BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

In the Matter of Minnesota Power's 2021-2035 Integrated Resource Plan	MPUC Docket No. E015/RP-21-33 **INITIAL COMMENT**

The Large Power Intervenors ("LPI")[1] submit this 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").[2]

I. INTRODUCTION/BACKGROUND

On February 1, 2021, Minnesota Power submitted its 2021 IRP to the Commission. Following Minnesota Power's initial filing and subsequent extensions, initial comments are now due by April 29, 2022, with reply comments due by June 29, 2022.

In the 2021 IRP, Minnesota Power presents its preferred plan ("Preferred Plan"), which it describes as the "next chapter in the Company's *Energy**Forward*** resource strategy."[3] If approved, the Preferred Plan will achieve an 80% reduction in carbon emissions by 2035.[4] The Preferred Plan is separated into a Short-Term Action Plan (2021 through 2025) and a Long-Term Plan (2026 through 2035). The elements of the Short-Term Action Plan are:

- Retire the currently idled Taconite Harbor Energy Center in 2021;
- Construct three solar projects totaling approximately 20 MW;

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1 LPI is an *ad hoc* consortium of industrial 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 Extended Comment Period (Mar. 3, 2022) (eDocket No. 20223-183412-01) (the "Notice").

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

4 *Id.*

- Adapt operations at the Boswell Energy Center Unit 3 ("BEC 3") to move to economic dispatch within the MISO market in 2021;
- Continue investigating and preparing to transition the 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]

Consistent with the Commission's order in its last IRP, Minnesota Power's Preferred Plan was developed after an extensive stakeholder engagement process that began in late 2019.[7] In its effort to solicit feedback, Minnesota Power "gathered the priorities, insights and feedback from over 70 diverse stakeholders representing various customer groups, environmental organizations, economic development entities, local government, industry, the host community and more."[8] Minnesota Power then asked these participants to look at various issues associated with the IRP and provide feedback outlining "best case" and "worst case" scenarios.[9] Minnesota Power took these results and combined them to create a map that captured the metrics within four broad categories: customers, host communities, the environment, and the grid.[10] Using this feedback,

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5 *Id.* at 14-15.
6 *Id.* at 5.
7 Minnesota Power 2021 IRP Appendix R: Stakeholder Engagement (Feb. 1, 2021) (eDocket No. 20212-170596-03).
8 *Id.* at 1.
9 *Id.*
10 *Id.*

the Preferred Plan represents Minnesota Power's efforts to develop a proposal that is responsive to the multitude of diverse stakeholders involved in the feedback process.

LPI has been an active participant in this docket, participating in the stakeholder engagement process (both LPI's counsel and specific member representatives participated in multiple stakeholder meetings), issuing discovery, and filing a petition to intervene on February 24, 2021.[11] In addition to its active role in this docket, LPI also retained Brubaker and Associates, Inc. ("BAI") to provide expert analysis on the 2021 IRP. In that capacity, BAI prepared an expert report, which is attached to this comment as Exhibit A.[12]

LPI is grateful to the Company and other stakeholders for the extensive record that has been developed for the Commission's consideration of Minnesota Power's IRP. LPI's comment and BAI's Report are submitted to expand that record, demonstrate the Preferred Plan is not least cost, and offer slight modifications to the Preferred Plan.[13] With these modifications, LPI is willing to support the Preferred Plan as a compromise, middle-ground proposal that attempts to balance current statewide trends in resource planning with cost and rate implications. To be sure, however, LPI's support of the Preferred Plan should not be construed as a willingness to further deprioritize industrial customers' rates and bills, which already fail to meet the state directive described in Minn. Stat. § 216C.05, subd. 2(4), and LPI cannot support any modifications to the Preferred Plan that result in larger customer rate increases.

II. ANALYSIS

A. The Preferred Plan Represents a Reasonably Well-Balanced Compromise That Warrants Approval

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 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

[11] LPI Petition to Intervene (Feb. 24, 2021) (eDocket No. 20212-171308-02).

[12] Expert Report by Brubaker and Associates, Inc. (Apr. 29, 2022) ("Exhibit A").

[13] *See* Exhibit A at 18.

> financial, social, and technological factors affecting 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.

(Emphasis added.) Because its members are concerned about service quality, reliability, and rate impacts, LPI prioritizes the objectives set forth in Minn. R. 7843.0500, subp. 3(A) and (B). LPI respectfully asserts that all ratepayers benefit from resource plans that promote reliability at the least cost. LPI acknowledges, however, that the Commission has recently deviated from least-cost planning to "cost-effective" planning with an emphasis on decarbonization.[14] Though the Commission's deviation from least-cost planning is concerning, LPI recognizes the Commission's desire to encourage expedited decarbonization. But it is imperative that any decarbonization efforts approved by the Commission run parallel with competitive electric rates and bills for customers, which are concepts built into resource planning regulations and state statute. The Preferred Plan presents the most realistic attempt to strike this important balance. And LPI urges the Commission to consider the following factors as it weighs the Preferred Plan against potential alternatives.

