

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Petition
for Approval of the Energy*Forward*
Resource Package

**FINDINGS OF FACT,
CONCLUSIONS OF LAW,
AND RECOMMENDATION**

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The above-entitled matter came before Administrative Law Judge Jeanne M. Cochran for an evidentiary hearing on March 26, 2018 in the large hearing room of the Minnesota Public Utilities Commission (Commission or PUC). In addition, a public hearing was held in Duluth, Minnesota on February 28, 2018 and written public comments were received until March 23, 2018. Post hearing briefs were filed on May 1, 2018, and responsive brief were filed on May 22, 2018. The hearing record closed on May 22, 2018, following the receipt of the last responsive brief.

Michael C. Krikava and Elizabeth M. Brama, Briggs and Morgan, P.A., and David R. Moeller, Senior Attorney, Minnesota Power, appeared on behalf of Petitioner Minnesota Power (the Company or MP).

Peter E. Madsen, Assistant Attorney General, appeared on behalf of the Department of Commerce, Division of Energy Resources (the Department or DOC-DER).

Ian Dobson, Assistant Attorney General, appeared on behalf of the Office of the Attorney General, Residential Utilities and Antitrust Division (the OAG).

Leigh Currie and Gretel Lee, Minnesota Center for Environmental Advocacy, and S. Laurie Williams, Sierra Club, appeared on behalf of the Clean Energy Organizations (the CEOs).

Sara Johnson Phillips, Andrew P. Moratzka, Sara Bergan, and Jennifer Mersing, Stoel Rives LLP, appeared on behalf of the Large Power Intervenors (LPI).

Sean Stalpes, Commission staff, also participated in the hearing.

STATEMENT OF THE ISSUES

In this docket, the Company seeks approval of the affiliated interest agreements and associated tariff changes for the Company's proposed purchase of a 48 percent share (approximately 250 megawatt (MW)) of the capacity from the approximately 525 MW Nemadji Trail Energy Center (NTEC), a natural gas power plant propose to be built in Superior, Wisconsin.¹

Pursuant to the September 19, 2017 Order Referring Gas Plant for Contested Case Proceedings, and Notice and Order for Hearing (Notice and Order for Hearing), the Commission has identified the "ultimate issue in this case" as "whether Minnesota Power's proposed gas plant [NTEC] is necessary and reasonable."² The Commission also noted that this issue "turns on numerous factors . . . , including but not limited to consideration of the certificate of need factors and the resource planning factors."³ In the Notice and Order for Hearing, the Commission requested that the Administrative Law Judge "identify the issues and determine the appropriate scope and conduct of the hearing, considering but not limited to the issues identified" in the Notice and Order for Hearing.⁴

During the prehearing process, the Administrative Law Judge and parties jointly identified a list of issues to be determined in this contested case proceeding.⁵ Those issues are included in the Final Issues List attached to the Second Prehearing Order and are set forth below:⁶

1. The ultimate legal issue for consideration is whether Minnesota Power has met its burden of proving by a preponderance of the evidence that the NTEC 250 MW purchase⁷ or any portion thereof is needed and reasonable based on all relevant factors including, but not limited to, the following:

(a) Minnesota Power's updated forecast of demand consistent with the requirements in chapters 7849 and 7843 (2017);

(b) Impact of the NTEC 250 MW purchase, including the criteria set forth in Minn. R. 7843.0500:

(i) Maintaining or improving the adequacy and reliability of utility service;

¹ Exhibit (Ex.) MP-2 at 1-1, 1-3 (Petition). The exhibits entered into the record during the contested case proceeding are listed on the Master Exhibit List. The Master Exhibit List is available at <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={30FA4463-0000-CF1C-8690-FA14A9D39BB7}&documentTitle=20185-142852-01>. All exhibits cited to in this report are public unless expressly noted otherwise.

² Notice and Order for Hearing at 5 (Sept. 19, 2017) (eDocket No. 20179-135644-01).

³ *Id.*

⁴ *Id.* at 8.

⁵ Second Prehearing Order (December 12, 2017) (eDocket No. 201712-138112-01).

⁶ *Id.* at Final Issues List.

⁷ The NTEC 250 MW purchase is also referred to as the 250 MW NTEC purchase in this report.

- (ii) Keeping customers' bills and Minnesota Power's rates as low as practicable, given regulatory and other constraints;
- (iii) Minimizing socioeconomic effects and adverse effects upon the environment, including consideration of the most recent environmental externality values established by the Commission in Docket 14-643;
- (iv) Enhancing Minnesota Power's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
- (v) Limiting the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

(c) Alternatives to some or all of the NTEC 250 MW purchase, including but not limited to additional wind and solar resources (with updated costs), storage, demand response, and additional energy efficiency;

(d) Alternatives eligible for consideration or required to be considered in a certificate of need proceeding under Minn. Stat. § 216B.243 (2016) and Minn. R. ch. 7849 or in a resource plan proceeding under Minn. Stat. § 216B.2422 (2016) and Minn. R. ch. 7843. In particular, the renewable resource requirements set forth in Minn. Stat. § 216B.2422, and Minn. Stat. § 216B.243, subd. 3a will apply to consideration of Minnesota Power's proposed gas plant;

(e) Whether the NTEC 250 MW Purchase is in the public interest including consideration of long-range emissions reduction planning, as enumerated in Minn. Stat. § 216B.2422, subd. 2c and Minn. R. 7843.0500;

(f) Total capital costs and related expenses for the NTEC 250 MW Purchase and related transmission upgrades, including underlying revenue requirement assumptions; and

(g) The potential increase of Minnesota Power's share of NTEC from 48 percent to 50 percent per footnote 10 on page 1-4 of the October 24, 2017 resubmitted Petition.⁸

2. Whether the Capacity Dedication Agreement (CDA) and the two Assignment of Rights Agreements (collectively the "affiliated interest agreements") are consistent with the public interest under the affiliated interest statute, Minn. Stat. § 216B.48 (2016), and Minn. R. 7825.1900-2300 (2017).

⁸ Second Prehearing Order, Final Issues List; Notice and Order for Hearing at 5.

3. Whether the proposed revisions to Minnesota Power's Fuel and Purchased Energy (FPE) Rider are in the public interest under Minn. Stat. § 216B.16, subd. 7(3) (2016) and Minn. R. 7825.2390 through 7825.2600 (2017), and whether the Company's proposed variances to the FPE Rider are justified consistent with Minn. R. 7829.3200 (2017).

4. Whether the guaranties by Minnesota Power referenced in the Ownership and Operating Agreement between South Shore and Dairyland Power Cooperative qualify as an assumption of an obligation as a "guarantor, endorser, surety, or otherwise in the security of another person" under Minnesota Statutes § 216B.49 (2016) and, if so:

(a) whether the relevant statutory criteria have been met in this case.

(b) If the relevant statutory criteria have not been met in this case, whether Minnesota law permits deferral of the issue to Minnesota Power's annual capital structure petition submitted under Minnesota Statutes § 216B.49.

5. Whether the affiliated interest agreements qualify as acquiring, leasing, or renting any plant as an operating unit or system in this state for a total consideration in excess of \$100,000 under Minnesota Statutes § 216B.50 (2016) and, if so, whether the relevant statutory criteria have been met.

6. Any other relevant legal issues raised by parties in a timely manner.⁹

SUMMARY OF CONCLUSIONS AND RECOMMENDATION

Based on the evidence in the hearing record, the Administrative Law Judge concludes Minnesota Power has not met its burden to show that the proposed NTEC 250 MW purchase is needed and reasonable. As a result, the Administrative Law Judge concludes that Minnesota Power has failed to demonstrate that the affiliated interest agreements are consistent with the public interest and recommends that the Commission not approve the agreements.

FINDINGS OF FACT

I. Overview of the NTEC Project and Affiliated Interest Agreements

1. NTEC is a 1x1 combined-cycle, natural gas power plant which is proposed to be jointly developed by Minnesota Power's affiliate, South Shore Energy, LLC (South Shore), and Dairyland Power Cooperative (Dairyland).¹⁰

2. NTEC is to be located in Superior, Wisconsin.¹¹ The NTEC site is located less than ten miles from two interstate pipelines: Great Lakes Gas Transmission (Great

⁹ Second Prehearing Order, Final Issues List.

¹⁰ Ex. 2 at 1-1 (Petition).

¹¹ *Id.* at 1-3.

Lakes) and Northern Natural Gas Company (Northern Natural Gas).¹² Each pipeline transports gas from different gas supply basins, which provides optionality for gas supply to the proposed facility.¹³

3. As proposed, NTEC will consist of one gas turbine generator, one heat recovery steam generator with duct firing, and one steam generator. The majority of the system will be located within enclosed structures to be insulated and heated.¹⁴

4. NTEC is expected to have total generating capacity of between 525-550 MW depending on final turbine selection.¹⁵

5. NTEC will be designed to operate as a dispatchable, variable load power plant. NTEC will be designed to operate in daily cycling mode with normal operation consisting of maximum load and automatic generation control operation for approximately 16 hours per day during weekdays. NTEC will be capable of running in a stable, continuous, and controllable operation, at any load level, while operating from minimum to maximum load. NTEC will also be designed to be capable of starting in all weather conditions, from freezing cold weather conditions to hot summer conditions.¹⁶

6. The NTEC project will include the installation of a new 345 kV collector bus to interconnect the output from the generating plant to a new offsite 345 kV substation near the NTEC site. Existing transmission lines that traverse the site will be relocated elsewhere on the site.¹⁷

7. NTEC has a proposed commercial operation date of 2024.¹⁸

8. NTEC will be jointly owned by South Shore and Dairyland.¹⁹ Minnesota Power will not have an ownership interest in NTEC because Wisconsin statutes only permit Wisconsin entities to obtain a Wisconsin license, permit, or franchise to own or operate a generation facility.²⁰ ALLETE, Minnesota Power's parent company, created South Shore, a Wisconsin affiliate of Minnesota Power, to own ALLETE's share of the NTEC.²¹

9. Each NTEC owner will have the right to 50 percent of NTEC's capacity.²²

¹² *Id.* at 4-20.

¹³ *Id.* at 4-21. Specifically, Great Lakes transports gas originating from western Canada, as well as backhauls from the Marcellus/Utica shale plays in the eastern United States. Northern Natural Gas transports gas from the southern shale plays in Texas and Oklahoma. *Id.*

¹⁴ *Id.* at 4-19.

¹⁵ *Id.* at 1-3, n. 4.

¹⁶ *Id.* at 4-19.

¹⁷ *Id.* at 4-19.

¹⁸ *Id.*; Ex. MP-25 at 21 (Supinski Direct).

¹⁹ Ex. MP-2 at 4-18 (Petition); Ex. MP-13 at 11 (Pierce Direct).

²⁰ Ex. MP-2 at 4-28 to 4-30; Ex. MP-13 at 12 (Pierce Direct).

²¹ Ex. MP-13 at 12 (Pierce Direct); Ex. DER-8 at 3 (Rakow Direct).

²² Ex. MP-13 at 11 (Pierce Direct).

10. While Minnesota Power will not be an owner of NTEC, South Shore and Dairyland have agreed that the Company will take the lead in developing, constructing, operating, and maintaining NTEC subject to Commission approval.²³ South Shore has also agreed to dedicate 48 percent of the capacity (approximately 250 MW) from NTEC to the Company and its customers.²⁴

11. The NTEC transaction includes two agreements between South Shore and Dairyland, and three proposed affiliated interest agreements between South Shore and Minnesota Power. The affiliated interest agreements are the subject of Minnesota Power's request for approval in this case.

12. The agreements between South Shore and Dairyland include a Development and Construction (D&C) Agreement²⁵ and an Ownership and Operating (O&O) Agreement²⁶ (together the NTEC Project Agreements). The NTEC Project Agreements establish a 50/50 partnership between South Shore and Dairyland and place South Shore in the role of project and plant manager.

13. The three affiliated interest agreements for which the Company seeks approval in order to effectuate Minnesota Power's role and the NTEC capacity purchase are:²⁷

- Assignment of Rights Agreement (Construction Agent), dated July 28, 2017, between South Shore and Minnesota Power, under which South Shore assigns to Minnesota Power the right to act as the Construction Agent for NTEC pursuant to Section 3.7.5 of the D&C Agreement;²⁸
- Assignment of Rights Agreement (Operating Agent), dated July 28, 2017, between South Shore and Minnesota Power, under which South Shore assigns to Minnesota Power the right to act as the Operating Agent for NTEC pursuant to Section 4.7.5 of the O&O Agreement;²⁹ and
- Capacity Dedication Agreement (CDA), dated July 28, 2017, between South Shore and Minnesota Power, by which South Shore would dedicate 48 percent of the NTEC's capacity (approximately 250 MW) and the associated energy to Minnesota Power.³⁰

²³ Ex. MP-2 at 1-4 (Petition); Ex. MP-13 at 13 (Pierce Direct); Ex. MP-25 at 24, 26, 28 (Supinski Direct).

²⁴ Ex. MP 13 at 11-13 (Pierce); Ex. MP-2 at 1-3, n. 4 (Petition).

²⁵ Ex. MP-5, Appendix (App.) F (Development and Construction Management Agreement between Dairyland and South Shore).

²⁶ Ex. MP-5, Appendix G (Ownership and Operating Agreement between Dairyland and South Shore).

²⁷ Ex. MP-2 at 1-9 (Petition).

²⁸ Ex. MP-4, App. D (Assignment of Rights Agreement (Construction Agent) between South Shore and Minnesota Power).

²⁹ Ex. MP-4, App. E (Assignment of Rights Agreement (Operating Agent) between South Shore and Minnesota Power).

³⁰ Ex. MP-5, App. H (Unit Contingent Capacity Dedication Agreement between South Shore and Minnesota Power).

14. Minnesota Power has also requested approval of necessary variances and associated tariff amendments to its Fuel and Purchased Energy (FPE) Rider, to ensure that fuel costs and Midcontinent Independent System Operator, Inc. (MISO) market costs related to Minnesota Power's share of the NTEC facility are recovered and that MISO revenues realized under the CDA flow back to customers through the FPE Rider.³¹

II. Parties to the Proceeding

15. Minnesota Power is a public utility operating division of ALLETE, Inc., with its headquarters in Duluth, Minnesota.³² The Company provides electric service to approximately 145,000 residential and commercial customers, 16 municipal systems, and some of the nation's largest industrial customers.³³ A substantial majority of the Company's electric load is created by 13 large industrial customers.³⁴ Energy sales to these large industrial customers make up about 72 percent of the Company's total annual retail energy sales.³⁵ The Company's service territory covers approximately 26,000 square miles in central and northern Minnesota.³⁶

16. The Department is a state government agency that advocates for the public interest in utility proceedings.³⁷

17. The OAG is statutorily charged with representing and furthering the interests of residential and small business customers in proceedings before the Commission involving utility rates and adequacy of utility service.³⁸

18. The CEOs consist of Minnesota Center for Environmental Advocacy, Sierra Club, Fresh Energy, and Wind on the Wires.³⁹ These organizations seek to promote energy efficiency, conservation, and low-carbon alternatives.⁴⁰ The CEOs are concerned about the environmental and public health consequences of the proposed new gas plant.⁴¹

19. LPI consists of ArcelorMittal USA (Minorca Mine); Blandin Paper Company; Boise Paper, a Packaging Corporation of America company, formerly known as Boise, Inc.; Gerdau Ameristeel US Inc.; Hibbing Taconite Company; Mesabi Nugget

³¹ Ex. MP-13 at 66-74 (Pierce Direct).

³² *Id.* at 7.

³³ *Id.*

³⁴ *Id.*

³⁵ *Id.* at 9.

³⁶ *Id.* at 7.

³⁷ See Minn. Stat. § 216A.07, subds. 2-3 (2016).

³⁸ See Minn. Stat. § 8.33 (2016). The OAG is a party to the proceeding but did not actively participate in the proceeding or take a position in the proceeding.

³⁹ Petition to Intervene of the Clean Energy Organizations at 1 (Oct. 23, 2017) (eDocket No. 201710-136720-02).

⁴⁰ *Id.* at 2.

⁴¹ *Id.* at 3.

Delaware, LLC; Sappi Cloquet, LLC; USG Interiors, LLC; United States Steel Corporation (Keetac and Minntac Mines); United Taconite, LLC; and Verso Corporation.⁴² These large industrial customers collectively consume roughly two-thirds of the power that the Company delivers at retail and will be directly impacted by the outcome of this proceeding.⁴³

III. Jurisdiction

20. The Commission has general jurisdiction over Minnesota Power as a public utility under Minn. Stat. §§ 216B.01, 216B.03, and 216B.04 (2016). The Commission has specific jurisdiction over the Company's proposed affiliated interest agreements under Minn. Stat. § 216B.48 (2016) and Minn. R. 7825.1900-.2300 (2017). The Commission is authorized to approve necessary variances to the Commission's automatic adjustment rules for the proposed revisions to the Company's FPE Rider under Minn. Stat. § 216B.16, subd. 7(3) (2016), Minn. R. 7825.2390-.2920 (2017), and Minn. R. 7829.3200 (2017). The Commission has jurisdiction over the Guaranty Agreement referenced in the O&O Agreement between South Shore and Dairyland under Minn. Stat. § 216B.49 (2016).

21. The case was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.57-.62 (2016).

IV. Procedural Background

22. On September 1, 2015, the Company filed its 2015 Integrated Resource Plan (2015 IRP) under Minn. Stat. § 216B.2422 and Minn. R. chapter 7843.⁴⁴ The Company supplemented the plan on November 4, 2015.⁴⁵

23. In its 2015 IRP, the Company anticipated minimal power-supply needs in the near term but projected a capacity deficit starting in the mid-2020s.⁴⁶ As part of its plan, the Company proposed to idle Taconite Harbor Units 1 and 2 (coal-fired units), using them for reliability when market conditions are favorable, and ceasing operations at Taconite Harbor by 2020.⁴⁷ The Company also proposed to: use bilateral contracts to supply capacity needs between 2016 and 2019; prepare its transmission system for the addition of the Manitoba Hydro purchased power in 2020; reduce the sulfur-dioxide emissions of its Boswell Energy Center Units 1 and 2; and begin a competitive procurement process for 200-300 MW of natural gas combined-cycle generation for implementation by 2024.⁴⁸

⁴² LPI Petition to Intervene at 1 (Nov. 13, 2017) (eDocket No. 201711-137311-02).

⁴³ *Id.* at 2.

⁴⁴ *In the Matter of Minnesota Power's 2016-2030 Integrated Resource Plan*, MPUC Docket No. E-015/RP-15-690, Order Approving Resource Plan with Modifications at 1 (July 18, 2016) (2016 IRP Order).

⁴⁵ *Id.*

⁴⁶ *Id.* at 3.

⁴⁷ *Id.* at 3-4.

⁴⁸ *Id.* at 3.

24. On October 15, 2015, the Company issued a Request for Proposals (RFP) for up to 400 MW of natural gas-fired capacity and energy, beginning in the 2022 to 2024 timeframe.⁴⁹

25. On January 4, 2016, the Department, the CEOs, and LPI filed comments on the Company's proposed 2015 IRP. On March 4, 2016, the Company, the Department, the CEOs, and LPI filed reply comments.⁵⁰

26. In its comments on the 2015 IRP, the Department recommended that Minnesota Power procure 200 MW of combined-cycle natural gas generation. According to the Department, its modeling suggested that 200 MW of combined-cycle generation along with renewable resources and energy conservation could cost-effectively replace the coal-fired units that the Company planned to retire or idle.⁵¹

27. The CEOs questioned Minnesota Power's need for 200-300 MW of natural gas capacity by 2024, citing concerns with the Company's load forecast. They also asserted that the RFP was premature and that any RFP should be fuel-neutral rather than fuel-specific.⁵²

28. LPI also questioned the need for and timing of the RFP. LPI suggested that the Company had failed to consider other alternatives that were potentially less expensive such as demand-response measures and customer-owned generation.⁵³

29. The Commission also received numerous comments from members of the public.⁵⁴

30. On July 18, 2016, the Commission issued its Order Approving Resource Plan with Modifications (2016 IRP Order).⁵⁵

31. In its 2016 IRP Order, the Commission made several modifications to the Company's preferred resource plan.⁵⁶ The Commission found that the Company had not demonstrated that it was reasonable to invest in sulfur dioxide reduction at Boswell Units 1 and 2, and instead required the Company to retire Boswell Units 1 and 2 when sufficient energy and capacity are available, but no later than 2022.⁵⁷

32. With regard to the RFP, the Commission allowed the Company to pursue the RFP "to investigate the possible procurement of combined-cycle natural gas generation to meet its energy and capacity needs in the absence of Boswell Units 1 and

⁴⁹ Ex. MP-7 at Attachment R.

⁵⁰ 2016 IRP Order at 1-2.

⁵¹ *Id.* at 8.

⁵² *Id.*

⁵³ *Id.*

⁵⁴ *Id.* at 2.

⁵⁵ *Id.* at 1.

⁵⁶ *Id.* at 14.

⁵⁷ *Id.* at 14-15.

2 and Taconite Harbor Units 1 and 2, with no presumption that any or all of the generation identified in that bidding process will be approved. . . .”⁵⁸ In addition, the Commission provided that “to ensure a wide variety of replacement options is considered in the next resource plan, the Commission will require that the plan include a full analysis of all alternatives to natural gas, including renewables, energy efficiency, distributed generation, and demand response, for providing the energy and capacity sufficient to meet the Company’s needs.”⁵⁹

33. The Commission further modified MP’s proposed 2015 IRP by requiring the Company to initiate a competitive bidding process to “procure 100-300 MW of installed wind capacity” and to “acquire solar units of 11 MW by 2016, 12 MW by 2020, and 10 MW by 2025” to meet its Minnesota Solar Energy Standard (SES) obligations.⁶⁰

34. The Commission further directed the Company to initiate a demand-response competitive-bidding process.⁶¹

35. The Commission also required the Company to file its next resource plan on February 1, 2018.⁶²

36. On June 8, 2017, the Company requested that it be allowed to file its next resource plan on October 1, 2019 rather than February 1, 2018. The Company made the request to accommodate the filing of its proposed *EnergyForward* resource package.⁶³

37. On July 28, 2017, the Company filed its initial petition for approval of its *EnergyForward* resource package.⁶⁴ The proposal included three energy components: (1) a power purchase agreement (PPA) with the 250 MW Nobles Wind Project in southwestern Minnesota; (2) a PPA with the 10 MW Blanchard Solar Project in central Minnesota; and (3) affiliated interest agreements dedicating to the Company 48 percent of the capacity of the proposed 525 MW NTEC facility.⁶⁵

38. By an order dated September 19, 2017, the Commission approved the Company’s request to file its next resource plan on October 1, 2019.⁶⁶ The Commission also ordered a contested case proceeding on the proposed 250 MW NTEC purchase included in the *EnergyForward* petition.⁶⁷

⁵⁸ *Id.* at 15.

⁵⁹ *Id.* at 9, 15.

⁶⁰ *Id.* at 15. The Commission also made other modifications as specified in its 2015 Resource Plan Order. *Id.* at 14-16.

⁶¹ *Id.* at 15.

⁶² *Id.* at 16.

⁶³ Notice and Order for Hearing at 1, 4.

⁶⁴ *Id.* at 2.

⁶⁵ *Id.*

⁶⁶ *Id.* at 5, 9.

⁶⁷ *Id.* at 5, 8-9.

39. The Commission did not refer the wind or solar projects included in the *EnergyForward* petition to the Office of Administrative Hearing for a contested case.⁶⁸ The Commission noted that it had already approved the acquisition of wind and solar generation by Minnesota Power, and ordered the Company to refile its wind and solar PPAs for Commission approval in a separate docket.⁶⁹

40. With regard to the proposed purchase from NTEC included in the *EnergyForward* package, the Commission required the Company to file an updated petition in this docket “limited to those portions relevant to consideration of the proposed gas plant, with a revised forecast and updated alternatives.”⁷⁰

41. In its September 19, 2017 order, the Commission requested the Administrative Law Judge identify the issues and determine the appropriate scope and conduct for the hearing, considering, but not limited to, the issues identified in the Notice and Order for Hearing.⁷¹

42. The Commission identified the Company and the Department as the parties to the proceeding, and indicated that other persons wishing to become formal parties could file a petition to intervene with the Administrative Law Judge.⁷²

43. On October 23, 2017, the CEOs filed a petition to intervene.⁷³

44. Also on October 23, 2017, the OAG filed a petition to intervene.⁷⁴

45. On October 24, 2017, the Company filed its updated petition (Petition).⁷⁵

46. On October 25, 2017, the Administrative Law Judge held a prehearing conference.

47. On November 1, 2017, the Administrative Law Judge issued the First Prehearing Order.⁷⁶ The First Prehearing Order granted the petitions to intervene of the OAG and the CEOs.⁷⁷ The order also set procedures for the parties to the case, and established the following schedule:⁷⁸

⁶⁸ *Id.* at 5.

⁶⁹ *Id.*

⁷⁰ *Id.* at 8-9.

⁷¹ *Id.* at 8.

⁷² *Id.* at 8.

⁷³ CEO Petition to Intervene at 1-2 (Oct. 23, 2017) (eDocket No. 201710-136720-02).

⁷⁴ OAG Petition to Intervene (Oct. 23, 2017) (eDocket No. 201710-136710-03).

⁷⁵ Exs. MP-1 to MP-10 (Petition and appendices).

⁷⁶ First Prehearing Order (Nov. 1, 2017) (eDocket No. 201711-137088-01).

