As part of the Inflation Reduction Act BESS is no longer required to be charged by an onsite renewable facility to qualify for tax credits. This means they can now be charged directly from the grid and still receive tax credits. The arbitrage value of the BESS is captured in the PLEXOS model as part of its optimization on an hourly basis.

The High Noon BESS will also provide regulating reserve and spinning reserve ancillary services to the MISO wholesale bulk electric market. Regulating reserve is capacity held in reserve by a frequency responsive generation resource, external asynchronous resource, stored energy resource, or demand response resource for the purpose of continuously adjusting the resource output to manage the MISO Balancing Authority Area in accordance with applicable reliability standards in both the up and down direction. Based on historic data, holding the BESS's capacity in reserve 14 percent of the time is estimated to be the optimal strategy for achieving value from regulating reserve revenues and could provide up to [redacted] in annual value in MISO ancillary service revenue. Spinning reserve is a specified percentage, based on applicable reliability standards, of contingency reserve that must be synchronized to the transmission system and meets all applicable reliability standards that can be converted to energy within the contingency reserve deployment period following a deployment instruction. For BESS the value of spinning reserve is determined by the percent of time the battery is not being held in reserve for regulating. Based on historic data the annual spinning reserve value could provide up to [redacted] per year in value. Combined the BESS could provide up to [redacted] per year in value from MISO ancillary service revenue. However, for modeling purposes and because those values assume perfect knowledge during day-to-day operation, WEC did not include a quantitative estimate for the value of regulating and spinning reserve because all units provide ancillary services to some degree and it is difficult to quantify the incremental benefit batteries provide compared to other technologies.

High Noon Annual Operating Costs

The fixed operating and maintenance ("O&M") costs forecasted for the Project include a [redacted] annual costs will include substation maintenance, vegetation management, land royalties, insurance premiums and administration/general ("A&G") costs. These costs amount to approximately [redacted] in 2027 for High Noon [redacted] applied over the course of the land lease (assumed to be 30 years). In total, the annual O&M costs in the first year of operation will be approximately [redacted]. Each utility is allocated its respective ownership share of the costs.

In addition to the annual O&M expenditures, the Project will also incur capital expenditures. However, in the economic model these costs were treated as O&M expenses for modeling purposes. The capital expenditures include inverter replacements in year 15 to extend the life of both the solar and BESS. Biannual BESS augmentation costs are also treated as O&M for purposes of the economic modeling.

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:

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Table 9 – Annual Fixed Costs (2023$)

Category (465 MW):	$000/yr	$/kW-yr
Base O&M	[redacted]	
Solar/BESS Spare Parts		
Substation Maintenance		
Vegetation Maintenance		
Land Royalties		
Insurance		
A&G		
BESS Augmentation		
CapEx		
Total (465 MW):		
Solar Only (300 MW):		

Purchase Power Agreement ("PPA")

WEC and MGE did not pursue a solar and/or BESS PPA. They have not received any proposals from developers for a solar and/or BESS 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 High Noon land agreement terms allow the Project to operate for up to 50 years (a 30-year initial term with a 20 year extension period). 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 High Noon development rights is estimated to be over $30 million. This is reflected in High Noon's 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.

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In addition to the interconnection value, the residual value can be significant. The solar modules will continue to generate power well after they have 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. Any residual value of the BESS would be an additional benefit to customers, which would not be available under a PPA.

Solar and storage 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.

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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 later in this document. 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.

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, WEC studied the impact of Capacity and Energy Assurance across four planning futures, resulting in 64 model runs:

1. Continued Fleet Change (Base Case)
2. Slow Economic Growth
3. Enhanced Decarbonization
4. High Economic Growth

Sensitivity Analysis: A sensitivity analysis examines the effect of changing just one variable at a time. For the Continued Fleet Change (Base Case) planning future WEC studied the effect of seven sensitivities, which are described in more detail below, on the economic value associated with solar and battery technologies, resulting in 108 model runs.

1. Solar Accreditation
2. Limited Wind Availability
3. USEPA GHG Rule
4. High Solar/Battery Capital Costs
5. Low Solar/Battery Capital Costs
6. Wisconsin Electric High New Load Estimates
7. Wisconsin Electric Low New Load Estimates

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Executive Summary

The overall need for capacity and energy for both Wisconsin Electric and WPSC is greater than the overall capacity and energy profile of High Noon, indicating other resources are needed. However, the modeling discussed below demonstrates that High Noon is part of the optimal resource mix across many different planning assumptions for Wisconsin Electric and WPSC.

The balance of the generation portfolio will continue to be evaluated once unit specific costs are known. All generic solar and battery resources included throughout the study period are modeled with the same cost characteristics as High Noon, which may or may not be true for other solar and/or battery projects when they are actually constructed. This analysis helps lay the foundation of meeting additional capacity and energy needs for Wisconsin Electric and WPSC and those needs are different for each utility. The key takeaways from the economic evaluation are:

1) Solar and battery resources continue to be part of the low cost plan for both utilities over a wide range of planning assumptions. The in-service year may differ between plans, especially for WPSC, but when looking at the overall picture and analysis it is clear that High Noon solar and battery provide an overall benefit to customers. High Noon's combined NPV savings for Wisconsin Electric and WPSC average approximately **$500 million** – with a minimum savings of **$159 million** and a maximum savings of **$1,163 million** – compared to not having solar or battery resources available until 2029.

Table 10 – Combined WEC NPV Results ($Millions)

Resource Planning Methodology	Continued Fleet Change	Slow Economic Growth	Enhanced Decarbonization	High Economic Growth
Capacity Assurance	492	434	1,163	491
Energy Assurance	205	221	880	159

2) Wisconsin Electric: Under all model runs performed in the scenario analysis when utilizing Capacity Assurance and Energy Assurance resource planning both the solar and battery aspects of the Project are selected as part of the optimum expansion plan. By 2030 solar capacity selected as part of the optimum plan ranges from 2,250 MW up to 2,700 MW across all planning futures. Similarly battery capacity ranges from 1,250 MW up to 2,125 MW. This, however, assumes that solar and battery capacity is available to be sourced in MISO LRZ 2 during this timeframe and at the same cost as High Noon.

   NPV savings from High Noon range from **$100 million** to **$299 million** when analyzed in the Continued Fleet Change planning future, as compared to not having solar and battery resources available until 2029. Alternative planning futures provide a much wider range of NPV savings with a range from **$11 million** all the way up to **$851 million**.

3) WPSC: Under all model runs performed in the scenario analysis when utilizing Capacity Assurance and Energy Assurance resource planning battery resources are selected as part of the

optimum expansion plan, ranging from 125 MW up to 225 MW by 2030. Solar resources are selected as part of WPSC's low cost plan in six of the eight scenarios analyzed across the four planning futures. However, solar is selected in all model runs performed utilizing Energy Assurance resource planning. When solar is selected the total capacity by 2030 range from 135 MW up to 1,080 MW.

NPV savings range **$105 million** to **$193 million** when analyzed in the Continued Fleet Change planning future, as compared to not having solar and battery resources available until 2029. Alternative planning futures provide a much wider range of NPV savings with a range from **$95 million** to **$313 million**.

4) Sensitivities: WEC's economic analysis stress tested the value of solar and battery resources over a wide range of planning assumptions. A common theme across all sensitivities is solar and battery resources being selected as part of the low cost plan as compared to available alternatives.

The model also consistently selects wind resources as a low cost option for both utilities up to the amount allowed. However, the amount of wind availability in MISO LRZ 2 is finite, and the model stress tests this variable. Future solar capacity accreditation, especially in the summer months when it is most valuable, is uncertain so the base assumption includes a conservative assumption of only 20 percent accreditation by 2030. Higher capacity accreditation is tested as a sensitivity given the uncertainty long term. Taking these two sensitivities into account the importance of solar resources in the resource mix becomes very evident, especially for WPSC.

