APPENDIX K: DETAILED ANALYSIS SECTION

This Appendix contains the support and approach for the analysis discussed in Section V of Minnesota Power's 2025-2039 Integrated Resource Plan ("2025 IRP"). The Appendix is organized in the following sections:

- Part A: New Generation Alternatives Cost Overview;
- Part B: Base Seasonal Capacity Positions;
- Part C: Summary of Capacity Expansion Analysis Results (Steps 1-3);
- Part D: Minnesota Power Reliability Criteria Evaluation;
- Part E: 2025 Plan Sensitivity Analysis;
- Part F: Detailed Comparison of Plan Cost;
- Part G: Load and Capability Tables for Base Plan and Growth Plan; and
- Part H: Steps 1-2 Capacity Expansion Analysis Result Figures.

A. New Generation Alternatives Cost Overview

This section explains how Minnesota Power (or the "Company") selected and reviewed demand and supply side alternatives for inclusion in the expansion plan modeling using the EnCompass Power Planning Software ("EnCompass"). In prior integrated resource plans, Minnesota Power limited the number of alternatives to evaluate simultaneously in the Capacity Expansion Analysis due to limitations with EnCompass. For the 2025 IRP, Minnesota Power expanded the number of new and emerging generation resources in addition to mature technologies to include in the Capacity Expansion Analysis. For this IRP, the Company increased the computing capabilities along with optimizing the modeling approach so that more supply and demand side alternatives could be evaluated in the Capacity Expansion Analysis.

Consistent with Minnesota Power's *Energy**Forward*** strategy, only carbon-minimizing or carbon-free energy resources were considered as viable power generation alternatives. These supply side and demand side resource options include renewable resources, energy efficiency, energy storage technologies, hydrogen capable natural gas-fired technologies, advanced nuclear, enhanced geothermal, and carbon dioxide ("CO_2") sequestration technology combined with mature coal-fired or natural gas-fired technologies.

The power supply alternatives Minnesota Power considered represent a diverse range of generation technologies including traditional baseload, intermediate, and peaking options, as well as renewable generation and energy storage. To compare technologies with similar operational characteristics through a review process, the alternatives were organized into three primary generation categories – Baseload/Intermediate, Peaking, and Renewable/Storage. This review process helps Minnesota Power gain insight into the type of resources expected to be selected in the Capacity Expansion Analysis based on their cost curves and operational characteristics.

Intermittent renewable resources like solar and wind are typically must-take energy, meaning when the wind is blowing or the sun is shining, this energy is used to reduce the dispatch of resources such as coal and natural gas by decreasing their generation to allow more renewables on the system. Renewable technologies, because they are largely intermittent, can vary in their capabilities and cannot be called upon when needed, except with the integration of energy storage. Battery (energy) storage technologies have unique characteristics that closely resemble those of peaking resources with some exceptions. Energy storage technologies must be charged prior to being called upon and charging times differ between energy storage technologies. Furthermore, as Minnesota Power expands its renewable portfolio to meet the Carbon-Free Standard ("CFS"), there will be several hours of excess renewables that could be used to charge storage. A storage portfolio can be used to reduce the potential for renewable curtailments and increase the availability of renewable resources, therefore better optimizing renewables to meet the CFS. These characteristics make storage resources appear similar to peaking resources, although compared to gas dispatchable generation there are operational limitations such as duration and frequency of dispatch, lower capacity factors due needing time to charge, and increased energy losses or degradation of energy stored.

Typically, a baseload generation resource is used to supply energy to customer load that is more constant in its profile (such customer demand is commonly referred to as "high load factor" or "base load"). Because a constant supply of generation is needed, energy production with a low variable cost is a general trademark of a baseload generation resource, such as coal or advanced nuclear generation. A baseload generation resource produces electricity seven days a week, 24 hours a day, to meet the base requirements and provide system reliability. Baseload generation resources typically are designed for a capacity factor between 50 to 80 percent.

As load requirements increase and growing renewable production varies throughout a typical day, intermediate generation resources are becoming more relied upon to supply load requirements, especially as baseload capable generation is retired. In addition to energy production with a moderate variable cost, intermediate generation resources, such as a combined cycle ("CC") unit, are characterized by their flexibility to dispatch around renewable generation. The typical operation for an intermediate generation resource is to produce energy over the course of 10 to 16 peak energy demand hours during the day and up to the entire day depending on renewable production, as shown in Figure 1. With the recent trend in lower natural gas prices and coal retirements, intermediate generation has operated more like a baseload type resource for short periods of time. Like baseload generation resources, intermediate generation resources typically are designed for a high-capacity factor between 30 to 65 percent.

During peak load hours when all baseload and intermediate generating capacity is already producing energy for customers, peaking generation resources and demand response are used to fulfill the remaining power supply requirements. Peaking generation, such as a combustion turbine or reciprocating internal combustion engines ("RICE"), are typically characterized by very flexible operations with high variable costs. The typical operation for a peaking generation resource is to produce energy for short periods of time ranging from 1 to 8 hours, as shown in Figure 1. Demand response can also offset a portion of the peaking energy requirements, providing a carbon-free resource to reduce customer demand during peak demand periods. Peaking generation resources typically are designed for a capacity factor between 5 and 25 percent.

Demand response resources, like central air conditioning ("CAC"), electric hot water heater ("HW") peak-shaving programs or industrial demand response with curtailable hours for economic (i.e., Minnesota Power's proposed Enhanced Demand Response modeled as an alternative in the IRP), are only effective when that demand is present. CAC is only effective at reducing peak load during the summer months because utilization of air conditioning units is effectively zero during the winter months in northern Minnesota. HW peak-shaving programs can only be used in conjunction with electric hot water heaters, which limits the potential base of customers because households with natural gas hot water heating are unable to participate. Demand timing for most residential hot water systems is not often correlated to peak hours and so the effectiveness of HW programs at reducing peak demand is diminished. A benefit to industrial demand response is that it is typically available during all seasons and is effective at reducing a large volume during a peak, high market price periods, or emergency event. CAC and HW peak-shaving programs have characteristics that make them similar to peaking resources but are only available when the devices controlled are in demand due to weather or typical usage patterns.

Minnesota Power notes with the increase in renewables that are expected to continue as Minnesota utilities make progress to comply with the CFS, the role traditional generation resources had typically provided in the past will continue to evolve. For example, with Minnesota Power moving Boswell Energy Center ("BEC") Unit 3 ("BEC3") to economic dispatch operations, its energy characteristics will mimic those of a CC generation unit. Coal generation is not as flexible as CC generation — the technology limits its ability to turn on and off for a day, but it is capable of running for a couple of days and coming offline during periods of low demand or high renewable production. It is evident to Minnesota Power that having a flexible and dispatchable portfolio will be important to complement a growing renewable portfolio as new technologies develop and advance.

Figure 1 below shows a load curve for a representative day (24 hours) and how different types of generation resources are generally dispatched to meet load requirements and to balance intermittent renewable generation.

Figure 1. Representative Load Generation Curve

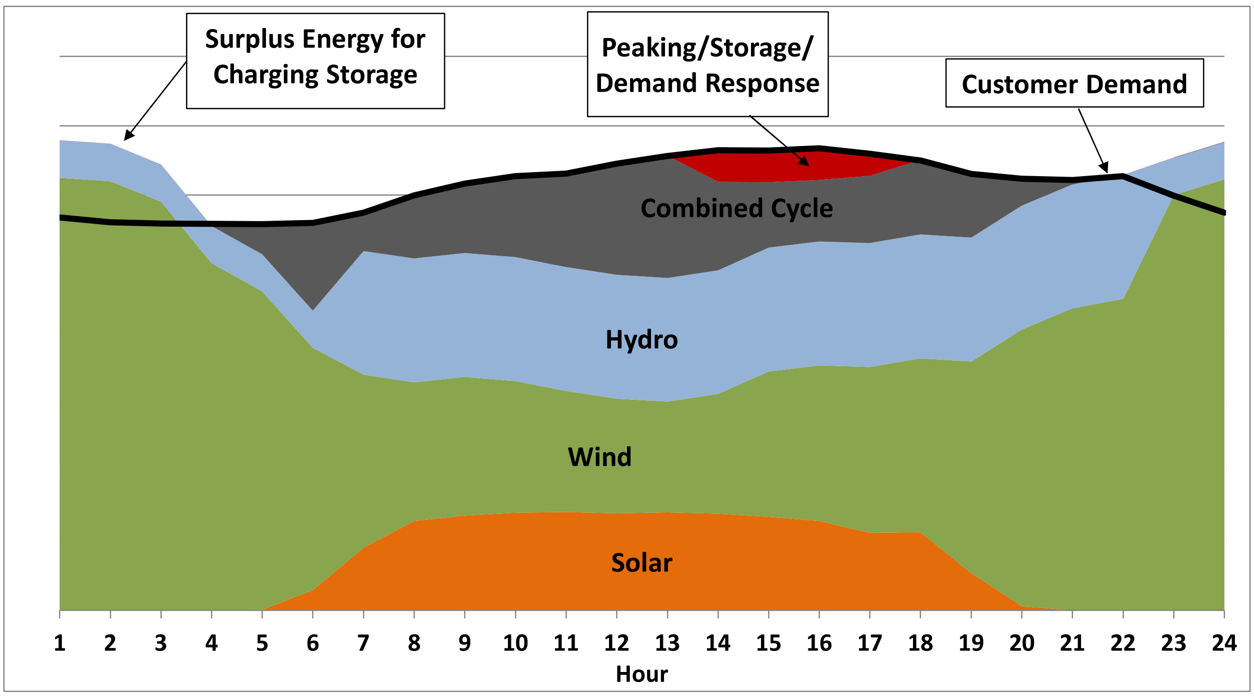


Table 1 below contains the set of resource technologies that were evaluated during the Capacity Expansion Analysis (Steps 1 to 4) in EnCompass. Note that for Step 4, the Emerging Technologies Analysis, only carbon free or carbon minimizing (e.g., carbon capture), were included in the analysis. Technologies were grouped by different operational characteristics and a range of sizes were included so that the model could best fit resource capability with need. For example, in the peaking category, the model could select from technologies that are 100 megawatts ("MW"), 200 MW, or 400 MW.

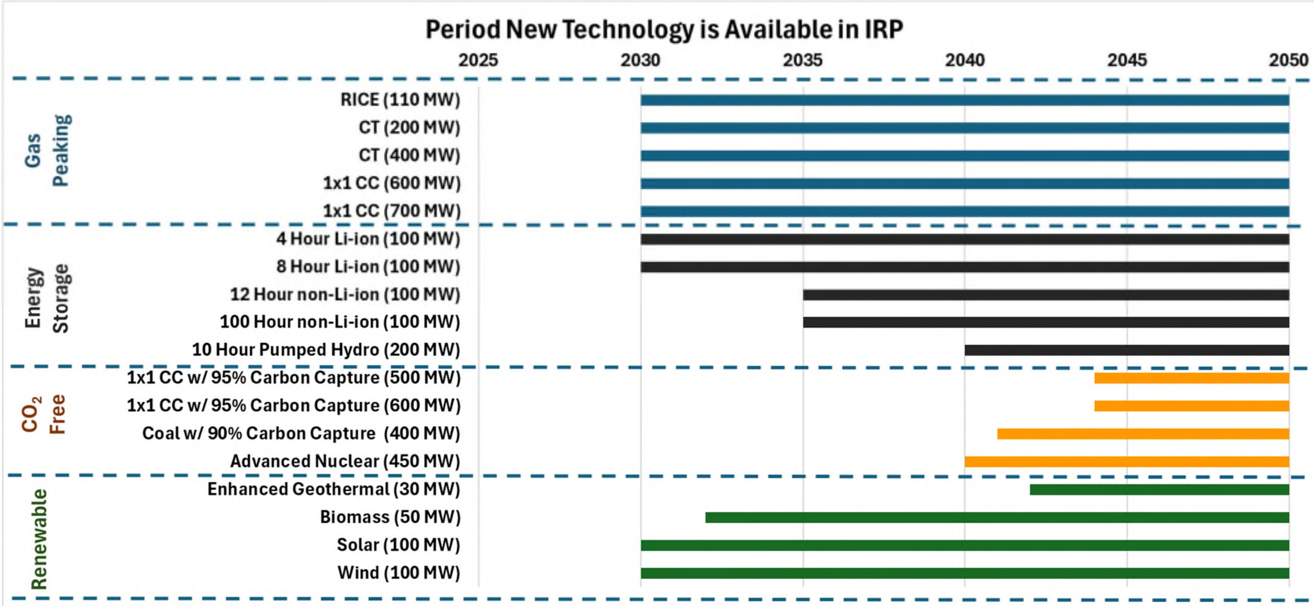
Table 1. Alternative Generation Technologies[1]

Baseload/Intermediate	Peaking/Storage	Renewable
▪ 1x1 CC (600 MW)	▪ CT (400 MW)	▪ Biomass (50MW)
▪ 1x1 CC w/ 95% Carbon Capture (500 MW)	▪ CT (200 MW)	▪ Enhanced Geothermal (30MW)
▪ 1x1 CC (700 MW)	▪ RICE (110 MW)	▪ Solar (100MW)
▪ 1x1 CC w/ 95% Carbon Capture (600 MW)	▪ 4 Hour Li-ion (100MW)	▪ Wind (100MW)
▪ Advanced Nuclear (450 MW)	▪ 8 Hour Li-ion (100MW)	
▪ Coal w/ 90% Carbon Capture (400 MW)	▪ 12 Hour non-Li-ion (100 MW)	
	▪ 100 Hour non-Li-ion (100 MW)	
	▪ 10 Hour Pumped Hydro (200MW)	

Additionally, related to the diverse technology analyzed in the 2025 IRP, as indicated in Figure 2 below, each had varying in-service dates that were used to determine when a new resource would be available to fulfill an energy need. The in-service dates chosen to model in EnCompass were based on several factors, including development timeline (regulatory approval, engineering, permitting, procurement, and construction), retirement of existing resources, ramp schedules for new load growth, and commercial availability of emerging technologies. Actual in-service dates or when new generation can be added to the power supply will depend on several factors, including some that are out of Minnesota Power's control, like environmental permitting and Midcontinent Independent System Operator's ("MISO's") generator interconnection process. Furthermore, if the Company is adding to an existing generator or procuring a project that is further along in its development process, that asset could be added to the power supply sooner than projects that have not been conceived or are earlier in the development process. Timing of when new resources can be added to meet customer needs or replace coal generation will vary. Minnesota Power continually looks for opportunities and advocates for policies that can bring on new generation more effectively, while being respectful to the environmental, customer cost, and the stakeholder input process.

[1] For the MW size of the generation technology, an approximate value is used.

Figure 2. Timming New Technology is Available to be Selected in EnCompass[2]



Cost Comparison of Alternatives Considered in IRP Analysis

The financial analysis was completed by developing and comparing a levelized busbar cost of each resource over a 20-year period. The levelized busbar approach is a simple and effective method to compare generation alternatives being evaluated in expansion. The levelized busbar cost for each power generation alternative included estimated capital, transmission, operation and maintenance (fixed and variable), fuel costs, and a 6.6534 percent discount rate. Busbar costs for resources were compared with the mid carbon regulation cost in the Reference Case Scenario ($40/ton starting in 2028).

Figures 3, 4, and 5 below show the $/megawatt hour ("MWh") levelized busbar cost comparison by category over a range of assumed capacity factors. Tables 2, 3, and 4 below show the alternative net plant cost in 2025$/kilowatt ("kW").

[2] In the EnCompass analysis, resources were allowed to be selected through 2039.

Figure 3. Baseload/Intermediate Alternatives 20-year Levelized Busbar Cost - Includes CO_2 Regulation Cost

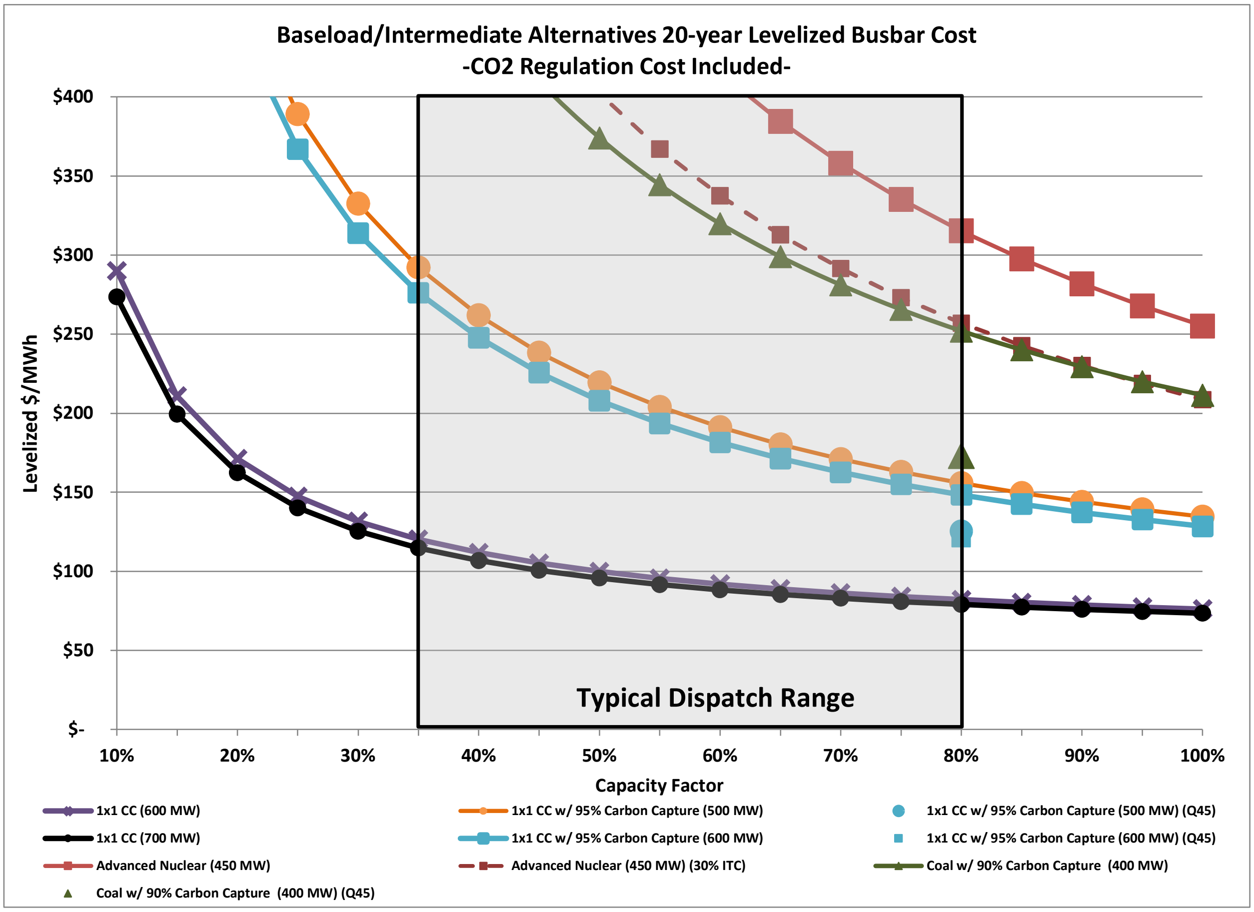


Table 2. Baseload/Intermediate Alternatives Net Plant Cost, 2025 $/kW

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The 1x1 CC without carbon capture technology represented the lowest levelized busbar cost across all capacity factors for the baseload/intermediate generation resource alternatives. An advantage of combined cycle generation is efficient energy conversion while still providing a lower emission profile. This is also supported by the EnCompass capacity expansion results where combined cycle generation was selected most often to meet the intermediate dispatchable needs of customers.

Conversely to the combined cycle, advanced nuclear generation was the highest cost option. A disadvantage of nuclear is that industry's experience with developing advanced nuclear is still new, with no pilot projects operational in the United States. Further, with nuclear, there is additional risk at both the state and the national levels related to nuclear waste storage and the current moratorium in Minnesota.

Figure 4. Peaking/Storage Alternatives 20-year Levelized Busbar Cost – Includes CO_2 Regulation Cost

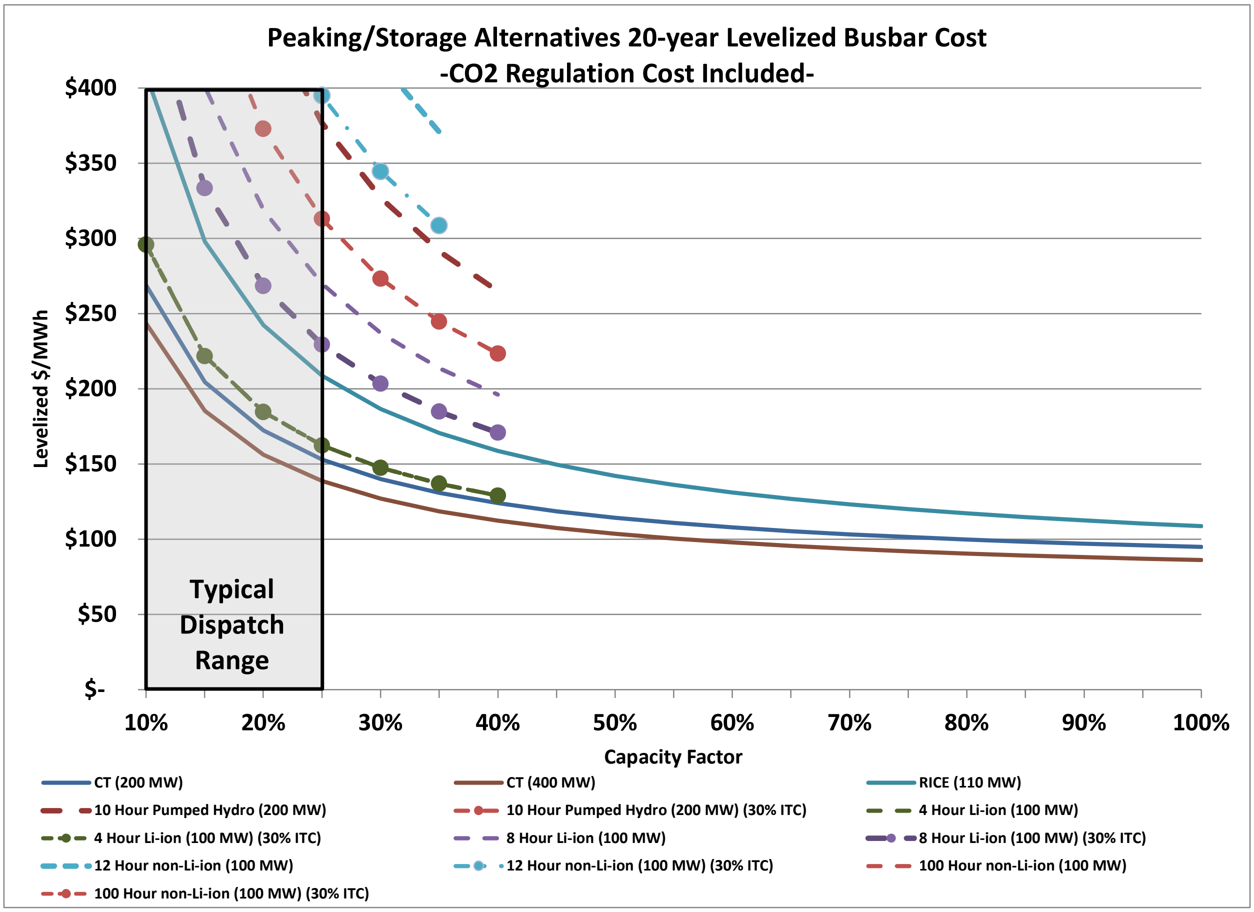

Table 3. Peaking Alternative Net Plant Cost, 2025$/kW

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For peaking/storage resources, the 200 MW and 400 MW CTs, also referred to as a simple cycle combustion turbine, represented the lowest levelized busbar costs across all capacity factors. This technology is one of the more efficient ways to convert natural gas to electricity, while delivering flexible operations.

Energy storage is shown at its theoretical max energy if it were to charge and discharge approximately once a day or once a week for the 100-hour non-lithium-ion ("round trip cycle efficiency"). Therefore, the levelized busbar costs are shown as representative capacity factors based on expected hourly production curves or round-trip cycle efficiency assumptions.

