



LARGE LOADS AND NATURAL GAS PRICE RISK

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TABLE OF CONTENTS

INTRODUCTION	1
MODELING ASSUMPTIONS	3
Load Forecast.....	3
Existing Resources.....	4
Resource Portfolios.....	7
Market Interchange	12
Natural Gas Price Scenarios.....	13
MODELING RESULTS	15
Generation and Market Purchases	15
Operational Costs Across Natural Gas Price Scenarios.....	16
Capital and Fixed Costs	18
CONCLUSION.....	23

INTRODUCTION

Large loads present many unique challenges to electric power systems. Primary among them is the size of these loads. In its work across multiple states, EFG sees integrated resource plans (“IRPs”) or IRP related filings with levels of load growth that will double, triple, or in some cases, quadruple electric utility’s current peak demand. Given this level of load growth and projected, high load factors of these large load customers, many utilities are seeking to build thermal resources to meet load growth. Some examples of recent utility filings that sought approval for new thermal resources to meet large load demand are outlined below:

- Evergy filed requests for two 710 MW Combined Cycle (“CC”) units¹
- Entergy filed a request for approval of 2,262 MW of new baseload generation (three CC units) to serve the anticipated load of a hyperscale data center²
- Kentucky Utilities and Louisville Gas & Electric (“KU/LG&E”) filed a request for two 645 MW CC units to meet a projection of 1,750 MW of new data center load³

As with these utilities, Wisconsin Electric Power Company (“WEPCO”)⁴ is also anticipating significant data center growth. In WEPCO’s request for approval of the 1,100 MW Oak Creek Combustion Turbines⁵ (“CT”) and 128 MW Paris⁶ (“RICE”) units, WEPCO cited “substantial additional load projected for Wisconsin Electric’s service territory”⁷ when discussing the need for the projects. In the Oak Creek CT and Paris RICE certificate of public convenience and necessity (“CPCN”) dockets, the level of new load growth projected by WEPCO was heavily redacted. However, in WEPCO Witness Arendt’s rebuttal testimony in the Oak Creek docket he hinted at the total load saying, “even if only 450 MW of demand actually materializes (i.e. approximately 20% of the forecasted new demand)...”⁸ Assuming 450 MW is 20% of the new large load forecast from WEPCO gives a total of approximately 2,250 MW of load. WEPCO Witness Stasik also submitted rebuttal testimony that referenced a report of another data center, referred to as the Cloverleaf project, and that referenced Cloverleaf requesting service for 3,000 – 3,500 MW.⁹

¹ Direct Testimony of Witness Vandeveld at 19. Docket No. 25-EKCE-207-PRE.

² Direct Testimony of Witness Beauchamp at 16. Docket No. U-37425.

³ Direct Testimony of Witness Conroy at 2-3. Case No. 2025-00045.

⁴ WEPCO is owned by WEC Energy Group (“WEC”).

⁵ Docket 6630-CE-317.

⁶ Docket 6630-CE-316.

⁷ Direct Testimony of Witness Arendt at 8. Docket 6630-CE-317.

⁸ Rebuttal Testimony of Witness Stasik at 5. Docket 6630-CE-317.

⁹ Rebuttal Testimony of Witness Stasik, Exhibit Stasik-25. Docket 6630-CE-317.

Given these large and varying levels of potential load, WEPCO is the subject of the case study in this report. Tariff setting for large loads is often focused on the major categories of cost needed to serve any load, i.e., generation, transmission, and distribution. However, relying on natural gas to meet demand from large load customers will increase natural gas cost exposure for all customer classes. In the examples outlined above, new CCs were proposed to serve large load customers. CCs, CTs, and RICE generators have tradeoffs between capital and operations and maintenance expenses. When gas thermal generators, such as CCs, CTs, or RICE units, are used to serve large load demand, this introduces additional exposure to the fluctuations inherent in natural gas prices.

Figure 1 shows the monthly Henry Hub natural gas prices going back to 2018. Looking at the historical data, the Henry Hub natural gas price has had swings from a low of \$1.49 per MMBTu to a high of \$8.81MMBTu during this time period.



Figure 1. Henry Hub Natural Gas Spot Price (\$/MMBTu)¹⁰

This illustrates that CCs, CTs, and RICE generators can face a wide range of fuel prices. And when resource portfolio build outs include those resources to meet high load factor customers, this cost exposure increases since those generators will be operating more to meet that demand. The analysis described in this report is intended to look at a spectrum of resource portfolios, ranging from one end where new CTs comprise the majority of the resource portfolio to meet large load customer growth to a portfolio that comprises solar, wind, and battery storage resources to meet large load customer growth. Those resource portfolios are then evaluated under a base, low, and high natural gas price scenario.

¹⁰ Data downloaded from United States Energy Information Administration ("EIA"). Retrieved from <https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>

MODELING ASSUMPTIONS

This analysis utilizes the EnCompass¹¹ software to perform production cost modeling on an 8,760 hourly basis for the 2030 study year. Assumptions for resource operating characteristics and costs, fuel price forecasts, and market price forecasts were derived from the Horizons National Database (“NDB”) that accompanies the EnCompass software. The following sections go into more detail on assumptions made for WEPCO’s load forecast, existing resource fleet, and the portfolio of new resources evaluated to meet the projected growth from large load customers.

