MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	November 10 and November 22, 2022		Agenda Item **1
Company	Minnesota Power (MP or the Company)		
Docket No.	**E015/RP-21-33** In the Matter of Minnesota Power's 2021-2035 Integrated Resource Plan		
Issues	1. Should the Commission approve, modify, or reject Minnesota Power's 2021 Integrated Resource Plan (IRP)? 2. When should Minnesota Power file its next IRP?		
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Relevant Documents	**Date**
Minnesota Power Initial Filing	
2021 Integrated Resource Plan	February 1, 2021
Appendices A through R (Public and Trade Secret)	February 1, 2021
Appendix M – Minnesota Power Plant Communities	February 3, 2021
Appendix Q – Securitization Plan	February 5, 2021
Supplemental Appendix K	April 1, 2021
Appendix I	April 1, 2021
Initial Comments (Intervenors)	
Office of the Attorney General (Public and Trade Secret)	April 29, 2022
Large Power Intervenors	April 29, 2022
Citizens Utility Board	April 29, 2022
Clean Energy Organizations • Comments (Public and Trade Secret) • Transmission Reliability Analysis (Public and Trade Secret) • Report (Public and Trade Secret) • Equity Analysis	April 29, 2022
Department of Commerce – Division of Energy Resources	April 29, 2022
LIUNA Minnesota/North Dakota	May 2, 2022

Supplemental Modeling

Department of Commerce	July 29, 2022

Reply Comments (Intervenors)

Office of the Attorney General	August 29, 2022
Large Power Intervenors	August 29, 2022
Citizens Utility Board of Minnesota	August 29, 2022
Clean Energy Organizations (Public and Trade Secret)	August 29, 2022
Department of Commerce – Division of Energy Resources	August 29, 2022
LIUNA Minnesota/North Dakota	August 30, 2022
Minnesota Power – Corrected Reply Comments and Attachment A (Public and Trade Secret)	September 7, 2022

Other Relevant Documents

Minnesota Power response to LPI IR 14	June 21, 2021
Minnesota Power response to LPI IR 25	September 30, 2021
Minnesota Power response to OAG IR 029	October 12, 2021
Minnesota Power - Letter	August 5, 2022
Clean Energy Organizations – Letter, Filing EPA Comments	August 8, 2022
Minnesota Power response to PUC IR 5	September 26, 2022

Participant Comments

Grand Rapids Area Chamber of Commerce – Comments	May 10, 2021
Duluth Chamber of Commerce – Comments	May 14, 2021
City of Duluth – Comments	June 10, 2021
UMN Recreational Sports Outdoor Program – Comments	April 28, 2022
City of Cohasset – Comments	April 29, 2022
IOUE Local 49 and NCSRC of Carpenters – Comments	April 29, 2022
Union of Concerned Scientists – Comments	April 29, 2022
Atlas Infrastructure – Comments	June 6, 2022
Fond du Lac Band of Lake Superior Chippewa – Comments	June 29, 2022
City of Cohasset – Reply Comments	August 26, 2022
MN Energy Transition Office – Comments	August 29, 2022
IBEW Local 31 – Comments	August 29, 2022
IOUE Local 49 and NCSRC of Carpenters	August 29, 2022
WPPI Energy – Reply Comments	August 29, 2022
Coalition of Utility Cities – Reply Comments	August 29, 2022

Minnesota Interfaith Power and Light	September 8, 2022
Honor the Earth	September 8, 2022
MN State Senator Jennifer McEwen	September 8, 2022

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I. List of Acronyms

AFR	Annual Forecast Report	LOLP	Loss of Load Probability
AIA	Affiliated Interest Agreements	LP	Large Power
BAI	Brubaker and Associates Inc	LPI	Large Power Intervenors
BEC	Boswell Energy Center	LRTP	Long Range Transmission Plan
BOP	Balance of Plant	MEPA	Minnesota Environmental Policy Act
CC	Combined Cycle	MHEB	Manitoba Hydro Electric Board
CEE	Center for Energy and Environment	MHEX	Manitoba Hydro Export
CEO	Clean Energy Organizations	MIPL	Minnesota Interfaith Power and Light
CIP	Conservation Improvement Plan	MISO	Midcontinent Independent System Operator
CT	Combustion Turbine	MP	Minnesota Power
CUB	Citizens Utility Board	MTEP	MISO Transmission Expansion Plan
DER	Distributed Energy Resources	NOMN	Northern Minnesota Voltage Stability
DG	Distributed Generation	NPV	Net Present Value
DR	Demand Response	NTEC	Nemadji Trail Energy Center
DSM	Demand Side Management	NWS	Non-Wires Solutions
DSP	Distributed Solar Parties	PPA	Power Purchase Agreement
EE	Energy Efficiency	PSE	Physicians, Scientists, and Engineers for Health Energy
EFG	Energy Futures Group	PTC	Production Tax Credit
ELCC	Effective Load Carrying Capacity	REC	Renewable Energy Credit
EPA	Environmental Protection Agency	RES	Renewable Energy Standard
EV	Electric Vehicle	RFP	Request for Proposal
FERC	Federal Energy Regulatory Commission	RICE	Reciprocating Internal Combustion Engine
GDP	Gross Domestic Product	ROFO	Right of First Refusal
GNTL	Great Northern Transmission Line	RUS	Rural Utility Service
GWh	Gigawatt hours	SES	Solar Energy Standards
HEW	Huber Engineered Woods	SREC	Solar Renewable Energy Credit
HVDC	High Voltage Direct Current	THEC	Taconite Harbor Energy Center
IDP	Integrated Distribution Plan	TIF	Tax Increment Financing
IRP	Integrated Resource Plan	VCE	Vibrant Clean Energy
ITC	Investment Tax Credit	VSSS	Voltage Support and System Strength
LOLE	Loss of Load Expectation	WDNR	Wisconsin Department of Natural Resources

II. Introduction

There are at least five major components of this case:

1. The plan for Minnesota Power (MP)'s remaining coal-fired units, Boswell Energy Center Unit 3, which is 350 nameplate megawatts (MW), and Unit 4, which is 582 nameplate MW (of which WPPI Energy holds a 20 percent ownership stake), located in Cohasset Minnesota.[1]
2. Transmission solutions to maintain reliability after MP's proposed closure of Boswell 3, as well as whether Boswell 4 can be feasibly retired or transition to economic dispatch.
3. MP's affiliated interest agreements (AIAs) for a 50 percent ownership share of the natural gas-fired, 525 MW Nemadji Trail Energy Center (NTEC) located in Superior, Wisconsin.
4. The approval or modification of MP's soonest-proposed resource acquisition, which is 200 MW of wind in 2024.
5. Whether to approve a recommendation from the Clean Energy Organizations (CEOs)[2] to retire the 44 MW Hibbard Renewable Energy Center (Hibbard), located in Duluth, Minnesota, which is capable of burning wood and wood wastes, coal, and natural gas.

As alternatives to MP's proposed resource plan, "the 2021 Plan," the Department of Commerce (Department) and the CEOs conducted their own capacity expansion modeling, using the EnCompass software, to develop modified resource plans.[3] Perhaps most notable among the alternatives is that the Department's plan retires Boswell 3 by 2025 and Boswell 4 by 2030, which MP believes is infeasible. The CEOs preferred plan removes NTEC and replaces it with substantial amounts of solar, but MP believes it needs dispatchable capacity to help ensure reliability. The CEOs model did not select new wind until 2029.

The table below compares MP's 2021 Plan to the two parties' alternative plans. For space, staff includes only the 2023-2031 timeframe, which captures both the five-year action plan and the Boswell replacement measures (i.e., generation or transmission).

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[1] Boswell Units 1 and 2 were retired in 2018.

[2] The CEOs include the nonprofit organizations Fresh Energy, Clean Grid Alliance, Sierra Club, and the Minnesota Center for Environmental Advocacy.

[3] Minn. R. 7843, Subp. 11 states: Parties and other interested persons may express support for the proposed resource plan filed by a utility. Alternatively, parties and other interested persons may file proposed resource plans different from the plan proposed by the utility. When a plan differs from that submitted by the utility, the plan must be accompanied by a narrative and quantitative discussion of why the proposed changes would be in the public interest, considering the factors listed in part 7843.0500, subpart 3.

Table 1: Comparison of Modeled IRP Plans

Year	MP 2021 Plan	Department Plan	CEOs Preferred Plan
2023			Retire Hibbard (-44 MW)
2024	200 MW wind	100 MW wind 1 transmission project	200 MW Net Zero solar[4]
2025	290 MW - 50% NTEC offtake[5]	Retire Boswell 3 (-350 MW)[6] 200 MW wind 2 transmission projects 290 MW - 50% NTEC offtake, or (see year 2027)	100 MW Net Zero solar 300 MW generic solar
2026		282 MW peaking resource[7]	
2027		116 MW - 20% NTEC offtake	
2028			
2029	Retire Boswell 3 (-350 MW) 200 MW Net Zero solar 50 MW demand response Transmission solutions for Boswell 3 retirement		Retire Boswell 3 (-350 MW) 100 MW ND wind
2030		Retire Boswell 4 and ensure that LRTP[8] is a sufficient Boswell 4 retirement solution; or, MP should acquire 593 MW of gas combined cycle (CC). 100 MW of solar sited at Boswell in the post-2030 time frame, using existing Boswell interconnection rights	200 MW MN wind 100 MW ND wind 143 MW 4-hr battery 100 MW 10-hr battery 100 MW solar-hybrid 25 MW battery-storage hybrid
2031		Boswell 4 retirement solution (LRTP or gas CC)	

[4] "Net Zero" Interconnection Service allows an interconnection customer to increase the gross generating capability at the same Point of Interconnection of an existing generating facility without increasing the existing generating facility's capacity at that Point of Interconnection (MISO Tariff, Attachment X, Section 3.2.3.1).
[5] As staff will discuss later, NTEC has been delayed until 2027; however, MP's modeling includes the approved in-service date of 2025. The Department considered an "NTEC change case," reduced NTEC offtake to 20 percent and assumed a 2027 in-service date.
[6] The Department acknowledged that the retirement date is based on its modeling results, but it can be adjusted for reliability purposes.
[7] The Department's comments discuss that it might not be feasible to retire Boswell 3 by 2025. Thus, the peaking resource – which is fuel neutral – would follow the actual Boswell 3 retirement date.
[8] LRTP is Tranche 1 Long Range Transmission Plan (LRTP) lines.

Below, staff provides a brief summary of the five issues listed above. The numbering does not indicate an order of importance.

Issue #1: Boswell Energy Center

Boswell Energy Center is the only remaining baseload generating station on MP's system, as well as in all of Northern Minnesota. Without it, MP explained, "the entire northern half of Minnesota and a large part of eastern North Dakota would be left with no operating baseload generators."[9] MP also emphasized the host community impacts of Boswell's closure, particularly in Cohasset, Grand Rapids, and Deer River. The CEOs countered that continuing Boswell Energy Center on coal is incompatible with the deep decarbonization needed to avoid catastrophic climate change. The Department found that retiring both Boswell Units 3 and 4 by the end of the decade is optimal for ratepayers. However, the Department acknowledged that a 2025 retirement date for Boswell 3 "would have to be pushed back by several years."[10] The Department also concluded that more analysis of the Boswell 4 retirement date should be considered in MP's next IRP.

MP's EnCompass modeling evaluated the following combinations of early retirement scenarios for Boswell 3 and 4 in Table 2:

Table 2: Comparison of Early Retirement Scenarios to Reference Case[11]

		Single Unit Retirement			Two Unit Retirement
	Base Case ("Do Nothing")	**2021 Plan**	**Retire BEC3 Early as Feasible**	**Retire BEC4 Early as Feasible**	**Expedited Retirement**
BEC3	No earlier than 2035	2029	2025	No earlier than 2035	2025
BEC 4	No earlier than 2035	No earlier than 2035	No earlier than 2035	2030	2030

In addition to information provided in the Petition, the appendices expand on the reliability impacts (Appendices F and P), economic analysis (Appendix K), and socioeconomic impacts (Appendix M) of Boswell retirement scenarios. Appendix K was supplemented in an April 1, 2021 filing with additional analysis of various carbon and environmental externality futures.

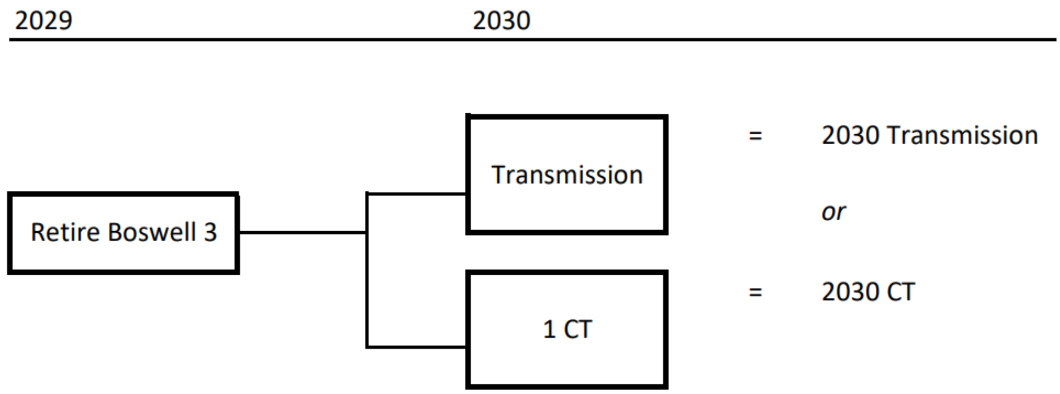
One issue the Commission will need to consider is whether MP considered a sufficient number of Boswell replacement options under the retirement scenarios. Based on its reliability analysis, MP determined that either firm dispatchable generation – e.g., a gas combustion turbine (CT) – or transmission upgrades were the only suitable replacements, although resources such as wind and solar could be selected for economic reasons. The Department accepted this approach in its modeling, while stating that in a resource acquisition proceeding,

[9] Appendix P of MP Petition, p. 11.
[10] Department, Reply Comments (August 29, 2022), p. 20.
[11] Appendix P of MP Petition, Figure 11, p. 33.

a "peaking" resource should be fuel-neutral. (This might mean that, as in Xcel's 2020-2034 IRP proceeding, the Commission may need to define what "firm dispatchable peaking resource" means.) The CEOs removed this modeling constraint and allowed their model to replace Boswell 3 with wind, solar, stand-alone storage, and solar-battery hybrids.

The Department's Initial Comments include diagrams illustrating MP's modeling constraints under each retirement scenario. For space, staff will present only two scenarios. The first is MP's 2021 Plan, taken from Attachment 1D, Figure 1D of the Department's Initial Comments, in which the modeling constraint was to select transmission or a CT. (Again, resources such as wind and solar could be selected if they were economic.)

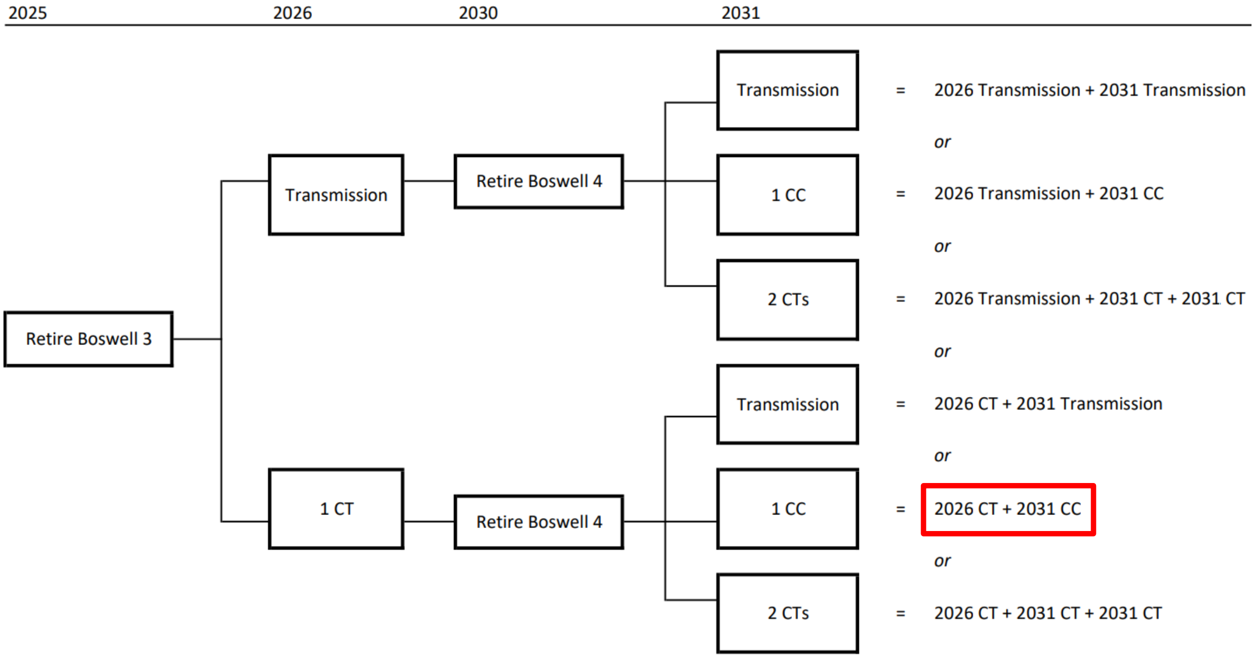
Figure 1: In MP's Step 1 Expansion Plan Database, the Boswell RS02 Retirement Scenario (Retire Unit 3 in 2029) requires one of two reliability mitigation options[12]



The second is Attachment 1F, Figure 1F from the Department's Initial Comments, which is an illustration of the Department's preferred plan, referred to as the "FastExit" plan. The Department's modeling results indicate that it is optimal to retire Boswell 3 in 2025 and Boswell 4 in 2030. As with Figure 1 above, once Boswell 3 is retired, the model can select a CT or transmission, and once Boswell 4 is retired, there are three different reliability mitigation options: 1) transmission; 2) one CC; or 3) two CTs (the Department's model selects one CC). The red box was added by staff to highlight the Department's preference, although several different factors can change the selected expansion plan.

[12] Department, Initial Comments, Attachment 1D, PDF p. 99.

Figure 2: In MP's Step 1 Expansion Plan Database, the Boswell RS04 Retirement Scenario (Retire Unit 3 in 2025 and Unit 4 in 2030) requires one of six reliability mitigation options[13]



Issue #2: Transmission Solutions after Boswell 3 Retirement

MP and the modeling parties agree that reliability solutions will be required upon the retirement of Boswell 3. However, they do not agree on the estimated cost, scale, or type of these solutions. MP's proposal to retire Boswell 3 in 2029 and develop transmission solutions to address reliability issues was informed by several reliability studies discussed in Appendix F, Part 7, which include the: MISO Generator Retirement (Attachment Y-2) Study, Northern Minnesota Voltage Stability Study, Beyond Boswell Study, Short Circuit Study, and the Synchronous Motor Starting Analysis. These studies identify several investments that will be required to provide voltage support and system strength, local power delivery, and regional power delivery. The CEOs retained Telos Energy (Telos) to provide expert reliability analysis, and Telos determined that retiring Boswell 3 "will require some transmission reinforcements, but probably fewer than MP has proposed."[14] As noted above, the Department proposed a 282 MW fuel-neutral peaking resource in 2026 following the retirement of Boswell 3.

One issue raised in parties' discussion of the economic modeling and transmission analysis is the impact of the approved MP MISO Long Range Transmission Project Iron Range – Benton – Cassie's Crossing transmission line (LRTP line, or Iron Range line). According to the Department's analysis, the LRTP line "drastically reduces the costs of the transmission Boswell constraint options, meaning that EnCompass should have a tendency to favor transmission over natural gas generation as a Boswell reliability mitigation option."[15] Moreover, the Department

[13] Department, Initial Comments, Attachment 1F, PDF p. 101.
[14] CEO, Initial Comments – Transmission Reliability Analysis (Telos Energy), Section 7.2, p. 26.
[15] Department, Comments - Supplemental Modeling (July 29, 2022), p. 26.

concluded "MISO's LRTP projects are expected to be on-line by the end of 2030. Thus, they will be available in a timely manner for the BEC 4 retirement dates studied in this docket."[16]

On August 1, 2022, in Docket No. ET2/CN-22-416, MP and Great River filed a Notice of Intent to Construct, Own, and Maintain the Iron Range – Benton County – Cassie's Crossing Transmission Project, which has been named the Northland Reliability Project.[17]

Issue #3: NTEC

Some parties and several members of the public recommend the Commission remove NTEC from the IRP. MP argued that NTEC is a Commission-approved resource, and parties have already requested and been denied reconsideration of the Commission's decision. Furthermore, the Commission's decision has been upheld in various legal proceedings, including by the Minnesota Supreme Court and the Minnesota Court of Appeals.

Since the Commission issued its January 24, 2019 *Order Approving Affiliated Interest Agreements with Conditions* (NTEC Order) and the Company filed its 2021 IRP, South Shore Energy, the Wisconsin subsidiary of MP, announced its plans to sell a portion of its ownership stake in NTEC to Basin Electric Cooperative (Basin). Basin would become a 30 percent owner in the facility, and South Shore will retain a 20 percent energy and capacity off-take from NTEC, down from the previously-approved 50 percent. Dairyland Power Cooperative (Dairyland) will continue to own 50 percent.

Importantly, all of MP's modeling runs locked-in NTEC at a 50 percent ownership share. In other words, there are no modeling runs in which MP considered NTEC at 20 percent ownership. (A 50 percent offtake from NTEC equates to approximately 290 MW, whereas 20 percent equates to approximately 116 MW.) The Department examined both 50 percent and 20 percent ownership stakes, but recommends the Commission make no determination regarding NTEC in this proceeding. Instead, the Department recommends that MP make a filing no later than 60 days following the final court ruling regarding NTEC.

Also, MP modeled the 50 percent NTEC share to be placed into service in 2025. However, the expected commercial operation has been delayed until March 2027. Table 3 below shows MP's expected NTEC construction timeline as of September 29, 2022.[18]

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[16] Department, Reply Comments (August 29, 2022), p. 13.

[17] The Northland Reliability Project involves the construction of a new approximately 150-mile, double-circuit 345/345 kV transmission connection from MP's Iron Range Substation in Itasca County to Great River Energy's Benton County Substation in Benton County and then replace an existing Great River Energy transmission line from Benton County to a new substation in Sherburne County. The new Sherburne County substation will be built as part of a separate project.

[18] MP response to PUC Information Request No. 5 (September 26, 2022).

Table 3: General NTEC Construction Schedule[19]

General NTEC Construction Schedule	
On-site relocation work	September 2022 – July 2023
Sheet pile wall construction	April 2023 – October 2023
BOP to Mobilize to site	April 2023 – May 2023
Site and BOP Construction	April 2023 – October 2025
Commercial operation	March 2027

While the Department modeled MP's 50 percent NTEC offtake by 2025, the Department also modeled an "NTEC change case," which reduced the assumed NTEC capacity and delayed the availability of that capacity until 2027.[20]

Finally, since Dairyland intends to request financial assistance from the U.S. Department of Agriculture – Rural Utilities Service (RUS), NTEC is a federal action subject to the National Environmental Policy Action (NEPA). On August 5, 2022, MP filed a letter in the instant docket attaching comments from MISO urging RUS to consider "that the electric grid is undergoing significant fleet changes" and stakeholders must "to work together to address and maintain electric reliability." On August 8, 2022, the CEOs filed a letter attaching comments from the U.S. Environmental Protection Agency (EPA), recommending the proposed action be modified to mitigate climate impacts. Until RUS makes a decision on this matter, RUS cannot provide any loans to Dairyland, although Dairyland can seek alternative sources of funding. Staff raises this issue merely so the Commission is aware of it, but staff does not believe it should affect the Commission's actions in this proceeding.

Issue #4: Resource Acquisition

MP's and the Department's modeling indicate that 200-300 MW of new wind will be cost-effective in the five-year action plan (2021-2025). Notably, however, wind in MP's five-year action was only selected if it qualified for federal Production Tax Credit (PTC) benefits, which MP assumed would not be available in 2025 and after. This means the recent passage of the Inflation Reduction Act (IRA) has not been taken into account in MP's modeling.

Resource acquisition proceedings typically follow the size, type, and timing of resources approved in a utility's five-year action plan (or slightly beyond), and given MP's and the Department's modeling results, the Commission could initiate a wind resource acquisition proceeding as part of its decision. However, the CEOs Preferred Plan does not include new wind until 2029, in part because the CEOs model selects solar early in the action plan, and in part because the CEOs model does not make new Minnesota wind available until 2026, given transmission and MISO queue constraints. Regardless, whatever action plan the Commission approves, the next step will be to guide the next steps for resource acquisition.

[19] MP response to PUC Information Request No. 5 (September 26, 2022).
[20] Department initial, p. 75.

Another issue the Commission will need to address is the Department's recommendation to issue a request for proposals (RFP) for a technology-neutral peaking resource in 2026 to replace Boswell 3. The Department's model selects a new peaking resource in 2026 following the Boswell 3 retirement in 2025; however, the Department recognizes that Boswell 3 cannot realistically be retired until several years after 2026. This may complicate the year in which a new peaking resource is needed and whether MP should begin a resource acquisition process to acquire a new peaking resource before its next IRP.

Issue #5: Hibbard Renewable Energy Center

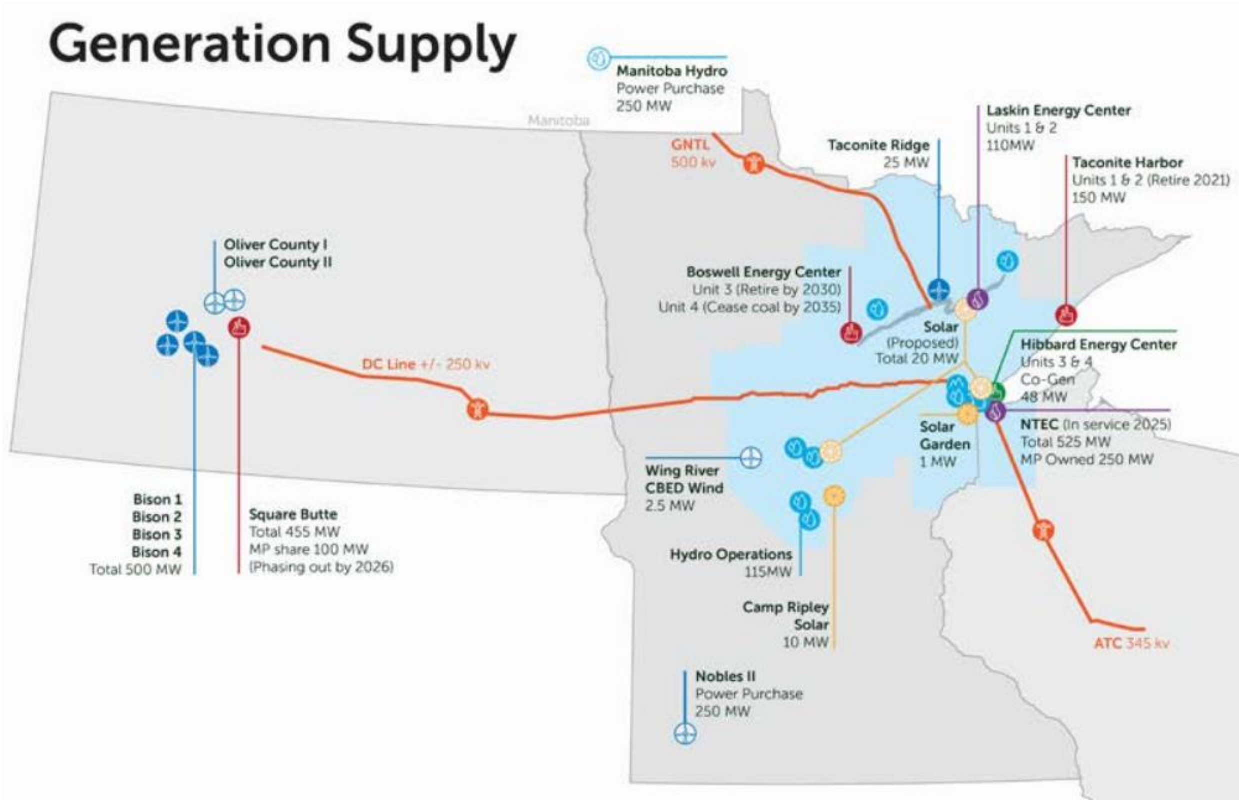
Hibbard Renewable Energy Center (HREC, or Hibbard) is a 60 MW facility,[21] located in Duluth, Minnesota, capable of burning wood and wood wastes, coal, and natural gas. Based on a report from Physicians, Scientists and Engineers for Healthy Energy (PSE), who the CEOs retained to study the public health and energy burden impacts from MP's 2021 Plan, the CEOs recommend retiring Hibbard in 2023. MP responded that the PSE report contained "factual inaccuracies and/or insufficient contextualization."[22]

III. Company Background

A division of ALLETE, Inc., MP serves about 145,000 retail electric customers and 15 municipal systems across a 26,000-square-mile service area in central and northeastern Minnesota. MP's generation supply is shown by the map below.

[21] 60 MW is from MP's 2022 Annual Forecast Report. Appendix C states that Hibbard is about 47 MW.
[22] MP, Reply Comments, p. 31.

Figure 3: Minnesota Power Generating Supply[23]



MP is a winter-peaking utility, with a peak demand of approximately 1,645 MW, although the seasonal difference between summer and winter is only about 20 MW.[24] Roughly 60 percent of MP's total sales served retail industrial customers in the taconite mining, iron concentrate, paper/pulp, and pipeline industries, which operate on a 24/7 basis. As a result, MP is a uniquely high load factor utility – its load factor is about 75 percent[25] – with less variation in demand than most utilities.

IV. 2015 IRP and NTEC Order

MP last filed an IRP on September 1, 2015, which the Commission approved with modifications on July 18, 2016.[26] Among other things, the Commission found that it was unreasonable to invest in sulfur dioxide (SO_2) reduction at the coal-fired Boswell Units 1 and 2, and instead required the Company to retire Boswell 1 and 2 when sufficient energy and capacity are available, but no later than 2022. MP retired Boswell 1 and 2 in December 2018.

The Commission's Order also required MP to file its next IRP on February 1, 2018. However, the following events delayed this IRP filing:

[23] Appendix P of MP Petition, Figure 2, p. 6.

[24] In 2021, MP's summer season peak was 1,625 MW and was reached in July, which is similar to its 1,645 MW February peak, as the Company reported in its 2022 AFR.

[25] MP, 2022 AFR, Docket No. 22-11, p. 76.

[26] Order Approving Resource Plan with Modification, July 18, 2015, Docket No. 15-690.

On June 8, 2017, MP announced its Energy*Forward* Resource Package, which included NTEC, Nobles 2 Wind (which became operational in December 2020), and Blanchard Solar (which did not come to fruition). The Commission referred NTEC to the Office of Administrative Hearings and, in its Referral Order, approved MP's request to delay the next IRP filing to October 1, 2019.

On January 24, 2019, the Commission issued its NTEC Order, which required MP to include in its next IRP:

1. a baseload retirement analysis examining the early retirement of Boswell 3 and 4;
2. a securitization plan that could be used to mitigate potential ratepayer impacts associated with any early retirement of one or both of the Boswell 3 and 4 facilities; and
3. a proposed bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years.

The NTEC Order extended the deadline for MP to file its IRP by one year, from October 1, 2019 to October 1, 2020.

On May 29, 2020, MP requested a six-month extension, from October 1, 2020 to April 1, 2021, to file its IRP. The Commission allowed an extension for a February 1, 2021 filing date.

Appendix Q of the Petition is MP's Securitization Plan, developed to investigate whether securitizing the outstanding costs of Boswell 3 and 4 could help mitigate the costs of an early plan retirement. In 2019, MP engaged the Rocky Mountain Institute (RMI) to evaluate securitization as a possible mechanism to accelerate the retirement of Boswell 3 and 4. MP ultimately concluded:

> Though securitization may not be necessary as a rate mitigation effort in Minnesota Power's specific case of retiring the Boswell Energy Center units early, it has high potential as a useful tool in mitigating other energy transition issues. In the event that securitization is legislated in Minnesota, the Company may consider it for other costs, such as transmission and distribution infrastructure or potential future storm response costs.[27]

The Department was the only party to address securitization. The Department stated that the optimal plan is for MP to retire Boswell 3 in 2025 and Boswell 4 in 2029. Neither MP's modeling nor the Department's modeling reflects any potential savings from securitization.

V. Summary of MP's Short-Term and Long-Term Plan

This section summarizes MP's short- and long-term action plans and provides the resulting impact on the Company's energy outlook. First, staff provides a summary of MP's "Key Planning Principles" discussed in the Petition, which MP stated reflects stakeholders' main concerns during the pre-filing stakeholder process and helped inform the 2021 Plan.

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[27] Appendix Q of MP Petition, p. 4.

Key Planning Principles

1. Advance sustainability

MP plans to provide 100 percent carbon-free energy by 2050, and the IRP decarbonizes the Company's generation portfolio such that it will be coal-free by 2035.

2. Ensure reliability

Resource adequacy requirements are met throughout the planning period, and grid improvements will provide energy availability during extreme weather conditions and under varying levels of renewable production.

3. Manage costs

MP's 2021 Plan is least-cost under multiple scenarios tested, and it avoids large changes in customer costs over a short period of time.

4. Allow time for a just transition for host communities

Power plant retirements must incorporate a just transition for the employees and communities directly affected. A resource plan should consider impacts to local tax base, jobs, industry, and community health. MP has transitioned seven of its nine coal-fired facilities in the region, and each has required careful planning and preparation.

5. Allow time for technology to develop and advance

A carbon-free future will require advancements in technology to provide adequate energy resources and ensure safe, reliable, and affordable electric service. Efficiencies and costs must continue to improve for technologies in place today, and new technologies must also emerge for critically-important dispatchable resources.

6. Handling Uncertainty/Resource Adequacy

While not incorporated as one of its five key principles, MP discussed how MISO is working with stakeholders on changes to the MISO resource adequacy construct that could impact how MP plans for the capacity and energy needs of the system in resource planning. MP stated, "the resource adequacy construct needs to continue to adapt for even higher levels of renewable energy penetration, and to ensure there can be energy coverage for all system conditions to ensure reliability. In the immediate future, the changes are focused on three broad categories: 1) multi-season resource adequacy construct, 2) accreditation enhancements for solar and energy storage, and 3) regional resource assessments of changing reliability risk profile."[28]

[28] Petition, p. 36.

Short-Term (Five-Year) Action Plan

Under Minn. R. 7843.0400 (Contents of Resource Plan Filing), a utility must submit an "action plan," which is a description of the activities the utility intends to undertake over a five-year period beginning with the filing date. The action plan must include a schedule of key activities, including construction and regulatory filings.

1. Retire the remaining 150 MW of the coal-fired Taconite Harbor Energy Center.

Taconite Harbor Energy Center (THEC) was originally constructed as a three-unit, 225 MW (75 MW each) coal plant. THEC 1, 2, and 3 were placed into service in 1957, 1957, and 1967, respectively. Unit 3 ceased coal-fired operations in 2015 and has been retired. Units 1 and 2 were idled in Fall 2016 and ultimately retired in September 2021. MP is not proposing to modify the existing accounting life of THEC, which runs through 2026, in this IRP.

2. Construct three solar projects – Laskin Solar, Sylvan Solar, and Duluth Solar – totaling approximately 21 MW in the Company's service territory by December 2022.

Laskin Solar is located near Hoyt Lakes, adjacent to the Laskin Energy Center; Sylvan Solar is near MP's Sylvan hydroelectric station west of Brainerd, on the Crow Wing River; and Duluth Solar is in northeast Duluth. The Commission approved the projects on June 29, 2021 in Docket No. 20-828.

Order Point 8 of the Commission's June 29, 2021 Order required MP to report on how the Laskin, Sylvan, and Duluth Solar projects are consistent with the information requested in the COVID-19 Economic Recovery docket[29] and other relevant dockets. In a July 29, 2022 Economic Recovery Report, MP stated that, for the three projects combined, MP has executed 60 contracts with local suppliers and contractors totaling $29.6 million worth of work.[30]

In an August 23, 2022 compliance filing, MP stated that the expected in-service date for the Duluth and Laskin projects remains December 2022, while the Sylvan project may be delayed into 2023.

3. Adapt operations at Boswell 3 to move to economic dispatch within the MISO market in 2021 and continue investigating Boswell 4 for future economic dispatch, in coordination with MISO and joint owner WPPI Energy.

On March 1, 2022, MP made a compliance filing in Docket No. 19-704 (Self-commitment of baseload generation facilities), in which the Company discussed its transition of Boswell 3 to economic dispatch. MP stated it was able to reduce the operational minimums from 175 MW to 75 MW. According to MP, this created significantly more flexibility for the unit in its daily dispatch and provided an overall customer benefit when the units were self-committed and

[29] Docket No. E, G-999/CI-20-492.
[30] Docket No. 20-828, Q2 2022, COVID Economic Recovery Report (July 29, 2022).

operating in a must-run status. For Boswell 4, MP is working with co-owner, WPPI, on an economic dispatch plan. The filing explained that in 2018 MP reduced the operational minimums for Boswell 4 from approximately 300 MW to 210 MW. In December 2021, Boswell 4 was able to lower the Emergency Minimums from 210 MW to 185 MW.

One area MP and WPPI continue to try to understand is market coordination and the customer impact of a jointly-owned unit. In the MISO market, Boswell 4 is modeled as two individual, distinct generators, and each ownership share has its own generator node. Under a must-run dispatch, MP coordinates with WPPI on the energy market parameters to ensure a consistent dispatch of Boswell 4 that optimizes the unit's economics.

4. Maintain leadership in conservation programs and electrification efforts.

MP has surpassed the state's conservation goals for the last decade and has committed in its most recent Conservation Improvement Program (CIP) Triennial Filing to an energy savings goal of 2.5 percent each year through 2023. The Company is also implementing infrastructure investments, rate design changes, and electric vehicle (EV) programs to position for a future grid that accommodates further electrification.

5. Implement the Product C Demand Response program for industrial customers in 2022.

On January 4, 2021, MP filed a petition for the approval of a new demand response (DR) product, Product C, in Docket No. 21-28. Product C is a Market Surplus Service Capacity Product that allows MP to work with participating customers to identify options for excess capacity that does not fit into other DR products, or MP's resource adequacy needs. MP received Commission approval of eight multi-year Product C agreements with industrial customers that will collectively enable between 100 and 202 MW of DR to be sold each year from 2022 to 2028. Staff notes that Product C subscriptions were modeled in the IRP as DR not available to MP for MISO Resource Adequacy requirements.

6. Add 200 MW of new wind by 2025.

Over the past 15 years, MP has added over 850 MW of new wind. MP's 2021 Plan proposes an additional 200 MW of new wind by 2025. MP explained that, in general, wind is selected earlier in the study period due to the availability of the federal PTC. EnCompass selected 100 to 300 MW of PTC-qualified wind prior to 2025, regardless of whether carbon regulation costs were included. MP assumed wind available in 2025 and beyond would receive no PTC benefits.

Long-Term Action Plan (2026-2035)

1. Retire Boswell Unit 3 by December 31, 2029.

MP's "Status Quo" scenario was developed to compare a scenario that did not retire Boswell 3 or 4, to combinations of one- and two-unit Boswell retirement dates—as early as 2025 for Boswell 3 and as early as 2030 for Boswell 4. According to MP's modeling, retiring Boswell 3 by

2030 while keeping Boswell 4 operational through the planning period was commonly a least-cost result among varying fuel price, environmental impact, and market price sensitivities.

2. Add 200 MW of new solar by 2030 at the Boswell site or another MP site, which will leverage existing interconnections and reinvest in host communities.

In general, EnCompass selected "Net Zero" solar as opposed to "generic" solar. Net Zero solar is able to interconnect at an existing generation site in Minnesota. Importantly, Net Zero and generic solar (i.e., solar that is not location-specific) were assumed to have the same capital costs. Up to 300 MW of Net Zero solar was available to be selected, but MP assumed there would be no transmission interconnection upgrade costs.

3. Implement transmission solutions to address reliability issues associated with retirement of Boswell Unit 3.

Appendix F of the Petition discusses MP's recent transmission planning upgrades resulting from coal plant closures in MP's service territory and reliability studies of the current transmission system. Staff notes that Tables 9 and 11 and Figure 20 of Appendix F are particularly informative for understanding MP's identified transmission solutions and transmission cost assumptions in EnCompass.

Appendix P is MP's Baseload Retirement Study required by the NTEC Order. Appendix P summarizes Boswell retirement from four perspectives: 1) reliability; 2) socioeconomic; 3) cost; and environmental issues.

4. Investigate options for refuel or remission of Boswell 4.

Section V of the Petition briefly describes conceptual ideas, such as hydrogen and carbon capture technologies, that could play a role as carbon-free options. For example, in scenarios in which Boswell 3 and 4 are retired, a 593 MW hydrogen-ready CC is selected, but MP is not proposing that this CC will necessarily be the Boswell 4 replacement resource.

5. Pursue up to 50 MW of demand response by 2030.

Large Power Intervenors (LPI) Information Request No. 14 inquired about the specific type of DR MP could pursue. MP replied, "[s]ince the type of new demand response has not been identified, it is not known what level of energy curtailment would be included with the additional 50 MW of DR."[31] Also, MP noted that the additional 50 MW of DR by 2030 is not reflected in the Company's capacity outlook.[32] Taken together, staff interprets MP's incremental DR to be a general goal, not necessarily a proposed resource.

Energy Portfolio

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[31] MP response to LPI Information Request No. 14 (June 21, 2021).
[32] MP, Petition, p. 60.

The impact of the 2021 Plan is depicted by the figures below. Figure 4 shows MP's base case energy outlook prior to the implementation of the 2021 Plan—that is, the energy mix if only existing resources are dispatched. Note that coal is initially displaced by NTEC coming online, but returning roughly to present-day output by 2035.