1. The Preferred Plan Does Not Represent the Least-Cost Option and Will Impose Additional Costs on Ratepayers Who Are Already Paying Rates That Do Not Comply with State Energy Policy Directives

Notwithstanding its support of the Preferred Plan, LPI notes that Minnesota Power's proposal does not represent the least-cost plan for ratepayers. The analysis prepared by BAI demonstrates that the status quo option is the least-cost path for ratepayers.[15] Based on costs truly incurred by customers, the status quo is between $94 million and $301 million less expensive than the Preferred Plan.[16] To put this in the context of Minnesota Power's pending request to increase rates, that is roughly one to three general rate cases.[17] LPI further emphasizes that existing industrial customer rates do not comply with state energy policy set forth in Minn. Stat. §§

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[14] *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, MPUC Docket No. E002/RP-19-368, Order Approving Plan with Modifications and Establishing Requirements for Future Filings at 13 (Apr. 15, 2022) ("Xcel IRP Order").

[15] Exhibit A at 9-14. The status quo scenario involves no new plant additions and operation of BEC 3 and BEC 4 through 2035. *See* Exhibit A at 1. *See also*, Minnesota Power Response to LPI Information Request No. 26 (Sept. 30, 2021) (eDocket No. 20219-178372-02).

[16] *Id.* at 14. BAI provides a detailed cost analysis in Exhibit A. *See also*, Minnesota Power Response to LPI Information Request No. 25 (Sept. 30, 2021) (eDocket No. 20219-178372-01).

[17] *See* MPUC Docket No. E015/GR-21-335.

216B.03, 216B.1696, and 216C.05. LPI, therefore, urges the Commission to consider these policy mandates in evaluation of the 2021 IRP.

LPI actively participated in the stakeholder engagement process, and was vocal about its concerns with Minnesota Power's industrial rates. As part of the stakeholder engagement process, customers commented on various price/MWh ranges, and provided the following analysis:[18]

Table 3. Large power and municipal utility competitiveness rating scale

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.

As demonstrated by Table 3, industrial rates between $70 and $80 per MWh (the "Worst Case" scenario) result in uncompetitive rates for industrial facilities and could lead to closures or lost business development opportunities. LPI continues to emphasize this reality in various proceedings before the Commission and in its direct engagement with Minnesota Power.

Notwithstanding LPI's feedback, after balancing the spectrum of stakeholder engagement, Minnesota Power selected the Preferred Plan as its preferred outcome in the 2021 IRP. Minnesota Power also produced a rate impact analysis by class under the Preferred Plan. For Large Power ("LP") and Large Light and Power ("LLP") customers, the Company estimated the following rates for 2021 to 2024.[19]

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[18] Minnesota Power 2021 IRP Appendix R: Stakeholder Process Final Report at 18, Table 3 (Feb. 1, 2021) (eDocket No. 20212-170596-04).

[19] Minnesota Power 2021 IRP Appendix L: Cost Impact Analysis by Customer Class at 3 (Feb. 1, 2021) (eDocket No. 20212-170593-09).

Rate Class Impacts \1	2021	2022	2023	2024
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
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.				

To be sure, $72.23/MWh represents the Worst Case scenario for LP industrial customers, and the situation is even worse for LLP customers. Importantly, these estimates fail to account for other rate increases that are pending or will be forthcoming. For example, Minnesota Power is in the process of litigating a general rate case in which it proposes to increase its revenue requirement by 17.79%, and has implemented a 14.23% interim-rate increase for LP and LLP customers.[20] These increases will likely push industrial customers' rates beyond the Worst Case scenario identified above, in direct contradiction of state energy policy directives.

For example, current rates for Minnesota Power's industrial customers do not comply with the state energy policy directive that rates for each customer class be at least 5% below the national average.[21] Minnesota Power acknowledges this fact in testimony provided by Company witness Jennifer Cady in its ongoing rate case, noting that "industrial customers paid approximately five

[20] Exhibit A at 17; *see* MPUC Docket No. E015/GR-21-335.

[21] Minn. Stat. §§ 216B.03, 216C.05, subd. 2(4). In its recent order regarding Xcel Energy's Time of Use Tariff, the Commission interpreted the phrase "to the maximum reasonable extent" in section 216B.03 pertaining to conservation, renewable energy use, and the goals in section 216C.05, be a "statutory directive." *In the Matter of a Petition of Northern States Power, doing business as Xcel Energy, for Approval of General Time-Of-Use Service Tariff*, MPUC Docket No. E002/M-20-86, Order to Conduct Pilot Programs for General Service Time-Of-Use Rates, and Setting Procedural Schedule at 11 (July 16, 2021) ("TOU Order").

percent more than the national average" in 2020.[22] Given the increases contemplated by the Preferred Plan and other proceedings, LPI is concerned that this delta will only be exacerbated by the outcomes in this and other regulatory proceedings before the Commission. As the Commission weighs Minnesota Power's Preferred Plan, LPI respectfully asserts that it must consider Minnesota Power's current noncompliance with explicit state energy policy directives in this area and cautions against approval of any alternatives that put additional rate pressures on industrial customers.[23]

2. The Preferred Plan Complies with Existing State Decarbonization Guidelines

While Minnesota Power's Preferred Plan does not comply with state energy policy with respect to rates, it far exceeds current state decarbonization targets. As is relevant here, Minn. Stat. § 216H.02, subd. 1, makes it the state goal to reduce greenhouse gas emissions 80% by 2050 when compared to 2005 levels. Importantly, if the Preferred Plan is approved, Minnesota Power will meet its share of the 80% statutory goal by 2035, 15 years before the timing set forth in Minn. Stat. § 216H.02, subd. 1. The tangible benefits to ratepayers resulting from this achievement are unclear. At the same time, and as articulated above, the 2021 IRP and pending dockets will result in rates that are within (or in excess of) the "worst case" range articulated by industrial ratepayers.