Stress testing for solar and battery resources includes the high capital cost and no USEPA GHG rule sensitivities. In these scenarios the economic benefits of solar and battery resources decrease. However, the combined NPV benefit of solar and battery resources for the WEC utilities remain positive, ranging from a savings of **$39 million** up to **$400 million** across both sensitivities.

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Scenario Analysis Results

The results below focus on a scenario analysis while utilizing Capacity Assurance and Energy Assurance resource planning for each of the four planning futures.

Case 1 model runs include all technologies to generate the optimal resource plan while maintaining seasonal reserve margin requirements. This model run focuses on what the optimal new resources are, specifically from 2027-2029 timeframe. High Noon is expected to enter commercial operation on January 1, 2027. In the event both solar and battery units, equivalent to High Noon's capacity, are not selected in 2027 an additional run with the suffix "HN" was performed with an equivalent amount of solar and battery to High Noon forced into the model to provide accurate cost comparisons based on the anticipated in-service date for High Noon. If an additional "HN" case was not performed then that specific Case 1 model run included solar and battery capacity at least equivalent to High Noon as part of the optimal plan in 2027.

Alternative Cases 2-4 all include variations of solar and battery unit availability in 2027 and 2028 to provide model runs showing the economics of both technologies compared to other resources. All three alternative runs are extensions of Case 1 but with the following changes:

- Case 2 does not allow solar or battery units to be built until 2029 at the earliest.
- Case 3 does not allow solar units to be built until 2029 at the earliest. However, battery units are available to be built in 2027 or 2028.
- Case 4 does not allow battery units to be built until 2029 at the earliest. However, solar units are available to be built in 2027 or 2028.

Each case identified above is then modeled in both Capacity Assurance and Energy Assurance resource planning methodologies. Case IDs with the suffix "A – D" refer to model runs assuming Capacity Assurance resource planning and Case IDs with the suffix "E – H" refer to model runs assuming Energy Assurance resource planning. For example, Case 2F is a model run assuming Energy Assurance resource planning in the Slow Economic Growth planning future with no solar or battery units available until 2029.

Wisconsin Electric Results

Resource Mix: Case 1 model run results (series "A – H"), which include all new resource options, indicate new solar and battery resources are part of the optimal plan from 2026 to 2029. In other words, since High Noon has the same operating and cost characteristics as generic solar and battery units, these results indicate High Noon is part of the low cost plan over a wide range of planning assumptions. As shown below in Figure 10, by the end of 2029 the model picks between 2,250 MW and 2,700 MW of new solar capacity and picks between 1,250 MW and 2,125 MW of new generic batter capacity across all planning futures in both the Capacity and Energy Assurance model runs.

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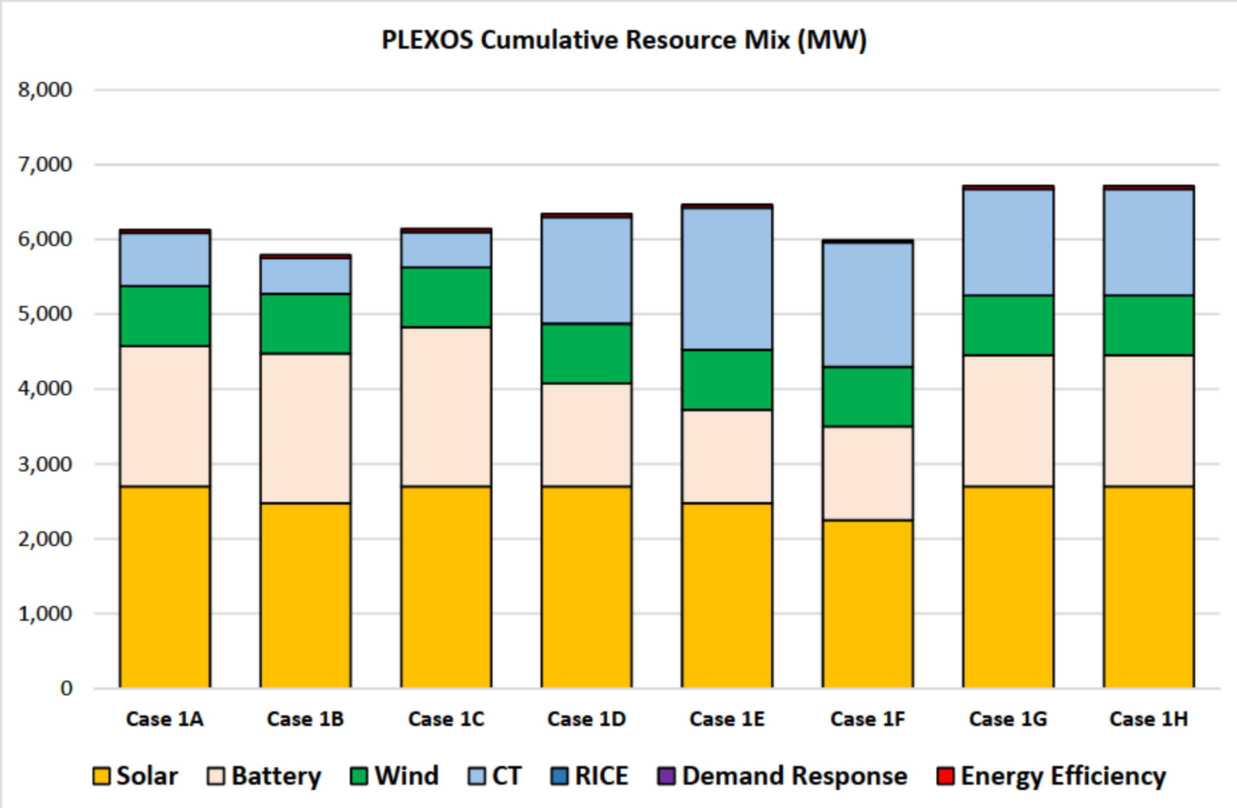
Figure 10 – Wisconsin Electric New Resource Mix



NPV Results: The tables below report the Capacity Assurance and Energy Assurance resource planning economic results for Wisconsin Electric for each planning future.

- Solar and battery resources are part of Wisconsin Electric's low cost plan in all model runs analyzed using Capacity and Energy Assurance resource planning. Also, all model runs include solar and battery capacity greater than High Noon. Therefore an additional model run with the suffix "HN" was not required.
- Solar and battery resources, including High Noon, provide NPV savings ranging between **$250 million and $851 million** when analyzed using Capacity Assurance resource planning.
- Solar and battery resources, including High Noon, provide NPV savings ranging between **$11 million and $637 million** when analyzed using Energy Assurance resource planning.
- Separating solar and battery resources from being selected at the same time confirms both technologies are cost effective.

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Table 11 – WEPCO Scenario Analysis NPV Results ($Millions): Capacity Assurance

Capacity Assurance Resource Planning		Continued Fleet Change "A"		Slow Economic Growth "B"		Enhanced Decarbonization "C"		High Economic Growth "D"	
		NPV	Delta	NPV	Delta	NPV	Delta	NPV	Delta
Case 1	Base run with no constraints	23,855		24,470		27,847		26,989	
Case 1 HN	Case 1 with equivalent solar/battery capacity to High Noon included, if needed								
Case 2	Base run with no solar or battery available until 2029	24,154	**299**	24,740	**269**	28,697	**851**	27,239	**250**
Case 3	Base run with no solar available until 2029	24,007	**152**	24,708	**238**	28,464	**617**	27,124	**135**
Case 4	Base run with no battery available until 2029	24,006	**151**	24,604	**133**	28,079	**232**	27,023	**34**

Table 12 – WEPCO Scenario Analysis NPV Results ($Millions): Energy Assurance

Energy Assurance Resource Planning		Continued Fleet Change "E"		Slow Economic Growth "F"		Enhanced Decarbonization "G"		High Economic Growth "H"	
		NPV	Delta	NPV	Delta	NPV	Delta	NPV	Delta
Case 1	Base run with no constraints	24,912		25,572		29,318		28,002	
Case 1 HN	Case 1 with equivalent solar/battery capacity to High Noon included, if needed								
Case 2	Base run with no solar or battery available until 2029	25,012	**100**	25,699	**127**	29,955	**637**	28,012	**11**
Case 3	Base run with no solar available until 2029	24,919	**7**	25,637	**65**	29,869	**551**	28,011	**9**
Case 4	Base run with no battery available until 2029	24,962	**50**	25,759	**186**	29,804	**486**	28,013	**11**

Seasonal Reserve Margins: PLEXOS incorporates seasonal reserve margin requirements, as previously described, as opposed to the traditional summer peak reserve margin requirement. This ensures each season is treated the same in terms of having sufficient mix of resources. Figure 11 provides the reserve margin results for Case 1 in the Continued Fleet Change (Base) planning future for both Capacity and Energy Assurance model runs as compared to the minimum reserve margin requirements and demonstrates how the model adheres to those requirements. It is evident in the graph below the Energy Assurance resource modeling requires more generation capacity as more renewable generation comes online to serve load 24 hours a day, 365 days a year without any reliance on the broader MISO market for energy.

