**BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION**
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| In the Matter of Minnesota Power's 2021-2035 Integrated Resource Plan | MPUC Docket No. E015/RP-21-33<br>**REPLY COMMENT** |

The Large Power Intervenors ("LPI")[1] submit this reply comment in response to the current notice of comment period issued by the Minnesota Public Utilities Commission ("Commission") in MPUC Docket No. E015/RP-21-33 related to Minnesota Power's (or the "Company") pending 2021-2035 integrated resource plan ("2021 IRP" or when discussing resource planning generally "IRP").[2] LPI appreciates the thorough record created by the collective participation of various stakeholders in this proceeding. And LPI applauds the Company's efforts to develop an IRP that truly attempts to balance the many viewpoints expressed by stakeholders. The Company's Preferred Plan represents a reasonable compromise that best balances ratepayer cost, reliability, flexibility, and emissions reductions. Therefore, LPI submits this reply comment to express its continued support of the Company's 2021 IRP Preferred Plan.

## I. INTRODUCTION/BACKGROUND

On February 1, 2021, the Company filed its 2021 IRP. The filing of the 2021 IRP was the culmination of the Company's extensive stakeholder process, seeking valuable feedback from customers, host communities, labor groups, and environmental advocates.[3] The Company developed its preferred plan ("Preferred Plan"), which is the "next chapter in the Company's *Energy**Forward*** resource strategy"[4] based, in part, upon the feedback it received from interested stakeholders. The Preferred Plan is separated into a Short-Term Action Plan (2021 through 2025)

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[1] LPI is an *ad hoc* consortium of Large Power and Large Light and Power customers of Minnesota Power consisting for purposes of this filing of Blandin Paper Company; Boise White Paper, L.L.C., a Packaging Corporation of America company, formerly known as Boise, Inc.; Cleveland-Cliffs Minorca Mine Inc.; Enbridge Energy Limited Partnership; Gerdau Ameristeel US Inc.; Hibbing Taconite Company; Northern Foundry, LLC; Sappi Cloquet, LLC; USG Interiors, Inc.; United States Steel Corporation (Keetac and Minntac Mines); and United Taconite, LLC.

[2] Notice of Amended Reply Comment Schedule (July 13, 2022) (eDocket No. 20227-187377-01) (the "Notice").

[3] 2021 Integrated Resource Plan at 6 (Feb. 1, 2021) (eDocket No. 20212-170583-01) ("2021 IRP").

[4] *Id.* at 3.

and a Long-Term Plan (2026 through 2035). The Company's Short-Term Action Plan includes the following items:

- Retire the currently idled Taconite Harbor Energy Center in 2021;
- Construct three solar projects totaling approximately 20 MW;
- Adapt operations at the Boswell Energy Center Unit 3 ("BEC 3") to move to economic dispatch within the Midcontinent Independent System Operator ("MISO") market in 2021;
- Continue investigating and preparing to transition Boswell Energy Center Unit 4 ("BEC 4") to economic dispatch;
- Continue conservation and electrification efforts;
- Implement Demand Response Product C for industrial customers in 2022; and
- Add 200 MW of new wind resources by 2025.[5]

The Long-Term Plan includes:

- Retire BEC 3 by the end of 2029;
- Add 200 MW of solar that uses the Boswell site or other Company facilities by 2030;
- Pursue 50 MW of long-term demand response by 2030;
- Develop transmission solutions to address reliability issues associated with the early retirement of BEC 3; and
- Investigate options to refuel or remission BEC 4 as coal operations cease by 2035.[6]

After the filing of the 2021 IRP, stakeholders reviewed and analyzed the Company's plan throughout the remainder of 2021 and into 2022, filing initial comments on April 29, 2022, and supplemental comments on July 29, 2022.

While the initial and supplemental comments contain an array of opinions and options for consideration, the core issues of the 2021 IRP are summarized in the table below.

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[5] 2021 IRP at 14-15.

[6] *Id.* at 15.

**TABLE 1**[7]

| Minnesota Power 2021 IRP<br>Summary of Major Issues by Party | | | | | |
|---|---|---|---|---|---|
| **Party** | **Boswell 3 Retirement** | **Boswell 4 Retirement** | **NTEC** | **Other New Resources and/or Retirements** | **Supports MP's Preferred Plan** |
| Minnesota Power | 2029 | 2035 | Yes | 200 MW Wind 2025<br>200 MW Solar 2030 | Yes |
| Department of Commerce, Division of Energy Resources (Department) | 2025 | 2030 | Yes | 200-300 MW Wind 2024/2025<br>282 MW peaking resource 2026*<br>593 MW NGCC 2031*<br>100 MW Solar 2030+* | No |
| Large Power Intervenors (LPI) | 2029 | 2035 | Yes | N/A | Yes |
| Clean Energy Organizations (CEO) | 2029 | 2035* | No | Retire Hibbard in 2023<br>600 MW Solar 2024/2025<br>400 MW Wind 2029/2030*<br>100 MW Solar 2030*<br>168 MW 4 Hr Battery Storage 2030*<br>100 MW 10 Hr Battery Storage 2030*<br>100 MW Wind 2035*<br>16 MW 4 Hr Storage 2035* | No |
| City of Cohasset | 2029 | 2035 | Yes | N/A | Yes |
| City of Hoyt Lakes | 2029 | 2035 | Yes | N/A | Yes |
| IBEW Local 31 | 2029 | 2035 | Yes | N/A | Yes |
| IUOE Local 49 and Carpenters | 2029 | 2035 | Yes | N/A | Yes |
| LiUNA | 2029 | 2035 | Yes | N/A | Yes |
| Office of the Attorney General (OAG) | N/A | N/A | No | N/A | No |
| Citizens Utility Board (CUB) | N/A | N/A | N/A | N/A | No |
| Union of Concerned Scientists | 2030 | 2030-2035 | No | N/A | No |
| * Resource decision based on Encompass modeling, not an explicit recommendation in formal comments. | | | | | |

As demonstrated by Table 1 above, only a few primary issues remain in the 2021 IRP. The first is the Minnesota Department of Commerce, Division of Energy Resources' ("Department") potential support of the FastExit modeling scenario ("FastExit Scenario"), which accelerates retirement dates of BEC 3 and BEC 4 to 2025 and 2030, respectively,[8] adds 200-300 MW of wind in the 2024-2025 timeframe, and, based on modeling, potentially adds a 282 MW peaking resource (i.e., a natural gas combustion turbine or transmission) in 2026, a 593 combined-cycle natural gas unit in 2031, and 100 MW of solar after 2030.[9] The second concerns the Nemadji Trail Energy

[7] Reply Expert Report prepared by Brubaker & Associates, Inc. ("BAI") ("Ex. B") at 7.

[8] Ex. B at 7-9. The Department's supplemental comments suggest that its modeling supports BEC 3 and BEC 4 early retirements and various other resource additions; however, the Department notes that it will outline its final recommendations in reply comments after accounting for various policy considerations. Supplemental Comment by the Department at 53-54 (July 29, 2022) (eDocket No. 20227-187976-01) ("Department Supplemental Comment"). Citizens Utility Board of Minnesota ("CUB") also refrained from making a final recommendation in initial comments and intends to do so in its reply comment. Initial Comment by CUB at 21 (Apr. 29, 2022) (eDocket No. 20224-185378-02). LPI reserves the right to supplement the record in response to new recommendations submitted by any stakeholder in reply comments.

[9] Ex. B at 7-9.

Center ("NTEC") and resource determinations resulting therefrom.[10] Stakeholders opposed to NTEC raised questions relating to the cost, Company's ownership stake, resource need, and environmental review related to the facility.[11] While certain comments limited the analysis of NTEC to general opposition, Fresh Energy, Clean Grid Alliance, Sierra Club, and the Minnesota Center for Environmental Advocacy (collectively, the "CEOs") used EnCompass to create the CEO Scenario, which proceeds without NTEC and other new fossil fuel generation.[12]

Notwithstanding the differing opinions concerning the FastExit Scenario and NTEC, the Company's Preferred Plan is otherwise supported by a diverse set of stakeholders, which includes ratepayers, labor organizations, and host communities. In developing its Preferred Plan, the Company recognized the important role its infrastructure plays in host communities such as the City of Cohasset, BEC's host community.[13] Similarly, labor organizations also emphasized their reliance on the Company for the career opportunities associated with building and maintaining the Company's generating facilities.[14] The Company's stakeholder process worked to ensure that these "not traditionally heard" (especially true in the case of host communities) perspectives informed its planning process.[15] And the Company's laudable efforts are captured by the broad coalition of support for its Preferred Plan.