LPI is troubled by this imbalance and urges the Commission to consider the full record in this proceeding as it evaluates the 2021 IRP. As it does so, LPI urges it to prioritize Minn. R. 7843.0500, subp. 3(B), which encourages resource plans that keep customers' rates and bills as low as practicable, criteria that are considered a statutory directive in future rate setting proceedings before the Commission.[24] Subject to the qualifications set forth below, LPI supports the Preferred Plan as a reasonable reflection of input provided to Minnesota Power and a realistic interpretation of recent Commission precedent.

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22 *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, MPUC Docket No. E015/GR-21-335, Direct Testimony of Jennifer J. Cady at 16:17-18 (Nov. 1, 2021).

23 LPI also encourages Minnesota Power, other stakeholders, and the Commission to work creatively to achieve industrial rates that further the goals set forth in Minn. Stat. §§ 216B.03, 216B.1696, and 216C.05, subd. 2(4).

24 *See* TOU Order at 11.

B. The Commission Should Adopt Two Future Requirements to Encourage Cost-Effective Planning and System Reliability

1. Minnesota Power Should Ensure Future Renewable Additions Are Cost Effective

Minnesota Power's plan proposes 200 MW of wind by 2025 and 200 MW of solar to be added at the Boswell site or other Company locations by 2030.[25] LPI does not oppose these additions from a size, type, and timing perspective; however, LPI respectfully asserts that Minnesota Power's implementation of these resources should be conditioned upon a finding that it is pursuing cost-effective options for ratepayers.[26] For example, when Minnesota Power moves forward with a specific proposal to acquire an additional 200 MW of wind by 2025, its selected project(s), purchase agreements, or other structures should be the most cost effective for ratepayers.[27] LPI remains concerned about the overall trajectory of industrial rates and bills on Minnesota Power's system and in Minnesota generally, therefore, common-sense mitigation options are necessary to protect ratepayers.

2. Minnesota Power Should Include Additional Reliability and Service Quality Evaluations in Its Next IRP

In its report, BAI observes that Minnesota Power failed to provide a detailed analysis of reliability.[28] LPI stresses the importance of comprehensive reliability analyses in light of Minnesota Power's and the state's shift to more intermittent resources. To ensure that Minnesota Power can continue reliably serving its customers with the same level of service quality that has been present for decades, it should be required to conduct a sub-hourly, stochastic LOLP study of its preferred plan in the next IRP. Additionally, LPI requests that Minnesota Power also include a service quality study of its next preferred plan. The study should provide a demonstration that Minnesota Power is able to safely and reliably support its heavily industrial load.[29]

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25 2021 IRP at 3-4.

26 *See* Exhibit A at 17. *See also*, Xcel IRP Order.

27 While LPI typically advocates for utility proposals that represent least cost, the Commission appears to be shifting to a less prescriptive, cost-effectiveness analysis. *See* Xcel IRP Order. Although it is not clear what criteria or considerations will be applied when making a cost-effective determination, LPI respectfully asserts that customer benefits, regional economic benefits, state policy compliance (including policy pertaining to rates), and reliability should be considered in conjunction with any environmental factors.

28 *Id.* at 15.

29 *See id.* at 15-16.

III. CONCLUSION

LPI is grateful for the opportunity to provide this initial comment and expert analysis of Minnesota Power's IRP. Minnesota Power should be commended for its efforts to gather stakeholder feedback and synthesize the information into the Preferred Plan. As articulated herein, LPI believes the Preferred Plan represents a realistic approach, given the current statewide trends in resource planning. Therefore, LPI encourages the Commission to approve Minnesota Power's Preferred Plan, subject to the reasonable qualifications set forth in this comment and Expert Report.

Dated: April 29, 2022

Respectfully submitted,

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EXHIBIT A

Exhibit A

Review of Minnesota Power's 2021 Integrated Resource Plan

Prepared by

Brubaker & Associates, Inc.

Final Report
April 29, 2022

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

Review of Minnesota Power's 2021 Integrated Resource Plan

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Review of Minnesota Power's 2021 Integrated Resource Plan

I. Summary of Findings and Recommendations

Brubaker & Associates, Inc. ("BAI") has conducted a thorough investigation into Minnesota Power's ("MP") 2021 Integrated Resource Plan ("2021 IRP," and when referring to integrated resource plans generally, "IRP"). We have independently verified the EnCompass modeling results that support the 2021 IRP. It is our opinion that the short- and long-term action plans proposed by MP represent a reasoned approach that balances cost and environmental considerations. Our conclusions and recommendations are 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, 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.
- MP's Preferred Plan in the 2021 IRP ("Preferred Plan") is a reasonable approach that balances both cost and environmental concerns.
- MP has not provided a sufficient reliability demonstration of the Preferred Plan.

Recommendations

- MP should be required in its next IRP 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.
- Any plan that would prescribe more aggressive retirement schedules than the Preferred Plan should be rejected because of both cost and 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.
- The Preferred Plan is a reasonable approach that balances both cost and environmental concerns, and should be approved subject to the conditions above.