LOAD FORECAST

The starting point for the 2030 WEPCO base load forecast, before consideration of any new large load customers, is derived from the Energy Information Administration (“EIA”) reported summer peak demand of 5,587 MW and energy of 24,294,027 MWh in 2023.¹² In order to extrapolate the demand and energy forecast out to 2030, the energy growth rate of 0.48% and demand growth rate of 0.60% from the Continued Fleet Change Planning Future presented by WEPCO in the Oak Creek filing were applied to the 2023 energy and peak demand values.¹³

After developing the base load forecast for 2030, two scenarios were developed to capture different assumptions around the level of new data center load growth. Scenario 1 assumes the first 450 MW phase from Microsoft in addition to an initial 1,300 MW from Vantage (the data center to be located in Port Washington), for a total of 1,750 MW. Scenario 2 assumes two phases of Microsoft for 900 MW (assuming 450 MW for each phase) and the full 3,500 MW for Vantage at the full projected load level. The 2030 peak for each of the forecasts is presented in **Table 1**.

¹¹ EnCompass is used by utilities across North America including Public Service Company of New Mexico, Xcel Energy, Minnesota Power, Otter Tail Power, Great River Energy, the Tennessee Valley Authority, DTE Electric, AES Indiana, and Duke Energy.

¹² EIA Form 861.

¹³ Volume III Appendix B – Need and Alternatives Analysis, Table 5 at 17. Docket No. 6630-CE-317.

Table 1. 2030 Summer Peak Across Scenarios (MW)

Peak Breakout	Base	Scenario 1	Scenario 2
Base	5,826	5,826	5,826
Data Center	-	1,750	4,400
Total Projected	5,826	7,576	10,226

The assumptions around the level of demand for the Microsoft¹⁴ and Vantage¹⁵ data centers are derived from news articles. For the Vantage data center, reporting from the Milwaukee Journal Sentinel said, “We Energies stated it would be able to deliver as much as 3.5 GW to fully power the proposed data center campus by 2030.”¹⁶ Without public information on the specific load factors for the data centers, an assumption of 90%¹⁷ was made and aligns with how AES Indiana modeled data center load in its most recent Integrated Resource Plan (“IRP”). A monthly shape was applied to the projected load to approximate seasonal differences based on cooling needs.

EXISTING RESOURCES

Table 2 and **Table 3** outline the existing resource fleet for WEPCO included in this modeling analysis. One important note is that the Elm Road Generating Station is assumed to have converted to natural gas by 2030. This assumption conforms with information WEPCO provided in the Oak Creek and Paris dockets.¹⁸

¹⁴ Retrieved from <https://www.cnbc.com/2025/09/18/microsoft-wisconsin-data-center.html?msockid=2e42423f0a5468fb2b1456c70b5569e7> and <https://wisconsinwatch.org/2025/05/wisconsin-utility-data-center-energy-tech-electricity-power-rates/>

¹⁵ Retrieved from <https://www.badgerinstitute.org/port-washington-data-center-on-track-to-by-far-be-states-largest-electricity-user/>

¹⁶ Retrieved from <https://www.pressreader.com/usa/milwaukee-journal-sentinel/20250521/281655375986547>

¹⁷ For its 2025 Integrated Resource Plan (“IRP”), AES Indiana assumed a 90% load factor. Retrieved from https://vault.aes.com/sites/aesvault.com/files/2025-10/AES%20Indiana_Stakeholder%20Meeting%204.pdf

¹⁸ Volume III Appendix B – Need and Alternatives Analysis at 23. Docket No. 6630-CE-317.

Table 2. WEPCO Existing Nuclear and Thermal Resources¹⁹

Resource	Nameplate (MW)
Nuclear:	
Point Beach ²⁰	1,030
Combined Cycle:	
Port Washington	1,150
West Riverside ²¹	200
Whitewater ²²	137
ST Gas:	
Elm Road 1	634
Elm Road 2	634
Valley Power Plant #1	136
Valley Power Plant #2	136
Combustion Turbines:	
Concord 1-4	400
Germantown 1-4	282
Paris 1-4	400
Oak Creek	1,185
RICE:	
Weston ²³	66
Paris	129

¹⁹ Resources without a specific footnote cite were retrieved from <https://www.wec-energies.com/company/generation-facilities>

²⁰ Wisconsin Electric Power Company Form 10-K at 14. Retrieved from https://www.wecenergygroup.com/invest/pdf_k_rpts/10K_2013_WE.pdf

²¹ WEC Energy 2024 Annual Report at F-64. Retrieved from <https://www.wecenergygroup.com/invest/annualreports/wec2024-annual-report.pdf>

²² Capacity reported by S&L.

²³ S&L data.