Figure 4: Base Case Energy Position Supply Outlook[33]

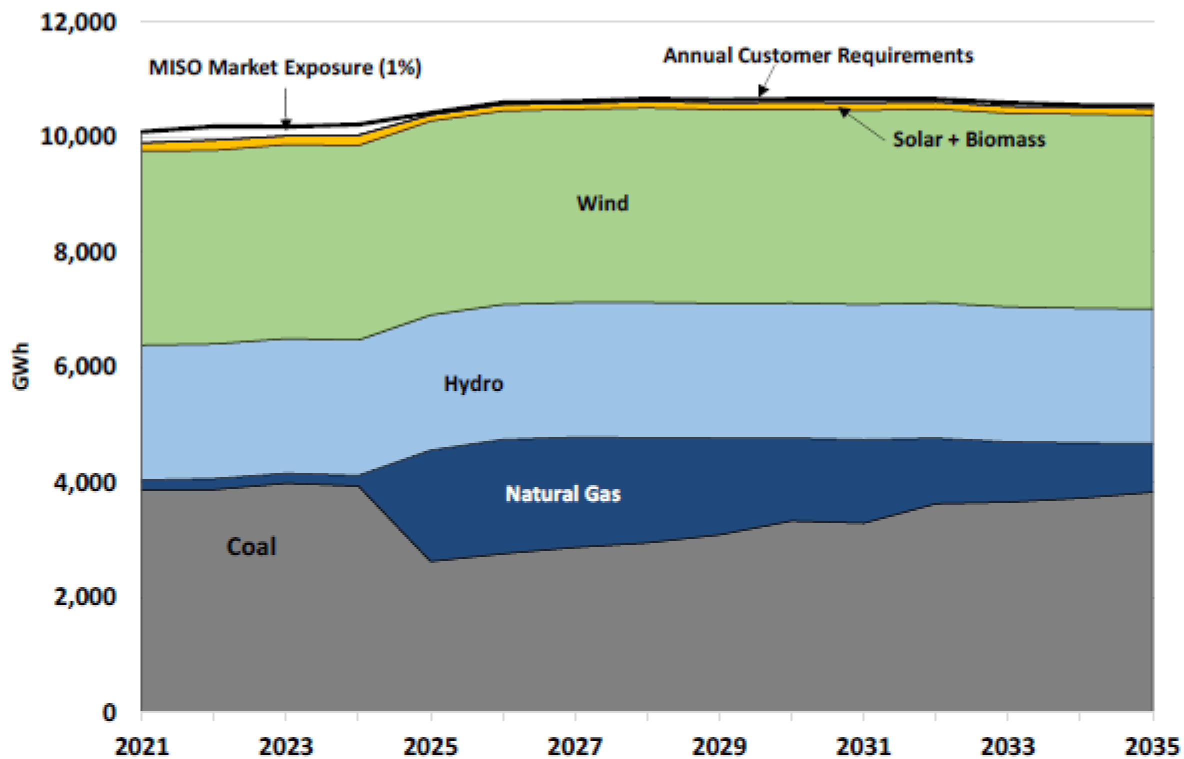
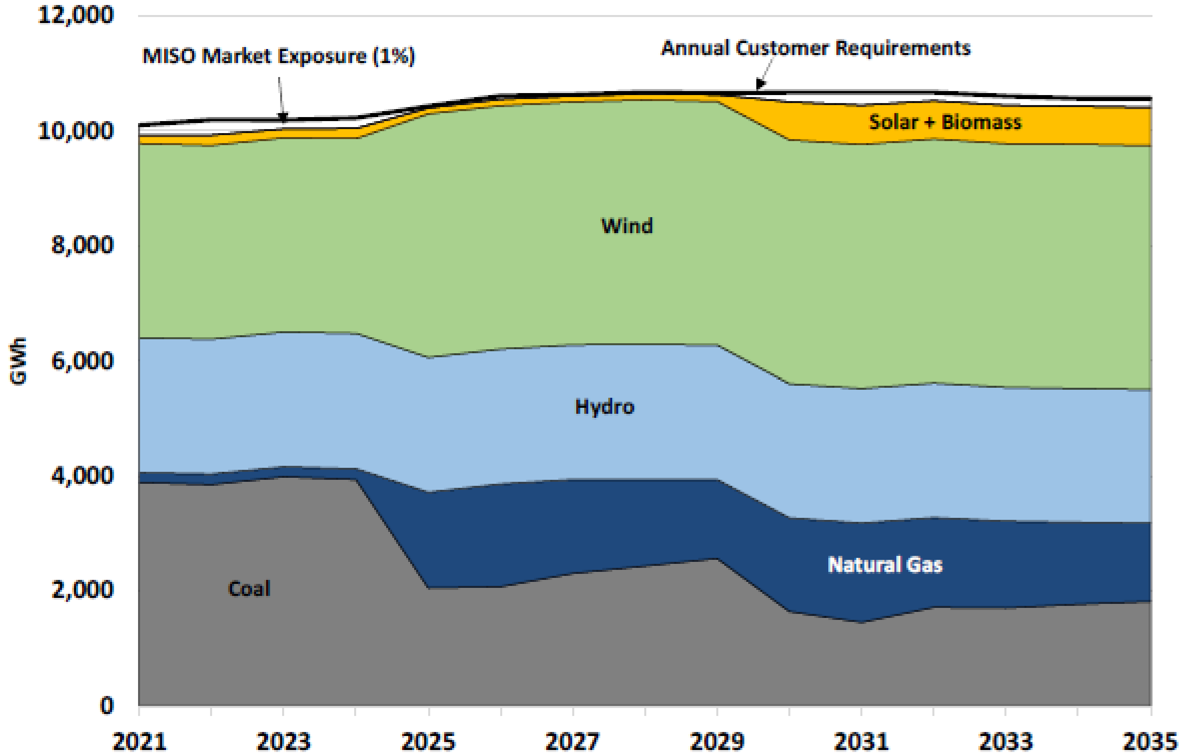


Figure 5 shows how the 2021 Plan changes MP's energy outlook. Notably, as with the figure above, coal generation declines once NTEC comes online, but then declines even further once Boswell 3 is retired. Solar becomes a much more meaningful contributor in 2029, and wind, hydro, and natural gas become MP's largest sources of energy supply. (This assumes a 50 percent NTEC ownership offtake.)

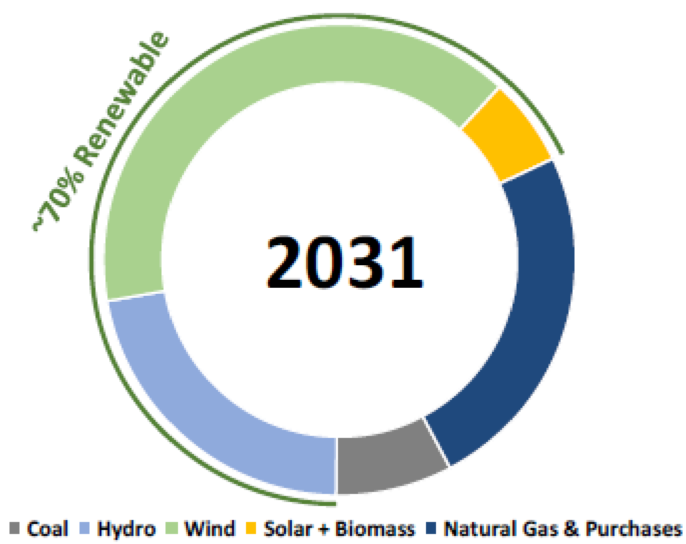
[33] MP, Petition, Figure 2, p. 18.

Figure 5: 2021 Plan Energy Position Outlook[34]



As shown in Figure 6, MP estimates that the 2021 Plan will increase its renewable generation to approximately 70 percent of its total power supply mix. Again, this largely comes from MP's substantial amount of wind and hydro.

Figure 6: 2021 Plan Power Supply Mix in 2031[35]



[34] MP, Petition, Figure 18, p. 62.
[35] MP, Petition, Figure 19, p. 63.

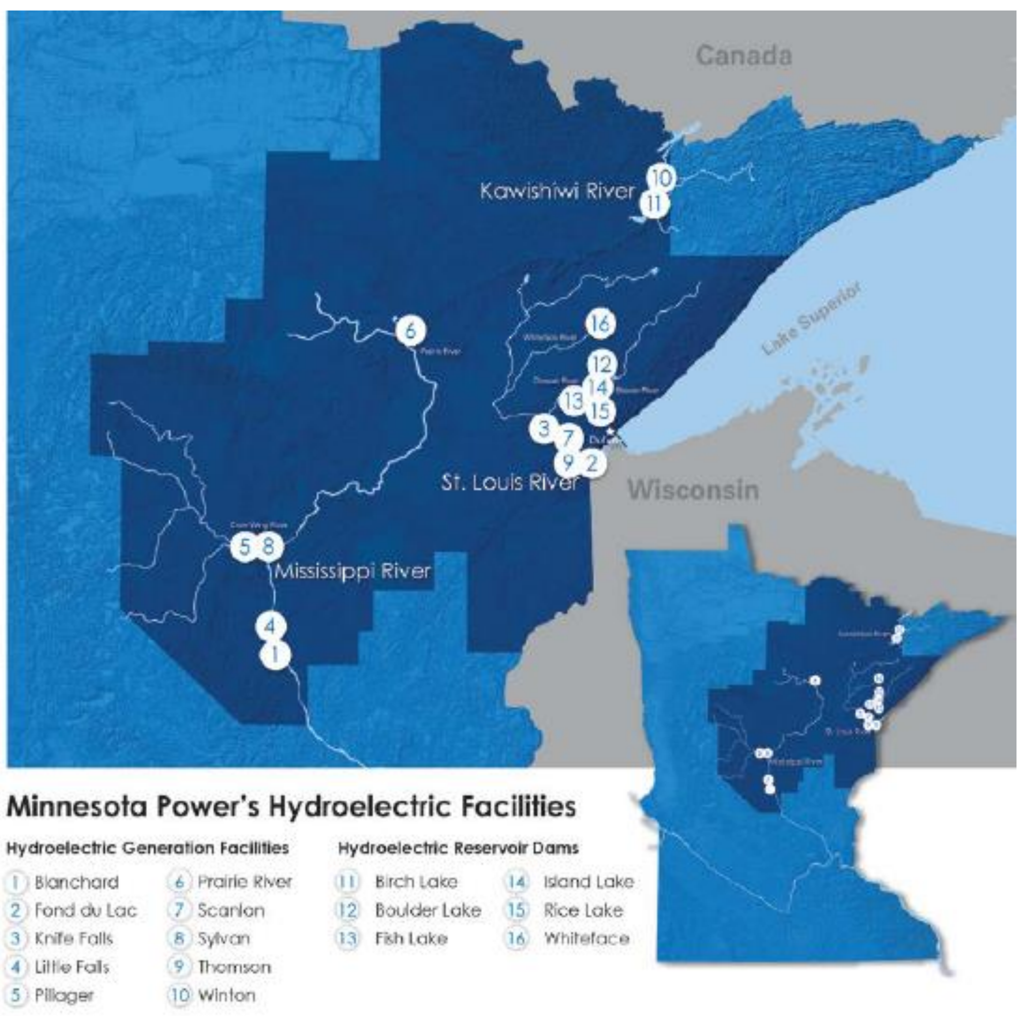
VI. Existing Resources

This section will discuss the facilities comprising each fuel type, as well as MP's compliance position with the Renewable Energy Standard (RES) and Solar Energy Standard (SES).

A. Hydro

MP is the largest producer of hydroelectric power in Minnesota, with generating capability of approximately 120 MW. The Company operates ten hydro stations on five rivers that are part of three main river systems in central and northern Minnesota—the Mississippi River, St. Louis River and Kawishiwi River. In addition to maintaining dams at each hydro station, the Company also maintains six headwater storage reservoirs. The Company operates its stations and reservoirs under eight federal licenses. (FERC oversees dam operations and safety in the U.S., and FERC licenses specify operating parameters.) Figure 7 is a map of MP's hydro resources:

Figure 7: Map of Minnesota Power Hydro Resources[36]



[36] Appendix C of MP Petition, Figure 2, p. 6.

MP also has a 250 MW capacity and energy power purchase agreement (PPA) with Manitoba Hydro Electric Board (MHEB), which began on June 1, 2020 and continues through May 31, 2035.[37] In June 2014, MP entered into an energy-only purchase from MHEB for up to 133 MW, which also began on June 1, 2020 and continues through May 31, 2040.

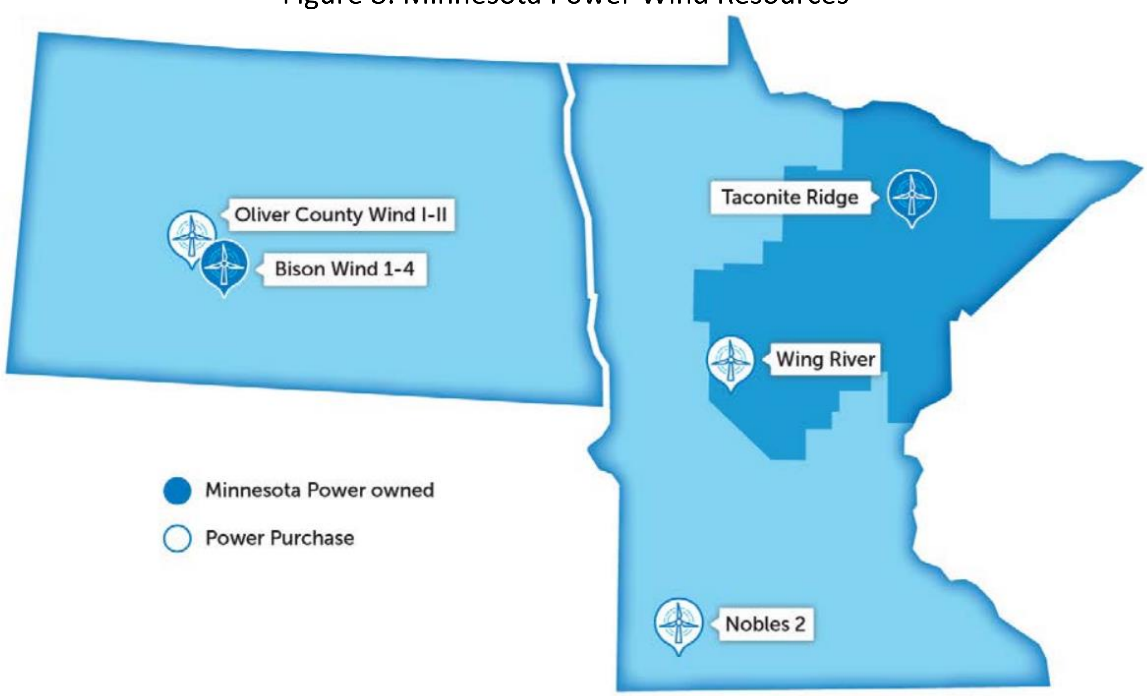
1. Staff Comment

The Commission received dozens of public comments regarding flow rates at the Thomson Dam. MP's agreed-upon flow rate is 350 cubic feet per second (cfs), yet public commenters voiced concerns that flows in recent years have been consistently below that amount, which has presented dangerous situations for local paddlers. MP responded that flow rates are strictly regulated by FERC. The current FERC license for the St. Louis River Project, which includes Thomson Dam, expires at the end of 2035, and that renewal process will begin in 2029. MP stated that the FERC licensing process is the appropriate place for stakeholders to voice their concerns over the operating parameters of the Thomson Dam.

B. Wind

Figure 8 is a map of MP's wind resources, which consists of the Company-owned Bison Wind 1-4 (497 MW) and Taconite Ridge (25 MW), and PPAs for the Nobles 2 (250 MW), Wing River (2.5 MW), and Oliver County I and II wind farms (MP's share of Oliver I-II is roughly 100 MW[38]).

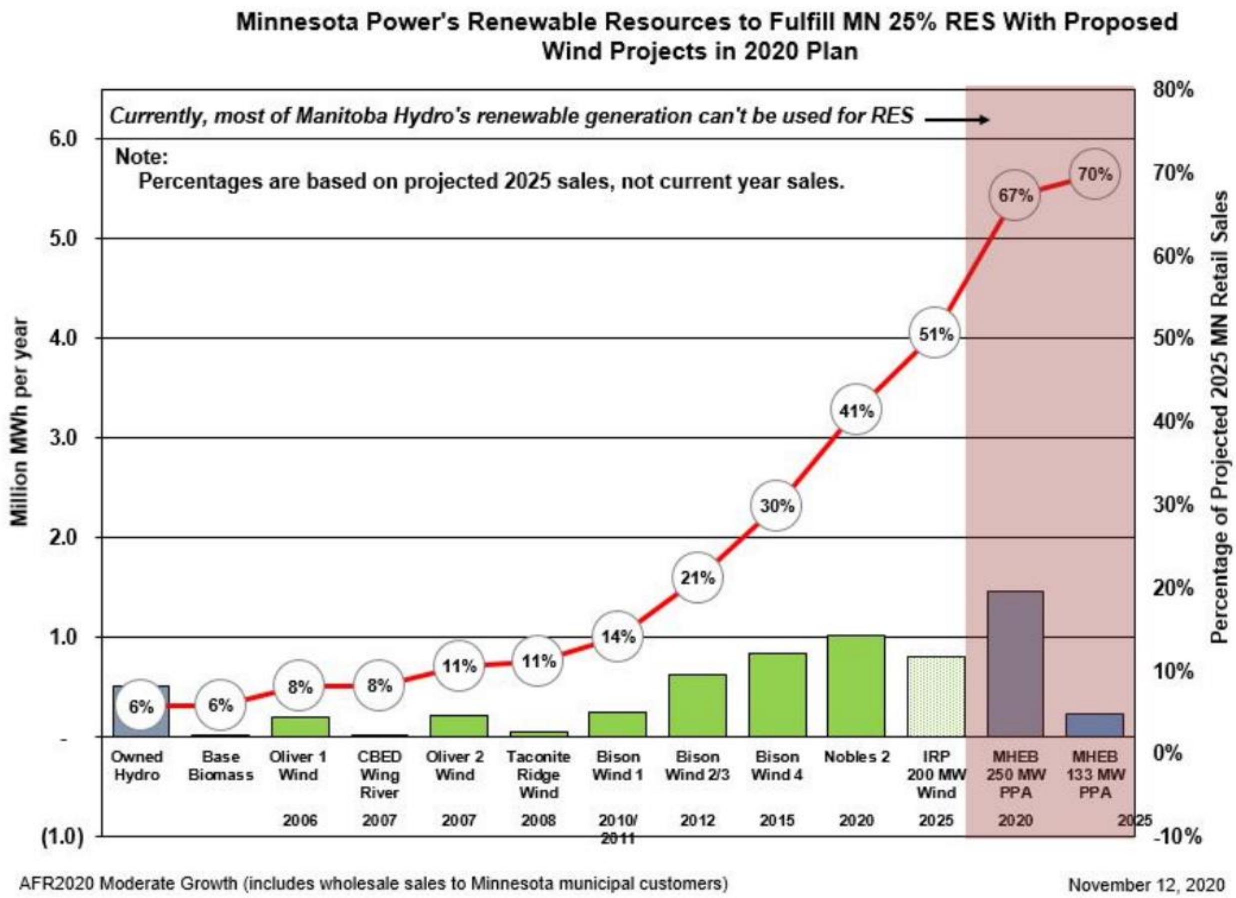
Figure 8: Minnesota Power Wind Resources[39]



[37] Docket No. 11-938.
[38] MP and Minnkota are the power offtakers.
[39] Appendix C of MP Petition, Figure 3, p. 8.

Figure 9 shows the renewable energy facilities that comprise the 70 percent renewable portfolio (note that the shaded area on the right means that most of Manitoba Hydro's renewable generation cannot be used for RES compliance). With the addition of 200 MW of the generic wind by 2025, MP's total RES-eligible renewable percentage will rise to 51 percent of total retail sales.[40]

Figure 9: The Company's Total Renewables with Proposed 200 MW Wind Project in 2021 Plan[41]



C. *Solar*

MP's existing and approved solar resources – which amount to roughly 35 MW – are shown in the table below.

[40] Minnesota law does not allow renewable generation from hydro units of 100 MW or larger to apply towards Minnesota's RES. As such, roughly 96 percent of the carbon-free energy generated by the Company's PPA with Manitoba Hydro is not counted toward the RES.
[41] Appendix H of MP Petition, Figure 3, p. 11.

Table 4: MP Solar Resources

Project	Size (MW)	Actual/*estimated* annual MWh	% of projected 2022 Retail sales[42]
Existing			
Camp Ripley	10	17,201	0.6%
CSG	1.04	1,912	0.1%
>40kW systems[43]	3.62	2,300	0.1%
Under Construction			
Laskin	9.6	*16,500*	*0.5%*
Sylvan	10	*21,700*	*0.7%*
Duluth	1.6	*2,600*	*0.1%*
Total	***35.86***	***62,213***	***1.9%***

MP estimates that it will need approximately 33 MW, or about 44,000 MWh, of solar to meet the Company's obligations under the SES. As indicated by the table above, the 10 MW Camp Ripley project in 2016 supplied about one-third of MP's SES requirement. With the recent approvals of Laskin, Sylvan, and Duluth Solar in Docket No. 20-828, MP will exceed its 33 MW of solar once the projects are in-service.

According to MP's June 2, 2022 Annual SES Report (Docket 22-12), MP would have enough banked Solar Renewable Energy Credits, or SRECs, to meet the first two years of the SES; however, MP will need purchase SRECs for 2022 and 2023 until its Laskin, Sylvan, and Duluth solar projects come online. This is shown by the table below from the Annual SES Report (staff illustrated surpluses and deficits of SRECs in green and red, respectively).

Table 5: MP Projected SES Compliance[44]

Year	Actual/Projected MN retail sales (MWh) minus SES exempt sales	SES Total Required (MWh)	Projected Total SRECs (MWh)	Projected Total Surplus/(Deficit) (MWh)
2021	2,936,701	44,051	**57,646**	**13,595**
2022	2,899,527	43,493	**35,736**	**(-7,757)**
2023	2,894,712	43,421	**55,337**	**11,916**
2024	2,894,321	43,415	**75,010**	**31,595**

D. Biomass

Hibbard Units 3 and 4, located in Duluth, Minnesota, is capable of burning wood and wood wastes, coal, and natural gas. Hibbard is capable of, and originally designed for, baseload

[42] Percentages taken from Figure 1, Appendix H of MP's Petition depicting fulfillment of the 1.5 percent SES requirements.
[43] Only systems that are registered in MRETS. Minnesota Power has an additional 5.77 MW of customer sited solar systems that are not registered in MRETS, and therefore not tracked towards SES standard compliance.
[44] MP, Annual SES Report - Amended, June 29, 2022, Docket 22-12, Attachment 2, p. 5.

operation and supports baseload energy generation when steaming capacity is available and energy is required.

Table 6: M.L. Hibbard Renewable Energy Center[45]

Unit #	Status	Year Installed	Nameplate Capacity (MW)	Net Generation (MWh)	Capacity Factor (%)	Forced Outage Rate (%)
3	Use	1949	30	55,925	19.95	0.1
4	Use	1951	30	55,312	22.55	0.8
			Plant Total	**111,237**		

1. Staff Comment

As noted in the Introduction, the CEOs recommend the Commission require MP to retire Hibbard, which is a recommendation based on a PSE report prepared for the CEOs.

E. Thermal Generation

Natural Gas. MP currently has minimal natural gas on its system. Laskin Energy Center was formerly a coal plant placed into service in 1953. Laskin was converted to natural gas – while using the existing steam boilers, turbine generators, and auxiliary equipment – in 2015. Laskin 1 and 2 each operate with a gross generation capability of approximately 52 MW (50 MW net) with 5 MW of existing station service steam to operate auxiliary equipment.

Coal. Boswell is MP's largest generating facility. Units 1 and 2 were retired in 2018. As shown in the table below, Unit 3 is 352 MW, and Unit 4 is 582 MW (nameplate), although MP's share is 468 MW. MP has made significant environmental and efficiency investments at Unit 4 since 2007, with its largest environmental retrofit being completed in 2015.[46]

Table 7: Boswell Energy Center[47]

Unit #	Status	Year Installed	Nameplate Capacity (MW)	Net Generation (MWh)	Capacity Factor (%)	Forced Outage Rate (%)
1	Retired	1958	0	0	0	
2	Retired	1960	0	0	0	
3	Use	1973	352	2,085,342	67.63	3.2
4	Use	1980	468*	2,366,363*	58.28	5.8
			Plant Total	**4,451,705**		
Minnesota Power share						

[45] Data from MP's Minnesota Electric Utility Annual Report filed in Docket No. 22-11.
[46] MP's capital cost estimate from Docket No. 12-920 was $349.8 million, with incremental O&M costs of $12.5 million annually (this is MP's portion). MP recovers the costs through an emissions-reduction rider.
[47] Data from MP's Minnesota Electric Utility Annual Report filed in Docket No. 22-11.

The 439 MW Milton R. Young 2 lignite coal generating station in North Dakota is owned by Square Butte Cooperative, managed by Minnkota Power Cooperative, and provides energy sales to MP and Minnkota. MP has been gradually reducing its 227.5 MW entitlement at Young 2, and by 2026, MP will not take any of the Young 2 output.

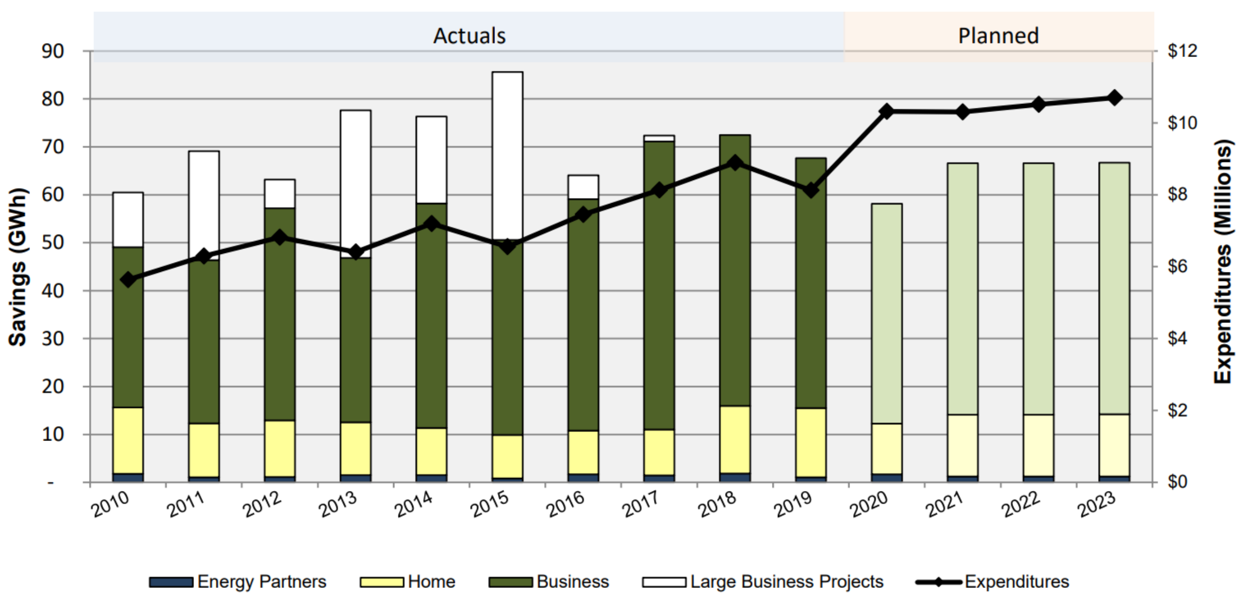
F. *Distributed Generation*

MP has a mix of small wind generators and solar PV systems from under 2 kW to 1,000 kW connected to the distribution system, the majority of which are solar systems that have been installed with the help of the SolarSense program offerings. SolarSense was expanded in 2017 to meet the small scale carve out of the SES. The program is currently approved to run through 2024. Total DER interconnections as of the start of 2022 include 15 wind generators and 602 solar installations totaling 10.64 MW of distributed generation on its system.[48] Distributed generation will be discussed further in the forecast section.

G. *Demand-Side Management*

In Appendix B, Demand-Side Management (DSM), MP discusses historical energy savings and its proposed CIP Triennial goal for 2021-2023. As indicated by the "Planned" area in the figure below, this equates to roughly 65 GWh of savings over the Triennial:

Figure 10: Minnesota Power Historical CIP Achievements and 2021-2023 Goal[49]

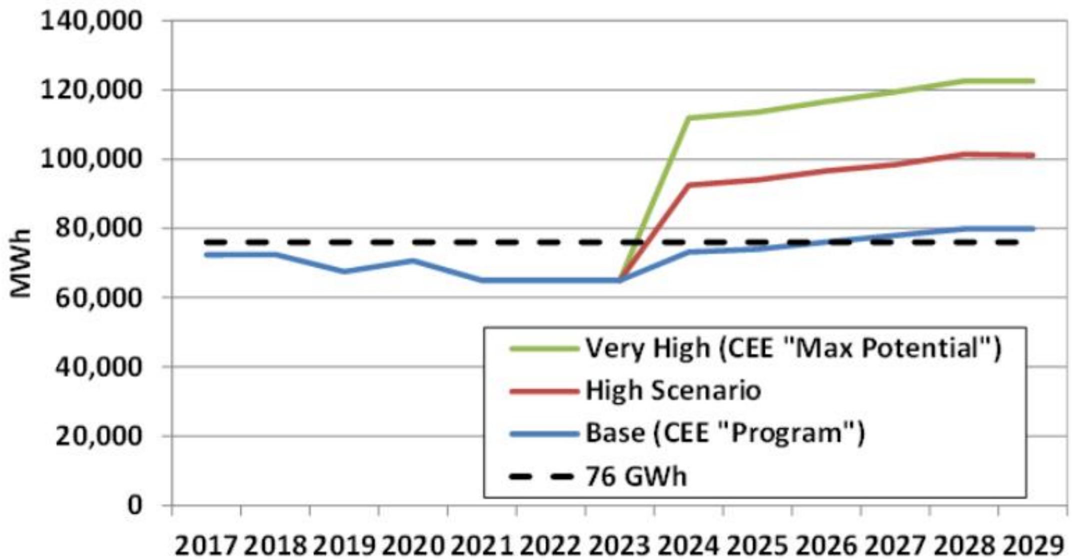


To develop long-term energy savings assumptions for the IRP, MP started with the 2020-2029 Minnesota State Demand Side Management Potential Study, funded by the Department and led by the Center for Energy and Environment (CEE). In the figure below, MP illustrates various IRP scenarios it contemplated, which staff summarizes in the following bullets:

[48] Minnesota Power Annual DER Interconnection Report, March 1, 2022, Docket E999/PR-22-10.
[49] Appendix B of MP Petition, Figure 1, p. 2.

- the "Very High" scenario used the CEE Max Potential from the DSM Potential Study;
- the dashed line – 76 GWh average annual– was the energy savings set by the Commission's Order from MP's 2015 IRP;
- the Base is the "CEE Program" base, and it captures a similar savings level as the 2015 IRP average annual; and
- the "High" scenario reflects the midpoint between "Very High" and "CEE Base" scenarios from the Minnesota DSM Potential Study.

Figure 11: 2020 IRP Energy Efficiency Scenarios[50]



Ultimately, MP modeled two energy savings scenarios:

1. Very High (reflecting the CEE "Max Achievable"), and
2. High (midpoint between Very High and CEE Base).

VII. Boswell Energy Center

Due to the significance of Boswell to the region, community impacts, and that Boswell is arguably the most significant issue in this IRP, this section will provide additional information on the facility in these key areas:

- Reliability;
- Customer impacts;
- Host community, employee, and socioeconomic impacts of Boswell retirements; and
- Environmental considerations.

A. Reliability

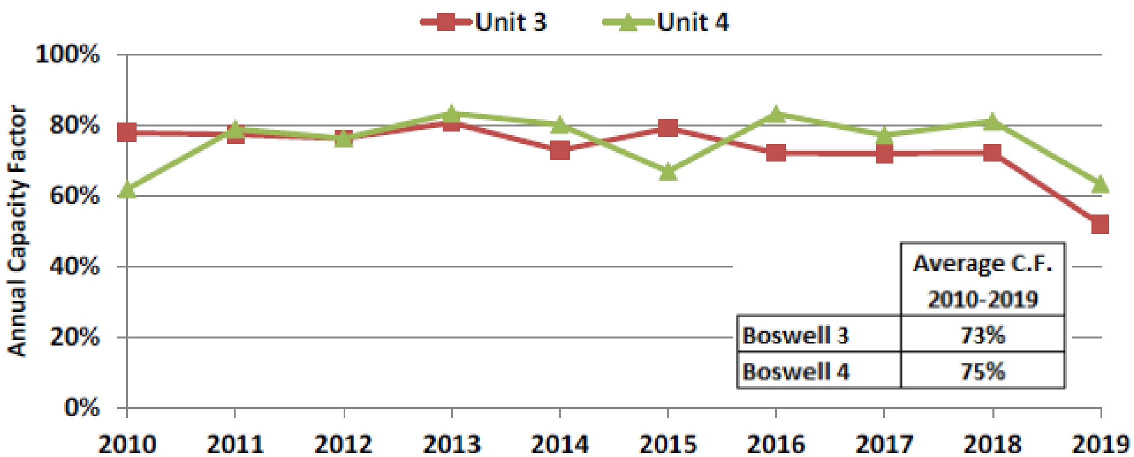
MP emphasized that it is important to consider Boswell Energy Center in the context of the broader MISO footprint; this involves, among other things, MISO's resource adequacy

[50] Appendix B of MP Petition, Figure 2, p. 5.

construct, including a transition to a multi-season resource adequacy construct, and how MP interacts with the energy market as both seller and purchaser.

First, without Boswell, MP explained that it is more likely to be a buyer than a seller in the MISO market, due to greater reliance on variable, renewable resources. MP cautioned that an over-reliance on MISO increases pricing risk for customers, and puts the Company (and other utilities) at risk of insufficient access to capacity and energy. According to MP, the Boswell units can be thought of as a hedge against market volatility, since the units' energy costs have been fairly stable, historically, and are especially economic during on-peak periods. As shown by the figure below, Boswell 3 and 4 have historically run at about 73 and 75 percent capacity factor, respectively, on average:[51]

Figure 12: Boswell Energy Center Historical Capacity Factor[52]



MP also discussed its experience with local and regional reliability issues that can arise from shutting down or changing the operational profile of a generation facility. For example, refueling Laskin Energy Center and retiring THEC and Boswell 1 and 2 required multiple local transmission projects.

MP summarized three "pillars" that highlight the significance of Boswell 3 and 4 and the transmission system impacts of changing operations:

1. ***Meeting the needs of large industrial customers.*** If Boswell 3 and 4 are shut down or transitioned to non-baseload operation, alternative solutions must be identified that can simultaneously meet the needs and expectations of large industrial sites, serve rural demand, and respond to significant variations in regional transfers across a large geographic footprint.

2. ***Voltage support, local power delivery, and regional power delivery.*** Solutions must be identified that can replace the essential reliability services formerly provided by the

[51] Appendix P of MP Petition, p. 14.
[52] Appendix P of MP Petition, Figure 4, p. 14.

local baseload generators on a continuous basis. MP identified three main aspects of essential reliability services provided by these units: a) Voltage Support and System Strength, b) Local Power Delivery, and c) Regional Power Delivery.

a. Voltage Support and System Strength: Solutions must be identified that can effectively and locally replace the voltage regulation, dynamic voltage support, and short circuit capability formerly provided by the local baseload generators on a continuous basis because these services cannot be imported from remote sources.
b. Local Power Delivery: Solutions must be identified that strengthen delivery paths for energy from remote sources to be delivered to the local transmission system and/or maintain a presence of local dispatchable generation to be delivered to energy consumers in northern Minnesota.
c. Regional Power Delivery: The regional transmission network must be strengthened to ensure continued stable and reliable operation of local dispatchable generation.

3. ***Sufficient lead-times.*** Transmission project implementation may take ten years or more depending on the scope and scale of the solutions. If Boswell 3 and 4 are shut down or transition to non-baseload operation, solutions must be thoroughly vetted and coordinated with other affected entities through a multi-year process of detailed analysis and project development, including applicable routing, permitting, and regulatory review timelines for large transmission projects.

B. Customer Impacts—Boswell 3 and 4 Depreciation Schedule

Boswell 3 and 4, as well as BEC common facilities, will be fully depreciated by the end of 2035. The remaining balance on these units presently totals approximately $725 million, excluding decommissioning costs, due in significant part to major environmental retrofits that occurred in 2009 for Boswell 3 and 2015 for Boswell 4. MP is not proposing any changes to the depreciation rates for Boswell 3 and 4 in the IRP, although MP noted that changes to the economic end of life of either unit may ultimately affect customer rates. Undepreciated capital amounts under each retirement scenario are shown in Figures 5 and 6 of Appendix P.

C. Host Community Impacts

A February 2020 report by the Center for Energy and Environment (CEE), titled "Minnesota's Power Plant Communities: An Uncertain Future," (Appendix M) explored community members' concerns and hopes about the future of Boswell Energy Center, among other host community sites. Some quick facts about Boswell from the CEE report include:[53]

[53] This table refers to Boswell 3 and 4 only.

Table 8: Boswell Energy Center Quick Facts[54]

Power Plant Information	
Power plant fuel type	Coal
Projected closure date (unit respective)	2035*, 2036*
Generation Capacity	922.5 megawatts
Employees	170
City Information	
City Population	2,700
% of plant workers residing in city	10%
% of city's tax base from power plant	69%
County Information	
Itasca County population	45,200
% of plant worker residing in county	90%
% of county's tax base from power plant	13%
School District Information	
% of school district's tax base from power plant	19%

*indicates date of full depreciation (or accounting lifetime) – there are currently no proposed retirement dates.

MP's 2021 Plan proposes to take the following actions in host communities:

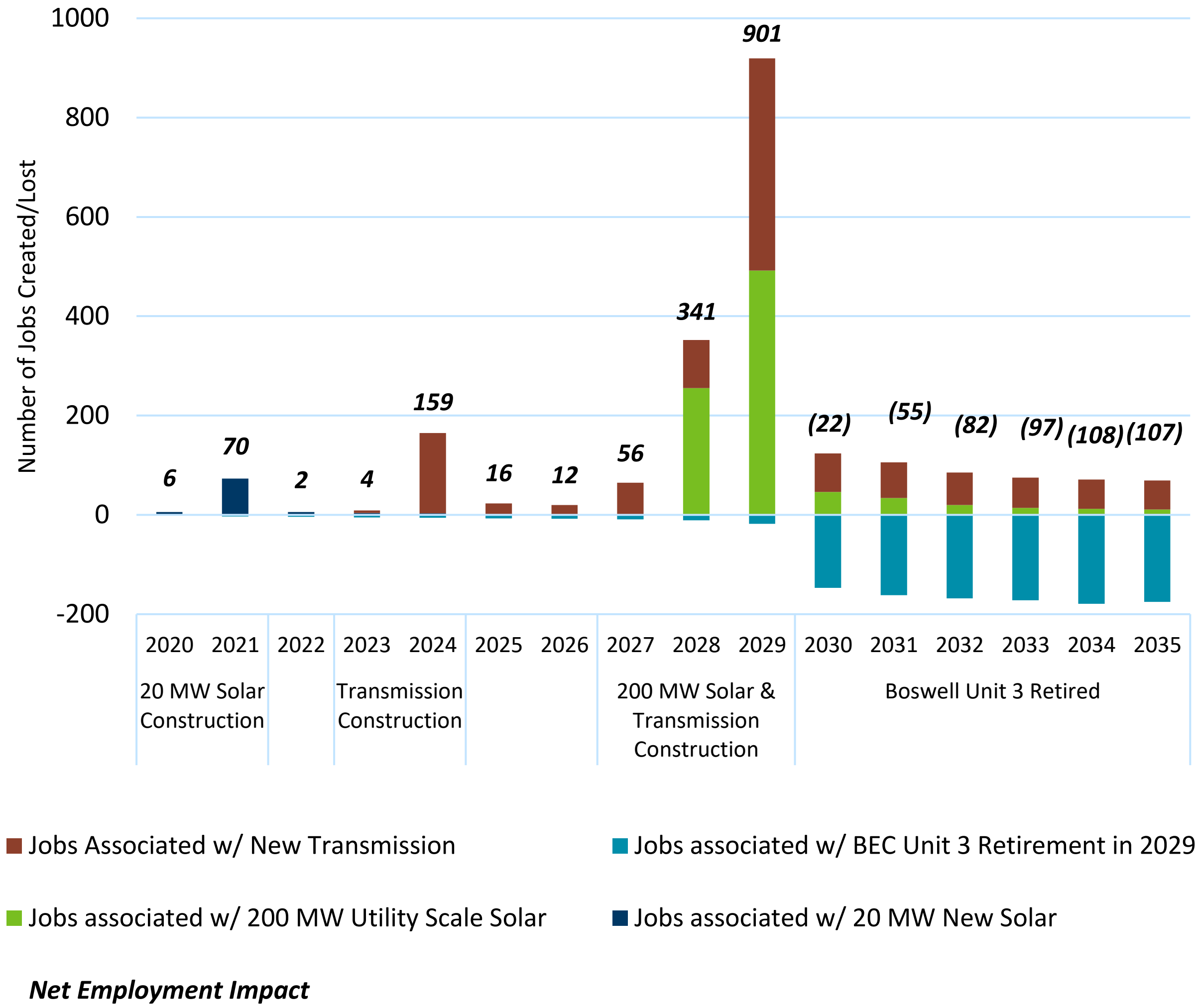
- procure 20 MW of solar in 2021 (approved in Docket No. 20-828);
- retire Boswell 3 by 2030;
- construct 200 MW of solar at the Boswell site in 2029; and
- invest in transmission solutions for reliability purposes.

To assess the socioeconomic impacts of these four actions, MP used a custom model built by Regional Economic Model, Inc. (REMI) software, which estimates various economic impacts individually and in the aggregate. Appendix M: MP Economic Impact report demonstrates the summarized regional economic impacts by year and by resource action for Minnesota Power's 2021 Plan.

Staff created the following figures from the data in Table 1 of Appendix M[55], which depict the local employment (Figure 13) and regional GDP (Figure 14) impacts of the components of MP's 2021 Plan.

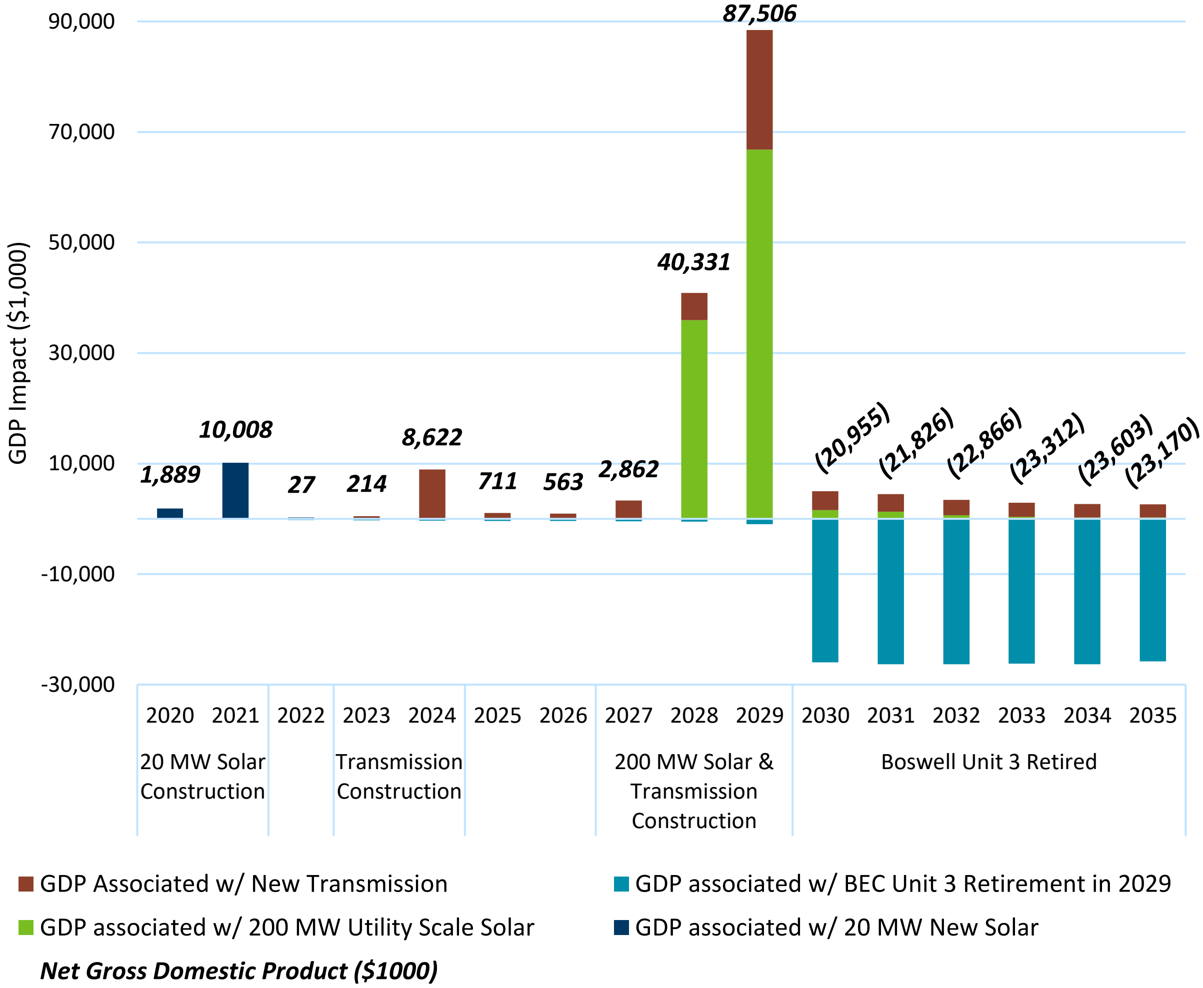
[54] Appendix M of MP Petition, Table 3, p. 19.
[55] Appendix M of MP Petition, p. 3.