II. Background

a. *Integrated Resource Planning*

An IRP, in its most simple definition, is a process by which an electric utility creates a plan to meet its expected load requirements over some time period. These plans are carefully crafted by complex analyses that evaluate numerous scenarios and sensitivities of inputs. In order to develop a plan for the future, a utility must consider changes to load, fuel prices, capital costs of generation alternatives, transmission alternatives, environmental costs, electric market prices, reserve margins, existing fleet operating characteristics, and a host of additional factors that can affect the optimal plan. Planning software exists that considers these inputs and can create optimal generation portfolios that meet the constraints of the problem in the least cost manner.

While the planning software can prescribe an optimal plan under a single set of inputs and assumptions, a utility typically has a substantial number of “optimal” portfolios to choose from. As only a single plan can be followed, it is up to the utility to determine its exact course of action. Typically, a plan is put forward that balances the cost, reliability, and sustainability concerns.

b. Minnesota Power's Proposed Action Plans

In the case of MP, the Preferred Plan identifies how MP intends to meet its projected MISO Planning Reserve Margin Requirement ("PRMR") from 2021 to 2035 and provides a path to 80% carbon reduction by 2035, 15 years before the goal set forth in section 216H.02 of the Minnesota Statutes. MP has presented both a short-term action plan and a long-term action plan. These are discussed below.

i. Short-Term Action Plan

MP's short-term action plan identifies the steps it plans to take from 2021 through 2025 in order to meet its load requirements, while reducing carbon emissions and adding renewable resources to the portfolio. The majority of these already have approval. These steps include the following:

- The Taconite Harbor Energy Center will be retired. This plant has been idled since 2016.
- 20 MW of solar will be constructed in 2021. These plants are under construction and expected to be operational this year.
- Move Boswell Energy Center Unit 3 ("BEC3") to economic dispatch from a must-run unit.
- Investigate moving Boswell Energy Center Unit 4 ("BEC4") 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. This program will enable between 100 and 202 MW of demand response product to be sold each year from 2022 to 2028 and was previously approved.
- Add 200 MW of new wind resources to MP's power portfolio.

ii. Long-Term Action Plan

MP's long-term action plan identifies the steps it will take from 2026 to 2035 to achieve further carbon emissions reductions. According to MP, this plan will be able to adapt to a range of economic and environmental futures, while maintaining service at a competitive cost. The steps are as follows:

- Retire BEC3 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 BEC3.
- Investigate the refuel or remission options for BEC4 by 2035, as well as the necessary transmission reliability upgrades.

c. *EnCompass Power Planning Software*

MP has utilized a new software tool to support the 2021 IRP. EnCompass is a power planning software tool developed by Anchor Power Solutions. EnCompass is designed for making optimal power supply decisions, from short-term scheduling and trading to long-term capital investment. By combining the full operational details of power plants, complex contracts, and transmission lines with the ability to simplify and relax constraints for long-term simulations, EnCompass covers all facets of power planning and forecasting. Large, interconnected power markets may be modeled in order to forecast energy, congestion, ancillary, and capacity prices; or determine the value of a single asset or entire portfolio using input market price assumptions.[1]

BAI has seen the use of EnCompass rise over the past few years. EnCompass appears to be the tool of choice for utilities that wish to thoroughly consider stakeholder input in the IRP process. The EnCompass tool is transparent, relatively easy to use, and budget friendly.

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[1] EnCompass User Manual at 22.

i. *EnCompass Inputs*

Appendix J of the 2021 IRP provides the primary assumptions used by MP in the 2021 IRP. The actual input files were provided as well, and are in line with the discussions in Appendix J. MP has segregated the inputs in the following six groups:

- Base Economic Modeling Assumptions;
- Asset Resource Alternatives;
- Energy Efficiency Assumptions;
- Sensibility Analysis Assumptions;
- Wholesale Market Interaction; and
- Retirement Assumptions.

The base economic modeling assumptions provide the framework for the entire analysis. The study period, environmental costs, market prices, fuel prices, import and export capability, energy and demand requirements, existing resource operating characteristics, capacity accreditation values, reserve margin, discount rate, and more are detailed in Appendix J and were carried through into the EnCompass input files. It is BAI's opinion that in the aggregate, these assumptions were reasonable at the time they were made.

The resource alternatives assumptions include 18 potential generic resource alternatives that the EnCompass model can choose from to meet future capacity and energy needs. MP initially considered 23 resource alternatives, but screened out some options using a levelized bus bar analysis, which compared the cost of each resource over a 20-year period. The cost assumptions and capacity values of the resource alternatives used within the EnCompass model appear reasonable at the time they were made.

ii. *EnCompass Outputs*

MP has made available all of the output files from its EnCompass modeling runs. As will be discussed in a later section, MP conducted approximately 1,200 EnCompass runs to support the 2021 IRP. They provided the output file from each run. These output files provide the annual system production costs, capacity sales, externality costs, emissions, operating results, etc. MP summarizes each run with a single number, the Net Present Value Revenue Requirement ("NPVRR"), which is the 2021 present value of 2021 to 2035 annual revenue requirements discounted at 7.0639%. The NPVRR is then used to compare the various portfolios across multiple futures and sensitivities.