LPI has been an active participant in this docket, participating in stakeholder meetings, issuing information requests, and filing an initial comment and expert report on April 29, 2022.[16] For the instant reply comment, LPI continued coordinating with its experts from Brubaker & Associates, Inc. ("BAI") to assess initial and supplemental comments, as well as modeling filed

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[10] Consistent with its Initial Comment, LPI does not advocate for a specific outcome with respect to the range of decision options surrounding NTEC (i.e., 50% ownership, 20% ownership, or no NTEC). LPI, however, asserts that the considerable range of options surrounding NTEC should deter the Commission from making significant/early retirement decisions on BEC 3 and BEC 4 without a full understanding of the Company's available dispatchable capacity.

[11] *See, e.g.,* Initial Comment by the Minnesota Office of the Attorney General—Residential Utilities Division ("OAG") at 7 (Apr. 29, 2022) (eDocket No. 20224-185389-01) ("OAG Initial Comment").

[12] Initial Comment by the CEOs at 36-50 (Apr. 28, 2022) (eDocket No. 20224-185372-02) ("CEOs Initial Comment"); Supplemental Report by the CEOs (July 29, 2022) (eDocket No. 20227-187928-02) ("CEOs Supplemental Report"). More details of the CEO Scenario are summarized in Ex. B at 7, 9.

[13] 2021 IRP at 6.

[14] Initial Comment by the Laborers District Council of Minnesota and North Dakota ("LiUNA") at 1 (May 2, 2022) (eDocket No. 20224-185403-01) ("LiUNA Initial Comment"); CEOs Initial Comment at 14-36.

[15] 2021 IRP at 6.

[16] Initial Comment by LPI with Exhibit A (Apr. 29, 2022) (eDocket No. 20224-185385-02) ("LPI Initial Comment" or "Ex. A" when referring to BAI's Initial Report).

by other stakeholders. BAI's expert analysis and recommendations are attached hereto as Exhibit B.

After its comprehensive review of the record, LPI submits this reply comment to continue supporting the Preferred Plan in light of the Department's (or any other stakeholders') support of the FastExit Scenario[17] and other stakeholders' support of other plans that deviate from the Company's (e.g., the CEO Scenario). LPI is always appreciative of the Department's commitment to the pursuit of sound energy policy for Minnesotans. However, in this instance, the Preferred Plan represents the best path forward for northern Minnesota and the state generally. The Company's collaborative approach to the 2021 IRP created a unique coalition of stakeholders who, more or less, agree on the major issues at stake. The Preferred Plan represents a creative compromise that truly captures years of stakeholder participation. Furthermore, when compared to the FastExit Scenario applying the resource planning evaluation criteria set forth in Minn. R. 7843.0500, subp. 3, the Preferred Plan, despite departing from least-cost resource planning, balances ratepayer rates and bills, reliability, environmental concerns, flexibility, and risk. Alternatively stated, the Preferred Plan is in the public interest consistent with Minn. Stat. § 216B.2422, subd. 2(a). Therefore, based upon the technical analysis provided by BAI and application of relevant Commission rules, LPI urges the Commission to approve the Company's Preferred Plan.

## II. <u>ANALYSIS</u>

### A. The Preferred Plan Better Balances Minnesota Resource Planning Decision-Making Factors Compared to the FastExit Scenario

Minnesota Rule 7843.0500 governs the Commission's review of IRPs. Subpart three of the rule provides a list of factors that the Commission is obligated to consider in its evaluation of an IRP. Minn. R. 7843.0500, subp. 3 states that

> resource plans must be evaluated on their ability to: (A) maintain or improve the adequacy and reliability of utility service; (B) keep the customers' bills and the utility's rates as low as practicable, given

[17] *See* Department Supplemental Comment at 53-54. Although the Department qualified its modeling analysis results supporting the FastExit Scenario by asserting there are other "important policy considerations" that must also be considered and may influence the Department's final recommendations, LPI must assume the Department's Supplemental Comment supports the FastExit Scenario.

> regulatory and other constraints; (C) minimize adverse socioeconomic effects and adverse effects upon the environment; (D) enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and (E) limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

These factors apply to both the utility's resource plan, and any other plans submitted by intervenors.[18] As large industrial consumers of electric energy, LPI members' operations rely on consistent service quality, reliability, and reasonable rates. In other words, LPI members generally prioritize the decision-making factors set forth in Minn. R. 7843.0500, subpart 3(A) and (B).[19] As a result, LPI's initial analysis focused largely on cost, service quality, and reliability, and this analysis supported adopting the Preferred Plan compared to various other modeling scenarios presented by the Company.[20] This is not, however, to say that the benefits of the Preferred Plan are limited to cost and reliability. To be sure, there are also environmental, socioeconomic, and other factors that support the Preferred Plan. And when directly comparing the Preferred Plan to the FastExit Scenario, the Preferred Plan actually balances all of the evaluation criteria contained within Minn. R. 7843.0500, subp. 3; unlike the FastExit Scenario, the Preferred Plan does not place the majority of the weight on environmental factors. The CEO Scenario suffers similar deficiencies as the FastExit Scenario. The Preferred Plan should therefore be adopted.

### 1. The FastExit Scenario Does Not Keep Real Rates and Bills "as Low as Practicable"

As demonstrated by the Department's analysis, the FastExit Scenario is more expensive for ratepayers in terms of real dollars.[21]

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18 Minn. R. 7843.0300, subp. 11.

19 LPI Initial Comment at 4.

20 *Id.* at 3-7.

21 Department Supplemental Comment at 4. As noted by LPI in its Initial Comment and confirmed by the Department's data, the status quo plan is the least-cost plan without $CO_2$ and externalities modeling. *See* LPI Initial Comment at 4-6; *see also* Ex. A at 10-14.

**Dept Table 2. Department's total cost results for each Boswell retirement scenario (Conditions: Mid/Mid Carbon Future, Base Contingency)**

| 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 |

Comparing the revenue requirements of the Preferred Plan to the FastExit Scenario, the FastExit Scenario is approximately $200 million more expensive ($8.329 billion - $8.128 billion) than the Preferred Plan. Notably, on a revenue requirement basis, the Status Quo is more than $60 million less expensive ($8.128 billion - $8.062 billion) than the Preferred Plan. Though these projections do not include externalities values, they are important values to consider because the similarities in total plan cost estimates (i.e., revenue requirement + externalities) are driven by increased capital costs borne by ratepayers to achieve reduced externalities costs. Indeed, as acknowledged by the Department, "As the Boswell retirement scenario becomes more aggressive, revenue requirement internal costs increase and externalities costs decrease."[22] The FastExit Scenario is the most extreme representation of this result—the FastExit Scenario has the lowest externalities costs that are paid for by incurring the highest revenue requirement costs.

Given existing concerns with the Company's rates, most recently manifested in the form of an interim rate reduction for only some of the Company's customers,[23] the Commission should be hesitant to choose any plan that results in ratepayers paying more than necessary over the life of the plan. Even under the Preferred Plan, Large Power customer rates are projected to exceed $72 per MWh and Large Light & Power rates are projected at more than $94 per MWh.[24] And these figures do not account for other increases on the Company's system such as the $108.3 million increase pending in the current general rate case, which includes an unmitigated interim rate increase for most customers.[25] In light of these facts, the undeniable failure to achieve state

[22] Department Supplemental Comment at 5.
[23] *In the Matter of the Application by Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E015/GR-21-335, Order Setting Interim Rates at 7-8 (Dec. 30, 2021).
[24] LPI Initial Comment at 4-6.
[25] *See In the Matter of the Application by Minnesota Power for Authority to Increase Electric Rates for Electric Service in Minnesota*, MPUC Docket No. E015/GR-21-335.

policy directives under Minn. Stat. § 216C.05, subd. 2(4) for commercial and industrial rates, and specific direction in its own rules to minimize rate and bill impacts under Minn. R. 7843.0500, subp. 3(B), there should be little (if any) deviation from the least-cost plan (which in this case is the Status Quo). Only the Preferred Plan attempts to strike a balance. Adopting the FastExit Scenario, which would foist an additional $200 million of costs to ratepayers compared to the Preferred Plan, is not prudent in the current climate of increasing electric rates and unsupportable under the factors the Commission must consider in evaluating a resource plan under Minn. R. 7843.0500.