⁷⁷ *Id.*

⁷⁸ *Id.*

| Milestone | Due Date |
|---|--|
| MP refiles its Petition | October 24, 2017 |
| MP Pre-Filed Direct Testimony | November 9, 2017 |
| Deadline for Intervention | November 17, 2017 |
| MP files a list of the legal issues that it believes are within the scope of this proceeding | November 21, 2017 |
| Any other party may file its own list of the legal issues that it believes are within the scope of the proceeding to the extent the party's view differs from MP's view | December 8, 2017 |
| Prehearing Conference to finalize the list of legal issues for the contested case proceeding | December 13, 2017 at 10:30 a.m. at the Commission |
| Intervenor Pre-Filed Direct Testimony | January 19, 2018 |
| All Parties' Rebuttal Testimony | February 23, 2018 |
| Public Hearing in Duluth | February 28, 2018 |
| All Parties' Surrebuttal Testimony | March 16, 2018 |
| Public Comment Deadline | March 23, 2018 |
| Prehearing Conference by telephone | March 23, 2018 at 9:30 a.m. |
| Evidentiary Hearings – Saint Paul | Monday, March 26-29, 2018 at the MPUC offices in St. Paul. |
| All Parties' Initial Briefs | May 1, 2018 |
| All Parties' Reply Briefs All Parties' Proposed Findings of Fact and Conclusions of Law | May 22, 2018 |
| Report of the Administrative Law Judge | July 2, 2018 |

48. On November 9, 2017, the Company filed the direct testimony of Julie I. Pierce, Eric J. Palmer, Lyssa S. Supinski, Frank L. Frederickson, and Stephen G. Brick.

49. On November 13, 2017, LPI filed its Petition to Intervene.⁷⁹

⁷⁹ LPI Petition to Intervene (Nov. 13, 2017) (eDocket No. 201711-137311-02).

50. On November 17, 2017, the Administrative Law Judge issued a Protective Order.⁸⁰

51. On November 21, 2017, the Administrative Law Judge issued an order granting intervention to LPI.⁸¹

52. Also, on November 21, 2017, the Company filed a proposed list of issues (Issues List) for hearing in accordance with the First Prehearing Order.⁸² The Company indicated that it had worked with the other parties to the proceeding in drafting the Issues List.⁸³

53. On December 8, 2017, the Department filed a letter with a suggested clarifying edit to legal issue No. 4.⁸⁴ In the letter, the Department noted that the Administrative Law Judge could determine that a second prehearing conference scheduled for December 13, 2017 would not be necessary.⁸⁵ No other party filed any comments on the Issues List filed by Minnesota Power.

54. On December 12, 2017, the Administrative Law Judge issued the Second Prehearing Order. The order specified that the issues in the case are those included on the Issues List filed by Minnesota Power, as amended by the Department's December 8, 2017 filing.⁸⁶

55. The Second Prehearing Order also cancelled the prehearing conference scheduled for December 13, 2017 based on the agreement by the parties to the issues in the case.⁸⁷

56. On January 19, 2018, the Department, the CEOs, and LPI filed direct testimony. The OAG did not file direct testimony.

57. The Department filed the Direct Testimony of Dr. Steve Rakow, Nancy A. Campbell, and Dr. Eilon Amit.

58. The CEOs filed the Direct Testimony of J. Drake Hamilton, Michael B. Jacobs, Dan Mellinger, Anna Sommer, and Dr. Elizabeth A. Stanton.

59. LPI filed the Direct Testimony of Robert R. Stephens, Michael P. Gorman, and Brian C. Andrews.

⁸⁰ Protective Order (Nov. 17, 2017) (eDocket No. 201711-137473-01).

⁸¹ Order Granting Intervention to the Large Power Intervenors (Nov. 21, 2017) (eDocket No. 201711-137564-01).

⁸² Issues List (Nov. 21, 2017) (eDocket No. 201711-137580-01).

⁸³ *Id.*

⁸⁴ Department Response to Minnesota Power Proposed Issues List (Dec. 8, 2017) (eDocket No. 201712-138051-01).

⁸⁵ *Id.*

⁸⁶ Second Prehearing Order, Final Issues List.

⁸⁷ *Id.* at 2.

60. On February 23, 2018, all parties except LPI and the OAG filed rebuttal testimony.

61. Minnesota Power filed the Rebuttal Testimony of Julie I. Pierce, Eric J. Palmer, Lyssa S. Supinski, Frank L. Frederickson, Stephen G. Brick, and Alan S. Taylor.

62. The Department filed the Rebuttal Testimony of Dr. Steve Rakow.

63. The CEOs filed the Rebuttal Testimony of Michael B. Jacobs and Anna Sommer.

64. On February 28, 2018, a public hearing was held in Duluth, Minnesota.⁸⁸

65. On March 12, 2018, the Commission issued its Findings of Fact, Conclusions, and Order in Minnesota Power's 2016 Rate Case. The Commission's Order directed Minnesota Power, LPI, and other stakeholders to develop a demand response rider and corresponding methodology for cost recovery, based on stakeholder input, for submission to the Commission. The Commission directed that the demand response issue be addressed either in the instant docket or in a new miscellaneous docket.⁸⁹

66. On March 16, 2018, all parties except the OAG filed Surrebuttal testimony.

67. Minnesota Power filed the Surrebuttal Testimony of Julie I. Pierce and Stephen G. Brick.

68. The Department filed the Surrebuttal Testimony of Dr. Steve Rakow, Nancy A. Campbell, and Dr. Eilon Amit.

69. The CEOs filed the Surrebuttal Testimony of J. Drake Hamilton, Michael B. Jacobs, Dan Mellinger, Anna Sommer, and Dr. Elizabeth A. Stanton.

70. LPI filed the Surrebuttal Testimony of Robert R. Stephens, Michael P. Gorman, and Brian C. Andrews.

71. On March 23, 2018, the period for written public comments closed.

72. Also on March 23, 2018, a prehearing conference was held with the parties by telephone to discuss hearing procedures and other related items.⁹⁰

⁸⁸ Public Hearing Transcript (Pub. Hearing Tr.) at 1 (Feb. 28, 2018).

⁸⁹ *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E-015/GR-16-664, Findings of Fact, Conclusions, and Order (2016 Rate Case Order) at 115 (Order Point 72) (March 12, 2018) (eDocket No. 20183-140963-01).

⁹⁰ Prehearing Transcript (Prehearing Tr.) at 1 (March 23, 2018).

73. On March 26, 2018, the evidentiary hearing was held in the Commission's Large Hearing Room in St. Paul, Minnesota.⁹¹

74. On April 23, 2018, the OAG filed a letter indicating that the OAG did not intend to file an initial post-hearing brief. The OAG also indicated that it would review the initial briefs filed by other parties, and then decide whether to submit a reply brief.⁹²

75. On May 1, 2018, all parties except the OAG filed initial briefs.

76. On May 22, 2018, all parties except the OAG filed reply briefs.

V. Summary of Oral and Written Public Comments

77. Approximately 65 people attended the public hearing on February 28, 2018, with 21 offering oral comments.⁹³ In addition, over 1,500 written comments were received by the March 23, 2018 deadline.⁹⁴ The public comments were submitted by Minnesota Power customers, environmental advocacy groups, trade and business associations, local businesses, and others.⁹⁵

78. The majority of the public comments received were in opposition to the proposed NTEC gas plant and Minnesota Power's 250 MW NTEC purchase. Many of the people who commented contend that the purchase is not needed to meet electricity needs. These commenters maintained that Minnesota Power could meet demand by increasing energy efficiency and investing in renewable energy alternatives, such as wind and solar. Many also objected to the fact that the gas will be derived from hydraulic fracturing (fracking). These commenters asserted that fracking damages the environment by contributing to water and air pollution. Some also maintained that fracking negatively impacts the health of those living nearby, including increasing incidences of certain cancers. Several people also expressed concern about the potential negative impact the proposed gas plant may have on Lake Superior and Minnesota's North Shore region. These commenters urged the Commission to reject

⁹¹ See Hearing Transcript, Vol. 1 (Tr.) at 1 (March 26, 2018).

⁹² OAG Letter (Apr. 23, 2018) (eDocket No. 20184-142229-01).

⁹³ Public Hearing Ex. 1 (sign-in sheet); Public Hearing Tr. at 2-3 (Feb. 28, 2018).

⁹⁴ See Public Comments (Feb. 26, 2018) (eDocket No. 20182-140475-01); Public Comments (Mar. 2, 2018) (eDocket No. 20183-140747-01); Public Comments (Mar. 6, 2018) (eDocket No. 20183-140826-01); Public Comment (Mar. 12, 2018) (eDocket No. 20183-140968-01); Public Comment (Mar. 14, 2018) (eDocket No. 20183-141015-01); Public Comment (Mar. 15, 2018) (eDocket No. 20183-141095-01); Public Comment (Mar. 20, 2018) (eDocket No. 20183-141201-01); Public Comment (Mar. 22, 2018) (eDocket Nos. 20183-141292-01, 20183-141291-01, 20183-141288-01, 20183-141286-01); Public Comment—Letter and Poll Regarding Proposed Nemadji Trail Energy Center (Mar. 22, 2018) (eDocket No. 20183-141280-01); Public Comments (Mar. 23, 2018) (eDocket No. 20183-141322-01, 20183-141298-01)). Additionally, Honor the Earth filed a public comment in the above-captioned proceeding via email by sending it to consumer.puc@state.mn.us on March 23, 2018 at 4:22 p.m., before the close of the public comment period. Honor the Earth's public comment was not efiled by the Commission staff in eDockets along with other public comments filed that day. As a result, on May 17, 2018, Honor the Earth filed its comments directly through eDockets into this docket. (eDocket No. 20185-143144-01).

⁹⁵ A detailed discussion of the public comments is provided in Attachment A to this Report.

the proposed in order to protect and maintain northern Minnesota's pristine environment and tourism industry.

79. One group, Honor the Earth, asserted that an Environmental Impact Statement is needed for the proposed 250 MW NTEC purchase before the NTEC purchase could be approved by the Commission because construction of NTEC would result in significant environmental impacts on the citizens of Minnesota, as well as on the land and waters of the state.⁹⁶ The group also recommended that the Company's petition for approval of the affiliated interest agreements for the proposed NTEC purchase be denied.⁹⁷ Finally, the group recommended that the Commission order the Company to provide a study of the impact of existing and future pipeline operations on Minnesota Power's operations as well as the regional transmission grid.⁹⁸

80. While most persons filing public comments expressed opposition to the NTEC proposal, comments of support for the proposed NTEC gas plant and power purchase were filed by businesses, organized labor, and economic development interests. These commenters maintained that gas is a clean burning resource and a better alternative than coal. They insisted that the proposed purchase will diversify the Company's energy options and will be a necessary generation resource when alternatives such as wind and solar facilities are not generating electricity. Many of these commenters also extolled the number of jobs that will result from the construction and operation of the plant as well as the estimated \$1 million in annual tax revenue.

VI. Applicable Legal Standards and Burden of Proof

81. In its Petition, the Company seeks approval of the affiliated interest agreements and associated tariff changes for its proposed purchase of a 48 percent share (approximately 250 MW) of the capacity from NTEC.⁹⁹

82. Pursuant to Minn. Stat. § 216B.48, subd. 3, a public utility must seek Commission approval of any contract or agreement between a public utility and any affiliated interest "for the furnishing of management, supervisory, construction, engineering, accounting, legal, financial, or similar services," or any "contract or arrangement for the purchase, sale, lease, or exchange of any property, right, or thing, or for the furnishing of any service, property, right, or thing."¹⁰⁰

83. The Commission shall approve the affiliated interest agreement "only if it clearly appears and is established upon investigation that it is reasonable and

⁹⁶ Public Comment by Honor the Earth at 3-15 (May 17, 2018) (eDocket No. 20185-143144-01).

⁹⁷ *Id.* at 15-16.

⁹⁸ *Id.* at 17-21.

⁹⁹ Ex. MP-2 at 1-1 (Petition).

¹⁰⁰ Minn. Stat. § 216B.48, subd. 3 (2016).

consistent with the public interest.”¹⁰¹ An affiliated interest agreement is not valid or effective without Commission approval.¹⁰²

84. In evaluating whether the proposed NTEC affiliated interest agreements are in the public interest, the Commission instructed the Administrative Law Judge to consider whether the proposed NTEC gas plant is needed and reasonable.¹⁰³

85. The Commission’s Order provides: “[t]he ultimate issue in this case is whether Minnesota Power’s proposed gas plant is necessary and reasonable.”¹⁰⁴ The Commission noted that the determination “turns on numerous factors . . . including but not limited to consideration of certificate of need factors and the resources planning factors.”¹⁰⁵ The Commission also specified the consideration is to be based on an updated demand forecast, an evaluation of costs (including socioeconomic and environmental costs, with recently adopted externality values), and an analysis of alternatives to some or all of the gas plant energy and capacity. The consideration of alternatives is to include, but not be limited to, “alternatives such as additional wind and solar resources (with updated costs), storage, demand response, and additional energy efficiency.”¹⁰⁶

86. The Commission also provided that the “renewable resource requirements set forth Minn. Stat. § 216B.2422 and Minn. Stat. § 216B.243, subd. 3a will apply to consideration of Minnesota Power’s proposed gas plant.”¹⁰⁷

87. Minn. Stat. § 216B.2422, subd. 4 includes a preference for renewable energy facilities. That provision states:

The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. When making the public interest determination, the commission must consider:

- (1) whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f;
- (2) impacts on local and regional grid reliability;

¹⁰¹ *Id.*

¹⁰² *Id.*

¹⁰³ Notice and Order for Hearing at 5-6, 8-9.

¹⁰⁴ *Id.* at 5.

¹⁰⁵ *Id.*

¹⁰⁶ *Id.* at 6.

¹⁰⁷ *Id.* at 9.

- (3) utility and ratepayer impacts resulting from the intermittent nature of renewable energy facilities, including but not limited to the costs of purchasing wholesale electricity in the market and the costs of providing ancillary services; and
- (4) utility and ratepayer impacts resulting from reduced exposure to fuel price volatility, changes in transmission costs, portfolio diversification, and environmental compliance costs.

88. Similarly, Minn. Stat. § 216B.243, subd. 3a requires a utility proposing to build a large electric generating facility in the state that uses a non-renewable energy source to demonstrate that “it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source.” While the NTEC facility will not be built in the state, the Commission has determined that this analysis is relevant to the determination of whether Minnesota Power’s proposed purchase of approximately 250 MW of generating capacity from NTEC, a gas fired power plant, is in the public interest.¹⁰⁸

89. Consistent with the Commission’s Notice and Order for Hearing, Minnesota Power has the burden of proof in this case to show that the proposed NTEC “gas plant or any portion thereof is needed and reasonable” and the NTEC affiliated interest agreements are in the public interest.¹⁰⁹

VII. The Company’s Forecast of its Energy Sales and Peak Demand

A. General Forecasting Process and Requirements

90. Pursuant to Minn. Stat. § 216C.17, each utility in the state is required to prepare and file annually a forecast of the utility’s demand for energy in five, ten, and 15 years.¹¹⁰

91. The utility is not required to use a specified forecast methodology. Rather, it “may use the forecast methodology that yields the most useful results for its system.”¹¹¹ The utility is required to discuss the overall methodological framework used, the data used, and assumptions made in the forecast.¹¹²

¹⁰⁸ *Id.* at 9.

¹⁰⁹ *Id.* at 5, 9.

¹¹⁰ Minn. Stat. § 216C.17 (2016); Minn. R. 7610.0320 (2017).

¹¹¹ Minn. R. 7610.0320, subp. 1.

¹¹² Minn. R. 7610.0320.

92. The utility's forecast is used in the resource planning process to help identify the size, type, and timing of resources necessary to meet the utility's demand in the next 15 years.¹¹³

93. Forecasts are also used in certificate of need (CON) proceedings. In CON proceedings, Minn. R. 7849.0270 specifies the forecast must include an estimate of the number of customers in the utility's service area and projected annual electric consumption by those customers based on customer class and in total.¹¹⁴ The rule also requires an estimate of peak demand and average system weekday load factor by month.¹¹⁵ Pursuant to this rule, the "forecast data . . . is subject to test of accuracy, reasonableness, and consistency."¹¹⁶

B. Background Regarding Minnesota Power's 2015 IRP Forecast

94. In its 2015 IRP, the Company included forecast information from its 2014 Annual Forecast Report (2014 AFR).¹¹⁷ The 2014 AFR showed significant industrial customer expansion and growth over the 15-year forecast period.¹¹⁸ On average, energy sales and peak demand were projected to grow at about 1.1 percent per year from 2014 through 2028.¹¹⁹

95. In comments on the 2015 IRP, the CEOs argued that the forecast overstated future industrial demand based on overly optimistic assumptions about when and whether several major proposals would come to fruition.¹²⁰ The Department disagreed with most of the CEOs criticisms and maintained that the Company had evaluated a reasonable range of forecasts in developing its 2015 IRP.¹²¹

96. In its 2016 IRP Order, the Commission concurred with the Department that MP's forecast range was reasonable for planning purposes, but noted that the CEO's comments highlighted "economic trends that have led to lower demand projections in recent forecasts."¹²² The Commission further stated that "[i]n light of these trends, Minnesota Power's load forecast scenarios used in its 2015 [IRP] may overstate the size or timing of future needs."¹²³

¹¹³ Minn. Stat. §§ 216B.2422, subd. 2a (2016); Minn. R. 7843.0400 (2017); Ex. MP-2 at 2-4 (Petition); Ex. DER-8, SRR-2 (Rakow Direct).

¹¹⁴ *Id.*, subd. 2.

¹¹⁵ *Id.*, subd. 2.

¹¹⁶ Minn. R. 7849.0270, subd. 3 (2017).

¹¹⁷ Ex. MP-2 at 2-6 (Petition)

¹¹⁸ *Id.*

¹¹⁹ *Id.*

¹²⁰ 2016 IRP Order at 4.

¹²¹ *Id.*

¹²² *Id.*

¹²³ *Id.*

97. As a result of this analysis, the Commission required the Company to file an updated forecast in the contested case proceeding in this matter.¹²⁴

C. 2017 Updated Forecast

98. In its Petition filed on October 24, 2017, Minnesota Power provided an updated forecast of its projected energy sales and peak demand through 2030 as requested by the Commission.¹²⁵

99. The Company's forecast method uses econometric modeling for all customer classes.¹²⁶ For the large industrial and resale classes, the Company then makes some modifications to the model outputs based on customer-specific information.¹²⁷ According to the Company, an "econometric approach utilizing regression modeling is optimal for estimating a baseline projection or the long-term industry trends within a given economic outlook" but econometric modeling alone "would not adequately project the kind of sudden and substantial swings in industrial customer load, particularly in mining, that occur with some frequency . . ." on Minnesota Power's system.¹²⁸ For that reason, the Company uses "market intelligence and customer-specific information" for its industrial and resale sectors to inform its econometric forecasts.¹²⁹

100. In addition, the Company's forecast model accounts for the Conservation Improvement Program (CIP) and Demand-Side Management (DSM) "through historical data."¹³⁰ The impact of existing CIP and DSM programs are present in the historical data used by Minnesota Power in its forecast modeling, and are therefore implicit in the Company's forecasts.¹³¹

101. The updated forecast included in the Petition is based on the 2017 Annual Forecast Report (2017 AFR) filed on June 29, 2017.¹³²

102. In developing the 2017 AFR, the Company made a number of changes to the approach it used for the 2014 AFR forecast submitted with the 2015 IRP.¹³³ Specifically, the 2017 AFR: assumed more conservative large industrial customer outlooks; accounted for the secondary economic impacts of large industrial customers;

¹²⁴ Notice and Order for Hearing at 5, 8.

¹²⁵ Ex. MP-2 at 2-1 to 2-18 (Petition).

¹²⁶ Ex. MP-13 at 45-46 (Pierce Direct).

¹²⁷ *Id.*

¹²⁸ Ex. MP-2 at 2-5 (Petition); Ex. MP-13 at 46 (Pierce Direct).

¹²⁹ Ex. MP-2 at 2-5 (Petition).

¹³⁰ Ex. MP-2 at 2-5 (Petition); Minnesota Power's 2017 Annual Elec. Util. Forecast Report, MPUC Docket No. E999/PR-17-11, Report at 13-14 (2017 AFR) (June 29, 2017).

¹³¹ Ex. MP-2 at 2-5 (Petition); 2017 AFR at 13-14.

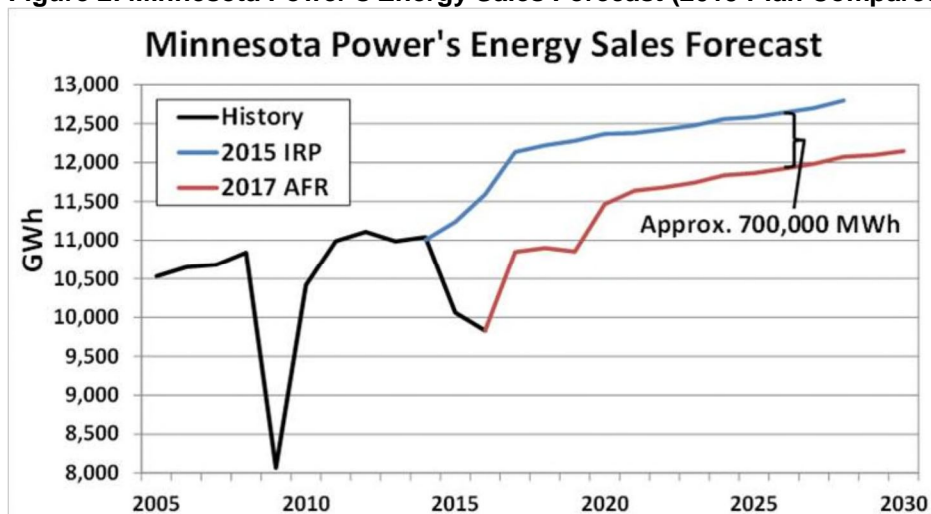
¹³² Ex. MP-13 at 45 (Pierce Direct); Ex. MP-2 at 2-8 (Petition); The Company's 2017 AFR also includes a fifteen year forecast of customer count by class, energy sales by class, along with a discussion of the methodology, assumptions, and supporting information for the annual forecast. 2017 AFR at 5-14, 27-40.

¹³³ Ex. MP-2 at 2-7 (Petition).

and implemented several methodological enhancements.¹³⁴ These changes were made in response to the Commission's July 2016 IRP Order.¹³⁵

103. Figure 2 from the Petition, set forth below, compares the 2017 AFR (in red) to the forecast included in the 2015 IRP (in blue):¹³⁶

Figure 2: Minnesota Power's Energy Sales Forecast (2015 Plan Compared to the 2017 AFR)



104. The 2017 AFR sets forth an energy sales forecast that is about 1,350,000 MWh per year lower than forecasted in the 2015 IRP in the pre-2020 timeframe, and about 720,000 MWh per year lower by 2025.¹³⁷

105. The majority of the decrease in the outlook is due primarily to more conservative overall assumptions concerning Minnesota Power's large industrial customers.¹³⁸ Since the filing of the 2015 IRP forecast, eight of ten large existing mining and metals customers on Minnesota Power's system experienced some idling of production, and some remain indefinitely idled. The 2017 AFR forecast used in the Petition has been updated to reflect the Company's current expectations for existing industrial customers.¹³⁹ The majority of the decrease in sales by 2025, as compared to the 2015 IRP forecast, is attributable to Mesabi Metallics and Magnetation Plants 2 and 4 being removed from the long-term forecast.¹⁴⁰ The forecast does assume the PolyMet mine (approximately 45 MW) will be fully operational by 2020.¹⁴¹ As to other

¹³⁴ *Id.*; Ex. MP-13 at 46, 49-50 (Pierce Direct). The methodological enhancements included: adjusting the historical sales series to avoid the potential for double-counting of load in econometric outputs; applying binary and trend variables to econometrically account for inflection of the sales growth trajectory since the 2007 recession. Ex. MP-2 at 2-7 (Petition).

¹³⁵ Ex. MP-13 at 46 (Pierce Direct).

¹³⁶ Ex. MP-2 at 2-8 (Petition); Ex. MP-13 at 51 (Pierce Direct).

¹³⁷ Ex. MP-13 at 47 (Pierce Direct).

¹³⁸ *Id.*

¹³⁹ *Id.*

¹⁴⁰ *Id.* at 52.

¹⁴¹ Ex. 17 at 20 (Palmer Rebuttal).

prospective new mining operations, Minnesota Power deferred the projected start dates or deemed them no longer likely enough to be included in the 2017 AFR forecast.¹⁴²

106. The remaining decrease in the 2017 energy sales forecast is due to: the secondary economic impacts of a more conservative large industrial sector employment outlook; econometric modeling enhancements implemented in the 2017 AFR; and an additional three years of observed energy sales.¹⁴³

107. The 2017 forecast does not take into account the late October 2017 announcement by Blandin of its plan to permanently close its Paper Mill 5 in the first quarter of 2018.¹⁴⁴ Blandin's Paper Mill 5 is one of two paper production lines in Grand Rapids, Minnesota, which lies within in the Company's service territory.¹⁴⁵ This information was not included in the Minnesota Power's large customer assumptions for the 2017 forecast because the announcement was made after the completion of the 2017 forecast.¹⁴⁶ The impact of this announcement is estimated to be a reduction of approximately 20 MW in the ongoing energy need of its sales.¹⁴⁷

108. Overall, Minnesota Power's current energy sales outlook forecasts a 0.9 percent per year compound annual growth rate from 2017 to 2030 versus the 1.1 percent rate included in the 2015 IRP.¹⁴⁸

109. The Company's 2017 forecast also projects annual peak demand through 2030. Figure 3 from the Petition, set forth below, compares the 2017 AFR annual peak demand outlook (in red) to the 2015 IRP forecast (in blue).¹⁴⁹

¹⁴² *Id.* at 47.