iii. *Benchmarking Runs*

MP did not provide the EnCompass databases that included the results. Instead, MP provided the necessary input databases and selected output reports for each of the scenarios. In order to verify the accuracy of MP's outputs, BAI ran the EnCompass model using MP's inputs. Again, MP conducted approximately 1,200 EnCompass runs to support its filing. It would require several hundred hours of processing time to run all of the 1,200 scenarios. Recreating all of these scenarios is not an effective use of resources for a customer group such as LPI. Therefore, BAI re-ran all of the Step 1 Capacity Expansion runs, and several of the Step 2 Swim Lane runs, to gain an understanding of the 2021 IRP's function and scenarios. Based on this subset of runs, BAI believes the output reports provided by MP accurately reflect the results of the EnCompass Power Planning Software when using MP's EnCompass database input files.

d. *Modeling Approach*

For the 2021 IRP, MP conducted its analysis in two steps. For both steps, MP created five Boswell retirement scenarios to be evaluated across six distinct futures using the EnCompass Power Planning Software. The five Boswell retirement scenarios are as follows:

1. 2021 Plan – BEC3 retires in 2029;
2. Expedited Plan – BEC3 retires in 2025, BEC4 retires in 2030;
3. BEC3 Early Plan – BEC3 retires in 2025;

4. BEC4 Early Plan – BEC4 retires in 2030; and

5. Base Case – BEC3 and BEC4 operate through 2035.

The six distinct futures are variations of environmental costs, four of which are required by the Minnesota Public Utilities Commission ("MPUC"). These futures have been summarized by MP with the following table from page 33 of the 2021 IRP.

FIGURE 1

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	-	-	-	-	-

i. *Step 1 Capacity Expansion Analysis*

In the Step 1 Capacity Expansion analysis, MP utilized the EnCompass model to allow it to optimally choose the resources that will meet the future capacity and energy needs of each Boswell retirement scenario in the least cost manner in each of the six futures.

The key findings from the Step 1 Capacity Expansion analysis are as follows:

- 100-300 MW of wind is consistently selected in the near term (prior to 2025) in nearly 90% of the modeling runs.

- Up to 300 MW of solar located at the Boswell site or at other MP facilities will be selected near the time of retirement of Boswell.

- In any scenario in which BEC4 retires early, some type of natural gas generation is selected, either a 590 MW combined cycle ("CC") plant or a 280 MW combustion turbine ("CT").

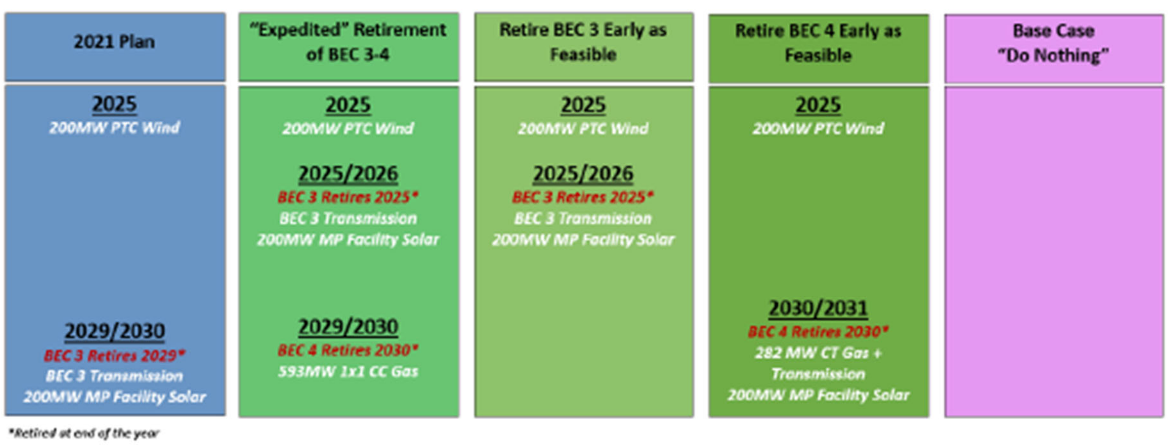
The Step 1 Capacity Expansion analysis informs MP of the resources that are necessary for the various retirement scenarios to maintain a portfolio that meets the resource adequacy constraints in the model, i.e., the resources needed to meet energy and capacity requirements. This leads to the Step 2 Swim Lane analysis.

ii. *<u>Step 2 Swim Lane Analysis</u>*

The Step 1 Capacity Expansion analysis allowed MP to turn each of the five Boswell retirement scenarios into a Swim Lane, or resource portfolio that can be used for further analysis. The Swim Lane analysis allows MP to compare the costs of the alternative power supply portfolios across the six distinct futures while performing sensitivity runs on individual inputs. MP summarized these portfolios in the following figure from page 50 of the 2021 IRP:

<u>FIGURE 2</u>

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



The purpose of the Swim Lane analysis is to compare the Preferred Plan to the other alternative portfolios to demonstrate that it is the least cost in the majority of the model runs. Again, MP modeled five Swim Lanes, across six futures, each with a base case and 38 sensitivity runs. This yields 1,170 model runs, each with a different NPVRR. In MP's