Table 3. WEPCO Existing Renewable, Battery Storage, and Demand Response Resources

Resource	Nameplate (MW)
Hydro	94.8
Biomass	50
Wind:	
Blue Sky	145
Glacier Hills	162
Montfort Energy Center	30
Solar:	
Badger Hollow II ²⁴	100
Paris ²⁵	150
High Noon ²⁶	225
Darien ²⁷	187.5
Koshkonong ²⁸	225
Solar Now ²⁹	35
DRER Solar ³⁰	99.15
Renewable Pathway ³¹	59
Storage:	
Paris ³²	82.5
High Noon ³³	123.75
Darien ³⁴	56.25
Koshkonong ³⁵	123.75
Demand Response³⁶	121.10

²⁴ WEC Energy 2024 Annual Report at F-73. Retrieved from <https://www.wecenergygroup.com/invest/annualreports/wec2024-annual-report.pdf>

²⁵ Docket 5-BS-254. Retrieved from <https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=404941>

²⁶ Docket 5-BS-276. Retrieved from <https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=490361>

²⁷ Docket 5-BS-XXX. Retrieved from <https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=406910>

²⁸ Docket 5-BS-258. Retrieved from <https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=410709>

²⁹ WEC Energy 2024 Annual Report at F-11. Retrieved from <https://www.wecenergygroup.com/invest/annualreports/wec2024-annual-report.pdf>

³⁰ Calculation based on 35 MW reported in WEC Energy 2024 Annual Report at F-11 and reported solar from S&L at 64.15 MW.

³¹ WEC Energy 2024 Annual Report at F-11. Retrieved from <https://www.wecenergygroup.com/invest/annualreports/wec2024-annual-report.pdf>

³² Docket 5-BS-254. Retrieved from <https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=404941>

RESOURCE PORTFOLIOS

MISO Direct Loss Of Load (“DLOL”) Construct

On August 31, 2022, the Federal Energy Regulatory Commission (“FERC”) approved MISO’s petition for changes to its resource adequacy construct and accreditation methodology. Those changes now require Load Serving Entities (“LSEs”) to satisfy a planning reserve margin requirement (“PRMR”) in each season.³⁷ MISO also implemented changes to the accreditation of thermal and renewable resources such that their accreditation would vary from season to season. Under this seasonal construct, MISO has developed resource accreditation and planning reserve margin (“PRM”) assumptions under the DLOL approach, which will go into effect for the MISO Planning Year 2028/2029. At this time, MISO has released indicative resource accreditation and seasonal PRMs, which are outlined in **Table 4**.

³³ Docket 5-BS-276. Retrieved from <https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=490361>

³⁴ Docket 5-BS-XXX. Retrieved from <https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=406910>

³⁵ Docket 5-BS-258. Retrieved from <https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=410709>

³⁶ EIA Form 861 reported peak demand savings for 2023. Retrieved from <https://www.eia.gov/electricity/data/eia861/>

³⁷ Summer is June through August; Fall is September through November; Winter is December through February; and Spring is March through May.

Table 4. MISO Indicative Resource Class-level DLOL (%)³⁸

PRM	Summer	Fall	Winter	Spring
PRM	2.3%	6%	5.6%	1%
Resource	Summer	Fall	Winter	Spring
Biomass	52%	47%	51%	49%
Dual Fuel Oil/Gas	87%	84%	79%	77%
Gas	88%	85%	64%	68%
Combined Cycle	95%	92%	77%	78%
Nuclear	94%	91%	90%	81%
Oil	77%	75%	74%	73%
Reservoir Hydro	89%	82%	76%	70%
Solar	45%	28%	19%	28%
Wind	8%	15%	23%	15%
Storage	61%	88%	85%	90%

These indicative PRM and resource accreditation values were applied for this analysis. While there is some uncertainty with what the PRM and resource accreditation might be for 2030, this analysis relies on these MISO indicative values to determine the accreditation for WEPCO's existing resource fleet and the accreditation for new resources contemplated to meet the projected load from large load customers. Since the portfolios were designed under the assumptions shown in **Table 4** for the 2030 study year, there is no consideration for future declines in accreditation values for resource technologies.

Portfolio Design

Four different resource portfolios were developed to evaluate differences in natural gas fuel price exposure depending on the resource mix. The level of new resources outlined in the WEC Capital Plan are the starting point for all portfolios and is given in **Table 5**.

³⁸ Retrieved from <https://cdn.misoenergy.org/PY%2025-26%20Indicative%20DLOL%20Results657893.pdf>

Table 5. WEC Capital Plan³⁹

Resources	MW
CT	675
RICE	114
Solar	2,900
Wind	900
Battery Storage	565

Table 6 shows the comparison of new resources across the four portfolios evaluated for this analysis. It is important to note that the level of new resources included across three new scenarios which represent new resources that are incremental to the level of resources from WEC's Capital Plan (as reflected in Capital Plan new resources). The design of the portfolios was not developed from capacity expansion modeling. Instead, the aim of this analysis is to test the impact of resource portfolio extremes, representing an all new thermal portfolio or a portfolio with only renewables and storage resources. The level of incremental new builds was determined through an evaluation of what level of resources would be needed to meet the seasonal PRM based on the indicative MISO DLOL accreditation and PRM discussed above.