### 2. Adopting the FastExit Scenario Creates Reliability Concerns

Minn. R. 7843.0500, subp. 3(A) requires the Commission to consider whether an IRP maintains or improves reliability. To be clear, no plan should be approved that lessens, or may lessen, reliability. With the grid transitioning to more intermittent resources, LPI remains concerned that reliability could become an issue in the future. Maintaining the reliability of the grid requires a thoughtful approach to both generator retirements and resource additions and should be more closely examined.[26] LPI, therefore, continues to recommend that the Company conduct a sub-hourly, stochastic Loss of Load Probability ("LOLP") study of its preferred plan in its next IRP.[27]

As reliability relates to the 2021 IRP, the Commission should adopt a plan that maintains reliability while minimizing risk for the Company and ratepayers. The FastExit Scenario fails to strike any balance of these factors because it exposes customers to significant risk (i.e., the FastExit Scenario fails to maintain or improve reliability). Figure 4 of the Department's Supplemental Comment shows that the FastExit Scenario requires new resources in the 2026 and 2030 timeframes.[28] By 2026, the Company will require a significant transmission investment or a new combustion turbine to offset the loss of BEC 3.[29] Similarly, by 2030, the Company will also require either new transmission, a large combine-cycle gas plant, or two combustion turbines to maintain reliability under the FastExit Scenario.[30] Adopting a plan that expedites the retirement

26 LPI Initial Comment at 8.
27 *Id.*
28 Department Supplemental Comment at Attach. 2, Fig. 4.
29 *Id.*
30 *Id.*

of two of the Company's major dispatchable resources and proposes to replace that dispatchable capacity with new, not previously planned (likely natural gas) facilities, creates several reliability concerns.[31]

First, based on the Company's current NTEC timeline, it is unlikely that a new natural gas facility can be built by 2026. The Company first suggested a new natural gas plant during the 2015 IRP.[32] As a result of the 2015 IRP, the Company's NTEC-specific proceeding began in July of 2017,[33] and the Commission approved the Company's petition in 2019.[34] Following appellate review and other delays, NTEC is now set to become operational in 2027.[35] This means that NTEC (unless its approval is revoked) will not be used and useful until approximately a decade after the Company's specific petition. This delay underscores the difficulty of adding new fossil fuel generation on the Company's system and the ability to add a new gas resource by 2026 is an unreasonable assumption.

Second, delays in MISO mean that it is unrealistic to assume that the Company's system will operate reliably under the FastExit Scenario. BAI analyzed the current interconnection timelines provided on the MISO website and found that the process is taking significantly longer than expected.[36] BAI's analysis shows that, in recent years, the process takes an average of 800 days to complete.[37] The numbers are even more severe when looking at completed Generator Interconnection Agreements ("GIA") reaching resolution within the last 12 months, where BAI's analysis shows that the timeline from application to GIA is around 1,232 days.[38] Furthermore, the average time from application to in-service date is approximately 1,872 days or over five years.[39] The upshot of these delays is that new generation resources likely cannot be placed in service until the 2027 to 2028 timeframe.[40] Because the FastExit Scenario calls for new dispatchable capacity

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31 *See* Ex. A at 15-16.

32 *In the Matter of Minnesota Power's Petition for Approval of the EnergyForward Resource Package*, MPUC Docket No. E015/AI-17-568, Order Approving Affiliated-Interest Agreements with Conditions at 1 (Jan. 24, 2019) ("NTEC Order").

33 *Id.*

34 *Id.* at 29.

35 *See* MISO Correspondence attached to Letter by Minnesota Power (Aug. 5, 2022) (eDocket No. 20228-188143-01).

36 Ex. B at 16-19.

37 *Id.*

38 *Id.*

39 *Id.*

40 *Id.*

prior to 2027 (i.e., a 282 MW peaking resource),[41] LPI is concerned that adopting the FastExit Scenario will result in significant reliability concerns due to the inability to procure replacement generation.

Third, approval of the FastExit Scenario could expose ratepayers to market pricing. MISO currently projects that it will have a capacity deficit of 2.6 GW below the 2023 Planning Reserve margin, which is restricted to the MISO North/Central region.[42] If there is a capacity shortage, net short utilities are exposed to the clearing price of Cost of New Entry ("CONE") for the planning year (i.e., they become a net importer subject to the market). The CONE price in the North/Central MISO region is $236.66/MW-Day for the 2022/2023 Planning Resource Auction ("PRA"). The Commission should be hesitant to approve any resource plan that increases the likelihood of leaving MP in a net short capacity position due to inherent reliability concerns and potential market pricing exposure.[43]

Finally, notwithstanding issues building new generation or acquiring resources from the market, current conditions in MISO may preclude early retirement of BEC 3 and/or BEC 4. Under certain conditions, MISO may characterize a resource as a System Support Resource ("SSR"). This designation allows MISO to continue operating units that would otherwise be retired because they are needed for reliability.[44] The retirement feasibility study (Y-2) conducted by MISO suggests that both BEC 3 and BEC 4 require significant replacement/mitigation solutions prior to retirement and could be designated as SSRs unless mitigation measures are implemented.[45] Due to the current delays in MISO, adequate mitigation measures are unlikely to be available on the timeline required for the FastExit Scenario, meaning that BEC 3 may be required to continue operating as an SSR.[46]

The foregoing analysis illustrates that approval of the FastExit Scenario could lock ratepayers into a situation where expected resource additions are challenged or delayed[47] creating both reliability and cost concerns as the Company would likely need to import capacity, ultimately

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41 *Id.*
42 *Id.*
43 Ex. B at 19-20.
44 *Id.*
45 *Id.*
46 *Id.*
47 Ex. B at 16-20.

leading to increased costs.[48] Alternatively, based on MISO's analysis, there is the potential that the retirements contemplated by the FastExit Scenario will not be allowed due to reliability needs. In short, applying the criteria in Minn. R. 7843.0500, subp. 3(A) to the FastExit Scenario and the Preferred Plan, the Preferred Plan outperforms the FastExit Scenario based on the ease by which the Company is able to maintain reliability.

### 3. Applying Minnesota Rule 7843.0500, Subparts 3(C) to (E) and Comparing the Preferred Plan to the FastExit Scenario, Demonstrates That the Preferred Plan Better Balances the Commission's Required Decision-Making Factors

Minn. R. 7843.0500, subparts 3(C) to (E) require the Commission to evaluate the IRP on its ability to minimize adverse socioeconomic effects and environmental impacts, create flexibility from technological, financial, and social standpoints, and limit risk to the utility and its customers. Comparing the Preferred Plan to the FastExit Scenario under this criteria, the Preferred Plan better preserves flexibility, and both ratepayer and utility protections, while maintaining aggressive $CO_2$ reductions.

Again, the Preferred Plan far surpasses statutory requirement and the timeline exceeds current statutory goals, satisfying the renewable portfolio standards and achieving an 80% reduction of greenhouse gas emissions by 2035, a full 15 years before the 2050 goal set forth in Minn. Stat. § 216H.02, subd. 1. Additionally, the Preferred Plan is supported by host communities, ratepayer groups, and labor organizations, confirming that it is appropriately balancing important socioeconomic considerations.[49] Conversely, the FastExit Scenario almost certainly requires natural gas additions, which will complicate the Company's ability to decarbonize in decades to come and/or potentially leave ratepayers paying for stranded, early-retired assets.[50] And the record is devoid of any socioeconomic analysis supporting the FastExit Scenario.

The Preferred Plan, on the other hand, provides more flexibility for the Company, which serves the public interest looking forward. As previously discussed, the FastExit Scenario

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[48] Ex. B at 18-19.

[49] *See* Ex. B at 7.