The 12-hour and 100-hour non-li-ion battery technologies, also referred to as long-duration energy storage ("LDES"), had the highest levelized busbar costs. Like nuclear, these technologies are still developing and have varying levels of technological and commercial maturity, which could result in lower cost in the future. Minnesota Power will continue to monitor advancements and cost projections and will continue to evaluate this technology in future IRPs.

Figure 5. Renewable Alternatives 20-year Levelized Busbar - Cost Includes CO_2 Regulation Cost

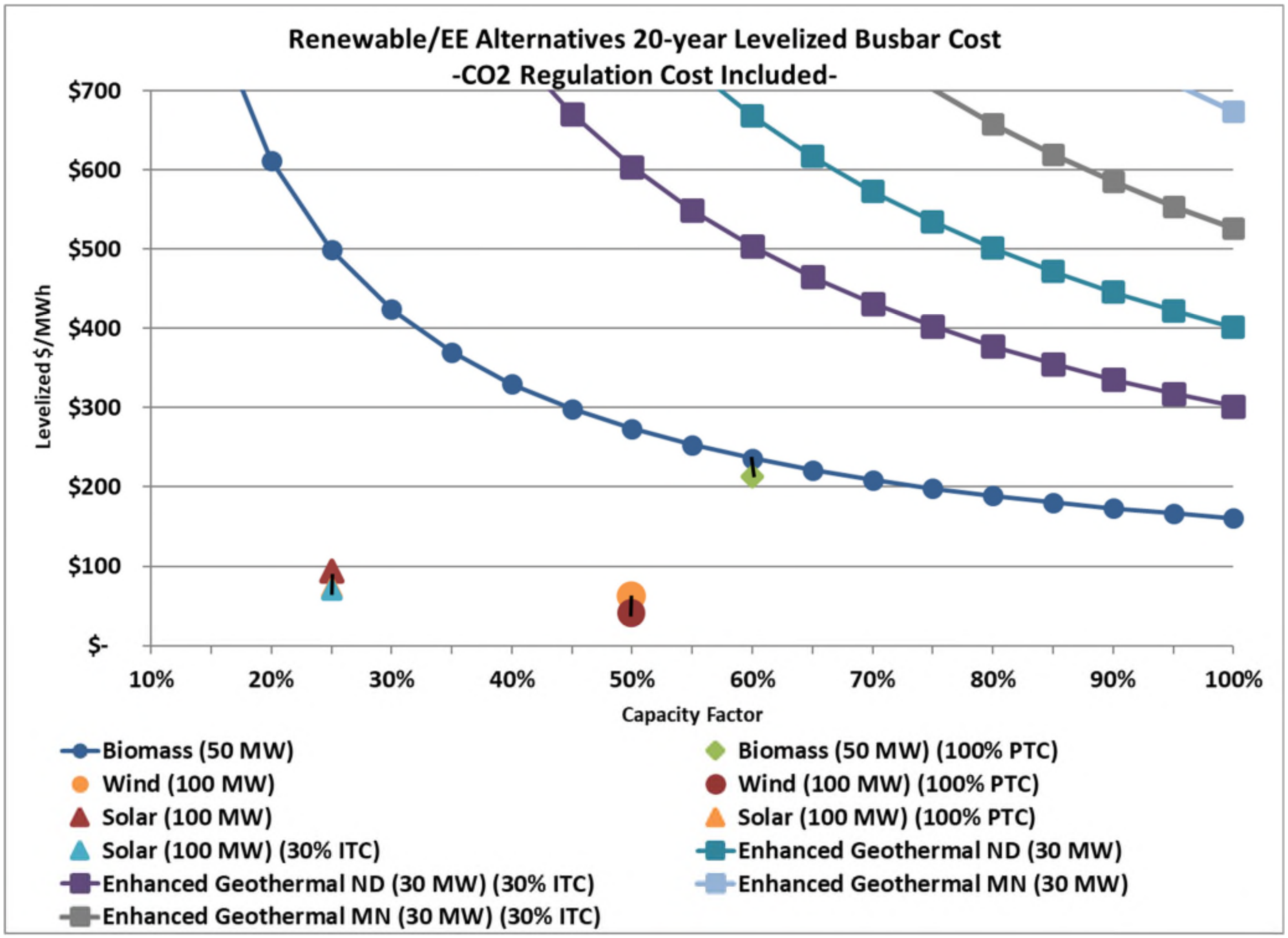

Table 4. Renewable/Storage/Energy Efficiency Options Net Plant Cost, 2025$/kW

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Except for biomass generation and enhanced geothermal, renewable options represent an intermittent source of power supply, therefore, the levelized busbar costs are shown as representative capacity factors based on expected hourly production curves.

The solar alternatives represent the lowest levelized busbar with wind alternatives having the second lowest levelized busbar. Note that the solar and wind busbar cost has been developed from Minnesota Power Request for Proposal bids received in 2024.

Minnesota Power determined that enhanced geothermal, even with anticipated incentives, is the highest cost renewable resource.

The levelized busbar cost is a simple and effective methodology for developing an understanding of how resource alternative cost compare across various capacity factors. This type of analysis creates a deeper understanding on reasoning for resource selection during the more complex and robust Capacity Expansion Analysis phase of the EnCompass modeling. However, this analysis does not show the interaction of long-term capacity requirements, utility load factor, state environmental costs, and existing resource mix that also factor into the Capacity Expansion Plan Analysis. Therefore, this review of new alternative cost is for informational purposes and not used to determine Minnesota Power's 2025 Plan.

Demand-Side Management and Conservation

Minnesota Power remains a state leader in the successful implementation of its conservation programs, consistently exceeding the statutory requirement to achieve energy savings of 1.75 percent of gross annual retain energy sales. All historic and planned conservation impacts that exceeded the energy savings requirement are reflected in Minnesota Power's 2024 Annual Electric Utility Forecast Report and associated energy and demand forecasts. In addition to the conservation programs assumed in the load forecast, incremental efficiency above the approximate 2.5 percent approved in the Company's most recent Energy Conservation and Optimization Triennial Plan[3] and peak shaving or demand response alternatives were also considered in Minnesota Power's 2025 IRP. The demand-side management and conservation assumptions were reviewed and updated for the 2025 IRP analysis. For example, the program cost for energy efficiency has increased 30 to 50 percent since the last IRP, reflecting the higher

[3] *In the Matter of Minnesota Power's 2024-2026 Energy Conservation and Optimization Triennial Plan*, Docket No. E-15/CIP-23-93, ECO Triennial Compliance Filing (June 22, 2023).

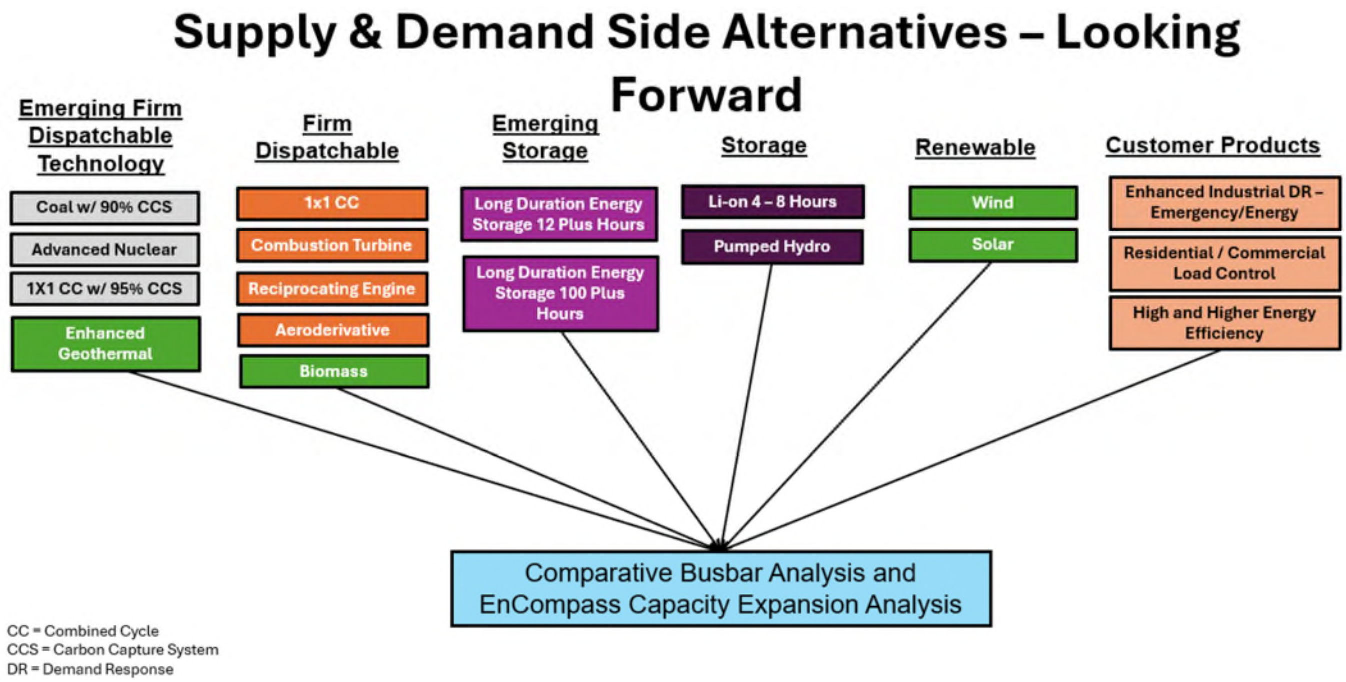
cost to achieve aggressive levels of program design, delivery, and marketing efforts required to achieve these levels of savings.

The economic feasibility of demand side management alternatives cannot be compared on the same $/MWh basis as new generation alternatives for a screening assessment. The energy efficiency, industrial demand response, and residential/commercial peak shaving programs were evaluated against supply-side options in later Capacity Expansion Analysis using the EnCompass model.

- Incremental Energy Efficiency ("EE High Scenario" and "EE Very High Scenario")
- Central Air Conditioning ("CAC") Cycling Peak Shave Program
- Electric Hot Water Heater ("HW") Cycling Peak Shave Program
- Long-Term Industrial Demand Response with Energy Curtailment

Figure 6 below is a summary of the resource alternatives evaluated in the Capacity Expansion Analysis in EnCompass. As stated earlier, Minnesota Power expanded the number of new and emerging generation resources in addition to mature technologies to include in the Capacity Expansion Analysis. This allowed Minnesota Power to evaluate emerging technologies alongside traditional resources like wind and gas CTs. Going forward, this allows Minnesota Power to monitor advancements in several emerging technologies using the EnCompass model.

Figure 6. Narrowing of Resource Alternatives Modeled in EnCompass

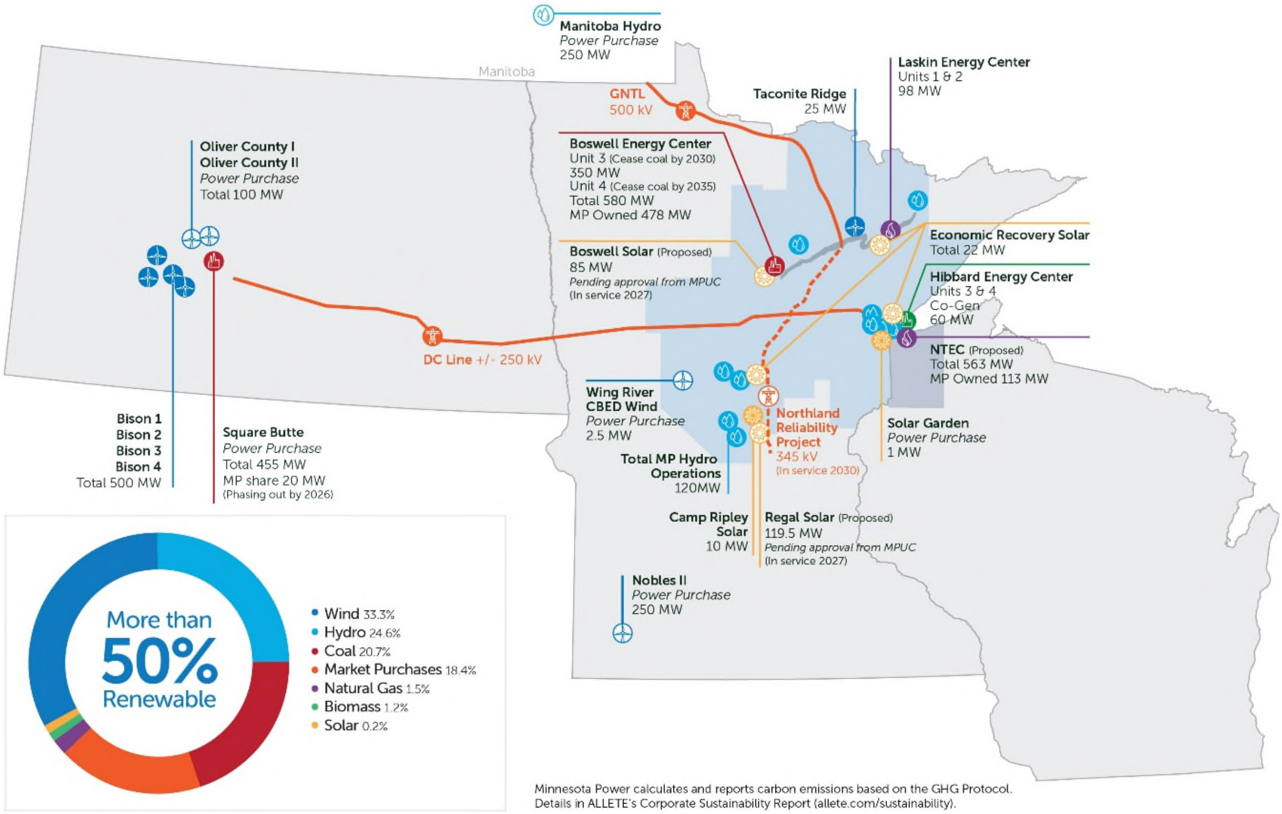


B. Base Seasonal Capacity Positions

As discussed in Section III of the 2025 IRP and to protect the reliability of its electric supply for customers, Minnesota Power cannot remove coal from the power supply until the capacity and energy is replaced with adequate generation resources. The Company is showing capacity deficits over 2500 MW by 2035 in the higher load growth scenarios. Even under the load loss scenario ("-200 MW") evaluated, there is a need for 500 MW of capacity as coal is removed. Furthermore, with MISO's Direct Loss of Load ("DLOL") proposal currently being phased into implementation, Minnesota Power anticipates these capacity deficits could increase.

Regardless of the load scenario evaluated, when BEC3 and BEC4 cease coal operations, there is a need to add new generation capability with a material accredited capacity value to the power supply. Tables 5 through 8 below show the Load and Capability ("L&C") capacity position for the four-planning seasons across all customer outlooks evaluated in the IRP. Minnesota Power's existing system, as shown in Figure 7 below, along with new generation resources approved by the Commission are included. Note in Table 7, Nemadji Trail Energy Center ("NTEC") is not included in the capacity position given Minnesota Power is restudying the broader need for natural gas generation in this IRP. These capacity positions are the starting point for in the 2025 IRP and the Capacity Expansion Plan analysis performed in EnCompass. A positive number demonstrates excess capacity on Minnesota Power's system, while a negative number denotes the capacity deficiency or need in that year.

Figure 7: Minnesota Power's Current and Proposed Generation Supply[4,5]



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[4] This Generation Supply Map was shared with participants during the 2025 IRP engagement meetings but has been updated to distinguish between proposed projects, including the Boswel Solar, Regal Solar, and NTEC Projects, and generation resources that are currently in-service.

[5] The Company's share of NTEC and associated contracts are still in effect, but the 113 MW associated with NTEC was removed from the Capacity Expansion Analysis to restudy the holistic need for new natural gas generation on the Company's system. On receipt of final local permits for NTEC, and if available to meet IRP needs, the Company will refile with the Commission as required.

Table 5. Spring Capacity Position Across All Load Scenarios

	Spring Capacity (MW) Positive = Surplus / Negative = Deficit				
	-200 MW	Base	+500 MW	+1100 MW	+1500 MW
2025	-150	-150	-150	-150	-170
2026	-59	-59	-59	-59	-89
2027	-79	-78	-321	-78	-483
2028	57	3	-362	-85	-655
2029	115	-34	-520	-299	-1067
2030	-170	-367	-974	-823	-1774
2031	-110	-354	-961	-1004	-2136
2032	-110	-354	-962	-1199	-2267
2033	-111	-354	-962	-1395	-2278
2034	-111	-355	-962	-1589	-2288
2035	-540	-783	-1391	-2126	-2727
2036	-546	-790	-1397	-2132	-2743
2037	-547	-791	-1399	-2134	-2755
2038	-549	-793	-1400	-2135	-2767
2039	-556	-801	-1411	-2149	-2783

Table 6. Summer Capacity Position Across All Load Scenarios

	Summer Capacity (MW) Positive = Surplus / Negative = Deficit				
	-200 MW	Base	+500 MW	+1100 MW	+1500 MW
2025	16	16	16	16	-1
2026	-89	-89	-89	-89	-114
2027	82	82	-125	82	-263
2028	124	48	-263	-27	-513
2029	200	72	-342	-153	-808
2030	-77	-245	-763	-634	-1444
2031	-40	-248	-766	-802	-1767
2032	-43	-250	-768	-970	-1881
2033	-45	-252	-770	-1139	-1892
2034	-47	-255	-772	-1307	-1903
2035	-447	-655	-1173	-1799	-2312
2036	-451	-658	-1176	-1803	-2324
2037	-454	-662	-1180	-1807	-2336
2038	-459	-667	-1185	-1811	-2349
2039	-466	-674	-1194	-1823	-2363

Table 7. Fall Capacity Position Across All Load Scenarios

	Fall Capacity (MW) Positive = Surplus / Negative = Deficit				
	-200 MW	Base	+500 MW	+1100 MW	+1500 MW
2025	139	139	139	139	121
2026	15	15	15	15	-12
2027	171	171	-45	171	-189
2028	232	140	-185	62	-446
2029	312	179	-254	-57	-741
2030	14	-161	-702	-568	-1415
2031	57	-160	-702	-740	-1748
2032	54	-163	-704	-915	-1868
2033	50	-167	-709	-1094	-1881
2034	42	-175	-716	-1275	-1897
2035	-442	-659	-1201	-1856	-2391
2036	-454	-671	-1212	-1867	-2411
2037	-466	-683	-1225	-1880	-2433
2038	-480	-697	-1238	-1893	-2456
2039	-485	-703	-1247	-1904	-2469

Table 8. Winter Capacity Position Across All Load Scenarios

	Winter Capacity (MW) Positive = Surplus / Negative = Deficit				
	-200 MW	**Base**	**+500 MW**	**+1100 MW**	**+1500 MW**
2025	139	139	139	139	119
2026	218	218	218	218	187
2027	60	61	-184	61	-348
2028	384	331	-37	243	-333
2029	428	278	-213	34	-765
2030	132	-67	-680	-503	-1488
2031	177	-69	-683	-701	-1869
2032	166	-80	-694	-933	-2013
2033	138	-108	-721	-1158	-2051
2034	108	-138	-751	-1385	-2091
2035	-438	-684	-1298	-2040	-2647
2036	-473	-719	-1333	-2075	-2692
2037	-509	-755	-1369	-2111	-2739
2038	-546	-793	-1406	-2149	-2786
2039	-574	-821	-1437	-2182	-2823

C. Summary Capacity Expansion Analysis Results (Steps 1-3)

As demonstrated by the L&C tables above, Minnesota Power needs large levels of capacity that can only be met with dispatchable generation resources that receive a high accredited capacity value. The Capacity Expansion Analysis supports the conclusions from the L&C by selecting over 2000 MW of gas generation in the higher load scenarios, along with over 2000 MW of renewables to meet the projected energy need while minimizing carbon emissions. Note the results shown here are prior to compliance with the CFS is applied to the modeling. This section summarizes the results from the Capacity Expansion Analysis for the BEC3 and BEC4 operational scenarios evaluated in the IRP across the several load scenarios considered. These results expand on the capacity analysis results shown in Section V of the 2025 IRP, where only the results for the "2025 Plan" for BEC was shown. As described in Section V, below is a list of the BEC3 and BEC4 operational scenarios included in the Capacity Expansion Analysis:[6]

- 2025 Plan: BEC3 refuels with natural gas by the end of 2029; BEC4 refuels with 40 percent natural gas by end of 2029 and ceases coal operations by the end of 2034;

[6] For all retirement scenarios, reference to a year indicates retirement on December 31 of that year.

- Full Retirement: Retirement of BEC3 and BEC4: BEC3 retires by the end of 2029 and BEC4 retires by the end of 2034; and
- Full Biomass/Gas Refuel: BEC3 cofires with biomass and natural gas by the end of 2029; BEC4 cofires with biomass and natural gas by the end of 2034.

A summary of the EnCompass capacity expansion results are shown in Table 9 below from Step 1-2. These capacity expansion results are based on traditional planning where the least cost plan is based on Minnesota planning requirements. The resource selections shown are based on the following futures: the Reference Case, High Carbon Regulation Cost and High Environmental Costs, Low Carbon Regulation Cost and Low Environmental Costs, and No Carbon Regulation Costs and No Environmental Costs as required for integrated resource planning in Minnesota.[7] Note the range in MW selected represents the variation in resource selection across the Minnesota environmental futures.

[7] *See In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minn. Stat.* §*216B.2422, Subd. 3,* Docket No. E-999/CI-14-643; *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06,* Docket No. E999/CI-07-1197; *In the Matter of Establishing an Updated 2022 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06,* Docket No. E999/CI-22-236, Order Addressing Environmental and Regulatory Costs (Dec. 19, 2023).

Table 9. Step 1 Capacity Expansion Results through 2039

Load Scenario	-200 MW Load	Base Load	+500 MW Load	+1100 MW Load	+1500 MW Load
Gas (MW)					
2025 Plan	250	650	1,150	1,600	2,000
Full Retirement	650	900	1,150	2,000	2,300
Full Biomass/Gas Refuel	0	0	650	1,150	1,600
Renewables (MW)					
2025 Plan	0 - 100	0 - 300	400 - 1,000	400 - 1,600	1,200 - 2,400
Full Retirement	0 - 200	100 - 400	600 - 900	1,200 - 1,600	1,200 - 2,400
Full Biomass/Gas Refuel	0	100 - 200	0 - 700	600 - 1,600	400 - 2,000
Storage (MW)					
2025 Plan	100	0	0 - 100	100	400
Full Retirement	100 - 200	0 - 100	200	100	400
Full Biomass/Gas Refuel	0	100	0	100	400
Demand Side Resources (MW)					
2025 Plan	100	105	100	100	105
Full Retirement	105	108	100	100	105
Full Biomass/Gas Refuel	100	100	100	105	105

Key Insights from Capacity Expansion Analysis

- 650 MW to 1600 MW of gas are added to support load growth scenarios which represents 12 of 15 scenarios in which additions were made. Supporting the need to add a minimum of approximately 750 MW of gas generation as a “no regrets” action in the 2025 IRP Base Plan outlook.
- Renewable additions increase significantly with incremental load added to the system. The minimum and maximum range of additions in each load scenario also coincide with the environmental futures modeled. This implies renewable additions were made to serve load and to minimize carbon emissions. Nearly all scenarios have renewable additions with 13 of 15 scenarios showing a minimum of 200 MW of renewables being selected, and over 900 MW of renewables selected in over 50 percent of the scenarios, showing that renewables are part of a least cost plan based on Minnesota planning criteria.

- Storage projects are typically added from 100 MW to 400 MW across all environmental futures and load growth scenarios, demonstrating that storage is an economical resource for managing surplus renewable energy within Minnesota Power's power supply.
- 100 MW of demand side resources were added across all environmental futures and load growth scenarios, clearly showing that expanded demand response with energy curtailment is an economical resource alternative for customers.

The results from the Capacity Expansion Analysis helped Minnesota Power develop new resource additions to support the Base Plan and Growth Plan.[8] These resultant plans from the traditional Capacity Expansion Analysis are before meeting the CFS was implemented – the results from the CFS analysis are shown in Section V of the IRP.