Figure 13: Net Employment Impacts of MP's 2021 Plan[56]



[56] Staff created figure using number from Table 1 in Appendix M of MP's petition

Figure 14: Regional GDP Impact of MP's 2021 Plan[57]



As depicted in Figure 13 above, the closure of Boswell 3 by the end of the planning period will result in a net loss of 107 jobs. Boswell 3's closure accounts for a loss of nearly 180 jobs, however that is somewhat offset by jobs associated with new solar and transmission. The drivers of annual GDP impacts in Figure 14 are similar – losses are caused by the closure of Boswell 3 and somewhat ameliorated by the presence of new solar and transmission. Appendix M also summarizes impacts to the overall population, which saw a reduction of 235 individuals, and local government revenue, with a reduction in revenues of about $3.5 million per year. [58]

D. Environmental Considerations

MP describes itself as a leader in environmental stewardship, and Boswell 3 and 4 meet or exceed all current environmental standards. Moreover, since MP continues to meet federal and state environmental law applicable to Boswell Energy Center, no additional major capital investments are anticipated.

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[57] Staff created figure using number from Table 1 in Appendix M of MP's petition

[58] Appendix M of MP Petition: Socioeconomic Impacts, p. 7.

E. Summary of Party Recommendations for Boswell 3 and 4

This section will briefly summarize parties' recommendations for Boswell 3 and 4. Results from parties' EnCompass modeling is reserved for later sections.

1. Clean Energy Organizations

The CEOs recommend the Commission order the retirement of Boswell 3 by the end of 2029 and order MP to commence planning to maintain the option of retiring Boswell 4 by 2030.

The CEOs emphasized the "worldwide effort underway to cut emissions enough to limit warming to 1.5°C," and utilities have a responsibility to participate in this global effort. Even with a 2035 retirement date for Boswell 4, MP would be on a coal-retirement schedule five years behind where it needs to be for alignment with 1.5°C pathways. Boswell 4 emitted an average of over 3.5 million tons per year of CO_2 during 2018 to 2020, and it is likely to become the state's largest carbon emitter by far after 2030, when Xcel's coal plants are retired. According to the PSE report prepared for the CEOs,[59] Boswell 4 is estimated to have caused over $50 million in health impacts in 2021, including causing up to 4.6 premature deaths that year.[60]

Additionally, the Boswell facility is located directly adjacent to the Leech Lake Band of Ojibwe reservation boundary and is upwind from the Fond du Lac, Milles Lacs, Bois Forte, and Grand Portage Reservations. CEOs urge the Commission to consider the magnitude of these public health impacts when making decisions about future plant operations and Minnesota Power's generation portfolio.

The CEOs fault MP's IRP for failing to include any steps to enable Boswell 4 to retire by 2035, which fails to comply with the Commission's NTEC Order. The lack of any action plan that could facilitate a retirement plan for 2035 leads the CEOs to question MP's claim that it can be "coal-free" by that year. The planning period extends through the end of Boswell 4's economic life, so MP did not even plan for an on-schedule retirement of Boswell 4.[61]

2. CUB

CUB disagreed with MP's decision to only offer thermal resources and transmission upgrades as Boswell replacement options. Specifically, CUB stated that MP's assertion that Boswell could only be replaced with a natural gas plant did not take into account down time for gas units. CUB pointed out that Laskin Energy Center could not procure gas during the February 2021 winter

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[59] CEO, Comments – Equity Analysis, PSE Energy, Incorporating Health and Equity Metrics into the Minnesota Power 2021 Integrated Resource Plan, p. 19.

[60] CEO, Comments – Equity Analysis, PSE Report at Section 3.2.2, Table 3, p. 19 These health estimates are based estimated 2021 generation.

[61] Of note, the CEOs did not model the early Boswell 4 retirement scenarios. This was because MP did not model beyond 2035, and MP did not develop Boswell 4 replacement options. Also, since the CEOs' intention was to isolate the question of whether NTEC is in the public interest, retiring Boswell 4 early may have prevented an apples-to-apples comparison between the MP and CEO preferred plans.

event, and was therefore unavailable. Instead, CUB explained there are hybrid wind or solar-plus-storage resources that EnCompass could have selected. CUB pointed to results from a recent PacifiCorp RFP that had over a gigawatt of solar paired with storage bids on its shortlist as evidence that carbon-free capacity resources are being deployed across the country.[62]

CUB stated that due to the modeling errors outlined above, it was not sure what the optimal retirement dates would be. If the Commission revokes the NTEC AIAs, CUB recommended ordering the 2029 retirement of Boswell 3. However, if the Commission allows NTEC to proceed, CUB recommended accelerating the retirement of Boswell 3 as quickly as feasible given the Company will have surplus capacity position starting in 2025.[63]

3. Department of Commerce

The Department's comments will be discussed in more detail in the modeling section. What is important for the Commission to know is that the Department recognizes the feasibility of, and operational challenges associated with, retiring the Boswell units. As such, while the Department's recommendations are *based on* its modeling results, the Department recognizes that some flexibility is likely required. Regarding the continued operation of Boswell 3 and 4, the Department recommends the Commission:

- Direct MP to retire Boswell 3 in 2025, with the actual date to be adjusted based on feasibility;
- Direct MP to proceed as if Boswell 4 were to be shut down in 2030;
- Direct MP to re-study the Boswell 4 2030 retirement decision in the next IRP, assuming it is filed in 2024.
- Direct MP to work with MISO to ensure that Tranche 1 LRTP would fully meet all reliability requirements associated with a 2030 Boswell 4 retirement; and
- Direct MP to begin planning for solar sited at Boswell, beginning around the time of the Boswell 4 retirement.

The Department also recommends the Commission adopt Cohasset's recommendations for a new docket on site development and remediation plans for the Boswell site, stakeholder meetings, and compliance filing, which would be consistent with Order Point 20 in the Commission's April 15, 2022 Order approving Xcel's IRP.[64]

4. Large Power Intervenors (LPI)

LPI believes MP's 2021 Plan reflects a reasonable balance between cost and environmental concerns. However, LPI noted that MP's Status Quo scenario, in which no Boswell unit is retired early, is the least-cost plan when only actual operational system costs are considered. LPI noted that environmental costs, which are not recovered through rates, account for over 20

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[62] CUB, Initial Comments, p. 12.
[63] CUB, Reply Comments, p. 7.
[64] Docket No. 19-368, Order Approving Plan with Modification & Establishing Requirements for Future Filings, p. 36.

percent of the costs reported in the 2021 Plan. LPI also questioned whether MP sufficiently evaluated the reliability of the plan.

To address these deficiencies, LPI recommends that MP should be required to conduct a sub-hourly, stochastic Loss of Load Probability (LOLP) study on its next IRP (Decision Option 12). Doing so would demonstrate that reliability is maintained on a system with far less firm dispatchable generation and far more reliance on intermittent renewable resources to serve MP's load. Additionally, MP should be required to provide a service quality study demonstrating that its next preferred plan is capable of safely and reliably serving a system with an industrial customer base that accounts for 61 percent of the energy requirements and an 80 percent system load factor (Decision Option 13).

Because LPI is wary that MP's proposed resource additions would be in ratepayers' interest but for environmental costs that do not presently exist, LPI recommends that the approval of the wind and solar resources proposed in the 2021 Plan should be conditioned upon a finding that MP must demonstrate the resources are cost-effective for ratepayers (Decision Option 8).

Finally, LPI recommends that any plan with more aggressive retirement schedules than the 2021 Plan should be rejected due to both cost and reliability concerns.

a. Staff Comment

Staff is unsure what software LPI expects MP to use, or what type of analysis MP needs to do, in order to conduct sub-hourly, stochastic LOLP analysis. MISO annually conducts a Loss of Load Expectation (LOLE) study to set a Planning Reserve Margin (PRM), which utilities use in their IRPs. LPI's recommendation seems to be more applicable to MISO analysis and planning, which is one of the benefits of being a member of an RTO.

5. LIUNA

LIUNA supported MP's 2021 Plan. LIUNA emphasized how the early retirement of the Boswell units will have a negative impact on its members. LIUNA requested that the Commission order MP to "prioritize opportunities for local investment as the utility considers plans for future generation and storage."[65]

VIII. Transmission Planning Activities

Appendix F of the Petition, MP's Transmission Planning Analysis, is critically important for understanding the reliability impacts of various retirement scenarios. Appendix F is comprised of nine parts, listed below.

- Part 1: Minnesota Biennial Transmission Projects Report Summary
- Part 2: Great Northern Transmission Line
- Part 3: Center – Arrowhead High Voltage Direct Current (HVDC) Line
- Part 4: Generator Interconnection Network Upgrade Assumptions

[65] LIUNA, Initial Comments, p. 2.

- Part 5: CapX 2050 Transmission Vision Report Overview
- Part 6: Fleet Transition Experience with Small Coal Unit Closures
- Part 7: Transmission System Analysis of Boswell Unit 3 & 4 Closures
- Part 8: Generator Retirement Network Upgrade Assumptions
- Part 9: MISO Attachment Y-2 Study (Redacted Version)

In this section, staff will focus on Parts 6-8.

A. Part 6: Fleet Transition Experience with Small Coal Unit Closures

Part 6 of Appendix F discusses the transmission system impacts and projects implemented after MP refueled Laskin and retired THEC and and Boswell 1 and 2. MP first discussed Laskin and THEC, which are both part of the North Shore Loop. The North Shore Loop is a 140-mile system of 115 kV and 138 kV lines that extends approximately 70 miles along the North Shore of Lake Superior from east Duluth to THEC, near Schroeder, and then turns west and extends approximately another 70 miles to the Laskin Energy Center near Hoyt Lakes.

1. North Shore Loop Transmission System

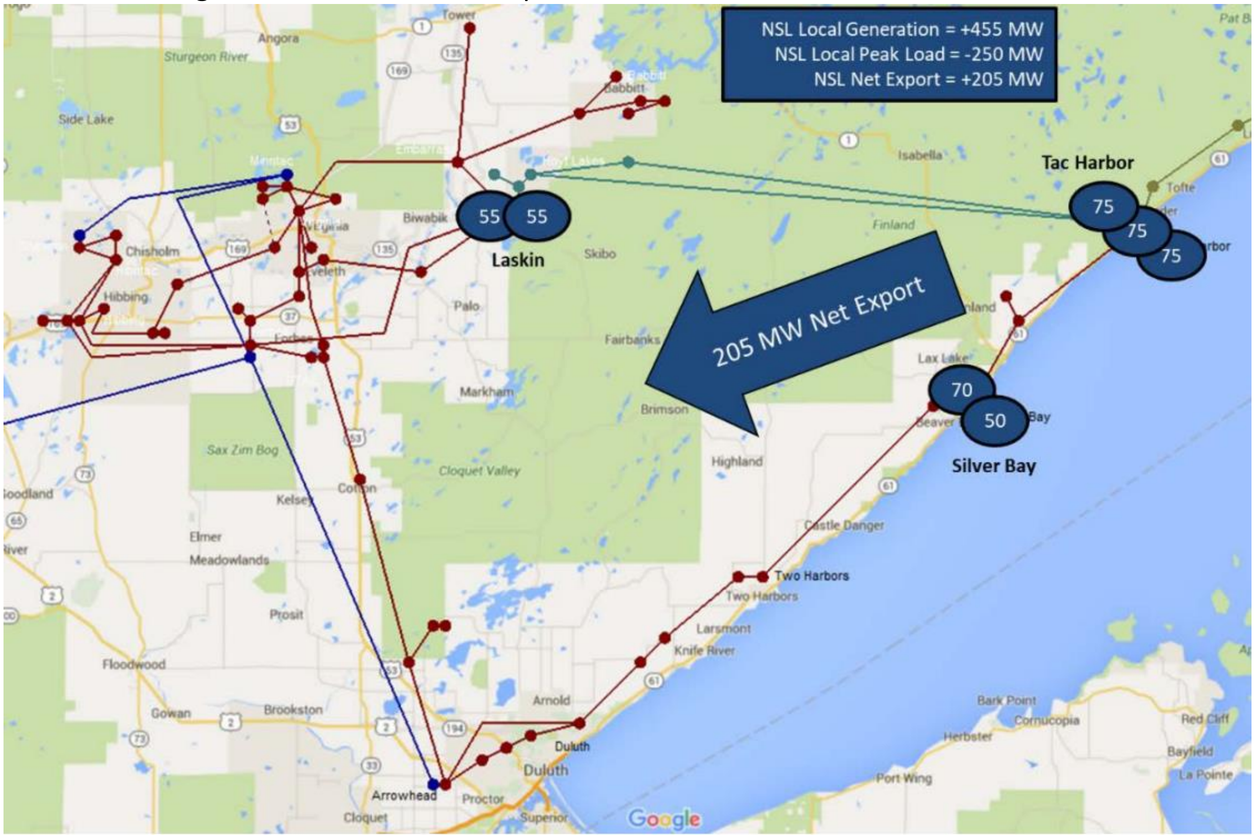
Since 2015, the following changes have occurred in the North Shore Loop transmission system:

- In 2015, the two units at Laskin were converted from coal-fired baseload units to peaking natural gas units.
- Also in 2015, MP retired THEC 3 (75 MW).
- In 2016, MP idled THEC 1 and 2, and these units were fully retired in September 2021.
- In June 2016, Silver Bay Power Company began operating with one of the two Silver Bay units normally idled, and in September 2019, Silver Bay idled both units.

These changes effectively decarbonized the North Shore Loop, leaving no baseload generators historically online.

Figure 15 and Figure 16 illustrate the shift of power delivery in the North Shore Loop. Figure 15 shows that, prior to the operational changes described above, there was approximately 205 MW more power generation capability in the North Shore Loop than the local peak load, which made the North Shore Loop a net exporter of power under most circumstances. Notice the blue box at the top, which shows 455 MW (local generation) - 250 MW (local peak load) = 205 MW (net export).

Figure 15: North Shore Loop Power Delivered from Local Generators[66]



As shown in Figure 16, after generators were refueled, idled, or retired, the area has become a <u>constant importer</u> of power, with a local peak load up to 250 MW, representing a 455 MW swing.[67] Notice the box near the top of the figure showing 455 MW (local generation) - 455 MW (retired) - 250 MW (local peak load) = -250 MW (net export).

[66] Appendix F of MP Petition, Figure 7, p. 25.

[67] Appendix F of MP Petition, p. 24.

Figure 16: North Shore Loop Power Delivered form Remote 230/115kV Sources[68]

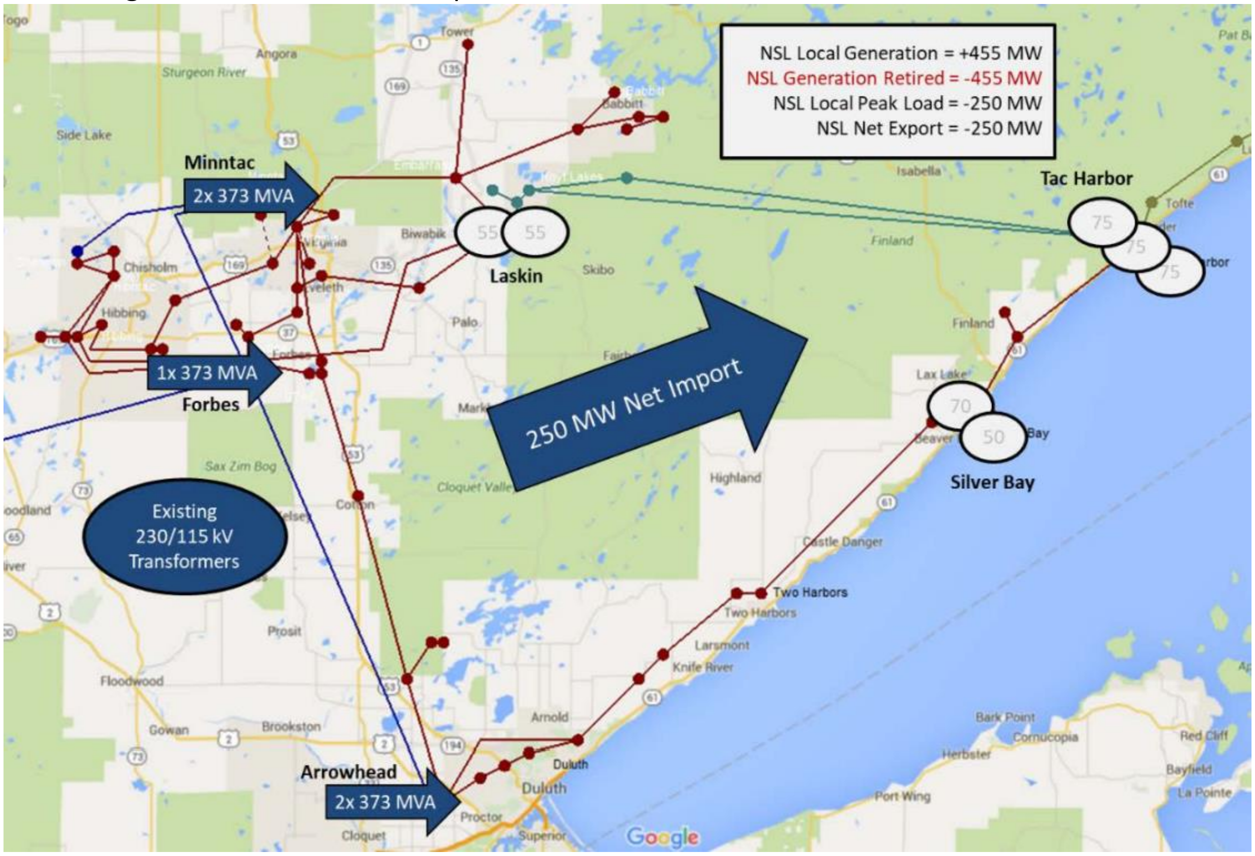
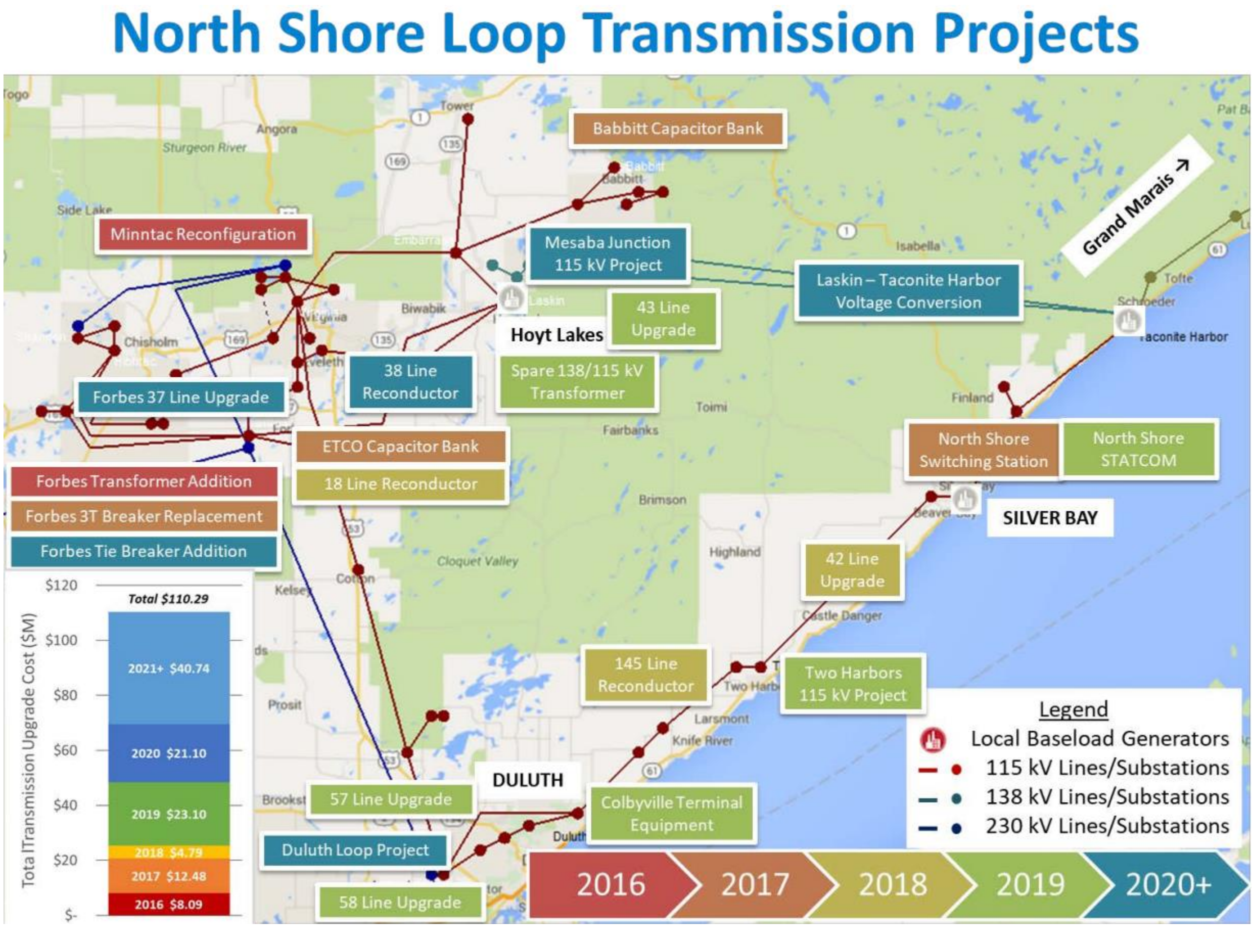


Figure 17 below summarizes the transmission projects required due to operational changes or retirements of local small coal units, beginning in 2016, which will continue into the mid-2020s. As indicated in the lower left of Figure 17, the total estimated cost of these projects through their completion is approximately $110 million.

[68] Appendix F of MP Petition, Figure 8, p. 26.

Figure 17: Summary of North Shore Loop Transmission Projects Related to Fleet Transformation[69]



MP summarized the figure above, and Part 6, as follows:

> The transmission system is designed to be highly reliable and redundant, yet affordable. Where local baseload generators have provided reliability services to the local transmission system for many years, the transmission system tends to be designed to rely on the local baseload generators being online. As long as the baseload generators were around to provide these reliability services, the cost of transmission upgrades that would decrease reliance on the generators was difficult to justify. With the removal of the local baseload generators, the transmission system in the surrounding area is practically guaranteed to require some amount of upgrading in order to offset the loss of reliability services formerly provided by the generators. The more dependent the transmission system was on the local baseload generators, the more significant the upgrades are likely to be.

[69] Appendix F of MP Petition, Figure 14, p. 35.

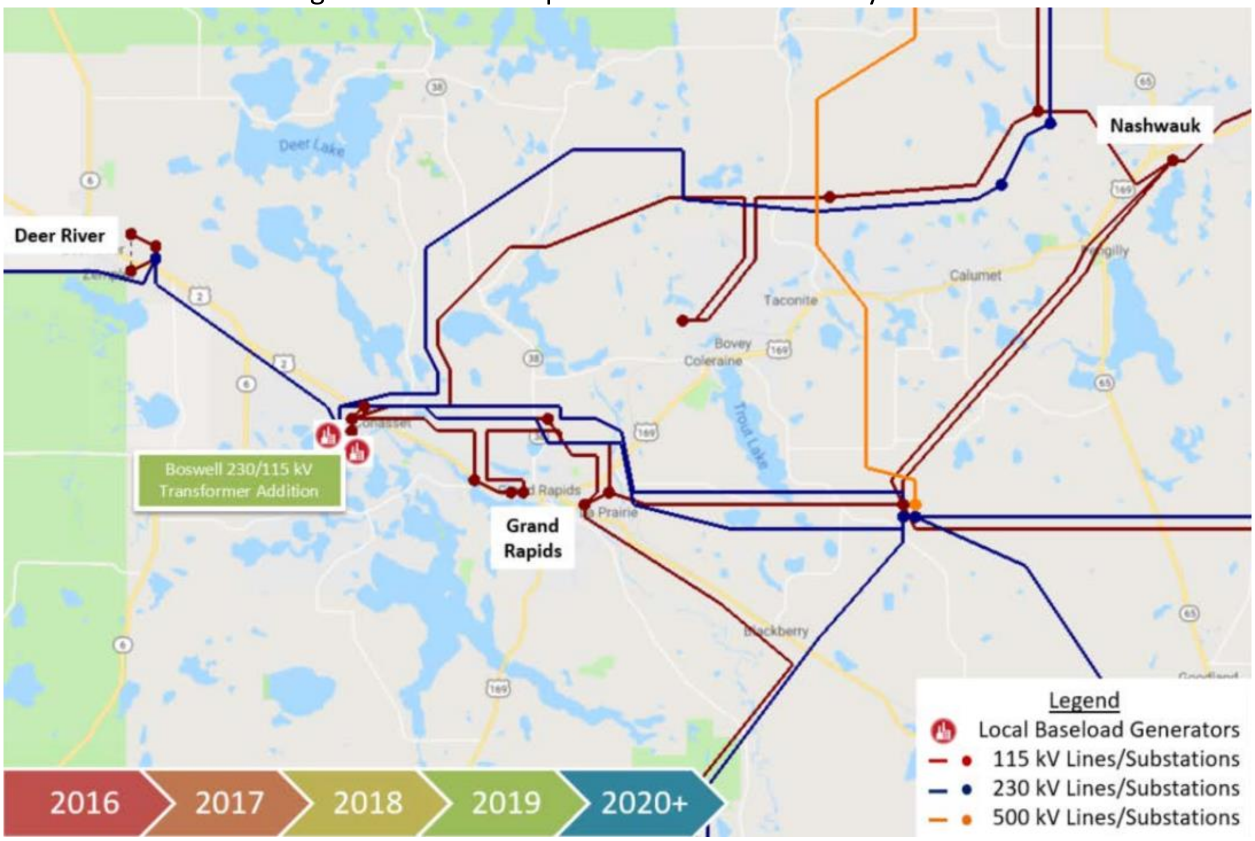
In the particular case of the North Shore Loop, Minnesota Power has found that the transmission system was highly dependent on the local baseload generators. Many transmission projects were necessary in the North Shore Loop to replace the voltage support formerly provided by the generators, strengthen and reinforce remote sources of power delivery and transmission paths as they became more heavily used to deliver replacement power formerly generated locally, and restore redundancy formerly provided by the local baseload units. Figure 14 below provides a summary of all the transmission projects related to the decarbonization of the North Shore Loop. As noted on the figure, the total estimated cost of these projects through their completion in the mid-2020s is approximately $110 million.[70]

2. The Grand Rapids Area: Boswell Units 1 and 2

Figure 18 below shows the Grand Rapids area transmission system. The Grand Rapids area is served by a 115 kV system including the Boswell, Blandin, Lind-Greenway, Grand Rapids, and Tioga substations. Three 115 kV transmission lines connect the Grand Rapids area transmission system to 230/115 kV sources at the Blackberry and Riverton substations. The figure also shows the local generators and one transmission upgrade, the Boswell Transformer Project. While four coal-fired generators were located at the Boswell Energy Center, only Units 1 and 2 were interconnected directly to the Grand Rapids area 115 kV system. Boswell 3 and 4 interconnect directly to the 230 kV system.

[70] Appendix F of MP Petition, p. 34.

Figure 18: Grand Rapids Area Transmission System[71]



Similar to the North Shore Loop generators, Boswell 1 and 2 contributed to the reliability of the Grand Rapids area transmission system for several decades. When planning to retire these units, the Boswell Transformer Project mentioned above aimed to ensure the system could continue to be operated at the same or better level of reliability, but what ensued reinforced the importance of having essential reliability services replaced before local generators are retired.

Prior to its completion, a manufacturing issue caused a delay that resulted in an approximately eight-month period of time in 2019 when Boswell 1 and 2 were retired, but the Boswell Transformer Project was not yet completed. During this time, a polar vortex event occurred, and a circuit breaker on one of the 115 kV transmission paths into the Grand Rapids area was locked out due to severe cold temperatures, causing a forced outage of one of the transmission sources to the Grand Rapids area. MP's system operators found that there were limited options in the local area for mitigating the low voltage without Boswell 1 and 2, which was precisely the condition that the Boswell Transformer Project was intended to mitigate.[72] While this was just once instance, if Boswell Energy Center were to shut down entirely, MP is concerned that there could be extended periods of time with local reliability risks.[73]

[71] Appendix F of MP Petition, Figure 15, p. 36.
[72] Appendix F of MP petition, p. 47.
[73] Appendix F of MP petition, p. 40.

B. *Part 7: Transmission System Analysis of Boswell Unit 3 & 4 Closures*

Studies discussed in Appendix F, Part 7 of MP's Petition include the:
- MISO Generator Retirement Study;
- Northern Minnesota Voltage Stability Study;
- Beyond Boswell Study;
- Short Circuit Study; and
- Synchronous Motor Starting Analysis.

MISO Generator Retirement Study

As a member of MISO, any generating unit closure on the MP system is required to utilize the MISO Attachment Y (unit retirement) process. In August 2018, MP submitted an Attachment Y-2 Study request (which is non-binding and informational-only) to MISO for a transmission system reliability assessment of various Boswell retirement combinations. MISO concluded that robust mitigating solutions would likely need to be built before retiring the Boswell units. Two significant areas of concern are identified on page 43 of the non-public version of Appendix F. Because MISO Attachment Y-2 studies do not prescribe reliability solutions, MP conducted its own analysis of the issues.

Northern Minnesota Voltage Stability Study

The Northern Minnesota Voltage Stability (NOMN) study investigated potential operating limits for the combinations of Boswell 3 and 4 operating scenarios evaluated in the MISO Attachment Y-2 Study.[74] In the NOMN study, MP considered four cases:
- Base Case: Boswell 3 & 4 Online
- Boswell Unit 3 Offline
- Boswell Unit 4 Offline
- Both Boswell Units Offline

On page 47 of Appendix F, MP explained that under each retirement scenario, either Northern Minnesota Load or Manitoba Hydro Import would need to be reduced to bring the NOMN Interface flow within the operating limit, depending on how much generation from Boswell is online. With no reduction, an identified minimum is necessary to maintain NOMN within the operating limit. According to MP, [a] long-term permanent transmission or dispatchable generation solution for Northern Minnesota is recommended to maintain reliability and a reasonable amount of operational flexibility with BEC Unit 4 or Both BEC Units offline."[75]

Beyond Boswell

The Beyond Boswell Study was performed by Siemens PTI and MP in 2016-'17 to understand the transmission issues surrounding the possible retirement of Boswell 3 and 4. The Beyond

[74] Appendix F of MP Petition, p. 44.
[75] Appendix F of MP Petition, p. 47.

Boswell Study provided an in-depth look at the steady state, voltage stability, and transient stability impacts from Boswell unit retirements.

Short Circuit Analysis

According to MP's description of the Short Circuit Analysis, "Minnesota Power is gathering information and working with MISO to determine the best way to establish and maintain a minimum system strength requirement for the Minnesota Power system to ensure adequate support is provided to the transmission system at all times. As of the writing of this section, the studies and coordination discussions around minimum system strength requirements were still in development.[76] However, at the time of the filing, MP concluded, among other things, that:

> Minnesota Power envisions the development of new system strength planning criteria requiring a minimum short circuit level at a handful of key nodes on the transmission system. The minimum short circuit level will take into account existing minimum short circuit levels with BEC units online, the design of transmission control and protection schemes, and allowable voltage deviations. Planning studies and system design will include credible prior outage scenarios to ensure the system can handle an outage (planned or unplanned) of at least any single source. Additional redundancy may be required for sources that require extended maintenance outages, such as generators or synchronous condensers.[77]

Synchronous Motor Starting Analysis

MP commissioned Siemens PTI to study potential impacts on motor starting capability for large power customers on the Iron Range if Boswell 3 and 4 are retired. The "Key Findings" stated:

> Key findings from the study are that steady-state voltages prior to motor starting are typically lower in the cases with BEC generation offline due to a loss of reactive power support. When motor starting simulations are performed with lower initial transmission system voltages, motor starting durations are extended and voltage dips during starting are more significant, both of which have a negative impact on motor starting. Additional sensitivity analysis was performed to generically replace the reactive power generated by the BEC units in the form of a fixed shunt capacitor bank at the representative 115 kV bus. Fixed shunt sizes were chosen in each scenario to perfectly match the 115 kV steady state voltage between the pre- and post-BEC retirement cases. Performing the motor starting simulations again with additional reactive support on the transmission system and BEC units offline, the differences in motor starting duration and voltage dip with and without the BEC units were negligible. This trend was observed across the entire range of

[76] Appendix P of MP Petition, p. 19.

[77] A synchronous condenser is essentially a generator that is driven by the transmission system rather than by a steam turbine or some other form of mechanical energy. Synchronous condensers require no fuel for continuous operation and produce only reactive power.

synchronous motor sizes and lower voltage impedances. From this, Minnesota Power concludes that large synchronous motor starting is primarily dependent on pre-starting steady-state voltage, which must be adequately and predictably regulated with or without BEC units online.[78]

C. Part 8: Generator Retirement Network Upgrade Assumptions

Appendix F, Part 8 discusses potential transmission upgrade costs under the Boswell 3 and 4 retirement scenarios. MP examined Boswell 3 and 4 under combinations of Baseload Operation, Economic Operation, and Shutdown states, as shown by Table 9 below. Staff notes that Scenario E1 would most closely resemble the StatusQuo, S1 would most closely resemble MP's 2021 Plan, and S3 would most closely resemble the Department's FastExit scenario.

Table 9: Boswell Unit Scenarios Evaluated[79]

Scenario	**Boswell Unit 3**	**Boswell Unit 4**
E1	**Economic Operation**	Baseload Operation
E2	**Economic Operation**	**Economic Operation**
S1	**Shutdown**	Baseload Operation
S2	Baseload Operation	**Shutdown**
S3	**Shutdown**	**Shutdown**

Under each scenario, MP considered the following impact categories: voltage support and system strength, local power delivery, and regional power delivery. Table 10 shows the identified solutions under each category for the E1 and E2, and S1, S2, and S3 scenarios. The estimated costs for addressing these impacts are reflected in the early retirement scenarios in EnCompass.

[78] Appendix F of MP Petition, p. 54.

[79] Appendix F of MP Petition, Table 8, p. 57.

Table 10: Summary of IRP Generator Retirement Transmission Issues and Solutions[80]

Category	Impact	Solution	E1	E2	S1	S2	S3
Voltage Support & System Strength	Needs a continuous source of VSSS	Synchronous Condenser		X			X
Voltage Support & System Strength	Contingency loss of source of VSSS	Synchronous Condenser	X	X	X	X	X
Voltage Support & System Strength	Prior outage plus loss of source VSSS	Synchronous Condenser			X	X	X
Voltage Support & System Strength	Steady state reactive power support	300 MVAR of additional capacitor banks			X	X	X
Local Power Delivery	Overload of [TS Data begins…TS Data Ends] Outlets	Rebuild [TS Data begins…TS Data Ends] Transformer	X	X	X	X	X
Local Power Delivery	Overload of [TS Data begins…TS Data Ends] Transformer	Rebuild [TS Data begins…TS Data Ends] Transformer			X	X	X
Local Power Delivery	Overload of [TS Data begins…TS Data Ends] Transformer and related prior outage overloads in the area	Build new [TS Data begins…TS Data Ends]			X	X	X
Regional Power Delivery	Norther Minnesota Voltage Stability & related issues	Define NOMN interface and manage in real-time	X	X	X	X	X
Regional Power Delivery	Underlying transmission overloads along NOMN interface	Upgrade existing [TS Data begins…TS Data Ends] Lines			X		
Regional Power Delivery	Northern Minnesota Voltage Stability & related issues	New regional extra high voltage transmission line				X	X

The assumed costs of these transmission solutions were added to provide an overall estimated transmission network upgrade cost for each Boswell operating scenario. Total mid-level scenario costs estimates in 2019 dollars are shown in Table 11 below, broken down into the three categories of transmission impacts discussed above. The values below are point estimates used for the purpose of EnCompass modeling.

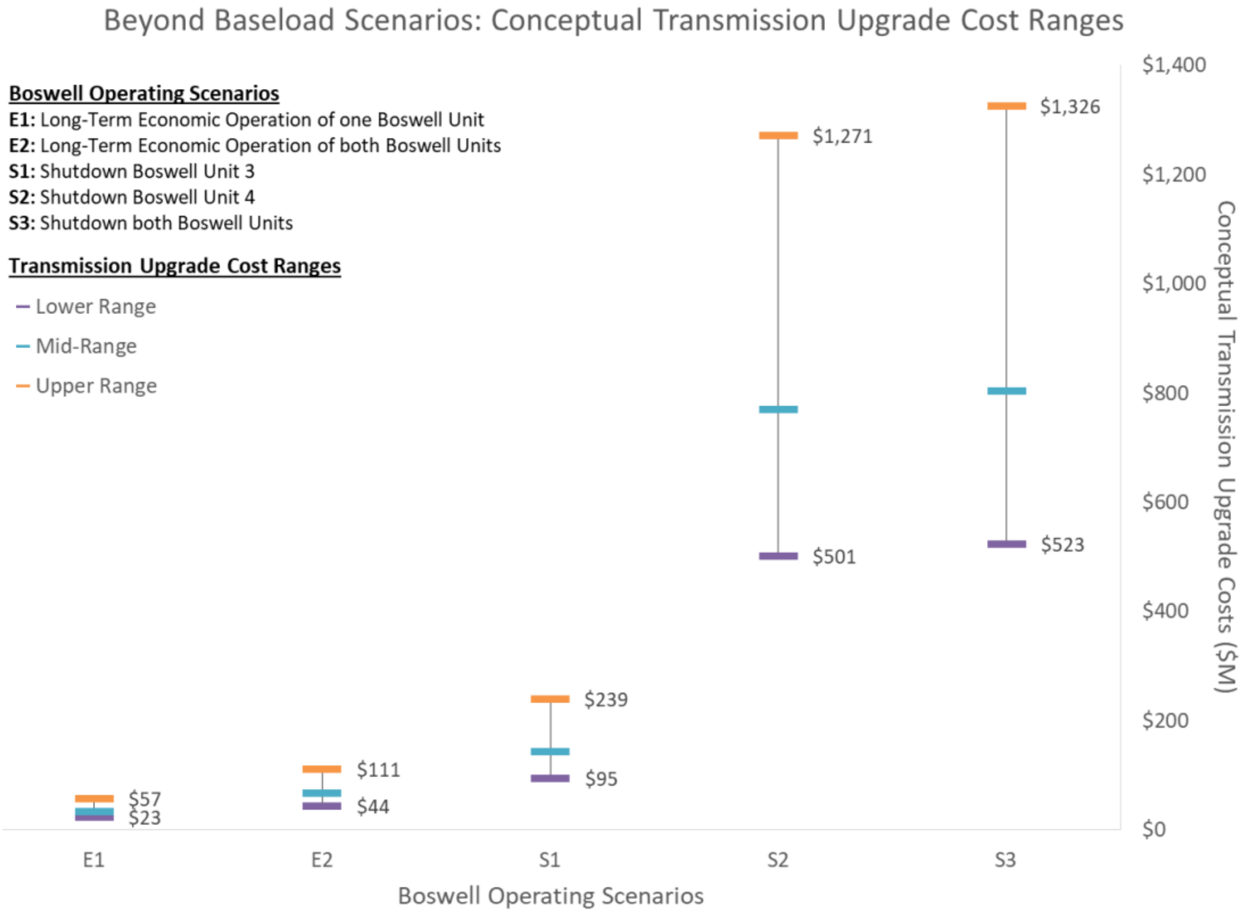
Table 11: IRP Generator Retirement Transmission Impact Cost Assumptions[81]

Boswell Operating Scenarios	**Scenario Cost Estimate ($M)**				
Type of Transmission Impact	E1	E2	S1	S2	S3
Voltage Support & System Strength	$33	$66	$69	$69	$102
Local Power Delivery	$1	$1	$61	$61	$61
Regional Power Delivery	-	-	$14	$640	$640
Total	$34	$67	$144	$770	$803

[80] Appendix F of MP Petition, Table 9, p. 61.
[81] Appendix F of MP Petition, Table 11, p. 64.

While a single cost assumption was used for IRP modeling, MP emphasized that the estimated transmission solution costs should be viewed in context of a range. MP's range was based on the MISO Guide of using an upper bound of +65 percent and a lower bound of -35 percent. The resulting cost ranges are shown in Figure 19 below. Note that the blue "Mid-Range" was used in EnCompass and reflects the value in the "Total" row above in Table 11.

Figure 19: Generator Retirement Network Upgrade Cost Ranges[82]



D. Clean Energy Organizations

CEOs retained Telos Energy (Telos) to analyze the transmission system-level reliability issues and solution options. Among other things, Telos examined the Boswell reliability mitigation assumptions described in Appendix F of MP's Petition, compared the CEOs' Preferred Plan to MP's 2021 Plan, and assessed the reliability benefit of NTEC.

1. Boswell 3 and 4

A key finding of the Telos report was that, like MP, Telos determined that retiring Boswell 3 will require transmission reinforcements. In the non-public version of Table 9 in Appendix F of MP's

[82] Appendix F of MP Petition, Figure 20, p. 65.

Petition, MP identifies building an existing line to enhance local power delivery. On page 26 of the Telos report, Telos states:

> Our analysis finds that MP's proposed transmission upgrades like the **[TRADE SECRET BEGINS… … TRADE SECRET ENDS]** would be sufficient mitigation when applied in conjunction with the CEO's Preferred Plan generation additions.[83,84]

Like MP, Telos determined that synchronous condenser is an appropriate solution upon retirement of Boswell 3 because it would improve voltage support and voltage stability. However, Telos recommends that Boswell 3 should be converted to a synchronous condenser, rather than MP's assumption that a new synchronous condenser would be required.

Telos also agreed with MP that retiring Boswell 4, in addition to Boswell 3, will increase the stress on the system, and planning for mitigations and/or other solutions needs to start now. However, Telos identified several limitations of MP's reliability analysis.