[50] *See* Ex. B. at 13. More aggressive carbon reduction mandates represent a very real possibility. At the state level, the Walz Administration has set the goal of reaching 100% carbon free electricity by 2040. President Biden's Administration is even more ambitious, setting the goal for 100% carbon free electricity by 2035. *See* Initial Comment by the Minnesota Office of the Attorney General—Residential Utilities Division ("OAG") at 7 (Apr. 29, 2022) (eDocket No. 20224-185389-01).

immediately locks the Company into a variety of resource additions and it is reasonably likely such additions require another large natural gas facility on the Company's system.[51] This outcome binds the Company, its ratepayers, and communities into a technological outcome that forces costs upon ratepayers and forces host communities to make difficult transitions earlier than planned.[52] Conversely, the Preferred Plan allows the Company to address resource additions in a future IRP, creating more time and flexibility to incorporate technological advancements that may benefit ratepayers and the environment.[53] Further, maintaining operations at BEC 3 and BEC 4 provides additional time for host communities to prepare for the loss of significant infrastructure and local tax base.[54]

Lastly, the FastExit Scenario presents risks to both the Company and ratepayers. The FastExit Scenario quickly shifts the Company's dispatchable capacity to natural gas generation. The lasting impacts of Winter Storm Uri underscore concerns with this approach. During the extreme weather event, utilities incurred significant costs associated with providing reliable natural gas service to Minnesotans. These costs are now being borne by ratepayers who are paying approximately 90% of the costs associated with extreme weather.[55] The utilities were also not immune as the Commission ordered them to absorb a portion of the costs associated with Winter Storm Uri as well.[56] The FastExit Scenario increases the state's reliance on natural gas, and by extension, the potential impact of extreme pricing events. In light of recent events surrounding natural gas supply and generation in the state, LPI cautions against approval of an IRP that increases reliance on natural gas.[57]

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[51] Ex. B at 7, 11-14.

[52] *See, e.g.*, Initial Comment by the City of Cohasset at 1-2 (Apr. 29, 2022) (eDocket No. 20224-185379-01) ("Cohasset Initial Comment").

[53] Ex. B at 11-14.

[54] *See* Reply Comment by the City of Cohasset at 6 (Aug. 26, 2022) (eDocket No. 20228-188618-01).

[55] *See In the Matter of a Commission Investigation into the Impact of Severe Weather in February 2021 on Impacted Minnesota Natural Gas Utilities and Customers*, MPUC Docket No. G-999/CI-21-135.

[56] Press Release: Minnesota Public Utilities Commission, Minnesota Public Utilities Commission Reduces Costs to Consumers by $58.5 Million from 2021 Natural Gas Spike (Aug. 11, 2022) https://content.govdelivery.com/bulletins/gd/MNPUBUC-327b20b?wgt_ref=MNPUBUC_WIDGET_2.

[57] Ex. B. at 11-13.

## B. The Early Retirements and Resource Alternatives Contemplated by the CEO Scenario Create Reliability Concerns and Lack Record Support

The CEOs also oppose the Company's Preferred Plan and instead advocate for the CEO Scenario. Within the Short-Term Action Plan time period, the CEO Scenario recommends retirement of the Hibbard plant in 2023 and 600 MW of solar by 2026.[58] The CEOs also recommend that the Commission revoke its prior approval of NTEC, which then triggers additional resource needs later in the 2020s.[59] The CEOs claim that the CEO Scenario (which does not allow for new fossil fuel generation additions) "performs well in comparison to the Revised MP Preferred Plan."[60] However, for many of the reasons previously articulated with respect to the FastExit Scenario, LPI opposes the CEO Scenario.

The CEO Scenario fails to satisfy the reliability evaluation criterion set forth in Minn. R. 7843.0500, subp. 3(A). Namely, the CEO Scenario does not satisfactorily demonstrate how it can safely and reliably serve the Company's system, which maintains an 80% load factor and approximately 60% industrial load.[61] Current project timelines within MISO make it highly unlikely that an additional 600 MW of solar could be built by 2026.[62] LPI is also concerned with the reliability implications of removing existing or planned dispatchable resources (Hibbard and NTEC) without providing viable dispatchable generation to replace it.[63] Minn. R. 7843.0500, subp. 3(A) requires the Commission to evaluate an IRP based upon the ability to "maintain or improve the adequacy and reliability of utility service." To be sure, removing existing or approved dispatchable capacity without similar replacements, cannot demonstrably improve or even maintain reliability and CEO Scenario should, therefore, be rejected.

Relatedly, because the CEO Scenario requires the removal of NTEC, the record is insufficient to approve the remainder of the CEO Scenario. The Company did not conduct its own modeling with respect to NTEC.[64] Without the Company assessing its own resource mix under a

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58 CEOs Initial Comment at 80.

59 CEOs Initial Comment at 80; CEOs Supplemental Report at 11.

60 CEOs Supplemental Comment at 11. The Revised MP Preferred Plan is a plan modeled by the CEOs reflecting the Company's proposed reduced share of NTEC.

61 Ex. B at 14-16. BAI's analysis revealed potential reliability issues associated with the CEO Scenario.

62 *Id.*

63 *Id.*

64 *See, e.g.*, Company Response to LPI Information Request No. 28 (Jan. 10, 2022) (eDocket No. 20221-181339-01).

scenario with no NTEC, the record is incomplete. LPI, however, notes that several stakeholders filed comments seeking reconsideration of the Commission's prior approval of NTEC,[65] and that the Commission may elect to reassess NTEC in this proceeding.[66] If the Commission chooses to, in fact, 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.

## III. <u>CONCLUSION</u>

LPI is grateful for the opportunity to submit this reply comment and expert analysis in response to the 2021 IRP. LPI is proud to have been a part of the collaborative effort initiated by the Company in this proceeding. Consistent with its initial comment, LPI continues its support of the Preferred Plan. Although not least cost in terms of ratepayer impacts, the Preferred Plan represents a reasonable approach and thoughtful compromise that best balances the diverse interests of the Company's stakeholders. Therefore, LPI requests that the Commission adopt the following proposals which are set forth in further detail in LPI's initial comment, expert reports, and below:

- Approve the Company's Preferred Plan subject to the following amendments and reservations:
  - Require that the Company make an affirmative showing of cost-effectiveness during the approval process for specific wind and solar resources contemplated by the Preferred Plan;
  - Require the Company 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; and
  - Require the Company to provide a service quality study of its next preferred plan.

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65 *See* OAG Initial Comment; CEOs Initial Comment at 80.

66 Given the range of proposals surrounding NTEC and the Company's confirmation that early retirement of BEC 3 and no NTEC could lead both capacity and energy needs, the Commission should be cautious about accelerating retirements based upon the incomplete record before it. Company Response to LPI Information Request No. 41 (Aug. 12, 2022) (eDocket No. 20228-188311-02).

- Alternatively, should the Commission update/revise its approval of NTEC in this proceeding, LPI requests that the Commission open a separate proceeding to allow all stakeholders to address the size, type, and timing of any substitute/replacement generation.

Dated: August 29, 2022

Respectfully submitted,

STOEL RIVES LLP

*/s/ Andrew P. Moratzka*

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ATTORNEYS FOR THE LARGE POWER INTERVENORS

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# EXHIBIT B

Exhibit B

# Expert Reply Report Supporting Minnesota Power's 2021 Integrated Resource Plan

Prepared by

Brubaker & Associates, Inc.

Final Report
August 29, 2022

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

# Expert Reply Report Supporting Minnesota Power's 2021 Integrated Resource Plan

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# Expert Reply Report Supporting Minnesota Power's 2021 Integrated Resource Plan

## I. Executive Summary

After conducting a thorough review of the initial comments and supplemental filings submitted by other stakeholders in response to Minnesota Power's ("MP") 2021 Integrated Resource Plan ("2021 IRP" and when referring to integrated resource plans generally, "IRP"), Brubaker & Associates, Inc. ("BAI") maintains its initial recommendation that the Minnesota Public Utilities Commission ("MPUC" or "Commission") should approve Minnesota Power's preferred plan ("Preferred Plan").

BAI's analysis demonstrates that MP's Preferred Plan is a reasonable approach that appropriately considers environmental concerns and host community impacts in its departure from least-cost resource planning. Some near-term highlights of the plan include: the transition of Boswell Energy Center Unit 3 ("Boswell 3") from a must-run unit to an economic dispatch unit and the construction of 20 MW of solar. The longer-term elements of the plan include the retirement of Boswell 3 at the end of 2029, addition of 200 MW of solar at the Boswell site, and development and implementation of transmission solutions to address the reliability issues that would otherwise arise due to the early retirement of Boswell 3. MP will also investigate opportunities to refuel or remission Boswell Energy Center Unit 4 ("Boswell 4") by 2035, including any necessary transmission reliability upgrades.