To explore what Minnesota Power's system could look like and operate under if only wind, solar, and energy storage were available to augment the energy portfolio, all gas supply side resources were removed from selection in EnCompass. These constraints were added to the "Full Retirement" scenario to show the capacity need for a Boswell station replacement in addition to meeting the CFS requirements. The storage selected included a mix of 4-hour, 8-hour, and 100-hour of storage capability. Although, these resource additions met the capacity needs, this portfolio of resources did not meet the reliability criteria. Due to the limited nature of energy storage operations, the LOLE and Event Analysis in Minnesota Power's Reliability Criteria showed a significant degradation in reliability when compared to Minnesota Power's recommended Base Plan. Table 10 below shows the resource selection.

Table 10. Capacity Expansion Results for Wind, Solar, and Storage Only

Resource Alternative Category	Installed Capacity (MW)
Storage	1,300
Wind	800
Solar	500
Demand Side	100

D. Minnesota Power Reliability Criteria Evaluation

The Company has developed a Minnesota Power Reliability Criteria ("MPRC") process that provides additional insights into the selection and implementation of the 2025 Plan. Minnesota Power recognizes the increased complexity of creating a long-term plan and the need to evaluate system reliability. The current MISO resource adequacy construct provides guidance on key elements including a seasonal planning reserve margin and resource accreditation. MISO moved to a seasonal resource adequacy approach starting in the Planning Year 2023-2024. In addition to the MISO resource adequacy changes, both current and the near future, Minnesota Power has determined that there is a need to establish a set of reliability criteria to clearly demonstrate that as the Company reduces carbon in the power supply, the reliable energy service delivered today will not change. The MPRC are designed to ensure the proposed 2025 Plan meets specific reliability criteria that were developed by the Company, in alignment with North American Electric

[8] As discussed in Minnesota Power's IRP filing, the Base Plan is the proposed plan to meet the Base Case, and the Growth Plan is the proposed plan to meet the +1100 MW Growth Scenario discussed in Section V.

Reliability Corporation ("NERC") and regional standards, and to provide guidance on the IRP Plan actions regarding critical electric system parameters that impact system reliability.

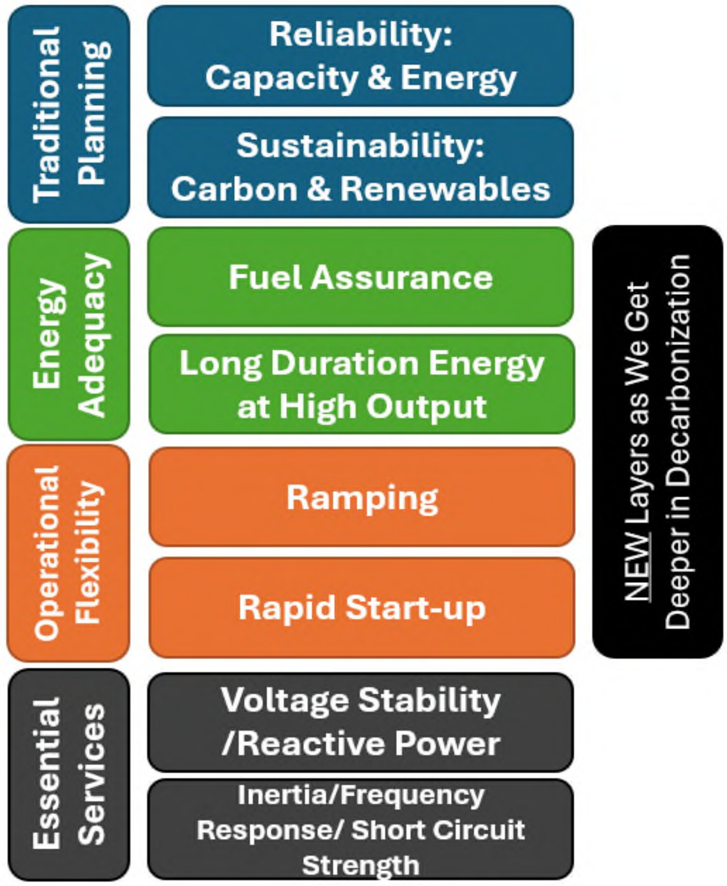
The rate of Minnesota Power and MISO resource transformation that has occurred to date from conventional resources to renewable resources is significant, with MISO projecting capacity shortfalls within the next couple of years[9] if utility plans are not adjusted. The resource transformation with declining dispatchable generation is one of the factors driving Minnesota Power to integrate reliability assessments more fully into the IRP process. The current MISO system has demonstrated the ability to cost effectively provide available resources when Minnesota Power resources are not available due to economics or outages. Going forward, there is enough uncertainty on the availability of resources and energy adequacy performance of the broader system to drive Minnesota Power to look closer at its own reliability performance during periods where the MISO system is stressed. It is critical that each load serving entity meet its responsibility to ensure its system is adequately covered with available resources to serve its projected load.

The MPRC are designed to provide guidance on the resource portfolio needed in the context of the MISO system resource transformation to higher levels of renewable generation and the change from coal fired resources to more natural gas resources. Minnesota Power is seeing the increased need to consider self-supply capabilities for energy production and ancillary services. Minnesota Power is continuing to refine the components of reliability criteria in collaboration with MISO and the electric industry sector as it is a critical issue for the broader transition underway across the nation.

The MPRC has four categories including Traditional Planning, Energy Adequacy, Operational Flexibility, and Grid Essential Services, as shown in Figure 8 below. Each of these categories have sub criteria for a complete review of total system reliability.

[9] MISO's Response to the Reliability Imperative at 6, Midcontinent Independent System Operator, available at https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216 (Feb. 2024).

Figure 8. Minnesota Power Reliability Criteria



Application of the MPRC is an innovative approach to quantifiably defining and applying a set of reliability criteria to a preferred plan. The MPRC allows Minnesota Power to establish a baseline of system performance across several of the reliability criteria. As Minnesota Power ceases coal operations and brings forward replacement plans to meet the Minnesota CFS, the Company can measure if reliability is improving or declining against a baseline where the system operates reliably today. This is valuable information to incorporate into an IRP evaluation to ensure the planning considers the important aspect that customers should receive the same reliable service as they do today.

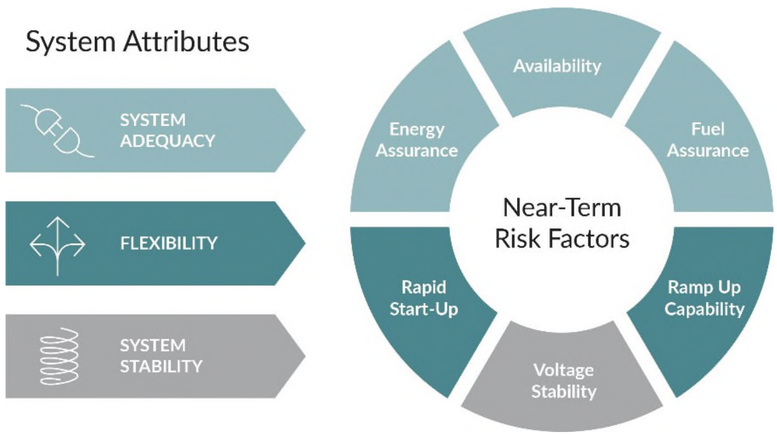
The MPRC also align with key reliability criteria issues identified by MISO during MISO's 2023 foundational analysis of the system reliability attributes. MISO's analysis focused on three priority attributes where risk to the MISO system is most acute: system adequacy, flexibility, and system stability. Each of the three system attributes identified by MISO has associated near-term risk factors that provide a framework for MISO's Attributes Roadmap, which provides proposals to ensure the sufficiency of the priority system reliability attributes.

- System Adequacy
    - Energy Assurance
    - Availability
    - Fuel Assurance

- Flexibility
  - Ramp up capability
  - Rapid Start-up
- System Stability
  - Voltage Stability

Figure 9 below provides a graphic showing the attributes and near-term risk factors.[10]

Figure 9. MISO Attributes Roadmap



The MISO Resource Attribute work is an excellent complement to the Company's MPRC and demonstrates the identified factors needed for system reliability. The Attributes Roadmap provides the additional guidance beyond only using the accredited MW attribute of a resource to assess the impacts on system reliability.

As part of the MISO Resource Adequacy requirements to establish a planning reserve margin, the TPL-001-5 NERC Standard requires that a Planning Coordinator have a defined criteria to evaluate the generation and transmission system adequacy. MISO uses a 1 day in 10 loss of load event as the criteria to determine the planning reserve margin.

NERC has formed an Energy Reliability Assessment Task Force ("ERATF") to "assess risks associated with unassured energy supplies, including the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load, which can result in insufficient amounts of energy on the system to serve electrical demand."[11] This effort is expected to compliment other initiatives to provide guidance in this extremely complicated realm of defining and evaluating resource adequacy.

[10] Attributes Roadmap A Reliability Imperative Report at 3, Midcontinent Independent Operator System, available at https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf (Dec. 2023).
[11] Energy Reliability Assessment Task Force, North American Electric Reliability Corporation, available at https://www.nerc.com/comm/RSTC/Pages/ERATF.aspx.

Traditional Planning

The Traditional Planning category of the MPRC includes what is most common with the planning in an IRP—the assessment of how a portfolio is defined and how it dispatches, using a tool like EnCompass, which provides key metrics including capacity and energy of resources, emissions, and costs.

Minnesota Power continues to use Traditional Planning mechanisms as in previous IRPs using the core data elements of the load and capability, system load forecast, and resource assessments as outlined in Capacity Expansion Analysis. The plan must have sufficient capacity to serve all four seasons with physical generation resources. Also, the plan must have sufficient energy to minimize unserved energy and market purchase price risk, while also meeting the Minnesota CFS requirements and other state sustainability requirements and goals. Minnesota Power performed the “Traditional Planning” evaluation by using the EnCompass model to assess and develop the most reasonable plan for customers to meet the capacity, energy, and sustainability requirements. Traditional Planning is the minimum requirement for ensuring an adequate resource plan. Minnesota Power includes additional processes as part of the MPRC for a more encompassing assessment of reliability.

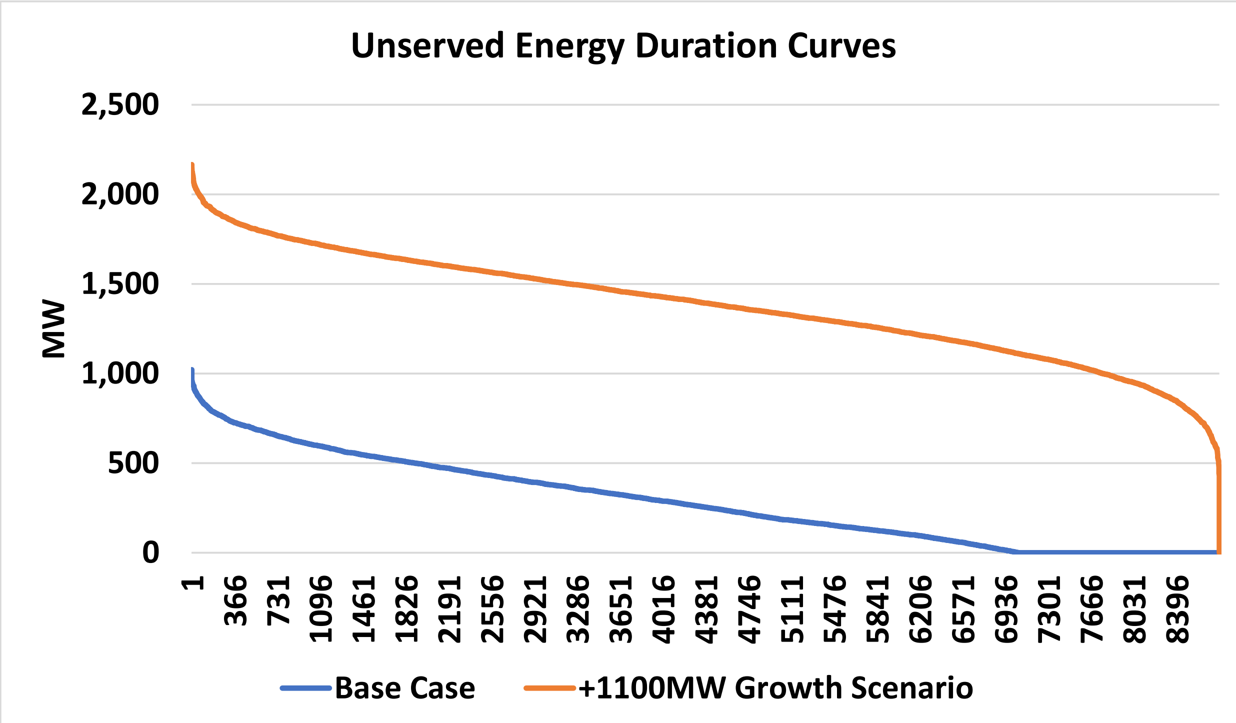
To augment the traditional planning work performed with EnCompass, Minnesota Power evaluated its energy need in more detail. This evaluation was broken into two analyses: (1) a higher-level look at Minnesota Power’s overall energy need by identifying key power supply metrics, and (2) evaluating the dispatch characteristics needed to minimize unserved energy risk.

The need for energy when starting from the actions approved in the 2021 IRP is drastically evident as seen in Table 11 and Figure 10 below. When retiring both BEC3 and BEC4 and layering in the 2025 IRP load forecast, the energy deficit that is created is large and spread across more than 75 percent of the hours throughout the year. In the Base Case demand forecast, the depth and frequency of unserved energy events creates the need for a resource that can dispatch over 1,000 consecutive hours to meet the energy need. In the +1100 MW Growth Scenario forecast, the energy need is constant throughout the year, showing the large volume of resources needed to meet the energy need.

Table 11. 2035 Energy Need Metrics by Load Scenario

	Base Case	+1100 MW Growth Scenario
Unserved Energy (MWh)	2,486,649	12,069,565
Max Unserved Energy in an Hour (MW)	1,022	2,166
Max Duration of Unserved Energy Event (Day)	18	365
Average Unserved Energy in an Hour (MW)	352	1,378
Average Duration of Unserved Energy Event (Hr.)	31	8,760
Annual Frequency of Unserved Energy Events	231	1

Figure 10. 2035 Duration Curve of Unserved Energy by Load Scenario



Next, the Company evaluated the dispatch characteristics that are needed by the system to minimize unserved energy risk. Using the hourly level data from the EnCompass model run and Base Case load forecast, the Company analyzed the dispatchable resource need after factoring in wind, solar, hydroelectric, and biomass production. This was a unique analysis, where the generation portfolio used in the analysis includes the 400 MW of wind recommended in the Base Plan but excludes the recommended energy storage and gas generation. Effectively, the Company is evaluating the dispatchable generation characteristic needs after meeting the CFS requirements in 2035. Minnesota Power's energy need was characterized by the number of hours in an event (i.e., the continuous period (or "block") of dispatchable energy need), MWh of need during the event, and the average MW need. This provides clarity and insight on the operational characteristics required for dispatchable generation to minimize unserved energy risk. The evaluation is also an indication on the type of generation EnCompass would likely select in the Capacity Expansion Analysis, although as higher levels of renewable energy are required to meet the CFS, this must be monitored.

There are 123 identified dispatch events (or period of consecutive hours where dispatchable generation is needed), showing a resource need. There are 84 dispatch events that are 100 hours or less, and 39 dispatch events that are more than 100 hours. This analysis provides clarity on the system resource needs net of wind, solar, hydroelectric, and biomass generation. The dispatch energy block is an indication of the duration of energy storage that would be needed on the system to minimize unserved energy but does not include the consideration of the resources needed to charge the storage system, nor the losses in the energy storage system. The need for continuous energy dispatch for more than 100 hours represents nearly 70 percent of Minnesota Power's total dispatchable energy need. This magnitude of energy and the length of continuous dispatch need provide an indication that the currently available energy storage technology would not be adequate or likely a cost-effective resource option to minimize all the unserved energy risk.

Dispatchable generation, such as gas fired generation, is needed to effectively minimize unserved energy.

Energy Adequacy

The "Energy Adequacy" component of the MPRC takes the "Traditional Planning" components one layer deeper by performing a more granular evaluation. For the 2025 IRP, Minnesota Power pursued two specific analytical constructs to evaluate the Energy Adequacy of the Base Plan and Growth Plan. The first was having a third-party perform a Loss of Load Expectation ("LOLE") evaluation and the second is hourly extreme event reliability analysis.

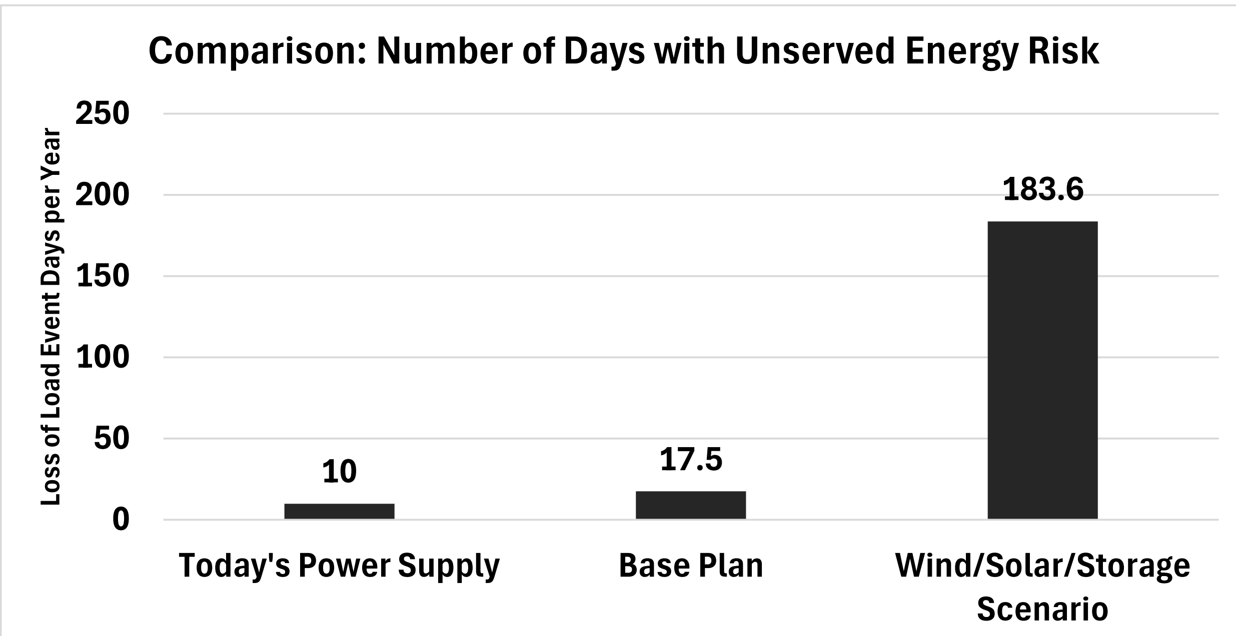
Loss of Load Expectation Modeling

Minnesota Power outsourced the LOLE modeling effort using Astrape Consulting. The intent of the LOLE study is to gain insights and develop a benchmarking tool into Minnesota Power's unserved energy risk. The LOLE study used the SERVM model which is also used by MISO for their Resource Adequacy construct, and NERC accepts this type of modeling to demonstrate resource adequacy of a system (i.e., 1 day in 10 years loss of energy standard). Minnesota Power's approach to understanding the loss of load risk of the system through this LOLE study is well documented and accepted method in the industry. The model has provided comparative benchmarking analysis for the current portfolio, the 2025 Plans (Base Plan and Growth Plan), and a scenario where only wind, solar, and storage (the "Wind/Solar/Storage Scenario") was allowed to meet the Company's incremental energy need. Each case was evaluated for its standalone capabilities using the LOLE metric as well as additional metrics looking at the depth and distribution of unserved energy across the 43 weather years and five load sensitivities. Minnesota Power views the LOLE analysis as being an effort that will be a benchmark to be reviewed and compared to in this IRP and for future planning analysis—it gives the Company a perspective on if reliability is improving or declining as the Company ceases coal operations and moves toward higher levels of renewable generation to meet the CFS.

The LOLE analysis for Minnesota Power as part of the MISO Local Resource Zone 1 ("LRZ1") results in a high level of reliability when utilizing the transmission interconnections between Minnesota Power and neighboring utilities and their generation resources to meet Minnesota Power's energy needs. These results typically show a result in the range of 1 day in 10 years due to the adequate resources and load diversity in MISO, specifically, in LRZ1. As the power supply transforms with additional coal retirements and higher levels of renewables, Minnesota Power is uncertain how much energy will be available over a wide range of weather year scenarios from other utilities when needed for reliability. Minnesota Power looked at the reliability of its own power supply and further evaluated the Company's reliance on neighboring generation resources to maintain reliability. The LOLE results show that Minnesota Power's system has a worse than the targeted result of 1 day in 10 (0.1 for a one-year evaluation), which is expected because the system is not planned to operate as an island. The LOLE results provide a more direct reliability comparison of the portfolios and shows the level of Minnesota Power need for MISO network resources. The traditional planning results show adequate accredited capacity values for each plan, but the LOLE evaluation of the Minnesota Power-only system allows for a comparison of reliability across plans.

The LOLE analysis showed that the proposed 2025 IRP Base Plan has equal to or higher level of energy adequacy reliability compared to the existing portfolio today. The figure below shows the LOLE results when studying Minnesota Power's system standing alone. This LOLE study clearly shows the reliability benefit of having a portfolio with some gas generation (Base Plan) versus a portfolio mostly reliant on energy storage. This study included the scenario discussed earlier, where Minnesota Power evaluated the capability for a portfolio of wind, solar, and energy storage to reliably and economically meet customer needs when BEC3 and 4 cease coal generation under the Base Case load forecast – this is referred to as "Wind/Solar/Storage Scenario." The Wind/Solar/Storage Scenario has 1300 MW of energy storage, including 600 MW with 100 hours of storage capability, replacing the 800 MW of dispatchable generation at BEC. In the Wind/Solar/Storage Scenario, the study showed a significant decline in energy adequacy reliability – there were several loss of load events that lasted for more than a day due to the limited dispatch duration and capabilities of energy storage. As shown in Figure 11 below, the LOLE results under the Wind/Solar/Storage Scenario were a full ten times higher than the Base Plan with a LOLE result of 183.6 days per year where Minnesota Power relies on generation from other utilities to maintain reliability. In comparison, the Base Plan relies on other utilities' generation to maintain reliability less than 20 days per year. This demonstrates the Base Plan has less risk, from both a market and reliability perspective, because that portfolio has better capability to serve customers energy needs.

Figure 11. Loss of Load Expectation Modeling Results



Major Event Analysis

The second analysis the Company undertook under the Energy Adequacy component of the MPRC was a major event analysis, looking at the actual hourly information of specific events such as Winter Storm Uri and Winter Storm Elliot. This is becoming a common approach for planners to evaluate system performance during historical stressed periods to help augment the traditional energy and capacity modeling performed with a tool like EnCompass. In the future, Minnesota Power is also planning to look into events known as wind droughts, where there is not a major storm event, but a lower level of wind output that typically extends for 4-5 days. Major event analysis provides insights on resource availability and the ability to serve load from Minnesota Power resources under the profiles of these real-world events. For this plan, this additional insight into system performance was also used to affirm the recommendation for dispatchable generation. The performance of the Base Plan and Growth Plan during a Winter Storm Uri like event is also discussed in Section V of the 2025 IRP.

Winter Storm Uri Evaluation

One event Minnesota Power looked at is the Winter Storm Uri event that occurred from February 13 – 17, 2021. This was a multi-day event of high demand due to extreme cold combined with stretches of low renewable production and higher forced outages of traditional resources. Figures 12 to 15 below show the power supply performance across multiple scenarios, including the Base Case (2021 IRP outcome with BEC3 and BEC4 removed at cease coal dates),[12] Base Plan, Growth Plan, and scenario where BEC3 and BEC4 are replaced with only wind, solar, and storage (i.e., the "Wind/Solar/Battery Only" scenario). Table 12 below provides key observations on reliability tracking during the event. In the "Wind/Solar/Battery Only" scenario, 15 percent of the energy needs were unserved during the Winter Storm Uri event, in comparison to the Base Plan and Growth Plan, which had no unserved energy. Gas generation is needed to provide sufficient energy during extended periods of high demand and lower renewable production.