For example, recall that Scenario S3 from Part 8 of Appendix F of MP's Petition, which retired both Boswell 3 and 4, required three new synchronous condensers at 300MVA each and a major new transmission project, with cost estimates ranging from $523 million to $1.326 billion. According to Telos, MP's estimates "span an enormous range, which indicates that the scenario and its costs have not been studied closely."[85] Moreover, the following limitations of the analysis indicate that estimates are overstated:

- MP did not consider synchronous condenser conversions of the Boswell units, and only considered preliminary concepts for new synchronous condensers, which are substantially more expensive than conversions.
- MP and the Y-2 Study make the severe assumption that Manitoba Hydro Export is flowing south-to-north at its maximum technical limit, contrary to historical experience.
- The upgrade to the Square Butte – Arrowhead HVDC link for importing power was not included.
- Energy storage resources at critical locations could help mitigate short-duration, high-demand events, but these resources were not considered.

2. Telos Report and the CEOs Preferred Plan

Telos began describing its methodology stating:

> The starting point for all modeling and analysis is the MISO Transmission Expansion Plan 2020 (MTEP20) database. This transmission reliability modeling approach, software type, and MISO database are the same as those used by MISO

[83] CEO, Initial Comments – Transmission Reliability Analysis (Telos Energy), p. 26.
[84] Based on Telos' analysis, Energy Futures Group used MP's proposed proxy **[TRADE SECRET BEGINS … …TRADE SECRET ENDS]** as the mitigation for Boswell 3's retirement in its EnCompass modeling for CEOs.
[85] CEO, Initial Comments – Transmission Reliability Analysis (Telos Energy), p. 23.

in its Attachment Y reliability analyses, which Minnesota Power relies on for much of its own reliability analysis.[86]

Beginning with the MTEP20 Winter Peak 2030 transmission planning case, Telos modified the case to reflect a set of scenarios of future grid operations. Importantly, Telos explained, "the power flow base case from MTEP20 is altered in ways specified below to create six different scenarios, in order to test the impact on system reliability of certain proposed resource changes or the impact of a particular modeling assumption."[87]

First, it is important to understand the differences between the Utilities' Preferred Plan Reference Case Scenario and the CEOs' Preferred Plan Reference Case Scenario explained in the analysis. The CEOs Reference Case started with the Utilities Case, but made the following changes, as summarized in Table 5 (Table 12 below) of the Telos Report:

Table 12: Summary of Modeled Generation Changes between Utilities' and CEOs' Preferred Plans Reference Case Scenarios[88]

Generating Resource Changes	Utilities' Preferred Plan	CEOs' Preferred Plan
Nemadji CC (NTEC)	In	Out
Sherco CC	In	Out
Proxy additional MN PV resources, 1990MW	Not included	In at 50% CF
Proxy additional MN storage, 1775MW	Not included	In at 50% CF

To determine whether the CEOs Preferred Plan scenario is as reliable or more reliable than the Utilities' Preferred Plan scenario, Telos analyzed six different scenarios, summarized in Table 1 of the Telos report (Table 13 below):

Table 13: Summary of Scenarios Developed for Evaluation[89]

Scenario	
Reference Case	**Sensitivities**
Utilities' Preferred Plan	
CEO's Preferred Plan	
CEO's Preferred Plan	NTEC In Service
CEO's Preferred Plan	Boswell 3 converted to a synchronous condenser
CEO's Preferred Plan	Boswell 4 Retired
CEO's Preferred Plan	Maximum MHEX Flow North (US --> Manitoba)

Telos explained the purposes for the sensitivities as follows:

- The NTEC In-Service scenario was developed to isolate and assess NTEC's impact on the AC contingency analysis.

[86] Final Attachment Y2 Study Scope, Minnesota Power Boswell Units 3 & 4: 959 MW, MISO. April 4, 2019. Attained through CEO IR-62, PUC Docket No. E015/RP-15-690.
[87] CEO, Initial Comments – Transmission Reliability Analysis (Telos Energy), p. 3.
[88] CEO, Initial Comments – Transmission Reliability Analysis (Telos Energy), Table 5, p. 9.
[89] CEO, Initial Comments – Transmission Reliability Analysis (Telos Energy), Table 1, p. 5.

- Telos assessed the impact of Boswell 3 being converted to a synchronous condenser as a cost-effective way for the Boswell 3 unit to continue to provide voltage support and grid strength services to the grid.
- Assessing a Boswell 4 retirement date of 2030 was because evolving decarbonization policies could plausibly lead to its retirement in that timeframe.
- The power export to Manitoba scenario was developed to assess the impact of a certain critical assumption in MP's Y-2 and Beyond Boswell studies regarding the export of power north to Manitoba. This assumption – that MP would be exporting electricity to its full capacity north to Manitoba during the most challenging winter conditions – was a change to MISO's base MTEP models that was specifically requested by MP for MISO to use in its Attachment Y-2 analysis and used by MP in its Beyond Boswell study.

Across reliability metrics considered, Telos found:

> Overall, across metrics the CEOs' Preferred Plan results in essentially equal, and often, better reliability than the Utilities' Preferred Plan. The thermal violation summary metrics generally show significantly better performance by the CEOs' Preferred Plan than by the Utilities' Preferred Plan. Specifically, the number and severity of overloaded elements are 26% lower under the CEOs' Preferred Plan, as indicated by the lower Total MW Thermal Overload. The CEOs' Preferred Plan also shows 17% fewer distinct elements thermally overloaded. While there is one additional contingency that triggers a thermal violation and the highest thermal overload is 1% increased, these differences are minor.
>
> The number and magnitude of low voltage violations of the CEOs' Preferred Plan is slightly higher than that of the Utilities' Preferred Plan. The difference is relatively small, though, and such low voltage violations can often be corrected relatively quickly and inexpensively by improving the voltage regulation characteristics of the new inverter-based resources.[90]

Other key findings include:

NTEC

- The NTEC plant does not provide a material transmission system-level reliability mitigation benefit and, in fact, creates thermal and voltage issues on MP's system in the vicinity of NTEC in the scenarios analyzed.

Boswell 3

- Retirement of Boswell 3 will require some transmission reinforcements, but probably fewer than MP has proposed. Telos found that MP's proposed transmission upgrades

[90] CEO, Initial Comments – Transmission Reliability Analysis (Telos Energy), p. 20

would be sufficient mitigation when applied in conjunction with the CEO's Preferred Plan generation additions.
- The conversion of Boswell 3 to a synchronous condenser would improve voltage support and voltage stability and is a recommended solution.

Boswell 4
- The retirement of Boswell 4, in addition to the retirement of Boswell 3, will increase the stress on the system.
- Planning for mitigations and/or other solutions needs to start now, even to prepare for retirement of Boswell 4 in 2035, and certainly to preserve the option of earlier retirement.

Manitoba – Minnesota Interchange Findings
- Assuming a maximum power flow from south to north during the winter peak, as was done by MP or at MP's request in the reliability studies it cites, is a critical and pessimistic initial condition. This assumption deviates from historical flow patterns and from the flows assumed MTEP20 winter peak base case, and no justification has been provided for the difference in the assumption.
- Use of this unsupported assumption greatly increases the perceived reliability issues associated with retiring both Boswell units, and therefore likely overestimates the scale and cost of the transmission upgrades needed to facilitate that retirement; and therefore, requires more analysis as a mitigation solution.
- A modified south-to-north power flow limit on the MHEX is a powerful lever for mitigating the stress on the grid in Northern Minnesota and should be considered a mitigation option for the retirement of the Boswell 4 unit.

IX. Nemadji Trail Energy Center (NTEC)

On January 24, 2019, the Commission issued an Order approving a Capacity Dedication Agreement for 50 percent of the capacity of the Nemadji Trail Energy Center (NTEC), a 525 MW natural gas combined-cycle power plant in Superior, Wisconsin.[91, 92] NTEC has received a Certificate of Public Convenience and Necessity from the Public Service Commission of Wisconsin for both the proposed generating facility and the required 345 kV high voltage transmission line. NTEC has also received a Prevention of Significant Deterioration Permit for a new major source of emissions from the Wisconsin Department of Natural Resources (WDNR), and the NTEC project partners are currently working with both the WDNR and the U.S. Army Corps of Engineers to obtain a Section 404 Wetland permit and its Section 401 Certification.

A. Minnesota Power

Currently, MP has a minimal level of natural gas generation in its power supply, with the Laskin Energy Center – a previous coal unit refueled with natural gas in 2015 – supplying 100 MW of

[91] Docket No. E-015/AI-17-568

[92] Staff notes that, technically, NTEC is not an existing resource because it has not yet been constructed. However, since it an *approved* resource, MP's base case capacity position and energy outlooks includes the NTEC facility.

peaking capacity. MP explained that its "Company's 50 percent capacity share of NTEC, providing efficient and low carbon emitting combined-cycle generation, will increase our natural gas generation portfolio to nearly 400 MW (Laskin Energy Center in addition to NTEC)."[93]

MP also discussed that, even though the plant will be located in Wisconsin, there will be socioeconomic benefits for Minnesota:

> [T]he Twin Ports of Duluth (where the majority of Minnesota Power's 145,000 electric customers reside) and Superior would see many direct and indirect benefits related to the construction and operation of NTEC, which would be the largest private investment in Douglas County history. With its headquarters in Duluth, Minnesota Power is part of a regional economy that includes the entire Twin Ports, as well as the broader northeastern Minnesota service territory. Because of their proximity, the economies of the Twin Ports are inextricably linked – for example, many residents of Duluth work in Superior and many residents of Superior work in Duluth. Therefore, residents of Duluth (Minnesota Power customers) would share in the economic benefits of NTEC being sited across the bridge in Superior.
>
> Over 260 construction jobs and approximately 22 full time positions would be created in the Twin Ports as a direct result of the project. Additional secondary economic impacts for northeastern Minnesota and northwestern Wisconsin include: regional economic benefit estimated to be over $1 billion during the first 20 years of plant operation (approximately $52 million per year) and the creation of 130 permanent jobs. Additionally, Minnesota Power customers benefit from the attributes of the NTEC location, to include good natural gas access and availability, electric transmission infrastructure and a shovel-ready site. Finally, investment of this size is the region will provide significant economic benefits following the business closures during the COVID-19 pandemic in 2020, including closure of Verso's Duluth paper mill and airline maintenance center AAR in Duluth. Between the closure of just those two facilities - Verso's Duluth mill and AAR – Duluth lost more than 400 permanent jobs, making the investment of NTEC even more impactful to the region.[94]

As discussed previously, on September 28, 2021, South Shore Energy, the Wisconsin subsidiary of MP, announced that it had sold part of its interest in NTEC to Basin, who will become a 30 percent owner in the facility, while South Shore will retain a 20 percent energy and capacity off-take. Dairyland Power Cooperative will continue to own 50 percent of NTEC. MP intends to submit an updated Capacity Dedication Agreement for Commission affiliate approval upon finalization of all Wisconsin and federal permits that will allow the project to proceed. Until that occurs, MP asserts no further Commission action is needed within this IRP.

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[93] MP Petition, p. 46.
[94] MP response to OAG Information Request No. 029 (October 12, 2021).

With the reduced off-take, NTEC would only represent less than 5 percent of MP's total power supply portfolio, but MP views NTEC as an important asset for balancing renewable energy additions and ensuring reliability. Moreover, MP does not anticipate any material impacts to the 2021 Plan with the Company's reduced share of NTEC's output. After Boswell 3 is retired, there could be energy and capacity requirements that will need to be addressed, and MP expects to provide a detailed replacement plan for both Boswell units in its next IRP, but MP expects these needs can be addressed in the next IRP.[95]

B. Clean Energy Organizations

The primary components of the CEOs comments and recommendations include MP withdrawing from NTEC and revoking the Commission's approval of the AIAs. The CEOs argue that the CEOs Preferred Plan, which does not include NTEC, is a better option for Minnesota; the Telos report shows that NTEC is not needed for reliability; moreover, circumstances have materially changed since the Commission approved NTEC. According to the CEOs:

> A core purpose of Minnesota's utility planning laws is to prevent the financial disasters caused in years past when utilities failed to adapt their power plant investment plans to changing circumstances (Part II.A). The Commission has repeatedly affirmed that prudence demands such adaptation, even when that means cancelling previously approved power plants (Part II.B). The continued pursuit of NTEC is also subject to Commission review under the Affiliated Interest Agreement statute, Minn. Stat. § 216B.48 (Part II.C), and under the expansive authority provided by Minn. Stat. § 216B.25 (Part II.D). In addition, important changes since the Commission considered NTEC in 2018, including more aggressive climate targets, greater risk that gas investments will be stranded, and Minnesota Power's parent company's decision to sell most of its share of NTEC, warrant an updated consideration of NTEC in this proceeding.[96]

Given the delays to the NTEC construction schedule, the CEOs believe there is minimal risk in removing NTEC from the IRP and replacing that capacity and energy with alternative resources. For instance, Wisconsin regulatory filings show that construction will not commence until September 2022 at the earliest, and commercial operation has been delayed until March 2027, which could be further delayed by litigation over the project in Wisconsin, or permanently blocked by its outcome. The CEOs summarized its argument by stating:

> The question before the Commission today is whether it is in the public interest in 2022 to keep pursuing a combined cycle plant scheduled to come online in 2027.[97]

CEOs also addressed MP's announcement to reduce its offtake from 50 percent to 20 percent. The CEOs believe MP's reduced offtake constitutes a materially changed circumstance,

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[95] MP, Reply Comment, pp. 24-25.
[96] CEO, Initial Comments, pp. 2-3.
[97] CEO, Initial Comments, p. 22.

especially since construction has not begun. From the CEOs' perspective, this IRP provides "an ideal opportunity for Minnesota Power to assess whether a long-term investment in a new carbon-emitting resource makes sense under current conditions."[98]

More broadly, the CEOs stress the need to avoid catastrophic climate change, stating:

> we must stop building new gas plants, and we must retire old coal plants by the end of this decade. Minnesota Power's IRP is conspicuously incompatible with this consensus given its ongoing plans to build NTEC and its failure to plan for Boswell 4's retirement.[99]

Further, MP and other utilities are not moving rapidly enough towards decarbonization. In fact, MP's plan is contrary to our nation's commitment to limit global warming to 1.5 degrees Celsius, which requires the world to cut emissions roughly in half by 2030 and to push for net zero emissions by mid-century. The U.S. has pledged through our Nationally Determined Contribution "to cut U.S. carbon emissions to 50-52% below 2005 levels by 2030 and then to reach net zero by 2050."[100]

The CEOs cite several Minnesota rules and statutes to justify its recommendation:

- Under Chapter 7843 of Minnesota Rules, NTEC results in "a risky plan that falls short on all five factors the Commission must consider under its IRP rule."[101] It fails to minimize adverse environmental and socioeconomic impacts under subpart 3(C), and relying on NTEC (and Boswell) increases the "risk of adverse effects … from financial, social, and technological factors that the utility cannot control," and constrains rather than enhances "the utility's ability to respond" to changes in those factors, under subparts.
- MP "must not only show that continuing to pursue NTEC is in the public interest but that 'a renewable energy facility is not in the public interest.'"[102]
- The Commission approved NTEC under the provisions of Minn. Stat. § 216B.48 (the AIA statute), but that law does not require that the Commission end its scrutiny of AIAs after initial approval. On the contrary, subdivision 6 specifies that the Commission retains "continuing supervisory control over the terms and conditions of the contracts . . . so far as necessary to protect and promote the public interest."[103]

C. Department of Commerce

The Department recommends the Commission make no determination regarding NTEC in this proceeding, but require MP to make a filing no later than 60 days following the final court ruling regarding NTEC. At a minimum, the filing should include an explanation of MP's plans regarding NTEC along with a request for any Commission approvals necessary for MP to implement its

98 CEO, Initial Comments, p. 14.
99 CEO, Initial Comments, p. 12.
100 CEO, Initial Comments, p. 19.
101 Minn. R. 7843.0500, subp. 3.
102 Minn. Stat. § 216B.2422, subd. 4.
103 Minn. Stat. § 216B.48, subd. 6.

plans. The Department recognizes that the Commission approved a 50 percent share of NTEC for MP, although since that approval, MP has indicated that it is pursuing a 20 percent share, which would require revising the NTEC agreements. The Department explained:

> NTEC ownership is at 50 percent currently and would require Commission approval to change. While the NTEC at 20 percent scenarios were very informative for the Department here and potentially in future dockets, the Department is reluctant to assume that any changes in NTEC ownership will definitely occur. First, MP can file a petition to adjust NTEC ownership at any time, so that a timely decision can be made. Second, from the information available in this proceeding, it is not clear that a 50 percent ownership level or 20 percent ownership level (or a no ownership level) is the most likely outcome. Therefore, changes in the IRP expansion plan due to changes in NTEC ownership can be addressed in a future proceeding, are highly uncertain, and need not be addressed at this time.[104]

D. Large Power Intervenors

LPI does not support NTEC directly but asserts that "the CEOs Scenario does not satisfactorily demonstrate how it can safely and reliably serve the Company's system" . . . and "because the CEO Scenario requires the removal of NTEC, the record is insufficient to approve the remainder of the CEO Scenario."[105] Therefore, from LPI's perspective, the Commission cannot consider the merits of the CEOs preferred plan because it does meet required reliability standards.

E. CUB

CUB recommended that MP re-evaluate moving forward with NTEC, especially in light of the Company's decision to reduce its stake in the project. CUB explained circumstances have changed since the NTEC, specifically delays in construction, changes in ownership, and increases in natural gas prices. CUB pointed out that the current IRP does not include modeling with any of these changed circumstances, which makes it difficult to evaluate whether NTEC remains in the public interest.[106] Therefore, CUB recommends removing NTEC from the Company's preferred plan.

According to CUB, MP bears the burden to show NTEC is still prudent in light of these changes. CUB pointed to the ongoing debate and legal challenges to NTEC's financing with the Rural Utility Service (RUS) that could result in further delays to construction, which the Company has not modeled into its IRP.[107] CUB weighed in on MISO's letter to the RUS on NTEC, stating that there are different roles between MISO and the Commission as it relates to NTEC. CUB stated that MISO's role is to ensure reliability while remaining technology-neutral, while it is the Commission's role to determine which resources are in Minnesota's interest.[108]

[104] Department, Initial Comments, p. 53.
[105] LPI, Reply Comments, p. 13.
[106] CUB, Initial Comments, pp. 19-20.
[107] CUB, Reply Comments, p. 5.
[108] CUB, Reply Comments, p. 6.

F. OAG

The OAG determined that NTEC is not in the public interest, and the Commission should remove NTEC from the resource plan and rescind the NTEC AIAs. The OAG cited the statutory authority under which the Commission can revoke the AIAs as follows:

> The Commission has the authority to revoke those portions of the NTEC Order approving the NTEC AIAs, as long as it notifies Minnesota Power of its intent to do so and provides the Company an opportunity to be heard.[109] The Commission may rescind, alter, or amend a prior order, on its own motion and at any time, with a newly-issued decision having the same effect as the original.[110] The Commission may also reopen a case to take further evidence; however, such an action is unnecessary here, where the interested parties have been noticed, there will be ample opportunity for all parties to be heard, and a robust evidentiary record will exist to inform a Commission decision.[111] It is enough that the energy and capacity deficits Minnesota Power projected when it proposed NTEC in 2017 overestimated the Company's resource need. This, combined with the fact that current conditions make NTEC an expensive and risky bet for Minnesota Power customers, provides sufficient justification for the Commission to rescind its prior approval of the NTEC AIAs. Thus, along with removing NTEC from the resource plan, the Commission should rescind its prior approval of the NTEC AIAs.
>
> The Commission also retains continuing supervisory control over the terms and conditions of the NTEC AIAs to protect and promote the public interest. The Commission has the same jurisdiction over a modified AIA as an original AIA.[112] And, the Commission may disallow payment under either an original or a modified AIA, if it appears that such payment will be unreasonable.[113] Because the record here demonstrates that no payment made pursuant to the NTEC AIAs could be considered reasonable, it follows that the AIAs themselves are unreasonable, imprudent, and not in the public interest. Thus, if the Commission does not rescind its approval of the NTEC AIAs, it should consider reducing the amount of capacity that Minnesota customers receive under the AIAs to zero and disallowing the recovery of NTEC costs from Minnesota customers.

The OAG further noted that rescinding the NTEC AIAs would not result in a hardship for the Company, as evidenced by the fact that parent company, ALLETE, Inc., was reimbursed for its NTEC project costs to date when it sold 30 percent of its ownership of NTEC to Basin.

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[109] *In re Peoples Natural Gas Co.*, 358 N.W.2d 684, 689-90 (Minn. Ct. App. 1984) (finding that "'[a]n administrative agency concerned with furtherance of the public interest is not bound to rigid adherence to precedent'"); Minn. Stat. § 216B.25.

[110] Minn. Stat. § 216B.25.

[111] *Id*.

[112] Minn Stat. § 216B.48, subd. 6.

[113] Minn Stat. § 216B.48, subds. 5-6.

In addition, as shown in Table 14 from the OAG's comments, NTEC's construction schedule has been significantly delayed, and NTEC is not expected to achieve commercial operation until 2027. This delay guarantees that MP's current IRP modeling is outdated.

Table 14: Current projected NTEC construction schedule[114]

General NTEC Construction Schedule	
On-site relocation work	September 2022 – July 2023
Sheet pile wall construction	April 2023 – October 2023
BOP Mobilize to site	April 2023 – May 2023
Site and BOP Construction	April 2023 – October 2025
Commercial Operation	March 2027

The following is a list of changed circumstances that have occurred since the NTEC Order.

1. Forecast Error

When the NTEC AIAs were approved, the Commission relied on MP's 2017 load forecast, but the capacity and energy needs predicted in 2017 were almost entirely attributable to forecast error, and NTEC is no longer necessary to meet customers' needs. Specifically, the NTEC Order cited a figure from MP's Energy*Forward* Petition that predicted "growing energy needs of about 1,000 gigawatt–hours (GWh) annually by 2020, increasing to 2,400 GWh by 2031."[115] Considering actual energy usage from 2017 through 2020, and MP's updated load forecast from 2021 through 2031, the projected energy need disappears.

Similarly, the Commission found in its NTEC Order that "in the absence of any resource additions, the Company forecasts a capacity deficit that will reach 300 MW by 2025 and grow to 500 MW by 2031." However, MP's projected capacity deficit was overestimated. Without NTEC, the Company forecasts a very small capacity deficits in most years – typically in the range of 6 to 36 MW – which is significantly lower than the capacity need of 500 MW by 2031 MP projected in the NTEC docket.

2. Capital Costs of a Combined Cycle Facility

The OAG also discussed how that NTEC, as a combined cycle unit (as opposed to a CT), presents additional risks for MP's ratepayers. Combined cycle natural gas facilities have higher capital costs relative to CT units, which are designed to operate only during high-priced "peak" events. Generally, since combined cycle units operate more efficiently than CTs, combined cycle units are cheaper than CTs if they are dispatched frequently enough to offset the higher capital cost. Thus, MP's customers absorb the risk of natural gas prices possibly being higher than expected, or if the Company, state, or federal government pursues aggressive decarbonization.

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[114] OAG, Initial Comments, Figure 5, p. 11.

[115] In the Matter of Minnesota Power's Petition for Approval of the EnergyForward Resource Package, PUC Docket No. E-015/AI-17-568, ORDER APPROVING AFFILIATED-INTEREST AGREEMENTS WITH CONDITIONS at 8 (eDocket No. 20191- 149543-01).

MP claims it intends to deliver 100 percent carbon-free energy to customers by 2050. The Walz Administration has proposed a target of 100 percent carbon-free electricity by 2040. The Biden Administration has set a goal of 100 percent carbon-free electricity by 2035. Since MP assumes a 40-year book life for NTEC, the facility's useful life would extend through 2064. This means that: 1) NTEC would need to be shut down well-before the end of its useful life; 2) it would require expensive upgrades that are not currently included in MP's modeling; or 3) MP will fall short of its own carbon reduction plans.

3. Removing NTEC from the Resource Plan

In addition to an overstated need, the costs of alternative sources of generation have fallen since the NTEC Order. MP's updated levelized cost forecast for new solar generation is 8-14 percent lower than its solar cost forecast in the NTEC docket. Battery storage costs have declined even faster, with average pack prices falling by 58 percent from 2017 to 2021.

Taking these factors into account, the OAG believes Minnesota law authorizes the Commission to remove NTEC from MP's IRP, as long as doing so is in the public interest, revisit the NTEC Order and rescind those portions of the order approving the NTEC affiliated-interest agreements ("AIAs), and modify the NTEC AIAs to preclude their applicability to Minnesota customers.

4. Square Butte Transmission Line

According to MP's price forecasts, PTC-available wind would have a lower energy cost than NTEC. MP also has unique opportunities to minimize interconnection costs for new wind with its planned investments in its Square Butte transmission line, which may increase the line capacity.

G. NTEC Reply Comments

1. Clean Energy Organizations

The CEOs agreed with the OAG's legal analysis of the Commission's authority to not approve NTEC. The CEOs stated:

> The OAG cites the same three distinct statutory bases of authority that CEOs cite – the Commission's authority under the resource planning statute,[116] its authority under the affiliated interest agreement statute,[117] and its general authority to rescind, alter, or amend any prior order.[118] And like CEOs, the OAG concludes that the Commission can implement its authority in this docket, without additional

[116] Minn. Stat. § 216B.2422, subds. 2(a) and 4.
[117] Minn. Stat. § 216B.48, subd. 6.
[118] Minn. Stat. § 216B.25. In addition to these ample sources of authority, CEOs have pointed to the Commission's authority over rates and its long line of cases holding that utilities seeking rate recovery are obliged to consider whether continued investment in a project is prudent when circumstances have changed. CEOs Initial Comments, Part II(B).

notice or evidence-taking, given the notice and robust evidentiary record already provided by this docket.

The CEOs also agreed with the OAG that the following changed circumstances since the NTEC Order undermine MP's former case for NTEC:

- MP's load forecast from 2017 overestimated the Company's capacity and energy; today's forecasts show no need for NTEC.
- Market energy and renewable energy costs are lower than previously projected, and therefore NTEC can no longer be viewed as a hedge against market energy costs.
- Natural gas prices have risen significantly and have experienced extreme volatility since 2018. Upgrades to the Square Butte Line would allow less expensive and likely readily-accessible new renewable projects, making NTEC even less comparatively economic.

Finally, the CEOs argued that the IRA, which was signed into law on August 16, 2022, will enable MP to take advantage of additional tax credits for wind, solar, and, for the first time, standalone battery storage. The CEOs stated further that another 10 percent tax credit is provided if these carbon-free technologies are built in an "energy community," which includes a community in which a coal-fired electric generating unit has been retired after 2009. This would presumably include the Boswell site, where Units 1 and 2 were retired in 2018.

2. Large Power Intervenors

LPI argued the CEOs Preferred Plan does not meet reliability criteria required by statute; therefore, because the CEOs Preferred Plan requires the removal of NTEC, the record is insufficient to approve the remainder of the plan. Moreover, without the Company assessing its own resource mix under a scenario without NTEC, the record is incomplete.

LPI further argued that the Commission could consider that several stakeholders recommending the removal of NTEC from MP's 2021 Plan previously filed comments seeking reconsideration of the Commission's prior approval of NTEC. However, if the Commission decides to reconsider NTEC, LPI requests that the Commission "acknowledge that the record is incomplete and open a separate proceeding to allow for full record development of issues surrounding the replacement of NTEC."[119]

3. OAG

In Reply Comments, the OAG observed that the Department's modeling showed that reducing MP's ownership stake in NTEC actually benefits MP's customers. While the Department did not model a No-NTEC scenario, because the Department's modeling showed reducing NTEC ownership from 50 percent to 20 percent results in "lower costs (on average) in all carbon futures, under both load forecasts, and in virtually all contingencies examined by the Department,"[120] this provides additional evidence that NTEC is uneconomic.

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[119] LPI, Reply Comments, pp. 13-14.
[120] OAG, Reply Comments, p. 3.

4. Minnesota Power

MP responded to parties' recommendation to remove NTEC by emphasizing that NTEC was approved by the Commission in January 2019; the Minnesota Supreme Court affirmed the Commission's decision on the application of Minnesota Environmental Policy Act (MEPA) in April 2021; and the Minnesota Court of Appeals further affirmed the Commission's approval of NTEC in August 2021. The Court of Appeals affirmed the Commission's decision stating:

> The commission explained that the EnergyForward package, including NTEC and the new wind and solar resources, moves Minnesota Power's resource plan increasingly toward renewable resources and away from the coal resources that are "the biggest obstacle to Minnesota Power achieving state emission-reduction goals in the long term." The commission also discussed the greater reliability NTEC provides, as opposed to wind or solar alternatives, and the costs that Minnesota Power would incur if it added still more of those intermittent resources instead of NTEC. And the commission emphasized the role NTEC can play in supporting an overall more diverse, environmentally conscious, and lower-cost portfolio of resources.
>
> The record, including to a limited extent the input the commission received at its two-day hearing, supports the conclusion that NTEC serves the public interest better than renewable-resource alternatives. As discussed above, Minnesota Power and the department offered extensive evidence and analyses showing that the transition away from coal and toward intermittent renewable resources impairs reliability and could increase reliance on energy markets, thereby increasing costs.
>
> Their analyses also demonstrated that NTEC addresses these concerns, providing a more reliable and lower cost (including environmental costs) source of energy than the equivalent renewable resources. Accordingly, substantial evidence supports the commission's determination that NTEC best serves the public interest.[121,122]

MP recognized that "the Commission has the right to reconsider decisions on its own motion at any time under Minn. Stat. § 216B.25; however, to do so as part of an IRP would negate the regulatory certainty that comes from Commission decisions and that are relied upon in future planning."[123]

MP then reiterated the attributes of NTEC, including its ability to generate energy and maintain reliability throughout that entire period. Also, "NTEC is being developed with state of the art technology that can pivot to burn hydrogen or add carbon capture at a future date,

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[121] *Matter of Minnesota Power's Petition for Approval of EnergyForward Res. Package*, No. A19-0688, 2021 WL 3716404, at *6 (Minn. Ct. App. Aug. 23, 2021).
[122] MP, Reply Comments, pp. 22-23.
[123] MP, Reply Comments, p. 23.

reducing the stranded asset risk for customers."[124]

From a resource acquisition standpoint, MP does not believe it is practical to remove NTEC and pursue competitive bidding proceedings for solar. MP argued as one justification that MISO has made its concerns clear that "a certain level of dispatchable and flexible resources are required for MISO to reliably manage the transition to a decarbonized energy future within its region."[125]

X. Forecasting

A utility's load forecast is the foundation of an IRP, and the issues raised on MP's forecasts could make the decision-making process uniquely challenging. First, to develop the 2021 Plan, MP used its then-most recent Annual Electric Utility Forecast Report (AFR),[126] which was AFR 2020, to forecast the capacity and energy outlook for the 15-year planning period. However, AFR 2020 incorporated severe economic effects from the COVID-19 pandemic, which leads to the second issue. Since AFR 2020 was filed, MP has developed two subsequent AFRs; while AFR 2021 was not remarkably different than AFR 2020, AFR 2022 forecasts a return of previously lost load. According to the Department, the most difficult forecasting question for this IRP is whether MP should plan to the base forecast from AFR 2020, which assumes the permanent loss of large power customer load, or plan to the high contingency from AFR 2020, which assumes the large power customer load returns to past levels. The OAG, who recommends that NTEC be removed from the IRP, argued that the need anticipated in the NTEC proceeding never materialized. Moreover, the OAG argued that MP has continually overestimated its resource need. Section 1.F. of AFR 2020[127] includes a discussion of MP's historical forecast accuracy.

A. System Peak Demand and Total Energy Sales

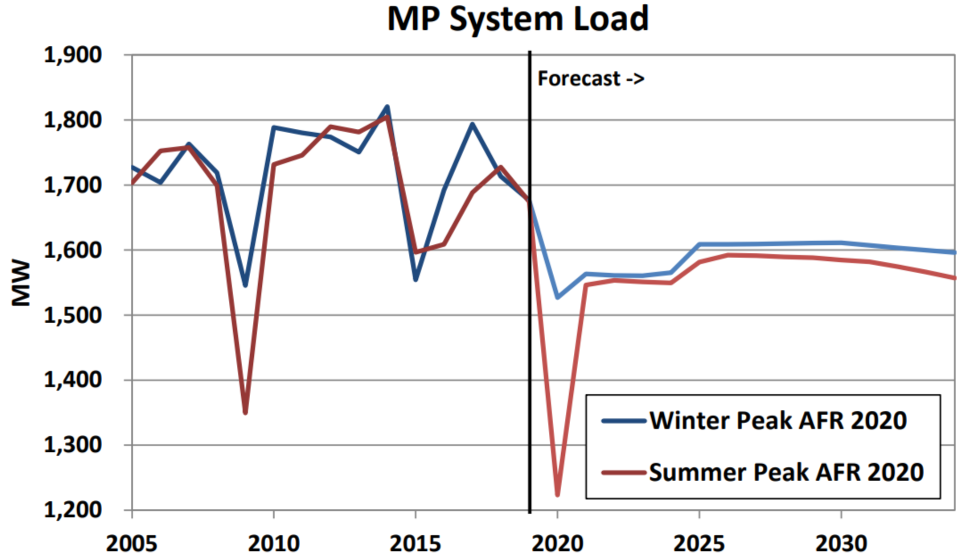
The AFR 2020 Expected Scenario (i.e., the base case outlook) assumes:

- An annual energy sales decline of about -0.4 percent per year (on average) from 2019 through 2034;
- Summer annual decline at average annual rate of -0.5 percent;
- Winter peak demands decline at average annual rates of -0.3 percent;
- Overall, a 103 MW **system load loss** by 2030. *(Emphasis added by staff.)*

Figure 20 below, from AFR 2020, depicts the significant near-term impacts of the COVID-19 pandemic recession in 2020, a partial recovery by industrial customers in 2021, and the PolyMet NorthMet mine's start-up in 2025. Note that long-term system load hovers around 1,600 MW:

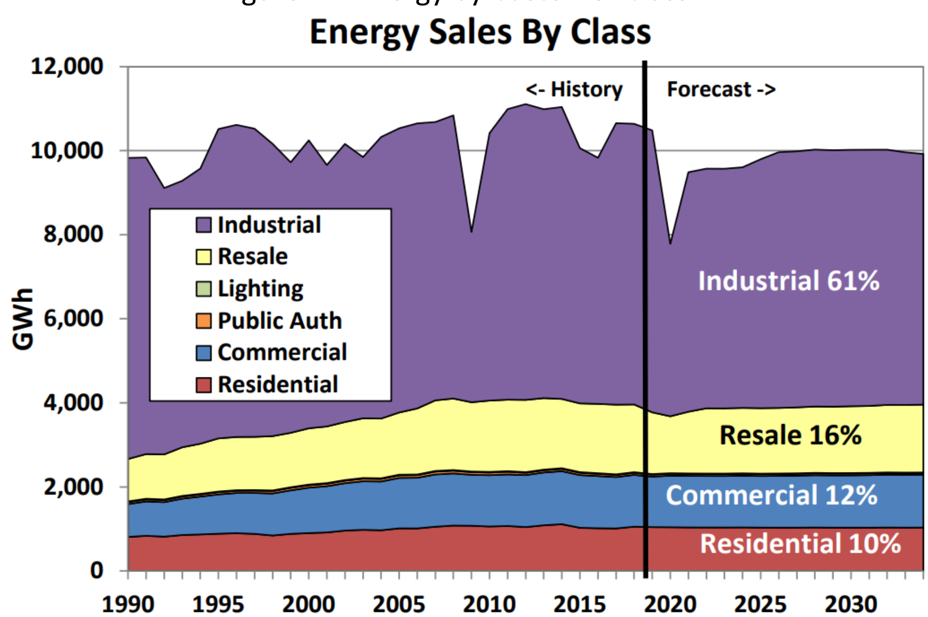
[124] MP, Reply Comments, p. 24.
[125] MP, Reply Comments, p. 26, quoting MISO.
[126] Minnesota laws and reporting rules governing electric utilities require that electric utilities providing service in Minnesota to submit an annual report to the Department, which contains historical and forecast customer sales and demand values, including forecast methodology and discussion. This Annual Electric Utility Forecast Report, or AFR, is due by July 1 of each year filed in the -11 dockets.
[127] Attachment A of MP Petition.

Figure 20: Peak Demand by Season[128]



For energy sales, Figure 21 from the Petition – again, based on AFR 2020 – shows historic and forecast energy requirements by customer class, and depicts the large influence the industrial class continues to have on the Company's energy requirements.

Figure 21: Energy by Customer Class[129]



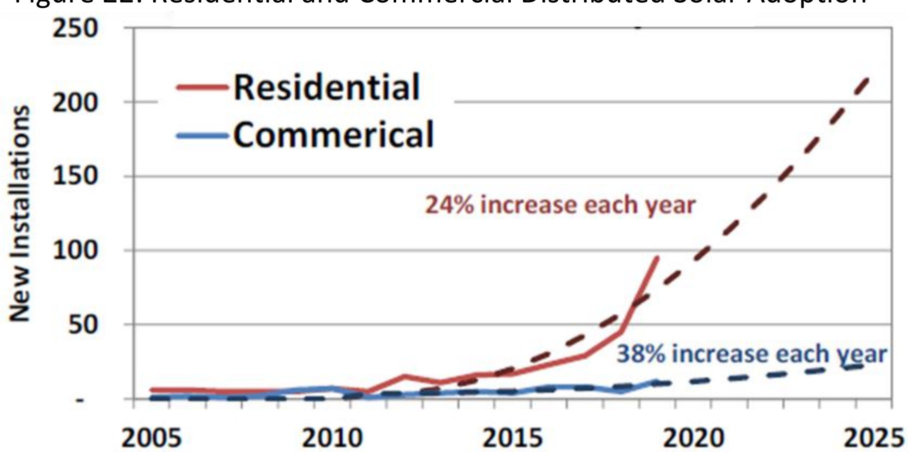
[128] MP, Petition, Figure 4, p. 22.
[129] MP, Petition, Figure 5, p. 23.

B. Distributed Energy Resources (DER)

MP used the forecast from AFR 2020 (included as Appendix A to its IRP filing) for its distributed solar, electric vehicle (EV), and DSM[130] programs. In 2019, the Company did not create individual forecasts for demand side programs. In response to increasing levels of DER penetration, in AFR 2019, MP created forecasts for conservation, EV, and distributed solar adoption in its service territory. The forecasts are then applied to adjust the Company's overall sales and peak demand forecasts accordingly. MP explained that only new DERs are included in the sales and peak demand forecast on a going forward basis, as systems installed prior to 2019 would already be accounted for in the forecast.[131]

The Company's forecast indicated that around 2,800 new DG solar installations would interconnect throughout the planning period (between 2020 and 2034), resulting in 49 MW of capacity and annual energy production of around 48,000 MW. Minnesota Power noted that its winter peak is usually 6PM or 7PM when DG solar is not producing, resulting in a 0% reduction of its winter peak. However, in the summer the Company's peak historically has occurred at 3PM or 4PM, thus MP used an effective load carrying capacity (ELCC) of 0.55 for installed DG solar capacity. This reduced the Company's summer peak by 0.6MW in 2020 and estimated a 15MW summer peak reduction by 2030.[132] Figure 22 depicts Minnesota Power's historic and forecasted adoption rate for distributed solar.[133]

Figure 22: Residential and Commercial Distributed Solar Adoption[134]

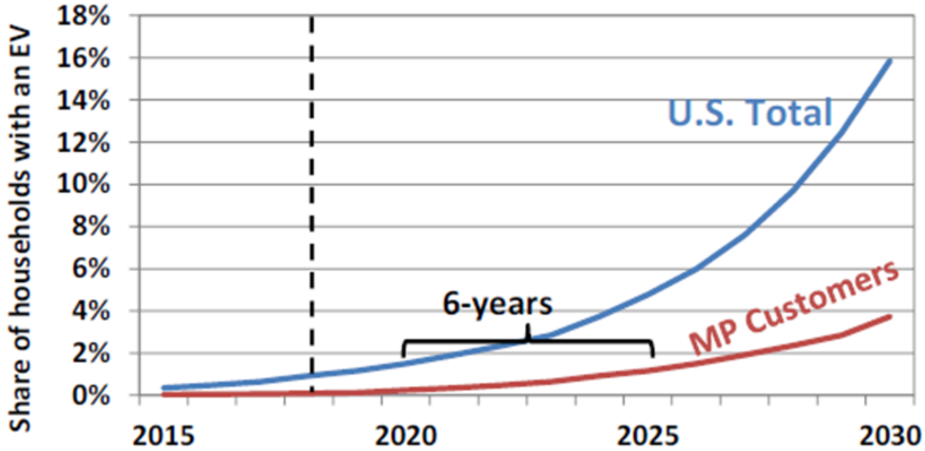


For EV adoption, MP forecasted residential EV adoption, but did not include fleet or commercial charging as adoption is currently too limited in its service territory to create an accurate forecast. The Company created the residential EV forecast by following a national projection for EV adoption, but delaying it by 6 years which follows current trends in its service territory for

[130] Minnesota Power describes three types of DSM: conservation through its CIP portfolio; peak shaving through its load control and interruptible programs; and load shifting through time-of-use rates.
[131] Appendix A of MP Petition, p. 18.
[132] Appendix A of MP Petition, p. 21.
[133] Appendix A of MP Petition, p. 19.
[134] Appendix A of MP Petition, Figure 6, p. 19.

EV purchases. Based on this assumption, MP forecasted there would be nearly 11,000 EVs in its service territory by 2034, requiring an incremental 27,295 MWh of energy annually. Figure 23 depicts MP's forecast for EV saturation among households in its service territory.

Figure 23: Minnesota Power vs. US Electric Vehicle Saturation[135]



C. Party Comments on MP's Forecasting

1. Department

As discussed above, MP's IRP was developed using AFR 2020, and the range of forecasts the Department considered in its IRP analysis was also based on this forecast. However, because AFR 2021 was filed after MP filed its IRP, the Department compared AFR 2020 to AFR 2021 to contemplate the appropriate forecast range. Based on this comparison, the two forecasts were too close for the differences to meaningfully impact the size, type, and timing of expansion units in this IRP. However, the Department considered other factors, such as possible return of lost industrial load and forecast error. To consider this possibility, the Department considered a high forecast contingency,[136] which assumes currently shut down large power customers will not remain shut down indefinitely. The Department explained that "it is not appropriate to plan based on MP's assumption that currently existing customers in AFR 2020 will remain shut down permanently without significant evidence that the customers will in fact, not be able to return."[137] Thus, the Department ran EnCompass both with MP's base case forecast, which assumed 93 MW of permanent lost load, and MP's high forecast, which assumes the lost load returns.

The Department also considered the possibility of forecast error. As shown in Table 15 below, the red-shaded cells indicate years when MP under-forecasted its needs, and the unshaded cells indicate over-forecasting. AFRs from 2000-2015 have overstated needs in the range of 10-

[135] Appendix A of MP Petition, Figure 7, p. 22.
[136] The high forecast contingency assumes the full operation of all taconite mining customers and the restart of the Verso Duluth paper mill, capturing about 100 MW of additional load over the Base Case.
[137] Department, Initial comments, p. 34.

30 percent, due to shutdowns among MP's taconite and paper industrial customers. However, AFRs 2016-2019 have a much lower error, suggesting MP has adjusted for this lost load.