¹⁴³ Ex. MP-13 at 48-49 (Pierce Direct).

¹⁴⁴ *Id.* at 47 (Pierce Direct). The Bland Paper Mill 5 closed in the end of December 2017. Ex. LPI-5 at 7 (Gorman Direct).

¹⁴⁵ Ex. LPI-5 at 7 (Gorman Direct).

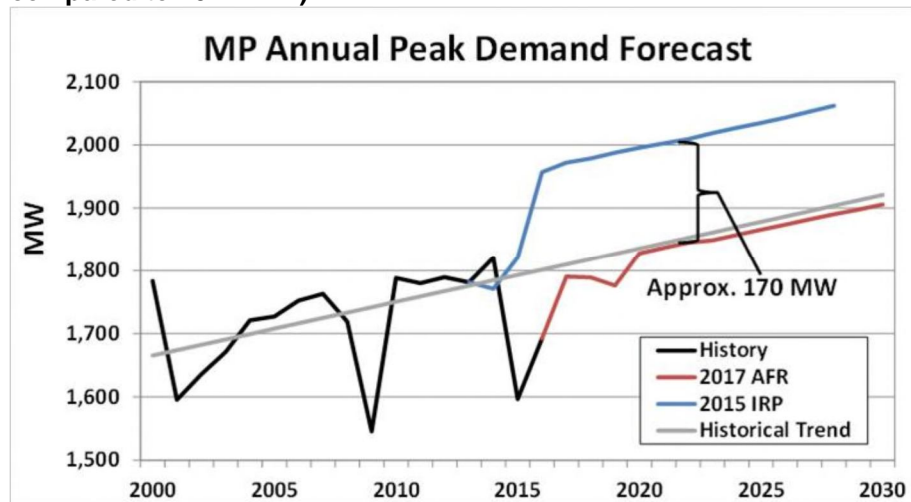
¹⁴⁶ Ex. MP-13 at 47 (Pierce Direct).

¹⁴⁷ *Id.* at 48; Ex. LPI-5 at 7 (Gorman Direct).

¹⁴⁸ Ex. MP-13 at 52 (Pierce); Ex. MP-2 at 2-9 (Petition).

¹⁴⁹ Ex. MP-2 at 2-9 (Petition); Ex. MP-13 at 53 (Pierce).

Figure 3: Minnesota Power's Annual Peak Demand Forecast Comparison (2015 Plan compared to 2017 AFR)



110. The 2017 AFR annual peak demand forecast is more modest than the 2015 IRP levels, responding in part to Commission concern that the 2015 IRP forecast may have overestimated future demand growth and reflecting updated assumptions in that regard.¹⁵⁰ By 2020, the 2017 AFR forecast is about 170 MW lower than the 2015 IRP forecast.¹⁵¹ The projected 2020 peak is about 35 MW higher than the recent, pre-downturn period when the average peak demand from 2010 to 2014 was 1,792 MW.¹⁵²

111. The forecast set forth above represents the expected growth based on the Company's modeling. To capture the plausible ranges of uncertainty in Minnesota Power's customer outlooks, which are inherent to the forecasting of future sales, two additional sensitivities were included in the Petition: the "2017 AFR High" scenario and "2017 AFR Low" scenario.¹⁵³ These sensitivities were used by Minnesota Power to recognize the range of uncertainty that exists with the Company's unique customer base.¹⁵⁴ These sensitivities are included in Figures 9 and 10 of the Petition, as set forth below:¹⁵⁵

¹⁵⁰ Ex. MP-2 at 2-9 (Petition); Ex. MP-13 at 53 (Pierce).

¹⁵¹ Ex. MP-2 at 2-9 (Petition); Ex. MP-13 at 53 (Pierce).

¹⁵² Ex. MP-2 at 2-9 (Petition); Ex. MP-13 at 53 (Pierce).

¹⁵³ Ex. MP-2 at 2-16 (Petition); Ex. MP-13 at 61 (Pierce Direct).

¹⁵⁴ Ex. MP-2 at 2-16 (Petition).

¹⁵⁵ Ex. MP-2 at 2-17 (Petition); Ex. MP-13 at 62 (Pierce Direct).

Figure 9: Minnesota Power's Energy Sales Forecast (2017 AFR High/Low Comparison)

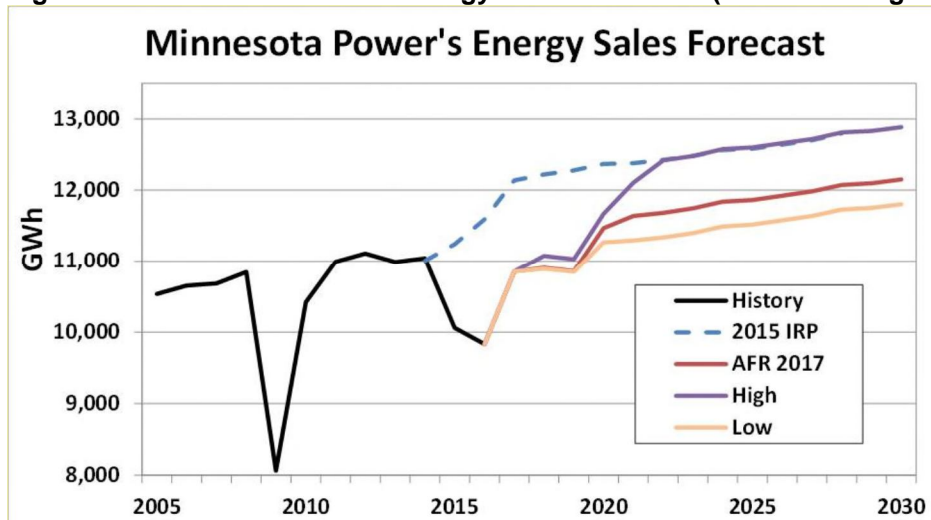
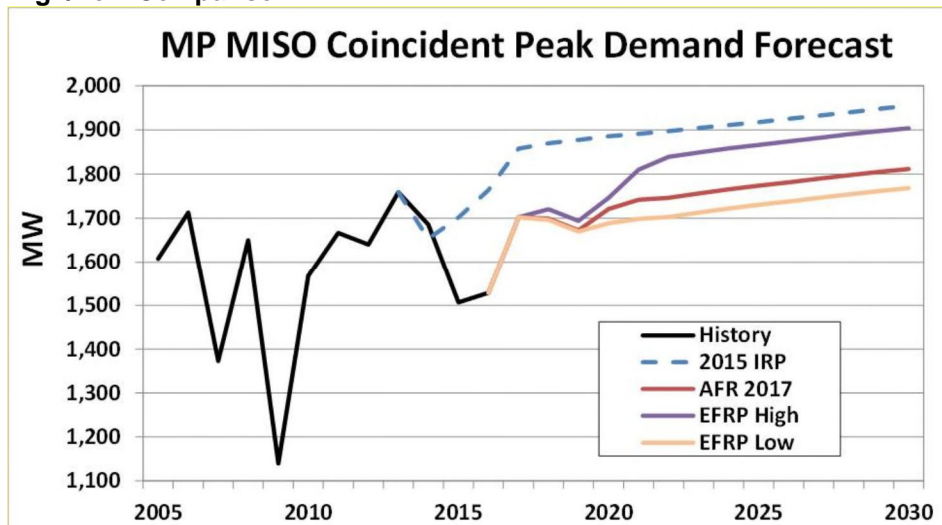


Figure 10: Minnesota Power's MISO Coincident Peak Demand Forecast (2017 AFR High/Low Comparison)



112. The “2017 AFR High” outlook assumes the resumption of operations by two recently-idled iron concentrate facilities and the startup of Mesabi Metallica, resulting in nearly 100 MW of additional growth.¹⁵⁶ The “2017 AFR Low” forecast evaluates a “status-quo” assumption with regards to the mining sector, where currently-idled facilities remain idled and the proposed PolyMet mine does not commence operations in the forecast timeframe.¹⁵⁷ Both the high and low forecasts assume the same residential and commercial energy use as in the base case 2017 AFR.¹⁵⁸

¹⁵⁶ Ex. MP-2 at 2-18 (Petition); Ex. MP-13 at 63 (Pierce Direct).

¹⁵⁷ Ex. MP-2 at 2-18 (Petition); Ex. MP-13 at 63 (Pierce Direct).

¹⁵⁸ See MP-2 at 2-18 (Petition).

113. While the Company included the high and low growth scenarios in its Petition, the Company based its projected need for resources and its evaluation of alternatives in this proceeding on the 2017 AFR base case (moderate growth scenario).¹⁵⁹

i. The Department's Comments on the Company's Updated Forecast

114. The Department did not review the technical accuracy of Minnesota Power's demand forecast in this proceeding.¹⁶⁰ Instead, the Department compared the Company's 2017 updated forecast to the forecast band used by the Department in the 2015 IRP proceeding to determine if the forecast used in the 2015 IRP needed to be updated for use in this proceeding.¹⁶¹ The Department concluded that the "2017 AFR is within the contingency bands employed by the Department," and no additional refinements are necessary for use in this proceeding.¹⁶²

ii. The Comments of the CEOs and LPI along with the Company's Response

115. The CEOs claimed that Minnesota Power's updated load and energy forecasts are upwardly biased.¹⁶³ The CEOs maintained that the Company failed to consider a reasonable range of possible future scenarios in its low, moderate, and high growth scenarios because: (1) there was inadequate consideration of recent consumption trends; (2) there was no consideration of possible flat or declining load scenarios in the commercial and residential sectors; and (3) there was no accounting for a possible economic downturn in the industrial sector. The CEOs argued that the over-forecasting contained in the Company's Petition is emblematic of Minnesota Power's history.¹⁶⁴ These issues are discussed in more detail below.

116. In addition, the CEOs and LPI both emphasized that Minnesota Power's base case (moderate growth) forecast fails to account for the closing of the Blandin Paper Mill 5 in December 2017, and thereby overestimates the Company's expected need for power.¹⁶⁵ This issue is discussed below as well.

¹⁵⁹ Ex. MP-2 at 2-10 to 2-11 (Petition); Ex. MP-5, App. I at I-5 (Assumptions and Outlooks).

¹⁶⁰ Ex. DER-11 at 6-7 (Rakow Surrebuttal).

¹⁶¹ *Id.* at 6-7. The Department's reply comments in MP's most recent IRP addressed the accuracy of MP's overall forecast process. The forecasting section of those comments are included in the record at Ex. DER-8, SRR-S-7 (Rakow Direct). The analysis states "the Department concludes that our use of ± 2.5 percent (mid-high and mid-low) and ± 5 percent (high and low) forecast bands reasonably captures the uncertainty present in [Minnesota Power's] forecasts." *Id.*, SRR-S-7 at 9.

¹⁶² Ex. DER-8, SRR-3 at 13 (Rakow Direct).

¹⁶³ Clean Energy Organizations' Initial Post-Hearing Brief (COE Initial Br.) at 7-8 (eDocket No. 20185-142674-02).

¹⁶⁴ Clean Energy Organizations' Initial Post-Hearing Br. (CEO Initial Br.) at 7-8; Ex. CEO-4 at 12-18 (Stanton Direct).

¹⁶⁵ LPI-5 at 7 (Gorman Direct).

a. Recent Consumption Trends

117. The CEOs criticized the Company's forecasting methodology for using the Company's historical database, which extends back to 1990, instead of limiting its historical dataset to include only the most recent ten years of sales information. The CEOs argued that the Company's reliance on the complete data set results in an overestimate of future energy usage.¹⁶⁶

118. The CEOs emphasized that recent trends have demonstrated flat or declining loads in the commercial and residential sectors. CEO witness Dr. Stanton broke down Minnesota Power's historical residential and commercial energy use into three time periods: 1990-1996, 1996-2006, and 2006-2016.¹⁶⁷

119. For the residential sector, there was 0.8 percent growth from 1990 to 1996, 0.0 percent growth from 1996 to 2006, and negative 0.3 percent growth from 2006 to 2016.¹⁶⁸

120. For the commercial sector, there was 1.1 percent growth from 1990 to 1996, 0.4 percent growth from 1996 to 2006, and negative 0.6 percent growth from 2006 to 2016.¹⁶⁹

121. According to Dr. Stanton, this data shows that usage per residential and commercial customer on Minnesota Power's system has been falling, on average, over the past ten years.¹⁷⁰

122. The CEOs did not provide a similar analysis for energy use by large industrial or resale customers.¹⁷¹

123. In response, Minnesota Power maintained that it is appropriate for the Company to use all available historical data (26 years) rather than a shorter period (ten years) for modeling energy use in its forecast. According to Minnesota Power witness Julie Pierce, regression models based on a ten-year historical timeframe have some statistical deficiencies that make any forecast results from ten years of data "untrustworthy and unusable."¹⁷² Ms. Pierce explained that the Company's "regression models using a 26-year dataset included only the economic and demographic predictor variables that had a strong correlation to energy use, and statistical measures indicated the Company and other stakeholders could be confident in the estimated relationship between employment, for example, and commercial energy use."¹⁷³ According to Ms. Pierce, after limiting the dataset to ten years, "the statistics indicated a lack of confidence in many of these previously useful predictor variables: they had become

¹⁶⁶ CEO Initial Br. at 8-9.

¹⁶⁷ Ex. CEO-4 at 14, 17 (Stanton Direct).

¹⁶⁸ *Id.* at 14.

¹⁶⁹ *Id.* at 17.

¹⁷⁰ *Id.* at 15.

¹⁷¹ See generally Ex. CEO-4 (Stanton Direct).

¹⁷² Ex. MP-14 at 42 (Pierce Rebuttal).

¹⁷³ *Id.* at 42-43.

insignificant. Models containing insignificant variables are said to be ‘mis-specified’ and should be disregarded.”¹⁷⁴

124. In addition, Ms. Pierce indicated that limiting the historical time frame to the last ten years is problematic because “a shorter timeframe is more volatile in its projections,” meaning the outlook can change sharply from one year to the next.¹⁷⁵ Ms. Pierce provided examples of how the results vary depending on which truncated time period is selected.¹⁷⁶

125. Ms. Pierce also asserted limiting the data period to ten years as suggested by the CEOs would allow a forecaster to “cherry-pick” the historical timeframe that produces the decided outcome. Ms. Pierce maintained that CEO witness Dr. Stanton had done just that. She noted that Dr. Stanton’s more limited dataset “happens to start at one of Minnesota Power’s highest sales years in a pre-recession timeframe, and then end on a year in which several large taconite mines were idle and residential/commercial sales were subdued by a mild La Nina winter.”¹⁷⁷ Ms. Pierce concluded that “[s]electing this 2007-2016 (sic)¹⁷⁸ timeframe for modeling any of the Company’s customer classes was guaranteed to produce a lower forecast and therefore is more subjective.”¹⁷⁹

126. In response, Dr. Stanton disagreed, stating:

[w]hile the 26-year trend supported by Ms. Pierce results in a strong positive projection of growth in per customer use, the most recent 10-year trend results in a strong negative projection of growth in the same variable. This sensitivity to a change in the years examined suggests that this regression analysis is not robust and that caution should be used when applying it to decisions involving the public welfare. The point of exposing the vulnerability of these regression results to changes in their inputs is less to advocate for a specific methodology as a best practice and more to shed light on the weakness of the methodology itself. . . . Certainly, as Ms. Pierce suggests, more data points can be an asset to a regression analysis. The Company could have made apparent the same shift in the pattern of growth in customer use while retaining a larger number of data points simply by including additional variables in their analysis. The Company’s Advance Forecast Report 2017 clearly states that “this year’s [residential per-customer use] model uses no economic variables; only weather and season binaries.”¹⁸⁰

¹⁷⁴ *Id.* at 43.

¹⁷⁵ *Id.*

¹⁷⁶ *Id.* at 44.

¹⁷⁷ *Id.* at 45.

¹⁷⁸ Dr. Stanton actually used the 2006-2016 timeframe, not 2007-2016 as stated by Ms. Pierce. See Ex. CEO-4 at 14, 17 (Stanton Direct).

¹⁷⁹ *Id.* at 45.

¹⁸⁰ Ex. CEO-11 at 6 (Stanton Surrebuttal).

127. With regard to the CEOs' claim that the Company did not consider economic variables in its residential-customer use analysis, Ms. Pierce agreed that the Company only used weather and season binaries. Ms. Pierce explained that Minnesota Power did consider economic and other variables besides weather and season but ultimately did not include them in the model because those variables did not perform well statistically in the regression process.¹⁸¹

b. Failure to Test Possible Flat or Declining Load Scenarios in the Commercial and Residential Sectors or an Economic Downturn in The Industrial Sector

128. The CEOs also raised concerns about the reasonableness of the 2017 forecast because all three scenarios (low, moderate, and high growth) include the same projected residential and commercial energy and load growth. The CEOs noted that the low and high growth cases "only varied what industrial sites would come to fruition, rather than also assessing variation in commercial and residential load growth."¹⁸²

129. In addition, the CEOs criticized Minnesota Power for failing to consider the possibility of an economic downturn in the industrial sector. The CEOs noted that the low forecast scenario is simply the current "status quo" for the industrial sector – i.e. currently idled facilities remain idled and PolyMet does not commence mining operations in the forecast timeframe.¹⁸³ The CEOs argued that given the recession of a decade ago, it is "irresponsible for the Company to not even consider that such events could happen again – on any scale or at any rate," thereby contributing to an inaccurate forecast.¹⁸⁴ And, the CEOs argue that the base case (moderate) forecast is overly optimistic in that it assumes that PolyMet, a controversial mining project, will be fully operational by 2020 even though it has not yet received all the necessary permits to operate.¹⁸⁵

130. In addition, the CEOs and LPI both maintained that the Company has overstated industrial demand in the base case by including the Blandin Paper Mill 5 in its forecast even though that facility closed at the end of 2017.¹⁸⁶ LPI noted that the plant closed in December 2017, and that closure translates to a reduction of load of approximately 20 MW.¹⁸⁷

131. The Company addressed each of these concerns. With respect to the failure to vary the residential and commercial usage in the low and high forecasts, the Company noted that sales to residential and commercial customers comprise just one-fifth of the Company's overall energy sales.¹⁸⁸ The Company also indicated that both

¹⁸¹ Tr. at 64-65 (Pierce).

¹⁸² Ex. CEO-4 at 4 (Stanton Direct).

¹⁸³ CEO Initial Br. at 10; Tr. at 32-34; Ex. CEO-4 at 19 (indicating that the low scenario is identical to the base case except for the exclusion of the proposed PolyMet mine).

¹⁸⁴ CEO Initial Br. at 10 (emphasis omitted).

¹⁸⁵ CEO Initial Br. at 10; Tr. at 49.

¹⁸⁶ Ex. CEO-4 at 4 (Stanton Direct); Ex. LPI-5 at 7 (Gorman Direct).

¹⁸⁷ Ex. LPI-5 at 7 (Gorman Direct).

¹⁸⁸ Ex. MP-17 at 18 (Palmer Rebuttal).

the low and high forecast scenarios assume large changes in energy sales.¹⁸⁹ While the changes are based on projections for industrial customers, “the increases or decreases in energy requirements could be applicable to changes in industrial demand or residential and commercial customers.”¹⁹⁰ The Company emphasized that the “main objective of demand sensitivities is to vary the potential outlook; the means on which customer load is adjusted is not as relevant.”¹⁹¹

132. Minnesota Power also asserted that any changes in residential or commercial demand over the planning period would have a minimal effect on the overall system.¹⁹²

133. Additionally, Minnesota Power maintained that its forecasting scenarios for PolyMet represent a good proxy for changes on Minnesota Power’s system, including potential changes to residential and commercial usage, because Polymet represents a much larger load than any other forecasting factors discussed in this proceeding.¹⁹³

134. With regard to the timing of the PolyMet facility, the Company maintained that no change to the Company’s PolyMet assumptions is warranted because the public position of the customer is that the plant will be online by 2020 and, even if the opening of the plant were to be delayed by two to three years, PolyMet would still be online prior to the start of the NTEC 250MW purchase in 2024.¹⁹⁴ The Company noted that PolyMet’s environmental impact statement has been found to be adequate and PolyMet has submitted applications for water and air quality permits.¹⁹⁵

135. With regard to the closing of the Blandin facility, Minnesota Power indicated that the decrease from the Blandin Paper Mill 5 (approximately 20 MW) is well within the range of load sensitivities evaluated in the analysis because the low load sensitivity assumed a peak demand decrease from the base forecast of 43 MW.¹⁹⁶ In addition, while Minnesota Power did not adjust its 2017 AFR due to the timing of the Blandin announcement, Minnesota Power did account for the load reduction related to Blandin in its revised alternatives analysis.¹⁹⁷

¹⁸⁹ *Id.*

¹⁹⁰ *Id.* at 18-19.

¹⁹¹ *Id.* at 19.

¹⁹² *Id.* at 18-19.

¹⁹³ Tr. at 49-50 (Pierce) (“PolyMet is a significant energy and capacity user on our system that we’re projecting to be in our base case in the 2020 time frame. The low load is removing that energy and capacity from the outlook. And the reason why I stated it as a good proxy is because it represents an industrial type load that is operating 24 by 7 at high capacity factors like the rest of our large component of our load, and it’s also a significant capacity reduction on our system. So when I said proxy, I meant that there’s many scenarios of what reducing our load by that much could entail. It could be one large customer, it could be several small customers, it could be a combination of many different classes in our customers, so that’s what I meant by having it be a good proxy.”)

¹⁹⁴ Ex. MP-17 at 20-22 (Palmer Rebuttal); Tr. at 61-62 (Pierce) (discussing ongoing negotiations to provide PolyMet full service for electric needs at facility once PolyMet comes online).

¹⁹⁵ Ex. MP-17 at 21 (Palmer Rebuttal).

¹⁹⁶ *Id.* at 20-21.

¹⁹⁷ *Id.* at 21; *see infra* at paragraph 196.

136. Minnesota Power also disagreed with the CEOs' suggestion that the forecast is invalid because it does not incorporate a potential recession or industrial downturn.¹⁹⁸

137. Minnesota Power noted that its energy and demand forecasts are driven by the best available projection of economic and demographic variables from IHS Global Insight, a third-party data vendor. The 2017 outlook from IHS Global Insight did not include a recession.¹⁹⁹ According to Minnesota Power, this does not mean the outlook does not provide a reasonable basis for sales data over time; rather, the outlook included neither a specific recession nor an economic boom but assumed slow GDP growth of 2.1 percent on average, which is well below historical rates.²⁰⁰

138. The Company asserted the CEOs' argument that the Company should assume a recession in its forecast is inappropriate, and that execution of this approach would be problematic for several reasons: (1) it would be uninformative with regard to resource planning for long-term system needs; (2) it would not help "account for uncertainty in both the residential and commercial energy sectors;"²⁰¹ (3) including a recession in the forecast timeframe is methodologically problematic because such an assumption is entirely subjective; and (4) a resource plan's assessment of need would be largely unchanged by the inclusion of a recession in the forecast because past recessions had only a temporary impact on total Minnesota Power energy sales and essentially no long term impact.²⁰²

c. CEO's Alternative Forecast

139. The CEO's expert Dr. Stanton developed her own forecast by making several adjustments to the Company's forecast. Dr. Stanton's forecast uses the ten (10) most recent years of available data in Minnesota Power's econometric model, removes 20 MW of demand to represent the closure of the Blandin Paper Mill 5, and increases the annual energy efficiency savings to 76.5 gigawatt hours (GWh).²⁰³ With these adjustments, Dr. Stanton's forecast shows a much smaller capacity need in 2025 than projected by the Company.²⁰⁴

140. Minnesota Power disagreed with the CEOs use of the modified assumptions and asserted that the CEOs overlook the need for energy, in addition to capacity.²⁰⁵

¹⁹⁸ Minnesota Power's Reply Br. at 12-13 (eDocket No. 20185-143255-01).

¹⁹⁹ *Id.* at 13-14 (citing 2017 AFR).

²⁰⁰ *Id.*

²⁰¹ See CEO Initial Br. at 10.

²⁰² Minnesota Power's Reply Br. at 13-15.

²⁰³ Ex. CEO-4 at 22-23 (Stanton Direct).

²⁰⁴ *Id.* at 23

²⁰⁵ Ex. MP-14 at 50 (Pierce Rebuttal).

D. Analysis and Conclusions Regarding the Company's Updated Forecast

141. The record shows that the Company's 2017 AFR forecast is substantially lower than the forecast used in the Company's 2015 IRP because the econometric estimates in 2017 AFR are driven by a more conservative economic outlook and include more conservative assumptions for industrial customer operations.²⁰⁶ The updated forecast also includes more current information.²⁰⁷

142. For the reasons discussed below, the Company has demonstrated its forecast methodology and the updated base case (moderate growth) forecast filed with its Petition are reasonable for use in this proceeding.