In response to MP's Preferred Plan, certain parties, such as the Department of Commerce, Division of Energy Resources ("DOC") and the Clean Energy Organizations ("CEO"), provided alternative resource scenarios that do not, based on BAI's analysis, fully consider the various planning factors that should be analyzed for an approved resource plan. The DOC recommended the Fast Exit scenario, which calls for more aggressive retirements for Boswell 3 and 4 and 200-300 MW of new wind resources by 2025. At a high level, the CEO's preferred scenario calls for removal the Nemadji Trail Energy Center ("NTEC") from MP's resource portfolio and requires 600 MW of solar by 2026. As demonstrated by BAI's analysis below, these proposals are impractical and not feasible. For example, current Midcontinent Independent System Operator ("MISO") interconnection delays will create reliability issues, because new generation resources will likely be unable to reach the grid prior to 2027/2028. Additionally, the Fast Exit scenario is also significantly more expensive than MP's Preferred Plan when the externality costs are removed from consideration. The CEO scenario suffers similar deficiencies.

BAI's initial analysis revealed that MP's Preferred Plan, on the other hand, is a thoughtful and reasonable approach that accounts for a variety of factors of resource planning. Additionally, after review of other parties' initial and supplemental filings, BAI's analysis demonstrates that none of the suggested alternatives provide a better outcome, for ratepayers, communities, and the environment. Therefore, MP's Preferred Plan continues to be a reasonable approach, and BAI maintains its initial recommendation that the Commission adopt MP's Preferred Plan.

## II. Background

### a. *Minnesota Power IRP*

In the 2021 IRP, MP presented its Preferred Plan which, if approved, will achieve an 80% reduction in carbon emissions by 2035. The Preferred Plan is separated into two parts, a Short-Term Action Plan (2021 through 2025) and a Long-Term Plan (2026 through 2035). The actions included in the Short-Term Action Plan were proposed to meet load requirements while reducing carbon emissions and adding renewable resources to the portfolio. These actions include the following:

- Retire Taconite Harbor Energy Center, which has been idled since 2016.
- Construct 20 MW of solar in 2021.[1]
- Move Boswell 3 from a must-run unit to economic dispatch.
- Investigate moving Boswell 4 to economic dispatch in coordination with MISO and the joint owner.
- Continue conservation and electrification programs.
- Implement the Product C Demand Response program for industrial customers in 2022 enabling between 100 and 202 MW of demand response product to be sold each year from 2022 to 2028.[2]
- Add 200 MW of new wind resources to MP's power portfolio.

The Long-Term Action Plan will achieve further carbon emission reductions as well as adopt a range of economic and environmental futures. These actions include the following:

- Retire Boswell 3 by December 31, 2029.
- Add 200 MW of solar at the Boswell site or other MP facilities to leverage existing grid interconnections and reinvest in the host community.
- Collaborate with industrial customers to pursue 50 MW of long-term demand response product by 2030.
- Develop and implement transmission solutions that address the reliability issues that arise due to the early retirement of Boswell 3.

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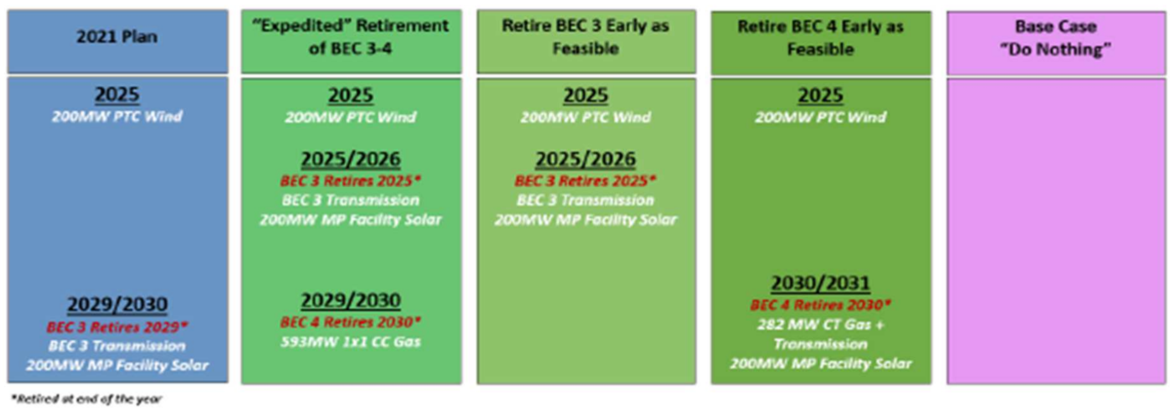
[1]Plants are under construction and expected to be operational this year.
[2]Product Cwas already approved by the MPUC. *See* MPUC Docket No. E015/M-21-28.

- Investigate the refuel or remission options for Boswell 4 by 2035, as well as the necessary transmission reliability upgrades.

To support the 2021 IRP, MP modeled five separate resource portfolios across six distinct futures. The five portfolios, or swim lanes, are summarized below.

**FIGURE 1**

**Figure 14: Alternative Power Supply Portfolios ("Swim Lanes") Evaluated in Step 2**




The six futures models reflect different levels of carbon and environmental costs. These futures are summarized in Figure 2 below.

**FIGURE 2**

**Table 2: Six Futures Considered in 2021 IRP Analysis**

| | | 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 | - | - | - | - | - |

BAI reviewed the modeling and concluded that MP correctly utilized the EnCompass Power Planning Software.[3] Additionally, based on MP's modeling BAI developed its initial expert report which was filed as Exhibit A to the initial comments submitted by the Large Power Intervenors ("LPI").

*b. <u>LPI Initial Comments</u>*

LPI filed an initial comment on April 29, 2022, including BAI's Initial Report (attached as Exhibit A to LPI's initial comment). In developing our Initial Report, BAI conducted a thorough investigation into the modeling and assumptions used to support MP's plan. Our Initial Report provided detailed analysis supporting our finding that the short- and long-term action plans proposed by MP represent a reasoned approach that balances important policy and environmental considerations despite deviating from least-cost resource planning. Our conclusions and recommendations, which have not changed, were as follows:

**Conclusions**

- 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, which are the costs passed on to ratepayers (i.e., the costs that appear on customers' bills), are considered.
- Externalities and regulation costs, mainly consisting of carbon dioxide, environmental and regulation costs, account for over 20% of the costs reported in the 2021 IRP. These externalities and regulation costs are not actually incurred by MP or included in MP's customer rates.

[3] BAI Initial Report at 1, 5-13 ("Initial Report").

- MP's Preferred Plan in the 2021 IRP is a reasonable approach that balances both policy considerations and environmental concerns, justifying the departure from least-cost resource planning.

**Recommendations for the Current IRP**

- The Preferred Plan is the best option for MP and stakeholders and should be adopted subject to the additional recommendations set forth below.
- Any plan that would prescribe more aggressive retirement schedules than the Preferred Plan should be rejected because of both cost and/or reliability concerns.
- At the time MP seeks approval of specific wind and solar resources contemplated in the Preferred Plan, MP should be required to demonstrate the specific proposal is cost effective in order to maximize flexibility and minimize rate increases in adding these resources to the system.

**Recommendations for Future IRP Proceedings**

- MP should be required to conduct a sub-hourly, stochastic Loss of Load Probability ("LOLP") study on its next preferred plan, thoroughly demonstrating that the reliability of the electrical grid is maintained on a system with far less firm, dispatchable generation and far more reliance on intermittent renewable resources to serve MP's load.
- MP should also 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% of the energy requirements and an 80% system load factor.

*c. <u>Positions of the Parties</u>*

Like LPI, other parties filed initial comments on April 29, 2022. There is significant support for MP's Preferred Plan from a number of parties, including LPI, the City of Hoyt Lakes, the City of Cohasset, IBEW Local 31, IUOE Local 49 and Carpenters, and LiUNA. Notably, support for the Preferred Plan encompasses a diverse group of stakeholders including labor, host communities, and ratepayers.