Table 15: MP's Energy Forecast Error (percent)[138]

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AFR 2000	-3.9%	1.5%	0.5%	1.9%	-0.6%	-2.2%	-2.9%	-2.7%	-3.7%	29.1%	1.0%	-5.1%	-5.0%	-3.5%	-3.4%					
AFR 2001		-2.0%	0.3%	3.4%	-1.0%	-3.1%	-4.1%	-3.9%	-4.2%	29.0%	0.5%	-4.2%	-4.4%	-3.1%	-3.3%	6.4%				
AFR 2002			-0.9%	3.1%	0.2%	-2.4%	-3.6%	-3.8%	-4.4%	28.2%	-0.4%	-5.4%	-5.9%	-5.0%	-5.5%	3.6%	5.8%			
AFR 2003				3.6%	-1.8%	-2.9%	-2.9%	-2.1%	-2.7%	31.6%	2.8%	-1.3%	-0.6%	2.0%	3.2%	15.2%	19.8%	12.5%		
AFR 2004					0.6%	-0.3%	-0.5%	0.0%	0.6%	36.1%	6.4%	2.4%	3.0%	6.0%	7.5%	20.1%	25.2%	17.7%	20.0%	
AFR 2005						-0.3%	-0.5%	0.6%	4.1%	41.5%	11.0%	6.8%	7.0%	10.2%	11.7%	24.8%	29.9%	21.8%	23.9%	27.7%
AFR 2006							-0.3%	1.4%	1.8%	41.8%	11.1%	7.4%	8.0%	10.0%	10.5%	22.3%	26.2%	17.2%	17.9%	20.9%
AFR 2007								0.0%	-0.5%	37.0%	6.0%	2.8%	3.4%	5.7%	6.0%	17.4%	21.0%	12.3%	12.9%	15.3%
AFR 2008									-2.0%	34.8%	8.9%	5.1%	4.0%	4.8%	4.1%	15.6%	19.3%	11.2%	12.4%	15.2%
AFR 2009										4.8%	-16.8%	-13.9%	-8.1%	-3.1%	-0.9%	11.0%	15.9%	8.5%	10.2%	13.4%
AFR 2010											-0.8%	-1.8%	-1.0%	0.7%	1.1%	11.6%	15.2%	6.9%	7.7%	10.1%
AFR 2011												-0.3%	-1.1%	0.5%	1.0%	11.9%	15.7%	7.5%	8.4%	10.8%
AFR 2012													-1.4%	0.5%	0.7%	11.5%	15.4%	6.9%	7.8%	10.2%
AFR 2013														-0.2%	-0.4%	18.1%	24.6%	18.7%	20.0%	22.6%
AFR 2014															-0.3%	13.9%	24.2%	13.9%	14.9%	17.2%
AFR 2015																2.4%	5.9%	9.9%	11.0%	13.1%
AFR 2016																	-1.4%	-0.6%	0.9%	1.7%
AFR 2017																		1.8%	2.5%	3.6%
AFR 2018																			1.4%	1.7%
AFR 2019																				-1.8%

Overall, the Department concluded that MP's forecasts are acceptable for planning purposes, since the forecast process performed well until the extended drop in energy and demand that began in 2015.[139]

2. OAG

The OAG argued that one justification for removing NTEC from MP's resource plan is because the need anticipated in that proceeding never materialized. The OAG continued that MP's forecast error from the NTEC docket is emblematic of a continued pattern. Figure 3 of the OAG's Initial Comments (Table 16 below) shows the average forecast error for AFRs 2009-2019; while MP's forecasts are fairly accurate in the first two years, the forecast error increases over time.

[138] Department, Initial Comments, Table 1, p. 31.

[139] Department, Initial comments, p. 33.

Table 16: MP average load forecast error, 2009-2019[140]

Over/(under)estimate		
	Energy	**Peak**
Year 1	1%	-1%
Year 2	1%	2%
Year 3	4%	4%
Year 4	7%	6%
Year 5	10%	8%
Year 6	11%	9%
Year 7	12%	10%
Year 8	10%	7%
Year 9	9%	7%
Year 10	10%	9%
Year 11	14%	11%

The OAG continued:

> The Company's forecast overestimates are also remarkably consistent: every AFR from 2009 through 2014 has overestimated load—for both energy and peak demand—in every year from forecast-years 7 through 12. In other words, there is not a single observation (out of a possible 42) in which load was underestimated in forecast-years 7 through 12 over this period.[141]

3. CUB

CUB noted that more than two-thirds of MP's retail energy sales were delivered to industrial customers in 2020, which makes the Company vulnerable to large and lumpy increases and decreases in demand that shift with conditions outside of its control. According to CUB, this makes large new generation or transmission projects, such as a new natural gas plant, especially risky. For instance, MP testified in its Company's 2021 General Rate Case that highly cyclical industries such as paper manufacturing and taconite mining and processing pose "a significant risk to the Company as changes in economic conditions could result in significant variations in the Company's sales." This risk makes it especially important for MP to ensure that its IRP is reflective of an accurate load forecast, to the degree possible, and that its investments minimize the chance of stranded assets despite the difficulty in predicting the Company's future sales.[142]

Since MP filed its IRP, MP has produced its 2021 AFR, which shows a 215 MW higher need by 2030 relative to the 2020 AFR. The 2020 AFR forecasts 103 MW of system loss by 2030, while the 2021 AFR forecasts 112 MW of system load growth by 2030. The change is driven almost entirely by MP's industrial load forecast—the 2021 AFR predicts additional load from several

[140] OAG, Initial Comments, Figure 3, p. 3.
[141] OAG, Initial Comments, p. 3.
[142] CUB, Initial Comments, pp. 15-16.

new and existing customers, including an industrial facility on the Iron Range by mid-2026 and a new industrial facility in Duluth in 2023.[143]

The significant change in industrial load forecasts from one forecast to the next highlights the unique risk to the utility and ratepayers attributable to the utility's load profile. By risk, CUB is primarily referring to the risk of stranded assets for building generation, transmission, and distribution plant to meet industrial load that does not materialize or disappears due to the conditions outside the control of the utility. This risk is most acute when the utility proposes to add large generation resources with long lives to meet this uncertain future load. One way that the utility can minimize its risk of stranded assets is to add relatively smaller increments of demand- and supply-side resources, which can be scaled up in a relatively short period of time.[144]

CUB pointed out that MP's plan considers two scenarios: 2020 Load with Keetac and AFR 2020 High Scenario, both of which account for the resumed operations at the Keetac facility. The AFR 2020 High Scenario forecasts compound annual growth for both energy sales and peak demand being 0.1 percent, which is comparable to AFR 2021, which forecasts compound annual growth of 0.6 percent and 0.4 percent for energy sales and peak demand, respectively. These sensitivities are important for understanding the optimal Boswell 3 and 4 retirement timeline.[145]

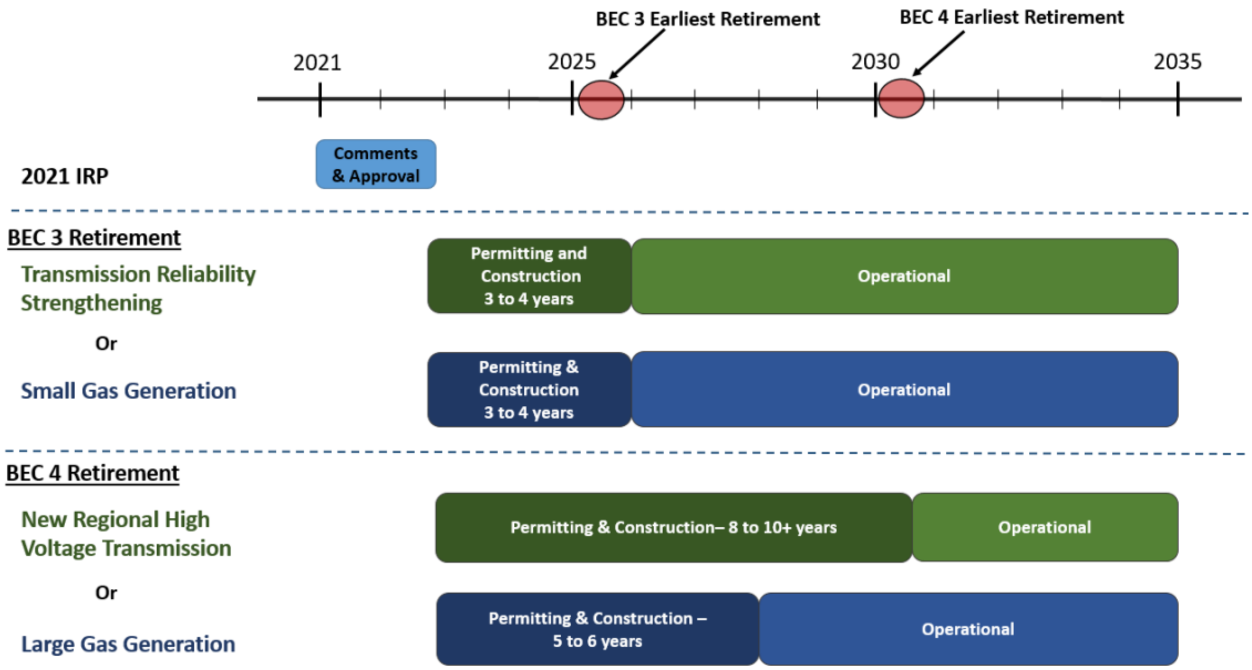
XI. MP's Modeling Results

A. *Earliest Feasible Date*

There is much discussion in the record over what the "earliest feasible date" means in the context of unit retirement. For instance, MP, Cohasset, and LPI argue that more aggressive retirement schedules are infeasible for reliability and socioeconomic reasons. MP also refers to a lead-time of at least ten years to feasibly retire Boswell 4, comparing the needed transmission investment to replace Boswell 4 to that of the Company's Great Northern Transmission Line (GNTL) project, which took over nine years to implement despite a very aggressive schedule. Figure 24, included in the Baseload Retirement Study, illustrates the estimated time needed to implement improvements to the transmission system or replace with new gas resources to accommodate early retirement of Boswell 3 and 4.

[143] CUB, Initial Comments, p. 16.
[144] CUB, Initial Comments, p. 16.
[145] CUB, Initial Comments, p. 16.

Figure 24: Approximate Timeline for Construction of Replacement Transmission or Gas Resources to Accommodate Early Retirement of BEC3 and BEC4[146]



The Department found that the FastExit plan is optimal, but Boswell 3 might require a later-than-2025 date; however, regarding Boswell 4, the Department concluded that because the LRTP line is expected to be on-line by the end of 2030, retiring Boswell 4 by 2030 is feasible. The CEOs agree and recommend the Commission require MP to immediately begin planning the transmission upgrades and other grid reliability mitigation options needed to retire Boswell 4 by 2030. Therefore, while examining MP's scenarios listed below, the Commission will not only need to consider the scenarios' costs, but simultaneously need to consider what is "feasible," and from multiple perspectives The next section will discuss MP's Boswell retirement scenarios, which are:

1. Retire Boswell 3 Early as Feasible (2025)
2. Retire Boswell 4 Early as Feasible (2030)
3. Expedited Retirement of both units, Boswell 3 (2025) & Boswell 4 (2030)
4. Base Case: no retirement earlier than 2035

B. Step 1 and Step 2

Before running the scenarios in EnCompass, MP screened resource alternatives because the model must have certain limitations on the number of alternatives the EnCompass model can evaluate. Available resource options are shown below.[147]

<u>Demand Side Alternatives</u>

1. Up to 200 MW Long-Term Industrial Demand Response

[146] Appendix P of MP Petition, Figure 10, p. 31.
[147] MP, Petition, pp. 31-32.

   a. EnCompass can select either Product B or Product D
2. Air Conditioning Load Control and Hot Water Load Control
3. High and Higher Energy Efficiency Scenarios

Supply Side Alternatives
1. 100 MW Wind Farm in Minnesota
2. 100 MW Wind Farm in North Dakota
3. 100 MW Solar Farm Located at Existing Generation Site in Minnesota (i.e., Net Zero)
4. 100 MW Solar Farm Located in Minnesota
5. 590 MW Natural Gas-Fired and Hydrogen Ready 1x1 Combined-Cycle (CC)
6. 280 MW Natural Gas-Fired and Hydrogen Ready Combustion Turbine (CT)
7. 110 MW Natural Gas-Fired Reciprocating Internal Combustion Engines (RICE)
8. 115 MW Natural Gas-Fired Aeroderivative LMS100 (Aero)
9. 100 MW Li-Ion Battery with 4 hours of Storage
10. 100 MW Li-Ion Battery with 8 hours of Storage
11. 100 MW Flow Battery with 12 Hours of Storage
12. 150 MW Bilateral Bridge Transaction

MP ran its analysis using a two-step process:

Step 1 was the capacity expansion analysis, in which EnCompass optimized the mix of supply- and demand-side resource with the resource options listed above under combinations of one-, and two-unit Boswell retirement scenarios, as well as a "Do Nothing" (i.e., no retirement) case.

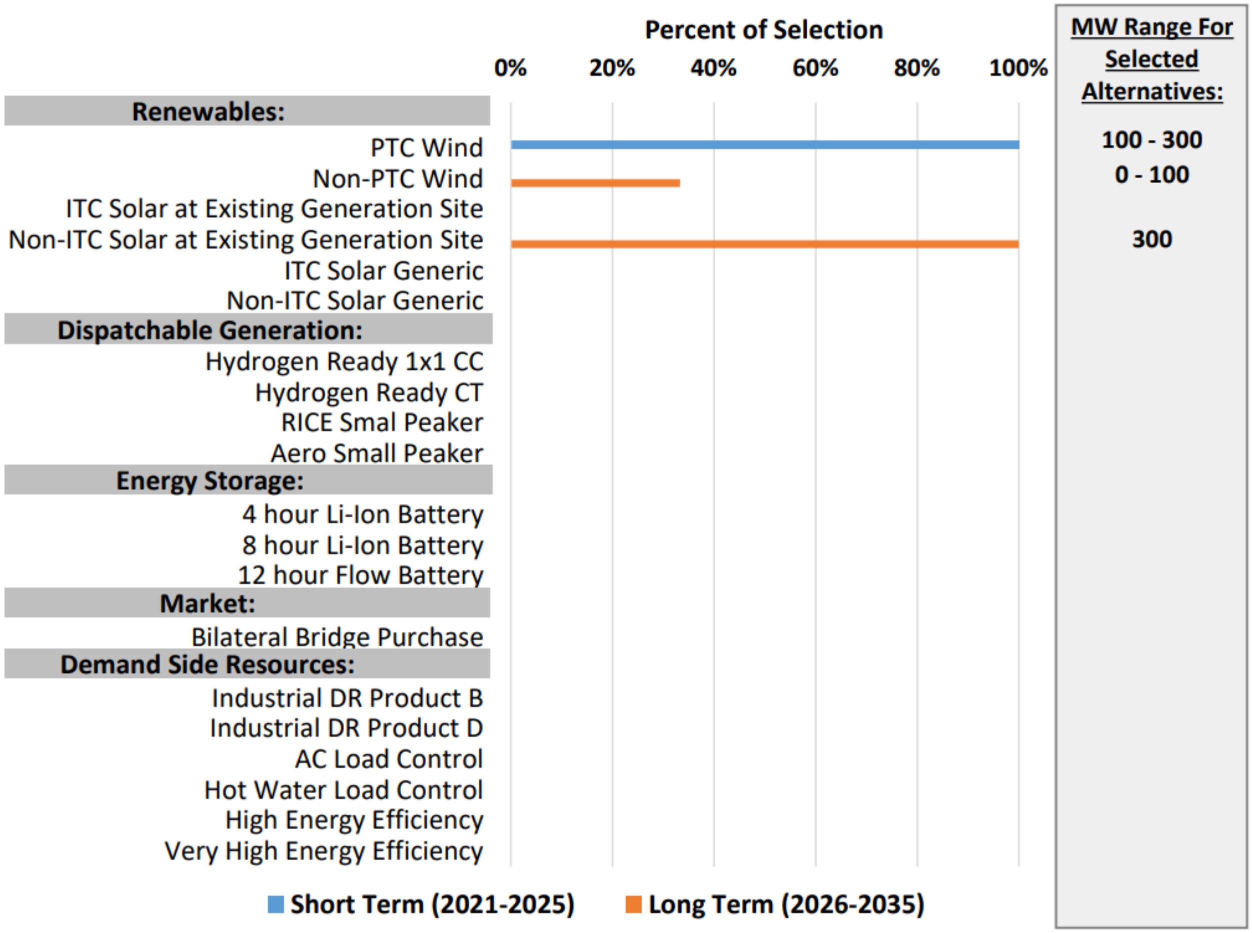
Table 17: Comparison of Early Retirement Scenarios to Reference Case[148]

		Single Unit Retirement			**Two Unit Retirement**
	Base Case ("Do Nothing")	**2021 Plan**	**Retire BEC3 Early as Feasible**	**Retire BEC4 Early as Feasible**	**Expedited Retirement**
BEC3	No earlier than 2035	2029	2025	No earlier than 2035	2025
BEC 4	No earlier than 2035	No earlier than 2035	No earlier than 2035	2030	2030

These scenarios were run under a variety of sensitivities to determine how frequently resources selected. Figure 25 below shows the results for the 2021 Plan (i.e., retire Boswell 3 in 2029 and continue Boswell 4). Under this scenario, PTC wind was selected 100 percent of the time in the short-term (as indicated by the blue bar), Net Zero solar was selected 100 percent of time in the long-term (orange), while non-PTC wind was occasionally selected in the long-term (orange). From this, MP was able to determine that under a variety of potential futures, 100-300 MW of near-term PTC wind and long-term Net Zero solar is likely cost-effective.

[148] Appendix P of MP petition, Figure 11, p. 33.

Figure 25: Capacity Expansion Analysis Results for BEC Unit 3 Retire in 2029 ("2021 Plan") [149]



Similar figures for other scenarios also run in Step 1 are shown in Appendix K (Detailed Analysis Section), but are not pictured here. Those scenarios are:

- Figure 6: Retire Boswell 3 in 2025 (Early as Feasible);
- Figure 7: Retire Boswell 4 in 2030 (Early as Feasible);
- Figure 8: Retire Boswell 3 in 2025, and retire Boswell 4 in 2030; and
- Figure 9: No Boswell retirement.

According to the results of Step 1, MP found that:

1. 100-300 MW of PTC Wind was selected in nearly all Boswell retirement scenarios.
2. 100-300 MW of Net Zero solar was selected near the time of a Boswell unit retirement.
3. When Boswell 3 only is retired, transmission solutions are selected instead building new gas CTs to address reliability issues.
4. When Boswell 4 is retired, gas generation was selected to avoid building high kV transmission projects needed to maintain grid reliability. Specifically,
   a. When Boswell 4 only is retired, a 282 MW hydrogen-ready CT was selected, and
   b. When both Boswell units are retired, a 593 MW hydrogen-ready CC is selected.

[149] MP, Petition, Figure 12, p. 41.

Step 2 was informed by these results. Under Step 2, MP locked in expansion units into a particular "Swim Lane," then ran production cost runs on each scenario with 38 sensitivities (high/low natural gas prices, high/low coal prices, and so forth). Figure 26 below shows MP's resources included in each Swim Lane.[150] Notice that all swim lanes except "Do Nothing" include 200 MW of wind by 2025 and 200 MW of Net Zero solar by 2030.

Figure 26: Alternative Power Supply Portfolios ("Swim Lanes") Evaluated in Step 2[151]

2021 Plan	"Expedited" Retirement of BEC 3-4	Retire BEC 3 Early as Feasible	Retire BEC 4 Early as Feasible	Base Case "Do Nothing"
2025 *200MW PTC Wind* **2029/2030** *BEC 3 Retires 2029** *BEC 3 Transmission* *200MW MP Facility Solar*	**2025** *200MW PTC Wind* **2025/2026** *BEC 3 Retires 2025** *BEC 3 Transmission* *200MW MP Facility Solar* **2029/2030** *BEC 4 Retires 2030** *593MW 1x1 CC Gas*	**2025** *200MW PTC Wind* **2025/2026** *BEC 3 Retires 2025** *BEC 3 Transmission* *200MW MP Facility Solar*	**2025** *200MW PTC Wind* **2030/2031** *BEC 4 Retires 2030** *282 MW CT Gas + Transmission* *200MW MP Facility Solar*	

**Retired at end of the year*

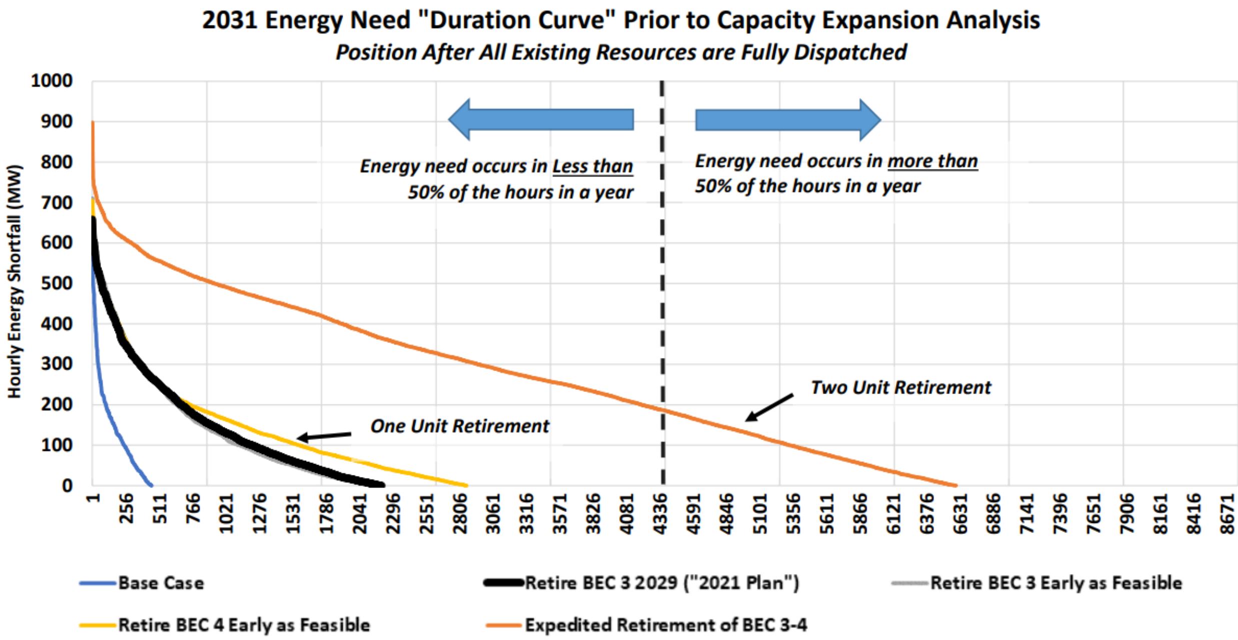
To further explain MP's Boswell retirement modeling, the following results were common:

- Boswell 3 only → transmission upgrades preferred over CT;
- Boswell 4 only → 282 MW gas CTs preferred over new high kV lines;
- Both Boswell units → 593 MW CC.

This result is driven largely by, in MP's words, "the magnitude (MW level needed in an hour) and the frequency (number of hours in a year energy is needed)" of the energy need.[152] Figure 27 below shows the duration curve of the energy need in 2031 as a simple illustration of the depth and frequency of the energy need under various retirement scenarios. As can be expected, the greatest energy need occurs under the expedited two-unit retirement scenario, with an average energy need of approximately 300 MW over 75 percent of the hours in a year. However, this need ranges from 1 MW to 900 MW, highlighting the variability of the need throughout the year. Among the one-unit retirement scenarios, there is a greater energy need under the Retire Boswell 4 early scenario (yellow) than the 2021 Plan (black), hence the need for a peaking CT under the Boswell 4 retirement scenario.

[150] MP, Petition, Figure 14, p. 50.
[151] MP, Petition, Figure 14, p. 50.
[152] MP, Petition, p. 40.

Figure 27: Energy Need Duration Curve in 2031 for BEC Units 3 and 4 Retirement Scenarios[153]



C. Swim Lane Results

Each Swim Lane and the 2021 Plan was put through a series of 37 sensitivities that stressed the main drivers for resource decisions, such as fuel costs, market prices, and customer demand. Table 18 below illustrates how the scenarios performed over a range of sensitivities under the Reference Case. According to these results:

1. The 2021 Plan was least-cost under 27 of 38 total futures (base case + 37 sensitivities); and
2. Scenarios with a 2029 Boswell 3 retirement represented a majority of least-cost plans, indicating that end-of-2029 is optimal timing.

[153] MP, Petition, Figure 11, p. 41.

Table 18: Step 2 Sensitivity Analysis-2021 NPV of Cost for Reference Case Scenario ($millions)[154]

	Single Unit Retirement			Two Unit Retirement	
EnCompass Sensitivities	2021 Plan *Retire BEC3* in 2029	Retire BEC3 Early as Feasible	Retire BEC4 Early as Feasible	Expedited Retirement of BEC 3 and 4	Base Case "Do Nothing"
Base Case	**$7,891**	$7,903	$7,918	$7,944	$8,010
1 Coal +20%	**$7,750**	$7,783	$7,762	$7,837	$7,846
2 Coal -10%	**$7,963**	$7,969	$7,991	$7,993	$8,093
3 Biomass +15%	**$7,888**	$7,908	$7,909	$7,932	$8,001
4 Biomass -15%	**$7,897**	$7,917	$7,917	$7,950	$8,006
5 Lower Gas -50%	$7,780	$7,809	**$7,758**	$7,814	$7,871
6 Low Gas -25%	$7,874	$7,887	**$7,862**	$7,914	$7,976
7 High Gas +25%	**$8,033**	$8,045	$8,075	$8,087	$8,163
8 Higher Gas +50%	**$8,133**	$8,139	$8,165	$8,166	$8,304
9 Highest Gas +100%	$8,359	**$8,338**	$8,391	$8,368	$8,545
10 Energy Market -50%	$6,619	$6,674	$6,673	$6,820	**$6,562**
11 Energy Market -25%	**$7,346**	$7,383	$7,377	$7,499	$7,358
12 Energy Market +25%	$8,339	$8,344	$8,357	**$8,316**	$8,537
13 Energy Market +50%	$8,578	$8,565	$8,565	**$8,493**	$8,790
14 Capital Costs -30%	$7,891	$7,903	$7,889	**$7,881**	$8,018
15 Capital Costs +30%	**$7,887**	$7,907	$7,935	$8,007	$8,011
16 No Market Sales	**$7,734**	$7,768	$7,761	$7,822	$7,818
17 No Sales and Purchases	$9,315	$9,524	**$9,162**	$9,307	$9,369
18 Market Access -50%	$8,298	$8,365	**$8,258**	$8,312	$8,401
19 Low Interconnect Costs	**$7,876**	$7,890	$7,898	$7,927	$8,014
20 ITC & PTC Extension	**$7,892**	$7,896	$7,907	$7,937	$8,005
21 Wind Cost Curve Low	**$7,895**	$7,907	$7,915	$7,949	$8,012
22 Wind Cost Curve High	**$7,892**	$7,911	$7,924	$7,946	$8,011
23 Solar Cost Curve Low	**$7,883**	$7,900	$7,905	$7,932	$8,008
24 Solar Cost Curve High	**$7,911**	$7,920	$7,938	$7,961	$8,013
25 Storage Cost Curve Low	**$7,892**	$7,911	$7,916	$7,946	$8,014
26 Storage Cost Curve High	**$7,891**	$7,910	$7,916	$7,944	$8,010
27 AFR 2020 Low Scenario	**$7,573**	$7,598	$7,607	$7,657	$7,668
28 AFR 2020 Load w Keetac	$8,385	$8,399	**$8,377**	$8,385	$8,511
29 AFR 2020 High Scenario	$8,424	$8,443	**$8,406**	$8,424	$8,551
30 Residential TOU	**$7,884**	$7,894	$7,908	$7,935	$8,012
31 Higher DG & EV Growth	**$7,896**	$7,900	$7,913	$7,946	$8,011
32 Renewable ELCC -2.5%	**$7,896**	$7,919	$7,916	$7,945	$8,013
33 Renewable ELCC +2.5%	**$7,888**	$7,905	$7,915	$7,947	$8,011
34 PRM -2%	**$7,892**	$7,909	$7,913	$7,935	$8,010
35 PRM +2%	**$7,899**	$7,917	$7,918	$7,946	$8,013
36 MISO CF -2%	**$7,886**	$7,902	$7,915	$7,942	$8,004
37 MISO CF +2%	**$7,906**	$7,927	$7,912	$7,946	$8,019
Sum of Least Cost Runs	**27**	**1**	**6**	**3**	**1**

[154] Appendix K of MP Petition, Table 4, p. 17.

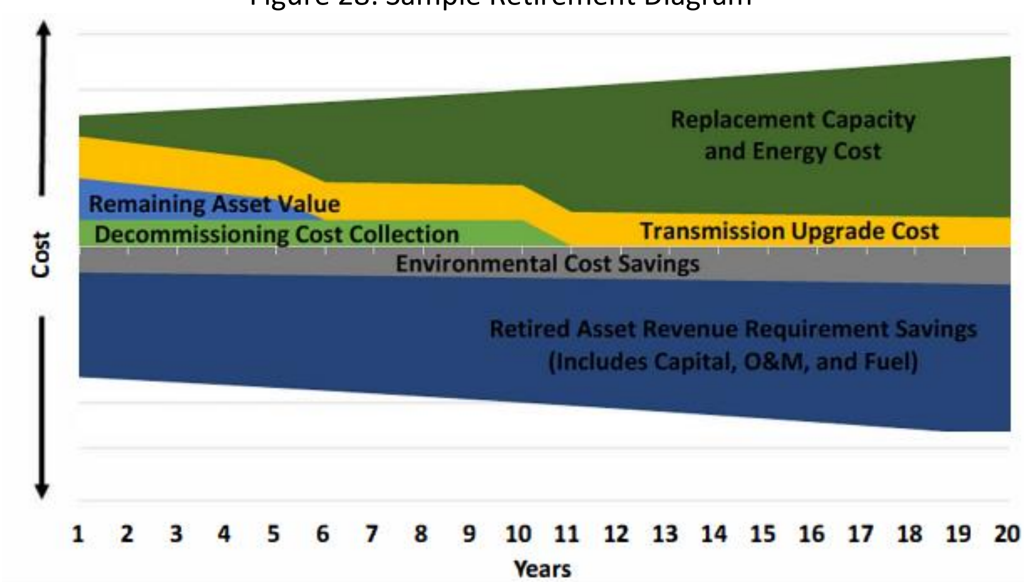
Of note, the Reference Case forecast applied the following assumptions (this is not, however, a comprehensive list of every single assumption in the Reference Case):

- The Reference Case Scenario applied the environmental externality cost of carbon from 2021 through 2024, and starting in 2025, and was used in the swim lane analysis only. For CO_2 regulatory costs, the middle value (ranging from $15.00/ton starting in 2021 to $18.55/ton in 2035) was included through the end of the study period and used in the expansion plan analysis and swim lane analysis.[155]
- For criteria pollutants, the Reference Case Scenario used the mid-point of the Metropolitan Fringe environmental cost values from the Commission's January 3, 2018 in Docket No. 14-643 (the most recent update to environmental externalities). Also, for carbon monoxide and lead, which were not updated in Docket No. 14-643, the Reference Case used the mid-point of the Metropolitan Fringe environmental costs established in Docket Nos. 93-583 and 00-1636.
- The Reference Case assumed natural gas for Minnesota to be $3.42/MMBtu in 2021 to $4.84/MMBtu in 2035.
- The Reference Case assumed wholesale market energy, with $15/ton carbon starting in 2025, at $27/MWh in 2021 to $50/MWh in 2035.

D. Methodology for Asset Retirement

To describe how the retirement scenarios were modeled in EnCompass, the base case assumes that Boswell 3 and 4 continued to operate through the end of each asset's currently approved accounting life. As shown by the sample retirement diagram (Figure 28 below), EnCompass accounts for several factors to derive the ultimate value equation by netting both the costs and benefits. MP emphasized that the diagram was created for demonstrative purposes only.

Figure 28: Sample Retirement Diagram[156]



[155] Appendix J of MP Petition, p. 2.
[156] Appendix J of MP Petition, Figure 2, p. 24.

MP's retirement methodology depicted in the diagram can be briefly described as follows:

- ***Remaining Asset Value:*** In the asset retirement scenarios, the remaining value of any facility was treated as a cost, which was assumed to be recovered over the currently-approved accounting life of the asset, regardless of when the retirement takes place. MP stated that although neither unit has a formal retirement date, 2035 is the current end of both units' depreciable lives.
- ***Decommissioning Cost:*** Expenses associated with the decommissioning of a generating asset were included as part of the expense of retirement and were assumed to be recovered over a 10-year period.
- ***Replacement Power Cost:*** Any unit retirement removes both energy and capacity from the system, and the modeling analysis identifies the least-cost solution to meet energy and demand requirements.
- ***Transmission Upgrade Costs:*** Appendix F details MP's transmission costs associated with the retirement of Boswell 3 and 4. Depending on the scope and scale of the transmission project, it could be expected to take over 8-10+ years to develop, permit, and construct a project, and the cost could approach $1 billion.

XII. Alternative Modeling from Parties

A. *Department Comments*

1. Summary

The Department used the same resource alternatives as the Company; a table of potential alternatives can be found in Attachment 1 of the Department's Initial Comments. The Department also examined the following variables:

- The same five Boswell retirement scenarios as MP;
- 6 carbon futures;
- 32 of MP's 38 contingencies;
- MISO's proposed LRTP lines;
- MP's sales forecast levels; and
- 50 percent and 20 percent NTEC ownership levels.

The retirement years for the five Boswell retirement scenarios are shown by Table 19 below.

Table 19: Dept Table 1. MP's Boswell Retirement Scenarios examined for the planning period (2021-2035), no retirement action taken in blank cells[157]

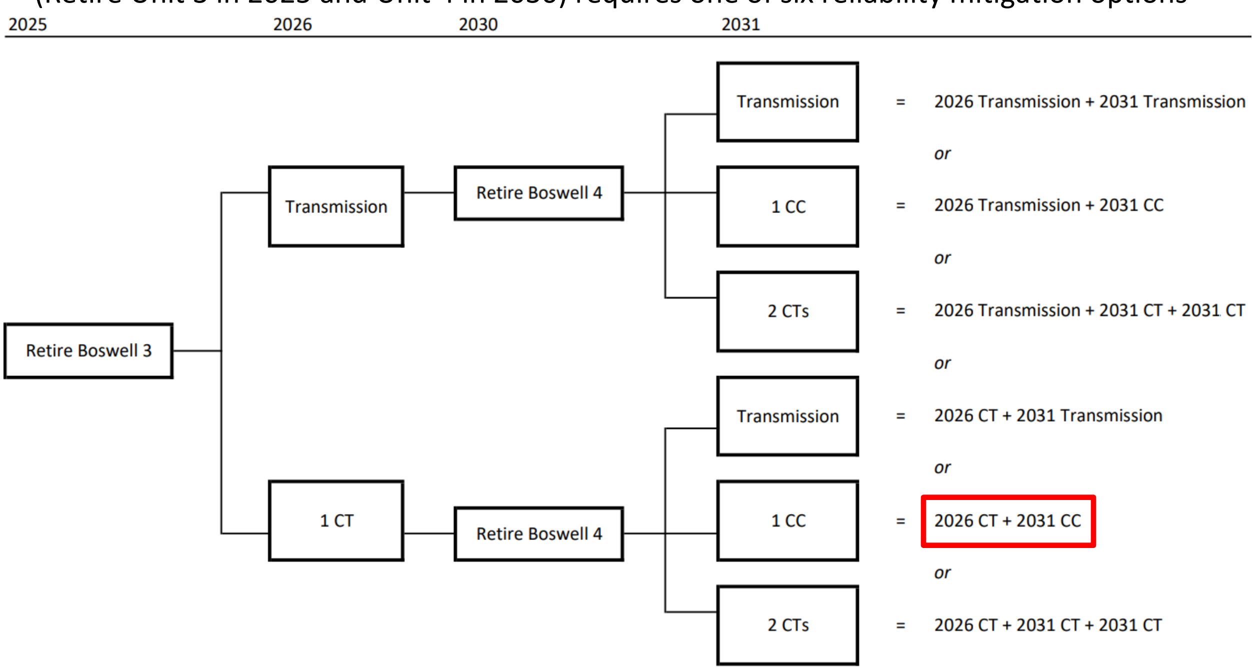
	Boswell 3 Retirement Date	Boswell 4 Retirement Date
Status Quo	-	-
MP PrefPlan	2029	-
Early3	2025	-
Early4	-	2030
FastExit	2025	2030

[157] Department, Comments – Supplemental Modeling (July 29, 2022), Table 1, p. 4.

MP's model forces specific capacity decisions in each Boswell retirement scenario as a way to mitigate reliability issues, and the Department did not modify this constraint. The following bullet points detail the constraints under the Department's scenarios in EnCompass. Note that the Department's recommendation is the FastExit scenario.

- ***StatusQuo***: No CTs or CC are permitted to be selected.
- ***Early3***: After Boswell 3 is retired in 2025, the model must choose one of two options in 2026: either transmission S1 or a CT.[158]
- ***PrefPlan***: After Boswell 3 is retired in 2029, the model must choose one of two options in 2030: either transmission S1 or a CT.
- ***Early4***: After Boswell 4 is retired in 2030, the model must choose one of four options in 2031: transmission S2, a CC, two CTs, or transmission S1 + one CT.
- ***FastExit***: After Boswell 3 is retired in 2025, the model must choose one of two options in 2026: either transmission S1 or a CT. After Boswell 4 is retired in 2030, the model must choose one of three options: transmission (S2 or S3, depending on 2026 selection), one CC, or two CTs. This results in six potential options for the model to choose from, which are shown in Figure 29 below (staff added a red box around FastExit).

Figure 29: In MP's Step 1 Expansion Plan Database, the Boswell RS04 Retirement Scenario (Retire Unit 3 in 2025 and Unit 4 in 2030) requires one of six reliability mitigation options[159]



Among the most significant changes the Department made to MP's modeling, the Department:

[158] Recall staff's previous discussion of Appendix F of the Petition, in which MP identified transmission solution for E1, E2, S1, S2, and S3.
[159] Department, Initial Comments, Attachment 1F, PDF p. 101.

removed the Step 2 Swim Lane datasets that locked in the expansion plans and replaced them with the Step 1 Expansion Plan Boswell retirement constraints datasets—in other words, the Department did not separate the analysis into two steps.

The Department's results suggest the following modifications to MP's 2021 Plan:
- Acquire 200-300 MW of wind in the 2024-'25 timeframe, with accompanying transmission.
- Retire Boswell 3 in 2025, and;
  - Acquire 282 MW of peaking resource as a Boswell 3 retirement mitigation measure, to be in service in 2026.
- Retire Boswell 4 in 2030, and;
  - Ensure that LRTP continues to be a sufficient Boswell 4 retirement mitigation measure; if LRTP is insufficient in this regard, MP should acquire a 593 MW gas CC resource to be in service in 2031.
- Acquire 100 MW of solar sited at Boswell in the post-2030 timeframe, using existing Boswell interconnection rights.

2. FastExit Expansion Plan

The following table shows the Department's capacity and transmission expansion plan results by the Boswell retirement scenarios and the resources selected.

Table 20: Dept Table 4. Department's capacity (MW) and transmission (number of projects) expansion plan resources chosen for each of the five Boswell retirement scenarios (Conditions: Mid/Mid Carbon Future, Base Contingency)[160]

Boswell Retirement Scenario	Battery	Contract Purchase	DR	EE	Gas CC	Gas CT/RICE/AERO	Solar	Transmission	Wind
Status Quo	0	0	0	0	0	0	200	3	300
PrefPlan	0	0	0	0	0	0	300	4	300
Early3	0	0	0	0	0	0	300	4	300
Early4	0	0	0	0	0	282	300	4	300
FastExit	0	0	0	0	593	0	200	4	300

Under the Department's modeling, EnCompass:
- chose 300 MW of wind resources in each Boswell retirement scenario;
- chose 200 to 300 MW of solar resources in each Boswell retirement scenario;
  - Solar resources were all Net Zero solar;
- chose 3 to 4 transmission projects in each Boswell retirement scenario; and
- only chose gas resources in the Early4 and FastExit scenarios.

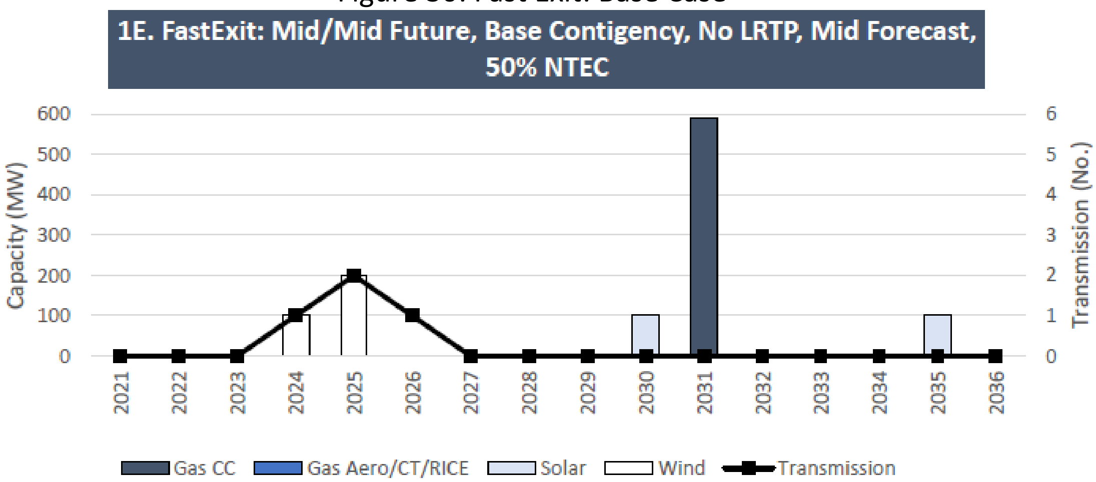
As staff compared the Department's and MP's modeling results, the Department's modeling results appear very similar to MP's Step 1 analysis, which may suggest that the differences

[160] Department, Comments – Supplemental Modeling (July 29, 2022), Table 4, p. 6.

between the MP and Department plans are largely driven by MP's decision to break its analysis into Step 1 and Step 2. MP and the Department should clarify this issue.

Whereas the table above shows total capacity addition over the planning period, Figure 30 below shows the FastExit expansion plan timeline.

Figure 30: Fast Exit: Base Case[161]



FastExit is least-cost under the Mid/Mid Carbon future and base case contingencies. However, Status Quo, or no retirement, is least-cost by revenue requirements only (i.e., no externalities or CO_2 regulatory costs).

Table 21: Department's total cost results for each Boswell retirement scenario (Conditions: Mid/Mid Carbon Future, Base Contingency)[162]

NPV Plan Costs ($Million)	StatusQuo	PrefPlan	Early3	Early4	FastExit
Revenue Requirement	$8,062	$8,128	$8,151	$8,227	$8,329
Externalities	$2,022	$1,901	$1,897	$1,857	$1,709
Revenue Requirement + Externalities (Total Plan Cost)	$10,084	$10,030	$10,048	$10,084	$10,038

3. LRTP

The Department ran several scenarios factoring in MISO's LRTP projects, which are expected to be on-line by the end of 2030. Notably, post-2030 under an LRTP change case, EnCompass made different selections from the other expansion plans, including:

- A 2031 transmission project as the Boswell 4 reliability mitigation selection;
- The addition of 100 MW of DR in 2031;
- The addition of 300 MW of Boswell-sited solar between 2031 and 2032; and

[161] Department, Comments – Supplemental Modeling (July 29, 2022), Figure 1E, p. 45.
[162] Department, Comments – Supplemental Modeling (July 29, 2022), Table 2, p. 4.