Table 6. Comparison of New Resources Across Portfolios (MW)

Demand (MW)	7,576	10,226	10,226	10,226
Portfolio Name	Capital Plan	Thermal Only	Combination	Renewable and Storage
Resource				
CT	711	5,451	3,045	711
RICE	114	114	114	114
Solar	2,900	2,900	3,625	3,400
Wind	900	900	1,800	3,000
Storage	565	565	1,554	3,100

³⁹ WEC Energy 2024 Annual Report at F-10. Retrieved from <https://www.wecenergygroup.com/invest/annualreports/wec2024-annual-report.pdf>

Capital Plan

Table 7 shows the capacity position of the Capital Plan under the assumption of Load Scenario 1, or 1,750 MW of data center load materializes by 2030. Under the MISO DLOL indicative resource accreditation and projected PRM, the level of resources included in WEC's Capital Plan would be enough to meet the PRM across the four seasons. However, if more than 1,750 MW of large loads were added, then additional resources will be needed since this portfolio just meets the MISO summer PRM of 2.3%.

Table 7. Capital Plan Capacity Position

	Winter	Spring	Summer	Fall
Peak Demand	6,331	6,246	7,576	7,083
Existing Resources	5,029	5,091	6,019	5,798
Surplus/(Deficit)	-1,302	-1,155	-1,557	-1,285
Reserve Margin	-21%	-18%	-21%	-18%
New Resources	1,766	1,743	1,733	1,743
Surplus/(Deficit)	464	588	176	458
Reserve Margin	7.33%	9.41%	2.32%	6.46%

Thermal Only Portfolio

Table 8 shows the capacity position of Thermal Only under the assumption of Load Scenario 2, or 4,440 MW of data center load materializing by 2030. Since WEC's capital plan would leave a deficit of capacity, in this portfolio, sufficient CT capacity of 4,740 MW is added to meet WEPCO's likely PRMR obligation.

Table 8. Thermal Only Capacity Position (MW)

	Winter	Spring	Summer	Fall
Peak Demand	8,754	8,841	10,226	9,644
Existing Resources	5,029	5,091	6,019	5,798
Surplus/(Deficit)	-3,725	-3,750	-4,207	-3,846
Reserve Margin	-43%	-42%	-41%	-40%
New Resources	4,800	4,559	4,485	4,559
Surplus/(Deficit)	1,075	809	278	713
Reserve Margin	12.28%	9.15%	2.72%	7.39%

Combination Portfolio

Table 9 shows the capacity position of the Combination portfolio under the assumption of Load Scenario 2, or 4,440 MW of data center load materializes by 2030. Under the MISO DLOL indicative resource accreditation and projected PRM, the level of resources included in WEC's Capital Plan would leave WEPCO with a significant capacity deficit. In order to meet the seasonal PRMRs, 2,334 MW of CTs, 725 MW of solar, 900 MW of wind, and 989 MW of storage (incremental to the WEC Capital Plan) would be needed to fill the deficit. The level of CT additions was approximated from the level of CT resources in Wisconsin that have submitted for interconnection study in MISO's Expedited Resource Addition Study ("ERAS").⁴⁰

Table 9. Combination Capacity Position (MW)

	Winter	Spring	Summer	Fall
Peak Demand	8,754	8,841	10,226	9,644
Existing Resources	5,029	5,091	6,019	7,559
Surplus/(Deficit)	-3,725	-3,750	-4,207	-2,085
Reserve Margin	-43%	-42%	-41%	-22%
New Resources	4,678	4,536	4,495	3,551
Surplus/(Deficit)	953	786	288	1,465
Reserve Margin	10.89%	8.89%	2.81%	15.19%

⁴⁰ Retrieved from

<https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fcdn.misoenergy.org%2FERRAS%2520Interconnection%2520Requests718482.xlsx%3Fv%3D20250925100619&wdOrigin=BROWSELINK>

Renewable Only Portfolio

Table 10 shows the capacity position of Renewable Only under the assumption of Load Scenario 2, or 4,440 MW of data center load materializes by 2030. Under the MISO DLOL indicative resource accreditation and projected PRM, the level of resources included in WEC's Capital Plan would leave WEPCO with a significant capacity deficit. In order to meet the seasonal PRMs, this portfolio was designed to fill the deficit from only renewables and storage resources. Without any new thermal resources above what has been proposed in WEC's Capital Plan, 500 MW of solar, 2,100 MW of wind, and 2,535 MW of storage (incremental to the WEC Capital Plan) would be needed to fill the deficit.