143. The record supports the Company's use of 26 years of historical data rather than ten years of data as suggested by the CEOs. A longer historical dataset provides greater statistical certainty in the resulting forecasts of a regression model, provides a more robust basis for projecting future energy needs, and is consistent with the past guidance from the Department and Commission.²⁰⁸

144. The record also supports the Company's decision to only include weather and season variables for the residential class because economic and other variables did not perform well statistically in the regression process.²⁰⁹

145. With regard to the Company's projections of flat residential and commercial use in all three forecast scenarios (low, moderate, and high growth), the Administrative Law Judge agrees with the CEOs that the Company has failed to provide a reasoned explanation for not varying the residential and commercial energy use levels in the low and high scenarios. The 2017 low and high forecast scenarios would have improved accuracy if these scenarios incorporated low and high projections for the residential and commercial classes, not just for the industrial class.²¹⁰ While the CEOs raise a legitimate concern in this regard, that concern does not affect the moderate forecast scenario, only the low and high forecast scenarios. Importantly, the Company

²⁰⁶ Ex. MP-2 at 2-8 to 2-9 (Petition).

²⁰⁷ *Id.* at MP-2 at 2-8.

²⁰⁸ *In the Matter of Minn. Power's 2010-2024 Integrated Res. Plan*, Docket No. E015/RP-09-1088, Comments of the Minnesota Office of Energy Security [a/k/a Department] at 6 (Sept. 27, 2010) ("MP's peak demand historical data is cut off around 2003 (i.e., it does not use data prior to 2003). MP explained that it truncated that data due to a structural change in the relationship between its energy sales and peak demand. . . . [The Department] disagrees with MP's truncation. If MP possesses other data that is sufficiently clean without error and reflects a theoretically sound relationship between the two variables, the volatile relation between MP's energy sales and peak demand can be captured using appropriate econometrics techniques."); see also *In the Matter of Interstate Power Co.'s 2003 Res. Plan*, Order Accepting Resource Plan, Requiring Reporting and Setting Requirements for Next Resource Plan, Docket No. E-001/RP-03-2040 at 4 (Dec. 17, 2004) ("For future resource plan filings, . . . the [Department] recommends estimating implicit [demand-side management ("DSM")] savings based on the same range of data used to develop the rest of its forecast, if available [T]he Commission concludes that analyzing all available data will make future estimates of implicit DSM more reliable.").

²⁰⁹ Tr. at 64-65 (Pierce).

²¹⁰ See Ex. MP-2 at 2-18 (Petition) (where the Company recognizes that it has an obligation to meet the future electric needs of all customers, not just large industrial customers).

used the moderate growth forecast in the Petition for determining whether additional resources are needed in the future. Moreover, the Company's use of the moderate growth 2017 AFR forecast in evaluating need is reasonable because the Company has a legal duty to provide reliable service.²¹¹ Using the low forecast would impose an unwarranted risk on the Company and its customers. For these reasons, the lack of variation in the residential and commercial use in the low and high scenarios does not render use of the 2017 AFR moderate growth forecast unreasonable in this proceeding.

146. The record also demonstrates that Minnesota Power appropriately utilized third-party data to develop its energy and demand forecasts consistent with industry standards. The use of this data is reasonable and supported by the record. The CEOs' assertion that the Company should have assumed a recession in its forecast is not supported by any evidence that such a recession is likely in the forecast period. The mere possibility of a recession without more does not support the inclusion of a recession in the modeling.

147. While inclusion of a recession is not supported by the record, the CEOs and LPI correctly point out that the 2017 AFR forecast would be improved if it was adjusted downward by approximately 20 MW to reflect the closure of Blandin Paper Mill 5 in the end of December 2017. As noted by LPI, this is a known and measurable change.²¹² The closure, however, was not announced by Blandin until the 2017 AFR was completed. In addition, as discussed in below in paragraph 197, the Company included a 20 MW reduction in demand in its revised modeling of alternatives.²¹³ Because the announcement was made after the 2017 AFR was complete, the Administrative Law Judge concludes that it was reasonable to use the 2017 AFR without that change but instead account for that change in the demand outlook in the modeling of alternatives.

148. In addition, the record demonstrates that the Company appropriately included the PolyMet mine in the moderate growth (base case) forecast. Given the large load (approximately 45 MW) that PolyMet is projected to use and the statements of the developer that the plant is expected to be operational by 2020, it was reasonable for the Company to include PolyMet in the base case forecast.²¹⁴ The Company and its customers will be exposed to an unnecessary reliability risk if PolyMet is developed but not included in the base case forecast projection.

149. With regard to the low forecast, the Administrative Law Judge agrees that the Company should have included additional reductions beyond simply assuming that PolyMet will not be built in the forecast period. The recent closure of the Blandin Paper Mill 5 in December 2017 and the fact that permitting of the PolyMet plant is not guaranteed suggest the low forecast should include a reduction beyond simply assuming PolyMet will not be built. Nonetheless, this short-coming affects only the low

²¹¹ Minn. Stat. § 216B.04 (2016).

²¹² Ex. LPI-5 at 7 (Gorman Direct).

²¹³ Ex. 17 at 21 (Pierce Rebuttal).

²¹⁴ *Id.*

forecast scenario, not the moderate growth scenario used by the Company in this proceeding.

150. For these reasons, the Administrative Law Judge concludes that the Company's moderate growth 2017 AFR forecast of its future energy sales and peak demand is reasonable for use as the base case forecast in this proceeding.

151. Conversely, the CEOs' alternative forecast is not reasonable for use in this proceeding because it uses only ten years of historical data.

152. While the Administrative Law Judge recognizes the forecast included in the Petition could be improved in some regards, the Administrative Law Judge concludes that the concerns raised by the CEOs and LPI do not make the base case forecast unreasonable or otherwise inappropriate for use in this proceeding.

VIII. The Company's Projected Resource Needs and Stated Need for the NTEC 250MW Purchase

153. Using the 2017 AFR, the Company analyzed the extent to which its generation facilities will be able to meet its base case forecasted energy sales and peak demand through 2031.²¹⁵

154. The Company emphasized it is in the process of removing or idling nearly 700 MW of baseload coal-fired generation from its power supply between 2013 and 2019 as part of its *EnergyForward* strategy.²¹⁶ The Company ceased coal-fired operations at Taconite Harbor Energy Center Unit 3 in 2015, refueled Laskin Energy Center with natural gas in 2015, idled Taconite Harbor Energy Center Units 1 and 2 in 2016, and has announced plans to close the coal-fired Boswell Energy Center Units 1 and 2 by 2019. Minnesota Power has also reduced its purchase of capacity from the Milton R. Young 2 lignite plant in North Dakota (Young 2) (from Square Butte Electric Cooperative) down from 227.5 MW to 100 MW as of August 2014, with a phase-out of Young 2 by 2026.²¹⁷

155. In addition, by mid-2020 Minnesota Power will have constructed or contracted to purchase more than 850 MW of wind generation (including 250 MW that is part of the *EnergyForward* Resource Package). The Company has also signed long-term agreements with the Manitoba Hydro-Electric Board to purchase 250 MW of hydroelectric generation beginning in 2020, and has begun adding solar power to its generation fleet with the 10 MW Camp Ripley Solar Project, 1 MW Community Solar Garden Pilot Program, and 10 MW of solar as part of the *EnergyForward* Resource Package. The net result is a power supply that includes significant new variable renewable generation and increasingly less baseload generation.²¹⁸

²¹⁵ Ex. MP-2 at 2-10 to 2-16 (Petition).

²¹⁶ Ex. MP-2 at 2-10 (Petition); Ex. MP-13 at 53-54 (Pierce Direct).

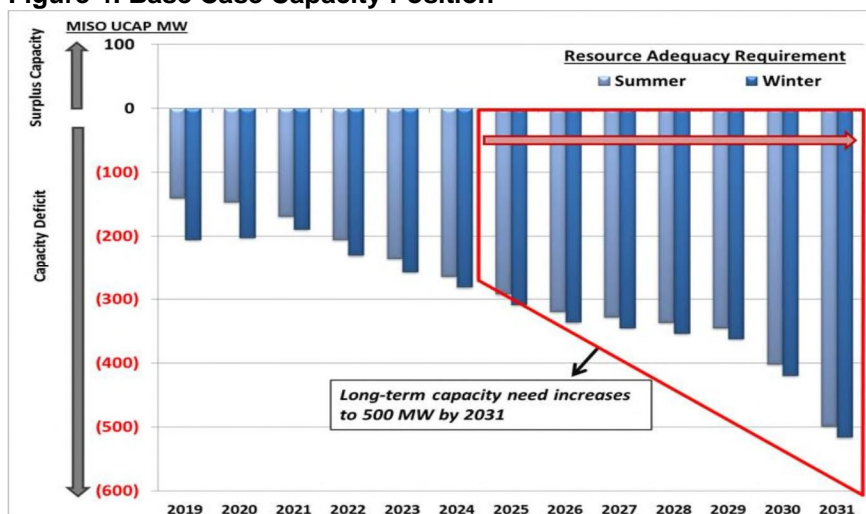
²¹⁷ Ex. MP-2 at 2-10 n.33, 4-4 (Petition); Ex. MP-13, at 15 (Pierce Direct).

²¹⁸ Ex. MP-13, at 15 (Pierce Direct).

156. Based on these reductions in coal-fired generation, the load growth projected in the 2017 AFR, as well as the changing shape of hourly energy requirements caused by the existing and additional variable renewable generation, the Company maintains it has a need for capacity and energy in the mid-2020s.²¹⁹

157. Figure 4 in the Petition, set forth below, illustrates Minnesota Power's projection for the capacity need to reach approximately 300 MW by 2025 and grow to around 500 MW by 2031.²²⁰ Minnesota Power is a winter peaking utility, which results in a slightly greater capacity need during the winter season, as also reflected in Figure 4 below.²²¹

Figure 4: Base Case Capacity Position



158. Further, the Company projects that, under its base case forecast, it will have growing energy needs of about 1 million MWh in 2020 and increasing to 2.4 million MWh by 2031, as Boswell Energy Center 1&2 and Young 2's baseload energy are removed from the power supply and customer energy needs grow. In the absence of demand-side and supply-side resource additions, by 2031, the Company projects that nearly 20 percent of its total demand would not be met by its power supply capabilities.²²²

159. Figure 7 from the Company's Petition, set forth below, depicts the Company's current power supply capability and its projection for its energy needs through 2031.²²³

²¹⁹ Ex. MP-2 at 2-10 (Petition); Ex. MP-13 at 54 (Pierce Direct).

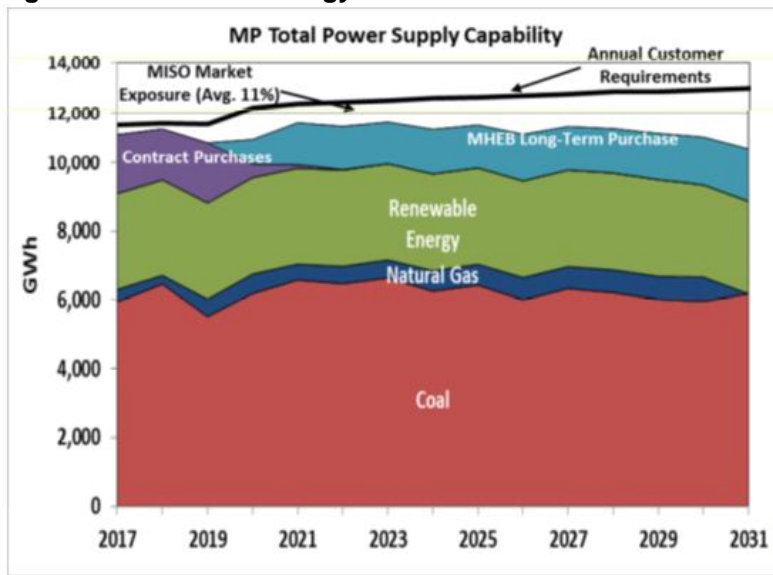
²²⁰ Ex. MP-2 at 2-10 (Petition); Ex. MP-13 at 54 (Pierce Direct).

²²¹ Ex. MP-2 at 2-11 (Petition); Ex. MP-13 at 54 (Pierce Direct). This analysis incorporates MISO's planning reserve margin requirements. Ex. MP-13 at 56 (Pierce Direct).

²²² Ex. MP- 13 at 56 (Pierce).

²²³ Ex. MP-2 at 2-14 (Petition).

Figure 7: Base Case Energy Position



160. Figure 7 does not include or factor in any new demand-side resources, such as additional energy conservation savings or demand response.²²⁴

161. In addition to its overall energy needs, the Company emphasized that the variability of wind generation creates additional planning needs.²²⁵ The Company's witness, Ms. Pierce, stated that by 2020, Minnesota Power will have over 850 MW of variable renewables on its system and a projected peak demand of 1700 MW.²²⁶ As a result, Minnesota Power's energy position could vary up to 850 MW in an hour, according to Ms. Pierce.²²⁷

162. In light of this variability, Minnesota Power argued that it must plan for dispatchable and flexible generation resources that can respond quickly to changing wind generation levels and minimize market exposure risk for customers.²²⁸ Minnesota Power stated that this challenge is exacerbated by the fact that the Company has both a high concentration of wind generation and an unusually high system load factor, creating additional risk of exposure to high energy prices in the event high demand corresponds with low or no wind availability.²²⁹ The Company noted that by 2020, its power portfolio will include nearly 50 percent of wind resources relative to peak demand, which is the highest percentage of any utility in Minnesota.²³⁰

163. Minnesota Power maintained that the addition of a combined-cycle natural gas resource like NTEC would help to fill the gap between renewable availability and customer needs by better balancing the characteristics of the energy resources and

²²⁴ See *id.* at 54-55, 57.

²²⁵ *Id.* at 58.

²²⁶ Ex. MP-14 at 10 (Pierce Rebuttal).

²²⁷ Ex. MP-13 at 58 (Pierce Direct)

²²⁸ *Id.*

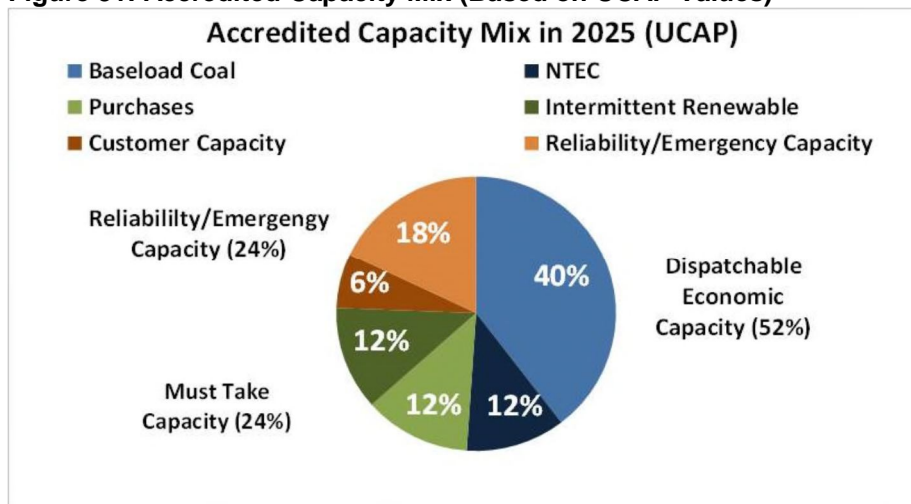
²²⁹ Ex. MP-14 at 10 (Pierce Rebuttal).

²³⁰ *Id.* at 10-11.

removing the need to rely on the short-term energy market for capacity and energy needs.²³¹ The Company also stated that it would position Minnesota Power for additional variable renewable generation by adding a generation facility that is able to operate more frequently (like a baseload resource) to serve higher capacity factor needs as variable generation grows.²³²

164. As shown in Figure 31 from the Petition, which is set forth below, Minnesota Power estimates that the addition of the 250 MW NTEC purchase would bring the accredited capacity of Minnesota Power's dispatchable resources to around 52 percent.²³³ The 250 MW NTEC purchase would represent approximately 12 percent of the total amount estimated by the Company.²³⁴

Figure 31: Accredited Capacity Mix (Based on UCAP Values)



IX. The Company's Evaluation of Alternatives for Meeting its Projected Capacity and Energy Needs

165. As noted above, in the Notice and Order for Hearing in this proceeding, the Commission required the Company to demonstrate that the proposed 250 MW NTEC purchase is needed and reasonable based on a considered of numerous factors, including "[a]lternatives to some or all of the gas plant energy and capacity by the Company, including but not limited to alternatives such as additional wind and solar resources (with updated costs), storage, demand response, and additional energy efficiency."²³⁵

²³¹ Ex. MP-13 at 18-19 (Pierce Direct).

²³² *Id.* at 18.

²³³ Ex. MP-2 at 4-10 (Petition).

²³⁴ *Id.*

²³⁵ Notice and Order for Hearing at 6, 9.

166. The Commission also specified that the resource planning factors apply in this proceeding to determine whether the proposed NTEC purchase is needed and reasonable, and in the public interest.²³⁶

A. The Company's Strategist Analysis

167. The Company used a software and modeling program called Strategist to compare various resource alternatives to meet its projected long-term customer demand for electricity through 2031.²³⁷ The Strategist software is a capacity expansion model used in resource planning by many electric utilities.²³⁸

168. The Strategist model can take into consideration many factors that affect resource decisions, such as energy demand, fuel cost, environmental regulation(s), and capital cost.²³⁹ Further, the Strategist model considers both energy and capacity requirements.²⁴⁰

169. Strategist compares the costs of various resource expansion plans, evaluates the impacts of different power supply mixes, and helps identify cost impacts when various factors are stressed.²⁴¹

170. Minnesota Power and other utilities use Strategist to help identify multiple least-cost expansion plans that are utilized to determine the best and least-cost resource mix across many contingencies.²⁴²

171. The results of the Strategist modeling depend on the inputs and the assumptions used.²⁴³

i. Minnesota Power's Strategist Inputs and Base Case

172. In conducting its evaluation of the Company's power supply requirements and resource alternatives, Minnesota Power updated and refined several inputs from the Company's 2015 IRP for purposes of evaluating how to meet customer energy and capacity needs between 2025 and 2031.²⁴⁴ In particular, Minnesota Power:

- updated its existing power supply to reflect recent changes in its generation portfolio, as described above;²⁴⁵

²³⁶ *Id.* at 5, 9.

²³⁷ Ex. MP-16 at 23 (Palmer Direct).

²³⁸ *Id.*

²³⁹ *Id.*

²⁴⁰ Ex. DER-11 at 7 (Rakow Surrebuttal).

²⁴¹ Ex. MP-16 at 23 (Palmer Direct).

²⁴² *Id.*

²⁴³ See Ex. MP-5, App. I (Assumptions and Outlooks); Ex. MP-16 at 18-21 (Palmer Direct); Ex. CEO-16 at 5-28 (Sommer Direct).

²⁴⁴ Ex. MP-16 at 10-13 (Palmer Direct).

²⁴⁵ *Id.* at 11; Ex. MP-7, App. K (Existing Power Supply).

- included the midpoint of the Commission's approved CO₂ cost range in four of the base case scenarios (Futures) starting in 2022, and assumes no CO₂ regulation cost in four other Futures;²⁴⁶
- updated its capacity resources to include near-term bilateral contract and accredited capacity values;²⁴⁷
- used the more recent industry data, including costs, for demand side management programs, generation technology, storage, natural gas, coal, and other key power supply drivers and trends;²⁴⁸
- updated the energy demand outlook based on the 2017 AFR, as discussed above;²⁴⁹
- updated the retirement assumptions for the existing thermal generation fleet;²⁵⁰
- included 33 MW of solar generation in the base case;²⁵¹
- updated the environmental externality values established by the Commission;²⁵² and
- assumed there to be 150 MW of industrial demand response.²⁵³

173. With regard to energy efficiency, incremental energy efficiency assumptions were developed using the same methodology as was used in the 2015 IRP.²⁵⁴ More specifically, the Company tested three different scenarios of incremental energy efficiency and capacity savings: 11 GWh, 15 GWh, and 30 GWh per year.

²⁴⁶ Ex. MP-16 at 11, 20, 24 (Palmer Direct).

²⁴⁷ *Id.* at 12 (stating "MISO's [Unforced Generating Capacity ("UCAP")] value for accredited capacity was used in the refined analysis, as well as Minnesota Power's coincident peak demand forecast and the associated planning reserve margin."); Tr. at 54-55 (Pierce) ("Q. And could you explain the difference between nameplate capacity and [UCAP] accredited capacity?" "A. Sure. Nameplate capacity is in general the physical capability of a facility to produce megawatts as it was originally designed. And accredited capacity takes into consideration, specifically in this UCAP look, it takes into consideration expectations for actual availability of the facility, including the performance of the unit in terms of how many outages it has had over the last period of time and other factors so that it can be a counted-on capacity value for meeting the reliability needs of the system....").

²⁴⁸ Ex. MP-16 at 12 (Palmer Direct); Ex. MP-5, App. J (Detailed Resource Planning Analysis).

²⁴⁹ Ex. MP-16 at 12 (Palmer Direct).

²⁵⁰ *Id.* at 12-13.

²⁵¹ These resources include the Camp Ripley Solar Project and Minnesota Power's solar garden pilot project. *Id.* at 13 (Palmer Direct); Ex. MP-2 at 3-28 to 3-29 (Petition).

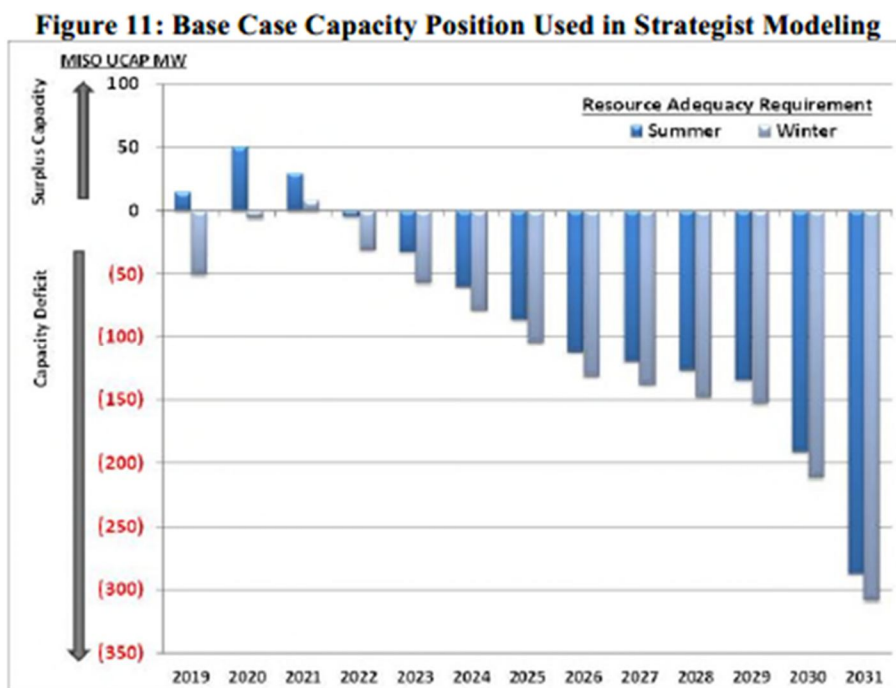
²⁵² *In the Matter of the Further Investigation into Envtl. and Socioeconomic Costs under Minn. Stat. § 216B.2422, Subd. 3*, MPUC Docket No. E999/CI-14-643, Order Updating Environmental Cost Values (Jan. 3, 2018). In Rebuttal Testimony, Minnesota Power provided an updated RFP selection analysis to reflect the Commission's final environmental cost value order. Ex. MP-17 at 30, Rebuttal Schedule 2 (Updated Dispatchable Capacity RFP selection analysis) (Palmer Rebuttal).

²⁵³ Ex. MP-16 at 13 (Palmer Direct).

²⁵⁴ *Id.*; Ex. MP-5, App. I at I-6 (Outlooks and Assumptions).

These amounts are in addition to the existing level (46 GWh) embedded in the base case 2017 AFR.²⁵⁵

174. The figure below, from the Petition, shows Minnesota Power's capacity position for summer and winter seasons after including 150 MW of large industrial interruptible demand, 11 GWh of incremental energy efficiency, and the 250 MW wind project and 10 MW solar project from the EnergyForward Resource Package.²⁵⁶



175. This capacity position was the designated “base case” capacity position used by the Company in its Strategist modeling.²⁵⁷

176. As this figure demonstrates, the Company's base case projects an approximately 100 MW capacity deficit in 2025.²⁵⁸ From, 2026 through 2029, the Company projects the need growing slowly to about 150 MW.²⁵⁹ In 2031, the projected capacity deficit under the base case is an approximately 300 MW.²⁶⁰

²⁵⁵ Ex. MP-5, App. I at I-6 (Outlooks and Assumptions), App. J at J-4 (Detailed Resource Planning Analysis).

²⁵⁶ Ex. MP-2 at 3-12 (Figure 11) (Petition); Ex. MP-16 at 13-14 (Palmer Direct). Consistent with the 2016 IRP Order, the Strategist model included 250 MW of wind (Nobles 2) and 10 MW of solar (Blanchard) in the base case. *Id.* at 14, n. 15.

²⁵⁷ Ex. MP-2 at 3-12 (Petition); Ex. MP-16 at 14 (Palmer Direct).

²⁵⁸ Ex. MP-16 at 14 (Palmer Direct)

²⁵⁹ Ex. MP-2 at 3-12 (Figure 11) (Petition).