- The addition of 200 MW of wind and accompanying wind transmission projects in 2033 and 2034.

Figure 31 below shows the FastExit expansion plan timeline with LRTP. Note that the expansion plan is the same as the FastExit-No LRTP scenario through 2029, but the plans differ significantly beginning in 2030. For example, FastExit-LRTP adds 200 MW of solar and 100 MW of DR in 2030, and another 100 MW of solar in 2031. No-LRTP adds 100 MW of solar in 2030 and a 593 MW CC unit in 2031.

Figure 31. Department 9D. FastExit: LRTP[163]

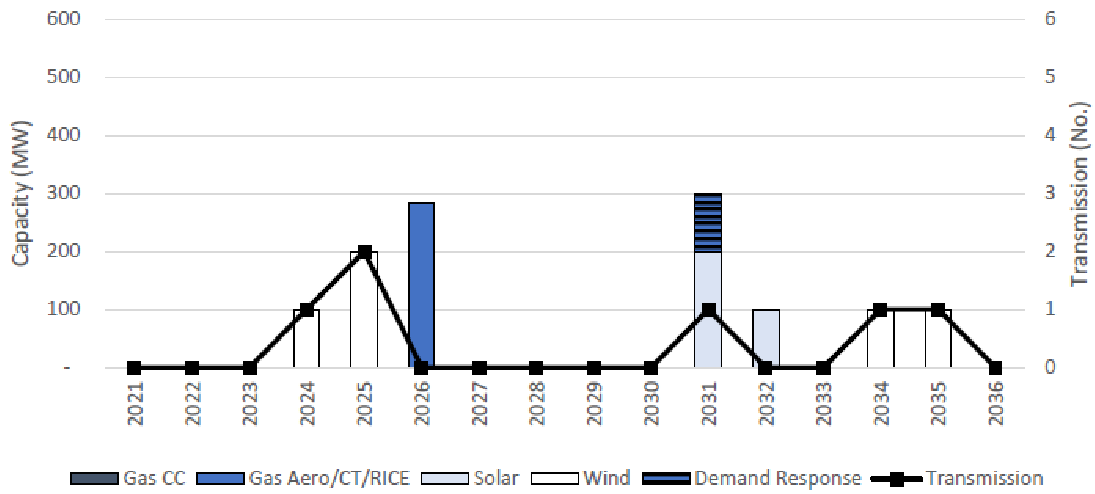
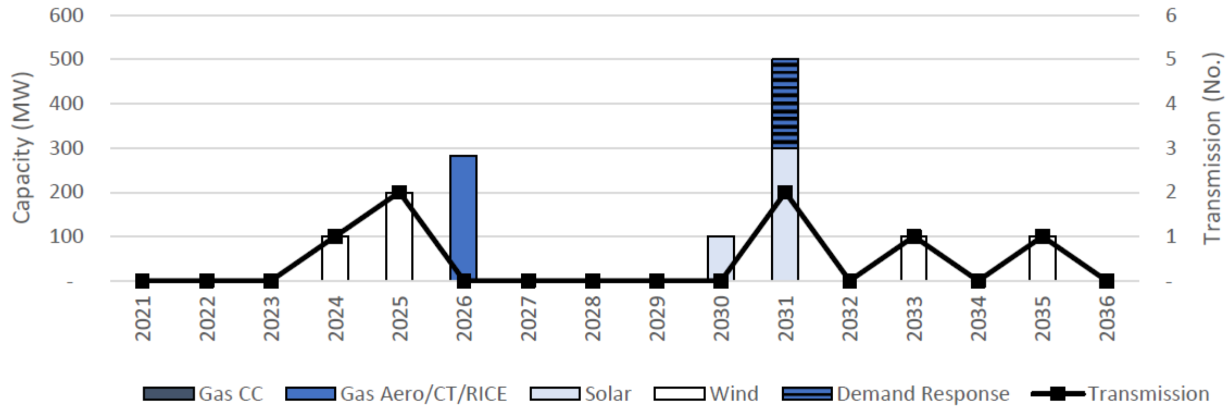


Figure 32 is a figure requested by Commission staff,[164] showing the expansion plan timeline under the FastExit, LRTP, 20 percent NTEC scenario, using a Mid/Mid carbon future, a mid-sales forecast, and a base contingency. This scenario adds much more solar (and sooner) and 100 MW of additional DR. Specifically, the scenario adds:

- 100 MW of solar in 2030;
- 300 MW of solar in 2031; and
- 200 MW of DR in 2030.

[163] Department, Comments – Supplemental Modeling (July 29, 2022), Figure 9D, p. 47.
[164] On September 27, 2022, the Department and Commission staff discussed Figures 1E and 9A-9G from the Department's July 29, 2022 Comments. Staff requested the Department filed a FastExit scenario that included LRTP and 20 percent NTEC ownership. Commission Staff e-filed an *ex parte* communication in the instant docket that same day.

Figure 32. FastExit: LRTP, 20% NTEC[165]



Finally, MP argued that retiring Boswell 4 by 2030 is not feasible, in part because MP assumes it will take at least ten years depending on the scope and scale of a high kV transmission project. The Department responded that the LRTP line will be available in a timely manner for the Boswell 4 retirement dates studied in this docket. The Department further explained how the costs of the LRTP line would be captured in the modeling:

> This would mean that MISO would trigger the costs of the line and recover the costs per its tariff, rather than MP's IRP triggering the transmission line and the entire cost falling on MP ratepayers. From a modeling perspective, this drastically reduces the costs of the transmission Boswell constraint options, meaning that EnCompass should have a tendency to favor transmission over natural gas generation as a Boswell reliability mitigation option.[166]

Moreover, the Department stated that if LRTP line is assumed as definite in the model, rather than only potentially triggered by the unit retirements, this can impact both plan costs and expansion plans of various Boswell retirement plans. Additional modeling observations include:

- With LRTP, the StatusQuo and PrefPlan scenarios become higher cost and Early4 and FastExit become lower cost.[167]
- In the no-LRTP runs, a CC unit was added in the FastExit scenarios for all carbon futures; however, in the LRTP runs, no intermediate gas capacity was added;[168] and
- In the no-LRTP runs, no demand response was added; by contrast, in the LRTP runs, DR was added in both the Early4 and FastExit Boswell scenarios under all carbon cost futures;[169]

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[165] Department, Letter (October 5, 2022).
[166] Department, Comments – Supplemental Modeling (July 29, 2022), p. 26.
[167] Department, Comments – Supplemental Modeling (July 29, 2022), p. 28.
[168] Department, Comments – Supplemental Modeling (July 29, 2022), p. 30.
[169] Department, Comments – Supplemental Modeling (July 29, 2022), p. 31.

4. NTEC

Typically, the Department found that under base conditions (Mid Forecast, 50% NTEC, and No LRTP), EnCompass tended to select transmission in 2026; however, if the forecast, NTEC ownership level, or LRTP is changed from these conditions, EnCompass tends to select a gas CT unit in 2026. The Department also found that found that for the 2031 selection, forecast level and NTEC ownership did not drive retirement mitigation selection, although the presence or absence of LRTP did.

In general, when NTEC ownership is reduced using a Mid forecast:

- Early4 jumps from being highest cost in two metrics to least cost in three metrics;
- FastExit becomes second least cost, but has results very close to Early4;
- StatusQuo goes from being highest cost in only one metric to highest cost in all three metrics; and
- PrefPlan drops from being second least cost in two metrics to second highest cost in three metrics.

5. Carbon Costs

The Department's Supplemental Modeling shows the ranking of the plans under various carbon futures.[170] FastExit is the least-cost scenario in all scenarios where CO_2 **are** included, but the StatusQuo scenario is least-cost when CO_2 costs **are not** included.

Table 22: Dept Base Scenario Rank Per Future (1-5 range each row)[171]

Carbon Future	StatusQuo	PrefPlan	Early3	Early4	FastExit
No/No	1	2	3	4	5
No/Low	5	2	3	4	1
No/High	5	2	3	4	1
Low/Low	5	3	2	4	1
Mid/Mid	5	1	3	5	2
High/High	2	3	1	4	5

1. CUB response to Department Modeling

CUB outlined a number of objections to the Department's modeling:

- The Department's decision to only model a 50 percent share of NTEC. CUB stated that the Department modeled LRTP lines that had not been approved and concluded the Department should have done the same for the 20% NTEC scenario.[172]
- The Department's inclusion of regulatory costs in the dispatch model. CUB stated it is more likely Boswell will be dispatched without regulatory costs, therefore the

[170] Tables 6B and 9B only show the plan rankings. Page 27 of the Department's July 29, 2022 comments present additional tables showing total costs and a summary of cost metrics..

[171] Department, Comments – Supplemental Modeling (July 29, 2022), Table 6B, p. 27.

[172] CUB, Reply, p. 11.

Commission should look at modeling results that include environmental costs but not regulatory costs.[173]
- The Department's restriction of Boswell replacement to thermal generation. CUB advocated for including hybrid storage + renewables options.[174]

B. Clean Energy Organizations (CEO)

CEOs also provided alternative Encompass modeling. CEOs' proposed modifications to MP's 2021 Plan include:
- removing NTEC,
- retiring the Hibbard Plant in 2023, and
- adding 600 MW of solar by 2026.

Regarding the Boswell units, CEOs recommend:
- retiring Boswell 3 by the end of 2029; and
- planning to maintain the option of retiring Boswell 4 by 2030.

The CEO recommended the Commission order stakeholder groups to examine the following topics and include them in MP's next IRP:
- Work with stakeholder to develop a 1.5°C pathways scenario;
- Improve modeling distributed solar, align IRP and IDP, and account for local community generation goals for distributed generation; (discussed in Section XV.A Distribution System Issues).
- Address equity issues, including disproportionate energy burdens.
- Analyze public health impacts.

CEOs retained Energy Futures Group (EFG), with additional support from Applied Economics Clinic, to analyze the Company's EnCompass generation capacity expansion modeling and to conduct additional modeling on the CEOs behalf.

EFG's modeling approach examined two portfolios with different capacity expansion plans:
1. A "Revised Minnesota Power [2021] Plan that includes a 20 percent stake in NTEC; and
2. A "CEO Preferred Plan," which is an all renewable, storage, and DSM plan.

EFG's Revised MP Plan was developed to create an apples-to-apples comparison to the CEO's Preferred Plan, which did not include the NTEC plant and retired the Hibbard Plant. In doing so, EFG made changes to MP's modeling assumptions which are shown in Table 7 of its report (Table 23 below). Note that one change was that the MP Revised 2021 Plan includes a 20 percent share of NTEC, whereas MP's 2021 Plan assumes a 50 percent ownership share.

Table 23: Summary of CEO Modeling Changes[175]

[173] CUB, Reply, p. 12.
[174] CUB, Reply, p. 13.
[175] CEO, Initial Comments – Report (Energy Futures Group), Table 7 p. 17.

Modeling Changes	MP Revised [2021] Plan	CEO Preferred Plan
NTEC Included (at 20% share)	X	-
Boswell 3 Retires 2029	X	X
High CO_2 Regulatory Cost, High Environmental Cost	X	X
CEO Transmission Upgrade Cost for Boswell 3	X	X
CEO Solar, Wind, and Battery Storage Costs	X	X
Add Solar-Battery Hybrid Resources as New Resource Option	X	X
MISO Zone 1 Solar Hourly Shape	X	X
Wind Constraint	X	X
MP's "High" Level of Energy Efficiency	-	X
Retire Hibbard Plant in 2023	-	X
Selection of "Partial" Battery Storage Resources	X	X
Change "Unserved Energy" Price	X	X
Demand Response Product B Excluded	X	X
Include 10 Hour Battery Storage and 100 MW Wind in 2030	-	X

To briefly summarize a few of the additional changes listed in Table 7 of the EFG Report (Table 23 above):

- In every scenario MP assumes a 50 percent share of the NTEC CC, or about 296 MW, to be added in 2025. However, MP since announced that it will sell a portion of its ownership to Basin. Therefore, EFG reduced this offtake to 20 percent as part of the re-optimization of the MP Revised 2021 Plan. The CEOs Preferred Plan removes NTEC.

- MP kept transmission constraints for Boswell 3 and 4. However, MP assumed that the Boswell 3 upgrade cost under the S1 scenario would be $144 million, but based on Telos's analysis, EFG lowered the upgrade costs to $25 million in S1.

- MP assumed Hibbard will continue to operate, and the CEOs did not change that assumption for the MP Revised 2021 Plan. However, the CEO Preferred Plan retired Hibbard at the end of 2023—the earliest retirement date practicable. This was because PSE Report, Attachment 3 of CEOs Initial Comments, found that Hibbard has significant human health impacts and that these impacts are disproportionately affecting low-income and Black, Indigenous, People of Color (BIPOC) populations.

- In the CEO Preferred Plan and the Revised MP 2021 Plan, EFP used the High Environmental Cost and High Carbon Regulation Cost Future.

- Because MP's IRP was filed in February 2021, the Company's treatment of the Investment Tax Credit (ITC) did not account for the 2020 extension of that credit. As shown below by Table 26, accounting for the ITC extension drastically reduced the cost of solar through 2025.

Table 24: Solar PV Investment Tax Credit (%)[176]

First year of operation	MP	CEO (current ITC)
2023	26%	26%
2024	10%	26%
2025	10%	22%
2026-2035	10%	10%

- MP only modeled self-build renewable and storage options and neglected to consider whether it might use a tax equity partnership or a PPA to allow the ITC to be credited in the first year of the project rather than "normalized" over the life of the resource. EFG used a levelized cost structure instead of rate-basing these resources.

- MP understated the capacity factor of solar PV resources that it could access outside of Minnesota. EFG used the energy profile from MISO Zone 1, which led to a 2 percent increase to the capacity factor. (This change applied only to generic solar, not Net Zero solar.)

- MP did not model solar and battery hybrid resources. EFG modeled a solar-battery hybrid option using the combination of its solar and battery storage costs.

- Due to transmission and MISO queue constraints, EFG assumed that new Minnesota wind would not be available until 2026.

- MP developed its energy efficiency assumptions based on the 2020-2029 Minnesota State Demand Side Management Potential Study. MP adopted the "High" scenario but assumed no new energy efficiency after 2029. EFG assumed the High Energy Efficiency case would continue through 2035.

- MP modeled new battery storage such that the model could select batteries in 100 MW increments. EFG utilized the "partial unit setting," which allowed EnCompass to select units in 0.1 MW or greater increments.

With these adjustments to the assumptions, the CEOs modeling found that a clean portfolio replacement is similar in cost to a portfolio that includes the NTEC plant.[177]

Similarities between the plans are that both plans add the maximum amount of Net Zero solar that MP allowed over the planning period—300 MW. Both plans select similar amounts of wind, although the CEO Preferred Plan adds wind later. Differences in resource additions include more solar in the CEOs plan, as well as a solar-battery hybrid project in 2030.

In Reply Comments, the CEOs submitted additional EnCompass analysis a "high-cost"

[176] CEO, Initial Comments – Report (Energy Futures Group), Table 3 p. 11
[177] CEO, Initial Comments – Report (Energy Futures Group), p. 7.

sensitivity, recognizing the inflationary pressures on resource costs. Under this new sensitivity, EFG increased costs for all new generation resources in the CEOs plan, as well as updated coal, natural gas, and electricity prices using public information. The results showed that the comparison between the CEOs' Preferred Plan and the Revised MP Preferred Plan remained consistent. In fact, the CEOs argued that with the passage of the Inflation Reduction Act, the Commission can expected even more savings of the CEOs plan relative to the Revised MP Preferred Plan.

C. Large Power Intervenors

LPI did not develop its own modeling, but LPI retained Brubaker & Associates, Inc. (BAI) to evaluate MP's 2021 Plan. BAI concluded:

- MP's input and resource alternative assumptions were reasonable at the time the 2021 IRP was filed.
- MP correctly utilized the EnCompass Power Planning Software.
- The Status Quo, which would have no new plant additions and operate the Boswell Energy Center through 2035, is the least-cost plan when only actual operational system costs are considered.
- CO_2 regulatory costs and environmental externalities account for over 20 percent of the costs reported in the 2021 IRP. Externalities are not recovered through customer rates, and currently no CO_2 regulation exists that would affect customer rates.
- MP has not provided a sufficient reliability demonstration of its 2021 Plan.
- However, MP's 2021 Plan reasonably balances both cost and environmental concerns, but LPI recommends the Commission address these deficiencies in MP's next IRP.

LPI argued that externalities and CO_2 regulation costs are not actually incurred by MP or included in MP's customer rates, yet including them in the modeling makes the Status Quo scenario a relatively poor-performing plan in EnCompass, despite being the least-cost plan on a revenue requirement basis. Below is a table, created by MP with its EnCompass Output files, excluding externality costs. CO_2 regulatory costs are still included. By removing environmental externalities, the Status Quo scenario is least-cost in every run.[178,179]

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[178] LPI, Initial Comments, p. 10.
[179]

Table 25: 2021 NPV of Cost for Reference Case Scenario Without Externalities ($ Millions)[180]

Plan NPV ($millions)	PrefPlan	FastExit	Early3	Early4	StatusQuo
Base Case	$6,252	$6,418	$6,313	$6,305	$6,214
1_Coal+20%	$6,355	$6,499	$6,403	$6,398	$6,324
2_Coal-10%	$6,195	$6,374	$6,256	$6,254	$6,143
3_Biomass+15%	$6,256	$6,418	$6,312	$6,309	$6,212
4_Biomass-15%	$6,248	$6,415	$6,307	$6,303	$6,209
5_Lower Gas-50%	$6,122	$6,226	$6,177	$6,135	$6,069
6_Low Gas-25%	$6,224	$6,356	$6,280	$6,259	$6,174
7_High Gas+25%	$6,391	$6,583	$6,448	$6,451	$6,354
8_Higher Gas+50%	$6,457	$6,675	$6,514	$6,521	$6,419
9_Highest Gas+100%	$6,596	$6,860	$6,655	$6,656	$6,551
10_Wholesale Market-50%	$5,953	$6,166	$6,020	$6,012	$5,850
11_Wholesale Market-25%	$6,191	$6,378	$6,252	$6,247	$6,128
12_Wholesale Market+25%	$6,367	$6,516	$6,429	$6,413	$6,327
13_Wholesale Market+50%	$6,374	$6,516	$6,445	$6,416	$6,334
14_Capital Costs-30%	$6,256	$6,356	$6,309	$6,285	$6,213
15_Capital Costs+30%	$6,254	$6,478	$6,309	$6,331	$6,210
16_No Externalities Costs	$6,253	$6,417	$6,310	$6,308	$6,213
17_No Market Sales	$6,317	$6,494	$6,378	$6,369	$6,262
18_No Sales and Purchases	$7,196	$7,410	$7,455	$7,113	$7,028
19_Market Access -50%	$6,444	$6,622	$6,539	$6,469	$6,367
20_Low Interconnect Costs	$6,234	$6,399	$6,293	$6,285	$6,212
21_ITC & PTC Extension	$6,250	$6,407	$6,301	$6,302	$6,212
22_Wind Cost Curve Low	$6,251	$6,417	$6,307	$6,304	$6,213
23_Wind Cost Curve High	$6,255	$6,422	$6,313	$6,312	$6,212
24_Solar Cost Curve Low	$6,241	$6,410	$6,302	$6,295	$6,212
25_Solar Cost Curve High	$6,270	$6,437	$6,327	$6,326	$6,209
26_Storage Cost Curve Low	$6,253	$6,415	$6,313	$6,306	$6,214
27_Storage Cost Curve High	$6,255	$6,417	$6,313	$6,304	$6,214
28_AFR 2020 Low Scenario	$6,080	$6,249	$6,136	$6,138	$6,037
29_AFR 2020 Load w Keetac	$6,529	$6,686	$6,602	$6,562	$6,470
30_AFR 2020 High Scenario	$6,554	$6,705	$6,627	$6,584	$6,496
31_Residential TOU	$6,253	$6,416	$6,304	$6,303	$6,209
32_Higher DG & EV Growth	$6,251	$6,413	$6,306	$6,310	$6,211
33_Renewable ELCC -2.5%	$6,259	$6,420	$6,317	$6,309	$6,212
34_Renewable ELCC +2.5%	$6,253	$6,418	$6,305	$6,309	$6,209
35_PRM-2%	$6,254	$6,414	$6,308	$6,307	$6,212
36_PRM+2%	$6,261	$6,420	$6,321	$6,306	$6,214
37_MISO CF-2%	$6,251	$6,417	$6,307	$6,307	$6,212
38_MISO CF+2%	$6,267	$6,425	$6,322	$6,309	$6,215
Sum of Least Cost Runs	**0**	**0**	**0**	**0**	**39**

[180] LPI, Initial Comments, Exhibit A – Review of MP's 2021 IRP, Figure 3, p. 11.

When both environmental externalities and CO_2 regulatory costs are removed, the results are more dramatic. Under the "No Environmental Cost and No Carbon Regulation Cost" future, the Status Quo is again the least cost plan in every single sensitivity run and the base case in this future. On average, the Status Quo is $129 million (2 percent) less expensive than MP's 2021 Plan.[181]

LPI also cited the Department's analysis, which separates the total net present value (NPV) by revenue requirements and externalities (in $million). As demonstrated by the Department's analysis, the FastExit Scenario is the most expensive scenario to ratepayers (i.e., considering revenue requirements only).[182]

Table 26: Department's total cost results for each Boswell retirement scenario (Conditions: Mid/Mid Carbon Future, Base Contingency)[183]

NPV Plan Costs ($Million)	StatusQuo	PrefPlan	Early3	Early4	FastExit
Revenue Requirement	$8,062	$8,128	$8,151	$8,227	$8,329
Externalities	$2,022	$1,901	$1,897	$1,857	$1,709
Revenue Requirement + Externalities (Total Plan Cost)	$10,084	$10,030	$10,048	$10,084	$10,038

XIII. Environmental Costs

Separate statutes require utilities to consider different types of environmental costs in resource planning and resource acquisition proceedings. Minn. Stat. § 216B.2422, subd. 3 requires the Commission to "quantify and establish a range of environmental costs" to use when "selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings." These refer to environmental externality costs, which assess the societal impact of CO_2 emissions and other pollutants. The Commission updated the environmental externality costs through its January 3, 2018 order in Docket No. 14-643.

Minn. Stat. § 216H.06 require the Commission "establish an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation." These CO_2 regulatory costs, which are updated regularly in Docket No. 07-1199, as well as in Department Investigation dockets, anticipate direct rate impacts as a result of carbon pricing, whether that is in the form of a direct tax, cap-and-trade system, or another type of regulation. A report from the Department and Minnesota Pollution Control Agency is pending in Docket No. 22-236. The Commission most recently updated the CO_2 regulatory costs through its September 30, 2020 order in Docket No. 07-1199. The Commission's September 30, 2020 Order directed utilities filing IRPs to incorporate a range of environmental costs and CO_2 regulatory costs under the following scenarios:[184]

[181] LPI, Initial Comments, pp. 13-14.
[182] Department, Comments – Supplemental Modeling (July 29, 2022), p. 4; LPI, Reply Comments, p. 6.
[183] Department, Comments – Supplemental Modeling (July 29, 2022), Table 2, p. 4.
[184] E-999/CI-07-1199; E-999/DI-19-406.

Table 27: Environmental and Regulatory Cost Ranges[185]

Scenarios:	Before 2025		2025 and Thereafter	
	Environmental Cost	Regulatory Cost	Environmental Cost	Regulatory Cost
Low Environmental Cost	Low End	-	Low End	-
High Environmental Cost	High End	-	High End	-
Low Environmental/ Regulatory Costs	Low End	-	-	$5/Ton
High Environmental/ Regulatory Costs	High End	-	-	$25/Ton
Reference Case Scenario	Middle to High End	-	Middle to High End	Middle to High End

What is meant by "low end" and "high end" refers to a specific decision in the externalities docket that the damage resulting from incremental CO_2 will be increasingly damaging to societal over time. This is referred to as the "marginal ton" of carbon emissions, and that is why the values in real terms increases in each year. The externality costs are shown below:

Table 28: Environmental Cost Values for CO_2 (2020-2035)[186]
(2015 dollars per net short ton)

	Low	High
2020	$9.05	$42.46
2021	$9.25	$43.36
2022	$9.46	$44.26
2023	$9.66	$45.16
2024	$9.87	$46.06
2025	$10.07	$46.96
2026	$10.28	$47.86
2027	$10.48	$48.77
2028	$10.69	$49.67
2029	$10.89	$50.57
2030	$11.10	$51.47
2031	$11.30	$52.37
2032	$11.51	$53.27
2033	$11.71	$54.17
2034	$11.92	$55.07
2035	$12.12	$55.97

[185] Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs, September 30, 2020, Docket No. E-999/CI-07-1199; E-999/DI-19-406, p. 8.
[186] Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs, September 30, 2020, Docket No. E-999/CI-07-1199; E-999/DI-19-406, Attachment A, p. 10.

MP ran six separate scenarios with various combinations of CO_2 regulatory costs and environmental externalities:

Table 29: Six Futures Considered in 2021 IRP Analysis[187]

		Carbon Dioxide (CO_2)				Other Criteria Pollutants
		Prior to 2025		2025 and Thereafter		
Futures	**EnCompass Case Name**	**Environmental Cost**	**Regulation Cost**	**Environmental Cost**	**Regulation Cost (2025)**	**Environmental Costs**
Low Environmental Cost	CLE1S	Low	-	Low	-	Low
High Environmental Cost	CHE1S	High	-	High	-	High
Low Environmental Cost and Low Carbon Regulation Cost	CLER1S	Low	-	-	\$5/Ton	Low
High Environmental Cost and High Carbon Regulation Cost	CHER1S	High	-	-	\$25/Ton	High
Reference Case	CREF1S	Mid	-	-	\$15/Ton	Mid
No Environmental Cost and No Carbon Regulation Cost [37]	CCUST1S	-	-	-	-	-

Some parties discussed how CO_2 regulatory cost are factored into a unit's dispatch costs, unlike the environmental externalities, which are not accounted for when making unit selection and dispatch decisions—they are factored in at the end of the modeling runs.

MP explained that "EnCompass does include the cost of a carbon regulation tax when dispatching units, but disregards Environmental Costs when dispatching generation."[188] Thus, when environmental externalities are applied after the units are dispatched, the results tend to select earlier retirement scenarios.

Similarly, the Department explained that "a theoretical carbon tax is represented in the model in futures that contain regulatory costs . . . Environmental costs, on the other hand, are not adequately captured in the EnCompass model." The Department continued:

> Since environmental costs represent externality costs that have not been internalized into rates, EnCompass accounts for these costs separately from the "internalized" or realized costs a given resource. This means that environmental costs are not factored into the model's decision-making, either in the capacity expansion or dispatch routines. Instead, after the model has made its capacity expansion or resource decisions, it calculates the externality costs attributable to

[187] MP, Petition, Table 2, p. 33.
[188] Supplemental Appendix K of MP Petition (April 1, 2021), p. 24.

> resources chosen. The modeler can then add the costs of externalities onto the final revenue requirement if they so choose. Since the externality costs do not impact either the expansion plan or the dispatch routine of the model, both the expansion plan and cost results will be the same as if no externality costs had been assumed. For purposes of this IRP, this means that both the expansion plan and certain cost results of NoReg/NoEnv, NoReg/HighEnv, and NoReg/LowEnv are identical.[189]

Table 30 below illustrates how different ways to account for carbon costs can affect a scenario's total emissions. Under the No(Reg)/No(Ext), No(Reg)/Low(Ext), and No(Reg)/High(Ext) carbon futures, which are the top three rows under each scenario), total CO_2 emissions are about the same. This is because externalities do not affect the dispatch decisions. However, once CO_2 regulatory costs are incorporated into dispatch decision-making (the bottom three rows under each scenario), high CO_2-emitting facilities like Boswell dispatch less, which is why those carbon futures emit less CO_2 annually.

Table 30: Corrected Dept Table 19. Department's Average CO_2 Emissions Results (tons) for each Boswell retirement scenario, by carbon future (3,870 runs)[190]

Carbon Future	StatusQuo	PrefPlan	Early3	Early4	FastExit
No/No	133,018,030	113,487,405	112,105,086	109,291,847	81,768,220
No/Low	132,999,657	113,470,658	112,111,440	109,259,638	81,777,221
No/High	133,017,643	113,484,369	112,113,825	109,287,870	81,767,868
Low/Low	115,366,403	98,992,216	98,027,102	94,833,303	74,764,116
Mid/Mid	86,843,419	81,389,028	80,056,245	77,306,246	67,937,129
High/High	73,018,252	71,198,736	67,869,463	68,456,241	64,517,431

The CEOs argued this approach leads to irrational outcomes because once the CO_2 regulatory costs are presumed to begin in 2025, utilities are allowed to assume that the environmental costs of carbon emissions disappear.[191]

CUB focused on how each type of CO_2 cost impacts the results. CUB stated, "Relying on scenarios with regulatory costs for determining the Company's plans will lead to unintended and poor outcomes."[192] Because environmental externalities are added to the total supply costs *after* the units have dispatched, environmental cost does not have any impact on the merit order of dispatch in the model. Since CO_2 regulatory costs reduce the units' output relative to historical levels, the model's projections of CO_2 emissions are greatly understated.[193]

[189] Department, Initial Comments, p. 51.
[190] Department, Reply Comments (August 29, 2022), Corrected Table 19, p. 11. Staff added gradient coloring to indicate the relative amount of carbon emissions of various scenarios.
[191] CEO, Initial Comments, p. 60.
[192] CUB, Initial Comments, p. 8.
[193] CUB, Initial Comments, p. 9.

LPI did not comment on how to properly account for CO_2 regulatory costs versus environmental externalities, but LPI argued that it is important to realize that, currently, there are no costs incurred by MP or its ratepayers for CO_2 emissions, yet these costs total roughly 20 percent of the reported costs of MP's 2021 Plan.[194]

XIV. Resource Acquisition Process

To implement the IRP, the Department recommends the Commission approve a bidding process for MP's future resource acquisitions as follows; MP shall:

1. use a bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years;
2. ensure that the RFP is consistent with the Commission's then-most-recent IRP order and direction regarding size, type, and timing unless changed circumstances dictate otherwise;
3. provide the Department and other stakeholders with notice of RFP issuances;
4. notify the Department and other stakeholders of material deviations from initial timelines;
5. update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings;
6. where MP or an affiliate proposes a project, engage an independent evaluator to oversee the bid process and provide a report for the Commission;
7. request that the independent evaluator, if engaged, specifically address the impact of material delays or changes of circumstances on the bid process; and
8. cap any [Right of First Refusal] (ROFO) offer made by MP at net book value; and
9. ensure that any RFP documents for peaking resources issued are technology neutral.

In Reply Comments, the OAG stated, "[t]he Department of Commerce's recommendations regarding the bidding process for future resource acquisitions would provide essential customer protections and should be approved in full."[195] The OAG highlighted the cap on any ROFO offer at net book value the requirement for competitive bidding processes to seek both PPAs and build-operate-transfer (BOT) projects as two particularly valuable customer protections.

XV. Parties' Comments – other topic areas

This section summarizes other topic areas raised by parties that filed petitions to intervene to the proceeding that do not fall into categories outlined above.

A. Distribution System Issues

CUB referred to MP's 2021 Integrated Distribution Plan (IDP), noting that the Company's statements about its ability to conduct non-wires solutions (NWS) were concerning. Specifically, CUB pointed to Minnesota Power's statement that "[n]on-wires solutions cannot displace the

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[194] LPI, Initial Comments, BAI report, p. 10.
[195] OAG Reply Comments, p. 5.

need to modernize and replace aging equipment, even when the modernization project may result in increased reliability or load-serving capability."[196] According to CUB, this is problematic because "NWS may be able to help alleviate the challenges identified by the Company when BEC closes."[197] CUB pointed out two examples where NWS were used to avoid significant upgrades: ConEd's demand management program to defer a $1.2 billion substation upgrade in Brooklyn, and Bonneville Power's cancellation of a 80 mile, 500 kV transmission line to be replaced with energy storage, grid management, and a NWS. CUB explained that MP retained a consultant to conduct a NWS, and recommended that the Company file the study results in both the IRP and IDP dockets. Furthermore, CUB recommended that the Commission require MP "to begin integrating NWS into all the company's planning practices, including its IRP and distribution plan, with a focus on how NWS can help ameliorate the localized reliability needs of northern Minnesota when BEC 3 and 4 eventually retire."[198] (Decision Option 23)

CEO explained that including more distributed solar generation in Minnesota Power's resource portfolio could deliver lower costs, local job creation, and cleaner energy. CEO cited a recent Vibrant Clean Energy (VCE) study, *Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid: Technical Report* that outlines how traditional capacity expansion planning models are unable to fully incorporate the benefits of distributed energy resources, including distributed solar. The VCE study used the WIS:dom-P modeling tool which combines capacity expansion and production cost models. CEO noted that the study found that:

> [T]raditional utility planning based on construction of utility scale generation fails to take into account the many benefits of a more distributed resource system, leading to an over-reliance on overbuilding peaking plants. Adding an optimal amount of distributed resources (by considering these benefits) allows the transmission system to be better utilized, and reduces the amount of peaking resources required. VCE's optimization shows that dramatically more distributed generation is beneficial than traditional models and utility planning account for.[199]

According to CEO, MP did not sufficiently account for the contributions of distributed solar, as it modeled DG as a load modifier instead of a supply side resource. CEO pointed to modeling done by the Distributed Solar Parties (DSP) and Sierra Club in Xcel Energy's IRP that indicated over 1,800 MW of distributed solar could reduce the total cost of Xcel's IRP. Based on those results, CEO made recommendations to enhance the consideration of distributed solar in Minnesota Power's next IRP. First, CEO suggested that MP expand access to distributed solar for low-income customers by enhancing its existing solar grant program, and by expanding low-income community solar projects. Second, CEO recommended that the Commission take similar steps to those it ordered in Xcel Energy's 2019 IRP, including working "with stakeholders to develop a modeling construct that enables the utility to model solar-powered generators connected to the company's distribution grid as a resource, take steps to better align distribution and resource planning, and consider local community generation goals for

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[196] Minnesota Power, 2021 Integrated Distribution Plan, Docket No. E015/M-21-390, p. 67.
[197] CUB, Initial Comments, p. 20.
[198] CUB, Initial Comments, p. 21.
[199] CEO, Initial Comments, p. 64.

distributed generation in its next IRP."[200] CEO recommended adopting language similar to that adopted in Xcel Energy's IRP:

- Require work with stakeholders to develop a modeling construct that enables Minnesota Power, as part of its next resource plan, to model solar-powered generators connected to the company's distribution grid as a resource. Minnesota Power and stakeholders shall address the following factors in developing the modeling construct:
    - using a "bundled" approach as is used to model energy efficiency and demand response;
    - the costs borne by the utility and the costs borne by the customer;
    - cost effectiveness tests; and
    - other topics as identified by stakeholders. (Decision Option 15)
- Take steps to better align distribution and resource planning, including:
    - set the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan;
    - conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level;
    - proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources;
    - improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Minnesota Power can take advantage of distributed energy resources to address discrete distribution system costs; and
    - plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours. (Decision Option 17)
- Account for local clean energy goals, in aggregate, in forecasting and modeling. In particular, the plan should include consideration of local community generation goals for distributed generation in its next IRP.[201] (Decision Option 19)

MP did not respond to CUB or CEO's recommendations in its reply comments. CEO continued to support its recommendations from initial comments in their reply comments.

B. Rate Impacts

LPI argued that while the 2021 Plan far exceeds current state decarbonization targets, existing industrial customer rates do not comply with state energy policy set forth in Minn. Stat. §§ 216B.03, 216B.1696, and 216C.05, and the rate increases contemplated by the 2021 Plan and in other proceedings exacerbate LPI's concerns.

LPI actively participated in the pre-filing stakeholder engagement process and vocalized its concerns about MP's industrial rates. Stakeholders commented on various price/MWh ranges and provided the following analysis.

[200] CEO, Initial Comments, pp. 64-65.
[201] CEO, Initial Comments, p. 81.

Table 31: Large power and municipal utility competitiveness rating scale[202]

Issue 2: Large Power and Municipal Utility Competitiveness				
0 Worst Case	1 Poor	2 Barely Acceptable	3 Good	4 Best Case
\$70–\$80 MWh Uncompetitive rates—large power (LP) facilities could/would close, and investments made elsewhere.	\$60–\$70 MWh Uncompetitive for LP and a tipping point for closures/ redirected investments (e.g., two LP customers recently idled). Currently high end for wholesale municipal rates and a tipping point for rates passed on to local customers.	\$50–\$60 MWh Ratings 1 and 2 represent a tipping point for these two customer classes. Based on recent experience, LP customers need rates at least in this range to have a reasonable opportunity to sustain current operations.	\$40–\$50 MWh Better rate mix favorability, which can stimulate investment and potential job growth.	\$30–\$40 MWh Competitive rates. Job growth likely. Greater ability to attract new LP customers.

LPI then referred to Table 1 in Appendix L of MP's Petition (Cost Impact Analysis by Customer Class), which projected the incremental power supply costs through 2024, to show that the impact to the average Large Power rate would be an increase of about 0.57 percent compared to 2021 base rates, an equivalent to an increase of \$24,674 per month, with an average Large Power (LP) rate of 7.223 cents/kWh. An average rate of 7.223 cents/kWh, or \$72.23/MWh, reflects the Worst Case scenario for LP industrial customers.

[202] Appendix R of MP Petition, Table 3, p. 18

Table 32: Estimated Average Rate Impacts of 2021 Plan Relative to 2021 Projected Base Rates[203]

Rate Class Impacts \1	2021	2022	2023	2024
Residential (average rate, cents/kWh)	12.114	12.114	12.114	12.114
Increase (cents/kWh)	-0.003	0.180	0.145	0.158
Increase (%)	-0.03%	1.49%	1.20%	1.31%
Average Impact ($ / month)	-$0.02	$1.28	$1.03	$1.12
General Service (average rate, cents/kWh)	12.053	12.053	12.053	12.053
Increase (cents/kWh)	-0.003	0.180	0.145	0.158
Increase (%)	-0.03%	1.49%	1.20%	1.31%
Average Impact ($ / month)	-$0.09	$4.72	$3.78	$4.10
Large Light & Power (average rate, cents/kWh)	9.434	9.434	9.434	9.434
Increase (cents/kWh)	-0.003	0.156	0.130	0.140
Increase (%)	-0.03%	1.66%	1.38%	1.49%
Average Impact ($ / month)	-$5.22	$374.16	$309.92	$335.11
Large Power (average rate, cents/kWh)	7.223	7.223	7.223	7.223
Increase (cents/kWh)	-0.002	0.055	0.035	0.041
Increase (%)	-0.03%	0.76%	0.48%	0.57%
Average Impact ($ / month)	-$1,140	$32,828	$20,752	$24,674
Lighting (average rate, cents/kWh)	19.086	19.086	19.086	19.086
Increase (cents/kWh)	-0.005	0.238	0.182	0.202
Increase (%)	-0.03%	1.25%	0.95%	1.06%
Average Impact ($ / month)	-$0.04	$1.85	$1.41	$1.56
Average Weighted Increase (cents/kWh)	-0.002	0.099	0.074	0.083
Avg Weighted Increase (%)	-0.03%	1.15%	0.86%	0.96%
Notes: 1/ Average current rates are 2021 estimates. These estimates are based on 2020 base rates from Minnesota Power's last rate case (E- 015/GR-19-442) with 2021 estimated cost recovery rider rates and estimated 2021 FPE and CPA factor added. CPA factor is not applied to Large Power Class.				

C. Pathways to 1.5°C

In its initial comments, CEOs highlighted the 2018 Intergovernmental Panel on Climate Change (IPCC) report and November 2021 Glasgow Climate Pact emphasizing the importance of limiting global warming to 1.5°C through aggressive greenhouse gas emissions reductions by 2030. CEOs noted that while MP's carbon emissions reduction efforts to date have been commendable, the Company's 2021 Plan still falls short of the decarbonization pathways necessary to meet global 1.5°C targets.[204] Therefore, CEOs recommended that the Commission

[203] Appendix L of MP Petition, Table 1, p. 3.

[204] CEO, Initial Comments, pp. 6-8

"order that Minnesota Power work with stakeholders to include an analysis in the next IRP that identifies the near-term steps needed to ensure Minnesota Power meets its customers' needs in a fashion compatible with 1.5°C pathways." (Decision Option 14)

D. Community Outreach and Stakeholder Group

CEOs explained that there are "connections between resource planning and equity," and pointed to the Commission's decision in Xcel Energy's IRP that required Xcel to establish a stakeholder group to address various equity goals.[205] CEOs asked the Commission to make a similar requirement of Minnesota Power in its IRP:

- Order Minnesota Power to, prior to the next IRP, conduct community outreach and establish a stakeholder group to: (Decision Option 21)
    - provide input on the public health analysis for the next IRP, including the methodology, results, and implications for Minnesota Power's resource plan;
    - inform the design of electricity services and programs that improve equitable electricity delivery, improve customer access to energy efficiency and load-shaping programs, and improve customer access to DG and renewable energy. These services and programs should particularly focus on reducing disparities in energy burden, ensuring equitable access to low-income residents, and ensuring equitable access to Black, indigenous, and communities of color that have disproportionately borne costs of unjust and inequitable energy decisions

    Order Minnesota Power, in its next IRP docket, and in a separate docket to be established by the Executive Secretary, to file details describing stakeholder outreach and progress on the above requirements in H, (above) by January 1, 2024, and annually thereafter.

E. Public Health Impacts

CEO recommended the Commission consider the public health and equity impacts of utility resource plans as a part of its decision-making process to choose a plan that is in the public interest.[206] Specific to Minnesota Power's resource plan, CEO asked the Commission to examine the health impacts of fossil fuel generation on marginalized communities. To aid the Commission in its consideration of public health and equity impacts, CEO commissioned a report from Physicians, Scientists, and Engineers for Health Energy (PSE)[207] to assess the impacts of Minnesota Power's 2021 plan. The report focuses on three main areas, "excess mortality caused by coal and biomass plant emissions, lifecycle greenhouse gas impacts of new gas plants like NTEC, and strategies to reduce energy burden and improve equity of clean energy access."[208] CEOs summarized four main findings from the report.

[205] CEO, Initial Comments, pp. 66-67
[206] CEO, Initial Comments, pp. 65-66.
[207] PSE is a multidisciplinary, nonprofit research institute dedicated to supplying evidence-based scientific and technical information on the public health, environmental, and climate dimensions of energy production and use
[208] CEO, Initial Comments, p. 68.

First, the PSE report found that Minnesota Power's coal and biomass plants contributed to 16 excess deaths and $177 million in public health costs in 2021 alone. Table 33 summarizes the report's health impacts of the individual plants during the term of MP's 2021 Plan.