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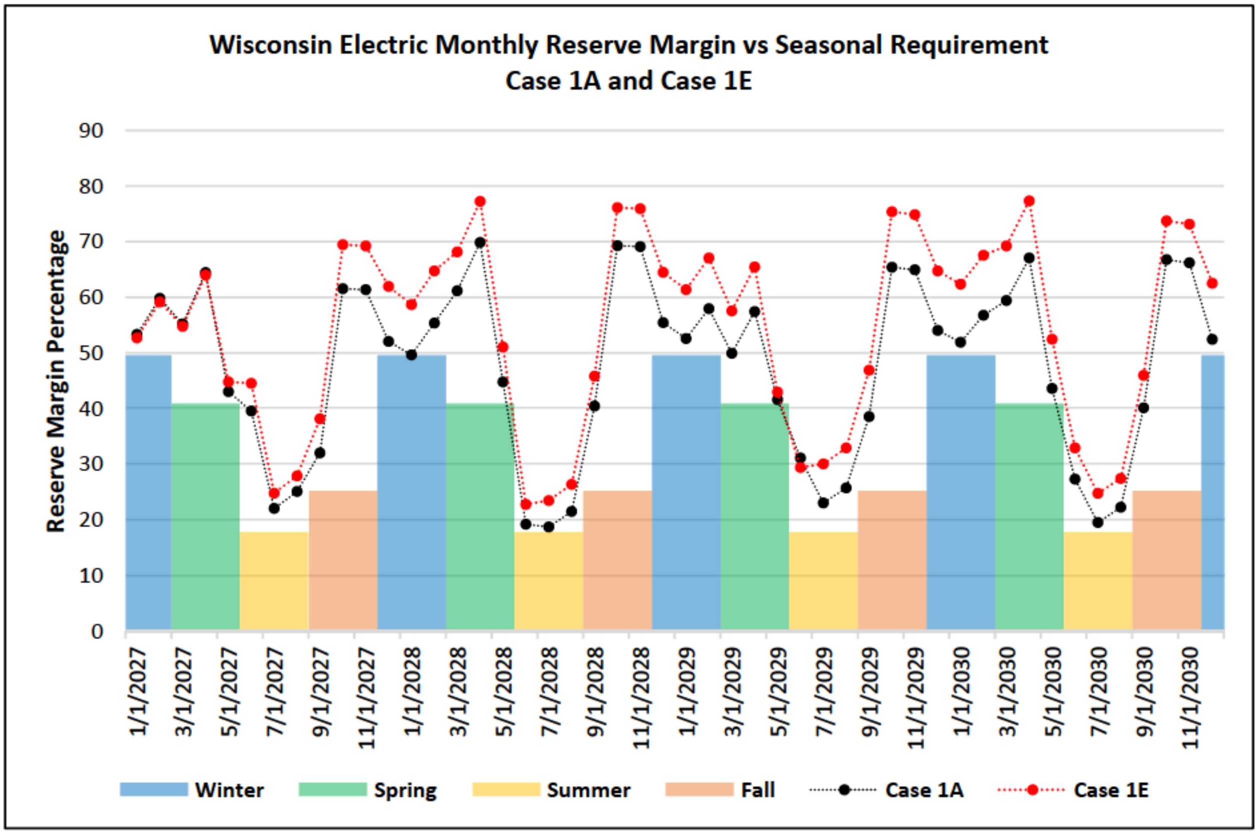
Figure 11 – Wisconsin Electric Seasonal Reserve Margins



WPSC Results

Resource Mix: Case 1 model run results (series "A – H"), which include all generic units as new resource options, indicate new solar and battery resources are part of the optimal resource plan from 2026 to 2029 in most scenarios. As shown below in Figure 12, by the end of 2029 new solar capacity ranges between 135 MW and 1,080 MW in six of the eight planning futures and new generic battery capacity ranges from 300 MW and 1,000 MW across all planning futures in both Capacity and Energy Assurance model runs.

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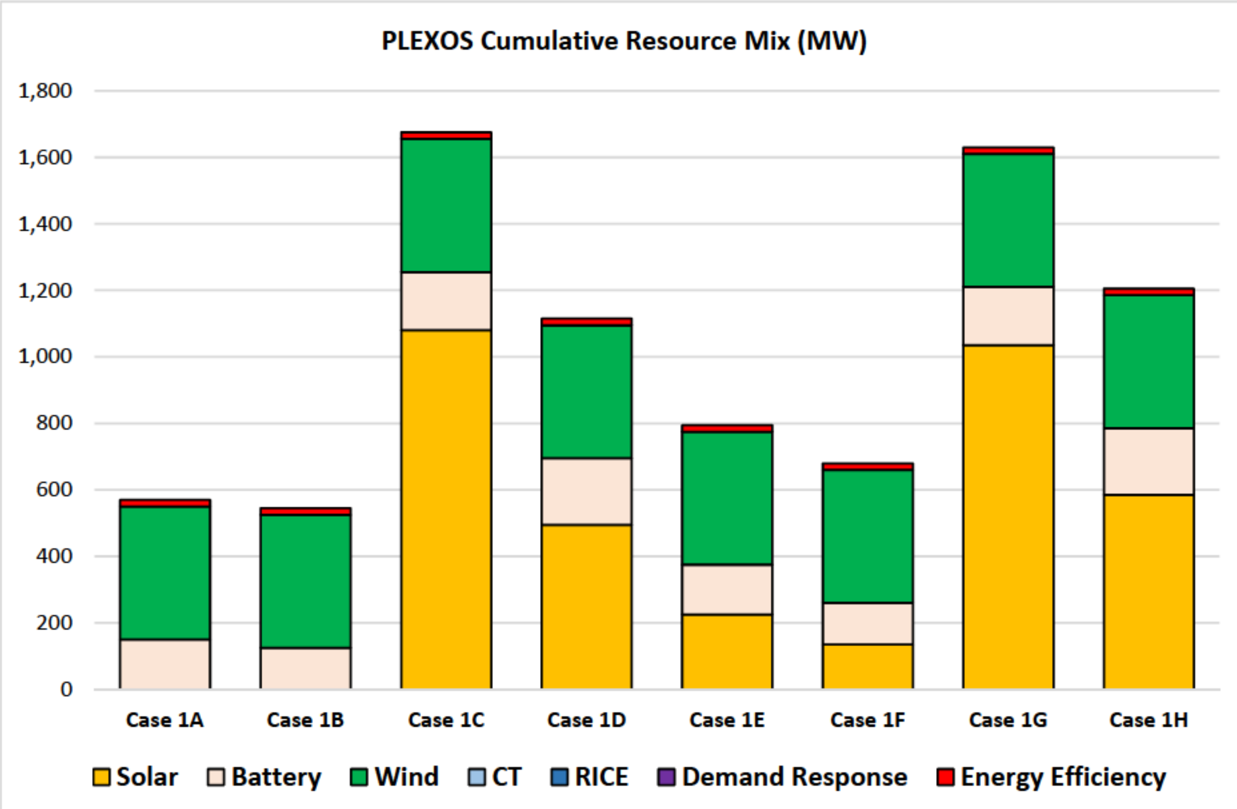
Figure 12 – WPSC Resource Plan Mix



NPV Results: The tables below report the Capacity Assurance and Energy Assurance resource planning economic results for WPSC for each planning future.