²⁶⁰ *Id.* The base case capacity position used in Strategist by the Company as reflected in Figure 11 above reflects a lower projected capacity deficit in each year than in the base case capacity position reflected in Figure 4 set forth above because the Company's base case for its Strategist analysis includes 150 MW of industrial demand response, 11 MW of incremental energy efficiency, and the renewable wind

ii. The Company's Two-Step Strategist Analysis

177. Having established its base case capacity position for use in its Strategist modeling, the Company conducted its Strategist analysis to evaluate resource alternatives.²⁶¹

178. The Company's analysis looked at the time period 2017 through 2031, and considered 15 years of "end effects" (i.e. power costs) after 2034.²⁶² End effects are a mathematical extrapolation of the last year of the planning period.²⁶³ The Company included "end effects" because it "better captures the impact to customer costs over the life of the facility."²⁶⁴

179. The Company's Strategist analysis included two steps.²⁶⁵

180. Step 1 was designed to identify a resource expansion plan that would best meet the customer requirements (capacity and energy needs) identified by the Company.²⁶⁶

181. In Step 1, the Company used the Strategist model to develop a least-cost resource portfolio by comparing NTEC and other resource alternatives under a variety of futures and sensitivities.²⁶⁷

182. The resource options included natural gas-fired facilities, battery storage, wind, solar, a bridge contract, and residential/commercial demand-side programs.²⁶⁸

183. Specifically, the Company allowed Strategist to select from the following supply and demand-side resource options in Step 1:

and solar projects from the *EnergyForward* resource package whereas Figure 4 does not. *Compare* Ex. MP-2 at 3-12 (Figure 11) *with* Ex. MP-2 at 2-11 (Figure 4) (Petition); Ex. MP-2 at 3-11 (Petition); *see also* Tr. at 27 (Pierce).

²⁶¹ Ex. MP-16 at 15 (Palmer Direct).

²⁶² Tr. at 101-02, 133 (Palmer); Minnesota Power's Reply Br. at 22.

²⁶³ Ex. CEO-18 at 21 (Sommer Surrebuttal). End effects are not "simulated" in the same way that the years within the planning period are simulated. The end effects period merely assumes that the results of the last year of the planning period can be carried forward modified by whatever escalation rates might apply to the various costs contained in the last year of the planning period. These costs are then brought back to present day dollars and added to the planning period present value of societal costs to determine the least-cost plan. *Id.*

²⁶⁴ Tr. at 133 (Palmer).

²⁶⁵ Ex. MP-16 at 15 (Palmer Direct).

²⁶⁶ *Id.*

²⁶⁷ *Id.*; Ex. LPI-8 at 7 (Andrews Direct); Ex. MP-5, App. J at J-9 (Detailed Resource Planning Analysis).

²⁶⁸ Ex. MP-16 at 22-23 (Palmer Direct); Ex. 2, App. J. (Detailed Resource Planning Analysis). This appendix includes a complete list of resource alternatives considered in the analysis. This list was screened to remove higher cost alternatives due to limitations on the number of resource alternatives that can be evaluated in Strategist. In compliance with Order Points 9 and 10 of the 2016 IRP Order, the Strategist model included 250 MW of wind (Nobles 2) and 10 MW of solar (Blanchard) in the base case.

- 250 MW share of a natural gas-fired 1x1 combined-cycle gas turbine (NTEC);
- 525 MW of natural gas-fired 1x1 combined-cycle gas turbine;
- 223 MW natural gas-fired combustion turbine;
- 112 MW natural gas-fired aeroderivative turbine;
- 50 MW lithium-ion battery storage;
- 55 MW natural gas-fired reciprocating engines;
- 100 MW wind farm located in Minnesota;
- 100 MW solar farm located in central Minnesota;
- 50 MW bilateral bridge transaction;
- Air conditioning load control and hot water load control.²⁶⁹

184. Minnesota Power imposed certain timing constraints on the selection of resources by the Strategist model. Minnesota Power did not allow the model to select any resources before 2025.²⁷⁰

185. In addition, Minnesota Power configured its Strategist modeling so that NTEC was only available for selection in 2025 and no other year.²⁷¹

186. Also, the 50 MW bilateral bridge purchase of energy and capacity was made available only in 2024 and for one year.²⁷² This one-year bridge purchase was modeled as an intermediate type resource.²⁷³

187. In terms of purchases from the MISO market, both capacity purchases and energy purchases were made available in the Strategist model to some degree.²⁷⁴ A 50 MW capacity purchase from the MISO market was available for each year of the plan.²⁷⁵ In addition, short-term energy purchases were also available, with the price increasing as greater amounts were purchased to reflect “the increased risk and volatility that is present when purchasing incrementally larger amount of energy from the short term market.”²⁷⁶

188. The Strategist software compared the cost of different resources alternatives under two resource adequacy seasons (summer and winter), with and without CO₂ regulation, and with and without sales of excess generation into the MISO market.²⁷⁷ As a result, there were eight different Futures modeled.²⁷⁸ The table below provides descriptions of the eight different Futures.²⁷⁹

²⁶⁹ Ex. MP-16 at 22-23 (Palmer Direct); Ex. 5, App. J (Detailed Resource Planning Analysis).

²⁷⁰ Ex. MP-16 at 15 (Palmer Direct); Tr. at 111-12 (Palmer).

²⁷¹ Tr. at 112 (Palmer); Ex. MP-16 at 15 (Palmer Direct).

²⁷² Ex. MP-5, App. I at I-4 (Assumptions and Outlooks), App. J at J-9 (Detailed Resource Planning Analysis).

²⁷³ *Id.*, App. I at I-4 (Assumptions and Outlooks).

²⁷⁴ *Id.*, App. I at I-2 to I-3, I-12 (Assumptions and Outlooks).

²⁷⁵ *Id.*

²⁷⁶ *Id.*, App. I at I-3.

²⁷⁷ *Id.* In the scenarios (Futures) without wholesale energy market sales, wholesale energy purchases were still available and all assumptions about wholesale energy purchases remained as the same. *Id.*

Table 1: Eight Futures Considered in the NTEC Combined-Cycle Analysis

| Futures | Strategist Case Name | Resource Adequacy Season | CO₂ Regulation Penalty | Excess Energy Sold Into Wholesale Market |
|----------------|-----------------------------|---------------------------------|--|---|
| Future 1 | C1S | Summer | No | Yes |
| Future 2 | C2S | Summer | No | No |
| Future 3 | C3S | Summer | Yes | Yes |
| Future 4 | C4S | Summer | Yes | No |
| Future 5 | C1W | Winter | No | Yes |
| Future 6 | C2W | Winter | No | No |
| Future 7 | C3W | Winter | Yes | Yes |
| Future 8 | C4W | Winter | Yes | No |

189. In Step 1, each of these eight Futures was run in Strategist with over 34 sensitivities. The sensitivities were designed to stress key power supply cost drivers such as delivered fuel, CO₂ regulations costs, capital costs, environmental externality values, and customer load outlooks.²⁸⁰ Using information and assumptions provided by the Company, the Strategist software enumerates all potential resource combinations and ranks them by net present value revenue requirements (NPVRR).²⁸¹

190. Once Step 1 was completed, the Company conducted Step 2 -- a “swim lane comparative analysis.” A swim lane is a mechanism to evaluate alternative packages by considering them in a side-by-side “lane.”²⁸² The Company’s swim lane analysis compared and stress-tested the proposed 250 MW NTEC purchase against three other viable power supply portfolio alternatives selected by the Company.²⁸³ Strategist was used in this step to determine the NPVRR of the pre-selected portfolio options.²⁸⁴

191. The four swim lanes evaluated were as follows: NTEC combined cycle portfolio²⁸⁵ (Swim Lane 1), the Company modeled a 75 percent renewable capacity

²⁷⁸ *Id.*

²⁷⁹ Ex. 16 at 24 (Palmer Direct).

²⁸⁰ *Id.* at 15, 24; Ex. MP-5, App. I (Assumptions and Outlooks), App. J at J-10.

²⁸¹ Ex. LPI-8 at 8 (Andrews Direct).

²⁸² Ex. MP-16 at 16, n.17 (Palmer Direct).

²⁸³ *Id.* at 15-16.

²⁸⁴ Ex. LPI-8 at 8 (Andrews Direct).

²⁸⁵ The NTEC combined-cycle portfolio consists of the EnergyForward package (NTEC purchase in 2025, 250 MW of wind in 2020, and 10 MW of solar in 2020) also assumes 12 MW of solar in 2025 (added to comply with the SES) and a 100 MW combustion turbine (“CT”) in the 2031 timeframe (as a placeholder showing a requirement to meet capacity needs post-2030). Ex. MP-16 at 16 (Palmer Direct).

portfolio (Swim Lane 2),²⁸⁶ a 50 percent renewable capacity portfolio (Swim Lane 3),²⁸⁷ and a large combustion turbine portfolio (Swim Lane 4).²⁸⁸

192. All four swim lanes also included 250 MW of wind generation and 10 MW of solar generation, as identified in the *EnergyForward* Resource Package.²⁸⁹

193. The Company stated that each swim lane alternative was evaluated under more than 30 sensitivities over eight Future scenarios that stressed the main drivers for resource decisions.²⁹⁰ Those drivers included: delivered fuel, capital costs, CO₂ regulation costs, revised externalities values, and additional energy efficiency programs.²⁹¹

194. The series of swim lanes were put through both scenarios with and without the Commission-approved mid-CO₂ regulation cost and with and without an energy market to sell surplus energy into, resulting in 260 unique sensitivities.²⁹² In order to delineate which resource decisions rely on revenue from the MISO market to be economical for customers, Minnesota Power created the base case scenarios without an energy market in which to sell surplus energy.²⁹³

195. The Company stated that its swim lane analysis was designed to “verify whether or not the alternative swim lane paths are in the best interest of Minnesota Power’s customers compared to the proposed purchase from the NTEC combined-cycle plant, and to further assess the benefits of the dispatchable capacity purchase for customers.”²⁹⁴

iii. The Company’s Revised Strategist Modeling

196. During the proceeding, Minnesota Power also conducted a revised Strategist analysis to respond to criticisms raised by testimony filed by the CEOs and LPI. First, the Company updated its base load forecast used in Strategist to account for the approximately 20 MW decrease in demand resulting from the closure of Blandin Paper Mill 5.²⁹⁵ Second, the Company added two new Futures to the original eight Futures that included the mid-environmental externality values and the CO₂ regulation

²⁸⁶ The 75 percent renewable capacity portfolio assumes 1950 MW of wind added from 2020 through 2031 in 250 MW to 550 MW blocks depending on capacity need and 108 MW of gas peakers to meet capacity needs. *Id.*

²⁸⁷ The 50 percent renewable capacity portfolio assumes 1350 MW of wind added from 2020 through 2031 in 250 MW to 450 MW blocks and 198 MW of gas peakers to meet capacity needs. *Id.*

²⁸⁸ The large combustion portfolio assumes 456 MW of gas peakers with the first 223 MW added in 2025 and the second in 2031, and 250 MW of wind in 2020. *Id.*

²⁸⁹ *Id.*

²⁹⁰ *Id.* at 17.

²⁹¹ *Id.* at 17, 63.

²⁹² *Id.* at 63.

²⁹³ *Id.* at 63-64.

²⁹⁴ *Id.* at 63.

²⁹⁵ Ex. MP-17 at 89 (Palmer Rebuttal). The Company also removed the 8 MW distributed generation program from the Step 1 and Step 2 analyses, due to the Rate Case outcome. *Id.*, Rebuttal Schedule 13 at 2.

cost.²⁹⁶ The energy market was also turned off by Minnesota Power “so that the application of externality values is equitable across all energy sources.”²⁹⁷ The ten Futures in the revised analysis were run in Strategist with both incremental efficiency values of 11 GWh (per the Company’s 2017-2019 CIP plan) and 30 GWh (per the Commission’s 2016 IRP Order), which resulted in a total of 20 unique Futures.²⁹⁸

197. Finally, in Step 1, the Company ran the revised Futures in Strategist with an additional resource alternative: 300 MW of industrial demand response was available as a resource alternative.²⁹⁹ To accomplish this, the Company removed the 150 MW of industrial demand response from the base case.³⁰⁰ Then two 150 MW blocks of demand response with 400 curtailable hours at \$9.50/kW-month were made available as alternatives starting in 2025 and throughout the rest of the study period.³⁰¹

198. In Step 2 of its revised Strategist analysis, the Company added two new swim lanes at the request of LPI. Swim Lane 5 included a 100 MW share of a combined-cycle resource like NTEC placed in service in 2025, a 50 MW combustion turbine (CT) installed in 2031, and 300 MW of industrial demand response with limitations and pricing based on LPI’s demand response proposal raised in the Company’s recent rate case.³⁰² Swim Lane 6 reduced the size of the proposed NTEC purchase from 250 MW to 200 MW and increased the size of the CT added in 2031 to 150 MW.³⁰³

iv. The Company’s Strategist Results

199. Under both the initial and revised Strategist analyses performed by the Company, the 250 MW NTEC purchase was selected as the least cost resource in the vast majority of scenarios based on a comparison with the generation alternatives included in the Strategist modeling.³⁰⁴

200. For Step 1, the Company’s initial Strategist results showed the 250 MW NTEC purchase was selected 96 percent of the time across 292 different scenarios.³⁰⁵

²⁹⁶ Ex. MP-17 at 89-90 (Palmer Rebuttal). Minnesota Power provided these additional futures in response to criticisms from the CEOs regarding the Company’s modeling of externalities. While Minnesota Power’s initial analysis did include the mid-externality values as a sensitivity, the Company’s update included those mid-externality values as a base case assumption. .

²⁹⁷ *Id.* at 89.

²⁹⁸ *Id.* at 90.

²⁹⁹ *Id.* at 86.

³⁰⁰ *Id.* at 86-87 and Rebuttal Schedule 13.

³⁰¹ *Id.*

³⁰² *Id.* at 78.

³⁰³ *Id.* at 81.

³⁰⁴ Ex. MP-16 at 25-26 (Palmer Direct). Strategist will produce a report that contains hundreds (perhaps thousands) of possible plans for each run. The “optimal” plan is the least-cost plan, while the remaining plans are often referred to as the “suboptimal” plans.” Ex. CEO-18 at 20 (Sommer Surrebuttal).

³⁰⁵ Ex. MP-16 at 25 (Palmer Direct).

Large scale solar (100 MW) was also selected at approximately 90 percent of the time across these same scenarios, but it was selected most often post-2030.³⁰⁶

201. In the revised Strategist analysis, the 250 MW NTEC purchase was selected as least cost in 87 percent of the 684 expansion plans evaluated.³⁰⁷

202. In addition, as noted above, the revised Strategist analysis included new Futures that added two 150 MW blocks of demand response starting in 2025 and throughout the rest of the study period.³⁰⁸ In the revised Strategist analysis with these new demand response options, NTEC was selected in 90 percent of the 684 expansion plans evaluated and a 150 MW block of industrial demand response was selected in approximately 78 percent of the cases. The revised Strategist results also show that in almost all cases, the 150 MW block of industrial demand response was selected post-2025, after the 250 MW NTEC purchase was selected.³⁰⁹

203. The Company maintained these Strategist results demonstrate that the proposed NTEC purchase is the best and least cost resource option for meeting its future energy needs in the mid-2020s because NTEC was chosen in the vast majority of scenarios.³¹⁰

B. Concerns Raised by the CEOs and LPI Regarding the Company's Strategist Modeling

204. Both the CEOs and LPI identified a number of issues with the Company's Strategist modeling that they believe make the results unreliable for purposes of evaluating whether the proposed NTEC 250 MW purchase is needed and reasonable. According to both the CEOs and LPI, Minnesota Power improperly limited the timing of resource selection and the range of alternatives used in the Strategist model.³¹¹ In addition, the CEOs asserted that Minnesota Power biased the modeling against the selection of wind and solar resources with unreasonable assumptions.³¹² The CEOs also maintained that the Company underestimated the amount of available energy efficiency and demand response in its modeling of alternatives.³¹³ LPI also asserted the Company used unreasonable demand response assumptions in the Strategist modeling.³¹⁴ As a result, both the CEOs and LPI maintained that the Company has

³⁰⁶ *Id.* at 26.

³⁰⁷ Ex. MP-17 at 90-91, Rebuttal Schedule 13 at 15 (Palmer Rebuttal); Tr. at 94 (Palmer).

³⁰⁸ Ex. MP-17 at 93 (Palmer Rebuttal).

³⁰⁹ *Id.* at 90-91.

³¹⁰ Ex. MP-13 at 23-24 (Pierce Direct).

³¹¹ CEO Initial Br. at 19-20; Post Hearing Br. of the Large Power Intervenors (LPI Initial Br.) at 10.

³¹² CEO Initial Br. at 19-20.

³¹³ *Id.* at 16-19.

³¹⁴ LPI Initial Br. at 14-15; Ex. LPI-6 at 15-16 (Gorman Surrebuttal).

failed to meet its burden to fully analyze alternatives.³¹⁵ These issues are addressed in turn below.

i. The Timing of NTEC and Other Resource Additions

205. According to LPI and the CEOs, the Company's Strategist modeling unreasonably constrained the timing of resources that could be selected in a manner that favored the selection of the NTEC purchase.³¹⁶

206. In particular, both LPI and the CEOs emphasized that the 250 MW NTEC purchase was only allowed for selection in 2025, and no other year.³¹⁷ As noted by the CEOs, allowing Strategist to choose NTEC only in one year is not typical in resource planning.³¹⁸

207. In addition, the CEOs point out there was no ability for Strategist to select any other resource until 2025 even though the "capacity deficit" claimed by Minnesota Power begins to grow between 5 and 30 MW in 2019 to around 100 MW in 2025 (where it remains until 2029).³¹⁹

208. Similarly, LPI points out that the 525 MW natural gas combined cycle generator was not made available until 2026, a year later than NTEC.³²⁰ Also, LPI noted that the bilateral bridge market purchase of 50 MW was only made available in 2024 for one year, just before the 250 MW NTEC purchase becomes available in 2025.³²¹

209. Both the CEOs and LPI maintained these timing constraints imposed by the Company in its Strategist analysis are biased in favor of the selection of NTEC and do not allow for analysis of a full range of alternatives.³²² LPI and the CEOs maintain the alternative analysis should not be constrained by the characteristics of the proposed NTEC purchase because the Commission has not yet made a size, type, and timing decision with respect to any additional natural gas generation resources.³²³

210. In addition, LPI noted that Company's base case does not project a capacity need for 250 MW until 2031. Given this projection by the Company, LPI expressed concern that the Company did not model a scenario where the 250 MW

³¹⁵ CEO Initial Br. at 15; LPI Initial Br. at 10. LPI and the CEOs also both emphasized that flawed assumptions resulted in NTEC being chosen the vast majority of the times by in the Company's Strategist runs. LPI Initial Br. at 10-15; Ex. CEO-16 at 5-6 (Sommer Direct).

³¹⁶ LPI Initial Br. at 10.

³¹⁷ *Id.* at 13; CEO Initial Br. at 20 (citing Tr. at 111-112) (Palmer).

³¹⁸ Ex. CEO-16 at 5 (Sommer Direct).

³¹⁹ CEO Initial Br. at 20.

³²⁰ Ex. LPI-8 at 12 (Andrews Direct).

³²¹ *Id.*; Ex. MP-5, App. I at I-4 (Assumptions and Outlooks); LPI Initial Br. at 13

³²² CEO Initial Br. at 15, 19-20; Clean Energy Organizations' Post-Hearing Reply Br. (CEO Reply Br.) at 2; LPI Initial Br. at 13-14; Ex. LPI-8 at 12-13.

³²³ LPI Initial Br. at 13; Reply Br. of the Large Power Intervenor (LPI Reply Br.) at 8; CEO Reply Br. at 2-3; see also 2016 IRP Order at 8-9.

NTEC purchase or a similar resource would come online in 2031.³²⁴ To the extent the Company maintains that NTEC is needed for energy purposes as claimed by the Company, LPI asserted that the Company should have analyzed an in-service date of 2031 with the Company relying on existing resources and market purchases for the interim.³²⁵ According to LPI, without modeling that scenario there is not sufficient information in the record to show the 250 MW NTEC purchase is needed and reasonable for energy purposes.³²⁶

211. In response to the concerns raised about the timing constraints included in the Strategist analysis, Minnesota Power argued that the purpose of this proceeding is “to evaluate a mid-2020s resource addition to meet the identified need in 2025, consistent with past IRP outcomes.”³²⁷

212. The Company added that by making new resources available starting in 2025, the Company was able to evaluate more resource alternatives than would typically be evaluated in a traditional IRP.³²⁸ This is due to limitations in the Strategist model.³²⁹

213. In addition, the Company maintained that Strategist was set up to select NTEC only in 2025 to be consistent with the bids received through the Company’s RFP process and with the NTEC capacity dedication agreement.³³⁰

214. The Administrative Law Judge concludes that the Company has not provided a reasonable explanation for constraints it placed on resource selection in the Strategist model. While the purpose of this proceeding is to determine whether the proposed 250 MW NTEC in purchase is needed and reasonable, the Commission has made no prior determination as to size, type, or timing of the addition of any gas-fired generation resource for the Company.³³¹

215. In the 2016 IRP Order, the Commission allowed the Company to continue with the IRP process that it had already started with “no presumption that any or all of the generation identified in that bidding process will be approved by the Commission.”³³² The Commission was clear that the question of whether a natural gas facility should be added would be decided after “a full analysis of all alternatives. . . .” in a subsequent proceeding.³³³

216. In the Notice and Order for Hearing in this matter, the Commission specifically required that the analysis of the need and reasonableness of the NTEC

³²⁴ LPI Reply Br. at 6; Ex. MP-2 at 3-12 (Figure 12) (Petition).

³²⁵ LPI Reply Br. at 6.

³²⁶ *Id.*

³²⁷ Minnesota Power’s Initial Br. at 55.

³²⁸ Ex. MP-17 at 60 (Palmer Rebuttal); Tr. at 111-12 (Palmer).

³²⁹ Ex. MP-17 at 60 (Palmer Rebuttal); Tr. at 111-12 (Palmer).

³³⁰ Tr. at 112 (Palmer).

³³¹ 2016 IRP Order at 8-9

³³² *Id.* at 8, 15.

³³³ *Id.* at 15.

proposal take into consideration a full range of alternatives as well as resource planning factors and certificate of need factors.³³⁴ In addition, the Commission required an updated forecast of demand.³³⁵

217. In essence, the Notice and Order for Hearing requires a new analysis of the Company's resource needs based on updated forecast information and a full range of alternatives to determine if the NTEC proposal is needed and reasonable. The Order did not place any timing constraints on the alternatives that could be considered. To the contrary, based on the language of the Notice and Order for Hearing, the Administrative Law Judge concludes the Commission intended that the type, size, and timing of any resource additions be considered in determining whether the NTEC proposal is in the public interest. Thus, the Company's decision to make the NTEC purchase available only in 2025 and to place timing constraints on other resource options is contrary to the analysis required by the Notice and Order for Hearing.

218. In addition, the Administrative Law Judge agrees with the CEOs and LPI that those constraints biased the Strategist modeling results in favor of NTEC. Because a size, type, and timing decision has not been made with respect to any new gas-fired generation on the Company's system, the alternatives analysis should not be dictated by the Company's NTEC contract. Rather, for purposes of analyzing whether there is actually a need for the NTEC project in 2025, NTEC or a similar resource must be made available in Strategist in future years, not just in 2025. Likewise, the Company must remove the other timing constraints in its Strategist analysis identified by the CEOs and LPI because they are biased in favor of NTEC.

219. In summary, because the Company placed unreasonable limitations on the in-service dates of resource options considered in its Strategist analysis, the Company has failed to analyze a reasonable range of alternatives to the NTEC proposal.

ii. Type of Resources Considered

220. In addition to the timing constraints, LPI and the CEOs also maintained that the Company's alternative analysis is not robust enough because it did not consider a broad enough range of resources.³³⁶

221. LPI asserted that the Company provided too few resource options for Strategist to choose from in Step 1, and as a result skewed the entire analysis in favor of selecting NTEC.³³⁷ LPI maintained that the Company should have included a smaller CT option than the 223 MW unit included in its Strategist analysis, and should have

³³⁴ Notice and Order for Hearing at 5-6, 9. The resource planning factors are considered as part of the resource planning process where the Commission determines the size, type, and timing of resources needed by a utility. Ex. DER-8 at SRR-2 (Rakow Direct).

³³⁵ Notice and Order for Hearing at 5, 9.

³³⁶ Ex. LPI-8 at 10 (Andrews Direct); CEO Initial Br. at 21.

³³⁷ Ex. LPI-8 at 10 (Andrews Direct).

included a smaller natural gas combined-cycle (NGCC) generator option than the 250 MW NTEC option in its Strategist analysis.³³⁸

222. LPI emphasized that the Company only included one generic CT option, which was a 223 MW unit.³³⁹ LPI's witness Brian Andrews noted that the U.S. Energy Information Administration (EIA) considers a conventional CT to be 100 MW, consisting of two LM-6000 units.³⁴⁰

223. LPI recognized that the Company did include a 100 MW natural gas aeroderivative turbine in its Strategist analysis, but noted that this type of natural gas generating resource is expensive compared to CT resources.³⁴¹

224. LPI also acknowledged that CT units are generally less efficient than combined cycle facilities, but asserted that "the overall lower capital and fixed costs of a smaller CT unit could outweigh the benefits associated with lower variable costs of a more efficient combined cycle unit."³⁴² Because the Company had not done this type of analysis, LPI maintained that the Company has not supported its assertion that the 250 MW NTEC purchase is a better resource choice.³⁴³

225. Likewise, LPI maintained that the Company should have included a smaller NGCC in its Strategist modeling.³⁴⁴ Mr. Andrews noted that the LM-6000 can be configured as a combined cycle as well as a CT.³⁴⁵ Mr. Andrews pointed out that the only NGCC generator that the Company considered in its Strategist modeling other than NTEC was a 525 MW NGCC facility.³⁴⁶

226. According to Mr. Andrews, modeling smaller CT and NGCC options available would allow for a much more flexible portfolio.³⁴⁷ Furthermore, Mr. Andrews noted that the smaller 100 MW option would be more consistent with the approximately 100 MW capacity need in 2025 identified by the Company in its Strategist base case capacity position.³⁴⁸

227. In addition to including more generic CT and combined cycle alternatives LPI also asserted that the Company should have considered a 200 MW NTEC purchase option as an alternative in Step 1 of its Strategist analysis.³⁴⁹ LPI pointed out that South Shore provided the Company with a 200 MW bid as part of its RFP process that the

³³⁸ *Id.* at 10-11; Ex. MP-16 at 23 (Palmer Direct) (listing resource alternatives considered in the Strategist analysis).