Table 33: Health Impacts of Minnesota Power's Coal and Biomass Power Plants[209]

	Hibbard	Boswell	Young
Plant Size	47MW	932MW	439MW
Excess Deaths - 2021	6.4 deaths	6.2 deaths	3.5 deaths
Public Health Costs - 2021	$70 million	$67.7 million	$39 million
Excess Deaths – projected through 2035	Unknown	47.5 deaths	10 deaths
Public Health Costs - projected through 2035	Unknown	$534 million	$110 million

CEO pointed to the disproportionate health impacts of the Hibbard plant relative to its size, noting that despite Hibbard being 5% of the capacity of the Boswell plant, it had higher public health impacts. Therefore, CEO concluded that it would be in the public interest to close Hibbard as soon as possible.[210]

Second, CEO pointed out that the health impacts of the plants outlined above disproportionately fall on BIPOC and low-income communities, and especially Native communities. CEO explained that Boswell is located on the border of the Leech Lake Band of Ojibwe's reservation, and upwind of the Fond du Lac, Milles Lacs, Bois Forte, and Grand Portage Reservations, while Hibbard is located in an urban setting. In particular, CEO noted:

> PSE found that "for every plant analyzed, the health impacts per capita were highest for Native populations, and larger by a factor of two to three as compared to the population at large." This is likely due to the location of many of these plants close to and upwind of Tribe lands and populations. Hibbard is located just east of the Fond du Lac reservation and upwind of Grant Portage, while Young is located upwind of all tribal lands in Minnesota. The Boswell facility is located directly adjacent to the Leech Lake Band of Ojibwe reservation boundary and is upwind from the Fond du Lac, Milles Lacs, Bois Forte, and Grand Portage Reservations.[211]

Third, PSE's report found that when upstream methane emissions and N_2O (nitrous oxide) emissions are included in an analysis of NTEC, the facility's climate impacts are doubled. CEOs explained that NTEC's air permit does not include these upstream methane or facility N_2O emissions, which provides an incomplete picture of the true impacts the plant will have on the climate.[212]

Finally, CEO noted that Minnesota Power should increase investments in low-income energy efficiency and community solar projects to address historic inequities in energy burden. PSE's report found that that approximately while 30% of Minnesota Power's customer base low-

[209] CEO, Initial Comments, Table 6, p. 72.
[210] CEO, Initial Comments, p. 72.
[211] CEO, Initial Comments, p. 74.
[212] CEO, Initial Comments, p. 75.

income, they are only projected to receive 13% of total energy efficiency savings in the near term and 11% in the longer term.[213] CEO noted that Minnesota Power has been a leader among Minnesota utilities for its investments in low income energy efficiency programs, and the passage of the Energy Conservation and Optimization Act will provide a path for increased investments going forward.[214] The PSE report also found inequities in the distribution of rooftop solar installations in Minnesota Power's service territory, with less than 5% of solar installations occurring in the lowest income bracket. CEOs recommended increased investments in low-income community solar projects to help address this gap.[215]

CEOs also recommend that the Commission require that "Minnesota Power's next IRP include an analysis of the public health impacts, over the 15-year planning period of its current generation fleet, its proposed plan, and other resource scenarios studied. The public health analysis should at minimum evaluate and quantify the health costs associated with fine particulate matter from coal and biomass power plants." (Decision Option 20)

1. CUB and OAG Response to Report

CUB strongly agreed with the conclusions of the report, and supported CEO's recommendation to close the Hibbard facility. CUB recommended that utilities incorporate similar analysis in future IRPs to assist with a just transition.[216]

The OAG similarly supported the CEOs recommendation for the Commission to consider public health impacts in its decision-making process, particularly in its decision on the Hibbard Plant.[217]

2. Minnesota Power Response to Report

Minnesota Power indicated that while it appreciated the intent to consider equity in the IRP proceeding, it had "serious concerns about the data, inputs and modeling utilized in this report," including "numerous factual inaccuracies and mischaracterizations of its operating units that were used to support recommendations."[218] This included concerns about the descriptions of the Hibbard facility and the materials burned at the plant, descriptions of coal ash disposal at the Boswell plants, and the mixed use of actual and estimated emissions from the Company's generating facilities.[219] In particular, Minnesota Power disagreed with the report author's decision to use emissions factors instead of actual emissions results in some modeling inputs, noting emissions factors are typically the highest values that could be in use and therefore less representative of the actual plant performance. According to Minnesota Power, this resulted in overstated emissions and associated health impacts.[220]

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[213] CEO, Initial Comments, p. 77.
[214] CEO, Initial Comments, p. 78.
[215] CEO, Initial Comments, pp. 78-79.
[216] CUB, Reply Comments, p. 9.
[217] OAG, Reply Comments, p. 4.
[218] MP, Reply Comments, p. 31.
[219] MP, Reply Comments, pp. 31-35.
[220] MP, Reply Comments, pp. 34-35.

3. LIUNA Response to Report

LIUNA disagreed with the conclusions drawn by the CEO report, and recommended that the Commission reject the report, stating the report "relies on flawed methodology, cherry-picks results, and is generally poorly informed regarding Minnesota's energy system and associated impacts." LIUNA explained that the PSE report does not evaluate the impacts of "non-operation," citing NTEC as an example where the report does not evaluate that the impacts of not running NTEC would be an increase in coal generation. [221] LIUNA also questioned the PSE report author's decision to reject the Environmental Protection Agency's (EPA) Environmental Just Screen (EJ Screen) indicators, stating it believed the report did not include that data because it would not support the author's conclusions. LIUNA pointed out that the EPA's data indicates Northern Minnesota overall has less pollution from criteria pollutants like PM 2.5 than urban areas.[222] LIUNA explained that while in its view the report failed to prove there are cumulative environmental burdens in MP's service territory, the report does highlight the socioeconomic burdens faced by northeastern Minnesota households. In LIUNA's view, the early closure of resources like Boswell and cancellation of NTEC will only deepen these disparities.[223]

XVI. Participant Comments

A. Individual Comments

The Commission received thousands of written public comments from individuals interested in the outcome of Minnesota Power's proceeding. In general, the majority of public comments provided input on the following topics:

- Commenters were concerned about the impacts of climate change, and urged the Commission to take swift action to reduce carbon emissions.
- Commenters recommended that the Commission prevent Minnesota Power from building NTEC.
- Commenters requested the Commission retire the Boswell units as soon as possible.
- Commenters urged the construction of additional renewable energy projects to offset retiring fossil generation.
- Commenters were concerned about the public health impacts of the Hibbard Generating Plant and encouraged the Commission to retire the plant by 2023.

B. Atlas Infrastructure

Comments were filed on behalf of Atlas Infrastructure on June 6, 2022, asking the Commission to (1) require Minnesota Power to model non-fossil fuel replacements for energy provided by the Boswell Unites; (2) review and rescind approval of this program upon finding of negative climate and economic impacts, while allowing prudent costs to be recovered; (3) consider reliability of resources in a public utility's IRP and alternative options like greater transmission

[221] LIUNA, Reply Comments, p. 2.
[222] LIUNA, Reply Comments, p. 4.
[223] LIUNA, Reply Comments, p. 6.

investment; (4) approve the Department's recommendation regarding FastExit retirement dates of the Boswell 3 and 4 Units; and (5) ensure expected utilization rates for continued fossil fuel generation resources are set such that their use until retirement does not exceed cumulative emissions exceeding a 2030 Budget for keeping warming below 2°C.

C. City of Cohasset

The City of Cohasset (Cohasset) discussed the importance of the Boswell Energy Center to the region and local economy, including hundreds of jobs that pay well-above the median household income for the area. Cohasset also discussed its positive relationship with MP, which has been an active partner in diversifying the local tax base. Cohasset noted that the city has already felt the impacts of the Boswell 1 and 2 retirements, which has significantly reduced the city's total tax capacity, as well as the share of its tax base that is contributed by the utility.

If the Commission approves MP's proposed retirement of Boswell 3, Cohasset recommends the Commission include similar provisions required in Xcel's IRP, which includes:

1. Authorize the Executive Secretary of the Commission to open a new docket on site development and remediation plans for the Boswell Energy Center site.
2. Minnesota Power shall conduct stakeholder meetings regarding the site with interested parties including the City of Cohasset; adjacent cities and townships including the City of Grand Rapids, Itasca County; the Minnesota Department of Commerce, the Minnesota Department of Natural Resources, the Minnesota Pollution Control Agency, the Center for Energy and Environment, the Minnesota Energy Transition Office, and labor unions. By January 1, 2024, Minnesota Power shall file in the new docket details describing updates on the site and the stakeholder outreach and meetings.
3. Following those stakeholder meetings, by December 31, 2024, or in its next resource plan if earlier—and annually thereafter—Minnesota Power shall submit to the Commission and to the City of Cohasset a detailed report describing the company's plans for disposition of the Boswell site, equipment, and buffer property. The report shall include at least the following items:
   a. To the extent possible, a detailed description of the timeline, estimated costs, and steps necessary to remediate pollution at the Boswell site.
   b. A section detailing how the company is working to ensure that plans for site remediation, economic development, or future development and maintenance of power generation, transmission, or distribution infrastructure are consistent with the community's long-range planning and vision.
   c. A description of any ongoing efforts by the company to evaluate future uses for the plant site, any buffer property owned by the company, or any adjacent property, including a description of how the company is involving interested stakeholders in those efforts.
   d. An update to the Commission on the status of efforts to support the city's and region's economic development efforts, including—to the extent possible—specific projects and investments the company is assisting the City and region in attracting.

e. A description of the company's efforts to work with local governments, and
f. Any other items the Commission or the company see fit to include

Cohasset further encourages the Commission to adopt any decision options designed to support workers who are employed at the plant, support the plant, or whose jobs will be in any way impacted by plant retirement.

In Reply Comments, Cohasset responded to the Department's FastExit plan, which retires Boswell 3 in 2025 and Boswell 4 in 2030. Cohasset emphasized that pursuing a more aggressive timeline would do permanent damage to the local economy, and may not even be technically feasible. Cohasset highlighted five essential points to understand about the tax impacts of plant retirement:

1. Because of the unique way power plant equipment is valued and ultimately taxed, retirement of a power plant results in an <u>immediate</u> and drastic impact to local governments.
2. The consequences of that lost tax base are huge reductions in property tax revenue to the local community, which requires immediate and extreme property tax increases for other homeowners and businesses in the community, deep cuts to city services, or all of the above.
3. The impacts of retiring the smaller Boswell 1 and 2 have already been felt, as shown by the table below illustrating the reduction in the City's total tax capacity in 2019 and 2020.[224] While manageable, the lost tax base has made it more difficult for the city to make investments to prepare for the retirement of the much larger Units 3 and 4.

Table 35: Impact of Boswell closure on Cohasset tax capacity[225]

Year	2019	2020	Change (2019 to 2020)
Cohasset levy	$2,936,092	$2,936,324	$232
Total Tax Capacity*	$11,267,612	$9,104,709	- $2,162,903
Tax rate	26.06%	32.25%	Percentage increase = 23.75%

* Total Tax Capacity is the share of local net tax capacity that can be taxed after subtracting captured tax increment, exempt power lines, fiscal disparity contribution net tax capacity

4. Because of the unique character of Itasca County and the Iron Range, retiring Boswell will have ripple effects throughout the entire region.
5. The work required to diversify and bolster the City's tax base in the long-term requires short-term sacrifices that will compound if Boswell 3 and 4 are closed too hastily.

Cohasset also emphasized the need for time to attrac new investment. For example, in June 2021, Huber Engineered Woods (HEW) announced plans to build a new production facility on land that is currently the site of the Boswell facility. HEW intends to invest $440 million to construct a 750,000 square foot facility that would produce Oriented Strand Board, which is

[224] City of Cohasset, Reply Comments, p. 6.
[225] City of Cohasset, Reply Comments, p. 6

used in the construction of homes and other buildings, and the plant is expected to create at least 150 direct new jobs. However, this project will require significant public investment; specifically, the city will use Tax Increment Financing, or TIF, which uses taxes to pay for part of the development.[226]

Other projects, such as a downtown riverfront redevelopment project and a Lake Country Power service center project, are also in the planning stage, but again, time matters to rebuild the tax base lost from retiring Boswell 3 to make public investments.

State-level host community transitions could ease the burden on host communities, Cohasset explained. The Community Energy Transition Grant Program was created in 2020 specifically to support host communities impacted by plant retirement; however, Cohasset has never been eligible to participate because the initial funding was appropriated from the Renewable Development Account, which are dollars derived from Xcel's ratepayers. The Energy Transition Office is still in its early stages, but aid needs to become available. Cohasset stated:

> Perhaps the single most impactful thing the state could do to support host communities is adopt a power plant transition aid program to alleviate the most extreme aspects of the tax impacts of plant retirement and give communities additional time to do the vital work of executing a transition strategy. Such a program could go a long way toward alleviating some of the concerns outlined in the sections above dealing with property taxes, but the fact is that the program does not exist today.
>
> As in the case of the two previous items, the City understands that the PUC cannot make decisions about energy resources based on what the legislature may or may not do in the future to support our communities. Collectively, however, the items in this section are meant to illustrate that both how encouraged we are with the steps the state is taking, but how much time and work even those steps will take. We hope that Minnesota will continue to be a nationwide leader in putting tools in place to support host communities, but Minnesota Power's [2021] plan is the only proposal in this docket that provides us a chance to fully benefit from that leadership.[227]

D. City of Duluth

The City of Duluth filed comments on June 10, 2021, in support of MP's 2021 IRP. The City of Duluth additionally requests that the IRP be approved with the modification that whenever possible, the investment in renewables and the retirement of fossil fuel infrastructure be accelerated and prioritized.

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[226] City of Cohasset, Reply Comments, pp. 7-8.
[227] City of Cohasset, Reply Comments, p. 13.

E. City of Hoyt Lakes

Hoyt Lakes filed comments on April 28, 2022 in support of Minnesota Power's IRP and indicated that environmental concerns to Hoyt Lakes were heard throughout the IRP process.

F. Coalition of Utility Cities

Coalition of Utility Cities ("CUC") filed comments on August 29, 2022, in support of the comments filed by the City of Cohasset. The CUC is in support of Minnesota Power's 2021 Plan as a balance between the interests of host communities, workers, ratepayers, and environmental impacts. The comments also indicate concern that the City of Cohasset's active projects will not fully replace the economic loss from the Boswell retirements.

G. Duluth Chamber of Commerce

Duluth Chamber of Commerce filed comments on May 14, 2021 in support of the proposed IRP. The Chamber of Commerce indicates that the plan aligns directly with several of the Chamber's 2021 Key Initiatives, namely competitive advantage, industry and community growth.

H. Fond du Lac Band

On June 29, 2022, the Fond du Lac Band of Lake Superior Chippewa (the Band) filed comments addressing some socioeconomic effects and health impacts of the proposed IRP. Specifically, the Band urges the Commission to closely examine health disparities resulting from the IRP, which are deemed manifestations of adverse socioeconomic and environmental effects.

The Band points to the PSE Healthy Energy report, which "conservatively" concludes that the Boswell Energy Center, Hibbard Energy Center, Syl Laskin Energy Center, and Milton R. Young Power Plant will cause over 100 premature deaths over the course of the IRP (2021-2035) if the IRP is approved as is. Additionally, the Band raises concerns that NTEC and could create poor air quality and is set to be constructed relatively close to the Fond du Lac Reservation and will result in adverse health effects.

The Band supports Commission revocation of approval for the NTEC for these reasons and because NTEC is considered somewhat "unnecessary" since if MP needs to procure energy to accommodate demand, it can do so in a more cost effectively by turning to renewables or purchasing energy from the market.

The Band additionally requests that MP make clear to the public what steps are being taken to ensure Boswell Unit 4 can be retired so that the company can be held accountable. The Band would additionally appreciate if MP provides greater transparency plans for retiring the Hibbard Energy Center moving forward, so the public and Native communities understand the Company's intentions and can respond accordingly. The Band also joins CUB in urging MP to research the feasibility of implementing non-wires solutions in lieu of traditional distribution and transmission projects, because non-wires solutions could potentially delay or permanently defer infrastructure upgrades.

I. Grand Rapids Area Chamber of Commerce

The Grand Rapids Area Chamber of Commerce filed comments on September 7, 2021 recommending approval of Minnesota Power's 2021 Plan. The Chamber commended Minnesota Power's stakeholder process and outreach, and encouraged consideration of clean, reliabile generation replacement at the Boswell Energy Center site.

J. Honor the Earth

Honor the Earth filed comments on September 8, 2022, requesting the Commission approve the CEOs' preferred energy resource plan.

K. IBEW Local 31

IBEW Local 31 filed comments on April 28, 2022 in support of the proposed IRP and the timeline projected for the Baseload Retirement Study. Local 31 also supports the latest retirement date possible (i.e., "no earlier than 2035," Base Case, Figure 11, Appendix P).

IBEW Local 31 filed additional comments on August 29, 2022 asking the Commission allow Minnesota Power to operate Units 3 and 4 of the Boswell Plant as long as possible so as to allow its members adequate time to transition to new jobs. Local 31 also asks the Commission to prioritize investments in new energy sources in and around Cohasset.

L. Itasca County

Itasca County filed comments on April 28, 2022, in support of Minnesota Power's IRP as the plan provides a framework for the future of the company while self-mandating 100% carbon-free energy by 2050.

M. Itasca Economic Development Corporation

The Itasca Economic Development Corporation (IEDC) filed comments on April 26, 2022 supporting Minnesota Power's IRP. IDEC noted that MP's plan will allow its communities time to transition prepare for the changes felt to the local economy with the closure of the Boswell Energy Center.

N. IUOE Local 49 And NCSRC Of Carpenters

Joint Comments were filed by IUOE Local 49 And NCSRC Of Carpenters on April 29, 2022. The joint commenters recognize the need to decarbonize Minnesota's electricity sector as part of the effort to meet Minnesota's greenhouse gas emission reduction goals but wish to protect workers through the transition. They commend Minnesota Power for putting forth a proposed IRP that balances these priorities.

Additional comments were filed on August 29, 2022, wherein the joint commenters responded to the comments of other parties. First, the joint commenters argue that the Department's modeling suggests that MP should acquire a number of new generation assets in a timeframe that is unrealistic and likely impossible. Specifically, the joint commenters believe accelerated closure of Boswell Unit 3 is unrealistic.

Additionally, based on the modeling and discussion in the Department's comments, the joint commenters believe that it is most prudent to move forward with Minnesota Power's 2021 Plan, to move forward with MP's plan to look at refueling options for 2035 and revisit the issue in the next IRP.

Additionally, the joint commenters oppose the conclusion reached by the OAG that NTEC is not necessary. The joint commenters believe that the conclusion presumes that Boswell Units 3 and 4 will not retire early. They additionally support the position of Minnesota Power that NTEC is needed but emphasize that the OAG's analysis implies a need to continue electricity generation at Boswell Unit 3 and 4 into the foreseeable future. The commenter additionally opposed the CEOs and OAG comments urging the Commission to reverse decisions granting an affiliated interest agreement based on the possibility of delays to energy transition efforts.

In response to the comments and attached Health and Equity Report filed by the CEOs, the joint commenters note the presence of benefits, such as health benefits, of a regulated utility system that provides reliable electric service to all customers. Additionally, in the context of disparities of solar adoption, the joint commenters indicate a preference for utility scale, grid-wide assets that are utilized by, and benefit all ratepayers–including those that are lower-income.

O. MN Energy Transition Office

The MN Energy Transition Office filed comments on August 29, 2022, indicating its understanding of nuanced economic, social, and environmental impacts of the energy transition and closing of power plants through the IRP.

P. MN State Senator Jennifer McEwen

MN State Senator Jennifer McEwen filed comments on September 8, 2022, requesting the Commission approve the CEOs preferred energy resource plan. Senator McEwen also indicates that building more renewable energy infrastructure is necessary, and requests the Commission revoke approval for NTEC.

Q. Minnesota Interfaith Power and Light

Minnesota Interfaith Power and Light ("MIPL") filed comments on September 8, 2022, disputing MP's usage of the term "Just Transition" in the IRP. MIPL asserts this term is an inaccurate characterization of Minnesota Power's initial filing because it disregards the impacts of fossil fuel workers "left behind" during the transition to cleaner energy. Additionally, MIPL asserts that the transition can correctly be referred to as "just" when lifting up people (such as those in poverty) negatively affected by the fossil fuel economy.

MIPL supports the CEO's Preferred Plan, as submitted in initial and additionally appreciates the PSE Health and Equity Study provided by the CEOs. Lastly, MIPL asks the Commission to strongly consider the recommendations of the CEO Preferred Plan and particularly in the light of the passage of the IRA when applying the concept of a "just transition."

R. *WPPI Energy*

WPPI Energy filed comments on August 29, 2022. WPPI Energy's energy portfolio includes power purchased from Boswell Unit 4. WPPI Energy indicates that it looks forward to working with Minnesota Power to meet its own carbon goals and transition to generating resources capable of providing reliable, affordable, and on-demand power currently provided by resources like Boswell Unit 4.

S. *UMD Recreational Sports Outdoor Program*

The UMD Recreational Sports Outdoor Program filed comments on April 28, 2022, requesting greater communication regarding FERC licensing of the hydro plant at Thomson Dam, along the St. Louis River.

T. *Union of Concerned Scientists*

The Union of Concerned Scientists (UCS) filed comments on April 29, 2022 requesting that Minnesota Power go further to address issues of environmental, racial, and economic justice issues. In particular, the UCS opposes the introduction of new gas plants and asks the Commission to ensure Minnesota Power does the following:

a. Respond to the climate crisis with 100 percent renewable energy production by 2035;
b. Drop plans to build the proposed NTEC fossil gas plant in Superior and commit to no new gas-fired power plants;
c. Retire the Boswell 3 & 4 coal units by 2030 or earlier;
d. Support community and worker transition through planning, building out local renewables, and advocacy;
e. Invest in expanding community and customer-owned solar in the Northland; and
f. Prioritize equitable access to benefits of clean energy.

XVII. Staff Discussion

In this section, staff will address the following issues:

- Resource need;
- Boswell Energy Center;
- Transmission investments;
- NTEC;
- Resource acquisition;
- Carbon regulatory costs;
- Resource adequacy;
- Hibbard; and
- The EPA "Good Neighbor Rule"

But first, some questions for the Commission to consider when reviewing this section include:

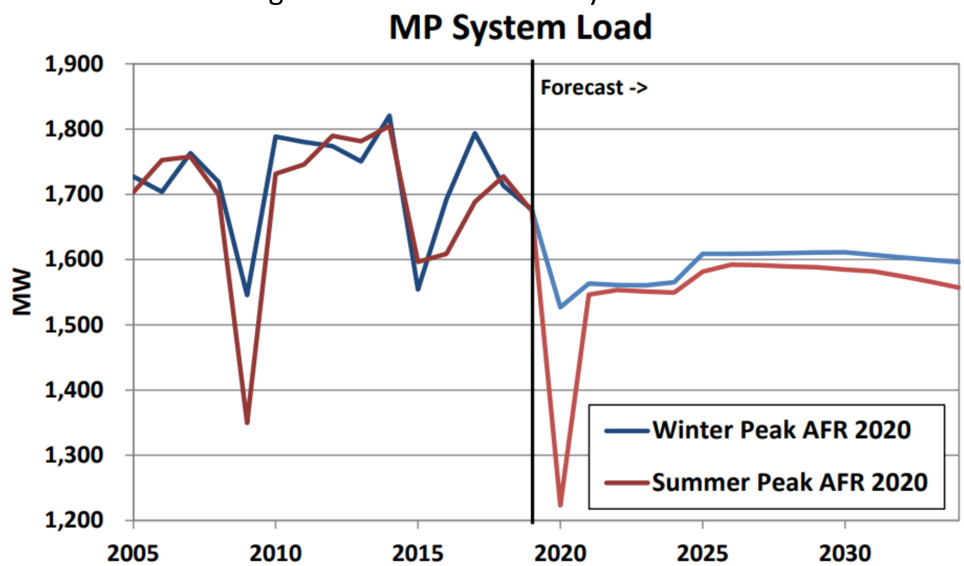
- What actions need to be taken in this IRP, and which can be addressed in the next IRP?
  - For example, MP and Telos agree that in order to reliably close Boswell 3, transmission solutions will be required, although their conclusions differ on what those should be. Telos determined that MP did not study siting energy storage at critical locations or a combination of solutions that could maximize flexibility of the future grid infrastructure. MP stated its long-term plan will "[d]evelop and implement transmission solutions to address reliability issues related to the early retirement of BEC3," but it is unclear when or if MP intends to implement solutions identified in its S1 scenario or continue to evaluate transmission solutions on an ongoing basis and present a refreshed analysis in the next IRP.
- How should the IRA factor into the decision?
  - MP assumed new wind would not be available for PTC benefits after 2024, which is now an outdated assumption given the passage of the IRA. The CEOs, who recommended solar but not wind in their five-year action plan, qualitatively described the benefits from the IRA, but did not provide modeling taking it into account (no party did). This may need to be addressed when the Commission deliberates resource acquisition.
- Does the Commission have the information to make a size, type, and timing resource need finding?
  - MP's IRP filing was developed using AFR 2020, but the modeling does not incorporate MP's most recent forecast, AFR 2022, which expects a return of load to pre-pandemic levels. The OAG bases its recommendation on historical forecast error, which is to say the forecast MP used to justify NTEC overstated its capacity and energy needs relative to both AFR 2020 and AFR 2022. The Department noted that MP's base forecast shows a significant, long-term drop in energy and demand requirements, while the high and mine restart contingencies essentially return demand and energy requirements to the historic levels and do not include significant new requirements. There are also a variety of recommendations for removing NTEC (or changing its offtake) and removing the Boswell units in different years. Altogether, there are several variables that will make it challenging for the Commission to determine MP's resource need.
- Some parties discussed how the MISO LRTP/Iron Range line can mitigate the reliability impacts of retiring Boswell. On August 1, 2022, MP and GRE filed a Notice of Intent to construct, own, and maintain the Northland Reliability Project in Docket No. 22-416.
  - How should the Commission factor in the Northland Reliability Project into the consideration of retiring the Boswell units, if at all?

A. Resource Need

1. AFR 2020 vs. AFR 2022

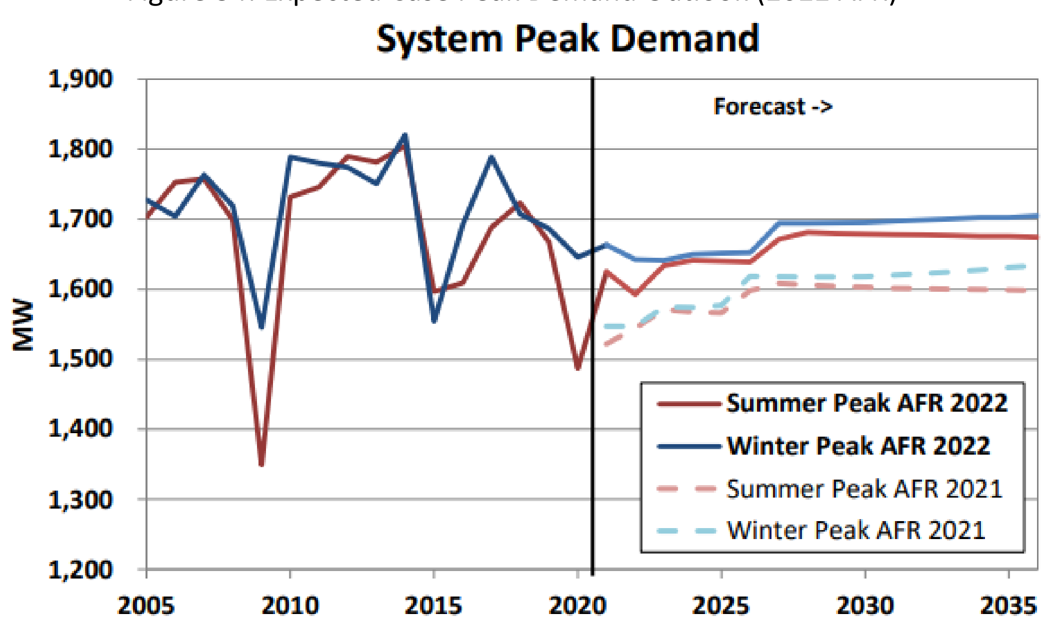
As discussed previously, MP's IRP was filed in February 2021 using the Company's AFR 2020, which was developed during the COVID-19 pandemic when the future of MP's industrial load was highly uncertain. This can be seen in Figure 33 below, which shows a severe decline in peak demand in 2020, before leveling off around 1,600 MW for the remainder of the planning period. Overall, AFR 2020 expected 103 MW of **system load loss** by 2030.

Figure 33: Peak Demand by Season[228]



Since that time, MP has developed two subsequent AFRs, the most recent being AFR 2022. AFR 2022 tells a different story than AFR 2020 and AFR 2021. The system peak demand forecast in AFR 2022 projects 42 MW of **system load growth** by 2036, and system peak demand hovers around 1,700 MW, which is similar to the AFR 2020 Summer HIGH contingency the Department discussed in its comments.

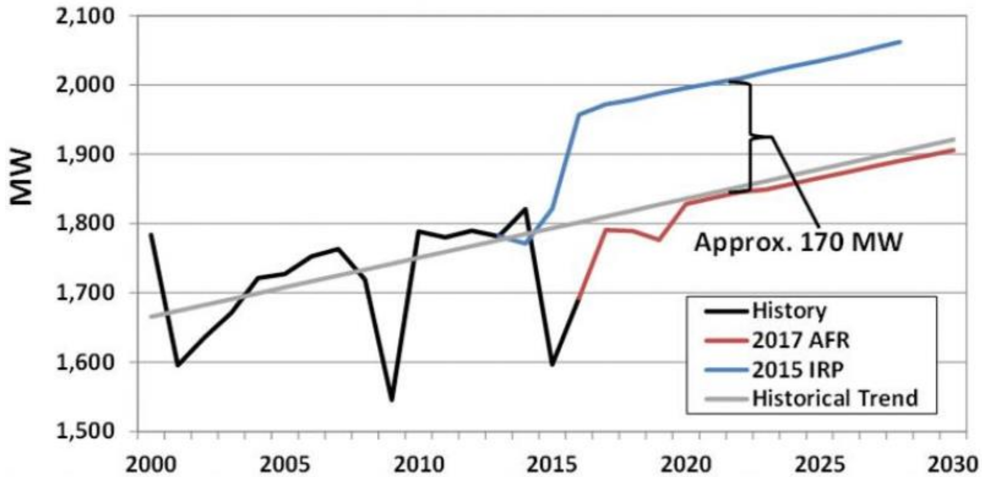
Figure 34: Expected Case Peak Demand Outlook (2022 AFR)[229]



[228] MP, Petition, Figure 4, p. 22.
[229] Minnesota Power, 2022 AFR, Docket E999/PR-22-11, June 28, 2022, Figure 2, p. 3.

Even though AFR 2022 shows some recovery since the beginning the pandemic, the OAG's argument is still valid, in that the most recent forecast is well-below the forecast used to justify NTEC. Figure 35 shows the annual peak demand forecast in AFR 2017 filed in the NTEC Petition, which showed an increase in peak demand to about 1,900 MW by 2030, and AFR 2017 was well-below the forecast MP used in its 2015 IRP (as illustrated by the difference between the blue and red lines).

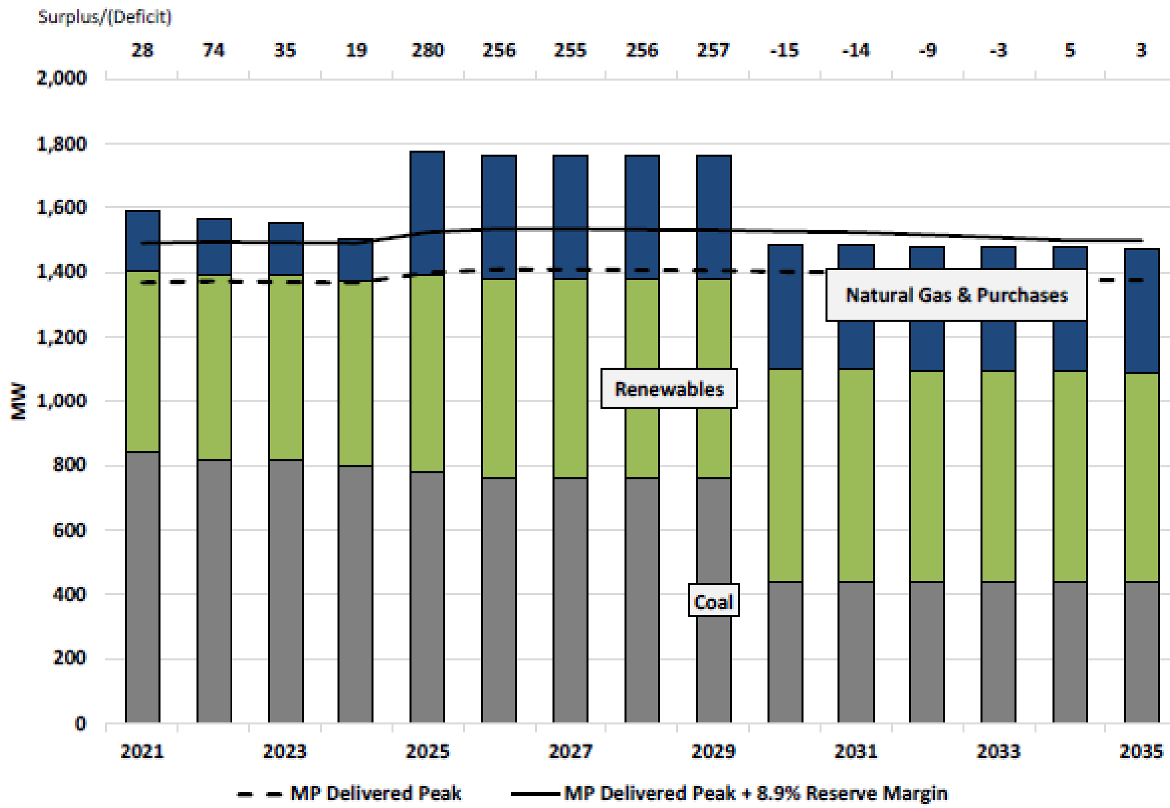
Figure 35: MP Annual Peak Demand Forecast Comparison (2015 Plan compared to 2017 AFR)[230]



With these three forecasts, there is a range of roughly 1,600 MW of peak demand (AFR 2020) to about 1,900 MW (AFR 2017). What is different, however, is MP's generation capability, which will be substantially lower after retiring Boswell 3, and to some degree with a reduced share of NTEC. Figure 36 below shows the 2021 Plan capacity outlook, which includes the NTEC offtake at 50 percent. Reducing the NTEC ownership share to 20 percent may not affect MP's net surplus a great deal, but removing it completely might create a resource adequacy risk under AFR 2022 conditions.

[230] Docket No. E015/AI-17-568, Petition for Approval of Gas Plant Proposal, p. 2-9

Figure 36: 2021 Plan Capacity Outlook[231]



In staff's view, a realistic assumption would be that MP's NTEC offtake reduces from about 290 MW beginning in 2025 to about 116 MW beginning in 2027, and Boswell 3 reduces MP's generating capability by about 350 MW by 2030. This leaves MP's generating capability with less than 1,500 MW after Boswell 3 retires. Given this decline, when examining which forecast is most reasonable, an equal amount of attention should be given to how much generating capability MP will have on its system under the 2021 Plan capacity outlook. Unless new resources are added, staff is concerned about MP's capacity position without NTEC.

2. MISO Seasonal Resource Adequacy Construct

Furthermore, given that MP's 2021 Plan transitions away from dispatchable generation and toward more solar and wind, the Petition stresses the need to plan for a multi-season resource adequacy construct and accreditation enhancements for solar,[232] which was affirmed by recent FERC approvals of MISO resource adequacy proposals. First, FERC accepted MISO's proposal to move to seasonal resource adequacy requirements, rather than a single requirement based on the summer peak. Second, MISO proposed to implement seasonal, availability-based accreditation (SAC), which, for non-thermal resources, will use MISO's current capacity valuation methodologies, adjusted for seasonality.

[231] MP, Petition, Figure 17, p. 61.
[232] Petition, p. 36.

Pages 19-20 of MP's Reply Comments briefly discuss the seasonal construct, but MP stated that the expected impacts on its resource portfolio is not fully understood.[233] In response to PUC Information Request No. 5, MP explained how the SAC may affect MP's spring, summer, fall, and winter requirements:

> Under the new MISO seasonal construct Minnesota Power will have four separate requirements each planning year. Minnesota Power is a winter peaking utility and expects total capacity requirements will be greater in the MISO defined winter season than during the summer season, the summer season was the basis for the current annual based construct. Minnesota Power is not able to calculate what our final requirements are for the winter (expected timeline for final requirements is December 15, 2022), but at this time we anticipate it could result in increasing total capacity requirements from the current summer requirement by up to **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]**. With the new MISO Fall and Spring seasons also having higher planning reserve margins than the Summer season, Minnesota Power will expect the total capacity requirements to increase during those seasons, by **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]** when compared to summer.
>
> Note, the higher seasonal requirements are being driven by the higher Planning Reserve Margin (PRM) requirements and Minnesota Power will need to consider its resource portfolio and the new seasonal variation of the accreditation values for winter, spring and fall. The final accreditation values for resources are still forthcoming, however, based on the preliminary analysis of SAC MW for a sampling of Minnesota Power generation units the Company anticipates to **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS].**
>
> Minnesota Power will continue to evaluate its capacity needs as more information becomes available on MISO's seasonal construct. Minnesota Power anticipates it will know the final capacity position by end of December. Most of the critical information on accredited capacity values is anticipated to be published by MISO on December 15th, 2022. Given that the timeline for implementing the new seasonal construct is extremely short, this will limit the options for procuring any additional capacity if it is needed by the Company. For example, it is unrealistic to build new capacity before the start of the new MISO Planning Year 2023-2024, which starts June 1, 2023. Longer-term, Minnesota Power will plan to incorporate the seasonal construct into the IRP process.

MP stated that the impacts of the most recent MISO proposal on the new ELCC for wind and solar resources on a seasonal basis are also difficult to assess, since the information has not been presented on a unit-by-unit basis. However, MP provided a MISO presentation explaining

[233] MP, Reply Comments, pp. 19-20.

a hypothetical portfolio, Portfolio 1, in which MISO indicated possible seasonal ELCC values for the initial planning year:[234,235]

- Solar Capacity
  - Winter Season – 0%
  - Summer Season – 45%
  - Spring Season – 40%
  - Fall Season – 30%

- Wind Capacity
  - Summer – 15%
  - Winter – 15%
  - Spring – 13%
  - Fall – 13%

If the Commission modifies MP's plan to incorporate solar in the five-year action plan, staff believes seasonal resource adequacy risk could be an issue. And given the amount of important and relevant information anticipated to be published in mid-December, staff recommends that MP make a compliance filing updating the Commission of the Company's final capacity position at least 30 days after MISO publishes the accredited capacity values.

3. DER Forecasts

Staff notes that MP is consistent across multiple dockets in its treatment of its DER forecasts, as the Company uses the AFR as the source of its forecasts. The consistent treatment of forecasts across planning processes results in greater transparency for stakeholders and the Commission as they work to evaluate the IRP, IDP, and other requests by the Company. Staff also reviewed AFR 2022, and while there are some changes to adoption rates, overall the methodology and trends are consistent with AFR 2020. Staff does not have concerns about MP's DG solar forecast and expects that as solar adoption throughout its service territory increases, it will be able to better test the accuracy of its long-term forecast.

B. Boswell Energy Center

1. Boswell 3

Boswell 3 is MP's second-largest resource (after Boswell 4), both in terms of its nameplate capacity and generation output. Boswell 3 and 4 are the two remaining baseload units on MP's system. As a large coal unit, Boswell 3 has a significant environmental footprint. As a large, Minnesota-located power plant, it has significant socioeconomic impacts. As an undepreciated asset, early retirement may affect customers' rates. Thus, the impacts of retiring Boswell 3 are far-reaching, more so than any other action the Commission may take in this proceeding (assuming the Commission re-examines Boswell 4 in the next IRP).

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[234] https://cdn.misoenergy.org/20220824%20RASC%20Item%2007c%20Non-Thermal%20Accreditation%20Presentation%20(RASC-2019-2%202020-4)626036.pdf
[235] The values listed are from MP response to PUC IR No. 5 (September 26, 2022).

Parties do not oppose retiring Boswell 3 by the end of the decade. The Department, while finding an optimal retirement date to be 2025, acknowledges that "the retirement date for [Boswell 3] would have to be pushed back by several years."[236] Staff therefore interprets the Department's recommendation to mean that Boswell 3 is uneconomic in the long-run, so as soon as it is feasible, retiring Boswell 3 is in the public interest. Since several other parties support MP's 2021 Plan, or at least the retirement of Boswell 3 in 2029, staff views retiring Boswell 3 by December 31, 2029 to be an undisputed issue.

However, the next question is whether to acquire replacement generation or implement transmission solutions. If the Commission adopts the Department's recommendation for a 282 MW peaking resource solution, then the Commission would need to decide whether a resource acquisition process is required. Since the peaking resource in 2026 is simply a modeling result, and the Department acknowledged that Bowell 3 cannot be retired until several years later, staff believes a resource acquisition process for a peaking unit it premature.

If the Commission determines transmission solutions are required, then the Commission may need to decide (a) which solutions are required and at what cost, (b) if those decisions need to be made in this IRP, or (c) if a Boswell 3-specific docket in-between IRPs should resolve outstanding issues.

Staff believes it is important and interesting that MP characterizes Boswell 3 reliability solutions are part of a "long-term action plan (i.e., 2026-2035)" and that MP will continue to "develop and implement" those solutions over time. This implies no Commission action is requested on this issue, but the Commission may find it unsatisfactory to not address the specifics at all. As a reminder, Table 9 in Appendix F (Table 35 below) identified solutions that could be required under the S1 (Boswell 3 only) scenario, and staff includes that table with red box to indicate the identified transmission solutions. But these are not proposed for Commission approval.

[236] Department, Reply Comments (August 29, 2022), p. 20.

Table 35: Summary of IRP Generator Retirement Transmission Issues and Solutions[237]

Category	Impact	Solution	E1	E2	S1	S2	S3
Voltage Support & System Strength	Needs a continuous source of VSSS	Synchronous Condenser		X			X
Voltage Support & System Strength	Contingency loss of source of VSSS	Synchronous Condenser	X	X	X	X	X
Voltage Support & System Strength	Prior outage plus loss of source VSSS	Synchronous Condenser			X	X	X
Voltage Support & System Strength	Steady state reactive power support	300 MVAR of additional capacitor banks			X	X	X
Local Power Delivery	Overload of [TS Data begins…TS Data Ends] Outlets	Rebuild [TS Data begins…TS Data Ends] Transformer	X	X	X	X	X
Local Power Delivery	Overload of [TS Data begins…TS Data Ends] Transformer	Rebuild [TS Data begins…TS Data Ends] Transformer			X	X	X
Local Power Delivery	Overload of [TS Data begins…TS Data Ends] Transformer and related prior outage overloads in the area	Build new [TS Data begins…TS Data Ends]			X	X	X
Regional Power Delivery	Northern Minnesota Voltage Stability & related issues	Define NOMN interface and manage in real-time	X	X	X	X	X
Regional Power Delivery	Underlying transmission overloads along NOMN interface	Upgrade existing [TS Data begins…TS Data Ends] Lines			X		
Regional Power Delivery	Northern Minnesota Voltage Stability & related issues	New regional extra high voltage transmission line				X	X

Importantly, Table 9 of Appendix F informed the transmission cost estimates presented in Table 11 of Appendix F, which was used in EnCompass to help MP determine that transmission solutions are preferable to generation reliability mitigations. However, what is unclear is whether the Commission is being asked to approve anything related to transmission solutions.