- Solar resources are part of WPSC's low cost plan in six of the eight model runs analyzed using Capacity and Energy Assurance resource planning.
- Battery resources are part of WPSC's low cost plan in all model runs analyzed using Capacity and Energy Assurance resource planning.
- Capacity Assurance:
    - Case 1A and Case 1B do not include solar resources in the low cost plan. However, when combined with battery resources included as part of the optimal plan, the total NPV cost only increases between **$7 million** and **$12 million** for these planning futures.
    - Solar and battery resources in Cases 1C and Case 1D, including High Noon, provide between **$247 million** and **$313 million** in NPV savings compared to not allowing solar or battery resources to be built prior to 2029 when analyzed utilizing Capacity Assurance resource planning.
    - Even though Case 1D includes solar and battery by the end of 2029, both solar and battery were not selected together in 2027. Therefore, an additional model run (Case

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1D HN) was performed to advance solar capacity equivalent to High Noon to 2027, which increased NPV **$7 million**.

- Energy Assurance:
    - All cases analyzed using Energy Assurance resource planning include solar and battery resources by the end of 2029 as part of the low cost plan. Solar and battery resources, including High Noon, provide between **$98 million** and **$244 million** in NPV savings compared to not allowing solar or battery resources to be built prior to 2029 when analyzed utilizing Energy Assurance resource planning.
    - Even though Case 1F includes solar and battery by the end of 2029, both solar and battery were not selected together in 2027. Therefore, an additional model run (Case 1F HN) was performed to advance solar capacity equivalent to High Noon to 2027, which increased the NPV **$3 million**.

Table 13 – WPSC Scenario Analysis NPV Results ($Millions): Capacity Assurance

Capacity Assurance Resource Planning		Continued Fleet Change "A"		Slow Economic Growth "B"		Enhanced Decarbonization "C"		High Economic Growth "D"	
		NPV	Delta	NPV	Delta	NPV	Delta	NPV	Delta
Case 1	Base run with no constraints	6,068		6,389		7,970		7,156	
Case 1 HN	Case 1 with equivalent solar/battery capacity to High Noon included, if needed	6,075	**7**	6,402	**12**			7,163	**7**
Case 2	Base run with no solar or battery available until 2029	6,268	**200**	6,567	**177**	8,283	**313**	7,403	**247**
Case 3	Base run with no solar available until 2029	6,068	**0**	6,389	**0**	8,006	**36**	7,156	**0**
Case 4	Base run with no battery available until 2029	6,268	**200**	6,567	**177**	8,252	**281**	7,395	**239**

Table 14 – WPSC Scenario Analysis NPV Results ($Millions): Energy Assurance

Energy Assurance Resource Planning		Continued Fleet Change "E"		Slow Economic Growth "F"		Enhanced Decarbonization "G"		High Economic Growth "H"	
		NPV	Delta	NPV	Delta	NPV	Delta	NPV	Delta
Case 1	Base run with no constraints	6,375		6,732		8,404		7,397	
Case 1 HN	Case 1 with equivalent solar/battery capacity to High Noon included, if needed			6,735	**3**				
Case 2	Base run with no solar or battery available until 2029	6,479	**105**	6,829	**98**	8,647	**244**	7,546	**149**
Case 3	Base run with no solar available until 2029	6,375	**1**	6,732	**0**	8,435	**31**	7,401	**4**
Case 4	Base run with no battery available until 2029	6,479	**105**	6,829	**98**	8,623	**220**	7,557	**160**

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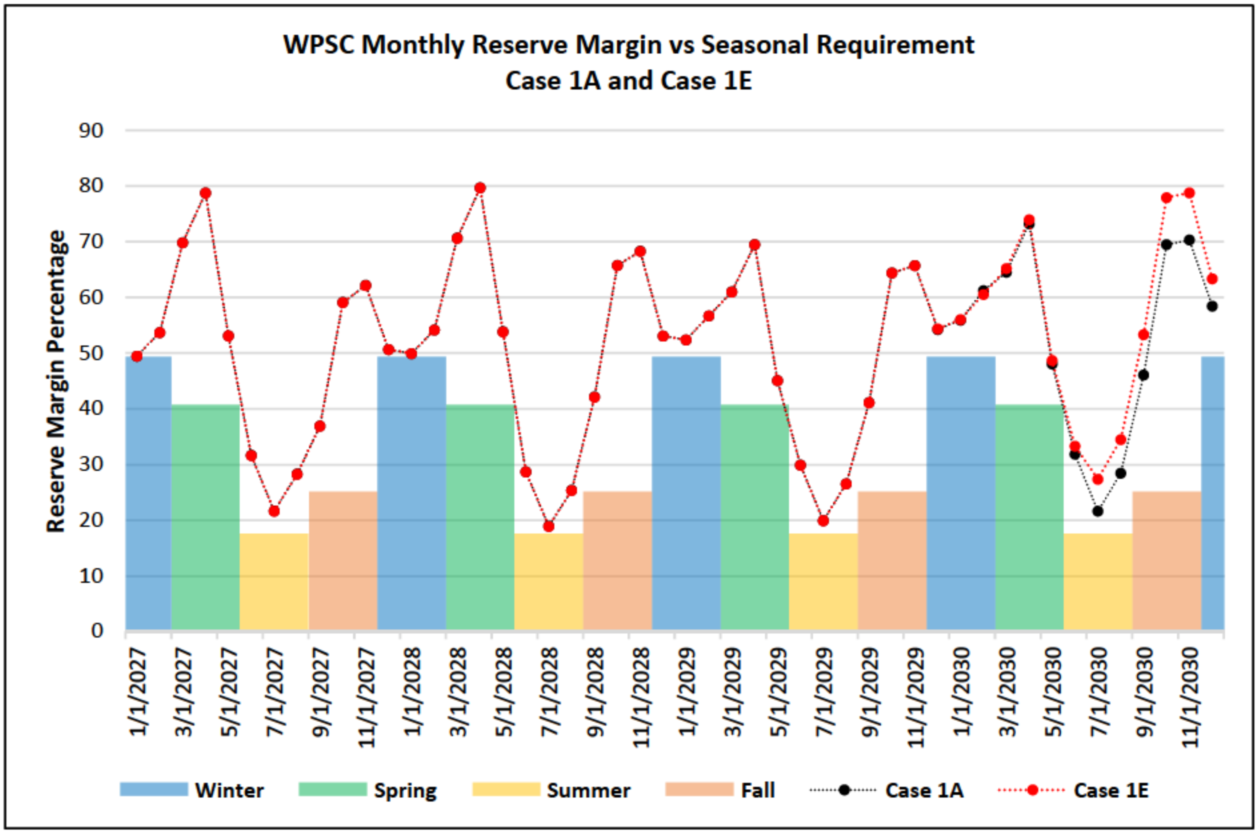
Seasonal Reserve Margins: PLEXOS incorporates seasonal reserve margin requirements, as previously described, as opposed to the traditional summer peak reserve margin requirement. This ensures each season is treated the same in terms of having the right mix of resources. Figure 13 provides the reserve margin results for Case 1 in the Continued Fleet Change Base) planning future for both Capacity and Energy Assurance model runs ("A and E" series) as compared to the minimum reserve margin requirements and demonstrates how the model adheres to those requirements.