Conversely, other parties are opposed to various aspects of the Preferred Plan. For example, the Minnesota Office of the Attorney General ("OAG") recommends that NTEC be removed form MP's portfolio, but has not taken a position on other issues. The Union of Concerned Scientists recommends that NTEC be removed from MP's resource portfolio and the complete shutdown of Boswell be completed on an accelerated timeline. Lastly, the DOC and CEO each proposed different resource portfolios. We have summarized the positions of the parties below in Table 1.

**TABLE 1**

**Minnesota Power 2021 IRP**
**Summary of Major Issues by Party**

| Party | Boswell 3 Retirement | Boswell 4 Retirement | NTEC | Other New Resources and/or Retirements | Supports MP's Preferred Plan |
|---|---|---|---|---|---|
| Minnesota Power | 2029 | 2035 | Yes | 200 MW Wind 2025<br>200 MW Solar 2030 | Yes |
| Department of Commerce, Division of Energy Resources (Department) | 2025 | 2030 | Yes | 200-300 MW Wind 2024/2025<br>282 MW peaking resource 2026*<br>593 MW NGCC 2031*<br>100 MW Solar 2030+* | No |
| Large Power Intervenors (LPI) | 2029 | 2035 | Yes | N/A | Yes |
| Clean Energy Organizations (CEO) | 2029 | 2035* | No | Retire Hibbard in 2023<br>600 MW Solar 2024/2025<br>400 MW Wind 2029/2030*<br>100 MW Solar 2030*<br>168 MW 4 Hr Battery Storage 2030*<br>100 MW 10 Hr Battery Storage 2030*<br>100 MW Wind 2035*<br>16 MW 4 Hr Storage 2035* | No |
| City of Cohasset | 2029 | 2035 | Yes | N/A | Yes |
| City of Hoyt Lakes | 2029 | 2035 | Yes | N/A | Yes |
| IBEW Local 31 | 2029 | 2035 | Yes | N/A | Yes |
| IUOE Local 49 and Carpenters | 2029 | 2035 | Yes | N/A | Yes |
| LiUNA | 2029 | 2035 | Yes | N/A | Yes |
| Office of the Attorney General (OAG) | N/A | N/A | No | N/A | No |
| Citizens Utility Board (CUB) | N/A | N/A | N/A | N/A | No |
| Union of Concerned Scientists | 2030 | 2030-2035 | No | N/A | No |

* Resource decision based on Encompass modeling, not an explicit recommendation in formal comments.

*i. The Department of Commerce*

In their Initial comment, DOC opposed MP's Preferred Plan.[4] The DOC recommended that the Commission approve the Fast Exit scenario which has Boswell 3 retiring in 2025 and Boswell 4 retiring in 2030. In addition to retiring Boswell 3 and 4, the DOC recommended that 200-300 MW of new wind resources be on-line in the 2024 to 2025 time frame. The DOC based this recommendation off of its own Encompass modeling showing that the least-cost runs tended to be in scenarios where both Boswell units were retired early.[5]

On July 29, 2022, the DOC submitted supplemental comments stating that the Fast Exit scenarios had been re-run because the "overnight capital costs" associated with the thermal unit options addressing the Boswell-area bulk system issues had not been included in the Department's runs submitted with the April 29, 2022, initial comments. This led Encompass to have a bias towards adding thermal units and making the Fast Exit scenario the least cost plan.[6] After submitting the corrected runs, the DOC concluded that, when <u>including</u> carbon externality costs, the Fast Exit scenario remained the least cost plan. Along with their conclusion, the DOC had the following recommendations for MP:

- Acquire 200 to 300 MW of wind in the 2024 to 2025 time frame.
- Retire Boswell 3 in 2025, and acquire a 282 MW peaking resource to come online in 2026.

[4] In its Supplemental Comment, the Department qualified its initial analysis supporting the Fast Exit scenario by asserting there are other "important policy considerations" that must also be considered and may influence the Department's final recommendations. For purposes of this analysis, BAI, however, assumes the Department's continued support of the Fast Exit scenario.

[5] Minnesota Department of Commerce Comments (Apr. 29, 2022) (eDocket No. 20224-185342-01) pg. 2.

[6] Minnesota Department of Commerce Supplemental Comments (July 29, 2022) (eDocket No. 20227-187976-01) pg. 2.

- Retire Boswell 4 in 2030, and ensure that the Tranche 1 Long Range Transmission Plan ("LRTP")[7] continues to be a sufficient Boswell 4 retirement mitigation measure. If, however, LRTP is insufficient in this regard, MP should acquire a 593 MW of gas combined-cycle resource by 2031.

- Acquire 100 MW of solar sited at Boswell in the post-2030 time frame, using existing Boswell interconnection rights; and

- Potentially acquire demand-response and wind resources in the post-2030 time frame.[8]

While these are the recommendations captured by DOC's filings thus far, BAI acknowledges that these are subject to change based on reply comments.

*ii. Clean Energy Organizations*

The CEO also filed comments opposing the MP Preferred Plan. The CEO argues that current decarbonization goals make investing in and depending on NTEC and Boswell inherently risky.[9] In place of the MP Preferred Plan, CEO presented its own scenario, the CEO scenario.[10] The CEO scenario removes NTEC, retires Hibbard in 2023, retires Boswell 3 in 2030, adds 700 MW of solar, adds 500 MW of wind, adds 184 MW of 4-hour battery storage, and adds 100 MW of 10-hour battery storage.

*iii. Nemadji Trail Energy Center*

As previously discussed, various parties oppose NTEC. In addition to general opposition relating to the facility, there have been multiple developments that have created more uncertainty surrounding NTEC. First, the United States Environmental

[7] The LRTP includes 18 new transmission projects in MISO's Midwest Subregion that are part of a $10.3 billion investment that was approved by the MISO Board of Directors, and will allow up to 53 GW of new transmission to connect to the transmission grid.

[8] BAI understands that LPI has previously worked with MP on demand-response proposals.

[9] Clean Energy Organizations Comments (Apr. 29, 2022) (eDocket No. 20224-185372-02) pg. 12.

[10] The Revised MP Preferred Plan is a scenario in which all of the CEO's modeling assumption cost and input changes are applied, but key elements of MP's Preferred Plan are included – namely, NTEC (at 20% ownership) and Hibbard.

Protection Agency ("EPA") recently filed comments with the United States Department of Agriculture's Rural Utilities Services ("RUS") regarding the Supplemental Environmental Assessment ("EA") prepared for NTEC.[11] Within these comments, the EPA states that the Supplemental EA does not fully quantify or adequately disclose the impacts of Greenhouse Gas ("GHG") emissions from the NTEC project over its anticipated lifetime. The EPA recommends an updated analysis of GHG emissions, which should include quantified estimates for all indirect GHG emissions reasonable and foreseeable including those from production, processing, and transmission of natural gas. In addition to GHG analysis, the EPA also provided the following recommendations regarding the Supplemental EA:

- Consider regulatory, policy, and energy transition trends that will affect new plants, as well as appropriate mitigations.
- Consider project modifications to address all practicable mitigation measures.
- Require a Social Cost of Greenhouse Gases analysis to accurately reflect NTEC's monetized costs, incorporating climate impacts from both direct and indirect GHG emissions.
- Consider and disclose climate resilience and adaptation planning in NTEC's design.
- Address Tribal and environmental justice concerns and mitigate disproportionate impacts.

Second, and related to the EPA's comments, MISO also filed comments to the RUS relating to NTEC. MISO's comments underscore the need for dispatchable capacity and state, in part, that:

[11] EPA Comments (Aug 8, 2022) (eDocket No. 20228-188197-01).

> 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. MISO currently faces declining levels of resource capacity which is challenging its ability to supply electricity to customers within the MISO Northern region, where the NTEC Project sits. Given the existing and projected regional supply situation, resources are needed to provide capacity and transmission grid stability to meet the system's needs. Even with the recognized growth of alternative and renewable energy sources, MISO continues to be concerned about the looming shortfall of generation needed to ensure grid reliability in the region. Within the MISO region, the retirement of generation plants is occurring far faster than new energy sources with equivalent attributes, whatever the fuel source, can be developed, constructed and brought online. The future of the electric grid and associated electric markets depend upon resource availability, flexibility and visibility.

MISO's letter underscores the need for dispatchable resources like NTEC in order to maintain the stability of the power grid as it transitions to more intermittent resources.