2. Boswell 4

Regarding Boswell 4, the CEOs recommend the Commission order MP to "commence planning the transmission system reliability mitigations needed to maintain the option of retiring the Boswell facility entirely, including unit 4, by no later than 2030."[238] As with the previous discussion on Boswell 3, it is unclear what the Commission is being asked to do regarding approving or modifying identified transmission upgrades. Moreover, staff believes clarification is required because "commence planning" may imply that the Commission believes the record supports retiring Boswell 4 by 2030, and staff does not believe that is the case. However, if the

[237] Appendix F of MP Petition, Table 9, p. 61.
[238] CEO, Reply Comments, p. 22.

CEOs recommendation is simply to require MP to perform additional reliability analysis of early retirement of Boswell 4 in the next IRP, then staff has no objection.

The Department recommended that MP:

a. proceed as if Boswell 4 were to be shut down in 2030; and
b. re-study the Boswell 4 2030 retirement decision in the next IRP.

Staff opposes the recommendation to proceed as if Boswell 4 were to be shut down in 2030, for two main reasons:

First, even though the Tranche 1 LRTP lines might make the timeline possible, staff has concerns that Boswell 3 and 4 can both be retired by 2030 without presenting significant reliability risks. Also, staff cannot conclude with certainty that MISO approval of the Iron Range line necessarily means the total costs for voltage support and system strength, local power delivery, and regional power delivery – all categories MP analyzed in its S2 and S3 scenario – make the decision to retire Boswell 4 in the ratepayers' interests. According to MP, "this specific transmission solution addresses system reliability (i.e., moving energy from generation to customer), but it does not address the source, attributes, and type of generation that could replace retired Boswell generation."[239] The Commission may decide that MP's intention to construct the Northland Reliability Project is insufficient evidence that Boswell 4 can be retired reliably.

Second, a common theme in the stakeholder meetings was that host communities need certainty in order to plan for the eventual retirement of power plants. Proceeding as though Boswell 4 will close by 2030 may have deleterious effects on Cohasset and the surrounding region. Simply put, to proceed under a plan to retire, only to re-examine early retirement in the next IRP, is the very thing communities stated they did not want. Cohasset explained that developing projects will require significant public investment, which Cohasset aims to do in part with TIF dollars. The problem with proceeding as though Boswell 4 will retire in 2030 is that Cohasset is left to assume there will be no tax revenue collected from Boswell Energy Center after 2030, which may place excessive uncertainty to all involved who are currently willing to move forward with redevelopment projects. Therefore, as an alternative to the Department's recommendation, staff would support modifying it as follows:

~~a. proceed as if Boswell 4 were to be shut down in 2030; yet~~
b. re-study the Boswell 4 2030 retirement decision <u>and other dates</u> in the next IRP.

Finally, the CEOs asserted that MP's 2021 Plan does not include any steps to enable Boswell 4 to retire by 2035, which fails to comply with the Commission's NTEC Order. Staff disagrees. Importantly, staff did not interpret the Commission's NTEC Order to mean that the next IRP would require either a retirement of, or major operational changes at, Boswell 4. Staff interprets the NTEC Order to mean that MP must investigate what an early Boswell 4 retirement plan would entail, which is what the Company developed.

[239] MP, Reply Comments, p. 46.

For example, MP ran early Boswell 3 and 4 retirement scenarios, which consistently found that a 593 MW hydrogen-ready CC was a least-cost replacement. Moreover, as illustrated in Table 9 and Figure 20 of Appendix F, MP's S3 scenario identified transmission solutions under three separate categories and developed conceptual cost ranges to use in EnCompass. It is true that MP did not propose an early retirement plan at Boswell 4, but it is debatable whether the Company was required to by the NTEC Order. As staff understands MP's position on Boswell 4:

1. Using current assumptions, if Boswell 4 were to retire in 2035, a CC unit would be the least-cost resource to replace it, and high kV transmission lines, transformers, and synchronous condensers would be required for reliability;
2. however, it is premature to commit to a specific resource type at this time, given that different combinations of emerging, carbon-free technologies might prove cost-effective in future IRP iterations;
3. therefore, MP asks that the Commission "allow time for technology to develop and advance" and "allow time for a just transition for host communities."[240]

While there are tradeoffs to setting a specific date for Boswell 4's eventual retirement, staff recommends restudying various retirement dates in the next IRP to remain flexible in how to meet the needs of MP's future system.

C. Transmission Investments

The Commission's July 18, 2016 Order approving MP's 2016-2030 IRP required MP to idle Taconite Harbor 1 and 2 in 2016 and cease coal-fired operation by the end of 2020, which the Company did. The Order recognized that MP identified several local transmission system issues that must be remedied by implementing local transmission system upgrades, as well as the costs of those upgrades:

> Minnesota Power's analysis found that shutting the plant down would create transmission- reliability concerns, requiring upgrades to ensure that electric service is maintained. One set of local transmission upgrades, costing approximately $8 million, would be required at the time of shutdown. A second set, costing approximately $30 million, would be required later if predicted load growth in the area materializes.[241]

Order Point 4 of the Commission's Order stated:

> Minnesota Power shall remedy the local transmission-system issues identified in its analysis of closing Taconite Harbor Energy Center Units 1 and 2. The Company will be allowed to recover the reasonable costs of the upgrades consistent with the estimate listed on page 16 of Appendix F of its resource plan.[242]

[240] MP, Petition, p. 35.
[241] Docket No. 15-690, Commission Order pp. 4-5 (July 18, 2016).
[242] Docket No. 15-690, Commission Order p. 14 (July 18, 2016).

As shown below in Figure 37, in an excerpt of the lower left of Figure 14 of Appendix F (shown in full in Figure 17 of the briefing paper), MP made $8 million in transmission investments in the North Shore Loop in 2016, but MP's current estimate is more than $110 million through the mid-2020s (including about $70 million spent from 2016-2020), which is clearly well-above the amount envisioned by the 2015 IRP Order. (To be clear, staff is not suggesting MP's investments were unnecessary or excessive, only that they are higher, and staff is unsure why.)

Figure 37: Total Transmission Upgrade Costs[243]

As shown in Table 36 below (Table 11 of Appendix F), the S1 scenario alone (Boswell 3 shutdown only) has a mid-level cost estimate of $144 million, whereas the mid-level cost estimate for retiring both Boswell units could be over $800 million.

Table 36: IRP Generator Retirement Transmission Impact Cost Assumptions[244]

Boswell Operating Scenarios	**Scenario Cost Estimate ($M)**				
Type of Transmission Impact	E1	E2	S1	S2	S3
Voltage Support & System Strength	$33	$66	$69	$69	$102
Local Power Delivery	$1	$1	$61	$61	$61
Regional Power Delivery	-	-	$14	$640	$640
Total	$34	$67	$144	$770	$803

Telos raised concern that MP's cost estimates spanned "an enormous range, which indicates that the scenario and its costs have not been studied closely."[245] Telos estimated the Boswell 3 transmission line upgrade to be $25 million dollars, which is roughly one-third of the $61 million cost of all Local Power Delivery upgrades identified in Table 11 from the MP IRP Appendix F.[246]

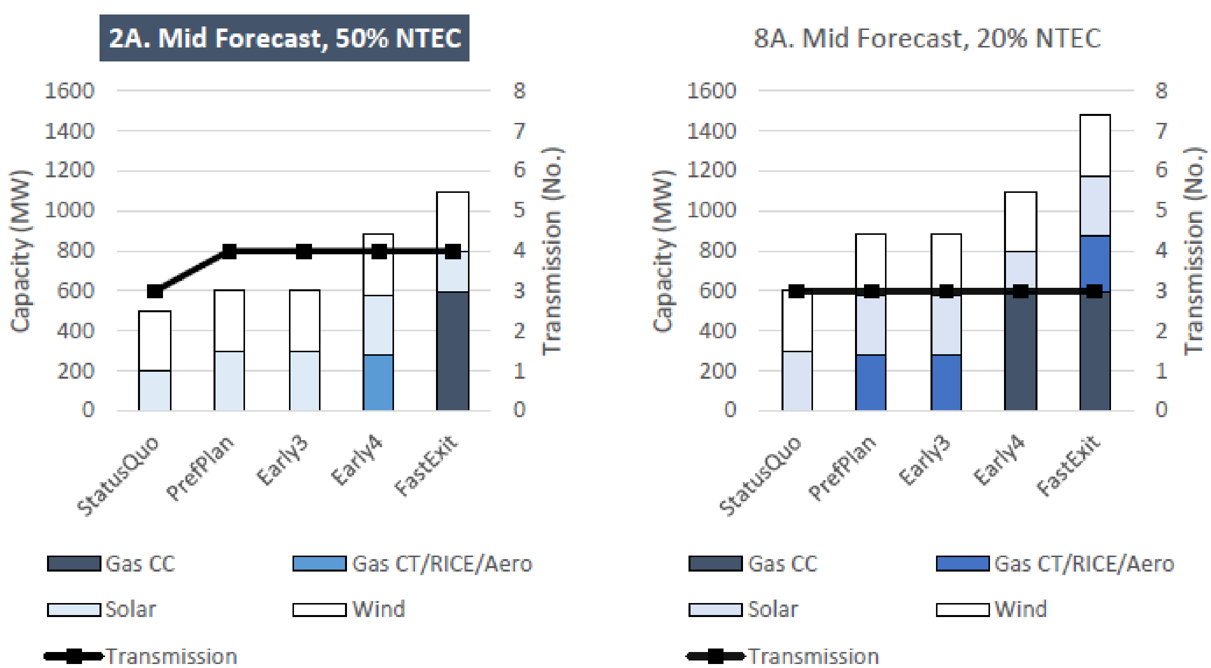
[243] Appendix F to Petition, Figure 14, p. 35
[244] Appendix F of MP Petition, Table 11, p. 64.
[245] CEO, Initial Comments – Transmission Reliability Analysis (Telos Energy), p. 23.
[246] CEO, Initial Comments – Transmission Reliability Analysis (Telos Energy), p. 11.

At this point, there does not appear to be a clear way for the Commission to oversee the reasonableness of the costs related to transmission investments. Until MP elaborates on what the Company expects the Commission to approve on the transmission-side, it is difficult to provide decision options, but staff believes oversight of MP's planned investments in transmission solutions requires more discussion.

D. NTEC

In staff's view, the greatest limitation of MP's IRP is that the Company did not conduct modeling runs with the 20 percent offtake in addition to 50 percent. MP stated that this was because "the change was not material to Minnesota Power's overall plan," but parties seem to unanimously disagree with MP's argument. For example, under the Department's modeling – using the Mid Forecast scenario as one example – significantly more resources were added under the 20 percent ownership scenario than to the 50 percent scenario.

Figure 38: Department capacity and transmission expansion resources selected for each Boswell retirement scenario, by Forecast/NTEC combination (Conditions: Base Contingency, Mid/Mid Future)[247]



Additionally, the Department concluded that the Boswell retirement reliability mitigation depended, in part, on MP's ownership stake in NTEC:

> [T]he Department's modeling results show that Boswell retirement mitigation selection depends largely upon forecast level, **NTEC ownership**, and LRTP. Typically, the Department found that under base conditions (Mid Forecast, 50% NTEC, and No LRTP), EnCompass tends to select transmission in 2026; however, if

[247] Department, Comments – Supplemental Modeling (July 29, 2022), Figures 2A and 8A, p. 36.

> the forecast, **NTEC ownership level**, or LRTP is changed from these conditions, EnCompass tends to select a gas CT unit in 2026.[248] (Emphasis added by staff.)

Moreover, the Department's modeling results found:

> Decreasing NTEC ownership makes FastExit, Early4, and Early3 more cost competitive and StatusQuo and PrefPlan less cost competitive.[249]

In other words, according to the Department's modeling, reducing the NTEC offtake makes the earlier retirement of the Boswell units more cost-competitive, which is an important finding.

MP also claims that NTEC can potentially change fuel sources to operate on hydrogen or be retrofitted with carbon capture technology; for instance, MP stated, "NTEC is being developed with state of the art technology that can pivot to burn hydrogen or add carbon capture at a future date, reducing the stranded asset risk for customers."[250] However, MP also stated that "the cost to convert NTEC to burn hydrogen or the cost to add carbon capture was not incorporated into prior modeling,"[251] which makes it speculative that constructing NTEC with plans to retrofit it in the future is economical.

Additionally, optionality at NTEC may overstated due to the challenges associated with co-ownership. While NTEC may theoretically operate on cleaner fuel sources, its ability to change to cleaner fuel sources depends on agreement among other co-owners. The Petition explains how co-ownership of Boswell 4 with WPPI creates challenges regarding dispatch operations. And as the Commission well-knows, Otter Tail Power's co-ownership of Coyote Station has presented challenges in Otter Tail's IRP dockets.

Having said that, staff agrees with MP that NTEC is an approved resource, that the Minnesota Supreme Court has affirmed the Commission's decision on the application of Minnesota Environmental Policy Act, and that the Court of Appeals affirmed the Commission decision to approve NTEC. While MP should arguably have supplemented the record with new modeling to show the impacts of a 20 percent ownership stake, it is understandable why MP did not run a no-NTEC scenario. If MP were to consider NTEC as a *potential* resource rather than an *approved* resource, that would have implied the merits of NTEC are still open for consideration, and MP believes the merits of the facility has been settled the Commission's contested case proceeding and court rulings.

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[248] Department, Comments – Supplemental Modeling (July 29, 2022), p. 52.
[249] Department, Comments – Supplemental Modeling (July 29, 2022), p. 35.
[250] MP, Reply Comments, p. 24.
[251] MP, Reply Comments, p. 24.

E. Resource Acquisition

1. Competitive Bidding

In the Commission's April 15, 2022 order approving Xcel Energy's 2020-2034 IRP,[252] the Commission required that Xcel implement its resource plan under the Commission-approved Track 2 and Modified Track 2 resource acquisition processes. Staff notes that MP does not have the same exact resource acquisition requirements as Xcel, although MP has similarly used competitive bidding processes to acquire renewable resources, most recently in the Company's acquisition of Nobles 2 Wind and Blanchard Solar.

The NTEC Order adopted specific steps reached through an agreement between MP and the Department for future resource acquisition reforms, which apply to supply-side acquisitions of 100 MW or more and lasting longer than five years.[253] The Department recommended steps for a future competitive bidding process in their Initial Comments, which essentially combined required steps from the NTEC Order with requirements used in past resource acquisition proceedings across utilities. In Reply Comments, the Department added one more step, underlined below, which was an inadvertent omission in their Initial Comments.

The Department/OAG recommendation for resource acquisition is that MP shall:

1. use a bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years;
2. ensure that the RFP is consistent with the Commission's then-most-recent IRP order and direction regarding size, type, and timing unless changed circumstances dictate otherwise;
3. provide the Department and other stakeholders with notice of RFP issuances;
4. notify the Department and other stakeholders of material deviations from initial timelines;
5. update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings;
6. where MP or an affiliate proposes a project, engage an independent evaluator to oversee the bid process and provide a report for the Commission;
7. request that the independent evaluator, if engaged, specifically address the impact of material delays or changes of circumstances on the bid process; and
8. <u>any RFP issued by MP must include the option for both PPA and BOT proposals unless the Company can demonstrate why either a PPA or BOT proposal is not feasible;</u>
9. cap any ROFO offer made by MP at net book value; and
10. ensure that any RFP documents for peaking resources issued are technology neutral.

2. Wind, Solar, and Peaking Resources

Typically, upon approving an IRP, the Commission's order will specify the size type, and timing of resources the utility shall procure, while the out-years of the planning period can be revisited

[252] Docket No. 19-368.

[253] Docket No. 17-568, January 24, 2019 Order, Attachment A, p. 17 of the Order lists these reforms.

in the next IRP. In this case, the modeling parties propose the following short-term action plans:

Table 37: Comparison of 5-year action plans

Year	MP 2021 Plan	Department Plan	CEOs Preferred Plan
2023			Retire Hibbard (-44 MW)
2024	200 MW wind	100 MW wind 1 transmission project	200 MW Net Zero solar
2025		Retire Boswell 3 (-350 MW) 200 MW wind 2 transmission projects	100 MW Net Zero solar 300 MW generic solar
2026		282 MW peaking resource	
2027	290 MW - 50% NTEC offtake	290 MW - 50% NTEC offtake, or 116 MW - 20% NTEC offtake	

Staff believes a reasonable Commission action would be to initiate a competitive bidding process for 200-300 MW of wind in the 2024-'25 timeframe. As discussed previously, the Department recommends the Commission direct MP to begin proceedings to acquire approximately 282 MW of peaking resource that would be built in 2026, following the Boswell 3 retirement. However, since Boswell 3 might not be retired until several years after 2025, a peaking resource RFP could be premature. Solar was only economic in the CEOs model, and this was partially the result of EFG updating MP's ITC assumption, which was outdated because the ITC was stepped down to 10 percent in 2024. The CEOs also argued that the benefits of the IRA have been capture at all in modeling in this proceeding, and staff agrees with the CEOs that there is an opportunity for MP to explore cost-effective solar resources as well as wind.

3. Cost-Effectiveness Test

LPI recommends that approval of the wind and solar proposed in MP's 2021 Plan should be conditioned upon a that it is pursuing cost-effective options for ratepayers. Staff agrees with LPI, but staff notes that the Commission is required to consider environmental externalities in all resource acquisition proceedings. Moreover, CO_2 regulatory costs are an anticipated rate impact and should be included in the analysis. Having said that, staff has no objection to No-externalities and No-CO_2 regulatory cost scenarios as being part of a comprehensive analysis.

F. Environmental Externalities and CO_2 Regulatory Costs

Staff agrees with the Department's response to CUB and the CEOs that if a party believes that the current CO_2 cost estimate is inappropriate, either in cost per ton or in the starting date, that party should indicate this in the Department's proceeding to update the values, which is currently underway in Docket No. 22-236. MP modeled carbon futures consistent with the Commission's order in the CO_2 values docket (Docket No. 07-1199) and in a manner consistent with the modeling practices of other Minnesota utilities.

If a carbon pricing mechanism exists by 2025, which the Commission determined would be likely, then it would be reasonable for MP to incorporate this cost into the dispatch of a carbon-emitting facility. CUB, however, argues that "[w]hile the regulatory cost scenarios provide useful analysis, we do not consider runs with a regulatory cost in dispatch decisions to be credible projections of the near-term future."[254] Again, CO_2 regulatory costs are a rate impact, and it would be reasonable to incorporate a regulation such as a direct tax as a dispatch cost.

Regardless, staff believes it is more important to understand *how* carbon pricing impacts the modeling, rather than getting too bogged down in methodological approaches, and staff believes MP and the Department provided sufficient analysis to answer this question.

MP evaluated several carbon pricing scenarios:

- Reference Case Scenario (Petition, Section V, Table 4)
  - 2021 Plan was least-cost in 27 of 38 runs
- High Carbon Regulation Cost and High Environmental Cost (Appendix K, Table 4)
  - 2021 Plan was least-cost in 23 of 38 runs
- Low Carbon Regulation Cost and Low Environmental Cost (April Supp., Table 5)
  - 2021 Plan was least-cost in 9 of 38 runs (early Boswell 3 retirement was the best preforming plan)
- Low Environmental Cost (April Supp., Table 6)
  - 2021 Plan was least-cost in 1 of 38 runs (early two-unit retirement was the best performing plan)
- High Environmental Cost (April Supp., Table 7)
  - 2021 Plan was least-cost in 0 of 38 runs (early two-unit retirement was the best performing plan)

LPI requested MP run a scenario which removed externalities, and the Status Quo (no retirement) scenario was least-cost 100 percent of the time.

The Department's comments dedicated a substantial amount of time discussing the cost results for each Boswell retirement scenario with various combinations of CO_2 regulatory costs and externalities. As one example, Table 38 below (Corrected Table 9B of the Department's August 29, 2022 Reply Comments) show the plan rankings under each carbon future. Status Quo ranked first under the No/No scenario, but performed poorly under the remaining futures. Note that this table assumes the LRTP lines.

[254] CUB, Initial Comments, p. 8.

Table 38: LRTP Scenario Rank Per Future (1-5 rank each row) - corrected[255]

Carbon Future	StatusQuo	PrefPlan	Early3	Early4	FastExit
No/No	1	2	4	3	5
No/Low	5	4	3	2	1
No/High	5	4	3	2	1
Low/Low	5	4	3	2	1
Mid/Mid	5	3	4	2	1
High/High	4	5	3	2	1

The takeaway is that the presence of carbon pricing can significantly impact the ranking of the modeled scenarios, which makes sense because Boswell emits a lot of CO_2. The Commission has previously determined that the CO_2 regulatory costs present a financial risk to the Company and its customers if carbon regulation will be in effect. The Commission has also previously determined that CO_2 emissions (and other pollutants) impose a societal cost. Therefore, staff believes giving too much weight to the No/No scenario conflicts with multiple statutes and Commission decisions, but giving it no weight at all unduly overlooks the revenue requirement impact.

G. Distribution System Issues

CEOs made two recommendations related to DERs – that MP developing a modeling construct for distributed solar and that the Company take steps to better align the IDP and IRP. Conceptually, staff supports both of CEO's recommendations as the Commission has already adopted identical requirements for Xcel Energy. However, because MP has lower levels of DER adoption than Xcel, especially in the rural areas of its service territory, staff suggests that the Commission consider allowing the Company more flexibility with the implementation of the suggestions.

On CEO's first recommendation, that the Commission Order MP to develop a new modeling methodology for distributed solar, staff believes there is a balance to be struck between enabling more dynamic modeling and the reality of solar adoption in Minnesota Power's service territory. The makeup of the Company's load, with it being heavily weighted towards large industrial customers, means that the potential contribution of small, customer-sited solar towards total load is much smaller than the potential in Xcel Energy's service territory.

CEOs also make several recommendations for IDP/IRP alignment; however, again staff believes the more nascent stage of DER development in MP's service territory warrants consideration. For example, CEOs suggests that the Commission require MP to "conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level," however, outside of certain feeders in Duluth, MP likely lack sufficient historical information to

[255] Department, Reply Comments (August 29, 2022), Corrected Table 9B, p. 9. Page 27 of the Department's July 29, 2022 comments present additional tables showing total costs and a summary of cost metrics. The Department corrected Table 9B in its August 29, 2022 Reply Comments, Staff has included the corrected table here.

accurately forecast feeder level adoption of DERs. Additionally, unlike Xcel, Minnesota Power does not have a distribution planning tool like LoadSEER to assist it with granular feeder level forecasting. Staff notes Minnesota Power already aligns its DER forecasts across planning process, thus the first of CEOs recommendations is already addressed.

This is not to suggest that distributed solar generation will not play an important role on the Company's system, but to acknowledge that the difference in MP's system from Xcel's may require a more phased approach to modeling DERs in the IRP. Staff believes that it may be more fruitful for MP to learn from the already initiated process in Xcel's IRP and IDP before proposing its own methodology. Given that stakeholder groups in MP's and Xcel's IRPs also overlap, this would conserve resources at a time when there are numerous ongoing workgroups.

Staff recommends the Commission modify CEOs two recommended decision options to be more discussion oriented in nature given the current status of DER adoption in the Company's service territory. Staff suggests the following redline modifications to CEO's decision options:

- Require Minnesota Power to track Xcel's ongoing stakeholder work ~~work with stakeholders~~ to develop a modeling construct that enables ~~Minnesota Power~~ Xcel, as part of its next resource plan, to model solar-powered generators connected to Xcel's distribution grid as a resource. ~~Minnesota Power and stakeholders shall address the following factors in developing the modeling construct:~~ In its next IRP Minnesota Power shall provide a timeline to incorporate a similar modeling construct that addresses the following factors after consultation with stakeholders:
    - using a "bundled" approach as is used to model energy efficiency and demand response;
    - the costs borne by the utility and the costs borne by the customer;
    - cost effectiveness tests; and
    - other topics as identified by stakeholders.

- Require Minnesota Power in its next IDP to provide information on how it could implement the following ~~take~~ steps to better align distribution and resource planning, ~~including:~~
    - set the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan;
    - conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level;
    - proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources;
    - improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Minnesota Power can take advantage of distributed energy resources to address discrete distribution system costs; and
    - plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.

The Commission could then revisit this order point in future IRPs and IDPs once Minnesota Power starts to have larger impacts from DERs on its distribution system. CEO's original decision options are DO 15 and DO 17. Staff's modifications are DO 16 and DO 18.

CEOs also recommended that the Commission require Minnesota Power to account for local clean energy goals in its next IRP (Decision Option 19). Staff confirms this requirement it is consistent with what the Commission ordered in Xcel's IRP, and supports adoption.

CUB made recommendations pertaining to Minnesota Power's non-wires alternatives analysis, related to filing an upcoming NWA study and requirements for MP on NWA going forward (Decision Option 23). Staff believes the IDP is the appropriate place to evaluate the Company's NWA performance and compliance, not the IRP. The Company's 2021 IDP, which the Commission accepted in its September 9 Order in Docket 21-390, contained a discussion of the Company's consultant led NWA analysis[256], however no stakeholders beyond the Department of Commerce weighed in. Staff encourages parties that are interested in NWA to participate in Minnesota Power's next IDP filing. Staff recommends that the Commission review the results of the Company's NWA study in its next IDP, filed November 1, 2023, and address stakeholder feedback in that proceeding.

H. Hibbard and Public Health Report

Staff notes that commenters were generally in agreement about the importance of assessing the public health and equity impacts of a utility's resource on the public, however they disagreed about whether the CEOs PSE report did a good job of evaluating those impacts. Staff believes that at this time there is not sufficient evidence in the record to use CEOs PSE report as the basis for retiring the Hibbard facility, especially because the impacts of retiring Hibbard in 2023 will have on MP's generating profile. At 60 MW, the Hibbard Plant is not an insubstantially-sized resource, and the impacts of retiring it are not thoroughly explored in any party's comments. In addition, Hibbard is an RES-qualifying resource, and it has historically utilized waste wood and forest residue from sustainably-managed wood species in northern Minnesota. However, the PSE report stated the paper mill to whom MP sold the steam was sold in 2021 to a new operator who has indicated the new facility will not use steam from the Hibbard plant. Therefore, according to PSE, it is unclear what fuel source Hibbard is burning. Staff believes this is an area that warrants further exploration.

Ultimately, staff advises the Commission not to modify MP's IRP to remove Hibbard until there is a more comprehensive cost-benefit framework on which to base its decision. Instead, staff believes it is reasonable to require MP to conduct an analysis of the Hibbard facility for the Commission's consideration in MP's next IRP. The Company favored this approach in Reply Comments:

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[256] Staff refers the Commission to page 69 (PDF p. 80) of MP's 2021 IDP, and page 4 of MP's June 6, 2022, reply comments in Docket 21-390 for a description of the ongoing NWA consultant process.

> Minnesota Power does not believe it is reasonable to retire Hibbard without a retirement study completed and the impact to both the system and the host community (Duluth) understood.[257]

Similar to the decision the Commission made in the Xcel/St. Paul Cogeneration docket,[258] the study could essentially be a societal cost-benefit analysis – not necessarily a retirement study – to demonstrate whether there is a net social benefit in continuing to operate the facility. Possible topics for examination could be system reliability, customer costs, environmental impacts, and host community impacts.

The CEOs also requested that the Commission order Minnesota Power to perform a public health impact analysis as a part of its next IRP (Decision Option 20). Staff notes that the models used to calculate the Commission's established externality values take human health (among other things) into account. Additional information on the public health impacts, or other factors, offered by any participant to the proceeding, can help identify particular facilities where additional considerations beyond modeling should be examined.

I. EPA FIP

On February 28, 2022, the Administrator of the U.S. Environmental Protection Agency (EPA) signed a proposed Federal Implementation Plan (FIP) to assure that the 26 states, including Minnesota, identified in the proposed FIP do not significantly contribute to problems attaining and maintaining the 2015 Ozone National Ambient Air Quality Standards (NAAQS) in downwind states. While the EPA FIP was not discussed at length in the docket record, the Department recommended that within 180 days of the EPA's issuance of its final order, MP shall submit a compliance filing that presents the utility's understanding of EPA's final FIP and an action plan in response to the final FIP.

This issue came up in Southern Minnesota Municipal Power Agency's (SMMPA) recent IRP, and staff noted in that proceeding the final rule could change significantly from proposed rule, and MP may not have to change its plan at all, in which case a compliance filing might not be necessary. More importantly, though, if SMMPA would have to alter its plans, a compliance filing could be insufficient, and SMMPA may be subject to the IRP changed circumstances rule, Minn. Rule 7843.0500 subp. 5. The Commission ultimately directed SMMPA to discuss the rule in its next IRP.

Staff does not object to the Department's recommendation, so long as the Commission, staff, MP, and parties have a common understanding that to the extent the FIP requires deviations from the approved resource plan, discussions should begin as early as possible to decide next steps.

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[257] MP, Reply Comments, p. 47.

[258] Docket No. E002/M-21-590.

J. *Next IRP filing date*

According to the Commission's IRP rules, utilities are required to file IRPs on a biennial basis; however, the Commission typically varies this rule to account for other utility IRP filings, among other reasons. Oftentimes, staff recommends the Commission set a deadline for the next IRP based on a blend of factors, including deadlines for other utility's IRPs and the issues that will need to be addressed.

Below is a table of pending and upcoming IRPs, which the Commission can take into account when setting the date for MP's next IRP filing.

Table 39: MN Utility IRP Statuses

Utility	Docket Number	Status
Minnesota Power	21-33	Pending
Otter Tail Power Company	21-339	Pending (OTP requested an extension to resubmit its IRP on Mar 31, 2023)
Minnkota Power Cooperative, Inc. **Northern Municipal Power Agency (NMPA)**	22-312	Pending
Great River Energy (GRE)	22-75	Apr 1, 2023
Xcel Energy	19-368	Feb 1, 2024
Southern MN Municipal Power Agency (SMMPA)	21-782	Dec 2, 2024
Minnesota Municipal Power Agency (MMPA)	18-524	Aug 1, 2025
Interstate Power & Light Company	17-374	Feb 1, 2026
Missouri River Energy Services (MRES)	21-414	Jul 1, 2026
Basin Electric Power Cooperative	22-311	July 1 annually (O-IRP)
Dairyland Power Cooperative	22-313	July 1 annually (O-IRP)

Staff does not have a strong opinion on when MP's next IRP should be filed. However, as a starting point, staff offers Friday, November 1, 2024 (Decision Option 9), which is roughly two years from the Commission's hearing on this matter. This date also allows time for parties to analyze Xcel's IRP, which is due February 1, 2024.

In the meantime, the Commission could require that MP facilitate another pre-filing stakeholder process, mirroring the stakeholder process that preceded the instant IRP, which was required by the NTEC Order. Order Point 7 of the NTEC order stated:

> 7. In developing the modeling analysis to be used in its next resource plan, Minnesota Power shall consult with stakeholders, including but not limited to the

Department of Commerce and the Clean Energy Organizations, regarding the Company's modeling inputs and parameters.[259]

Any issues that the Commission will anticipate addressing in the next IRP, but which might be premature or undeveloped for this IRP, could be developed as part of an informal proceeding or stakeholder process. Staff flags the following issues for the Commission's consideration, and the corresponding decision options where applicable:

- Boswell 4 retirement and associated socioeconomic and reliability impacts;
- Modeling scenarios and costs for Boswell 4 retirement;[260] (see pages 23-24 of Telos Energy)
- MISO capacity and energy market reform;
- MISO's Long Range Transmission Planning (LRTP);
- Cost-benefit analysis of the Hibbard facility;
- MP's stated goal of 50 MW of long-term demand response;
- Deep decarbonization as recommended by CEOs to remain on a path to limit warming caused by climate change to 1.5°C;
- Equity measures.

Staff notes parties have offered individual decision options on some of the topics above. Staff offers Decision Option 30 as an alternative, which would direct the Company to work with stakeholders on a list of topics to be identified by the Commission and address them in the next IRP.

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[259] Docket No. 17-568, Order Approving Affiliated-Interest Agreements with Conditions (January 24, 2019), p. 29.

[260] See pages 23-24 of Telos Energy report, included as CEOs April 29, 2022 Comments—Transmission Reliability Analysis.

XVIII. Decision Options

1. Approve Minnesota Power's 2021 Plan as presented in its initial February 2021 filing which includes but is not limited to:
    a. Retire the Boswell Energy Center Unit 3 by December 31, 2029;
    b. Add 200 MW of Net Zero solar that leverages the Boswell site or other Minnesota Power facilities by 2030, leveraging existing interconnections and reinvesting in utility host communities;
    c. Work collaboratively with customers to pursue up to 50 MW of long-term demand response by 2030 to address future resource adequacy changes;
    d. Develop and implement transmission solutions to address reliability issues related to the early retirement of Boswell Unit 3;
    e. Develop and implement transmission solutions to address reliability issues related to the early retirement of Boswell Unit 3
    f. Investigate options to refuel or remission Boswell Unit 4 and associated reliability transmission as coal operations cease by 2035. (Minnesota Power, LIUNA, Local 49/Carpenters, LPI)

2. Require Minnesota Power to:
    a. Retire BEC 3 in 2025, with the actual date to be adjusted based on feasibility
    b. Proceed as if BEC 4 were to be shut down in 2030 *(Staff note: As explained in the Staff Discussion, staff opposes this option.)*
    c. Begin proceedings to acquire approximately 282 MW of peaking resource that would be built in 2026, following BEC 3 retirement *(Staff note: This may not be needed if Boswell 3 cannot feasibly retire for several years after 2025.)*
    d. Acquire 200 to 300 MW of wind in the in the 2024 to 2025 time frame
    e. Work with MISO to ensure that Tranche 1 LRTP would fully meet all reliability requirements associated with a 2030 BEC 4 retirement; and
    f. Begin planning for solar sited at BEC, beginning around the time of the BEC 4 retirement. (Department)

3. Approve Minnesota Power's 2021 Plan from its initial February, 2021 filing with the following modifications:
    a. Require Minnesota Power to withdraw from the NTEC project and revoke the Commission's approval of the related affiliated interest agreements;
    b. Require retirement of the Hibbard plant in 2023; and
    c. Find a need for approximately 600 MW of solar by 2026. (CEO, CUB)

Nemadji Trail Energy Center (NTEC)

4. Make no determination regarding NTEC in this proceeding. Require MP to make a filing no later than 60 days following the final court ruling regarding NTEC. At a minimum the filing should include an explanation of MP's plans regarding NTEC along with a request for any Commission approvals necessary for MP to implement its plans. (Department)

5. Remove NTEC from Minnesota Power's resource plan and rescind the NTEC affiliated-interest agreements. (OAG, CEOs, Fond Du Lac - *same as decision option 3.a)*

Resource Acquisition

6. Open a separate proceeding to allow all stakeholders to address the size, type, and timing of any substitute/replacement generation for NTEC. (LPI, if NTEC is removed)

7. Require MP to use a bidding process for MP's future resource acquisitions as follows; MP shall:
    a. use a bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years;
    b. ensure that the RFP is consistent with the Commission's then-most-recent IRP order and direction regarding size, type, and timing unless changed circumstances dictate otherwise;
    c. provide the Department and other stakeholders with notice of RFP issuances;
    d. notify the Department and other stakeholders of material deviations from initial timelines;
    e. update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings;
    f. where MP or an affiliate proposes a project, engage an independent evaluator to oversee the bid process and provide a report for the Commission;
    g. request that the independent evaluator, if engaged, specifically address the impact of material delays or changes of circumstances on the bid process; and
    h. any RFP issued by MP must include the option for both PPA and BOT proposals unless the Company can demonstrate why either a PPA or BOT proposal is not feasible
    i. cap any ROFO offer made by MP at net book value; and
    j. ensure that any RFP documents for peaking resources issued are technology neutral. (Department, OAG)

8. Condition Minnesota Power's implementation of resource acquisitions upon a finding that it is pursuing cost-effective options for ratepayers at the time the resources are acquired. (LPI, Department)

Issues for the Next IRP

9. Require Minnesota Power to file its next IRP by November 1, 2024.

10. Direct MP to re-study the BEC 4 2030 retirement decision in the next IRP assuming the IRP is filed in 2024. (Department)

OR [choose 10 or 11, or neither]

11. Direct MP to re-study the BEC 4 2030 retirement decision and other retirement dates in the next IRP ~~assuming the IRP is filed in 2024~~. (Staff variant of Department recommendation)

12. Require Minnesota Power to conduct a sub-hourly, stochastic LOLP study of its next IRP preferred plan, thoroughly demonstrating that the reliability of the electrical grid is maintained as the system transitions to more intermittent resources. (LPI)

13. Require Minnesota Power to provide a service quality study of its next preferred plan. (LPI)

14. Require Minnesota Power to work with stakeholders to include an analysis in the next IRP that identifies the near-term steps needed to ensure Minnesota Power meets its customers' needs in a fashion compatible with 1.5°C pathways. (CEO)

15. Require Minnesota Power to work with stakeholders to develop a modeling construct that enables Minnesota Power, as part of its next resource plan, to model solar-powered generators connected to the company's distribution grid as a resource. Minnesota Power and stakeholders shall address the following factors in developing the modeling construct:
    a. using a "bundled" approach as is used to model energy efficiency and demand response;
    b. the costs borne by the utility and the costs borne by the customer;
    c. cost effectiveness tests; and
    d. other topics as identified by stakeholders. (CEO)

OR [choose 15 or 16, or neither]

16. Require Minnesota Power to track Xcel's ongoing stakeholder work to develop a modeling construct that enables Xcel, as part of its next resource plan, to model solar-powered generators connected to Xcel's distribution grid as a resource. In its next IRP Minnesota Power shall provide a timeline to incorporate a similar modeling construct that addresses the following factors after consultation with stakeholders:
    a. using a "bundled" approach as is used to model energy efficiency and demand response;
    b. the costs borne by the utility and the costs borne by the customer;
    c. cost effectiveness tests; and
    d. other topics as identified by stakeholders. (Staff modification of CEO)

17. Require Minnesota Power to take steps to better align distribution and resource planning, including:
    a. set the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan;
    b. conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level;
    c. proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources;
    d. improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Minnesota Power can take advantage of distributed energy resources to address discrete distribution system costs; and
    e. plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours. (CEO)

OR [choose 17 or 18, or neither]

18. Require Minnesota Power in its next IDP to provide information on how it could implement the following steps to better align distribution and resource planning:
    a. set the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan;
    b. conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level;
    c. proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources;
    d. improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Minnesota Power can take advantage of distributed energy resources to address discrete distribution system costs; and
    e. plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours. (Staff modification of CEO)

19. Require Minnesota Power to account for local clean energy goals, in aggregate, in forecasting and modeling. In particular, the plan should include consideration of local community generation goals for distributed generation in its next IRP. (CEO)

20. Require Minnesota Power's next IRP to include an analysis of the public health impacts, over the 15-year planning period, of its current generation fleet, its proposed plan, and other resource scenarios studied. The public health analysis should at minimum evaluate and quantify the health costs associated with fine particulate matter from coal and biomass power plants. (CEO)

21. Require Minnesota Power to, prior to the next IRP, conduct community outreach and establish a stakeholder group to:
    a. provide input on the public health analysis for the next IRP, including the methodology, results, and implications for Minnesota Power's resource plan;
    b. inform the design of electricity services and programs that improve equitable electricity delivery, improve customer access to energy efficiency and load-shaping programs, and improve customer access to DG and renewable energy. These services and programs should particularly focus on reducing disparities in energy burden, ensuring equitable access to low-income residents, and ensuring equitable access to Black, indigenous, and communities of color that have disproportionately borne costs of unjust and inequitable energy decisions;

    Order Minnesota Power, in its next IRP docket, and in a separate docket to be established by the Executive Secretary, to file details describing stakeholder outreach and progress on the above requirements by January 1, 2024, and annually thereafter. (CEO, CUB)

Other

22. Require Minnesota Power to commence planning the transmission system reliability mitigations needed to maintain the option of retiring the Boswell facility entirely, including unit 4, by no later than 2030. Require the Company to submit annual reports to the Commission beginning one year from the date of this order and continuing until the filing of the next IRP. Such reports must:
    a. describe work done to date and work yet to be completed, providing a schedule of expected milestones, and estimating the earliest date for completion of the transmission system reliability mitigations; and
    b. specifically evaluate converting Boswell 3 to a synchronous condenser upon retirement.

    (CEO)

23. Require Minnesota Power to file the results from its consultant led non-wires alternative study in the current IRP and IDP dockets. Require Minnesota Power to begin integrating NWS into all the company's planning practices, including its next IRP and IDP, with a focus on how NWS can help ameliorate the localized reliability needs of northern Minnesota when BEC 3 and 4 eventually retire. (CUB)

24. Within 180 days of the EPA's issuance of its final order, require Minnesota Power to submit a compliance filing that presents the utility's understanding of EPA's final Federal Implementation Plan (FIP) and an action plan in response to the final FIP. (Department)

25. Delegate authority to the Executive Secretary of the Commission to open a new docket on site development and remediation plans for the Boswell site. (Department, Cohasset)

26. Minnesota Power shall conduct stakeholder meetings regarding the site with interested parties including the City of Cohasset; adjacent cities and townships including the City of Grand Rapids, Itasca County; The Minnesota Department of Commerce, the Minnesota Department of Natural Resources, the Minnesota Pollution Control Agency, the Center for Energy and Environment, the Minnesota Energy Transition Office, and labor unions. By January 1, 2024 of the year following approval of this plan, Minnesota Power shall file in the new docket details describing updates on the site and the stakeholder outreach and meetings. (Department, Cohasset)

27. By December 31, 2024, or in its next resource plan if earlier—and annually thereafter—Minnesota Power shall submit to the Commission and to the City of Cohasset a detailed report describing the company's plans for disposition of the Boswell site, equipment, and buffer property. The report shall include at least the following items:
    a. To the extent possible, a detailed description of the timeline, estimated costs, and steps necessary to remediate pollution at the Boswell site.
    b. A section detailing how the company is working to ensure that plans for site remediation, economic development, or future development and maintenance of power generation, transmission, or distribution infrastructure are consistent with the community's long range planning and vision.
    c. A description of any ongoing efforts by the company to evaluate future uses for the plant site, any buffer property owned by the company, or any adjacent property, including a description of how the company is involving interested stakeholders in those efforts.
    d. An update to the Commission on the status of efforts to support the city's and region's economic development efforts, including—to the extent possible—specific projects and investments the company is assisting the City and region in attracting.
    e. A description of the company's efforts to work with local governments and
    f. Any other items the Commission or the company see fit to include

    (Department, Cohasset)

Staff Additions

28. In its next IRP, Minnesota Power shall include a societal cost-benefit analysis of the M.L. Hibbard Renewable Energy Center to analyze whether continuing the facility would provide an overall net benefit to Minnesota Power customers. The analysis shall consider system reliability, customer costs, environmental impacts, and host community impacts. (Staff)

29. MP shall make a compliance filing updating the Commission of the Company's final capacity position at least 30 days after MISO publishes the accredited capacity values. (Staff)

30. In developing its next resource plan, Minnesota Power shall consult with stakeholders, including but not limited to parties to the current proceeding, to develop analysis that shall inform its next IRP on the following topics: (Staff)
    a. [topics identified by the Commission – for examples see list in "Staff Discussion – Next IRP"]