Table 12. Winter Storm Uri Reliability Analysis

	Base Case w/ BEC 3-4 Removed	Base Plan	Growth Plan	Wind/Solar/ Battery Only
Max Unserved Energy (MW)	1109	0	0	1050
Average Hourly Unserved Energy (MW)	649	0	0	380
Max Consecutive Hours of Unserved Energy	168	0	0	42
Number of Occurrences a Shortfall Event Occurred	1	0	0	9
Percent of Energy Served	51%	100%	100%	85%

[12] "Base Case" is the starting point for this IRP analysis. *See* "Base Case" in Section III, Table 2, in the 2025 IRP filing.

Figure 12. Energy Supply Performance During Winter Storm Uri with Base Case and BEC3 and BEC4 Removed

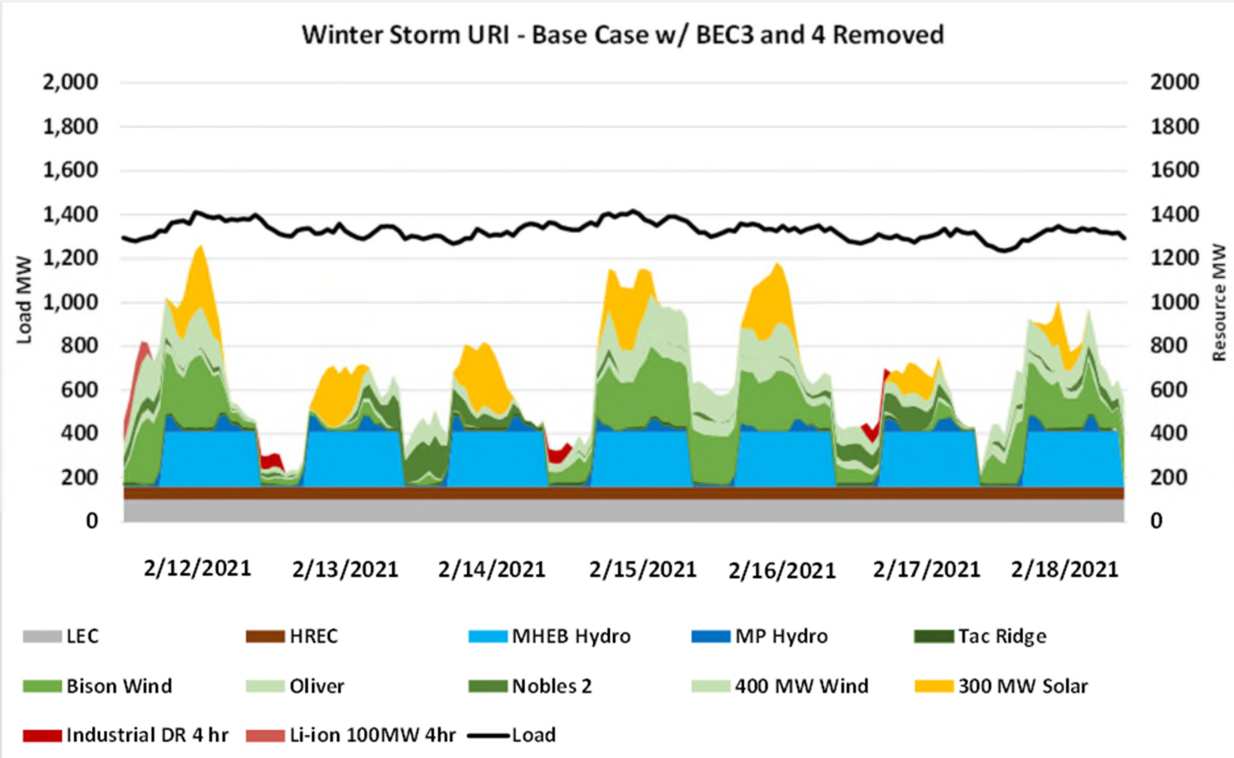
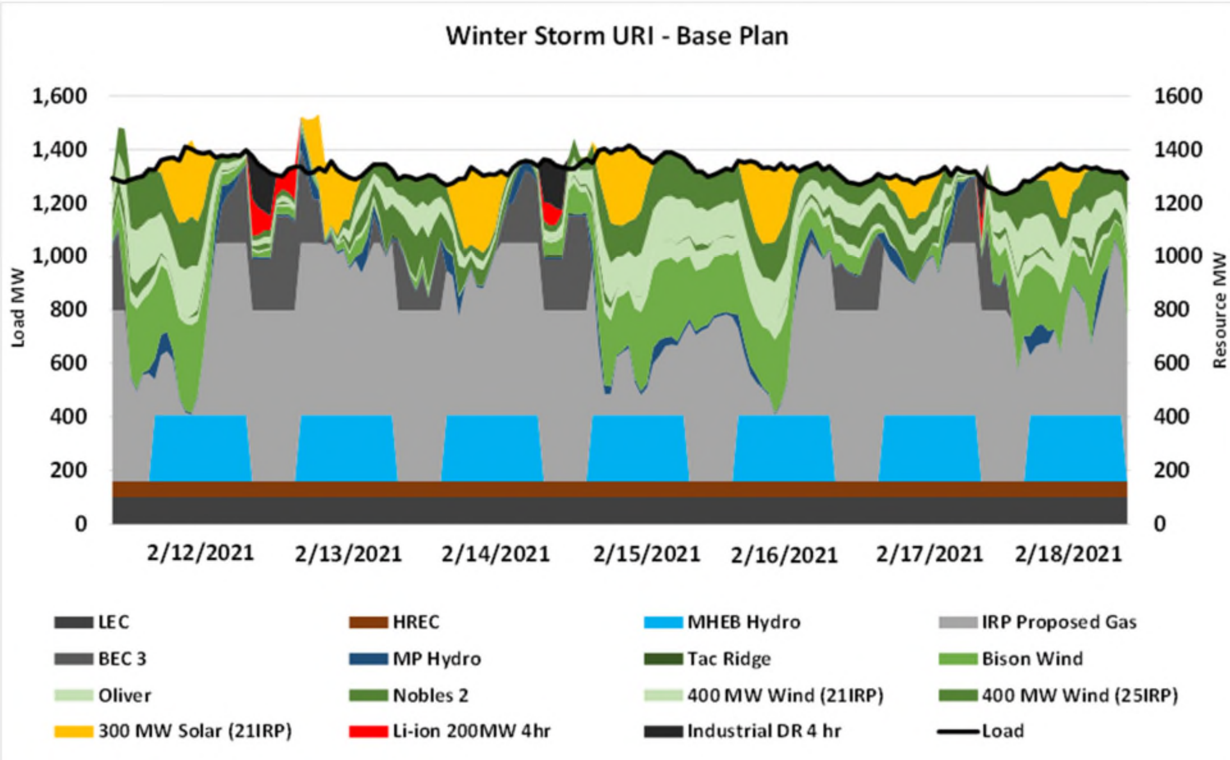
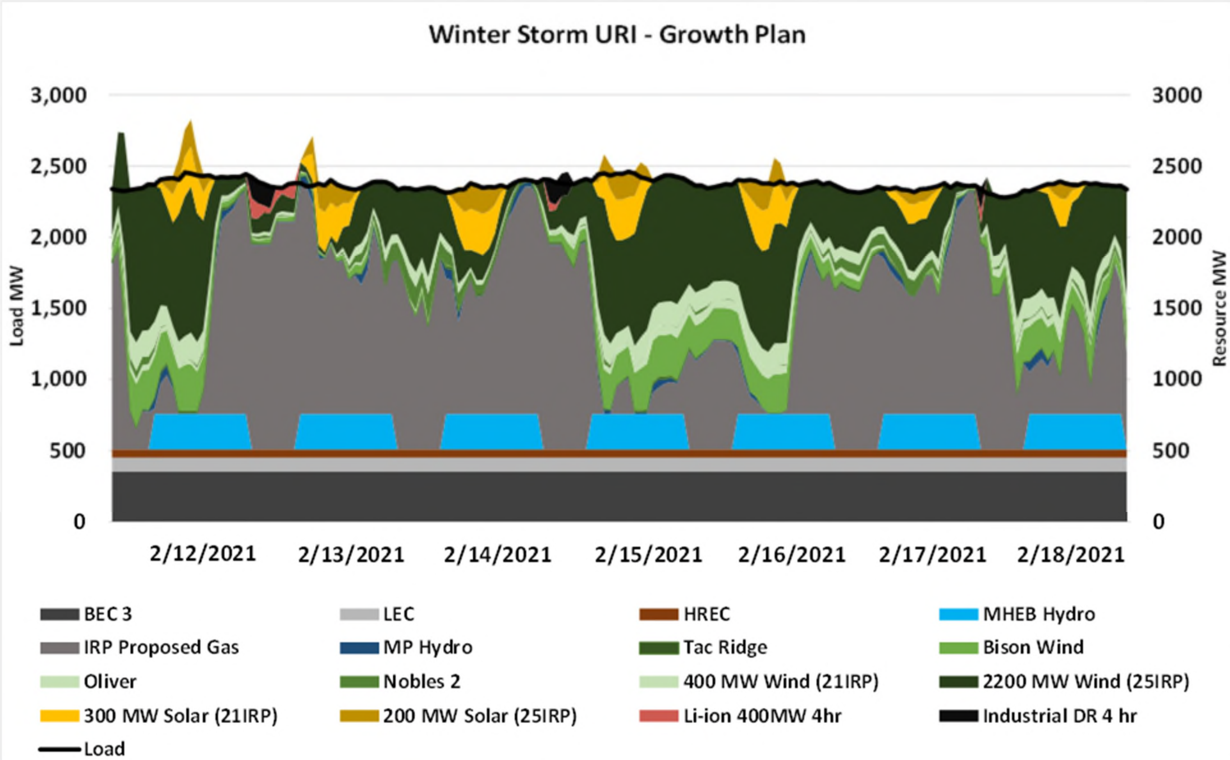


Figure 13. Energy Supply Performance During Winter Storm Uri with Base Plan[13]



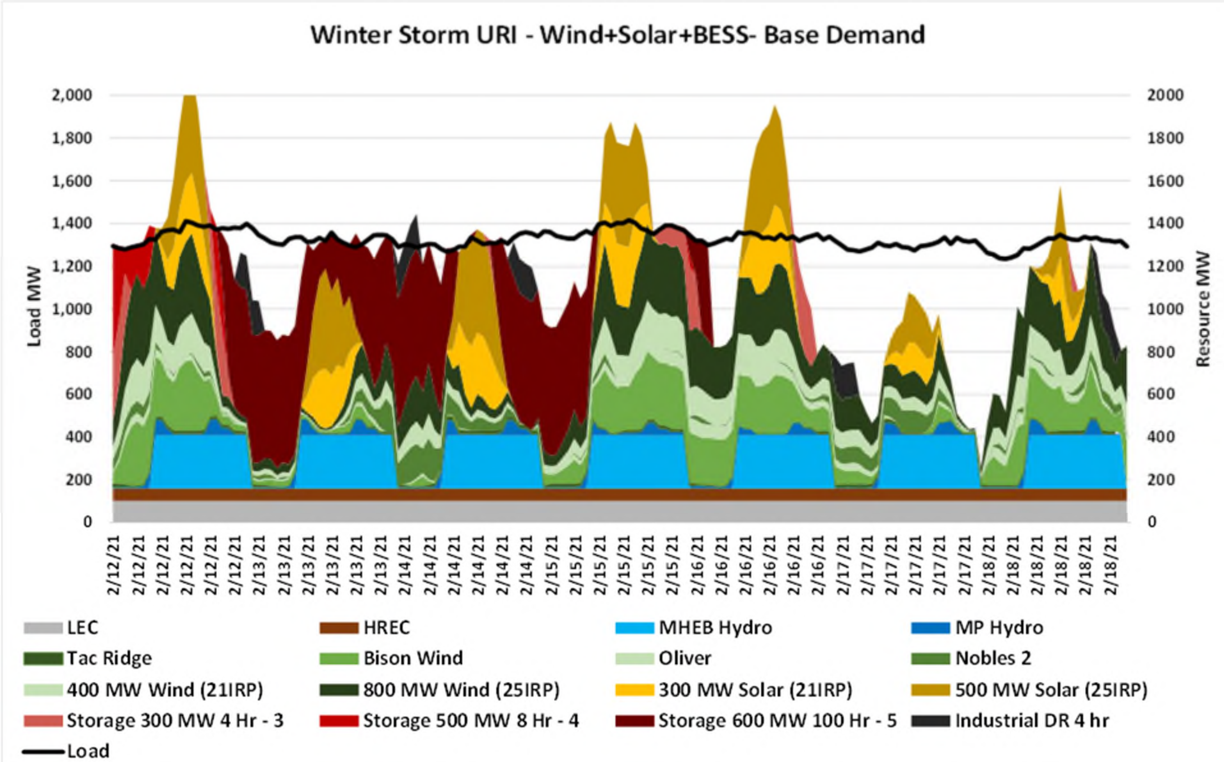
13 This figure is also shown in Section V of the IRP filing. In the figure shown here in Appendix K, Minnesota Power made a small modification to the energy storage dispatch logic, which changes the appearance of the figure slightly from what is shown in Section V.

Figure 14. Energy Supply Performance During Winter Storm Uri with Growth Plan[14]



[14] This figure is also shown in Section V of the IRP filing. In the figure shown here in Appendix K, Minnesota Power made a small modification to the energy storage dispatch logic, which changes the appearance of the figure slightly from what is shown in Section V.

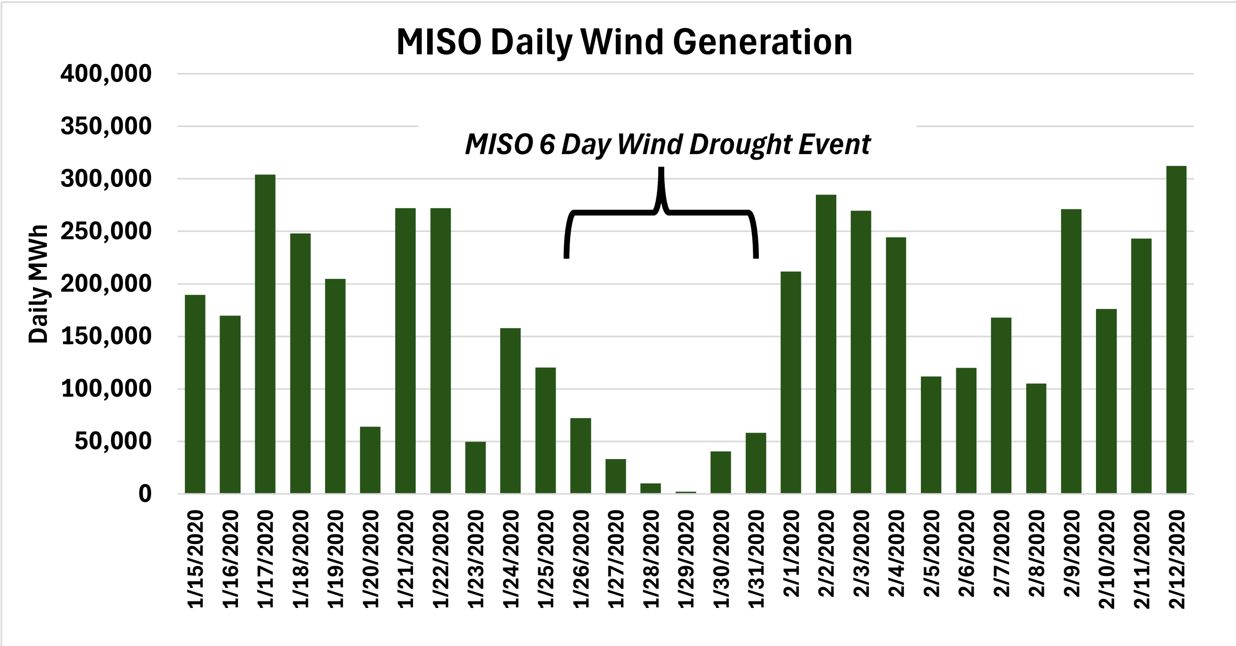
Figure 15. Energy Supply Performance During Winter Storm Uri with Wind/Solar/Battery Only Scenario



The Base Plan and Growth Plan, with their diverse and flexible generation mix, can meet customer needs during a Winter Storm Uri type event. Prior to replacing the removed coal energy at BEC3 and BEC4, Minnesota Power's remaining power supply was unable to serve 49 percent of the energy during the Winter Storm Uri event, with unserved energy occurring every hour. The Base Plan and Growth Plan fill the unserved energy gap with a mix of wind, solar, energy storage, demand response, and gas generation, resulting is an adequate portfolio to meet customer needs during a Winter Storm Uri like event. In contrast, the Wind/Solar/Battery Only scenario has a much higher level of unserved energy, with a maximum level of unserved energy of 1050 MW in an hour. During the event there were 42 consecutive hours that unserved energy was observed. The challenge with operating a system with mostly storage is that during high demand and low renewable stretches, there is limited opportunity to charge the batteries once they are depleted – leaving the system with unmanageable levels of unserved energy until storage can be refilled. The high load factor load shape and the high number of hours for the event provided a significant challenge for the Wind/Solar/Battery Only scenario to serve customer energy needs during this event.

Minnesota Power believes that adding known historical "renewable drought" periods to future event analysis will have value in demonstrating whether an energy portfolio is reliable. For example, in January 2020, there was a six-day period between January 26 and January 31 (or 144 hours) where there was minimum wind energy production across MISO, as shown in Figure 16 below. MISO wind generation decreased from a consistent daily energy production ranging from 200,000-400,000 MWh down to daily totals for January 26-January 31 averaging 35,000 MWh. This type of event will create challenges on recharging batteries once storage is depleted, warranting further study and monitoring and continuing to bolster the need for a diverse supply portfolio approach.

Figure 16. MISO Daily Wind Generation



Operational Flexibility

Operational Flexibility needs must be understood to reliably integrate and optimize renewables by having a generation portfolio with sufficient flexibility characteristics. These operational flexibility characteristics include ramp rate and duration, cycling on and off, and rapid start up capabilities. Minnesota Power will monitor the operational flexibility needs and 2025 Plan capabilities, to evaluate the characteristic needs of the recommended dispatchable generation in the 2025 Plan. Also, MISO included a conclusion from the January 2025 Regional Resource Assessment (“RRA”)[15] indicating a three-fold increase in the need for system ramping capabilities, supporting the need to include Operational Flexibility in the MPRC.

Grid Essential Services

Grid Essential Services is one of the key areas where integrated planning occurs between resource planning and transmission/distribution planning. Minnesota Power coordinates internally among resource, transmission, and distribution system planners on study work needed when significant action (i.e., baseload retirement) is taken that could impact the reliability of the grid. An Essential Services evaluation could include transmission studies that evaluate local and regional aspects of any of the following depending on the need: steady state power flow and voltage regulation, voltage stability, transient stability, inertia, frequency response, and short circuit strength. Many of these types of studies are also occurring on a regional level in MISO’s Long Range Transmission Planning process, which Minnesota Power is a participant in and has brought forward regionally beneficial solutions to address system issues that were identified in prior IRPs. There is also coordination on how future transmission projects could impact the capability of integrating new generation onto the system, which is factored into the 2025 Plan.

[15] Regional Resource Assessment 2024, Midcontinent Independent System Operator, available at https://cdn.misoenergy.org/2024%20RRA%20Report_Final676241.pdf (Jan. 2025).

Please refer to Appendix F and Appendix O for more on areas where integrated planning occurred between resource and transmission planners in this IRP, including the Hibbard Retirement Study.

E. 2025 Plan Sensitivity Analysis

After Steps 1-4 were complete, Minnesota Power used insights from the Capacity Expansion Analysis to determine the new resources to add in the Base Plan and the Growth Plan. The Capacity Expansion Analysis clearly indicates that new dispatchable gas generation, wind, solar, storage, and enhanced industrial demand response are the least cost resources to replace coal operations at BEC4, to meet the incremental demand in the +1100 MW Growth Scenario, and to comply with the Minnesota CFS. The timing of the gas additions aligns with retiring or ceasing coal at BEC3 and BEC4 and with the increase in demand in the +1100 MW Growth Scenario. Renewables follow a similar timeframe with additions being driven by action at BEC3 and BEC4 and the timing of load growth, although to meet the CFS, we see significant renewable additions in 2030 and 2035 at the 80 percent and 90 percent milestones, respectively. Industrial demand response and storage have a similar role, both help manage a large renewable portfolio to operate more efficiently, with demand response being selected prior to storage additions. A risk evaluation was performed on the Base Plan and Growth Plan to assess potential risks posed to Minnesota Power's power supply. The variables stressed in the sensitivity analysis include environmental futures, commodity and market variability, supply and demand side generation variability, and resource adequacy impacts from uncertainty. There were nearly 20 sensitivities evaluated in the Company's development of the 2025 Plan and key insights are discussed in more detail below.

Environmental Futures Evaluation

The environmental costs impact on the 2025 Base Plan and Growth Plan are shown in Table 13 and Table 14 below. Three components making up the 15 Year net present value ("NPV") of each plan are the power supply costs, which represent total system costs excluding any environmental costs from generation; the carbon regulation costs; and the environmental costs. In addition to the four environmental futures discussed in Section V and the Detailed Comparison of Plan Cost section below, there were two futures in which only externality cost impacts were evaluated on the Base and Growth Plans.[16] The regulation costs were not included in these scenarios and the externality "add-on" was assessed as part of Minnesota Power's risk analysis. An observation from this analysis was although demand more than doubles between the Base Plan and Growth Plan, the increase in environmental costs was nominal compared to the magnitude of the demand increasing, demonstrating that most of the incremental energy need in the Growth Plan is being met with renewables.

[16] The costs shown incorporate the Minnesota planning requirements per Minn. Stat. §§ 216B.2422 and 216H.06 for carbon regulation and environmental cost.

Table 13. Base Plan 15 Year NPV Across Environmental Futures

15-Year NPV Base Plan Revenue Requirements ($M)	Power Supply	CO_2 Regulation	Environmental Cost	Total
MN Reference Case	$7,864	$539	$7,667	$16,070
Low Env./Reg. Cost	$7,823	$77	$4,627	$12,527
High Env./Reg. Cost	$7,884	$974	$10,786	$19,644
Low Env. Cost	$7,828	$0	$4,741	$12,570
High Env. Cost	$7,823	$0	$12,858	$20,681

Table 14. Growth Plan 15 Year NPV Across Environmental Futures

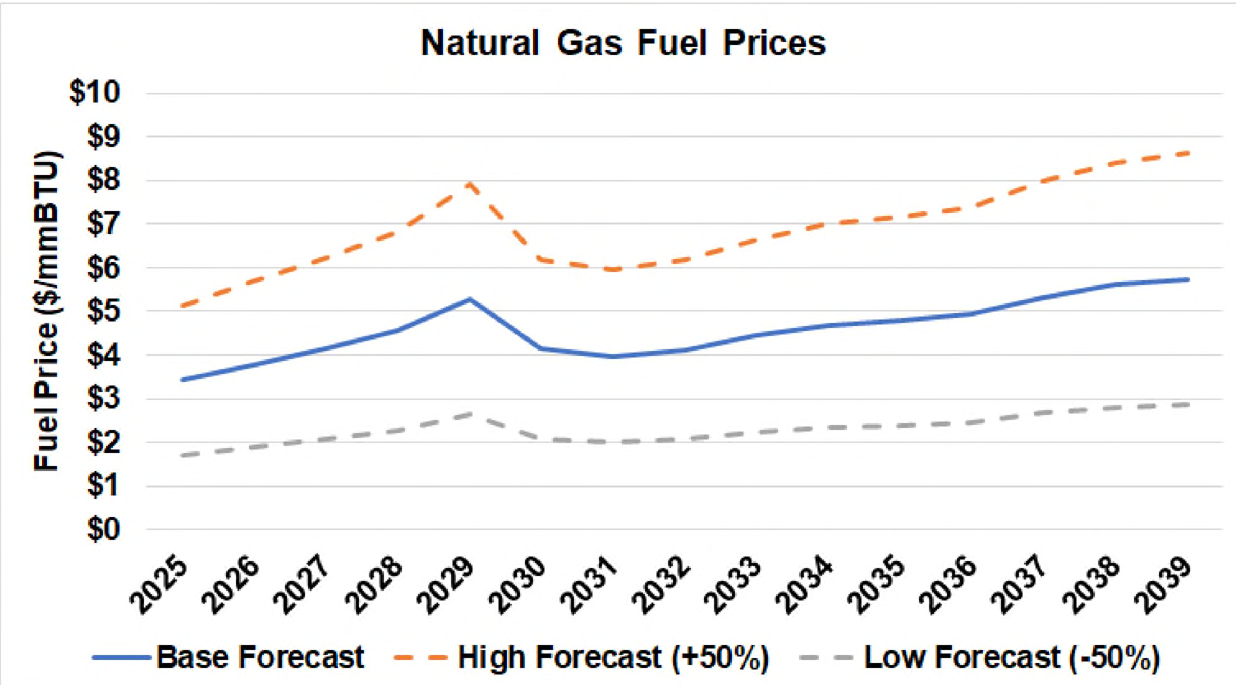
15-Year NPV Base Plan Revenue Requirements ($M)	Power Supply	CO_2 Regulation	Environmental Cost	Total
MN Reference Case	$11,151	$708	$8,834	$20,693
Low Env./Reg. Cost	$11,135	$97	$5,322	$16,554
High Env./Reg. Cost	$11,138	$1,289	$12,389	$24,814
Low Env. Cost	$11,127	$0	$5,450	$16,577
High Env. Cost	$11,128	$0	$14,747	$25,875

Commodity Pricing

Commodity price fluctuations will impact the dispatch of Minnesota Power's generation portfolio and power supply costs. With Minnesota Power transitioning from coal to gas as the main dispatchable fuel source in the 2025 Plan, it introduces a higher level of cost exposure to natural gas prices than the Company has had historically. With the diverse portfolio of renewables, storage, and biomass generation in the 2025 Plan, the sensitivity analysis shows natural gas volatility has minimal impacts on the power supply cost. Given the volatility in commodity markets, it was important to study their impact to customer cost in both the Base Plan and Growth Plan. The following commodity prices were stressed in this sensitivity: natural gas, biomass, and MISO energy market.