Figure 13 – WPSC Seasonal Reserve Margins



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Summer Solar Accreditation Sensitivity

The results below focus on Capacity Assurance and Energy Assurance resource planning while utilizing the Continued Fleet Change planning future, with the exception that all solar summer accreditation only decreases to 50 percent – as opposed to the base assumption of 20 percent – by 2030. There is considerable uncertainty about summer accreditation for solar in the future as more solar is added to the MISO footprint, hence the importance to test different assumptions to see how the value of such resources is impacted. These modeling runs include all the same assumptions as Cases 1-4, except for the summer accreditation value for all solar units. In other words, there are no changes to the fall, winter or spring season accreditations.

- Case 5 allows all technologies, including solar and battery, to be built. In the event both solar and battery units, equivalent to High Noon's capacity, are not selected in 2027 or 2028 an additional run with the suffix "HN" was performed with an equivalent amount of solar and battery to High Noon forced into the model.
- Case 6 does not allow solar or battery units to be built until 2029 at the earliest.
- Case 7 does not allow solar units to be built until 2029 at the earliest. However, battery units are available to be built in 2027 or 2028.
- Case 8 does not allow battery units to be built until 2029 at the earliest. However, solar units are available to be built in 2027 or 2028.

Wisconsin Electric Results:

Resource Mix: The table below shows the results of this sensitivity under the Continued Fleet Change (Base) planning future using both the Capacity Assurance and Energy Assurance methodologies. The optimal plans indicate new solar and battery resources are part of the optimal plan in 2027 for both Capacity and Energy Assurance resource planning.

Table 15 – WEPCO Solar Accreditation Build Plan

Capacity Assurance					Energy Assurance				
Case 5A	**2027**	**2028**	**2029**	**2030**	**Case 5E**	**2027**	**2028**	**2029**	**2030**
CC									
CT	711	711	711	711	CT	1,185	1,896	1,896	1,896
Demand Response					Demand Response				
Energy Efficiency	15	29	44	58	Energy Efficiency	15	29	44	44
RICE					RICE				
Solar	**900**	**1,800**	**2,700**	**3,038**	**Solar**	**788**	**1,688**	**2,475**	**2,475**
Wind	300	600	800	1,100	Wind	300	600	800	1,100
Battery	**750**	**1,375**	**1,875**	**1,875**	**Battery**	**625**	**625**	**1,250**	**1,375**
Total	2,676	4,515	6,130	6,782	Total	2,912	4,838	6,465	6,890

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NPV Results:

- Solar and battery resources, including High Noon, provide **$341 million** in NPV savings compared to not allowing solar or battery resources to be built prior to 2029 when analyzed utilizing Capacity Assurance resource planning.
- Solar and battery resources, including High Noon, provide **$106 million** in NPV savings compared to not allowing solar or battery resources to be built prior to 2029 when analyzed utilizing Energy Assurance resource planning.

Table 16– WEPCO Solar Accreditation Sensitivity NPV Results ($Millions)

Continued Fleet Change Planning Future		Capacity Assurance "A"		Energy Assurance "E"	
		NPV	Delta	NPV	Delta
Case 5	Base run with no constraints	23,810		24,912	
Case 5 HN	Case 5 with equivalent solar/battery capacity to High Noon included, if needed				
Case 6	Base run with no solar or battery available until 2029	24,151	**341**	25,018	**106**
Case 7	Base run with no solar available until 2029	23,933	**123**	24,925	**13**
Case 8	Base run with no battery available until 2029	24,630	**820**	24,963	**51**

WPSC Results

Resource Mix: The table below shows the results of this sensitivity under the Continued Fleet Change (Base) planning future using both the Capacity Assurance and Energy Assurance methodologies.

- The optimal plans include battery resources in 2027 in both Capacity and Energy Assurance resource planning.
- 225 MW of solar is selected in 2029 in the Energy Assurance planning scenario.

Table 17 – WPSC Solar Accreditation Build Plan

Capacity Assurance					Energy Assurance				
Case 5A	**2027**	**2028**	**2029**	**2030**	**Case 5E**	**2027**	**2028**	**2029**	**2030**
CT					CT				
Demand Response					Demand Response				
Energy Efficiency	7	13	20	26	Energy Efficiency	7	13	20	20
RICE					RICE				
Solar					**Solar**			**225**	**225**
Wind	150	300	400	550	Wind	150	300	400	550
Battery	**150**	**150**	**150**	**150**	**Battery**	**150**	**150**	**150**	**200**
Total	307	463	570	726	Total	307	463	795	995

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NPV Results:

- Since battery resources are selected as part of the optimal plan High Noon's economic impact is driven by the advancement of the solar resource to 2027 from when it was optimally selected.
- Utilizing Capacity Assurance resource planning the NPV increases **$9 million** to include the equivalent solar resource in 2027.
- Utilizing Energy Assurance resource planning the NPV increases **$4 million** by advancing the solar resource two years to 2027.

Table 18 – WPSC Solar Accreditation Sensitivity NPV Results ($Millions)

Continued Fleet Change Planning Future		**Capacity Assurance "A"**		**Energy Assurance "E"**	
		NPV	**Delta**	**NPV**	**Delta**
Case 5	Base run with no constraints	6,026		6,389	
Case 5 HN	Case 5 with equivalent solar/battery capacity to High Noon included, if needed	6,035	**9**	6,393	**4**
Case 6	Base run with no solar or battery available until 2029	6,196	**170**	6,473	**84**
Case 7	Base run with no solar available until 2029	6,026	**0**	6,389	**0**
Case 8	Base run with no battery available until 2029	6,196	**170**	6,471	**81**

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Limited Wind Availability Sensitivity

This set of sensitivities tests the economic impacts of limited availability of wind resources in LRZ 2 by reducing the amount the model can select prior to by 2030 to 50 percent of the baseline assumptions. As previously discussed above, there are physical limitations to the amount of wind capacity that is available in MISO LRZ 2. 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 before 2030. All other planning assumptions are consistent with Cases 1-4.

- Case 17 allows all technologies, including solar and battery, to be built. In the event both solar and battery units, equivalent to High Noon's capacity, are not selected in 2027 or 2028 an additional run with the suffix "HN" was performed with an equivalent amount of solar and battery to High Noon forced online.
- Case 18 does not allow solar or battery units to be built until 2029 at the earliest.
- Case 19 does not allow solar units to be built until 2029 at the earliest. However, battery units are available to be built in 2027 or 2028.
- Case 20 does not allow battery units to be built until 2029 at the earliest. However, solar units are available to be built in 2027 or 2028.

Wisconsin Electric Results

Resource Mix: The table below shows the results of this sensitivity under the Continued Fleet Change (Base) planning future using both the Capacity Assurance and Energy Assurance methodologies. The optimal plans indicate new solar and battery resources are part of the optimal plan in 2027 for both Capacity and Energy Assurance resource planning.

Table 19 – WEPCO Limited Wind Build Plan

Capacity Assurance					Energy Assurance				
Case 9A	**2027**	**2028**	**2029**	**2030**	**Case 9E**	**2027**	**2028**	**2029**	**2030**
CC									
CT	1,422	1,659	1,659	1,659	CT	1,659	1,896	2,133	2,133
Demand Response					Demand Response				
Energy Efficiency	15	29	44	58	Energy Efficiency	15	29	44	58
RICE					RICE	129	258	258	258
Solar	**900**	**1,800**	**2,700**	**3,263**	**Solar**	**900**	**1,800**	**2,700**	**3,263**
Wind	300	600	800	1,100	Wind	300	600	800	1,100
Battery	**750**	**1,375**	**2,125**	**2,250**	**Battery**	**625**	**1,125**	**1,625**	**1,875**
Total	3,387	5,463	7,328	8,330	Total	3,627	5,708	7,559	8,686

NPV Results:

- Solar and battery resources, including High Noon, provide **$264 million** in NPV savings compared to not allowing solar or battery resources to be built prior to 2029 when analyzed utilizing Capacity Assurance resource planning.

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- Solar and battery resources, including High Noon, provide **$173 million** in NPV savings compared to not allowing solar or battery resources to be built prior to 2029 when analyzed utilizing Energy Assurance resource planning.