Lastly, in addition to ongoing review of NTEC, various other changes also contribute to the uncertainty surrounding the project. These changes include: (1) delaying the in-service date until March 2027; and (2) MP's announcement that it sold 60% of its stake in NTEC, leaving it with approximately 120-130 MWs of installed capacity.[12]

## III. <u>Response to Initial and Supplemental Comments</u>

### *a. Minnesota Department of Commerce*

BAI does not believe the Fast Exit scenario proposed by the DOC is in the public interest for several reasons. First, BAI disagrees with the DOC's cost assessment of the Fast Exit scenario. The DOC concludes that the Fast Exit retirement scenario is the least-cost plan, but this is only the case when externality costs are included. As BAI

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[12] As of now, the MPUC's sale has not been analyzed by the MPUC.

previously articulated, MP does not incur, nor do customers currently pay, externalities costs. These costs represent over 20% of the reported costs and, when included, the results are skewed away from the Preferred Plan. When there are no externality costs assumed, the DOC's models show that the Status Quo is the least cost plan and the Fast Exit scenario is the highest-cost plan.[13] In its assessment of the DOC's recommendations, BAI examined the costs contained in tables 6A, 11A, 12A, and 13A of DOC's supplemental report.[14] BAI's findings show that the removal of externality costs results in the Fast Exit scenario being more expensive than MP's Preferred Plan (i.e., the ratepayers pay more in terms of actual rates and bills). On average, the 24 Fast Exit scenarios examined by BAI were $280 million higher than Preferred Plan scenarios, when the externalities were excluded.

In addition to cost concerns, BAI is concerned that the new resource additions contemplated by the Fast Exit scenario cannot be achieved in the necessary time frame, exposing customers to market risk. The DOC's suggestion that MP can add 200-300 MW of wind in the 2024 to 2025 time frame and 282 MW of a peaking resource in 2026 does not seem plausible given MISO interconnection delays, which are discussed later in this report.[15]

Lastly, under the Fast Exit scenario, the DOC recognizes the need for replacement generation post-2030 to replace Boswell 4. As discussed above, the DOC's modeling and comments suggest that this replacement comes in the form of

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[13]Minnesota Department of Commerce Supplemental Comments (July 29, 2022) (eDocket No. 20227-187976-01) pg. 4; BAI also completed a thorough analysis of the implications of regulatory and externalities costs in its Initial Report. *See* Initial Report at 10-14.

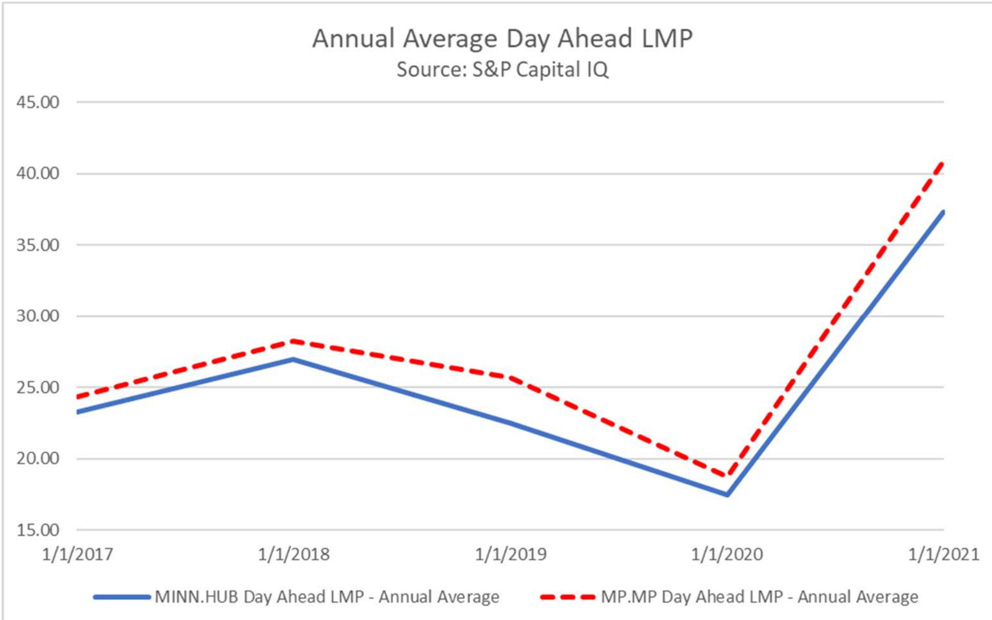
[14]Minnesota Department of Commerce Supplemental Comments (July 29, 2022) (eDocket No. 20227-187976-01) pg. 33-34.

[15]BAI acknowledges that the Preferred Plan also calls for 200 MW of wind by 2025; however, because both Boswell 3 and 4 remain on the system, BAI does not have the same reliability concerns.

either a new 593 MW natural gas combined cycle unit or the LRTP. With respect to a new natural gas facility, with existing decarbonization goals in Minnesota and beyond, BAI is concerned that adding a new natural gas resource may not be an option. MP's experience with NTEC already underscores that difficulty of adding new natural gas in the state. Additionally, BAI is concerned that committing to another large natural gas facility around 2030 will harm ratepayers, because of the likely abbreviated operational life of the facility, which could be under a decade. BAI believes that operating a natural gas facility for such a short time will likely lead to stranded costs associated with a relatively young power plant not being used or useful.

Alternatively, if the transmission solution is sufficient to reliably replace Boswell 4, this solution is one that leaves MP highly exposed to market risk resulting in higher energy prices for MP's customers. A review of the annual average market prices for the MP load zone compared to the Minnesota Hub, shows that MP's load zone averages 8% more expensive than the Minnesota Hub over the past five years. *See* Figure 3 below.

**<u>FIGURE 3</u>**




In short, MP's customers are likely harmed if the utility is forced into a resource plan that increases reliance on the market, increasing the cost concerns associated with the Fast Exit scenario.

BAI's analysis uncovered significant cost and reliability concerns with the Fast Exit scenario. At a basic level, the Fast Exit scenario is already more expensive than the Preferred Plan. Additionally, the timing and feasibility of required replacement generation is suspect, which increases reliability concerns and cost. BAI does not believe potential emissions reductions that increase both reliability and cost risks are in the public interest. Therefore, BAI recommends that the Fast Exit scenario be rejected.

*b. <u>Clean Energy Organizations</u>*

Like the Fast Exit scenario, BAI does not believe the CEO scenario is in the public interest. The CEO recommends retiring Hibbard in 2023, retiring Boswell 3 by 2029, maintaining the option to retire Boswell 4 by 2030, and the removal of NTEC. It is the CEO's position that MP should procure 200 MW of solar in 2024 and another 400 MW of solar in 2025. As will be discussed below, these resource additions are not feasible in light of MISO's current interconnection delays. The earliest new generation services are likely to be placed in service is in the years 2027 or 2028. As such, the CEO's recommended portfolio, which contains no thermal dispatchable generation, will put MP's system at significant exposure to the MISO market, increasing risk for ratepayers.

With respect to the CEO's recommended retirement of the Hibbard biomass plant, no study isolating the impact of this retirement has been conducted, and it is not apparent that this recommendation would provide any cost benefits to MP's customers. The Hibbard plant is a renewable energy resource placed in service in 2005.[16] The Encompass models suggest this plant has an operating life through 2050, thus this facility likely has a significant amount of unrecovered investment associated with it. Consistent with BAI's finding in its Initial Report, accelerated retirement of dispatchable resources creates both cost and reliability concerns on MP's system.[17] Therefore, the retirement of this dispatchable renewable energy resource in the middle of its useful life should be rejected.

Furthermore, CEO has not provided any demonstration that the CEO scenario can safely and reliably serve MP's system with an 80% load factor and 61% of system sales for industrial load. As we indicated in our Initial Report, we are quite skeptical of plans that would call for accelerating the retirement of Boswell faster than MP's Preferred Plan. This skepticism translates to the CEO scenario, which would remove

[16]For purposes of this report and analysis, BAI considers biomass a renewable resource.
[17]Initial Report at 18.

two additional dispatchable resources (Hibbard and NTEC) from MP's system[18] Therefore, for similar reasons as the Fast Exit scenario, BAI recommends rejection of the CEO scenario.