Table 10. Renewable Only Capacity Position (MW)

	Winter	Spring	Summer	Fall
Peak Demand	8,754	8,841	10,226	9,644
Existing Resources	5,029	5,091	6,019	5,798
Surplus/(Deficit)	-3,725	-3,750	-4,207	-3,846
Reserve Margin	-43%	-42%	-41%	-40%
New Resources	4,499	4,466	4,457	4,466
Surplus/(Deficit)	774	716	250	621
Reserve Margin	8.85%	8.10%	2.44%	6.44%

MARKET INTERCHANGE

In the modeling WEPCO performed for the Oak Creek CT and Paris Applications, WEPCO evaluated portfolios under two different assumptions for market access. The first approach WEPCO refers to as that are referred to as Capacity Assurance and the second approach is referred to as Energy Assurance. Under the Capacity Assurance approach, WEPCO can exchange power with the MISO market, however, that interaction is limited to 800 MW in any given hour.⁴¹ Under the Energy Assurance modeling, WEPCO's assumption is that by 2026, there is no access to the MISO market either for the purposes of purchasing or selling energy.⁴² While this analysis does not endorse either the Capacity Assurance or Energy Assurance approach, in order to reflect the real world operations of WEPCO as a market participant in MISO, WEPCO's hourly import/export assumption of 800 MW is assumed in the model.

⁴¹ Direct Testimony of Citizens Utility Board Witness Burgess at 26. Docket No. 6630-CE-317.

⁴² Volume III Appendix B – Need and Alternatives Analysis at 16. Docket No. 6630-CE-317.

NATURAL GAS PRICE SCENARIOS

Natural Gas Price

The selection of high and low natural gas prices to model was made by evaluating historical Henry Hub price data between 2018 and 2024. **Table 11** shows the average annual Henry Hub price across these years. On average, 2020 was the lowest price year at \$2.02/MMBtu, and 2022 was the highest price year at \$6.38/MMBtu. These years became the basis for the low and high natural gas price scenarios for this analysis.

Table 11. Average Henry Hub Between 2018 and 2024 (\$/MMBtu)

Year	Average
2018	\$3.16
2019	\$2.56
2020	\$2.02
2021	\$3.84
2022	\$6.38
2023	\$2.53
2024	\$2.24

When inflation is applied to the 2020 and 2022 Henry Hub prices to bring them forward to our 2030 study year, the result is an average Henry Hub price of \$2.56/MMBtu and an average Henry Hub price of \$7.82/MMBtu for the high scenario. In comparison, our base case average Henry Hub price is \$3.34/MMBtu. The NDB assumption for the Chicago Citygate basis differential was applied to each scenario to estimate delivered fuel costs to WEPCO.

Market Price for Natural Gas Scenarios

Because natural gas is frequently the marginal fuel in MISO, a change in gas pricing results in a change in hourly market prices. A time series regression analysis was developed by Component Reliability Consultants, LLC, which incorporates independent variables for the prior day's market price, the daily Henry Hub price, and the MISO load. The hourly MISO market price under the base case natural gas price scenario was then modified using the information from this time series regression analysis to develop a corresponding hourly MISO market price to model for the high and low natural gas price scenarios. **Figure 2** shows a comparison of the MISO market price forecasts across the natural gas price scenarios.

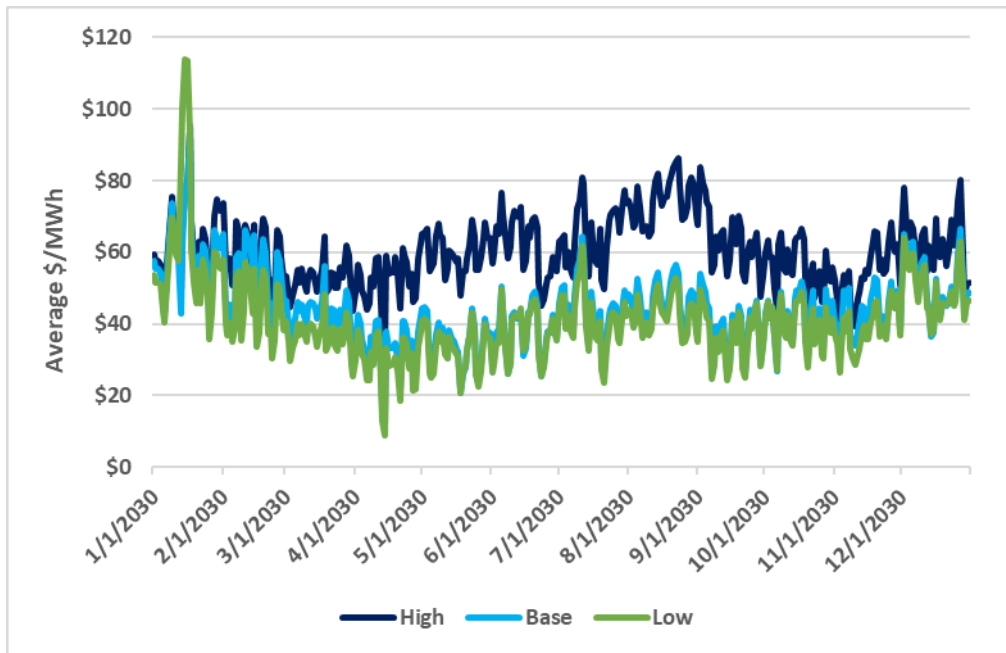


Figure 2. Comparison of MISO Market Prices (Average \$/MWh)

MODELING RESULTS

GENERATION AND MARKET PURCHASES

Table 12 shows a comparison of the generation mix across the Thermal Only, Combination, and Renewable Only. The following sections will focus on these three portfolios since they all contain the same load forecast assumption. The generation mix shown in **Table 12** is broken into three categories. Thermal represents the natural gas and oil-fired generating units. Renewables includes generation from nuclear, hydro, biomass, wind, and solar resources. Market purchases represent the level of imports from the MISO market representation in the model.