Table 20 – WEPCO Limited Wind NPV Results ($Millions)

Continued Fleet Change Planning Future		Capacity Assurance "A"		Energy Assurance "E"	
		NPV	Delta	NPV	Delta
Case 17	Base run with no constraints	24,483		25,390	
Case 17 HN	Case 17 with equivalent solar/battery capacity to High Noon included, if needed				
Case 18	Base run with no solar or battery available until 2029	24,747	**264**	25,562	**173**
Case 19	Base run with no solar available until 2029	24,662	**179**	25,507	**118**
Case 20	Base run with no battery available until 2029	24,486	**3**	25,545	**155**

WPSC Results

Resource Mix: The table below shows the results of this sensitivity under the Continued Fleet Change (Base) planning future using both the Capacity Assurance and Energy Assurance methodologies.

- The optimal plans include battery resources in 2027 in both Capacity and Energy Assurance resource planning.
- The optimal plans include solar resources in both Capacity and Energy Assurance resource planning model runs but not until 2029 and 2028, respectively.

Table 21 – WPSC Limited Wind Build Plan

Capacity Assurance					Energy Assurance				
Case 17A	**2027**	**2028**	**2029**	**2030**	**Case 17E**	**2027**	**2028**	**2029**	**2030**
CT					CT				
Demand Response					Demand Response				
Energy Efficiency	7	13	13	20	Energy Efficiency	7	13	20	26
RICE					RICE				
Solar			**45**	**45**	**Solar**		**45**	**405**	**405**
Wind	100	200	200	350	Wind	100	200	200	350
Battery	**150**	**150**	**150**	**150**	**Battery**	**150**	**150**	**150**	**150**
Total	257	363	408	565	Total	257	408	775	931

NPV Results

- Solar and battery resources, including High Noon, provide between **$95 million** and **$200 million** in NPV savings compared to not allowing solar or battery resources to be built prior to 2029.
- Since battery resources are selected as part of the optimal plan High Noon's economic impact is driven by the advancement of the solar resource to 2027 from when it was optimally selected.

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- Utilizing Capacity Assurance resource planning the NPV increases **$12 million** by advancing the solar resource two years to 2027.
- Utilizing Energy Assurance resource planning the NPV increases **$2 million** by advancing the solar resource one year to 2027.

Table 22 – WPSC Limited Wind Sensitivity NPV Results ($Millions)

Continued Fleet Change Planning Future		Capacity Assurance "A"		Energy Assurance "E"	
		NPV	Delta	NPV	Delta
Case 17	Base run with no constraints	6,160		6,382	
Case 17 HN	Case 17 with equivalent solar/battery capacity to High Noon included, if needed	6,172	**12**	6,384	**2**
Case 18	Base run with no solar or battery available until 2029	6,359	**200**	6,478	**95**
Case 19	Base run with no solar available until 2029	6,160	**0**	6,383	**1**
Case 20	Base run with no battery available until 2029	6,363	**203**	6,478	**95**

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USEPA GHG Rule Sensitivity

This set of modeling runs assumes the proposed USEPA GHG rule is not enacted and implemented. This would eliminate the capacity factor constraints on existing combined cycle units and combustion turbines, allow new combined cycle units without CCS to be built, and would not require Elm Road and Weston 4 to be repowered to natural gas by 2027. However, in these model runs Elm Road and Weston 4 would still be repowered to natural gas by 2030, consistent with previous announcements regarding the elimination of coal as a fuel source for Wisconsin Electric and WPSC.

- Case 21 allows all technologies, including solar and battery, to be built. In the event both solar and battery units, equivalent to High Noon's capacity, are not selected in 2027 or 2028 an additional run with the suffix "HN" was performed with an equivalent amount of solar and battery to High Noon forced into the model.
- Case 22 does not allow solar or battery units to be built until 2029 at the earliest.
- Case 23 does not allow solar units to be built until 2029 at the earliest. However, battery units are available to be built in 2027 or 2028.
- Case 24 does not allow battery units to be built until 2029 at the earliest. However, solar units are available to be built in 2027 or 2028.

Wisconsin Electric Results

Resource Mix: The table below shows the results of this sensitivity under the Continued Fleet Change (Base) planning future using both the Capacity Assurance and Energy Assurance methodologies.

- The optimal plans include battery resources by 2028 in both Capacity and Energy Assurance resource planning.
- The optimal plan using Capacity Assurance resource planning includes solar resources in 2027. However, solar resources were not selected as part of the optimal plan using Energy Assurance resource planning.

Table 23– WEPCO USEPA GHG Sensitivity Build Plan

Capacity Assurance					Energy Assurance				
Case 21A	**2027**	**2028**	**2029**	**2030**	**Case 21E**	**2027**	**2028**	**2029**	**2030**
CC		418	418	418	CC		418	836	836
CT	474	474	474	474	CT	1,896	1,896	1,896	1,896
Demand Response					Demand Response		50	50	50
Energy Efficiency	15	29	29	29	Energy Efficiency	15	15	15	15
RICE		55	55	55	RICE		55	55	55
Solar	**900**	**900**	**900**	**900**	**Solar**				
Wind	300	900	1,600	2,000	Wind	300	300	300	400
Battery	**1,000**	**1,125**	**1,625**	**1,625**	**Battery**		**125**	**375**	**500**
Total	2,689	3,901	5,101	5,501	Total	2,211	2,859	3,527	3,752

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NPV Results

- Solar and battery resources, including High Noon, provide **$223 million** in NPV savings compared to not allowing solar or battery resources to be built prior to 2029 when analyzed utilizing Capacity Assurance resource planning.
- Solar and battery resources, equivalent to High Noon, increase NPV costs **$25 million** compared to the optimal plan when analyzed utilizing Energy Assurance resource planning.

Table 24 – WEPCO USEPA GHG Sensitivity NPV Results ($Millions)

Continued Fleet Change Planning Future		Capacity Assurance "A"		Energy Assurance "E"	
		NPV	Delta	NPV	Delta
Case 21	Base run with no constraints	23,508		24,389	
Case 21 HN	Case 21 with equivalent solar/battery capacity to High Noon included, if needed			24,414	**25**
Case 22	Base run with no solar or battery available until 2029	23,731	**223**	24,419	**30**
Case 23	Base run with no solar available until 2029	23,650	**142**	24,389	**0**
Case 24	Base run with no battery available until 2029	23,657	**148**	24,406	**16**

WPSC Results

Resource Mix: The table below shows the results of this sensitivity under the Continued Fleet Change (Base) planning future using both the Capacity Assurance and Energy Assurance methodologies.

- The optimal plans include battery resources in 2027 in both Capacity and Energy Assurance resource planning.
- The optimal plan does not include solar resources in Capacity Assurance resource planning. However, solar resources are included when utilizing Energy Assurance resource planning but not until 2030.

Table 25– WPSC USEPA GHG Sensitivity Build Plan

Capacity Assurance					Energy Assurance				
Case 21A	**2027**	**2028**	**2029**	**2030**	**Case 21E**	**2027**	**2028**	**2029**	**2030**
CT					CT				
Demand Response					Demand Response				
Energy Efficiency	7	13	13	13	Energy Efficiency	7	13	20	20
RICE					RICE				
Solar					**Solar**				**45**
Wind	150	300	400	550	Wind	150	300	400	550
Battery	**150**	**150**	**150**	**150**	**Battery**	**150**	**150**	**150**	**250**
Total	307	463	563	713	Total	307	463	570	865

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NPV Results

- Since battery resources are selected as part of the optimal plan, High Noon's economic impact is driven by the inclusion of the solar resource in 2027.
- Including solar resources equivalent to High Noon increases NPV costs by **$13 million** compared to the optimal plan when analyzed utilizing Capacity Assurance resource planning.
- Including solar resources equivalent to High Noon increases NPV costs by **$11 million** compared to the optimal plan when analyzed utilizing Energy Assurance resource planning.