³³⁹ *Id.*; Ex. 16 at 23 (Palmer Direct).

³⁴⁰ Ex. LPI-8 at 10.

³⁴¹ Ex. LPI-10 at 2-3 (Andrews Surrebuttal).

³⁴² LPI Initial Br. at 12 (citing LPI-10 at 7 (Andrews Surrebuttal)).

³⁴³ *Id.*

³⁴⁴ *Id.*

³⁴⁵ Ex. LPI-8 at 11 (Andrews Direct).

³⁴⁶ *See id.*

³⁴⁷ *Id.* at 10.

³⁴⁸ *Id.* at 11; LPI Initial Br. at 12.

³⁴⁹ Ex. LPI-8 at 11 (Andrews Direct).

Company declined.³⁵⁰ LPI recognized that the Company created a new swim lane for the 200 MW purchase in Step 2 of its revised Strategist analysis, at LPI's request.³⁵¹ Nonetheless, LPI maintained that inclusion of this alternative in Step 1 is necessary to determine whether the proposed 250 MW purchase is the least cost and best resource option because the Step 2 results are affected by the existing biases in favor of NTEC in Step 1.³⁵²

228. The CEOs also maintained that Minnesota Power inappropriately limited the size of alternatives.³⁵³ The CEOs pointed out the Company only allowed solar to be selected in 100 MW blocks.³⁵⁴ According to the CEOs, the Company should have allowed Strategist to choose solar in 25 MW blocks because the Company has “relatively little need for capacity.”³⁵⁵

229. In response to LPI, Minnesota Power asserted that a 100 MW CT in 2025 is not a viable option because a 100 MW CT is a “peaking” resource and the Company’s stated need is for an “intermediate” resource.³⁵⁶ The Company described an “intermediate” resource as a resource relied upon after a base load resource, as load requirements increase during the day, and “peaking” resource as a resource used only during peak load hours to fulfill remaining power supply requirements.³⁵⁷ In addition, the Company noted that an intermediate resource is typically characterized as having moderate variable costs and operational flexibility whereas a peaking resource is characterized as having high variable costs and very flexible operations.³⁵⁸

230. Moreover, the Company maintained a 100 MW CT would require Minnesota Power to enter into a partnership for the CT, and such a partnership does not exist today.³⁵⁹

231. With respect to the LPI’s assertion that the Company should have considered a 200 MW NTEC option, the Company noted it modeled a new swim lane in its revised Step 2 analysis. That swim lane (Swim Lane 6) modified the Company’s combined-cycle proposal (Swim Lane 1) by reducing the size of the NTEC purchase in 2025 from 250 MW to 200 MW and increasing the size of the combustion turbine in 2031 from 100 MW to 150 MW.³⁶⁰

³⁵⁰ *Id.*

³⁵¹ *Id.*

³⁵² See LPI Initial Br. at 13-15; Ex. LPI-8 at 13 (Andrews Direct). LPI asserted that the swim lane analysis is also inherently designed to favor NTEC for similar reasons. In addition, LPI noted that Swim Lanes 2 and 4 include capacity that is significantly above the Company’s projected needs. *Id.* at 13-14.

³⁵³ CEO Initial Br. at 21.

³⁵⁴ *Id.*

³⁵⁵ Ex. CEO-16 at 21-22 (Sommer Direct); Ex. CEO-18 at 12 (Sommers Surrebuttal).

³⁵⁶ Minnesota Power’s Initial Br. at 64.

³⁵⁷ Ex. MP-5, App. J at J-2 (Detailed Resource Planning Analysis).

³⁵⁸ *Id.*

³⁵⁹ Ex. MP-17 at 74 (Palmer Rebuttal).

³⁶⁰ Ex. LPI-8 at 14, 17 (Andrews Direct).

232. Minnesota Power acknowledged that the revised Step 2 modeling results show the portfolio with the 200 MW of NTEC is the lowest cost portfolio in 56 percent of the sensitivity runs in revised Step 2, but maintained price difference is inconsequential.³⁶¹ Minnesota Power pointed out that the proposed 250 MW NTEC alternative had a nearly identical impact to power supply cost as the 200 MW portfolio option across a range of sensitivities.³⁶²

233. The Company also stated that the 200 MW NTEC offer is not currently available to Minnesota Power and therefore should not be considered a viable alternative in the instant proceeding.³⁶³

234. With regard to the size of the solar blocks included in the Strategist analysis, the Company maintained that it included the 100 MW block to be consistent with direction from the Commission in the 2016 IRP Order. In that order, the Commission found that “up to 100 MW of solar by 2022 is likely an economic resource for Minnesota Power’s system” and required the Company to “account for this finding in any competitive acquisition process.”³⁶⁴

235. The Administrative Law Judge concludes that LPI and the CEOs have raised important concerns about Minnesota Power’s selection of resource alternatives. First, the Company has failed to provide a reasonable basis for not including a 100 MW CT alternative which could provide more flexible resource portfolio options. The Company maintained that it would need to enter into a partnership to develop a 100 MW CT but there is no evidence in the record to support this assertion. In addition, the record suggests that the 100 MW aeroderivative turbine analyzed in the Company’s Strategist is more expensive than a 100 MW CT option.³⁶⁵

236. Moreover, the Company’s claim that a 100 MW CT (a peaking resource) is not a viable resource option is not supported by the record. As discussed above, there has been no size, type, or timing determination by the Commission with respect to any natural gas generation facility. Nor has there been any determination by the Commission that the Company has a need for an intermediate resource (i.e. combined-cycle natural gas plant) in the mid-2020s as opposed to some other type of resource (peaking, renewable, additional demand response, or additional energy efficiency). The purpose of this proceeding is to conduct a full analysis of all alternative resource types based on updated forecast information.

237. Similarly, with regard to the size of the solar resources, the Commission did not limit the Company’s consideration to only 100 MW blocks. Rather the

³⁶¹ Ex. MP-17 at 81-82 (Palmer Rebuttal); Ex. LPI-8 at 17 (Andrews Direct).

³⁶² Ex. MP-17 at 81-2 (Palmer Rebuttal).

³⁶³ Ex. MP-26 at 10 (Supinski Rebuttal) (stating “South Shore had submitted bids for 250 MW and 200 MW alternatives for consideration, which were analyzed by both the Company and the independent evaluator, Sedway Consulting. The 250 MW alternative was judged superior based on that analysis and negotiations proceeded on the 250 MW proposal. Thus, the 200 MW bid from South Shore was not selected and is no longer available as an alternative for consideration.”).

³⁶⁴ Ex. MP-16 at 25 (Palmer Direct); 2016 IRP Order at 11.

³⁶⁵ Ex. LPI-10 at 2-3 (Andrews Surrebuttal); see also Ex. 2, App. I at I-7 (Assumptions and Outlooks).

Commission simply required consideration of “up to 100 MW” of solar resources. Nothing in the 2016 IRP Order precludes the Company from considering smaller size additions as long as it has accounted for a total of 100 MW in its planning. MP has not provided any reasonable explanation for not using smaller blocks of solar resources as an alternative choice to allow for more flexible portfolio options.³⁶⁶

238. With regard to the 200 MW NTEC purchase, the Administrative Law Judge recognizes that the Company analyzed this option in a new swim lane (Swim Lane 6) and the power supply costs were similar. Nonetheless, the 200 MW option was selected in 56 percent of the scenarios, calling into question whether the 250 MW NTEC purchase is actually the least cost option even with the biases built into the Company’s Strategist analysis.

239. In summary, the Administrative Law Judge concludes that Minnesota Power’s Strategist modeling failed to consider a reasonable range of alternatives. While the Administrative Law Judge recognizes that the Company cannot analyze an endless range of alternatives, a broader range of alternatives is necessary to determine whether the NTEC purchase is needed and reasonable.

v. Wind and Solar Assumptions

240. The CEOs asserted that the Company understated the capacity credit attributable to wind and solar resources. Capacity credit is the portion of a unit’s nameplate rating that counts towards a utility’s resource adequacy requirements.³⁶⁷ The CEOs stated that Minnesota Power appears to have assumed in its Strategist analysis that any additional wind resources would have no capacity credit and any additional solar resources would have a capacity credit of approximately 27 percent.³⁶⁸

241. The CEOs claimed that assuming a capacity credit of zero for wind runs counter to MISO’s guidance for MISO Zone 1, where Minnesota Power’s system is located. They noted that according to MISO’s 2018 Wind Capacity report, the Zone 1 average wind capacity credit is 18.3 percent and the MISO system-wide average is 15.2 percent. Even if wind penetration in MISO were to triple from its 2nd quarter 2017 levels, MISO estimates that the system-wide average accredited capacity still would remain 12.5 percent.³⁶⁹

242. With regard to solar, the CEOs noted that the current MISO guidance states that solar projects with less than 30 days of metered data should assume a 50 percent capacity credit.³⁷⁰

243. The CEOs also claimed that Minnesota Power’s assumption that the price of new wind generation will be \$45 per MWh throughout the entire planning period is not

³⁶⁶ Ex. CEO-18 at 12 (Sommer Surrebuttal).

³⁶⁷ Ex. CEO-16 at 12 (Sommer Direct).

³⁶⁸ *Id.*

³⁶⁹ *Id.* at 12-13.

³⁷⁰ *Id.* at 12.

reasonable because this assumption fails to account for the fact that installed wind project costs have declined dramatically over the last decade and are likely to continue on that trajectory.³⁷¹ The CEOs witness Ms. Sommer asserted even if the expiration of the Production Tax Credit puts some upward pressure on wind project costs in the near-term, costs will likely continue to decline through the planning period due to turbine cost declines and technological advancements that lead to increased performance.³⁷²

244. In response, Minnesota Power argued that the Company appropriately modeled the capacity credit for any additional wind and solar resources. The Company maintained that, due to limited transmission capacity existing in high wind zones located in MISO, using no capacity credit for new wind generation resources is justifiable.³⁷³

245. The Company also asserted that the CEOs' assumed wind capacity credit of 18.3 percent is flawed and produces unreasonable modeling results because it is based on the current system and fails to consider how capacity credit will be affected in the future by the cost of new transmission facilities, curtailment, and additional resources on the system.³⁷⁴

246. In addition, Minnesota Power argued that its assumed cost of new wind at \$45/MWh following the sunset of the Production Tax Credit is reasonable and within industry norms.³⁷⁵ The Company noted that in OtterTail Power's recent IRP docket, the Department assumed new wind at \$44/MWh in 2024 and increased the cost to \$53/MWh in 2026.³⁷⁶

247. Furthermore, the Company argued that the CEOs concerns about the price for new wind are immaterial because the Company's Strategist analysis includes a lower range of sensitivities for the cost of wind ranging from \$25/MWh to \$35/MWh, which is below the \$39/MWh used by the CEOs.³⁷⁷

248. In response, the CEOs witness Ms. Sommer noted that her projected cost of wind did include network upgrade costs. She stated that the CEOs disagreement with the Company is about the trajectory of pricing and maintains that her pricing is based on a detailed analysis by the National Renewable Energy Laboratory (NREL).³⁷⁸

249. Ms. Sommer also maintained that the 18.3 percent capacity assumption is forward-looking, not reflective of the current system as asserted by Minnesota Power, because 18.3 percent is less than the 21.1 percent capacity credit that Minnesota Power currently is getting from its existing wind on the MISO system.³⁷⁹ She noted information from MISO shows that the MISO wind capacity credit for Zone 1 (where

³⁷¹ *Id.* at 13-14

³⁷² *Id.*

³⁷³ Ex. MP-17 at 54 (Palmer Rebuttal).

³⁷⁴ *Id.* at 53-55.

³⁷⁵ *Id.* at 57.

³⁷⁶ *Id.*

³⁷⁷ *Id.*

³⁷⁸ Ex. CEO-18 at 13 (Sommers Rebuttal).

³⁷⁹ *Id.* at 13-14.

Minnesota Power is located) will not drop dramatically even with extensive wind build-out.³⁸⁰ She also asserted that Minnesota Power failed to consider that wind technology continues to improve and these improvements translate into improved performance.³⁸¹ Ms. Sommer also maintained that any transmission constraints are likely to be addressed by MISO because MISO conducts transmission planning on an annual basis, which results in new transmission portfolios.³⁸²

250. The Administrative Law Judge concludes that the record demonstrates that the use of the Company's assumed capacity credit of zero for wind and approximately 27 percent for solar are not reasonable. MISO's guidelines support a 50 percent capacity credit for solar. With regard to the wind capacity rating, the MISO guidelines also support a capacity credit above zero. Further, the transmission constraints pointed to by the Company as reason to assign a capacity rating of zero are likely to be addressed, at least to some degree, by MISO's planning process.

251. Finally, while the wind price assumed by the Company appears to be on the high side, the Company's lower range of sensitivities include much lower prices and thereby address this pricing concern.

vi. Energy Efficiency

252. The CEOs maintained that the Company underestimated the potential use of energy efficiency as an alternative or as a part of a series of alternatives.³⁸³ As a result, the CEOs claimed that the Company has not analyzed a sufficient range of alternatives and has overstated its need for new generation resources.³⁸⁴

253. The CEOs noted that the Company's base case for its Strategist modeling assumes the Company will add 11 GWh of additional energy efficiency savings beyond the 46 GWh of energy efficiency embedded in the forecast (based on historical data) for a total of 57 GWh.³⁸⁵ The 57 GWh amount is the conservation level approved in the Company's 2017-2019 Triennial Conservation Improvement Plan (CIP) filing.³⁸⁶

254. The CEOs also pointed out the incremental amount of savings that Minnesota Power included in its base case peaks in the time period from 2017 to 2020 at 57 GWh of incremental savings, and then steadily declines to reach 0 GWh of incremental savings by 2032 as illustrated in the figure below.³⁸⁷

³⁸⁰ *Id.* at 14.

³⁸¹ *Id.* at 15.

³⁸² *Id.* at 16.

³⁸³ CEO Initial Br. at 16.

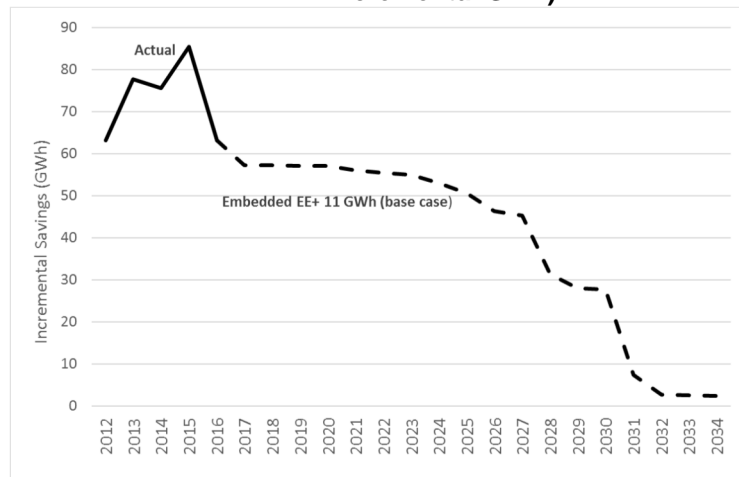
³⁸⁴ *Id.* at 16-18.

³⁸⁵ Ex. CEO-4 at 7 (Stanton Direct).

³⁸⁶ *Id.* at 8; Ex. 16 at 45 (Palmer Direct).

³⁸⁷ Ex. CEO-4 at 8 (Stanton Direct).

Minnesota Power's Actual Energy Efficiency Savings vs. Base Case Future Assumptions (Annual Incremental GWh)



255. The CEOs maintained that the Company's forecast of incremental energy efficiency savings set forth in the figure above is unreasonable because it is significantly lower than what the Company has achieved in recent years.³⁸⁸

256. The CEOs presented evidence showing that the Company has far exceeded its CIP energy efficiency savings targets from 2012 through 2016.³⁸⁹ The CEOs noted that in the past five years, the Company has saved an average of 50 percent more than its CIP savings targets.³⁹⁰

257. The CEOs acknowledged that the Company also modeled sensitivities adding +15 GWh and +30 GWh of incremental savings beyond the historical amount of 46GWh, but argued that + 30 GWhs (or 76 GWhs total) of incremental savings should not be the upper end of what is modeled in Strategist. They maintain that 30 GWh is "a reasonable base case, not a high case" because it most closely matches the level that the Company has achieved in the recent past.³⁹¹

258. The CEOs also pointed out that in the 2016 IRP Order, the Commission set the Company's annual energy saving goal at 76.5 GWh for resource planning purposes.³⁹² The CEOs maintained that the Company's modeling of a total of 57 GWh in its Strategist base case is contrary to the Commission's 2016 IRP Order and the Company's statutory duty to "aggressively" pursue energy savings as a resource.³⁹³

259. The CEOs also claimed 76.5 GWh (embedded savings +30 GWh) is not the upper end of the Company's achievable energy efficiency savings.³⁹⁴

³⁸⁸ *Id.*

³⁸⁹ *Id.* at 9.

³⁹⁰ *Id.*

³⁹¹ *Id.* at 10- 12; see also Ex. CEO-1 (Mellinger Direct).

³⁹² Ex. CEO-4 at 11 (Stanton Direct); CEO Initial Br. at 16; 2016 IRP Order at 13.

³⁹³ CEO Initial Br. at 16, 18.

³⁹⁴ *Id.* at 16-17; Ex. CEO-4 at 12; Ex. CEO-1 (Mellinger Direct).

260. The CEO's witness, Dan Mellinger, identified five different energy efficiency programs and practices that have not been implemented, which he maintains could be used to increase energy efficiency savings.³⁹⁵ Those programs include:

- Strategic Energy Management for industrial and other large customers;
- Commercial Lighting: LED Linear Potential and Connected Controls;
- Midstream Programs for Commercial HVAC/R, and Residential HVAC;
- Residential Connected Lighting Controls; and
- Residential Behaviors.³⁹⁶

261. In addition, based on testimony from Mr. Mellinger, the CEOs argued that the Company used unreasonably high prices for additional energy efficiency programs in Strategist for the scenarios it modeled.³⁹⁷

262. Minnesota Power disagreed with the CEO's position. First, Minnesota Power maintained that its analysis already includes reasonable energy efficiency assumptions.³⁹⁸

263. Minnesota Power argued that the energy efficiency assumptions proposed by the CEOs are overly optimistic because the Company's industrial class customers are "CIP exempt," which means the Company cannot rely on them to help meet overall energy efficiency targets.³⁹⁹

264. The Company recognized that it has exceeded its CIP energy efficiency targets in recent years but maintains additional energy efficiency savings will be more difficult and costly to achieve because the "low hanging fruit" have already been realized.⁴⁰⁰ The Company noted the higher savings achievement and relatively lower costs in those years have been attributed to a few large savings opportunities that were associated with large construction projects or significant customer expansion.⁴⁰¹

265. Minnesota Power asserted that there is a high degree of risk associated with assuming that the historical performance of energy efficiency programs is sustainable, and in assuming that significant new savings can be found each year. In the event that the energy efficiency programs do not perform as projected, additional

³⁹⁵ Ex. CEO-1 at 4-6 (Mellinger Direct).

³⁹⁶ *Id.* at 6-34.

³⁹⁷ CEO Initial Br. at 16; Ex. CEO-1 at 36 (Mellinger Direct).

³⁹⁸ Ex. MP-17 at 29 (Palmer Rebuttal).

³⁹⁹ Ex. MP-14 at 8 (Pierce Rebuttal); see Minn. Stat. § 216B.241, subd. 1a (2016).

⁴⁰⁰ Ex. MP-14 at 7-8 (Pierce Rebuttal); Ex. MP-17 at 14 (Palmer Rebuttal).

⁴⁰¹ Ex. MP-17 at 48 (Palmer Rebuttal).

power supply would be required, and large resource additions take years to implement.⁴⁰²

266. Lastly, Minnesota Power claimed that Mr. Mellinger's testimony is based on severely over-simplified calculations and generalized assumptions that do not reflect local or Company-specific realities and programs currently being offered.⁴⁰³ Minnesota Power concluded that because Mr. Mellinger does not adequately consider the uniqueness of the Company's system, his analysis should not be relied upon in this case.⁴⁰⁴

267. Ultimately, Minnesota Power took the position that both the CEOs' individual assumptions and overall energy efficiency savings estimates were unreasonable and unsupported.⁴⁰⁵ The Company concluded that reliance on such assumptions could result in unduly exposing Minnesota Power's customers to the risk of market exposure or inadequate electricity to reliably and affordably serve customer needs.⁴⁰⁶

268. While the Administrative Law Judge recognizes that the Company has a duty to provide reliable service at a reasonable rate to its customers, the Administrative Law Judge concludes that the energy efficiency assumptions used by the Company in its Strategist modeling are not reasonable.

269. Minnesota law encourages utilities to aggressively pursue cost effective energy efficiency savings.⁴⁰⁷

270. As noted above, in the 2016 IRP Order the Commission set the Company's annual energy savings goal at 76.5 GWh for resource planning purposes.

271. Given the legislature's direction and the Commission's decision in the 2016 IRP Order to use 76.5 GWh as the Company's annual energy saving goal, it was not reasonable for the Company to model 76.5 GWh (or +30 GWh incremental savings) as the maximum achievable energy efficiency amount modeled in Strategist.⁴⁰⁸ To be consistent with the Commission's 2016 IRP Order and state policy, the Company should have used 76.5 GWh (or +30 GWh) in its base case or, at a minimum as the mid-level sensitivity, not the highest level sensitivity.

272. The Company's history of exceeding its CIP targets by an average of 50 percent in each of the last five years, along with opportunities for additional energy efficiency savings identified by the CEOs expert, Mr. Mellinger, confirm that 76.5 GWh

⁴⁰² Ex. MP-16 at 46 (Palmer Direct).

⁴⁰³ Ex. MP-17 at 49-50 (Palmer Rebuttal).

⁴⁰⁴ *Id.* at 49-53.

⁴⁰⁵ *Id.* at 52-53.

⁴⁰⁶ Minnesota Power's Reply Br. at 38.

⁴⁰⁷ Minn. Stat. § 216B.2401.

⁴⁰⁸ See 2016 IRP Order at 13; Ex. CEO-4 at 12 (Stanton Direct).

(or +30 GWh) of incremental savings should not be the upper end of what is modeled in Strategist.⁴⁰⁹

273. The Administrative Law Judge understands the Company's argument with regard to CIP-exempt customers, and recognizes that the Company does not have an obligation to provide energy efficiency programs to CIP-exempt customers.⁴¹⁰ Nonetheless, CIP-exempt customers have the financial incentive to undertake new energy efficiency projects that are cost-effective on their own, resulting in energy savings by these large customers which are reflected on the Company's system as a whole. For that reason, the Company should not ignore potential energy efficiency savings by the CIP-exempt customers. Instead, the Company's estimate of future energy efficiency savings on its system should include a reasonable estimate of cost-effective savings that these large industrial CIP-exempt customers are likely to implement on their own. To the extent the Company has not already done so, it should survey these customers to determine whether and to what extent these customers are likely to implement energy efficiency programs on their own during the applicable planning period.⁴¹¹

274. Furthermore, in the Commission's 2016 IRP Order, the Company also raised its concern about consideration of energy savings from of CIP-exempt customers. Nonetheless, the Commission set the Company's annual energy savings goal at 76.5 GWh.⁴¹² Thus, even taking into account the Company's position on CIP-exempt customers, the record demonstrates the energy efficiency savings assumptions used by the Company in its Strategist modeling were not reasonable.

vii. Demand Side Management Assumption

275. In its Strategist modeling of alternatives, the Company included 150 MW of demand response from large customers in its base case capacity position.⁴¹³ This amount is the Company's average level of demand response from large industrial customers available over the past five MISO planning years (2013-2017).⁴¹⁴

276. In its initial Strategist modeling, the Company did not model any additional levels of industrial demand response.⁴¹⁵ The only additional demand side resource options that Strategist was allowed to choose from were two residential and commercial

⁴⁰⁹ Ex. CEO-4 at 9, 12 (Stanton); see also Ex. CEO-1 (Mellinger Direct).

⁴¹⁰ See Minn. Stat. § 216B.241, subd. 1a.

⁴¹¹ The Administrative Law Judge is aware that the Company's 2017 AFR is based on customer specific information but it is unclear whether that information includes future energy efficiency measures and related savings for CIP-exempt customers. The Administrative Law Judge also recognizes that CIP-exempt customers have no legal obligation to respond to such a survey. See Minn. Stat. § 216B.241, subd. 1a(b). However, given the Company's ability to obtain other customer specific information from these customers regarding their future energy use, they may also be willing to share this information on a confidential basis with the Company.

⁴¹² 2016 IRP Order at 12-13.