Table 12. 2030 Generation Comparison Across Portfolios (% of Generation)

	Thermal Only	Combined	Renewable Only
Thermal	67%	60%	49%
Renewables	31%	38%	45%
Market Purchase	2%	3%	6%

With Thermal Only reflecting the WEC capital plan and new CT resources to meet large load growth, it has the highest level of generation from thermal resources and the lowest generation from renewable resources. On the other hand, Renewables Only has the lowest generation from thermal resources and highest generation from renewable resources. One important distinction to make for this portfolio is that the portfolios were not optimized in a capacity expansion model, but were designed to give radically different portfolio mixes while still meeting WEPCO's seasonal PRMR. As a result, the portfolios were designed to meet capacity requirements.

The results of the modeling indicate that across the resource portfolios, the new CTs operate at high levels. This modeling did not assume any operational limits on the thermal resources, such as constraints on the capacity factor. This was done to see the level at which the model would dispatch those resources. Under the base case natural gas price, the capacity factor for the new CTs ranged from approximately 55% under Capital Plan to approximately 74% under Renewables Only. While Renewables Only has a lower level of thermal generation, there is an important takeaway about the level of operation from the thermal resources included in the portfolio. In addition to high operational levels for the new CTs, reliance on existing generators also increased. For example, under Renewables Only, the converted Elm Road units had a capacity factor of 53%.

The level of generation needed to meet the level of large load evaluated in Thermal Only, Combination, and Renewable Only may change the nature of costs faced by customers by either increasing the reliance of thermal generation or market purchases needed to meet the additional load. When the portfolio of resources consists almost entirely of renewable and storage resources, the overall level of thermal generation is lower, but there is increased operation from existing thermal resources, in addition to a higher level of market purchases needed. On the other hand, the portfolio that consists almost entirely of new CT resources increases the reliance on natural gas, and therefore, the price exposure to fluctuations in natural gas prices.

OPERATIONAL COSTS ACROSS NATURAL GAS PRICE SCENARIOS

In evaluating the results of the different portfolios across the three natural gas price scenarios, there are several metrics that are important to consider. The first is the level of market interaction. **Table 13** shows the level of market interaction for purchases and sales, as a percentage of the annual energy requirements in 2030. On the basis of comparing resource portfolios, it is important to note that the Capital Plan has a different load assumption than Thermal Only, Combination, and Renewable Only so the Capital Plan cannot be directly compared as a result.

Renewable Only, or the only renewables and battery storage portfolio, has a higher level of purchases and a lower level of sales compared to the other resource portfolios under the base natural gas price scenario. One important distinction to make for this portfolio is that the portfolios were not optimized in a capacity expansion model, but were designed to give radically different portfolio mixes while still meeting WEPCO's seasonal PRMR. The second takeaway when comparing across the natural gas price scenarios is that sales typically increase under the low natural gas price scenario and decrease under the high natural gas price scenario. As can be seen across the portfolios, the level of market purchases increases when looking from the base to the high natural gas price scenario. This means that over the hours simulated for 2030, the model leans on market purchase over the existing and new thermal fleet under higher natural gas prices.

Table 13. 2030 Market Interaction Across Natural Gas Price Scenarios (% of Annual Energy)

	Low	Base	High
	% of Purchases		
Capital Plan	1%	2%	14%
Thermal Only	1%	3%	10%
Combined	1%	3%	11%
Renewable Only	3%	6%	11%
	% of Sales		
Capital Plan	16%	13%	2%
Thermal Only	10%	8%	1%
Combined	10%	8%	1%
Renewable Only	7%	3%	0.26%

The other metrics to consider in addition to the market interaction are the total operational costs, which include fuel, variable operations and maintenance (“VOM”), and the net market cost. For the net market cost calculation, a negative value represents a reduction in cost from the portfolio having more sales revenue than costs for market purchases, and a positive value represents a cost since the purchase cost was higher than the sales revenue. **Table 14** presents these cost categories for each portfolio across the three natural gas price scenarios.