Table 26 – WPSC USEPA GHG Sensitivity NPV Results ($Millions)

Continued Fleet Change Planning Future		Capacity Assurance "A"		Energy Assurance "E"	
		NPV	Delta	NPV	Delta
Case 21	Base run with no constraints	5,816		6,171	
Case 21 HN	Case 21 with equivalent solar/battery capacity to High Noon included, if needed	5,829	**13**	6,182	**11**
Case 22	Base run with no solar or battery available until 2029	6,007	**190**	6,285	**114**
Case 23	Base run with no solar available until 2029	5,816	**0**	6,171	**0**
Case 24	Base run with no battery available until 2029	6,007	**190**	6,285	**114**

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Solar/Battery Capital Cost Sensitivities

Cases 25-32 include a range of capital cost estimates for solar and battery resources. These model runs include a 15 percent increase and 15 percent decrease in the overall capital costs for solar and battery units, adjusted for the equivalent capital cost reduction for tax credits. The resulting capital cost estimates for solar and battery units are reflected in the table below. All other planning assumptions are consistent with Cases 1-4.

Table 27 – Capital Cost Sensitivities (2023$)

		Solar	Battery
Baseline Cost	$/kW	[redacted]	
Equivalent Tax Credit	$/kW		
Modeled Baseline Cost	**$/kW**		

		Solar	Battery
15% Increase	$/kW	[redacted]	
Equivalent Tax Credit	$/kW		
Modeled 15% Increase	**$/kW**		

		Solar	Battery
15% Decrease	$/kW	[redacted]	
Equivalent Tax Credit	$/kW		
Modeled 15% Increase	**$/kW**		

High Solar/Battery Capital Cost Cases

- Case 25 allows all technologies, including solar and battery, to be built. In the event both solar and battery units, equivalent to High Noon's capacity, are not selected in 2027 or 2028 an additional run with the suffix "HN" was performed with an equivalent amount of solar and battery to High Noon forced into the model.
- Case 26 does not allow solar or battery units to be built until 2029 at the earliest.
- Case 27 does not allow solar units to be built until 2029 at the earliest. However, battery units are available to be built in 2027 or 2028.
- Case 28 does not allow battery units to be built until 2029 at the earliest. However, solar units are available to be built in 2027 or 2028.

Low Solar/Battery Capital Cost Cases

- Case 29 allows all technologies, including solar and battery, to be built. In the event both solar and battery units, equivalent to High Noon's capacity, were not selected in 2027 or 2028 an additional run with the suffix "HN" was performed with an equivalent amount of solar and battery to High Noon forced into the model.
- Case 30 does not allow solar or battery units to be built until 2029 at the earliest.

- Case 31 does not allow solar units to be built until 2029 at the earliest. However, battery units are available to be built in this 2027 or 2028.
- Case 32 does not allow battery units to be built until 2029 at the earliest. However, solar units are available to be built in 2027 or 2028.

Wisconsin Electric Results

Resource Mix: The table below shows the results of this sensitivity under the Continued Fleet Change (Base) planning future using both the Capacity Assurance and Energy Assurance methodologies.

- High Solar/Battery Capital Costs: Solar resources continue to be part of the optimal plans in 2027 when utilizing Capacity Assurance resource planning when analyzed with high capital cost assumptions. Battery resources, although not selected in 2027, are selected in 2030. When using Energy Assurance resource planning, both solar and battery resources are not selected as part of the optimal plan prior to 2030. However, battery resources are selected in 2030.
- Low Solar/Battery Capital Costs: The optimal plans indicate new solar and battery resources are part of the optimal plan in 2027 for both Capacity and Energy Assurance resource planning when analyzed using lower capital cost assumptions for solar and battery resources.

Table 28– WEPCO High Solar/Battery Capital Costs Build Plan

Capacity Assurance					Energy Assurance				
Case 25A	**2027**	**2028**	**2029**	**2030**	**Case 25E**	**2027**	**2028**	**2029**	**2030**
CC									
CT	1,422	2,370	2,607	2,607	CT	1,896	2,844	3,318	3,318
Demand Response					Demand Response				
Energy Efficiency	15	29	44	44	Energy Efficiency	15	29	44	58
RICE					RICE				
Solar	**563**	**900**	**1,688**	**1,800**	**Solar**				
Wind	300	600	800	1,100	Wind	300	600	800	1,100
Battery				**250**	**Battery**				**125**
Total	2,299	3,899	5,138	5,801	Total	2,211	3,473	4,162	4,601

Table 29– WEPCO Low Solar/Battery Capital Costs Build Plan

Capacity Assurance					Energy Assurance				
Case 29A	**2027**	**2028**	**2029**	**2030**	**Case 29E**	**2027**	**2028**	**2029**	**2030**
CC									
CT	474	474	474	474	CT	1,185	1,185	1,185	1,185
Demand Response					Demand Response				
Energy Efficiency	15	29	29	29	Energy Efficiency	15	29	29	29
RICE					RICE				
Solar	**900**	**1,800**	**2,700**	**3,263**	**Solar**	**900**	**1,800**	**2,700**	**3,263**
Wind	300	600	800	1,100	Wind	300	600	800	1,100
Battery	**1,000**	**1,750**	**2,000**	**2,125**	**Battery**	**625**	**1,250**	**2,000**	**2,000**
Total	2,689	4,653	6,003	6,991	Total	3,025	4,864	6,714	7,577

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NPV Results

- High Solar/Battery Capital Costs: Including solar and battery resources equivalent to High Noon increase NPV costs between **$34 million** and **$40 million** when compared to the optimal plans.
- Low Solar/Battery Capital Costs: Solar and battery resources, including High Noon, provide between **$858 million** and **$1,294 million** in NPV savings compared to not allowing solar or battery resources to be built prior to 2029.

Table 30 – WEPCO High Solar/Battery Capital Costs NPV Results ($Millions)

Continued Fleet Change Planning Future		Capacity Assurance "A"		Energy Assurance "E"	
		NPV	Delta	NPV	Delta
Case 25	Base run with no constraints	24,484		25,166	
Case 25 HN	Case 1 with equivalent solar/battery capacity to High Noon included, if needed	24,525	**40**	25,199	**34**
Case 26	Base run with no solar or battery available until 2029	24,568	**83**	25,166	**0**
Case 27	Base run with no solar available until 2029	24,504	**20**	25,166	**0**
Case 28	Base run with no battery available until 2029	24,484	**0**	25,166	**0**

Table 31 – WEPCO Low Solar/Battery Capital Costs NPV Results ($Millions)

Continued Fleet Change Planning Future		Capacity Assurance "A"		Energy Assurance "E"	
		NPV	Delta	NPV	Delta
Case 29	Base run with no constraints	22,825		23,914	
Case 29 HN	Case 29 with equivalent solar/battery capacity to High Noon included, if needed				
Case 30	Base run with no solar or battery available until 2029	23,683	**858**	25,207	**1,294**
Case 31	Base run with no solar available until 2029	23,187	**363**	24,274	**360**
Case 32	Base run with no battery available until 2029	23,225	**400**	24,402	**488**

WPSC Results

Resource Mix: The table below shows the results of this sensitivity under the Continued Fleet Change (Base) planning future using both the Capacity Assurance and Energy Assurance methodologies.

- High Solar/Battery Capital Costs: Battery resources are included in the optimal plans in 2027 with both Capacity and Energy Assurance resource planning when analyzed with the high capital cost assumptions. Solar resources are not selected using Capacity Assurance resource planning but are selected in 2029 using Energy Assurance resource planning.

- Low Solar/Battery Capital Costs: Solar and battery resources are included in the optimal plans in 2027 with both Capacity and Energy Assurance resource planning when analyzed with the low capital cost assumptions.