⁴¹³ Ex. MP-16 at 13 (Palmer Direct).

⁴¹⁴ *Id.* at 40; Ex. MP-17 at 46 (Palmer Rebuttal).

⁴¹⁵ Ex. MP-16 at 22-23 (Palmer Direct); Ex. 5, App. I (Assumptions and Outlooks).

programs: the central air demand response program and the electric hot water heater demand response programs.⁴¹⁶

277. The CEOs and LPI asserted that the level of industrial demand response used by the Company in its base case capacity position is too low.⁴¹⁷ The CEOs emphasized that assumed level of 150 MW “is a significant drop” from the 265 MW of actual demand response that the Company had available in 2017 and is “much lower” than the Company’s average level of 194 MW of total accredited demand response capacity over the past three years (2015-2017).⁴¹⁸ The CEOs also noted, even using the Company’s five year average approach, the average with updated data shows an average of 190 MW per year for the most recent five years (2014-2018).⁴¹⁹

278. LPI’s witness Mr. Andrews also emphasized that the assumed level of 150 MW of industrial demand response is less than the 265 MW of industrial response currently under contract. Mr. Andrews also asserted that this unreasonably low assumption results in an exaggerated need for capacity.⁴²⁰

279. In response, Minnesota Power argued that its assumed level of demand response is reasonable and fully supported based on its five year average for 2013-2017, and assuming a greater level of demand response, as recommended by the CEOs and LPI, would not be reasonable or prudent planning for meeting customer needs.⁴²¹

280. Further, Minnesota Power noted that existing contracts for demand response are not long-term contracts. Instead, they are short-term contracts for one year.⁴²² Minnesota Power asserted that it is concerned that if customers see an increase in actual physical interruptions in the next five to ten years, those customers may not want to sign up for the demand response program anymore.⁴²³

281. Finally, to address LPI’s criticism that further study of demand response products should be considered in Step 1, Minnesota Power performed a revised Step 1 analysis where 300 MW of industrial demand response was available as a resource alternative starting in 2025.⁴²⁴ The 300 MW were available in two 150 MW blocks with

⁴¹⁶ Ex. MP-16 at 22-23 (Palmer Direct); Ex. MP-5, App. I at I-6 to I-7 (Assumptions and Outlooks).

⁴¹⁷ Ex. CEO-16 at 11 (Sommers Direct); Ex. LPI-5 at 20-21 (Gorman Direct); Ex. LPI-8 at 13 (Andrews Direct).

⁴¹⁸ Ex. CEO-16 at 11 (Sommer Direct).

⁴¹⁹ CEO Initial Br. at 18-19. In addition to underestimating the total level of available demand response, the CEOs asserted that the Company failed to recognize that demand response also provides flexibility and ancillary services capabilities to the Company’s system. Ex. CEO-2 at 27 (Jacobs Direct). The CEOs raised similar concerns with regard to the Company’s treatment of energy storage resources. *Id.* The CEOs maintained that the Company’s failure to recognize these benefits resulted in the Company’s analysis being biased against these resources because the Company did discuss ancillary services as one of the benefits of the proposed NTEC project. CEO Initial Br. at 29.

⁴²⁰ Ex. LPI-8 at 13 (Andrews Direct).

⁴²¹ Ex. MP-17 at 46 (Palmer Rebuttal).

⁴²² Ex. MP-16 at 40 (Palmer Direct); MP-17 at 46 (Palmer Rebuttal).

⁴²³ Tr. at 126 (Palmer).

⁴²⁴ Ex. MP-17 at 86 (Palmer Rebuttal).

400 curtailable hours at \$9.50/kW-month.⁴²⁵ The results showed the proposed 250 MW NTEC capacity was still selected in 83 to 96 percent of the cases depending on the level of energy efficiency assumed.⁴²⁶ According to Minnesota Power, these results show that NTEC is a superior resource for meeting customer capacity and energy needs compared to industrial demand response.⁴²⁷ Minnesota Power also included a new swim lane in its revised Step 2 that made 300 MW of demand response available.⁴²⁸ The swim lane analysis showed that the 250 MW NTEC purchase is lower cost than procuring 300 MW of demand response.⁴²⁹

282. In any event, Minnesota Power noted that demand response is akin to a peaking resource and does not meet the Company's stated need for an intermediate resource.⁴³⁰ As such, the Company maintained that the precise amount of demand response to be used for resource planning does not alter the evaluation of the NTEC resource.⁴³¹

283. In response to Minnesota Power, the CEOs asserted that there has been no finding by the Commission that the Company has a need for an intermediate resource.⁴³² And, when updated demand response data including 2018 is used, the Company's five year average (2014-2018) is 190 MWs of industrial demand response. The CEOs noted that this result is much higher than the 150 MW assumed by the Company and is very close to the 194 MW suggested by the CEOs as a reasonable assumption for future available demand response.⁴³³

284. In addition, LPI asserted that the Company's assumptions regarding the 300 MW demand response option were not reasonable and did not adequately account for savings that could be achieved by reducing the need to add new generating capacity that might otherwise be necessary.⁴³⁴

285. The Administrative Law Judge agrees with the CEOs and LPI that the Company's assumed level of 150 MW of industrial demand response is unreasonably low. The most current data shows that the Company has been able to acquire an average of 190 MW per year over the last five years.⁴³⁵ In addition, the Company's currently available levels even higher -- 264 MW in 2018 and 265 MW in 2017.⁴³⁶

286. Furthermore, the Company's contention that an intermediate resource is necessary to meet its resource needs is contrary to the Commission's direction in this

⁴²⁵ *Id.* at 86.

⁴²⁶ *Id.* at 87.

⁴²⁷ *Id.*

⁴²⁸ *Id.* at 78.

⁴²⁹ *Id.* at 78-81.

⁴³⁰ Ex. MP-15 at 11 (Pierce Surrebuttal).

⁴³¹ *Id.*

⁴³² CEO Reply Br. at 14.

⁴³³ *Id.*

⁴³⁴ LPI Initial Br. at 27.

⁴³⁵ CEO Initial Br. at 18-19.

⁴³⁶ CEO Initial Br. at 18; Tr. at 86 (Palmer).

proceeding. As discussed above, the Commission has not determined that the Company has a need for an intermediate resource as opposed to some other type of resource.⁴³⁷ In fact, the Commission expressly required consideration of a broad range of alternatives including “demand response.”⁴³⁸

287. Thus, it is important the Company’s Strategist modeling of alternatives include a reasonable level of industrial demand response in the base case capacity position used in Strategist. The CEOs suggested level of 194 MW has much greater support in the record.

288. In addition, while the Company did make two 150 MW blocks of industrial demand response available in its revised Strategist modeling, the results of those Strategist runs are not reliable for purposes of determining whether NTEC is needed and reasonable as compared to a portfolio with demand response because of other problems with the Strategist analysis discussed above that bias the model in favor of NTEC. In addition, the 150 MW block size is too small, at least for the first block, because it is less than the average amount of industrial demand response currently on its system.

289. For these reasons, the Administrative Law Judge concludes that the base case capacity position used in Strategist should include at least 190 MW (the 2014-2018 average) of demand response and any new swim lane analysis should be adjusted accordingly as well.

viii. Impact of Recent Tax Legislation

290. LPI asserted that the Company’s failure to consider and model the impacts of the 2017 Tax Cuts and Jobs Act (TCJA) is a significant oversight further demonstrating that the Company failed to meet its burden of proof.⁴³⁹

291. The TCJA reduced the federal corporate income tax rate from 35 percent down to 21 percent.⁴⁴⁰ The TCJA became law in December 2017, after direct testimony in this proceeding was filed but before rebuttal and surrebuttal testimony were filed.⁴⁴¹

292. According to LPI’s witness, Michael Gorman, this change in tax law does not impact each resource included in Strategist in the same manner.⁴⁴² Mr. Gorman noted that “[t]ax rates have a substantial effect on capital costs and capital costs vary across different resources. . . . If the capital costs change, then the economics of the fixed capital costs compared to the lower variable energy costs could impact the resource selection.”⁴⁴³ As a result, LPI maintained that Minnesota Power’s Strategist

⁴³⁷ *Id.* at 5, 9; 2016 IPR Order at 8-9.

⁴³⁸ Notice and Order for Hearing at 9.

⁴³⁹ LPI Initial Br. at 9.

⁴⁴⁰ Ex. LPI-5 at 5 (Gorman Direct).

⁴⁴¹ Ex. LPI-5 at 5 (Gorman Direct); First Prehearing Order (setting for filing dates for testimony).

⁴⁴² Ex. LPI-6 at 9 (Gorman Surrebuttal)

⁴⁴³ *Id.*

modeling “is no longer valid and cannot be relied upon to identify the most economic resource available to meet its projected customer capacity and energy needs.”⁴⁴⁴

293. In addition, LPI recommended that the impact of TCJA be fully studied before a significant resource investment is approved.⁴⁴⁵

294. In response, Minnesota Power argued that the changes in the tax rates will affect all bids on approximately the same order of magnitude, making an update of the Company’s planning studies unnecessary.⁴⁴⁶

295. Minnesota Power pointed out that economic changes are occurring all the time and that more will likely occur before and after a Commission decision in this docket.⁴⁴⁷ The Company also noted that other economic events have occurred during this proceeding, and LPI did not raise those issues (e.g., impositions of tariffs on steel and solar panel imports).

296. In addition, Minnesota Power argued that LPI’s request for analysis of how TCJA might affect the different resource options merely seeks analysis for its own sake without any possibility of new information that would ultimately alter the decision on the Company’s proposal.⁴⁴⁸

297. In its Strategist modeling, the Company used high level engineering projects to estimate the capital costs of different resource alternatives.⁴⁴⁹ The estimates “typically have a +/- 30 percent range of accuracy.”⁴⁵⁰

298. The Administrative Law Judge finds that, given the capital costs used for the different resource options in the Strategist analysis are high level and could be off by as much as 30 percent, the impact of TCJA may be within the range of uncertainty included in these estimates. Further, as Minnesota Power correctly noted, there are bound to be economic changes during the course of a proceeding.

299. Therefore, the Administrative Law Judge concludes that the Company’s failure to incorporate the impacts of TCJA is not unreasonable. Nonetheless, given the potential for some impact on resource choices, the Administrative Law Judge recommends the Company consider the impacts of TCJA in the Company’s next resource plan.

⁴⁴⁴ Ex. LPI-5 at 6 (Gorman Direct); Ex. LPI-6 at 3 (Gorman Surrebuttal).

⁴⁴⁵ Ex. LPI-6 at 3 (Gorman Surrebuttal).

⁴⁴⁶ Minnesota Power’s Reply Br. at 61; Ex. MP-17 at 85 (Palmer Rebuttal).

⁴⁴⁷ Minnesota Power’s Reply Br. at 62.

⁴⁴⁸ *Id.* at 61-62.

⁴⁴⁹ Ex. 2, Page I-6 (Petition).

⁴⁵⁰ *Id.*

C. The Department's Strategist Modeling

300. The Department conducted its own Strategist modeling as part of its review of the proposed 250 MW NTEC purchase.⁴⁵¹ The overall goal of the Department's analysis was to "ensure that the proposed [NTEC] resource acquisition is reasonably tied to IRP outcomes."⁴⁵²

301. In its modeling, the Department did not use the base case prepared by the Company for this proceeding.⁴⁵³ Instead, the Department relied on an update to the base case from the Company's last IRP (the 2015 IRP) to assess the accuracy of Minnesota Power's model in this case.⁴⁵⁴

302. In determining which inputs to update, the Department's witness, Dr. Rakow, evaluated at which inputs had changed outside of the bounds studied in the 2015 IRP.⁴⁵⁵ Based on this review, Dr. Rakow updated:

- the load forecast but used the 2016 AFR rather than the 2017 AFR because the 2017 AFR was not available when the Department performed its analysis;⁴⁵⁶
- the prices for generic wind units;⁴⁵⁷
- the prices for solar units;⁴⁵⁸

303. In addition, Dr. Rakow added a new natural gas combined cycle resource (NTEC) as an alternative. This resource was made available for selection only in 2025.⁴⁵⁹

304. While the Department did not use the 2017 AFR due to timing issues, the Department noted that the 2017 AFR is within the contingency bands employed by the Department.⁴⁶⁰

305. The Department noted that it also kept the existing intermediate unit option (a natural gas combined cycle unit) from the 2015 IRP as an option for selection by the Strategist model.⁴⁶¹ The NTEC unit was the first combined cycle gas generator to be selected by Strategist as modeled by the Department. When a second

⁴⁵¹ Ex. DER-8 at 19, SRR-3 at 12-16 (Rakow Direct).

⁴⁵² *Id.* at 19.

⁴⁵³ *Id.*, SRR-3 at 13.

⁴⁵⁴ *Id.*, SRR-3 at 12-13.

⁴⁵⁵ *Id.*, SRR-3 at 13.

⁴⁵⁶ *Id.*

⁴⁵⁷ *Id.*

⁴⁵⁸ *Id.*

⁴⁵⁹ *Id.*, SRR-3 at 14.

⁴⁶⁰ *Id.*, SRR-3 at 13.

⁴⁶¹ *Id.*, SRR-3 at 14.

intermediate unit was selected, it was the existing natural gas combined cycle option, which add another 190 MW of accredited capacity.⁴⁶²

306. In its modeling, the Department used the same energy efficiency assumptions as were used in the 2015 IRP and as were used by Minnesota Power in its modeling. The range included:

- 57.3 GWh average annual energy savings (+11 GWh above the 46.5 GWh target in the Company's 2014-2016 CIP filing⁴⁶³);
- 61.2 GWh average annual energy savings (+15 GWh above the 46.5 GWh);
- 76.5 GWh (+30 GWh above the 46.5 GWh).

307. With these updated inputs and assumptions, the Department's modeling consistently selected the 250 MW NTEC option as part of the least cost expansion plan.⁴⁶⁴ When the Commission's most recent approved-levels of externality values were added, the result was the same.⁴⁶⁵ The Department also noted that its modeling results show that NTEC is being added to the Company's system because NTEC's energy output reduces overall societal costs, not because NTEC is necessarily filling a capacity need.⁴⁶⁶

308. In the Department's view, its Strategist analysis support the Company's pursuit of about 250 MW of intermediate resources by 2025 (i.e. the acquisition of the 250 MW NTEC purchase), assuming that the project-specific information from the bidding process shows that the NTEC project is reasonable.⁴⁶⁷

309. The Department also noted that the need for an intermediate resource is consistent with Strategist modeling done by the Department in past in the context of the Company's IRP proceedings.⁴⁶⁸

310. The CEOs raised concerns about the Department's approach to updating the last IRP base case and questioned a number of assumptions used by the Department in its modeling.⁴⁶⁹ As a result, the CEOs did not agree with the

⁴⁶² *Id.*

⁴⁶³ *Id.*; In *the Matter of Minnesota Power's 20-14-2016 Energy Conservation Improvement Plan*, MPUC Docket No. E015/CIP-13-409, Decision of the Deputy Commissioner, Department of Commerce (October 10, 2013).

⁴⁶⁴ Ex. DER-8, SRR-3 at 15 (Rakow Direct).

⁴⁶⁵ Ex. DER-11 at 10-11, 45 (Rakow Surrebuttal).

⁴⁶⁶ Ex. DER-11 at 42. Dr. Rakow designated the NTEC unit both as "not superfluous" and as "superfluous" in different runs. *Id.* When NTEC was not labeled as "superfluous," it was not selected very often. Once NTEC was labeled as "superfluous," NTEC was selected in virtually every case. *Id.*

⁴⁶⁷ Ex. DER-8 at 20 (Rakow Direct); *see also* Ex. DER-11 at 42-43 (Rakow Surrebuttal)

⁴⁶⁸ Ex. DER-8, SRR-3 at 8, 15 (Rakow Direct).

⁴⁶⁹ Ex. CEO-17 at 3-10 (Sommer Rebuttal).

Department's conclusion that the Department's Strategist modeling supports the Company's pursuit of about 250 MW of intermediate resources by 2025.⁴⁷⁰

311. The CEOs asserted that the Department's alternatives analysis was unreasonable because the NTEC option could only be selected in 2025. The CEOs maintained that the modeling was unreasonable because the size and timing of the NTEC resource option was predetermined.⁴⁷¹

312. The CEOs also argued that: (1) the wind prices used by the Department were higher than is reasonable; (2) the demand response level included in the Department's modeling was less than that used by the Company in its modeling and far less than the 194 MW level recommended by the CEOs; (3) the 2016 AFR is not reasonable; and (4) the Department did not include the Nobles 2 wind farm in its calculation of firm capacity available to the Company.⁴⁷²

313. The Department did not agree with the CEOs critique, arguing that its assumptions are reasonable for use in Strategist modeling and consistent with Strategist modeling practices.⁴⁷³

314. The Administrative Law Judge agrees with the CEOs that the Department's Strategist modeling included some unreasonable assumptions. In particular, because the Department only allowed the NTEC resource option to be selected in 2025, the Department's modeling results were biased in favor of NTEC. Because the Commission has not made a decision that a resource of this type is need in 2025, the Department's modeling unreasonably constrains the resource options. Like Minnesota Power's Strategist analysis, the Department's Strategist analysis fails to analyze a sufficient range of alternatives to determine whether the NTEC resource is truly needed in 2025 or whether some other portfolio of resources would better meet the Company's resource needs in a cost-effective manner.

315. In addition, with regard to demand response, the Administrative Law Judge agrees that it was unreasonable for the Department to model of level of demand response lower than that used by the Company in its modeling.

316. Also, the Department's energy efficiency assumptions are unreasonably low for the reasons set forth above in paragraphs 253-274.

317. Because these underlying assumptions are not reasonable, the Department's Strategist results are not sufficiently robust or reliable for purposes of determining whether the 250 MW NTEC purchase is needed and reasonable.

⁴⁷⁰ *Id.* at 4.

⁴⁷¹ *Id.*

⁴⁷² *Id.* at 6-8.

⁴⁷³ Ex. DER-11 at 41-4 (Rakow Surrebuttal).

D. The CEOs' Strategist Modeling

318. The CEOs also performed their own Strategist modeling to analyze potential resource alternatives for meeting the Company's future demand.⁴⁷⁴

319. The CEOs' witness, Ms. Sommer, made the following changes to the assumptions used by Minnesota Power in the CEOs' Strategist modeling:⁴⁷⁵

- Assumed Minnesota Power could secure 194 MW of accredited demand response throughout the planning period, similar to the most recent available 5-year average;⁴⁷⁶
- Assumed Minnesota Power could achieve 30 GWh in incremental energy efficiency savings, consistent with the goal set by the Commission in the 2016 IRP Order;⁴⁷⁷
- Assigned a 50 percent capacity credit to new solar projects based on MISO guidance for new solar resources;⁴⁷⁸
- Allowed Strategist to add solar in 25 MW blocks rather than 100 MW blocks;⁴⁷⁹
- Assumed that half of a combustion turbine could be selected after 2025;⁴⁸⁰
- Included a wind price without production tax credit using NREL's Annual Technology Baseline price forecast;⁴⁸¹
- Assigned 18.3 percent capacity credit to new wind projects, the average wind capacity credit for Zone 1 of MISO;⁴⁸²
- Removed Blandin Paper Mill 5 load from base load forecast due to closure;⁴⁸³
- Modified the Planning Reserve Margin from 7.8 percent to 8.4 percent, per MISO's updated Loss of Load Expectation study;⁴⁸⁴
- Included the mid-point of the Commission's environmental externality values, as per the Commission's September 19, 2017 Order;⁴⁸⁵ and

⁴⁷⁴ Ex. CEO-16 at 20-29 (Sommer Direct).

⁴⁷⁵ *Id.* at 20-21.

⁴⁷⁶ *Id.* at 21-22; CEO Initial Br. at 18-19.

⁴⁷⁷ *Id.* at 22.

⁴⁷⁸ *Id.*

⁴⁷⁹ *Id.*

⁴⁸⁰ *Id.* at 22-23.

⁴⁸¹ *Id.* at 23-24.

⁴⁸² *Id.* at 24.

⁴⁸³ *Id.* at 25.

⁴⁸⁴ *Id.*

- Turned off wholesale market sales but allowed for market purchases.⁴⁸⁶

320. According to Ms. Sommer, Minnesota Power has very little need for any capacity at all when the Commission's level of energy efficiency from the 2016 IRP Order is used along with "more reasonable assumptions about the level of achievable demand response."⁴⁸⁷

321. In conducting her Strategist modeling, Ms. Sommer ran the following sensitivities:

- Inclusion of CEO Witness Dan Mellinger's energy efficiency savings;⁴⁸⁸
- Market capacity prices after 2023 that increase consistent with the prior years' rate of increase;
- Market sales enabled, but the Company's energy market price tiers turned off.⁴⁸⁹

322. Ms. Sommer noted that the number of sensitivities that she ran is far fewer than the number run by the Company, but indicated that she was constrained by time and does not believe that many of the sensitivities run by the Company are particularly meaningful.⁴⁹⁰

323. Using Ms. Sommer's revised assumptions, the CEOs modeling results showed that NTEC was not the most economic choice to meet Minnesota Power's potential need in the late 2020s.⁴⁹¹ The CEOs modeling showed that the "optimized result" (meaning the result "chosen" by Strategist to be least cost) added 300 MW of wind and 100 MW of solar between 2025 and 2030, and did not add NTEC.⁴⁹²

324. When Ms. Sommer forced NTEC to be selected in 2025 as part of the resource portfolio, the model selected NTEC, 300 MW of wind and 25 MW of solar in the 2025 to 2030 timeframe, but the present value societal cost of the plan increased from \$10.26 billion to \$10.41 billion.⁴⁹³

325. According to the CEOs, Ms. Sommer's modeling is not intended to substitute for the full analysis that should precede a size, type, and timing decision.

⁴⁸⁵ *Id.* Minnesota Power did not consider externalities in its base case and instead modeled their impact as sensitivities. *Id.* at 17.

⁴⁸⁶ *Id.* at 25.

⁴⁸⁷ *Id.*

⁴⁸⁸ See Ex. CEO-1 at 30-32 (Mellinger Direct).

⁴⁸⁹ Ex. CEO-16 at 26 (Sommer Direct).

⁴⁹⁰ *Id.* at 26-27.

⁴⁹¹ *Id.* at 27.

⁴⁹² *Id.* at 28, Table 3, Row 1.

⁴⁹³ *Id.*, Table 3, Row 2.

Instead, her runs “were merely intended to show that a reasonable set of alternatives can provide a very different picture than that painted by the Company.”⁴⁹⁴

326. The CEOs also maintained that Ms. Sommer’s modeling demonstrates when Strategist inputs are not biased towards selecting NTEC, the model results “show that NTEC is not the least-cost plan.”⁴⁹⁵ The CEOs emphasized that Ms. Sommer’s results align with the statutory preference for energy efficiency and renewable resources over non-renewable options.⁴⁹⁶

327. In response, the Company asserted that Ms. Sommer’s Strategist modeling contains a number of flaws that biased the results in favor of not selecting the 250 MW NTEC purchase.⁴⁹⁷ First, Minnesota Power’s witness Mr. Palmer noted that in four Strategist cases used by Ms. Sommer, the State externality values were applied to Minnesota Power generation and bilateral purchases, but not applied to market purchases.⁴⁹⁸ According to Mr. Palmer, when externality values are not applied equitably across all resources, the Strategist model will bias the results towards resources that do not have externality values assigned.⁴⁹⁹ When Minnesota Power models the State externality values, it typically does not include MISO market purchases “to ensure resource selection is not biased due to inequitable treatment of externality values.”⁵⁰⁰

328. In addition, Minnesota Power maintained that Ms. Sommer’s modeling was also biased against NTEC because NTEC was only modeled as not “superfluous.”⁵⁰¹ When Mr. Palmer changed the model to allow NTEC to be “superfluous” and turned off the energy market, the 250 MW capacity purchase (NTEC) was selected in all cases.⁵⁰²

329. The Company also maintained that Ms. Sommer’s alternatives analysis failed to analyze resource alternatives “under a range of assumptions about environmental values – including at least one scenario that excludes consideration of environmental externalities” as required by the Commission’s January 3, 2018 order updating the environmental cost values in Docket No. E-999/CI-14-643).⁵⁰³ The Company emphasized that the Strategist analysis performed by Ms. Sommer did not

⁴⁹⁴ Ex. CEO-18 at 26 (Sommer Surrebuttal).

⁴⁹⁵ CEO Initial Br. at 22.

⁴⁹⁶ *Id.* at 25 (citing Minn. Stat. §§ 216B.243, subd. 3a, 216B.2401).

⁴⁹⁷ Ex. MP-17 at 61-66 (Palmer Rebuttal).

⁴⁹⁸ *Id.* at 61.

⁴⁹⁹ *Id.* at 62.

⁵⁰⁰ *Id.* at 63.

⁵⁰¹ *Id.* at 63. When a unit is designated as not “superfluous” (e.g. “superfluous” set to “0”), then the unit cannot be picked for economic reasons. Rather, it can only be selected if minimum reserve and reliability criteria were not already met through other resources. Ex. CEO-18 at 19 (Sommer Surrebuttal). When a unit is designated as “superfluous,” it can be picked for economic reasons. *Id.*; see also Ex. DER-11 at 42 (Rakow Surrebuttal).

⁵⁰² Ex. MP-17 at 63-65.