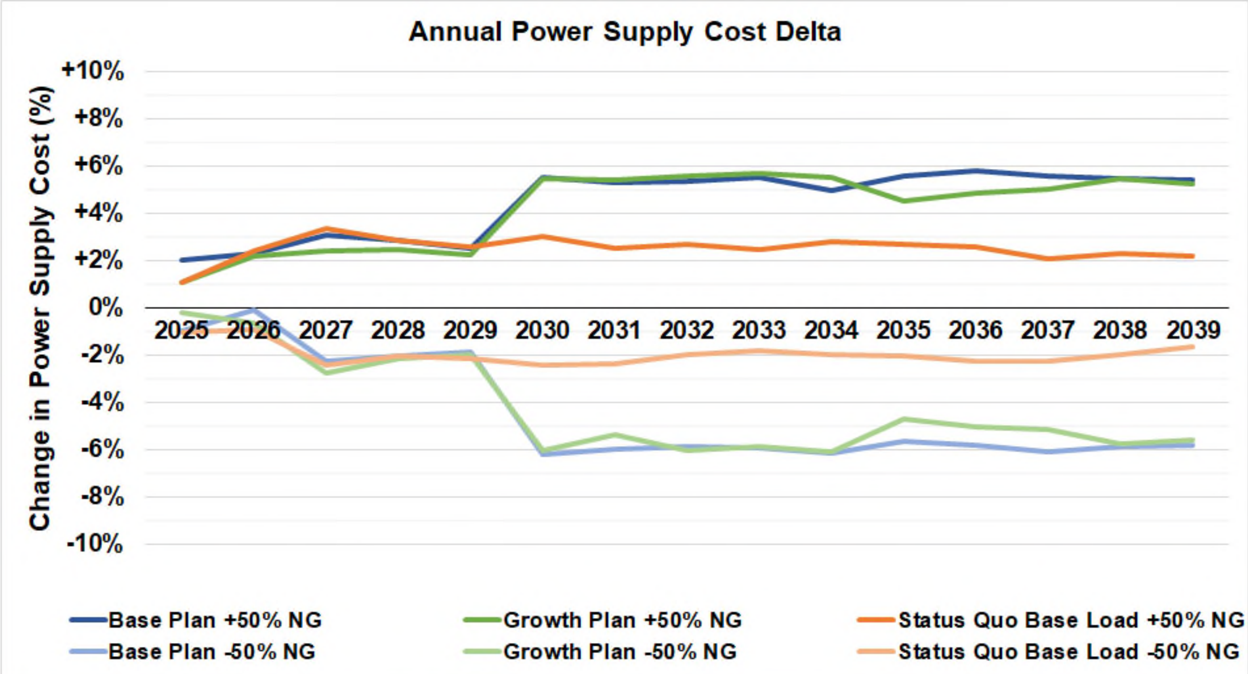
To assess the plan's exposure to natural gas price fluctuations, the EnCompass model simulated the impact using a low gas forecast (base price forecast -50 percent) and a high gas forecast (base price forecast +50 percent). Figure 17 below show the price forecasts utilized in each sensitivity throughout the study period. The natural gas forecast used in the IRP was comprised of two components, a price forecast for the physical natural gas, and a cost adder for delivery to each gas fired generation facility. Only the underlying fuel forecast for the physical natural gas was adjusted for these sensitivities, while the fuel delivery adder remained unchanged.

Figure 17. Natural Gas Fuel Prices



To serve as a comparison to the Base Plan and Growth Plan, a "Status Quo" scenario was modeled assuming BEC3 and BEC4 continue operating on coal through the study period. This scenario serves as a baseline to highlight the relative increase in commodity risk in the Base Plan and Growth Plan. The modeling demonstrated that both the Base Plan and Growth Plan are resilient to fuel price variations and show moderately more risk compared to the “status quo” baseline. The 50 percent increase in gas prices led to an approximate 5 percent increase in the annual power supply system costs throughout the study period. Conversely, a 50 percent reduction in gas prices resulted in a 6 percent decrease in the annual power supply cost for both the Base Plan and the Growth Plan. Compared to coal, power supply cost is more sensitive to the price of gas. Due to the diverse portfolio of renewables, biomass, and storage in the 2025 Plan, there is a hedge against natural gas prices that limits the impact on customer cost. Figure 18 below shows the changes in annual power supply costs under high and low gas price sensitivities compared to the base forecast for natural gas.

Figure 18. Annual Power Supply Delta from Base Gas Price Forecast



A +50 percent and -50 percent energy market and +15 percent and -15 percent biomass fuel price sensitivity was also performed as part of the commodity pricing sensitivity analysis. However, the power supply cost impacts from stressing these variables did not produce a material impact to portfolio costs. With the Base Plan and Growth Plan having minimum unserved energy levels, as reflected in Figures 13 and 14 in Section V, when market prices are stressed higher, there is minimal impact on customer cost.

Low Wind Generation

A low wind generation sensitivity was included in the EnCompass model runs to understand the impact lower wind generation has on meeting the CFS and market exposure risk. The largest portion of Minnesota Power's renewable portfolio is wind. As a reference in the Base Plan, by 2035, wind makes up 70 percent of Minnesota Power's renewable portfolio. Annual variability in the wind portfolio will have impacts on how Minnesota Power meets customers' needs annually and further supports the need of having a sufficient dispatchable generation portfolio to make-up lost wind generation. This sensitivity was performed by reducing the operating capacity factors of any existing and planned wind generating resources by approximately 7 percent. The 7 percent reduction is based on historical annual volatility observed in the current wind portfolio. In Table 15 below, the renewable percentages drop by approximately 3-6 percent. When lower wind production years are observed, Minnesota Power may need to purchase or utilize banked RECs to comply with the CFS. Given that Minnesota Power's renewable portfolio also includes solar, hydroelectric, and biomass, Minnesota Power believes this risk of lower wind generation and impact on CFS compliance is manageable.

Table 15. Renewable Percentages Comparison between Base Plan and Low Wind Sensitivity

	Base Plan		Growth Plan	
	2030	2035	2030	2035
Base	84%	90%	83%	90%
Low Wind	81%	86%	78%	84%

Another comparison the Company looked at was the change to market exposure with the low wind sensitivity. Minnesota Power monitored the unserved energy level in the low wind sensitivity compared to the base case to see if there was sufficient dispatchable generation to offset the lower wind production. As seen in Table 16 below, the level of unserved energy is largely unchanged as dispatchable generation is being utilized to mitigate this. This analysis demonstrates the robustness of the Base Plan and Growth Plan, that there are sufficient alternative sources of generation to offset lower than expected wind production.

Table 16. Market Exposure Comparison between Base Plan and Low Wind Sensitivity

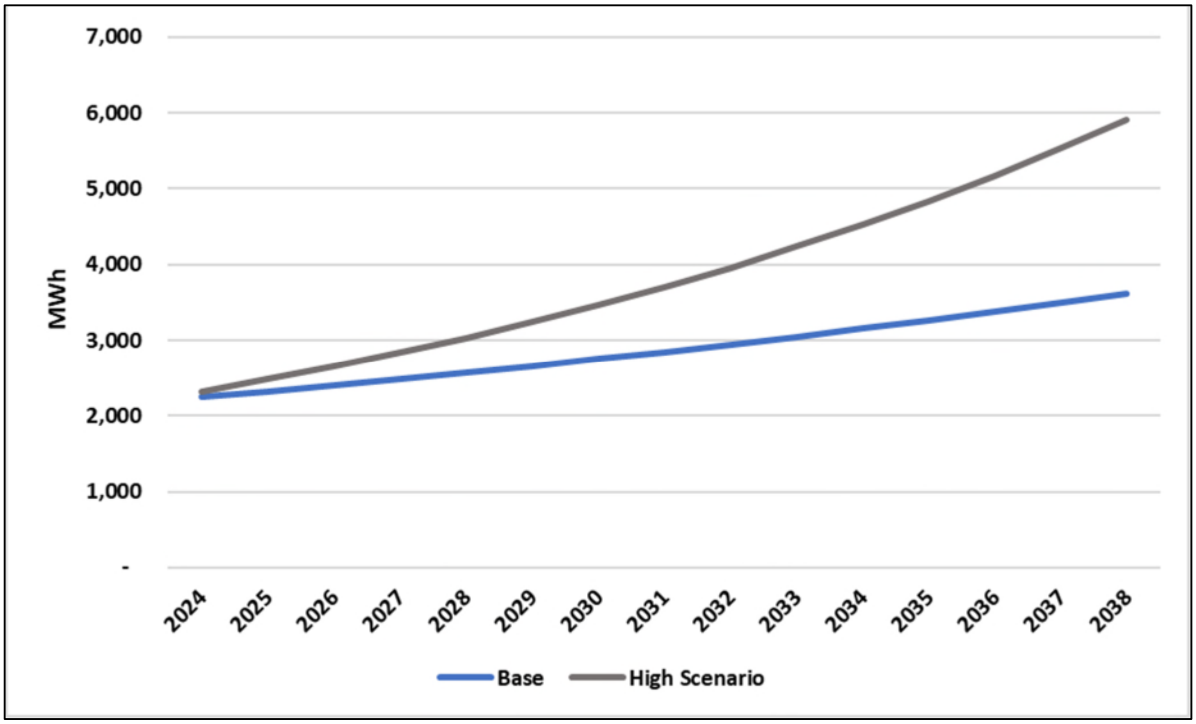
	Base Plan		Growth Plan	
	2030	2035	2030	2035
Base	1%	1%	<0.5%	<0.5%
Low Wind	1%	1%	<0.5%	<0.5%

Customer Energy Usage Sensitivity

The customer energy usage sensitivity included two scenarios that stressed how customers use energy. The first sensitivity is increasing the rate at which customers are adding distributed generation ("DG") solar, resulting in lower demand for Minnesota Power's generation. The second sensitivity is modeling the impact of implementing a Time of Use rate program or residential customers. The following insights were drawn from this analysis. Note that these sensitivities were only performed on the Base Plan.

The high DG growth sensitivity reflects a proactive approach to understanding the potential for increased customer-owned solar generation and its impact on the grid. The projected increase in DG capacity and the corresponding reduction in sales indicates a growing trend towards some customers' preference for self-generation. Minnesota Power's high DG growth scenario forecast projects approximately 5,590 new small-scale DG solar installations connected to the grid by 2038, adding about 58,000 kW of nameplate capacity. This is higher than the base case forecast of about 4,220 new installations, adding almost 44,000 kW. The high DG growth scenario is estimated to result in almost 61,000 MWh per year of reduced sales to the residential and commercial sectors, compared to the base case reduction of about 46,000 MWh per year, an incremental reduction in sales 15,000 MWh or approximately a 0.15 percent decrease in overall energy sales. This scenario assumes a 14 percent compound annual growth rate ("CAGR") in DG solar adoption from 2023 to 2038, compared to the base case CAGR of 12 percent. Figure 19 below shows a comparison of lost sales under the high DG growth sensitivity and the base case scenario. The distributed solar generation by Minnesota Power customers leads to a direct reduction in the Company's retail and required resale energy sales, as these customers generate their own electricity.

Figure 19. Reduction in Sales in Base and High DG Solar Scenarios



When modeling the higher DG solar generation sensitivity, Minnesota Power observed in the EnCompass modeling a reduction of carbon over the study period. There was also a small reduction in power supply cost over the study period, showing that higher levels DG solar has environmental and customer cost benefits. Minnesota Power continues to promote DG solar adoption through the Solar Sense program, along with recently issuing a Request for Proposals for new DG solar projects to meet the Distributed Solar Energy Standard ("DSES"). Minnesota Power will continue to monitor the impacts DG solar has on long-term planning of the power supply.

The preliminary analysis for implementing residential Time-of-Day ("TOD") rates estimated that participants reduced their load during on-peak periods by 1.88 percent on average. Off-peak periods saw an estimated 0.66 percent reduction in usage, and super off-peak periods had an estimated 4.5 percent increase, which was adjusted to be net neutral for the residential customer class overall, meaning the usage timing shifts without an overall increase or decrease. This suggests a modest but potentially valuable shift in load, which could help improve grid efficiency and reduce the need for peaking resources. However, the current impact is limited by the ongoing phased implementation and the fact that these impacts are not yet incorporated into the Base Case forecast. Realistically, the immediate cost impacts of these sensitivities might be relatively small, especially for TOD rates, given their preliminary stage and neutral net energy impact.

When modeling the TOD rates sensitivity, Minnesota Power observed in the EnCompass modeling a slight increase of carbon emissions and a small reduction in power supply cost, showing that TOD has slight but positive customer cost benefits. Further evaluation would be needed to fully understand why there was a slight increase in carbon emissions.

The high DG growth scenario will have a more direct impact on sales volumes, but the overall cost implications will depend on various factors, including the cost of solar and incentives available to make it more affordable. Minnesota Power will continue monitoring the adoption rates of distributed generation and the price responsiveness of customers under TOD rates. As DG increases and TOD programs mature, their combined effect on load profiles and system costs could become material.

Resource Adequacy Sensitivity

Changes to MISO's resource adequacy construct could have impacts to the capacity needs in Minnesota Power's Base Plan and Growth Plan. The most significant change that is coming is transitioning to the DLOL in Planning Year 2028-2029. Minnesota Power anticipates that when DLOL changes are incorporated into the resource adequacy program, there will be a significant shift in its capacity position starting in Planning Year 2028-2029. Based on preliminary snapshots of Minnesota Power's system under DLOL that MISO provided, Minnesota Power is anticipating a significant decrease in accredited capacity. Another area of uncertainty is the planning reserve margin, which has fluctuated up to +/-2 percent annually. Included in the resource adequacy sensitivity is a projected impact to Minnesota Power's capacity position when DLOL is implemented in Planning Year 2028-2029 and the planning reserve margin ("PRM") was adjusted up and down by 2 percent to capture potential system accreditation methodology shifts. These adjustments are shown in Table 32 through Table 39 in the Load and Capability Tables for Base Plan and Growth Plan section. This section expands on Tables 7 through 10 in Section V by including all study years and the PRM adjustments.

The DLOL sensitivity approximates the potential impact the change could have on Minnesota Power's capacity needs. To date, MISO has provided minimal information on the impact to our existing power supply and to future supply additions. Furthermore, the entire DLOL methodology has not been discussed at MISO stakeholder meetings or filed with the Federal Energy Regulatory Commission ("FERC") for approval. The DLOL sensitivity is provided to show the directional impacts based on the best available information obtained by the Company. Minnesota Power will continue to monitor the impacts as MISO makes future filings at FERC and more information is provided.

Historically, the system was optimized to meet winter and summer peak load plus reserves. However, with the expanded scope of the MISO seasonal construct, Minnesota Power is monitoring its capacity position across the four seasons. With the DLOL sensitivity and based on the minimal information available today, the 2025 Base Plan and Growth Plan show sufficient capacity to meet the PRM in all planning seasons from 2030 through 2039 (i.e., the capacity expansion period), when factoring in the 100 MW of market capacity purchases included in the modeling. When transitioning to DLOL in planning year 2028-2029, the Base Plan shows a less than 100 MW deficit in 2 of the 4 planning seasons, demonstrating the need for Minnesota Power to maintain its current generation portfolio and that any action taken to cease coal will require replacement capacity. It can also be seen that with a 2 percent reduction in planning reserve margin requirements during the same period, this number changes to 1 of the 4 planning seasons showing a less than 100 MW deficit, reducing the capacity market risk by half. This illustrates the inherent uncertainty surrounding the MISO resource adequacy construct during the transition to DLOL, and continuous monitoring of the impacts will be needed to fully understand the impacts to Minnesota Power customers as the program evolves at MISO and through the FERC approval processes.

F. Detailed Comparison of Plan Cost

Minnesota Power performed a cost performance comparison across the three BEC operational scenarios (2025 Plan, Full Retirement, and Full Biomass/Gas Refuel) and all load scenarios (-200 MW, Base Case, +500 MW, +1100 MW Growth Scenario, and +1500 MW). Each of these scenario pairs were sent through the capacity expansion steps outlined in Section V of the IRP to determine an optimal resource selection. Tables 17 through 31 below show the detailed cost breakdown of each plan after the resource selection in the Capacity Expansion Analysis performed in Step 1-2 across the different environmental regulation scenarios (Minnesota Reference Case, Low Regulation and Environmental Costs, and High Regulation and Environmental Costs). The results of this analysis clearly indicate how close the costs are and reaffirms the preferred plan for BEC is the most reasonable choice for customers by leveraging existing infrastructure and minimizing customer impacts as the Company transitions away from coal.

Table 17. Cost Comparison of Base Plan in -200 MW Load Scenario

15-Year NPV in the 2025 Plan -200 MW Load Scenario				
Revenue Requirements ($M)	**Power Supply**	**CO_2 Regulation**	**Environmental Cost**	**Total**
MN Reference Case	$7,101	$453	$7,057	$14,612
Low Env./Reg. Cost	$7,056	$67	$4,292	$11,415
High Env./Reg. Cost	$7,055	$830	$10,034	$17,919

Table 18. Cost Comparison of Base Plan in Base Case Scenario

15-Year NPV in the 2025 Plan Base Case Scenario				
Revenue Requirements ($M)	**Power Supply**	**CO_2 Regulation**	**Environmental Cost**	**Total**
MN Reference Case	$7,825	$564	$7,841	$16,230
Low Env./Reg. Cost	$7,725	$87	$4,979	$12,790
High Env./Reg. Cost	$7,843	$971	$10,774	$19,588

Table 19. Cost Comparison of Base Plan in +500 MW Scenario

15-Year NPV in the 2025 +500 MW Load Scenario				
Revenue Requirements ($M)	**Power Supply**	**CO_2 Regulation**	**Environmental Cost**	**Total**
MN Reference Case	$9,653	$818	$9,846	$20,317
Low Env./Reg. Cost	$9,475	$131	$6,601	$16,207
High Env./Reg. Cost	$9,731	$1,365	$13,133	$24,229

Table 20. Cost Comparison of Base Plan in +1100 MW Growth Scenario

15-Year NPV in the 2025 Plan +1100 MW Growth Scenario				
Revenue Requirements ($M)	**Power Supply**	**CO_2 Regulation**	**Environmental Cost**	**Total**
MN Reference Case	$10,785	$929	$10,443	$22,156
Low Env./Reg. Cost	$10,634	$162	$7,632	$18,428
High Env./Reg. Cost	$10,863	$1,474	$13,413	$25,750

Table 21. Cost Comparison of Base Plan in +1500 MW Load Scenario

15-Year NPV in the 2025 Plan +1500 MW Load Scenario				
Revenue Requirements ($M)	**Power Supply**	**CO_2 Regulation**	**Environmental Cost**	**Total**
MN Reference Case	$13,389	$1,267	$13,126	$27,782
Low Env./Reg. Cost	$13,152	$189	$8,665	$22,006
High Env./Reg. Cost	$13,527	$2,163	$17,477	$33,167

Table 22. Cost Comparison of Full Biomass/Gas Operation in -200 MW Load Scenario

15-Year NPV in the Full Biomass/Gas Refuel -200 MW Load Scenario				
Revenue Requirements ($M)	**Power Supply**	**CO_2 Regulation**	**Environmental Cost**	**Total**
MN Reference Case	$7,222	$407	$6,733	$14,362
Low Env./Reg. Cost	$7,202	$66	$4,269	$11,537
High Env./Reg. Cost	$7,201	$710	$9,450	$17,361

Table 23. Cost Comparison of Full Biomass/Gas Operation in Base Case Scenario

15-Year NPV in the Full Biomass/Gas Refuel Base Case Scenario				
Revenue Requirements ($M)	**Power Supply**	**CO_2 Regulation**	**Environmental Cost**	**Total**
MN Reference Case	$7,708	$538	$7,673	$15,919
Low Env./Reg. Cost	$7,592	$85	$4,903	$12,580
High Env./Reg. Cost	$7,724	$886	$10,368	$18,978

Table 24. Cost Comparison of Full Biomass/Gas Operation in +500 MW Load Scenario

15-Year NPV in the Full Biomass/Gas Refuel +500 MW Load Scenario				
Revenue Requirements ($M)	Power Supply	CO_2 Regulation	Environmental Cost	Total
MN Reference Case	$9,788	$795	$9,682	$20,265
Low Env./Reg. Cost	$9,572	$141	$6,963	$16,677
High Env./Reg. Cost	$9,844	$1,311	$12,849	$24,005

Table 25. Cost Comparison of Full Biomass/Gas Operation in +1100 MW Growth Scenario

15-Year NPV in the Full Biomass/Gas Refuel +1100 MW Growth Scenario				
Revenue Requirements ($M)	Power Supply	CO_2 Regulation	Environmental Cost	Total
MN Reference Case	$10,774	$854	$9,932	$21,561
Low Env./Reg. Cost	$10,575	$145	$7,031	$17,751
High Env./Reg. Cost	$10,833	$1,368	$12,935	$25,136

Table 26. Cost Comparison of Full Biomass/Gas Operation in +1500 MW Load Scenario

15-Year NPV in the Full Biomass/Gas Refuel +1500 MW Load Scenario				
Revenue Requirements ($M)	Power Supply	CO_2 Regulation	Environmental Cost	Total
MN Reference Case	$13,361	$1,296	$13,368	$28,025
Low Env./Reg. Cost	$13,424	$254	$10,959	$24,637
High Env./Reg. Cost	$13,509	$2,076	$17,091	$32,676

Table 27. Cost Comparison of Full Retirement in -200 MW Load Scenario

15-Year NPV in the Full Retirement -200 MW Load Scenario				
Revenue Requirements ($M)	Power Supply	CO_2 Regulation	Environmental Cost	Total
MN Reference Case	$7,388	$484	$7,245	$15,117
Low Env./Reg. Cost	$7,360	$71	$4,425	$11,856
High Env./Reg. Cost	$7,344	$752	$9,575	$17,671

Table 28. Cost Comparison of Full Retirement in Base Case Scenario

15-Year NPV in the Full Retirement Base Case Scenario				
Revenue Requirements ($M)	Power Supply	CO_2 Regulation	Environmental Cost	Total
MN Reference Case	$7,954	$597	$8,040	$16,591
Low Env./Reg. Cost	$7,941	$91	$5,124	$13,156
High Env./Reg. Cost	$8,020	$925	$10,460	$19,404

Table 29. Cost Comparison of Full Retirement in +500 MW Load Scenario

15-Year NPV in the Full Retirement +500 MW Load Scenario				
Revenue Requirements ($M)	Power Supply	CO_2 Regulation	Environmental Cost	Total
MN Reference Case	$9,708	$841	$9,954	$20,503
Low Env./Reg. Cost	$9,532	$136	$6,739	$16,407
High Env./Reg. Cost	$9,751	$1,345	$12,980	$24,075

Table 30. Cost Comparison of Full Retirement in +1100 MW Growth Scenario

15-Year NPV in the Full Retirement +1100 MW Growth Scenario				
Revenue Requirements ($M)	**Power Supply**	**CO_2 Regulation**	**Environmental Cost**	**Total**
MN Reference Case	$11,113	$894	$10,191	$22,198
Low Env./Reg. Cost	$10,945	$148	$7,117	$18,210
High Env./Reg. Cost	$11,168	$1,459	$13,344	$25,971

Table 31. Cost Comparison of Full Retirement in +1500 MW Load Scenario

15-Year NPV in the Full Retirement +1500 MW Load Scenario				
Revenue Requirements ($M)	**Power Supply**	**CO_2 Regulation**	**Environmental Cost**	**Total**
MN Reference Case	$13,580	$1,241	$12,949	$27,770
Low Env./Reg. Cost	$13,389	$224	$9,897	$23,510
High Env./Reg. Cost	$13,737	$2,103	$17,153	$32,993

G. Load and Capability Tables for Base Plan and Growth Plan

The detailed seasonal L&C for the Base Plan and Growth Plan are shown below in Table 32 through Table 39. The last two rows of each L&C table include the results for the DLOL and +/-2 percent reserve margin sensitivities. This section expands on Tables 7 through 10 in Section V by including all study years and seasons.