Table 14. 2030 Fuel, VOM, and Net Market Costs Across Natural Gas Price Scenarios (\$000)

Portfolio	Low	Base	High
	Fuel		
Thermal Only	\$1,110,706	\$1,396,371	\$2,476,187
Combined	\$1,007,569	\$1,247,583	\$2,127,100
Renewable Only	\$855,995	\$989,267	\$1,880,505
	VOM		
Thermal Only	\$317,499	\$306,361	\$253,865
Combined	\$298,600	\$283,435	\$226,293
Renewable Only	\$290,007	\$248,593	\$213,723
	Net Market		
Thermal Only	(\$146,664)	(\$134,942)	\$517,987
Combined	(\$160,774)	(\$129,591)	\$530,262
Renewable Only	(\$60,661)	\$82,503	\$595,155
	Total Operational		
Thermal Only	\$1,281,540	\$1,567,790	\$3,248,039
Combined	\$1,145,396	\$1,401,427	\$2,883,654
Renewable Only	\$1,085,342	\$1,320,364	\$2,689,383

The costs reported in **Table 14** reflect the cost tradeoffs that exist in resource portfolios that comprise different levels of new CTs, renewables, and battery storage resources. That level of cost risk is higher for Thermal Only (all new CTs) when compared to the Combination portfolio (combination of CTs, renewables, and storage), and Renewable Only (renewables

and storage) across all three natural gas price scenarios. **Table 15** shows that cost difference across all three natural gas price scenarios, which ranges from approximately \$136 million dollars to \$364 million for Combination, to \$196 million dollars to approximately \$559 million dollars when comparing to Renewables Only. This cost represents the operational cost exposure, primarily driven by natural gas prices, for portfolios with higher levels of CTs included to meet large load growth.

Table 15. Cost / (Savings) Comparison (\$000)

	Low	Base	High
Combined relative to Thermal Only	(\$136,145)	(\$166,363)	(\$364,385)
Renewable Only relative to Thermal Only	(\$196,199)	(\$247,427)	(\$558,656)

CAPITAL AND FIXED COSTS

The analysis presented so far has focused on the exposure to fuel, VOM, and net market costs to compare the resource portfolios. In order to capture the additional costs for resources, including capital and fixed costs, a levelized cost calculation was determined for Thermal Only, Combination, and Renewable Only. **Table 16** shows the assumptions for the levelization, which include the capital, investment tax credit ("ITC"), WEPCO discount rate, resource life, and capital recovery factor ("CRF"). The assumptions for fixed costs include fixed operations and maintenance ("FOM") and for thermal resources, this also includes representative costs for access to a firm natural gas supply. For this analysis, a firm gas rate was based on an equivalent cost for liquefied natural gas ("LNG").⁴³ The Oak Creek LNG facility project costs were estimated at \$456,300,000 with 300,000 Dth/day capacity.⁴⁴ Under this cost and Dth/day assumption, the estimated firm gas cost is \$29.57/kW.⁴⁵

⁴³This approach is in line with what WEPCO assumed in Volume III Appendix B – Need and Alternatives Analysis at 24. Docket No. 6630-CE-317.

⁴⁴ WEPCO Application at 1-10 for the project cost and WEPCO Application, Table 2-2 at 2-2 for the Oak Creek LNG Dth/day. Docket 6630-CG-140.

⁴⁵ The levelized cost for the LNG facility is approximately .35 \$/Dth/day. The \$/kW-year calculation assumes a maximum capacity of 237 MW and a heat rate of 9,900 for the CT resource.

Table 16. Assumptions for Capital and Fixed Costs

	Solar	Wind	Storage	CT
Capital Cost ⁴⁶ (\$/kW)	\$1,902	\$2,238	\$2,043	\$1,901
ITC	30%	30%	30%	-
Capital Cost with ITC (\$/kW)	\$1,331	\$1,567	\$1,430	\$1,901
WEPCO Discount Rate ⁴⁷	7.54%	7.54%	7.54%	7.54%
Life	30	30	20	30
CRF	8.50%	8.50%	9.84%	8.50%
FOM (\$/kW-Year)	\$17	\$36	\$25	\$6.90
Firm Gas	-	-	-	\$29.57

⁴⁶ Capital costs and FOM are from Kentucky Utilities and Louisville Gas and Electric ("KU/LG&E") 2024 Integrated Resource Plan and 2025 CPCN Case No. 2025-00045.

⁴⁷ Volume III Appendix B – Need and Alternatives Analysis at 18. Docket No. 6630-CE-317.

These inputs were then applied to the level of new resources contained in Thermal Only, Combination, and Renewable Only. The breakdown of the capital and fixed costs is shown in **Table 17**. One important note about the Thermal Only portfolio is that the capital assumptions are based on an assumption of only CTs being built to meet the new data center load. Combined cycles were not considered for this portfolio since there have not been any announced plans by WEPCO to pursue those resources. **Table 18** presents the capital and fixed cost assumptions for the portfolios if the ITC is not assumed for solar and wind resources.