Reference Case future (named CREF1S in EnCompass), which included mid-range prices for carbon regulation and environmental costs, the Preferred Plan is shown to be least cost in 27 of the 39 sensitivity runs, including the base case. MP uses these results to claim that the Preferred Plan is the most sustainable plan that ensures reliability, manages costs for customers, provides for a just transition for host communities, and allows for time for technology to develop and advance.[2] In other words, MP concluded that the Preferred Plan represents a reasonable balance of the multitude of factors that must be considered by the MPUC in evaluating resource plans under Minn. R. 7843.0500.[3]

e. <u>Modeling Results</u>

As discussed previously, MP used the Swim Lane analysis results to claim that the Preferred Plan is the least cost plan in 27 of the 38 sensitivity runs in its Reference Case future.[4] It is important to understand the costs that are included in the tables presented in the 2021 IRP. To use the Preferred Plan in the Reference Case future, with base case assumptions as an example, MP shows that the NPVRR of this plan is $7.891 billion. This figure represents a net present value of the revenue requirements from 2021 to 2035. This figure can be split into two cost categories: the production model operational system cost and externalities. The operational system cost reflects the cost of fuel, O&M, and fixed capital costs for the resources needed to meet system load requirements. Carbon regulation costs are also captured in the operational system cost. The externalities reflect environmental costs, which are not actually incurred by MP or included in base rates. Out of the total $7.891 billion of the NPVRR of the Preferred Plan, $1.639 billion or 21% is attributed to externality costs. In addition to the externalities, there is $215 million included for a carbon regulation cost beginning in 2025. This

[2]2021 IRP at 56.

[3]Under Minn. R. 7843.0500, factors that the MPUC must consider include: adequacy and reliability of utility service, and keeping customers' rates and bills as low as practicable.

[4]The Reference Case, which is a required modeling scenario, assumes mid-carbon regulatory costs starting in 2025.

carbon regulation cost accounts for 3% of the NPVRR of the Preferred Plan. In total, there are $1.854 billion of environmental and regulation costs (24% of the NPVRR) that are not actually incurred by MP. Support for this conclusion is set forth in the analysis below.

f. *<u>Externalities and Regulatory Costs</u>*

The externalities costs that are included in MP's table include environmental costs related to emissions of nitrogen oxides (NO_x), sulphur dioxide (SO_2), particulate matter 2.5 (PM2.5), lead (Pb), and carbon dioxide ("CO_2"). These costs total $1.639 billion or 21% of the reported costs of the Preferred Plan. A MPUC order[5] required the consideration of the CO_2 costs. The CO_2 costs account for 92% of the externality costs. It is important to realize that currently, there are no costs incurred by MP for any CO_2 emissions (or other emissions for that matter). These costs are modeled to evaluate societal costs (i.e., externality costs) and the potential future costs imposed via tax or other regulation (i.e., regulatory costs). When the externality costs alone are not considered the results of the analysis are substantially different. Below is a table, created by MP with its EnCompass Output files, similar to the results table presented on page 57 of the 2021 IRP, but excluding only externality costs. The carbon regulation costs are still included in the table.

[5]Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs, published September 30, 2020, in docket nos. E999/CI-07-1199 and E999/DI-9-406.

FIGURE 3

2021 NPV of Cost for Reference Case Scenario Without Externalities ($ Millions)

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**

As can be seen from Figure 3 above, the Status Quo, the scenario in which BEC3 and BEC4 operate through 2035, is shown to be the least cost plan in the base case and all 38 sensitivity runs. On average, the Status Quo is $49 million less or 1% less than the Preferred Plan. The Status Quo ranges between $22 million and $168 million less than the Preferred Plan. This makes the Status Quo the least cost plan, when excluding externality costs.

When also excluding regulatory costs, the results are more dramatic. The "No Environmental Cost and No Carbon Regulation Cost" future (EnCompass Case name CCUST1S) is the most representative of the current regulatory and operational environment in terms of the assumptions for carbon environmental and/or regulation costs. There are currently no environmental costs or carbon regulation costs passed through customer rates.[6] In the Swim Lane analysis of the CCUST1S future, the Status Quo is shown to be even less expensive than the Preferred Plan.[7] The results table is shown below in Figure 4.

[6] *See* MP's response to LPI Information Request No. 25.
[7] *See* MP's response to LPI Information Request No. 26.