Table 32. 2025 Base Plan Capacity Outlook – Spring

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
System Needs: Spring															
Forecasted Gross Load	1542	1551	1541	1545	1584	1583	1582	1582	1581	1580	1576	1580	1580	1581	1586
FAC/FERC System Coincidence	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%
Coincident Load	1479	1487	1478	1482	1519	1518	1517	1517	1516	1516	1512	1516	1516	1516	1522
MISO Planning Reserve Margin (UCAP)	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
MP Obligation (Spring)	1874	1884	1872	1877	1925	1924	1922	1922	1921	1920	1915	1920	1920	1921	1928
Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Spring)															
Demand Response, Existing	80	205	66	66	66	66	66	66	66	66	66	66	66	66	66
Coal	750	730	843	804	804	259	259	259	259	259	0	0	0	0	0
Natural Gas	101	100	100	105	105	278	278	278	278	278	105	105	105	105	105
Biomass	59	56	51	49	49	49	49	49	49	49	49	49	49	49	49
Energy Storage	0	0	0	39	39	77	77	77	77	77	77	77	77	77	77
Hydro	374	373	374	375	375	375	375	375	375	375	375	375	375	375	375
Wind	192	192	192	275	275	275	275	275	275	275	275	275	275	275	275
Solar	18	18	18	18	29	29	29	29	28	27	26	25	24	22	21
Distributed Solar Energy Standard (DSES)	0	0	0	0	0	0	11	11	11	10	10	10	9	9	8
Customer Distributed Generation	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149
Existing Resources	**1724**	**1825**	**1794**	**1880**	**1891**	**1557**	**1568**	**1568**	**1567**	**1565**	**1132**	**1131**	**1129**	**1128**	**1127**
Summer Net Resource (Need)/Surplus After Existing and Approved Resources	**(150)**	**(59)**	**(78)**	**3**	**(34)**	**(367)**	**(354)**	**(354)**	**(354)**	**(355)**	**(783)**	**(790)**	**(791)**	**(793)**	**(801)**
Preferred Plan Incremental Distributed Resources (Season Accredited Capacity, Spring)															
Incremental Distributed Resources Brought Forth in This Plan	**0**	**0**	**0**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**
Summer Net Resource (Need)/Surplus After Additional Distributed Resources	**(150)**	**(59)**	**(78)**	**130**	**93**	**(240)**	**(227)**	**(227)**	**(228)**	**(228)**	**(656)**	**(663)**	**(664)**	**(666)**	**(675)**
Preferred Plan Resource Additions (Seasonal Accredited Capacity, Spring)															
Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	98	98	98
BEC3 Gas Conversion	0	0	0	0	0	372	372	372	372	372	372	372	372	372	372
Natural Gas	0	0	0	0	0	0	0	0	0	0	630	630	630	630	630
Wind	0	0	0	0	0	24	24	24	24	24	48	48	48	48	48
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Preferred Plan Resource Additions	**0**	**0**	**0**	**0**	**0**	**396**	**396**	**396**	**396**	**396**	**1050**	**1050**	**1148**	**1148**	**1148**
Projected Net Position (Need)/Surplus	**(150)**	**(59)**	**(78)**	**130**	[redacted]										
Preferred Plan Resource Additions (Direct Loss Of Load (DLOL) Capacity, Spring)															
DLOL Resourse Accreditation Adjustment (+ Increased Capacity / - Decreased Capacity)	0	0	0	0	(576)	(571)	(581)	(583)	(581)	(589)	(506)	(504)	(523)	(522)	(520)
Planning Reserve Margin System Impacts (+ Increase Obligation / - Decrease Obligation)	0	0	0	0	(406)	(405)	(405)	(405)	(405)	(405)	(404)	(405)	(405)	(405)	(406)
Projected Change In Capacity Position	0	0	0	0	(171)	(165)	(176)	(178)	(176)	(184)	(102)	(100)	(118)	(117)	(114)
DLOL Projected Net Position (Need)/Surplus	[redacted]				**(78)**	**(9)**	**(7)**	**(9)**	**(8)**	**(16)**	**291**	**287**	**365**	**365**	**360**
Planning Reserve Margin Sensitvity (+/-2%), Spring)															
DLOL Projected Net Position (Need)/Surplus + 2% PRM	**(180)**	**(89)**	**(108)**	**100**	**(108)**	**(40)**	**(37)**	**(39)**	**(38)**	**(47)**	**261**	**257**	**335**	**335**	**329**
DLOL Projected Net Position (Need)/Surplus - 2% PRM	**(121)**	**(29)**	**(49)**	**159**	**(48)**	**21**	**23**	**21**	**22**	**14**	**321**	**318**	**396**	**396**	**390**

Table 33. 2025 Base Plan Capacity Outlook - Summer

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
System Needs: Summer															
Forecasted Gross Load	1615	1615	1613	1645	1655	1655	1654	1656	1657	1657	1660	1662	1665	1668	1674
FAC/FERC System Coincidence	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%
Coincident Load	1535	1535	1532	1563	1573	1573	1572	1573	1574	1575	1577	1579	1582	1585	1591
MISO Planning Reserve Margin (UCAP)	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
MP Obligation (Summer)	1673	1673	1670	1703	1714	1714	1714	1715	1716	1717	1719	1722	1724	1727	1734
Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Summer)															
Demand Response, Existing	173	56	56	56	56	56	56	56	56	56	56	56	56	56	56
Coal	666	675	726	726	726	238	238	238	238	238	0	0	0	0	0
Natural Gas	98	101	101	101	101	259	259	259	259	259	101	101	101	101	101
Biomass	53	54	52	52	52	52	52	52	52	52	52	52	52	52	52
Energy Storage	0	0	39	39	77	77	77	77	77	77	77	77	77	77	77
Hydro	332	332	333	333	333	333	333	333	333	333	333	333	333	333	333
Wind	192	192	272	252	248	245	242	242	242	242	242	242	242	242	242
Solar	21	21	21	40	40	40	40	39	38	37	36	35	35	34	33
Distributed Solar Energy Standard (DSES)	0	0	0	0	0	16	16	15	15	15	14	14	14	13	13
Customer Distributed Generation	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Existing Resources	**1689**	**1584**	**1752**	**1751**	**1786**	**1469**	**1466**	**1465**	**1463**	**1462**	**1064**	**1063**	**1062**	**1061**	**1059**
Summer Net Resource (Need)/Surplus After Existing and Approved Resources	**16**	**(89)**	**82**	**48**	**72**	**(245)**	**(248)**	**(250)**	**(252)**	**(255)**	**(655)**	**(658)**	**(662)**	**(667)**	**(674)**
Preferred Plan Incremental Distributed Resources (Season Accredited Capacity, Summer)															
Incremental Distributed Resources Brought Forth in This Plan	**0**	**0**	**0**	**109**	**109**	**109**	**109**	**109**	**109**	**109**	**109**	**109**	**109**	**109**	**109**
Summer Net Resource (Need)/Surplus After Additional Distributed Resources	**16**	**(89)**	**82**	**157**	**181**	**(136)**	**(139)**	**(141)**	**(143)**	**(146)**	**(546)**	**(549)**	**(553)**	**(558)**	**(565)**
Preferred Plan Resource Additions (Seasonal Accredited Capacity, Summer)															
Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	98	98	98
BEC3 Gas Conversion	0	0	0	0	0	330	330	330	330	330	330	330	330	330	330
Natural Gas	0	0	0	0	0	0	0	0	0	0	605	605	605	605	605
Wind	0	0	0	0	0	36	32	32	32	32	64	64	64	64	64
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Preferred Plan Resource Additions	**0**	**0**	**0**	**0**	**0**	**366**	**362**	**362**	**362**	**362**	**999**	**999**	**1097**	**1097**	**1097**
Projected Net Position (Need)/Surplus	**16**	**(89)**	**82**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Preferred Plan Resource Additions (Direct Loss Of Load (DLOL) Capacity, Summer)															
DLOL Resourse Accreditation Adjustment (+ Increased Capacity / - Decreased Capacity)	0	0	0	(285)	(291)	(326)	(333)	(348)	(356)	(355)	(370)	(369)	(388)	(387)	(385)
Planning Reserve Margin System Impacts (+ Increase Obligation / - Decrease Obligation)	0	0	0	(97)	(142)	(98)	(98)	(98)	(98)	(98)	(98)	(98)	(98)	(98)	(99)
Projected Change In Capacity Position	0	0	0	(188)	(150)	(228)	(236)	(250)	(258)	(257)	(272)	(271)	(290)	(288)	(287)
DLOL Projected Net Position (Need)/Surplus	[redacted]	[redacted]	[redacted]	**(32)**	**32**	**2**	**(13)**	**(30)**	**(40)**	**(41)**	**181**	**178**	**254**	**251**	**245**
Planning Reserve Margin Sensitvity (+/-2%), Summer)															
DLOL Projected Net Position (Need)/Surplus + 2% PRM	**(15)**	**(119)**	**51**	**(63)**	**0**	**(30)**	**(44)**	**(62)**	**(72)**	**(73)**	**149**	**147**	**222**	**219**	**213**
DLOL Projected Net Position (Need)/Surplus - 2% PRM	**46**	**(58)**	**113**	**(0)**	**63**	**33**	**19**	**1**	**(9)**	**(10)**	**212**	**210**	**286**	**283**	**277**

Table 34: 2025 Base Plan Capacity Outlook – Fall

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
System Needs: Fall															
Forecasted Gross Load	1548	1547	1547	1592	1592	1592	1592	1594	1598	1605	1614	1625	1637	1649	1655
FAC/FERC System Coincidence	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%
Coincident Load	1468	1466	1467	1509	1509	1509	1509	1512	1515	1522	1531	1541	1551	1564	1569
MISO Planning Reserve Margin (UCAP)	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%
MP Obligation (Fall)	1676	1674	1675	1723	1723	1723	1724	1726	1731	1738	1748	1759	1772	1786	1792
Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Fall)															
Demand Response, Existing	185	63	63	63	63	63	63	63	63	63	63	63	63	63	63
Coal	800	791	828	828	828	285	285	285	285	285	0	0	0	0	0
Natural Gas	103	102	105	105	105	295	295	295	295	295	105	105	105	105	105
Biomass	41	47	50	50	50	50	50	50	50	50	50	50	50	50	50
Energy Storage	0	0	39	39	77	77	77	77	77	77	77	77	77	77	77
Hydro	360	361	357	357	357	357	357	357	357	357	357	357	357	357	357
Wind	164	164	243	243	243	243	243	243	243	243	243	243	243	243	243
Solar	17	17	17	33	33	34	34	34	34	34	34	34	34	34	34
Distributed Solar Energy Standard (DSES)	0	0	0	0	0	13	13	13	13	13	13	13	13	13	13
Customer Distributed Generation	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147
Existing Resources	**1815**	**1690**	**1847**	**1863**	**1902**	**1563**	**1563**	**1563**	**1563**	**1563**	**1089**	**1089**	**1089**	**1089**	**1089**
Summer Net Resource (Need)/Surplus After Existing and Approved Resources	**139**	**15**	**171**	**140**	**179**	**(161)**	**(160)**	**(163)**	**(167)**	**(175)**	**(659)**	**(671)**	**(683)**	**(697)**	**(704)**
Preferred Plan Incremental Distributed Resources (Season Accredited Capacity, Fall)															
Incremental Distributed Resources Brought Forth in This Plan	**0**	**0**	**0**	**114**	**114**	**114**	**114**	**114**	**114**	**114**	**114**	**114**	**114**	**114**	**114**
Summer Net Resource (Need)/Surplus After Additional Distributed Resources	**139**	**15**	**171**	**254**	**293**	**(46)**	**(46)**	**(49)**	**(53)**	**(60)**	**(545)**	**(557)**	**(569)**	**(583)**	**(590)**
Preferred Plan Resource Additions (Seasonal Accredited Capacity, Fall)															
Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	98	98	98
BEC3 Gas Conversion	0	0	0	0	0	353	353	353	353	353	353	353	353	353	353
Natural Gas	0	0	0	0	0	0	0	0	0	0	613	613	613	613	613
Wind	0	0	0	0	0	42	42	42	42	42	84	84	84	84	84
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Preferred Plan Resource Additions	**0**	**0**	**0**	**0**	**0**	**395**	**395**	**395**	**395**	**395**	**1050**	**1050**	**1148**	**1148**	**1148**
Projected Net Position (Need)/Surplus	**139**	**15**	**171**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Preferred Plan Resource Additions (Direct Loss Of Load (DLOL) Capacity, Fall)															
DLOL Resourse Accreditation Adjustment (+ Increased Capacity / - Decreased Capacity)	0	0	0	(266)	(259)	(280)	(279)	(280)	(290)	(290)	(316)	(316)	(337)	(337)	(336)
Planning Reserve Margin System Impacts (+ Increase Obligation / - Decrease Obligation)	0	0	0	(83)	(83)	(83)	(83)	(83)	(84)	(84)	(84)	(85)	(86)	(86)	(87)
Projected Change In Capacity Position	0	0	0	(183)	(176)	(196)	(196)	(197)	(206)	(206)	(232)	(231)	(251)	(250)	(250)
DLOL Projected Net Position (Need)/Surplus	[redacted]	[redacted]	[redacted]	**71**	**117**	**152**	**153**	**149**	**136**	**129**	**273**	**262**	**328**	**315**	**309**
Planning Reserve Margin Sensitvity (+/-2%), Fall)															
DLOL Projected Net Position (Need)/Surplus + 2% PRM	**110**	**(14)**	**142**	**41**	**87**	**122**	**123**	**119**	**106**	**98**	**242**	**231**	**297**	**284**	**277**
DLOL Projected Net Position (Need)/Surplus - 2% PRM	**169**	**45**	**201**	**101**	**147**	**182**	**183**	**179**	**166**	**159**	**303**	**293**	**359**	**346**	**340**

Table 35. 2025 Base Plan Capacity Outlook – Winter

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
System Needs: Winter															
Forecasted Gross Load	1626	1629	1627	1630	1673	1675	1677	1682	1687	1695	1705	1716	1728	1742	1748
FAC/FERC System Coincidence	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%
Coincident Load	1566	1569	1567	1570	1611	1613	1615	1620	1625	1632	1642	1653	1665	1678	1684
MISO Planning Reserve Margin (UCAP)	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%
MP Obligation (Winter)	1995	1999	1996	2000	2053	2055	2058	2064	2071	2080	2092	2106	2121	2138	2146
Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Winter)															
Demand Response, Existing	70	195	66	66	66	66	66	66	66	66	66	66	66	66	66
Coal	944	903	885	893	893	308	308	308	308	308	0	0	0	0	0
Natural Gas	71	73	61	62	62	267	267	267	267	267	62	62	62	62	62
Biomass	54	50	48	57	57	57	57	57	57	57	57	57	57	57	57
Energy Storage	0	0	0	39	39	77	77	77	77	77	77	77	77	77	77
Hydro	357	357	357	361	361	361	361	361	361	361	361	361	361	361	361
Wind	493	493	493	706	706	706	706	701	680	659	638	617	596	575	554
Solar	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0
Distributed Solar Energy Standard (DSES)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer Distributed Generation	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
Existing Resources	**2134**	**2217**	**2057**	**2331**	**2331**	**1989**	**1989**	**1984**	**1963**	**1942**	**1408**	**1387**	**1366**	**1345**	**1324**
Summer Net Resource (Need)/Surplus After Existing and Approved Resources	**139**	**218**	**61**	**331**	**278**	**(67)**	**(69)**	**(80)**	**(108)**	**(138)**	**(684)**	**(719)**	**(755)**	**(793)**	**(822)**
Preferred Plan Incremental Distributed Resources (Season Accredited Capacity, Winter)															
Incremental Distributed Resources Brought Forth in This Plan	**0**	**0**	**0**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**
Summer Net Resource (Need)/Surplus After Additional Distributed Resources	**139**	**218**	**61**	**459**	**405**	**61**	**58**	**47**	**20**	**(10)**	**(557)**	**(591)**	**(628)**	**(665)**	**(694)**
Preferred Plan Resource Additions (Seasonal Accredited Capacity, Winter)															
Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	98	98	98
BEC3 Gas Conversion	0	0	0	0	0	380	380	380	380	380	380	380	380	380	380
Natural Gas	0	0	0	0	0	0	0	0	0	0	622	622	622	622	622
Wind	0	0	0	0	0	74	74	74	74	74	148	148	148	148	148
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Preferred Plan Resource Additions	**0**	**0**	**0**	**0**	**0**	**454**	**454**	**454**	**454**	**454**	**1151**	**1151**	**1249**	**1249**	**1249**
Projected Net Position (Need)/Surplus	**139**	**218**	**61**	[redacted]											
Preferred Plan Resource Additions (Direct Loss Of Load (DLOL) Capacity, Winter)															
DLOL Resourse Accreditation Adjustment (+ Increased Capacity / - Decreased Capacity)	0	0	0	(758)	(758)	(808)	(813)	(816)	(800)	(788)	(813)	(792)	(791)	(770)	(749)
Planning Reserve Margin System Impacts (+ Increase Obligation / - Decrease Obligation)	0	0	0	(430)	(442)	(442)	(443)	(444)	(445)	(447)	(450)	(453)	(456)	(460)	(461)
Projected Change In Capacity Position	0	0	0	(328)	(316)	(366)	(371)	(372)	(355)	(341)	(363)	(339)	(335)	(310)	(288)
DLOL Projected Net Position (Need)/Surplus	[redacted]			**131**	**89**	**149**	**142**	**130**	**119**	**103**	**231**	**220**	**286**	**273**	**267**
Planning Reserve Margin Sensitvity (+/-2%), Winter)															
DLOL Projected Net Position (Need)/Surplus PRM +2%	**108**	**187**	**30**	**99**	**56**	**117**	**110**	**97**	**87**	**70**	**198**	**187**	**253**	**240**	**233**
DLOL Projected Net Position (Need)/Surplus PRM -2%	**170**	**249**	**92**	**162**	**121**	**182**	**174**	**162**	**152**	**136**	**264**	**253**	**320**	**307**	**301**

Table 36. Growth Plan Capacity Outlook – Spring

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
System Needs: Spring															
Forecasted Gross Load	1542	1551	1541	1617	1802	1959	2117	2277	2437	2596	2681	2685	2685	2686	2696
FAC/FERC System Coincidence	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%	95.91%
Coincident Load	1479	1487	1478	1551	1728	1879	2030	2184	2337	2490	2571	2575	2575	2576	2585
MISO Planning Reserve Margin (UCAP)	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
MP Obligation (Spring)	1874	1884	1872	1965	2190	2380	2572	2767	2961	3155	3258	3263	3263	3263	3276
Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Spring)															
Demand Response, Existing	80	205	66	66	66	66	66	66	66	66	66	66	66	66	66
Coal	750	730	843	804	804	259	259	259	259	259	0	0	0	0	0
Natural Gas	101	100	100	105	105	278	278	278	278	278	105	105	105	105	105
Biomass	59	56	51	49	49	49	49	49	49	49	49	49	49	49	49
Energy Storage	0	0	0	39	39	77	77	77	77	77	77	77	77	77	77
Hydro	374	373	374	375	375	375	375	375	375	375	375	375	375	375	375
Wind	192	192	192	275	275	275	275	275	275	275	275	275	275	275	275
Solar	18	18	18	18	29	29	29	29	28	27	26	25	24	22	21
Distributed Solar Energy Standard (DSES)	0	0	0	0	0	0	11	11	11	10	10	10	9	9	8
Customer Distributed Generation	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149
Existing Resources	**1724**	**1825**	**1794**	**1880**	**1891**	**1557**	**1568**	**1568**	**1567**	**1565**	**1132**	**1131**	**1129**	**1128**	**1127**
Summer Net Resource (Need)/Surplus After Existing and Approved Resources	**(150)**	**(59)**	**(78)**	**(85)**	**(299)**	**(823)**	**(1004)**	**(1199)**	**(1395)**	**(1589)**	**(2126)**	**(2132)**	**(2134)**	**(2135)**	**(2149)**
Preferred Plan Incremental Distributed Resources (Season Accredited Capacity, Spring)															
Incremental Distributed Resources Brought Forth in This Plan	**0**	**0**	**0**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**
Summer Net Resource (Need)/Surplus After Additional Distributed Resources	**(150)**	**(59)**	**(78)**	**42**	**(172)**	**(697)**	**(877)**	**(1072)**	**(1268)**	**(1463)**	**(1999)**	**(2006)**	**(2007)**	**(2009)**	**(2022)**
Preferred Plan Resource Additions (Seasonal Accredited Capacity, Spring)															
Energy Storage	0	0	0	0	0	0	0	0	98	98	98	98	98	295	295
BEC3 Gas Conversion	0	0	0	0	0	372	372	372	372	372	372	372	372	372	372
Natural Gas	0	0	0	0	0	711	711	711	711	937	1566	1566	1566	1566	1566
Wind	0	0	0	0	0	96	120	144	168	192	264	264	264	264	264
Solar	0	0	0	0	0	0	0	0	34	34	34	34	34	34	34
Preferred Plan Resource Additions	**0**	**0**	**0**	**0**	**0**	**1179**	**1203**	**1227**	**1384**	**1633**	**2335**	**2335**	**2335**	**2531**	**2531**
Projected Net Position (Need)/Surplus	**(150)**	**(59)**	**(78)**	**42**	[redacted]										
Preferred Plan Resource Additions (Direct Loss Of Load (DLOL) Capacity, Spring)															
DLOL Resourse Accreditation Adjustment (+ Increased Capacity / - Decreased Capacity)	0	0	0	0	(576)	(673)	(683)	(713)	(758)	(812)	(733)	(731)	(730)	(769)	(767)
Planning Reserve Margin System Impacts (+ Increase Obligation / - Decrease Obligation)	0	0	0	0	(461)	(502)	(542)	(583)	(624)	(665)	(687)	(688)	(688)	(688)	(690)
Projected Change In Capacity Position	0	0	0	0	(115)	(171)	(141)	(130)	(134)	(147)	(46)	(44)	(42)	(81)	(77)
DLOL Projected Net Position (Need)/Surplus	[redacted]				**(287)**	**311**	**185**	**25**	**(19)**	**23**	**289**	**285**	**285**	**442**	**432**
Planning Reserve Margin Sensitvity (+/-2%), Spring)															
DLOL Projected Net Position (Need)/Surplus PRM +2%	**(180)**	**(89)**	**(108)**	**11**	**(322)**	**274**	**144**	**(18)**	**(65)**	**(27)**	**238**	**234**	**234**	**390**	**380**
DLOL Projected Net Position (Need)/Surplus PRM -2%	**(121)**	**(29)**	**(49)**	**73**	**(253)**	**349**	**226**	**69**	**28**	**73**	**341**	**337**	**337**	**493**	**484**