## IV. MISO Timing And Reliability Issues

### a. *MISO Generation Interconnection Delays*

Current MISO interconnection timelines complicate resource planning scenarios that require short-term resource acquisitions. In order for new generation to be brought online and connected to the power grid, certain steps must be taken with MISO. The MISO Tariff provides Generator Interconnection ("GI") procedures necessary for an interconnection customer to move through the generator interconnection queue. If a project completes the interconnection study process and advances through the interconnection queue, it will eventually execute a Generator Interconnection Agreement ("GIA") that allows the customer to connect generation to the MISO grid. Per the MISO website, the GI starting with the Application Process and ending with the GIA is forecasted by MISO to be completed in approximately 599 days (approximately 20 months).

BAI researched current interconnection delays using the schedule provided on the MISO website for the Central, East (ATC), East (ITC), South, and West regions.[19] The data shows that the process which starts with Application and ends with execution of a GIA is taking significantly longer than the MISO process mapped timeline of

[18] It is worth noting that the CEO wants to maintain the option of retiring Boswell 4 no later than 2030, yet their Encompass models do not have the plant retiring before 2035.

[19] https://cdn.misoenergy.org/Definitive%20Planning%20Phase%20Schedule106547.pdf.

approximately 599 days (approximately 20 months) in all five regions.[20] On average, the Generation Interconnection Process for the four most recent cycle years (2019-2022) is taking at least 800 days (over two years and two months). If the 2022 cycle is removed, which has not begun and still includes the MISO best case scenario timeline, the number increases to an average of at least 867 days (nearly two years and five months).

In addition to expected completion time, BAI has also examined the actual timeline for all of the GIAs MISO has completed within the last 12 months based on the data in MISO's generation interconnection queue.[21] This analysis shows an average time from application to GIA of 1,232 days (over three years and five months). In addition, the average time from application to in-service date of a generation facility is 1,872 days (over five years and two months).

It is also important to note that even if an application is submitted before the application due date for a cycle, the application would still not be reviewed by MISO until after the application due date for that cycle. For example, a project submitted on August 1, 2022, for the 2022 cycle would not be reviewed by MISO until after the September 15, 2022, application due date for the cycle. Given these delays within MISO, it is likely that new generation resources cannot be placed into service until the 2027 to 2028 time frame at the earliest. These delays will make it very difficult for any new solar or wind resources to be brought online to replace the capacity need associated with an earlier Boswell 3 retirement or the withdrawal of NTEC. BAI is,

[20] MISO Definitive Planning Phase Schedule (Apr. 1, 2022).
[21] MISO Generator Interconnection Queue (Apr. 22, 2022).

therefore, opposed to resource planning scenarios that remove existing capacity in favor of other near-term additions.

*b. Reliability Concerns*

During its summer readiness workshop, MISO stated that it is projecting insufficient firm resources to cover summer peak forecasts under typical demand and generation outages. This is consistent with the message that was conveyed with the 2022/2023 Planning Resource Auction ("PRA") results and the 2022 OMS-MISO Survey. The PRA provides a vehicle for Load Serving Entities to either obtain or demonstrate that they have enough Zonal Resource Credits to cover their Planning Reserve Margin Requirements ("PRMR"). The PRA also allows MISO to determine a market-based value associated with having resources located in certain geographical areas, which is required by FERC order. The OMS-MISO survey is an annual voluntary survey conducted by MISO and the Organization of MISO States to assess available resource capacity to serve projected load over the next five years. Recent results suggest that emergency resources and non-firm energy imports are likely needed to maintain system reliability. MISO projects a capacity deficit of 2.6 GW below the 2023 PRMR.[22] Similar to the 2022 PRA results, the capacity deficit is restricted to MISO North/Central, partially offset by exports from the South region, and capacity deficits are projected to widen in subsequent years. A capacity shortfall exposes entities with net short positions to the clearing price of Cost of New Entry ("CONE") for the planning year. The CONE calculation is the dollar value of what would be the overnight construction cost of a new natural gas plant if capacity was deficient. The

[22] 2022 OMS-MISO Survey Results (Jun. 10, 2022).

CONE price in the North/Central regions for the 2022/2023 PRA is set at $236.66/MW-day.[23] The North/Central MISO regions will need to complete a significant number of MISO GI projects by 2027 to cover projected Committed Capacity deficit. Committed Capacity includes resources assumed to be used to meet the PRMR including installed generation resources and projects with interconnection agreements with commercial operation dates expected during the survey year.

In addition to MISO, BAI reiterates the importance of comprehensive reliability analyses in light of MP's and the state's shift to more intermittent resources. A sub-hourly, stochastic LOLP study of its preferred plan should be conducted in the next IRP to ensure that MP can continue reliably serving its customers with the same level of service quality that has been present for decades. Additionally, BAI recommends that MP also include a service quality study of its next preferred plan. The study should provide a demonstration that MP is able to safely and reliably support its heavily industrial load.

MISO has already stated that it has reliability concerns in the near-term and more aggressive retirements like those contemplated by the Fast Exit scenario will only exacerbate these reliability issues. BAI's analysis shows the current time from application to in-service date for the GI is, on average, over five years. Unless MP has renewable projects already in the MISO interconnection queue, it is unlikely any new projects will come online to support an earlier retirement of Boswell 3.

[23] 2022/2023 MISO Planning Auction Results (Apr. 14, 2022).

c. *System Support Resources and Transmission Solutions*

A System Support Resource ("SSR") designation allows MISO to maintain operations of units that would otherwise be retired in order to preserve reliability. As it pertains to the 2021 IRP, MISO studied potential issues surrounding different Boswell retirement scenarios. The Attachment Y-2 study[24] concluded that there are reliability issues related to potentially changing the operational status of Boswell Units 3 and 4, jointly or separately, which require robust mitigating solutions be built before the retirement of the unit(s) could be allowed. Unless this occurs, one or both units may need to be designated as SSR units prior to the retirement date indicated in the future Attachment Y study request.

As reiterated throughout this report, BAI is skeptical that mitigating reliability solutions can be developed fast enough to match the Fast Exit scenarios or other proposals removing dispatchable capacity. For example, one potential mitigation solution is the LRTP project recently announced by ALLETE.[25] However, this project will not come online until 2030. BAI is unaware of, and it is highly unlikely that there is, any robust mitigating solution to address reliability issues if Boswell 3 is retired in 2025. The findings of the Y-2 study affirm BAI's belief that accelerated retirements are not feasible at this time. Therefore, the Preferred Plan affords the safest path forward by maintaining dispatchable resources that are required for reliability. Furthermore, by maintaining these resources now, MP will preserve flexibility to make other determinations in future IRPs.

[24] Minnesota Power 2021 IRP Appendix F, Part 9.

[25] https://investor.allete.com/news-releases/news-release-details/minnesota-power-and-great-river-energy-build-transmission-line.

## V. Recommendations

At the outset, BAI thoroughly reviewed MP's 2021 IRP and determined that the Preferred Plan is the best path forward. After our review of the initial and supplemental comments filed by other parties in this proceeding, BAI's recommendations and conclusions are unchanged. We continue to recommend that the Commission approve the short- and long-term action plans proposed by MP as they represent a reasoned approach that balances the various resource planning considerations. Therefore, BAI maintains the following recommendations:

**2021 IRP**

- The Preferred Plan should be approved. Though it is not the least-cost plan, it effectively balances environmental concerns with both reliability and host community impacts.
- At the time MP seeks approval of specific wind and solar resources contemplated in the Preferred Plan, MP should be required to demonstrate the specific proposal is cost effective in order to maximize flexibility and minimize rate increases.
- Any plan (i.e., the Fast Exit scenario or the CEO scenario) that prescribes more aggressive retirement schedules that the Preferred Plan should be rejected due to cost and/or reliability concerns.

**Minnesota Power's Next IRP**

- MP should be required to conduct a sub-hourly, stochastic LOLP study of its next preferred plan, thoroughly demonstrating that the reliability of the electrical grid is maintained with a system with far less firm, dispatchable generation and increased reliance on intermittent resources to serve load.
- MP should also be required to provide a service quality study demonstrating that its future preferred plan is capable of safely and reliably serving a system with an industrial customer base that accounts for over 60% of the energy requirements and an 80% system load factor.