Table 32– WPSC High Solar/Battery Capital Costs Build Plan

Capacity Assurance					Energy Assurance				
Case 25A	**2027**	**2028**	**2029**	**2030**	**Case 25E**	**2027**	**2028**	**2029**	**2030**
CT					CT				
Demand Response					Demand Response				
Energy Efficiency	7	13	20	26	Energy Efficiency	7	13	20	26
RICE					RICE				
Solar					**Solar**			**135**	**135**
Wind	150	300	400	550	Wind	150	300	400	550
Battery	**150**	**150**	**150**	**150**	**Battery**	**150**	**150**	**150**	**225**
Total	307	463	570	726	Total	307	463	705	936

Table 33– WPSC Low Solar/Battery Capital Costs Build Plan

Capacity Assurance					Energy Assurance				
Case 29A	**2027**	**2028**	**2029**	**2030**	**Case 29E**	**2027**	**2028**	**2029**	**2030**
CT					CT				
Demand Response					Demand Response				
Energy Efficiency	7	13	20	20	Energy Efficiency	7	13	20	20
RICE					RICE				
Solar	**45**	**225**	**585**	**585**	**Solar**	**135**	**135**	**495**	**495**
Wind	150	300	400	550	Wind	150	300	400	550
Battery	**150**	**150**	**150**	**150**	**Battery**	**150**	**150**	**150**	**150**
Total	352	688	1,155	1,305	Total	442	598	1,065	1,215

NPV Results

- High Solar/Battery Capital Costs: Since battery resources are selected as part of the optimal plan, High Noon's economic impact is driven by the inclusion of the solar resource in 2027. When using Capacity Assurance resource planning, including solar resources equivalent to High Noon increase NPV costs **$16 million**. When using Energy Assurance resource planning, advancing solar resources equivalent to High Noon two years to 2027 increases NPV costs **$4 million.**
- Low Solar/Battery Capital Costs: Solar and battery resources, including High Noon, provide between **$174 million** and **$236 million** in NPV savings compared to not allowing solar or battery resources to be built prior to 2029.

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Table 33 – WPSC High Solar/Battery Capital Costs NPV Results ($Millions)

Continued Fleet Change Planning Future		Capacity Assurance "A"		Energy Assurance "E"	
		NPV	Delta	NPV	Delta
Case 25	Base run with no constraints	6,113		6,474	
Case 25 HN	Case 25 with equivalent solar/battery capacity to High Noon included, if needed	6,129	**16**	6,478	**4**
Case 26	Base run with no solar or battery available until 2029	6,289	**176**	6,517	**43**
Case 27	Base run with no solar available until 2029	6,113	**0**	6,474	**0**
Case 28	Base run with no battery available until 2029	6,260	**147**	6,517	**43**

Table 35 – WPSC High Solar/Battery Capital Costs NPV Results ($Millions)

Continued Fleet Change Planning Future		Capacity Assurance "A"		Energy Assurance "E"	
		NPV	Delta	NPV	Delta
Case 29	Base run with no constraints	5,991		6,257	
Case 29 HN	Case 29 with equivalent solar/battery capacity to High Noon included, if needed				
Case 30	Base run with no solar or battery available until 2029	6,227	**236**	6,431	**174**
Case 31	Base run with no solar available until 2029	6,001	**10**	6,262	**5**
Case 32	Base run with no battery available until 2029	6,226	**236**	6,431	**174**

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Wisconsin Electric New Load Sensitivities

Cases 9-12 and Cases 13-16 are two sets of sensitivities that evaluate High Noon's economic value for Wisconsin Electric under varying projections of new load in the I-94 corridor. As previously discussed, load for Wisconsin Electric is expected to grow to approximately [redacted] MW of peak capacity demand and [redacted] MWhs of energy per year by 2034, and those projections are included in the base case. [redacted] Sensitivities were performed on the level of new load by changing requirements by plus and minus 50 percent in capacity and energy.

Since these model runs are a sensitivity for only Wisconsin Electric to show High Noon continues to provide economic value across a wide range of new load possibilities, these runs were only performed in the Continued Fleet Change planning future but do include runs in both Capacity Assurance and Energy Assurance resource planning.

Resource Mix: The table below shows the results of this sensitivity under the Continued Fleet Change (Base) planning future using both the Capacity Assurance and Energy Assurance methodologies.

- High New Load: Solar and Battery resources continue to be part of the optimal plans in 2027 when utilizing Capacity and Energy Assurance resource planning when analyzed with high new load assumptions.
- Low New Load: Battery resources continue to be part of the optimal plans in 2027 when utilizing Capacity and Energy Assurance resource planning when analyzed with high new load assumptions. Solar resources also continue to be part of the optimal plan when using Capacity Assurance resource planning but are not included as part of the optimal plan when using Energy Assurance resource planning.

Table 36– WEPCO High New Load Build Plan

Capacity Assurance					Energy Assurance				
Case 9A	**2027**	**2028**	**2029**	**2030**	**Case 9E**	**2027**	**2028**	**2029**	**2030**
CC									
CT	1,422	1,659	1,659	1,659	CT	1,659	1,896	2,133	2,133
Demand Response					Demand Response				
Energy Efficiency	15	29	44	58	Energy Efficiency	15	29	44	58
RICE					RICE	129	258	258	258
Solar	**900**	**1,800**	**2,700**	**3,263**	**Solar**	**900**	**1,800**	**2,700**	**3,263**
Wind	300	600	800	1,100	Wind	300	600	800	1,100
Battery	**750**	**1,375**	**2,125**	**2,250**	**Battery**	**625**	**1,125**	**1,625**	**1,875**
Total	3,387	5,463	7,328	8,330	Total	3,627	5,708	7,559	8,686

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Table 37– WEPCO Low New Load Build Plan

Capacity Assurance					Energy Assurance				
Case 13A	**2027**	**2028**	**2029**	**2030**	**Case 13E**	**2027**	**2028**	**2029**	**2030**
CC									
CT	237	237	237	237	CT	1,185	1,659	2,133	2,133
Demand Response					Demand Response				
Energy Efficiency		15	15	29	Energy Efficiency	15	29	29	29
RICE					RICE				
Solar	**675**	**1,013**	**1,013**	**1,013**	**Solar**				
Wind	300	600	800	1,100	Wind	300	600	800	1,100
Battery	**625**	**1,250**	**1,375**	**1,625**	**Battery**	**125**	**250**	**250**	**250**
Total	1,837	3,114	3,439	4,004	Total	1,625	2,538	3,212	3,512

NPV Results:

- High New Load: Solar and battery resources, including High Noon, provide between **$236 million** and **$305 million** in NPV savings compared to not allowing solar or battery resources to be built prior to 2029.
- Low New Load: Solar and battery resources, including High Noon, provide **$91 million** in NPV savings compared to not allowing solar or battery resources to be built prior to 2029 when using Capacity Assurance resource planning. However, since battery resources are selected as part of the optimal plan when using Energy Assurance resource planning High Noon's economic impact is driven by the inclusion of the solar resource in 2027. Including solar resources equivalent to High Noon increases NPV costs **$32 million**.

Table 38 – WEPCO High New Load NPV Results ($Millions)

Continued Fleet Change Planning Future		**Capacity Assurance "A"**		**Energy Assurance "E"**	
		NPV	**Delta**	**NPV**	**Delta**
Case 9	Base run with no constraints	30,004		30,898	
Case 9 HN	Case 9 with equivalent solar/battery capacity to High Noon included, if needed				
Case 10	Base run with no solar or battery available until 2029	30,240	**236**	31,203	**305**
Case 11	Base run with no solar available until 2029	30,264	**260**	31,195	**297**
Case 12	Base run with no battery available until 2029	30,080	**76**	31,023	**124**

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Table 39 – WEPCO Low New Load NPV Results ($Millions)

Continued Fleet Change Planning Future		Capacity Assurance "A"		Energy Assurance "E"	
		NPV	Delta	NPV	Delta
Case 13	Base run with no constraints	18,508	n/a	19,364	n/a
Case 13 HN	Case 13 with equivalent solar/battery capacity to High Noon included, if needed			19,396	**32**
Case 14	Base run with no solar or battery available until 2029	18,599	**91**	19,364	**0**
Case 15	Base run with no solar available until 2029	18,533	**25**	19,368	**5**
Case 16	Base run with no battery available until 2029	18,530	**22**	19,366	**2**