Table 37. 2025 Growth Plan Capacity Outlook - Summer

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
System Needs: Summer															
Forecasted Gross Load	1615	1615	1613	1717	1873	2031	2189	2351	2513	2673	2765	2767	2770	2773	2783
FAC/FERC System Coincidence	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%	95.02%
Coincident Load	1535	1535	1532	1631	1780	1930	2081	2234	2387	2540	2627	2629	2632	2635	2645
MISO Planning Reserve Margin (UCAP)	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
MP Obligation (Summer)	1673	1673	1670	1778	1940	2104	2268	2435	2602	2769	2864	2866	2869	2872	2883
Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Summer)															
Demand Response, Existing	173	56	56	56	56	56	56	56	56	56	56	56	56	56	56
Coal	666	675	726	726	726	238	238	238	238	238	0	0	0	0	0
Natural Gas	98	101	101	101	101	259	259	259	259	259	101	101	101	101	101
Biomass	53	54	52	52	52	52	52	52	52	52	52	52	52	52	52
Energy Storage	0	0	39	39	77	77	77	77	77	77	77	77	77	77	77
Hydro	332	332	333	333	333	333	333	333	333	333	333	333	333	333	333
Wind	192	192	272	252	248	245	242	242	242	242	242	242	242	242	242
Solar	21	21	21	40	40	40	40	39	38	37	36	35	35	34	33
Distributed Solar Energy Standard (DSES)	0	0	0	0	0	16	16	15	15	15	14	14	14	13	13
Customer Distributed Generation	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Existing Resources	**1689**	**1584**	**1752**	**1751**	**1786**	**1469**	**1466**	**1465**	**1463**	**1462**	**1064**	**1063**	**1062**	**1061**	**1059**
Summer Net Resource (Need)/Surplus After Existing and Approved Resources	**16**	**(89)**	**82**	**(27)**	**(153)**	**(634)**	**(802)**	**(970)**	**(1139)**	**(1307)**	**(1799)**	**(1803)**	**(1807)**	**(1811)**	**(1823)**
Preferred Plan Incremental Distributed Resources (Season Accredited Capacity, Summer)															
Incremental Distributed Resources Brought Forth in This Plan	**0**	**0**	**0**	**109**	**109**	**109**	**109**	**109**	**109**	**109**	**109**	**109**	**109**	**109**	**109**
Summer Net Resource (Need)/Surplus After Additional Distributed Resources	**16**	**(89)**	**82**	**82**	**(44)**	**(525)**	**(693)**	**(861)**	**(1030)**	**(1198)**	**(1690)**	**(1694)**	**(1698)**	**(1702)**	**(1714)**
Preferred Plan Resource Additions (Seasonal Accredited Capacity, Summer)															
Energy Storage	0	0	0	0	0	0	0	0	98	98	98	98	98	295	295
BEC3 Gas Conversion	0	0	0	0	0	330	330	330	330	330	330	330	330	330	330
Natural Gas	0	0	0	0	0	697	697	697	697	912	1517	1517	1517	1517	1517
Wind	0	0	0	0	0	144	160	192	224	256	352	352	352	352	352
Solar	0	0	0	0	0	0	0	0	46	46	46	46	46	46	46
Preferred Plan Resource Additions	**0**	**0**	**0**	**0**	**0**	**1171**	**1187**	**1219**	**1395**	**1642**	**2343**	**2343**	**2343**	**2540**	**2540**
Projected Net Position (Need)/Surplus	**16**	**(89)**	**82**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Preferred Plan Resource Additions (Direct Loss Of Load (DLOL) Capacity, Summer)															
DLOL Resourse Accreditation Adjustment (+ Increased Capacity / - Decreased Capacity)	0	0	0	(285)	(291)	(456)	(460)	(511)	(586)	(631)	(667)	(665)	(664)	(703)	(702)
Planning Reserve Margin System Impacts (+ Increase Obligation / - Decrease Obligation)	0	0	0	(101)	(110)	(120)	(129)	(139)	(148)	(158)	(163)	(163)	(163)	(163)	(164)
Projected Change In Capacity Position	0	0	0	(184)	(181)	(337)	(331)	(372)	(437)	(474)	(504)	(502)	(501)	(540)	(538)
DLOL Projected Net Position (Need)/Surplus	[redacted]	[redacted]	[redacted]	**(102)**	**(225)**	**309**	**163**	**(15)**	**(73)**	**(29)**	**149**	**147**	**145**	**298**	**288**
Planning Reserve Margin Sensitvity (+/-2%), Summer)															
DLOL Projected Net Position (Need)/Surplus PRM +2%	**(15)**	**(119)**	**51**	**(134)**	**(261)**	**270**	**121**	**(59)**	**(120)**	**(80)**	**97**	**94**	**92**	**245**	**235**
DLOL Projected Net Position (Need)/Surplus PRM -2%	**46**	**(58)**	**113**	**(69)**	**(190)**	**347**	**204**	**30**	**(25)**	**21**	**202**	**200**	**197**	**351**	**341**

Table 38. 2025 Growth Plan Capacity Outlook – Fall

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
System Needs: Fall															
Forecasted Gross Load	1548	1547	1547	1664	1810	1968	2127	2289	2454	2621	2719	2730	2742	2754	2765
FAC/FERC System Coincidence	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%	94.80%
Coincident Load	1468	1466	1467	1577	1716	1866	2017	2170	2327	2485	2578	2588	2599	2611	2621
MISO Planning Reserve Margin (UCAP)	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%
MP Obligation (Fall)	1676	1674	1675	1801	1959	2131	2303	2479	2657	2838	2944	2956	2968	2982	2993
Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Fall)															
Demand Response, Existing	185	63	63	63	63	63	63	63	63	63	63	63	63	63	63
Coal	800	791	828	828	828	285	285	285	285	285	0	0	0	0	0
Natural Gas	103	102	105	105	105	295	295	295	295	295	105	105	105	105	105
Biomass	41	47	50	50	50	50	50	50	50	50	50	50	50	50	50
Energy Storage	0	0	39	39	77	77	77	77	77	77	77	77	77	77	77
Hydro	360	361	357	357	357	357	357	357	357	357	357	357	357	357	357
Wind	164	164	243	243	243	243	243	243	243	243	243	243	243	243	243
Solar	17	17	17	33	33	34	34	34	34	34	34	34	34	34	34
Distributed Solar Energy Standard (DSES)	0	0	0	0	0	13	13	13	13	13	13	13	13	13	13
Customer Distributed Generation	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147
Existing Resources	**1815**	**1690**	**1847**	**1863**	**1902**	**1563**	**1563**	**1563**	**1563**	**1563**	**1089**	**1089**	**1089**	**1089**	**1089**
Summer Net Resource (Need)/Surplus After Existing and Approved Resources	**139**	**15**	**171**	**62**	**(57)**	**(568)**	**(740)**	**(915)**	**(1094)**	**(1275)**	**(1856)**	**(1867)**	**(1880)**	**(1893)**	**(1905)**
Preferred Plan Incremental Distributed Resources (Season Accredited Capacity, Fall)															
Incremental Distributed Resources Brought Forth in This Plan	**0**	**0**	**0**	**114**	**114**	**114**	**114**	**114**	**114**	**114**	**114**	**114**	**114**	**114**	**114**
Summer Net Resource (Need)/Surplus After Additional Distributed Resources	**139**	**15**	**171**	**176**	**57**	**(454)**	**(625)**	**(801)**	**(980)**	**(1160)**	**(1741)**	**(1753)**	**(1765)**	**(1779)**	**(1790)**
Preferred Plan Resource Additions (Seasonal Accredited Capacity, Fall)															
Energy Storage	0	0	0	0	0	0	0	0	98	98	98	98	98	295	295
BEC3 Gas Conversion	0	0	0	0	0	353	353	353	353	353	353	353	353	353	353
Natural Gas	0	0	0	0	0	692	692	692	692	908	1521	1521	1521	1521	1521
Wind	0	0	0	0	0	168	210	252	294	336	462	462	462	462	462
Solar	0	0	0	0	0	0	0	0	40	40	40	40	40	40	40
Preferred Plan Resource Additions	**0**	**0**	**0**	**0**	**0**	**1213**	**1255**	**1297**	**1477**	**1735**	**2474**	**2474**	**2474**	**2671**	**2671**
Projected Net Position (Need)/Surplus	**139**	**15**	**171**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Preferred Plan Resource Additions (Direct Loss Of Load (DLOL) Capacity, Fall)															
DLOL Resourse Accreditation Adjustment (+ Increased Capacity / - Decreased Capacity)	0	0	0	(266)	(259)	(417)	(434)	(481)	(562)	(616)	(683)	(683)	(683)	(723)	(723)
Planning Reserve Margin System Impacts (+ Increase Obligation / - Decrease Obligation)	0	0	0	(87)	(95)	(103)	(111)	(120)	(128)	(137)	(142)	(143)	(143)	(144)	(145)
Projected Change In Capacity Position	0	0	0	(179)	(165)	(314)	(323)	(362)	(433)	(479)	(540)	(540)	(539)	(579)	(578)
DLOL Projected Net Position (Need)/Surplus	[redacted]	[redacted]	[redacted]	**(3)**	**(108)**	**446**	**307**	**134**	**64**	**96**	**192**	**181**	**169**	**313**	**302**
Planning Reserve Margin Sensitvity (+/-2%), Fall)															
DLOL Projected Net Position (Need)/Surplus PRM +2%	**110**	**(14)**	**142**	**(35)**	**(142)**	**408**	**266**	**91**	**18**	**46**	**141**	**129**	**117**	**261**	**250**
DLOL Projected Net Position (Need)/Surplus PRM -2%	**169**	**45**	**201**	**28**	**(73)**	**483**	**347**	**178**	**111**	**146**	**244**	**233**	**221**	**365**	**354**

Table 39. 2025 Growth Plan Capacity Outlook – Winter

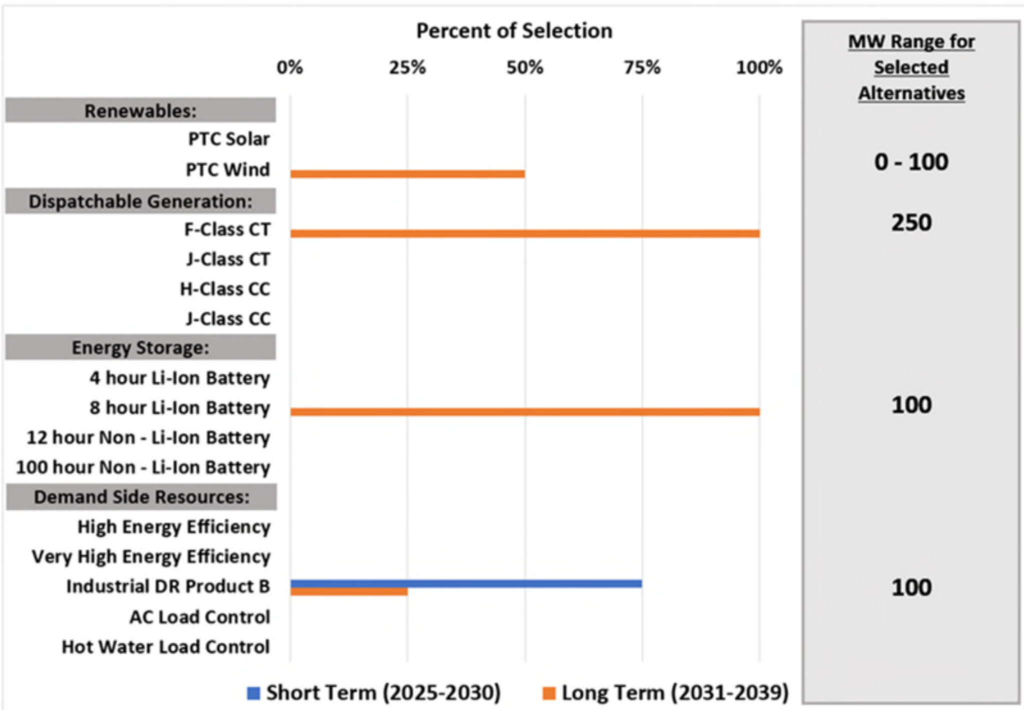
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
System Needs: Winter															
Forecasted Gross Load	1626	1629	1627	1702	1891	2051	2212	2377	2543	2711	2810	2821	2833	2847	2857
FAC/FERC System Coincidence	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%	96.33%
Coincident Load	1566	1569	1567	1639	1821	1975	2131	2290	2450	2611	2707	2717	2729	2742	2753
MISO Planning Reserve Margin (UCAP)	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%
MP Obligation (Winter)	1995	1999	1996	2089	2321	2517	2715	2917	3121	3327	3448	3462	3477	3494	3507
Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Winter)															
Demand Response, Existing	70	195	66	66	66	66	66	66	66	66	66	66	66	66	66
Coal	944	903	885	893	893	308	308	308	308	308	0	0	0	0	0
Natural Gas	71	73	61	62	87	292	292	267	267	267	62	62	62	62	62
Biomass	54	50	48	57	57	57	57	57	57	57	57	57	57	57	57
Energy Storage	0	0	0	39	39	77	77	77	77	77	77	77	77	77	77
Hydro	357	357	357	361	361	361	361	361	361	361	361	361	361	361	361
Wind	493	493	493	706	706	706	706	701	680	659	638	617	596	575	554
Solar	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0
Distributed Solar Energy Standard (DSES)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer Distributed Generation	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
Existing Resources	**2134**	**2217**	**2057**	**2331**	**2355**	**2013**	**2013**	**1984**	**1963**	**1942**	**1408**	**1387**	**1366**	**1345**	**1324**
Summer Net Resource (Need)/Surplus After Existing and Approved Resources	**139**	**218**	**61**	**243**	**34**	**(503)**	**(701)**	**(933)**	**(1158)**	**(1385)**	**(2040)**	**(2075)**	**(2111)**	**(2149)**	**(2183)**
Preferred Plan Incremental Distributed Resources (Season Accredited Capacity, Winter)															
Incremental Distributed Resources Brought Forth in This Plan	**0**	**0**	**0**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**	**127**
Summer Net Resource (Need)/Surplus After Additional Distributed Resources	**139**	**218**	**61**	**370**	**162**	**(376)**	**(574)**	**(806)**	**(1031)**	**(1257)**	**(1913)**	**(1948)**	**(1984)**	**(2021)**	**(2055)**
Preferred Plan Resource Additions (Seasonal Accredited Capacity, Winter)															
Energy Storage	0	0	0	0	0	0	0	0	98	98	98	98	98	295	295
BEC3 Gas Conversion	0	0	0	0	0	380	380	380	380	380	380	380	380	380	380
Natural Gas	0	0	0	0	0	698	698	698	698	904	1526	1526	1526	1526	1526
Wind	0	0	0	0	0	296	370	444	518	592	814	814	814	814	814
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Preferred Plan Resource Additions	**0**	**0**	**0**	**0**	**0**	**1375**	**1449**	**1523**	**1695**	**1975**	**2819**	**2819**	**2819**	**3016**	**3016**
Projected Net Position (Need)/Surplus	**139**	**218**	**61**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Preferred Plan Resource Additions (Direct Loss Of Load (DLOL) Capacity, Winter)															
DLOL Resourse Accreditation Adjustment (+ Increased Capacity / - Decreased Capacity)	0	0	0	(782)	(782)	(1069)	(1125)	(1180)	(1228)	(1288)	(1417)	(1396)	(1375)	(1394)	(1373)
Planning Reserve Margin System Impacts (+ Increase Obligation / - Decrease Obligation)	0	0	0	(449)	(499)	(541)	(584)	(627)	(671)	(715)	(742)	(745)	(748)	(751)	(754)
Projected Change In Capacity Position	0	0	0	(333)	(283)	(528)	(541)	(553)	(556)	(573)	(675)	(651)	(627)	(643)	(619)
DLOL Projected Net Position (Need)/Surplus	[redacted]	[redacted]	[redacted]	**37**	**(121)**	**471**	**334**	**164**	**107**	**145**	**231**	**220**	**208**	**352**	**342**
Planning Reserve Margin Sensitivty (+/-2%), Winter)															
DLOL Projected Net Position (Need)/Surplus PRM +2%	**108**	**187**	**30**	**4**	**(158)**	**431**	**291**	**118**	**58**	**93**	**177**	**166**	**154**	**297**	**286**
DLOL Projected Net Position (Need)/Surplus PRM -2%	**170**	**249**	**92**	**70**	**(85)**	**510**	**377**	**210**	**156**	**197**	**285**	**275**	**263**	**407**	**397**

H. Step 1-2 Capacity Expansion Analysis Result Figures

Minnesota Power performed the capacity expansion steps outlined in Section V of the IRP across the three BEC operational scenarios (2025 Plan, Full Retirement, and Full Biomass/Gas Refuel) and all load scenarios (-200 MW, Base Case, +500 MW, +1100MW "Growth Scenario," and +1500 MW), and all environmental scenarios (MN Reference Case, Customer Look Case, Low Regulation and Environmental Costs, and High Regulation and Environmental Costs).[17] Each of these scenario combinations lead to different levels and types of resource selection. The results shown here are for Steps 1 and 2 of the Capacity Expansion Analysis.

Figures 20 through 34 below summarize the results of the EnCompass Capacity Expansion Analysis by showing how often certain types of resources were selected and the range of capacities that were chosen. Each figure shows the results of a given BEC operational scenario and load scenario pair across the four different environmental scenarios.

Figure 20. Base Plan Capacity Expansion Results -200 MW Load Scenario



[17] See Table 4 in Section IV of the IRP.