Table 17. Levelized Capital and Fixed Costs for Portfolios

	Thermal Only	Combined	Renewable Only
	Capital		
CT	\$880,811,902	\$497,850,206	\$114,888,509
Solar	\$328,194,596	\$410,243,245	\$384,779,871
Wind	\$119,846,542	\$239,693,084	\$399,488,473
Storage	\$79,480,936	\$253,213,602	\$436,090,092
Total Capital	\$1,408,333,976	\$1,401,000,136	\$1,335,246,945
	Fixed Cost		
CT	\$198,803,761	\$112,367,343	\$25,930,925
Solar	\$49,300,000	\$61,625,000	\$57,800,000
Wind	\$32,400,000	\$64,800,000	\$108,000,000
Storage	\$14,125,000	\$45,000,000	\$77,500,000
Total Fixed	\$294,628,761	\$283,792,343	\$269,230,925
	Capital + Fixed Cost		
CT	\$1,079,615,663	\$610,217,549	\$140,819,434
Solar	\$377,494,596	\$471,868,245	\$442,579,871
Wind	\$152,246,542	\$304,493,084	\$507,488,473
Storage	\$93,605,936	\$298,213,602	\$513,590,092
Total Capital + Fixed	\$1,702,962,737	\$1,684,792,479	\$1,604,477,871

Table 18. Levelized Capital and Fixed Costs for Portfolios – No ITC

	Thermal Only	Combined	Renewable Only
	Capital		
CT	\$880,811,902	\$497,850,206	\$114,888,509
Solar	\$468,849,423	\$586,061,779	\$549,685,531
Wind	\$171,209,346	\$342,418,691	\$570,697,819
Storage	\$79,480,936	\$253,213,602	\$436,090,092
Total Capital	\$1,600,351,607	\$1,679,544,277	\$1,671,361,950
	Fixed Cost		
CT	\$198,803,761	\$112,367,343	\$25,930,925
Solar	\$49,300,000	\$61,625,000	\$57,800,000
Wind	\$32,400,000	\$64,800,000	\$108,000,000
Storage	\$14,125,000	\$45,000,000	\$77,500,000
Total Fixed	\$294,628,761	\$283,792,343	\$269,230,925
	Capital + Fixed Cost		
CT	\$1,079,615,663	\$610,217,549	\$140,819,434
Solar	\$518,149,423	\$647,686,779	\$607,485,531
Wind	\$203,609,346	\$407,218,691	\$678,697,819
Storage	\$93,605,936	\$298,213,602	\$513,590,092
Total Capital + Fixed	\$1,894,980,368	\$1,963,336,621	\$1,940,592,875

Under these cost assumptions, Renewables Only shows a reduction in capital and fixed costs of approximately \$98 million when compared to Thermal Only when an ITC is assumed for the solar and wind resources included across each portfolio. Under the assumption of solar and wind not being able to receive the ITC, the levelized capital cost and fixed costs are approximately \$46 million higher in Renewables Only when compared to the Thermal Only portfolio. The capital and fixed costs difference for the Combined and Renewable Only portfolios compared to the Thermal Only portfolio are shown in **Table 19**.

Table 19. Capital and Fixed Cost Comparison to Thermal Only

	Combined	Renewable Only
Difference with ITC	(\$18,170,258)	(\$98,484,867)
Difference Without ITC	\$68,356,253	\$45,612,507

Since we do not have specific information unique to Wisconsin for new projects, it is unclear what level of solar and wind projects would be able to secure the ITC before the expiration. However, even if there is no consideration for solar and wind to qualify for the ITC, the capital and fixed cost increase for Renewables Only is less than the cost risk difference presented in **Table 15**.

Table 20 provides a comparison of the operational and capital costs for the 2030 study year for the three portfolios across the three natural gas price scenarios. The costs are presented on a total basis and as an average cost of serving the load in the scenarios. It is important to note that this calculation is not based on total cost of service, but the incremental costs across the portfolios.

Table 20. Operating, Capital, and Fixed Costs Across Natural Gas Price Scenarios

	Low	Base	High
	Operational + Capital + Fixed Cost		
Thermal Only	\$2,984,502,924	\$3,270,753,025	\$4,951,001,803
Combined	\$2,830,188,057	\$3,086,219,468	\$4,568,446,722
Renewable Only	\$2,689,819,390	\$2,924,841,622	\$4,293,860,704
	Total Cost (\$/MWh)		
Thermal Only	\$48.36	\$53.00	\$80.23
Combined	\$45.86	\$50.01	\$74.03
Renewable Only	\$43.59	\$47.39	\$69.58

CONCLUSION

When gas thermal generators, such as CCs, CTs, or RICE units, are used to serve large load demand, this introduces additional exposure to the fluctuations inherent in natural gas prices. Given the level of reported potential data center load for WEPCO, the WEPCO system was evaluated under alternative resource portfolios consisting of different levels of new thermal, renewable, and storage builds. These portfolios were designed to capture both extremes, ranging from a portfolio that consists almost entirely of new CT resources to meet the large load, and another portfolio that consists almost entirely of renewable and battery storage resources to meet the large load. Comparing the operational costs of these two portfolios under a base, low, and high natural gas price assumption indicates that a portfolio that relies almost entirely on new thermal resources to meet the large load growth has higher operational costs, driven primarily by the fuel costs. Tariff setting for large loads is often focused on the major categories of cost needed to serve any load, i.e., generation, transmission, and distribution. However, relying on natural gas to meet demand from large load customers will increase natural gas cost exposure for all customer classes.