FIGURE 4

2021 NPV for No Environmental Cost and No Carbon Regulation Cost Future ($ Millions)

Plan NPV ($millions)	PrefPlan	FastExit	Early3	Early4	StatusQuo
Base Case	$5,965	$6,198	$6,044	$6,028	$5,841
1_Coal+20%	$6,096	$6,297	$6,165	$6,155	$6,001
2_Coal-10%	$5,885	$6,139	$5,972	$5,947	$5,741
3_Biomass+15%	$5,965	$6,199	$6,050	$6,027	$5,844
4_Biomass-15%	$5,958	$6,195	$6,033	$6,018	$5,835
5_Lower Gas-50%	$5,843	$5,999	$5,918	$5,865	$5,713
6_Low Gas-25%	$5,940	$6,137	$6,017	$5,991	$5,814
7_High Gas+25%	$6,084	$6,353	$6,158	$6,146	$5,951
8_Higher Gas+50%	$6,117	$6,428	$6,202	$6,182	$5,984
9_Highest Gas+100%	$6,237	$6,606	$6,335	$6,311	$6,094
10_Wholesale Market-50%	$5,830	$6,062	$5,901	$5,890	$5,694
11_Wholesale Market-25%	$5,983	$6,212	$6,049	$6,043	$5,857
12_Wholesale Market+25%	$6,022	$6,254	$6,102	$6,076	$5,889
13_Wholesale Market+50%	$6,014	$6,249	$6,107	$6,063	$5,873
14_Capital Costs-30%	$5,963	$6,135	$6,039	$5,999	$5,839
15_Capital Costs+30%	$5,962	$6,260	$6,042	$6,053	$5,843
16_No Externalities Costs					
17_No Market Sales	$6,061	$6,292	$6,135	$6,122	$5,933
18_No Sales and Purchases	$6,870	$7,119	$7,134	$6,698	$6,569
19_Market Access -50%	$6,138	$6,376	$6,235	$6,167	$5,984
20_Low Interconnect Costs	$5,946	$6,173	$6,018	$6,007	$5,840
21_ITC & PTC Extension	$5,960	$6,189	$6,032	$6,022	$5,838
22_Wind Cost Curve Low	$5,961	$6,192	$6,042	$6,022	$5,841
23_Wind Cost Curve High	$5,963	$6,198	$6,041	$6,025	$5,840
24_Solar Cost Curve Low	$5,950	$6,187	$6,037	$6,007	$5,844
25_Solar Cost Curve High	$5,982	$6,215	$6,059	$6,042	$5,841
26_Storage Cost Curve Low	$5,963	$6,197	$6,041	$6,029	$5,839
27_Storage Cost Curve High	$5,964	$6,199	$6,043	$6,022	$5,840
28_AFR 2020 Low Scenario	$5,828	$6,058	$5,900	$5,890	$5,704
29_AFR 2020 Load w Keetac	$6,185	$6,423	$6,279	$6,228	$6,038
30_AFR 2020 High Scenario	$6,207	$6,441	$6,309	$6,246	$6,063
31_Residential TOU	$5,958	$6,197	$6,036	$6,024	$5,839
32_Higher DG & EV Growth	$5,962	$6,199	$6,037	$6,023	$5,841
33_Renewable ELCC -2.5%	$5,967	$6,201	$6,052	$6,023	$5,839
34_Renewable ELCC +2.5%	$5,963	$6,195	$6,036	$6,026	$5,839
35_PRM-2%	$5,965	$6,194	$6,039	$6,024	$5,838
36_PRM+2%	$5,967	$6,203	$6,049	$6,025	$5,838
37_MISO CF-2%	$5,959	$6,194	$6,037	$6,023	$5,837
38_MISO CF+2%	$5,973	$6,206	$6,054	$6,027	$5,838
Sum of Least Cost Runs	**0**	**0**	**0**	**0**	**38**

Again, the Status Quo is 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%) less expensive than the

Preferred Plan. The Status Quo is between $94 million and $301 million less than the Preferred Plan.

g. Developments

MP filed the 2021 IRP in February 2021, with a supplemental filing in April 2021. Since that time, there have been substantial developments that affect MP and Minnesota.

First, MP has announced that it will be selling 60% of its stake in the Nemadji Trail Energy Center ("NTEC"), a new 600 MW baseload CC plant that is expected to be placed in service in 2025. MP previously owned a 50% stake in the plant. Now it appears that MP will have only a 20% stake in the project, or approximately 120 MW. After the retirement of Boswell, NTEC will be the only source of baseload generation for MP. MP does not believe that this sale will impact the Preferred Plan. MP has not updated any of the 2021 IRP modeling to account for the loss of 180 MW of baseload generation at NTEC. This development may not severely impact the Preferred Plan, but it does raise some reliability concerns, to be discussed later in the report.

Second, Xcel Energy's 2019 IRP has been approved by the MPUC.[8] The approved plan would have all of Xcel Energy's coal plants retired by 2030 and largely replaced with solar and wind resources, as well as small CTs. This results in Minnesota being more dependent upon intermittent resources. Again, reliability becomes a concern. MISO appears to be addressing this concern with substantial transmission system investments, which may mean the actual rate impact of any plan approved by the MPUC will be higher than projected in MP's analysis in this proceeding.

In fact, MISO recently published its response to the Reliability Imperative – the shared responsibility of utilities, states, and MISO to address fleet change, extreme weather events, and other challenges facing the region. In MISO's Long-Term Transmission Planning, it expects

[8] *See* Order Approving Plan with Modifications and Establishing Requirements for Future Filings (Apr. 15, 2022) MPUC Docket No. E002/RP-19-368.

grid upgrades (both transmission and generation) to be as much as $530 billion through 2039 to maintain a reliable power grid, under futures that include more renewable resources and less coal and gas generation. It is therefore clear that maintaining the reliability of a power grid that is more reliant on renewable resources will take massive investment.

III. <u>Analysis</u>

a. Reliability

MP has not provided any analyses that substantiate assured reliability of the Preferred Plan, nor any of the other Swim Lane portfolios. MP contends that "all Swim Lanes are resource adequate during the study period per MP's planning criteria and MISO's current resource adequacy requirements."[9]

Resource adequacy is generally the ability of the resources on the electric system to supply the aggregate electrical demand and energy requirements of end-use customers at all times, taking into account scheduled and reasonably expected outages. Resource adequacy is typically analyzed by performing stochastic LOLP studies[10] that are aimed at maintaining the traditional Loss of Load Expectation ("LOLE") target of no more than one day of firm load curtailment of any amount in a 10-year period. This is sometimes expressed as an average annual LOLE for firm load curtailment of no more 0.1 days per year.