Figure 21. Base Plan Capacity Expansion Results Base Load Scenario

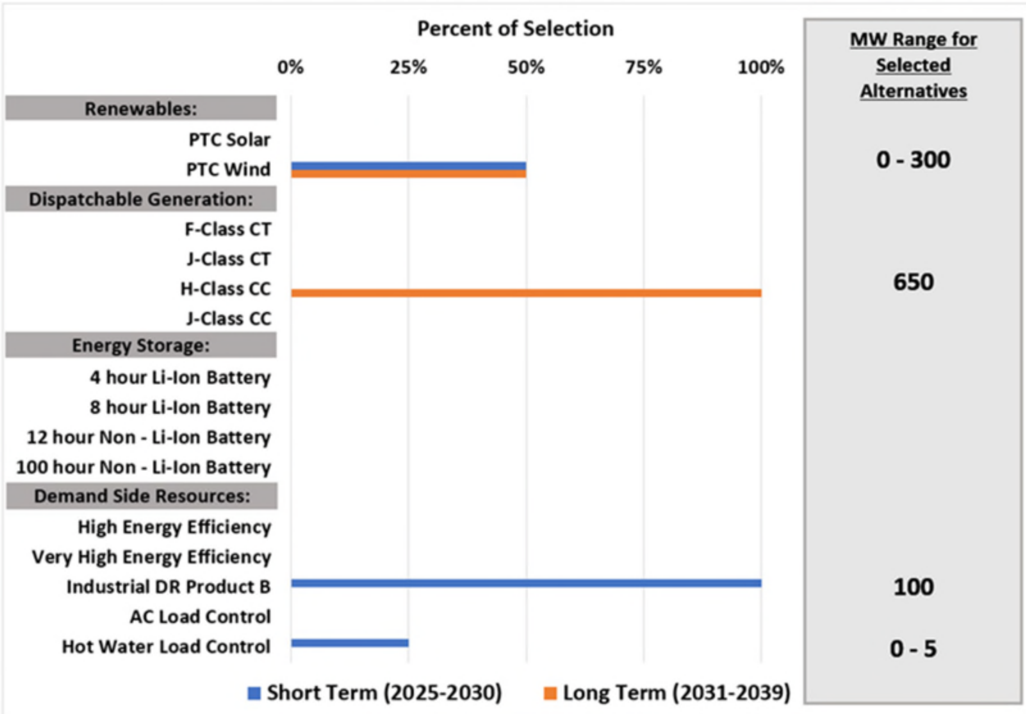


Figure 22. Base Plan Capacity Expansion Results +500 MW Growth Scenario

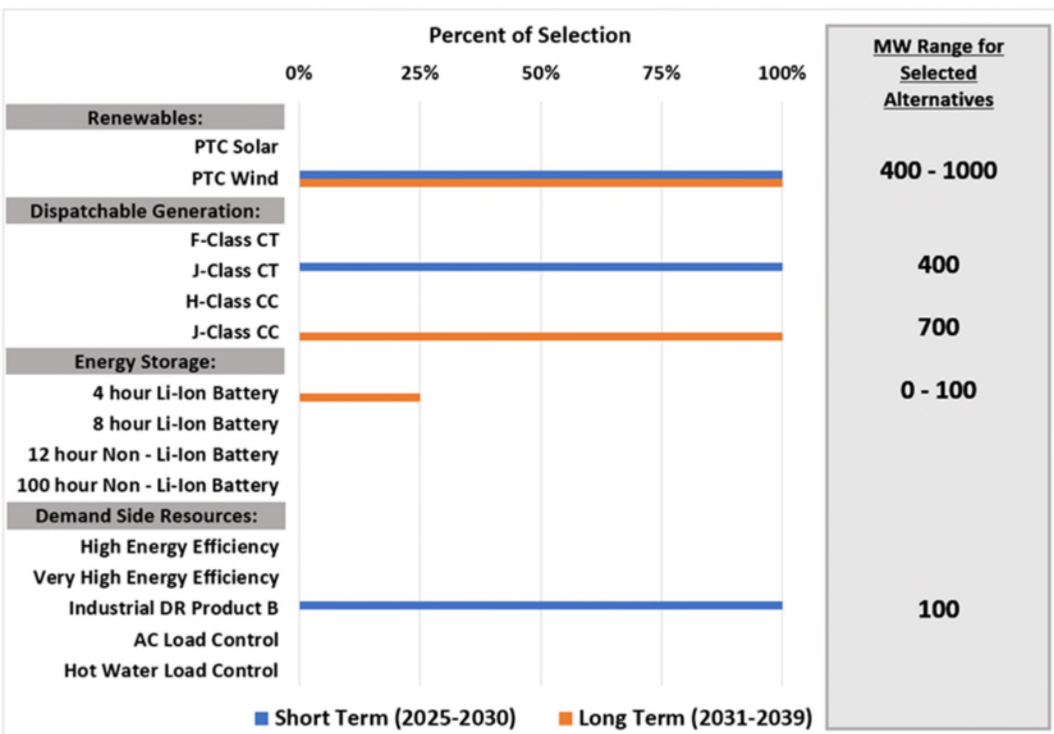


Figure 23. Base Plan Capacity Expansion +1100 MW Growth Scenario

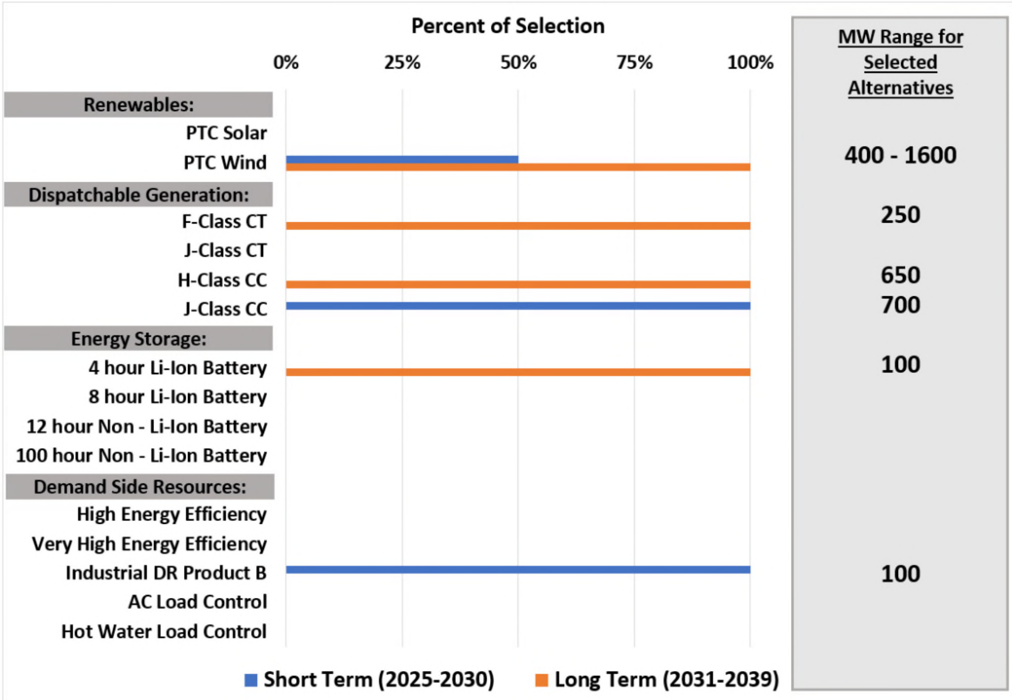


Figure 24. Base Plan Capacity Expansion Results +1500 MW Growth Scenario

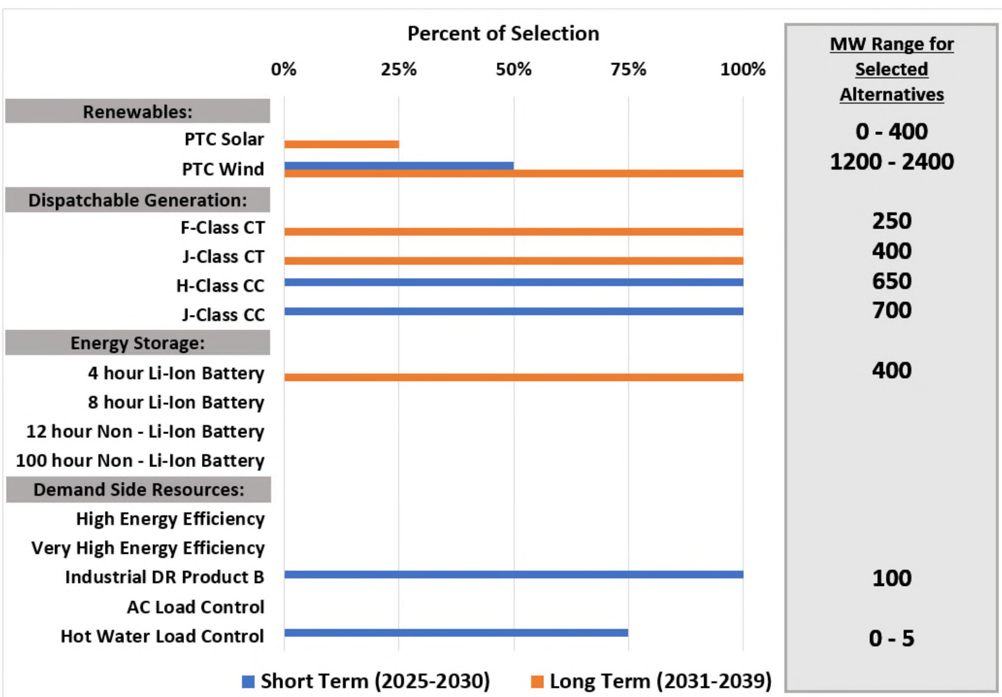


Figure 25. Full Biomass/Gas Refuel Capacity Expansion Results -200 MW Scenario

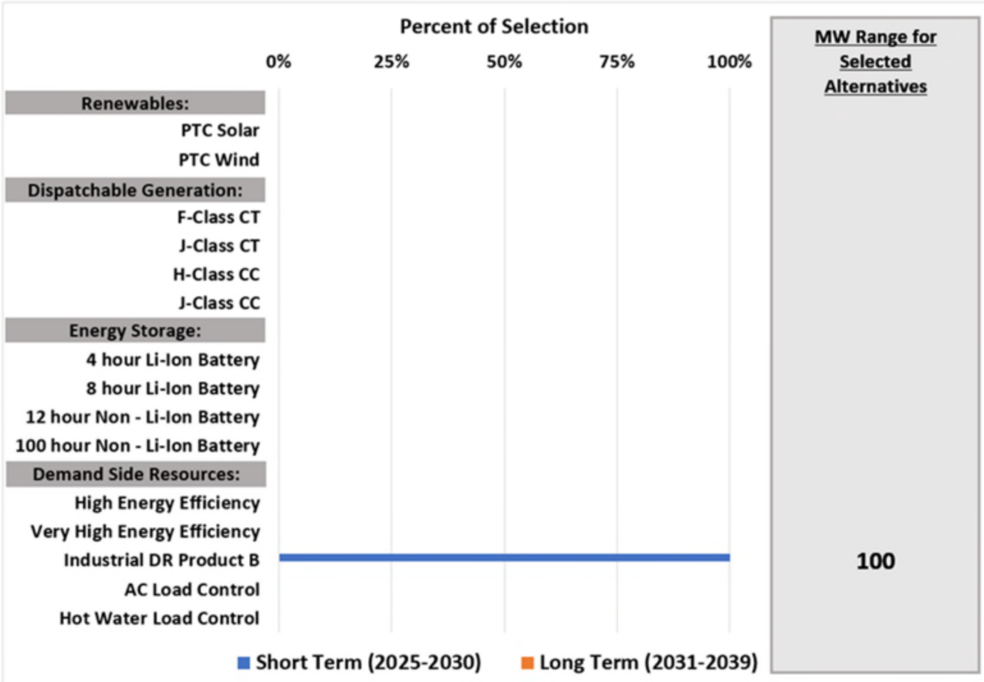


Figure 26. Full Biomass/Gas Refuel Capacity Expansion Results Base Load Scenario

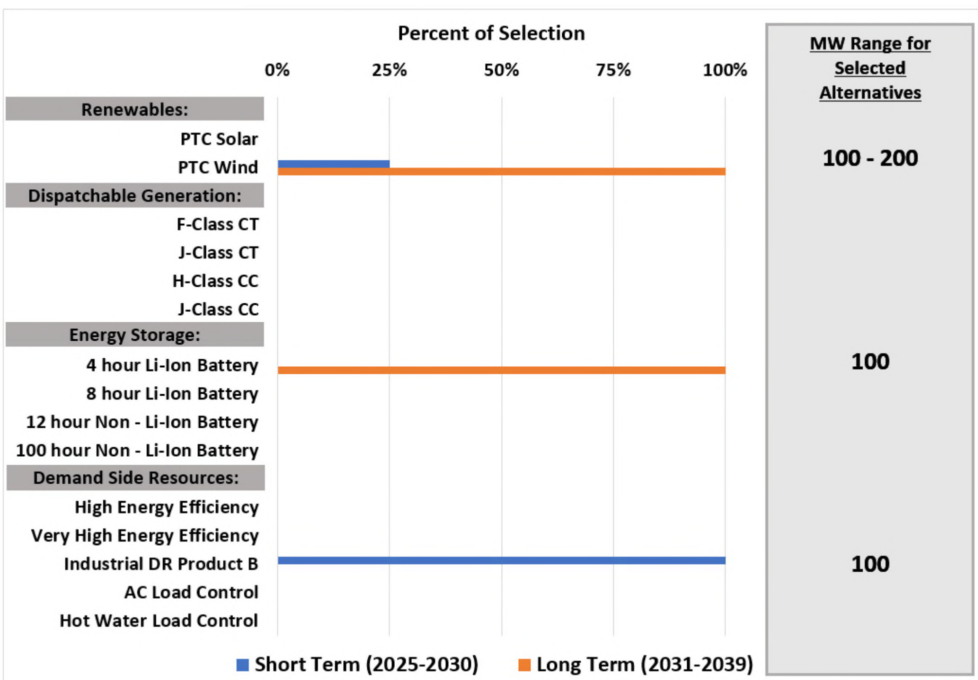


Figure 27. Full Biomass/Gas Refuel Capacity Expansion Results +500 MW Growth Scenario

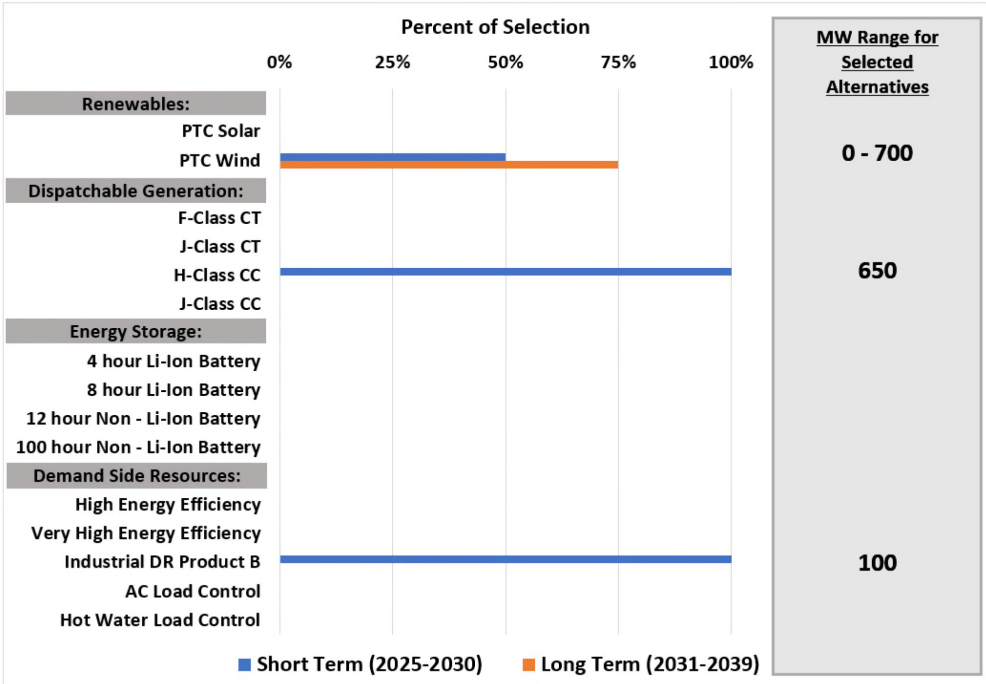


Figure 28. Full Biomass/Gas Refuel Capacity Expansion Results +1100 MW Growth Scenario

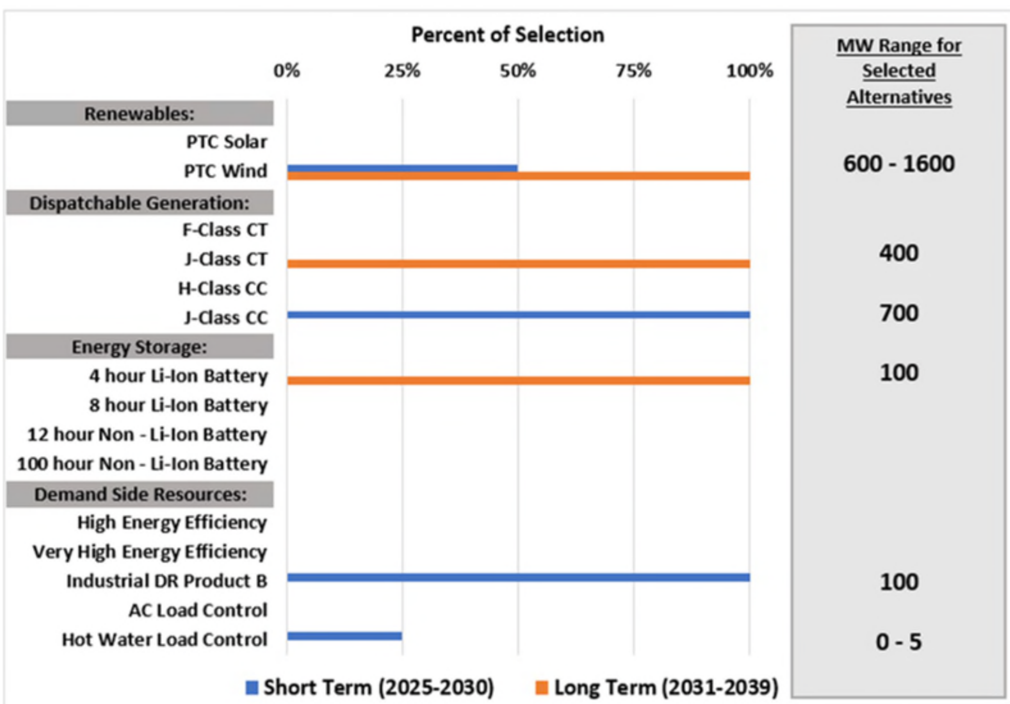


Figure 29. Full Biomass/Gas Refuel Capacity Expansion Results +1500 MW Growth Scenario

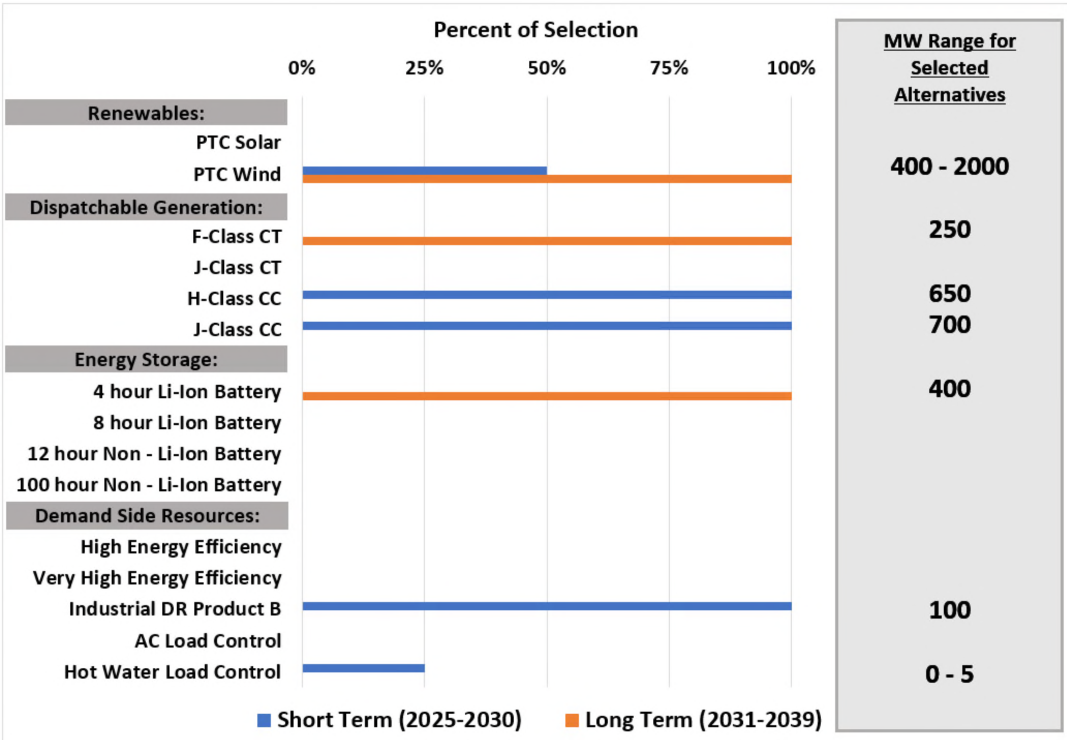


Figure 30. Full Retirement Capacity Expansion Results -200 MW Load Scenario

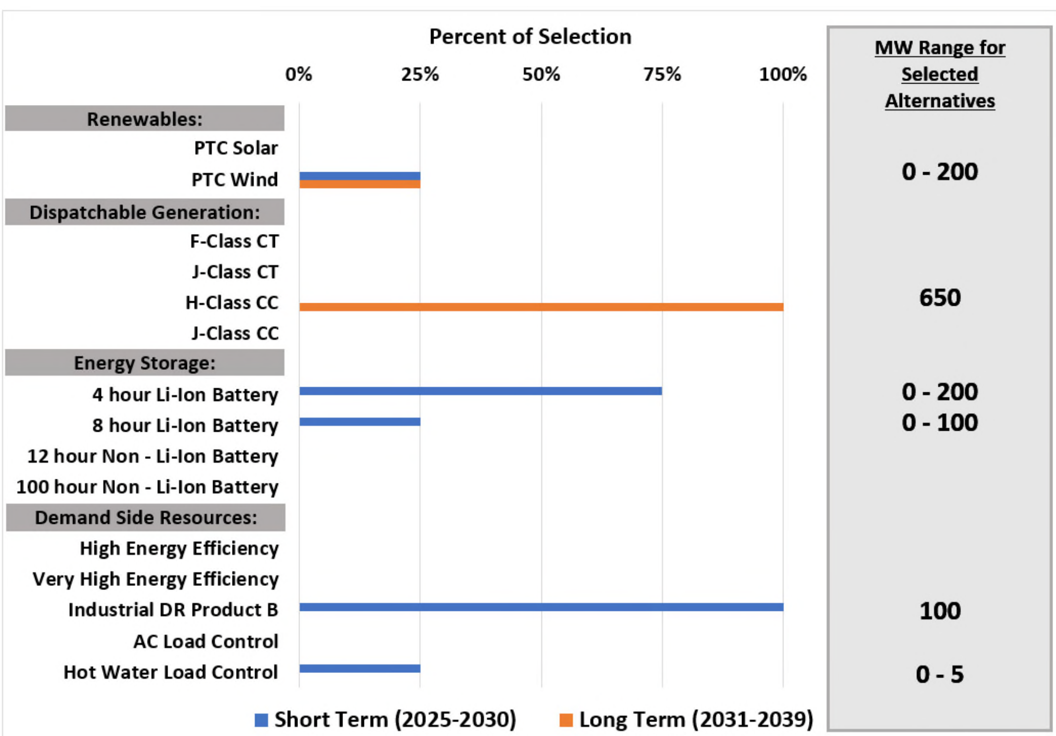


Figure 31. Full Retirement Capacity Expansion Results Base Load Scenario

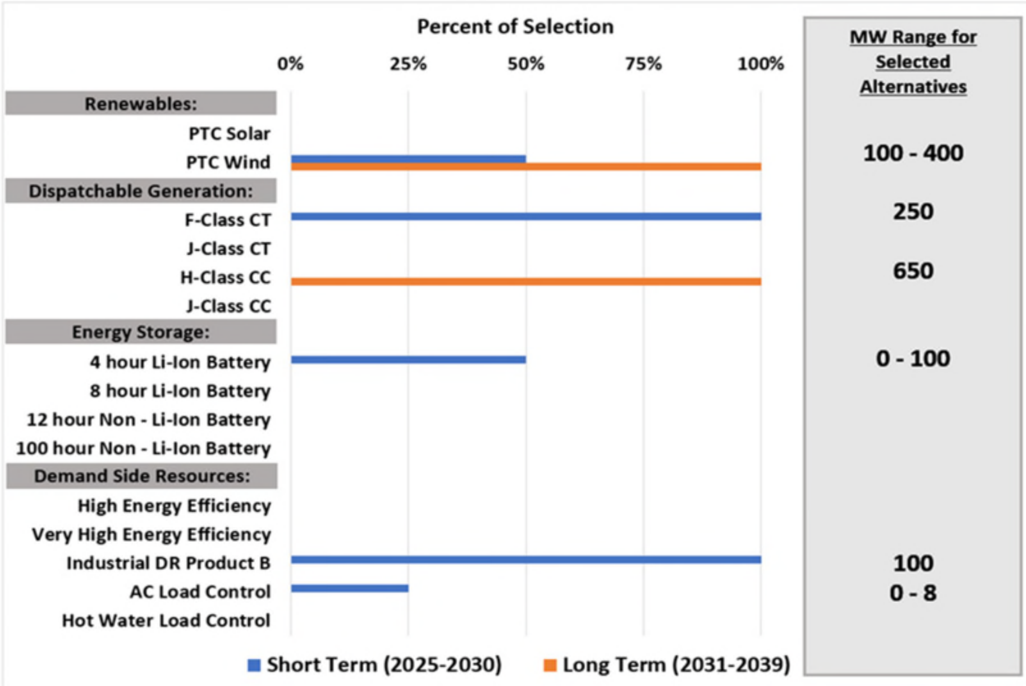


Figure 32. Full Retirement Capacity Expansion Results +500 Growth Scenario

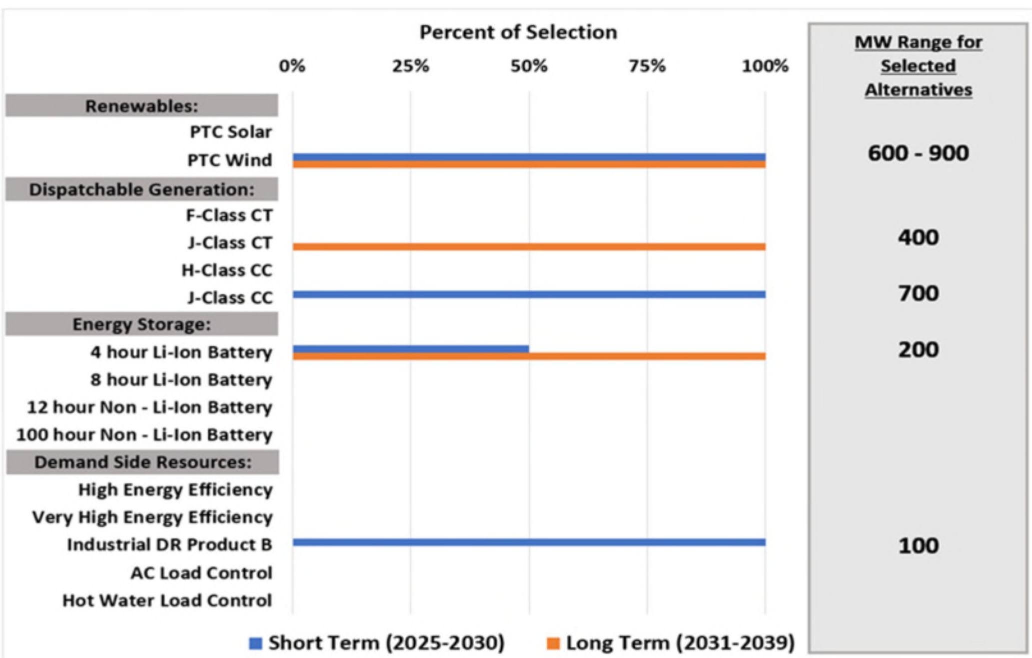


Figure 33. Full Retirement Capacity Expansion Results +1100 Growth Scenario

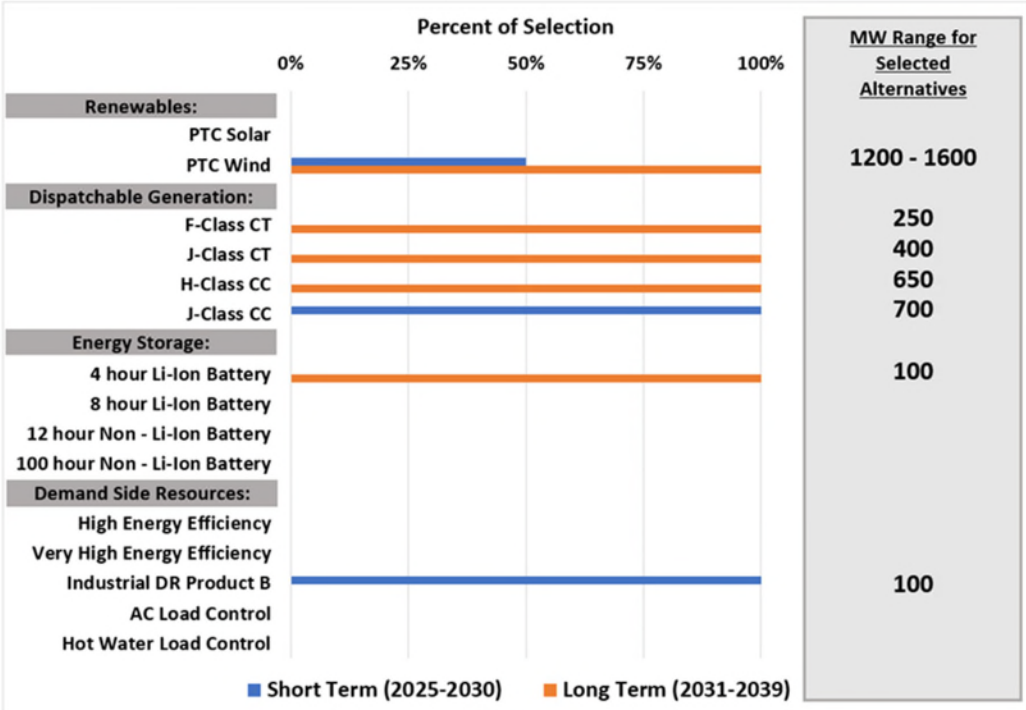


Figure 34. Full Retirement Capacity Expansion Results +1500 MW Growth Scenario