While it is true that all of the Swim Lanes, including the Preferred Plan, are "resource adequate" in the EnCompass models, a more detailed demonstration has not been performed. With the developments concerning NTEC and Xcel Energy closing all of its coal plants and relying more heavily on intermittent resources, reliability in Minnesota must be thoroughly explored; however, MP states that it "does not have the capability to perform sub-hourly, stochastic modeling of any of the Swim Lanes for this resource plan."

[9] MP's response to LPI IR No. 10.

[10] Stochastic studies examine a very large number of cases where input assumptions are varied based on probability and the application of random number draws.

The Preferred Plan would retire BEC3 in 2030 and BEC4 in 2035. Although it is likely that the Preferred Plan can be pursued while maintaining a reliable system given the amount of time remaining until those retirement dates, reliability has not been formally analyzed. Therefore, MP should be required in its next IRP to conduct a sub-hourly, stochastic LOLP study on its Preferred Plan. Additionally, any more aggressive retirement schedules should be rejected, unless and until a thorough demonstration has been made that ensures reliability of the electric grid in Minnesota and MP's system is maintained.

MP should also be required in its next IRP to conduct a service quality study that provides a demonstration that the preferred resource portfolio is able to safely and reliably support its system that has an industrial customer base representing 61% of the system energy requirements and has a system load factor of 80%. This study should be a detailed assessment of service quality demonstrating that system voltage remains within the acceptable ranges from the MISO bulk transmission system down to the primary voltage distribution system to ensure MP's electric service meets the needs of its end-use customers.

b. <u>Customer Rate Impacts</u>

MP shows in Appendix L of the 2021 IRP that the Preferred Plan will increase the power supply costs in 2024, over the 2021 base rates, by 1.31% for residential customers, 1.49% for Large Light & Power customers, and 0.57% for the Large Power customers. These projected rate increases are consistent with the results of the EnCompass outputs for the CCUST1S future, in which the Preferred Plan was, on average, 2% more expensive than the Status Quo. In the Stakeholder Process Report, filed in Appendix R, it shows that Large Power prices in the range of $70 to $80/MWh are the worst-case scenario. Rates in this range are uncompetitive, potentially leading to facilities shutting down and companies investing elsewhere.[11] MP projected rates for the Large Power customer class of approximately $72/MWh under the

[11]2021 IRP Appendix R Stakeholder Process Report at 18.

Preferred Plan,[12] this projection relates only to rate proposals in the five-year action plan. Other investments outside of the five-year action plan will undoubtedly be submitted for cost recovery in various rate case and rider proceedings. For example, in MP's recently filed rate case, Docket No. E015/GR-21-335, MP is proposing to increase its revenue requirement by 17.79%, with a 14.23% interim rate increase.[13] This proposed rate increase alone would have the Large Power rates higher than the worst-case scenario. MP should strive to find creative solutions to mitigate the rate increases being passed down to the customers.

c. Ensuring Cost Effectiveness

The Preferred Plan calls for 200 MW of wind to be added by 2025 and 200 MW of solar to be added at the Boswell site or other MP facilities. There is no mention in the IRP of the procurement of these resources. In order to mitigate future rate increases, these resources should be acquired subject to a demonstration that they are cost effective compared to other options. This will help ensure that the resources are provided at the lowest reasonable costs. Further, MP should explore all opportunities for meeting these needs, as maximum flexibility may also help minimize future rate increases. The MPUC should therefore subject MP's procurement process for the wind and solar resources described in the Preferred Plan to a cost-effectiveness test.[14]

d. MP's Preferred Plan Is Reasonable

LPI's primary concerns are reliable service at competitive rates. The Status Quo would be the portfolio to support if cost and reliability are the primary considerations. Given recent developments within Minnesota, it appears that decarbonization that is faster than the goals set forth in section 216H.02 of the Minnesota Statutes is the primary resource planning

[12] 2021 IRP Appendix L at 3.

[13] Docket No. E015/GR-21-335, Direct Schedule B-10 (IR) at 1.

[14] *See* Order Approving Plan with Modifications and Establishing Requirements for Future Filings (Apr. 15, 2022) MPUC Docket No. E002/RP-19-368.

consideration, rendering the Status Quo an unlikely plan to be approved. As an alternative to the Status Quo that reflects this reality, while balancing the broad input MP obtained through the stakeholder process, MP's Preferred Plan is reasonable. The Preferred Plan could be made more attractive if the Commission requires that any wind or solar resources prescribed are procured subject to a demonstration of the chosen resource being cost effective. Outside of this recommendation, and the request to require reliability analysis in the next IRP proceeding, we recommend supporting the Preferred Plan.

IV. Recommendations

BAI has conducted a thorough investigation into the 2021 IRP. We have independently verified the EnCompass modeling results supporting the 2021 IRP. It is our opinion that the short- and long-term action plans proposed by MP represent a reasoned approach that balances cost and environmental considerations. We recommend the following:

2021 IRP

- The Preferred Plan is a reasonable approach that balances both cost and environmental concerns, and should be approved subject to the conditions set forth below.
- 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.
- Any plan that would prescribe more aggressive retirement schedules than the Preferred Plan should be rejected because of both cost and reliability concerns.

Minnesota Power's Next IRP

- MP should be required in its next IRP to conduct a sub-hourly, stochastic LOLP study of its preferred plan, thoroughly demonstrating that the reliability of the electrical grid is maintained with a system with far less firm, dispatchable generation and far more reliance on intermittent renewable resources to serve MP's load.

- In its next IRP, 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 61% of the energy requirements and an 80% system load factor.

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