⁵⁰³ *Id.* at 65.

include at least one scenario that excludes consideration of environmental externalities.⁵⁰⁴

330. The Company's witness Mr. Palmer also asserted that the CEOs Strategist analysis: used unreasonable energy efficiency assumptions; excluded the Commission-approved carbon regulation cost; included overly optimistic wind capacity values, demand response, and energy efficiency savings; and failed to consider how solar capacity values will vary in a multi-season resource adequacy construct.⁵⁰⁵

331. Further, the Company asserted that Ms. Sommer should have included some scenarios with market purchases turned off to understand the Company's capability to meet its own energy need "without over-reliance on the market."⁵⁰⁶

332. In response, the CEOs witness, Ms. Sommer asserted that the assumptions she used in her modeling are reasonable.⁵⁰⁷ She also provided additional support for the following assumptions used in her modeling: the demand response level, and wind costs and capacity credit.⁵⁰⁸

333. With regard to the applying externality values to MISO market purchases, Ms. Sommer agreed that it would be reasonable to include emissions rates when they become available, but asserted that turning off market purchases (as Minnesota Power did in its modeling) is not a "cure all" because turning off market purchases exaggerates the amount and cost of "emergency power" assumed in the non-NTEC portfolios.⁵⁰⁹

334. Ms. Sommer noted that she replicated Mr. Palmer's runs with all of his assumptions including with market purchases turned off and noticed that the plans without NTEC actually had the same cost as plans with NTEC on a present value basis when "end effects" were not included. In other words, according to Ms. Sommer, it was only with the addition of "end effects" (costs beyond the 15 year planning period) that NTEC is chosen as the least-cost resource even with the Company's assumptions.⁵¹⁰ Given that the "end effects" do not accrue until after 2031, Ms. Sommer asserted the use of end effects introduces "a level of uncertainty and unreliability about the benefits of adding NTEC over alternatives."⁵¹¹

335. Ms. Sommer also denied that she set up her Strategist modeling in a manner that prevented NTEC from being selected as alleged by Mr. Palmer.⁵¹² According to Ms. Sommer, in the Strategist databases and macros provided by Minnesota Power, the Company had designated NTEC as not "superfluous." According to Ms. Sommer, when she changed the designation for NTEC to "superfluous," the

⁵⁰⁴ *Id.*

⁵⁰⁵ *Id.* at 61-66.

⁵⁰⁶ *Id.* at 64.

⁵⁰⁷ Ex. CEO-18 (Sommer Surrebuttal).

⁵⁰⁸ *Id.* at 11-18.

⁵⁰⁹ *Id.* at 18, 20-23.

⁵¹⁰ *Id.* at 20-21.

⁵¹¹ *Id.* at 21.

⁵¹² *Id.* at 19-20.

program crashed.⁵¹³ As an alternative, Ms. Sommer conducted additional runs where NTEC was forced to be selected as part of the resource portfolio, which renders the Company's argument moot according to the CEOs.⁵¹⁴

336. In addition, in response to Mr. Palmer's rebuttal testimony, Ms. Sommer reran each of her runs without the addition of environmental externalities and allowed NTEC to be superfluous. She also allowed Strategist to purchase power on the market, but not sell power.⁵¹⁵ Ms. Sommer's results show that, even without externalities, NTEC is not the preferred plan over a plan without NTEC on a cost basis using the CEOs assumptions.⁵¹⁶

337. The results of CEOs' Strategist modeling demonstrate that the Strategist results depend heavily on the assumptions that are used.

338. For reasons discussed above, the Administrative Law Judge concludes that many of the assumptions used by the CEOs in its modeling (such as energy efficiency, demand response, removal of Blandin Paper Mill 5 load, solar capacity assumption, and others) are more reasonable than those used by the Company in its modeling.

339. While the CEOs' Strategist results showed that NTEC was not the most economic choice to meet the Company's potential needs in the late 2020s, these results are not necessarily sufficient by themselves for making a resource decision as they are based on a small number runs.⁵¹⁷ The CEO's modeling was not intended to substitute for the full analysis that should proceeding a size, type, and timing decision for a utility's resource selection but rather "were merely intended to show that a reasonable set of alternatives can provide a very different picture than that painted by the Company."⁵¹⁸

E. Conclusions Regarding the Strategist Results

340. For the reasons discussed above in paragraphs 204-339, the Company's Strategist analysis of NTEC and other resource options is insufficient to demonstrate that NTEC is needed and reasonable as compared to other alternatives to meet the future electric needs of Minnesota Power's customers.

341. The fact that Strategist chose NTEC as the least-cost resource in the vast majority of runs conducted by the Company is not persuasive because the Company

⁵¹³ Minnesota Power was surprised by Ms. Sommer's statement that Strategist crashed when she designated NTEC as "superfluous" because Minnesota Power did not get a similar result. Ex. MP-17 at 64. Minnesota Power was able to run the Strategist program with NTEC labeled as "superfluous." *Id.* at 64-65.

⁵¹⁴ Ex. CEO-18 at 19-20 (Sommer Surrebuttal); Ex. CEO-16 at 27-28 (Sommer Direct).

⁵¹⁵ Ex. CEO-18 at 23 (Sommer Surrebuttal).

⁵¹⁶ *Id.* at 24.

⁵¹⁷ *Id.* at 25.

⁵¹⁸ *Id.* at 26. Ms. Sommer also criticized the Company's Strategist modeling of scenarios and sensitivities as "incrementalism" and noted that the scenarios tested by the Company in Strategist failed to evaluate higher levels of energy efficiency combined with additional demand response. *Id.*

used a number of unreasonable assumptions in its modeling, failed to analyze a reasonable range of resources, and placed constraints on the model that resulted in its analysis being systematically biased in favor of NTEC and away from alternatives.

342. Similarly, the Department's Strategist results are not sufficiently robust or reliable for purposes of determining whether the 250 MW NTEC purchase is needed and reasonable because its analysis also used a number of unreasonable assumptions.⁵¹⁹

343. The CEO's Strategist modeling, which reached different results with more reasonable assumptions, confirms that a more robust alternatives analysis is necessary.

344. In summary, the Company's analysis of alternatives using Strategist fails to demonstrate that the 250 MW NTEC purchase is needed and reasonable as compared to alternative resource options "including but not limited to alternatives such as wind and solar resources (with updated costs), storage, demand response, and additional energy efficiency."⁵²⁰

F. Pace Global Report

345. In addition to analyzing alternatives using Strategist, the Company engaged Pace Global as a third-party evaluator to conduct an independent risk-based resource analysis of the *EnergyForward* resource package as a whole relative to other resource alternatives.⁵²¹

346. As discussed above, the *EnergyForward* resource package includes the proposed 250 MW NTEC purchase along with 250 MW of new wind resources and 10 MW of new solar resources.⁵²²

347. The Pace Global analysis considered four alternatives to the *EnergyForward* resource package: Portfolio 1 includes 75 percent wind; Portfolio 2 includes 50 percent wind; Portfolio 3 includes new wind as well as 210 MW of new battery resources; and Portfolio 4 includes 440 MW of new natural gas-fired peaking capacity.⁵²³

348. The Pace Global analysis also assumes that Minnesota Power will add at total of 22 MW of solar by 2034 to comply with the Minnesota Solar Energy Standard.

⁵¹⁹ See *supra* at 314-316.

⁵²⁰ Notice and Order for Hearing at 9.

⁵²¹ Ex. MP-2 at 3-59 to 3-60 (Petition); Ex. MP-13 at 36-38 (Pierce Direct); Ex. MP-7, App. N. (Pace Global 2017 Independent Resource Analysis dated July 25, 2017).

⁵²² See Notice and Order for Hearing at 2.

⁵²³ Ex. MP-7, App. N at N-6, N-7, N-18. Like the *EnergyForward* package, each of these portfolios also assume that Minnesota Power will add 10 MW of solar by 2024 and an additional 12 MW of solar by 2034 to meet its solar energy standard (SES), and include the 250 MW of wind contracted for by Minnesota Power pursuant to the 2016 IRP Order along with the 250 MW Manitoba Hydro contracted capacity. *Id.*, App. N. at N-18.

The Pace Global analysis did not consider any additional levels of solar or include an alternative with large amounts of solar.⁵²⁴

349. The Pace Global analysis also did not include demand response or additional energy efficiency as alternatives.⁵²⁵

350. Based on a comparison of the *EnergyForward* portfolio to the other four portfolios listed above, Pace Global concluded that the *EnergyForward* resource package is the preferred resource portfolio for Minnesota Power and its customers. Pace Global's conclusion was based on 200 simulations, which identified the *EnergyForward* resource package as the lowest cost portfolio under both expected market conditions and worst-case market conditions.⁵²⁶

351. The Pace Global analysis, completed on July 25, 2017, was included with the initial *EnergyForward* resource package petition filed by Minnesota Power on July 28, 2018.⁵²⁷

352. The July 25, 2017 Pace Global analysis relies on load forecast information provided by Minnesota Power.⁵²⁸ The Pace Global report does not discuss in any detail the load forecast information that was provided by the Company and used in the analysis.⁵²⁹ Thus, it is unclear exactly what forecast information was used by Pace Global.

353. The Pace Global report also does not expressly quantify the amount of energy efficiency savings or demand response that was assumed in the load forecast.⁵³⁰

354. In its Notice and Order for Hearing dated September 17, 2017, the Commission directed the Company to refile its petition, with a revised forecast and updated alternatives.⁵³¹

355. The Company did not submit an updated version of the Pace Global analysis with its updated Petition filed on October 24, 2017.⁵³² Instead, it refiled the same analysis with its updated Petition.⁵³³

⁵²⁴ *Id.*, App. N at N-6, N-7, N-18.

⁵²⁵ *Id.*

⁵²⁶ Ex. MP-2 at 3-59 to 3-60 (Petition); Ex. MP-13 at 36-38 (Pierce Direct); Ex. MP-7, App. N.

⁵²⁷ Initial Filing, App. N (Pace Global 2017 Independent Resource Analysis dated July 25, 2017) (eDocket No. 20177-134360-5).

⁵²⁸ Ex. MP-7, App. N at N-30.

⁵²⁹ *Id.*

⁵³⁰ *Id.*

⁵³¹ Notice and Order for Hearing at 8.

⁵³² *Compare* Ex. MP-7, App. N (Pace Global 2017 Independent Resource Analysis dated July 25, 2017) (eDocket No. 201710-136800-07) with Initial Filing, App. N (Pace Global 2017 Independent Resource Analysis dated July 25, 2017) (eDocket No. 20177-134360-5).

⁵³³ *Id.*

356. Because the Pace Global report has not been updated to reflect the Company's updated forecast, it is unclear whether the results of the Pace Global analysis would change with the updated customer demand information.

357. In addition, the report is not particularly useful as an alternatives analysis because it does not consider additional energy efficiency, additional demand response, or additional solar beyond the SES requirement as alternatives in any of the portfolios examined. Furthermore, the assumptions about energy efficiency and demand response used in the analysis are unclear.

358. The Pace Global report also does not include consideration of the most recent environmental externality values established by the Commission in Docket 14-643.⁵³⁴

359. For these reasons, the Administrative Law Judge concludes that the Pace Global analysis fails to demonstrate that the 250 MW NTEC purchase is the best resource option for Minnesota Power and its customers as claimed by Minnesota Power.⁵³⁵

G. Overall Conclusion Regarding the Company's Alternative Analyses

360. In summary, the Company has failed to demonstrate that the proposed 250 MW NTEC purchase is the best and least-cost resource alternative to meet its customers' capacity and energy needs as claimed by the Company.

361. Neither the Company's Strategist analysis nor the Pace Global analysis of alternatives is sufficiently robust to meet the Company's burden to demonstrate that the proposed 250 MW NTEC purchase is needed and reasonable in comparison to alternative resource options.

X. The Company's Claimed Need for 250 MW of Dispatchable Resources

362. In addition to relying on the alternatives analyses discussed above, the Company presented other evidence to support its claimed need for 250 MW of new generation in the 2025 timeframe.

363. Because it will have approximately 850 MW of wind generation on its system by the mid-2020s, the Company maintained it has a need for "dispatchable capacity and flexible energy to mitigate and balance exposure to energy markets."⁵³⁶ The Company claimed that currently missing from Minnesota Power's portfolio is dispatchable capability that can be readily ramped up or down to follow demand and

⁵³⁴ See Notice and Order for Hearing at 9; Ex. MP-7, App. N.

⁵³⁵ Due to time constraints, the Administrative Law Judge is not making any additional findings or reaching any other conclusions with regard to the other assumptions used in the Pace Global report and the overall analysis conducted by Pace Global.

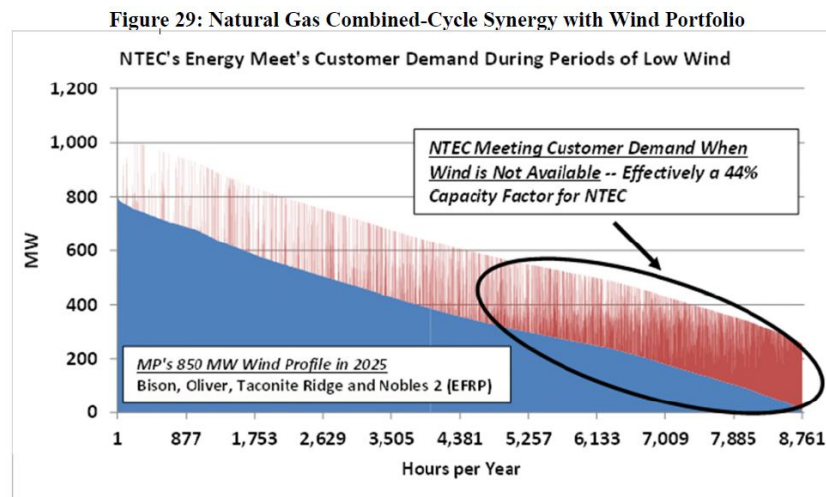
⁵³⁶ Ex. MP-13 at 58 (Pierce direct).

variable wind generation throughout the day.⁵³⁷ The Company asserted that the 250 MW purchase of dispatchable capacity from the proposed NTEC combined cycle gas plant is needed and reasonable for this purpose.⁵³⁸

364. In support of its position, the Company presented information on its need for ramping capability.⁵³⁹ The Company also presented an analysis of the costs and benefits of adding NTEC compared to wind generation for dispatch and balancing purposes.⁵⁴⁰ In addition, the Department presented its own analysis of the Company's need for dispatchable resources.⁵⁴¹ Each of these items is discussed below.

A. The Company's Ramping Capability Analysis

365. In its Petition, the Company estimated the extent to which NTEC would be dispatched to meet customer demand during periods of low wind generation if NTEC is added to the Company's system.⁵⁴² The Company's projection is based on an hourly dispatch model.⁵⁴³ Figure 29 from the Petition, set forth below illustrates that projection.⁵⁴⁴



366. After filing its Petition, the Company performed an additional analysis which compared the absolute rate of change on a five-minute basis of Minnesota power's load and wind generation to the maximum "ramp" capability of Minnesota Power's dispatchable generation that is expected to be in-service and online for the majority of the year in 2025.⁵⁴⁵ Actual Minnesota Power load and wind generation data from calendar years 2016 and 2017 were used by Minnesota Power as the basis for this

⁵³⁷ Ex MP-2 at 4-6 (Petition).

⁵³⁸ *Id.* at 4-4 to 4-12.

⁵³⁹ Ex. MP-17 at 67-71 (Palmer Rebuttal); Ex. MP-2 at 4-7 (Petition)

⁵⁴⁰ Ex. MP-19 at 13-15 (Brick Direct).

⁵⁴¹ Ex. DER8, SRR-4 (Review of Minnesota Power's Dispatchable Capacity Need).

⁵⁴² Ex. MP-17 at 67-68 (Palmer Rebuttal); Ex. MP-2 at 4-7 (Petition).

⁵⁴³ Ex. MP-2 at 4-6 to 4-7 (Petition).

⁵⁴⁴ Ex. MP-2 at 4-7 (Petition); Ex. MP-17 at 68 (Palmer Rebuttal)

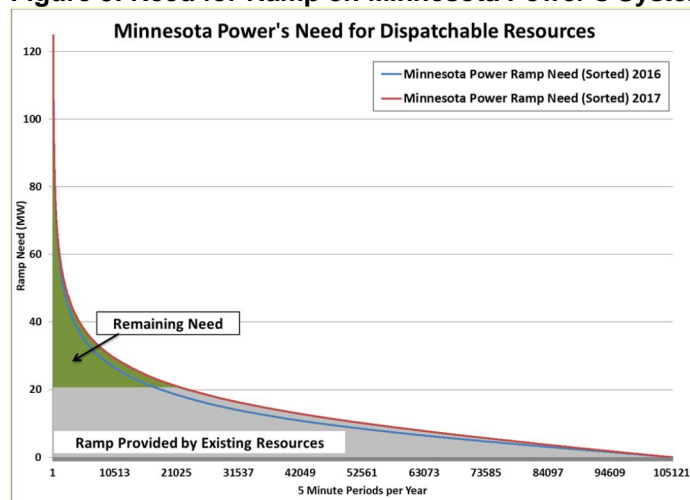
⁵⁴⁵ Ex. MP-17 at 69 (Palmer Rebuttal).

analysis.⁵⁴⁶ In addition, Minnesota Power included the projected generation on a five-minute basis of the Nobles 2 wind farm proposed in southwestern Minnesota as part of its *EnergyForward* package.⁵⁴⁷

367. Minnesota Power estimated that its existing resources can only provide about 20 MW of “ramp.”⁵⁴⁸ As used by Minnesota Power, “ramp” means the amount of generation that can be increased or decreased in a five-minute period.⁵⁴⁹

368. Based on its analysis of this information, Minnesota Power estimated that its dispatchable resources, which are expected to be in operation in 2025, fall short of the ramp need in approximately 18.5 percent of five-minute periods. Figure 5 from Mr. Palmer’s Rebuttal Testimony, set forth below, provides Minnesota Power’s estimate of the need for ramp on Minnesota Power’s system.⁵⁵⁰

Figure 5: Need for Ramp on Minnesota Power’s System



369. Mr. Palmer’s modeling also showed that the Company would be able to meet the ramp needs of its own load in over 99 percent of five-minute periods with the proposed 250 MW NTEC purchase.⁵⁵¹ He noted that Minnesota Power’s share of the NTEC facility has the capability to ramp over 110 MW in a five-minute period.⁵⁵²

370. Mr. Palmer emphasized that Minnesota Power has an obligation to plan for its system needs and develop a diverse power supply to meet its need for flexible generation.⁵⁵³

⁵⁴⁶ *Id.* at 68.

⁵⁴⁷ *Id.*

⁵⁴⁸ *Id.*

⁵⁴⁹ *Id.*

⁵⁵⁰ *Id.* at 69.

⁵⁵¹ *Id.* at 71.

⁵⁵² *Id.*

⁵⁵³ *Id.* at 70-71.

371. Mr. Palmer also noted that the ramp needs of the MISO system and the Minnesota Power system are similar.⁵⁵⁴ He maintained that if Minnesota Power and other utilities relied exclusively on MISO to meet their individual system needs, the broader MISO system would no longer be able to function reliably.⁵⁵⁵

372. The CEOs disputed the meaningfulness of the modeling done by Mr. Palmer. First, the CEOs questioned Mr. Palmer's claim that the Company's existing resources can only provide about 20 MW of "ramp." They noted that Mr. Palmer failed to specify in his testimony what resources were included in his "ramp" estimate.⁵⁵⁶ Based on an Information Request response, the CEOs determined that Mr. Palmer's "ramp" capability calculation did not include Minnesota Power's Laskin Energy Center, which is a natural gas facility with a nameplate capacity of 110MW, or its Hibbard Renewable Energy Center, which has 54.2 MW of nameplate capacity in the summer and 47.2 MW of nameplate capacity in the winter.⁵⁵⁷ In addition, the CEOs asserted that Minnesota Power "omitt[ed] or severely discount[ed] the capabilities of the demand response, 86 MW of hydro, and any of the wind and solar generation currently in Minnesota Power's portfolio."⁵⁵⁸ The CEOs also noted that Minnesota Power's analysis also excludes any potential new resource options that are available to add flexibility other than the proposed NTEC purchase.⁵⁵⁹

373. According to the CEOs, the exclusion of existing resources on the Company's system undermines Minnesota Power's assertion that it requires additional ramping resources. Similarly, the exclusion of any potential new resource options other than NTEC undermines the Company's assertion that NTEC is the preferred solution.⁵⁶⁰ As a result, the CEOs maintained that Minnesota Power's modeling of its "ramp" needs is biased in favor of NTEC.⁵⁶¹

374. In addition, the CEOs witness Mr. Jacobs asserted that Minnesota Power has overstated its obligation to balance its load and generation in real time.⁵⁶² Mr. Jacobs noted that Minnesota Power's generation resources (and the generation of other utilities in the region) are dispatched and ramped by MISO.⁵⁶³ As a result, "[v]ery seldom, if ever with a modern independent system operator such as MISO, is the variability of both supply and demand met exclusively with resources specific to the load-serving entity responsible for meeting the demand in question."⁵⁶⁴ "In short, MISO does not look to meet the 5-minute variability, or the hourly and daily changes in demand [on Minnesota Power's system], with only Minnesota power-owned

⁵⁵⁴ *Id.* at 70.

⁵⁵⁵ *Id.*

⁵⁵⁶ Ex. CEO-9 at 4-5 (Jacobs Surrebuttal); Ex. 17 at 69 (Palmer Surrebuttal).

⁵⁵⁷ Ex. CEO-9 at 7, Schedule 1 (Jacobs Surrebuttal); Ex. 2 at 2-10, n. 35, App. K at K-1 (Petition) (listing the nameplate capacity of existing Minnesota Power resources).

⁵⁵⁸ Ex. CEO-9 at 5 (Jacobs Surrebuttal).

⁵⁵⁹ *Id.*

⁵⁶⁰ *Id.*

⁵⁶¹ *Id.*

⁵⁶² *Id.* at 5-6

⁵⁶³ *Id.* at 6.

⁵⁶⁴ *Id.*

resources.”⁵⁶⁵ According to Mr. Jacobs, MISO has the benefit of “diverse loads, uncorrelated changes in supply and demand and numerous resources,” that improve the reliability, efficiency, and cost-effectiveness of the system.⁵⁶⁶ Thus, the CEOs asserted that Minnesota Power has overstated its need to plan for and add dispatchable ramping resources for managing the Company’s individual short-term variations in supply and demand.⁵⁶⁷

375. The Administrative Law Judge concludes that Minnesota Power has overstated its ramp need in 2025. As the CEOs noted, Minnesota Power failed to include two existing dispatchable generation facilities, Laskin Energy Center and Hibbard Renewable Center, in its calculation of its existing “ramp” capability.⁵⁶⁸ Together these facilities have a total name plate capacity of at least 157 MW, and may be able to meet any remaining ramp needs.⁵⁶⁹

376. Minnesota Power has not provided a reasonable basis for excluding these resources from its “ramp” calculation. Minnesota Power claimed it did not include these resources because they are rarely dispatched by MISO.⁵⁷⁰ Rare dispatch by MISO only means that the MISO system as a whole has more cost-effective resources that are being dispatched to balance the system before these units, not that these dispatchable units are not physically able to provide ramping resources for Minnesota Power’s customers.⁵⁷¹ There is no reasonable basis for excluding these dispatchable resources, particularly if Minnesota Power is actually analyzing whether its own resources can cover its own ramping needs.

377. In addition, while the Administrative Law Judge recognizes the Company has an obligation to plan to meet its customers’ needs and provide reliable service, the CEOs properly pointed out that the Company considered NTEC as the only new resource option to meet its “ramp” needs.⁵⁷² Minnesota Power has not provided a reasonable explanation for not considering other resource options. Nor has Minnesota Power properly taken into account the extent to which its participation in MISO helps to address this need in a more efficient manner than if Minnesota Power were operating its system in isolation.⁵⁷³

378. For these reasons, the Administrative Law Judge concludes that the Company has failed to demonstrate that its ramping needs cannot be addressed through its existing facilities or that NTEC is the best resource for addressing any ramping needs it may have.

⁵⁶⁵ *Id.*

⁵⁶⁶ *Id.*

⁵⁶⁷ *Id.* at 7-9.

⁵⁶⁸ *Id.* at 9 (quoting from Minnesota Power’s Response to CEOs’ Information Request (IR) No. 118).

⁵⁶⁹ See Ex. 2 at 2-10, n. 35, App. K at K-1 (listing the nameplate capacity of existing Minnesota Power resources).

⁵⁷⁰ Ex. CEO-9 at 7 (Jacobs Surrebuttal) (quoting from Minnesota Power’s Response to CEOs IR No. 118).

⁵⁷¹ *Id.* at 8.

⁵⁷² Ex. MP017 at 69-71 (Palmer Rebuttal).

⁵⁷³ Ex. CEO-9 (Jacobs Surrebuttal) at 6-8.

B. Minnesota Power's Analysis of the Costs and Benefits of Adding NTEC Compared to Wind for Dispatchability and Flexibility Purposes

379. In addition to its ramping analysis, the Company presented the testimony of Stephen Brick, an outside consultant, who has expertise in electricity system planning and economics, to support its claim that the 250 MW NTEC purchase is needed for flexibility and to mitigate exposure to energy markets.⁵⁷⁴

380. According to the Company, Mr. Brick's analysis "is an economic analysis that balances the costs and benefits of integrating high volumes of wind energy into the system with the costs and benefits of adding natural gas capacity and energy to balance the system and ensure that the renewable generation is being efficiently deployed."⁵⁷⁵

381. Mr. Brick used a diagnostic model, which he created, to analyze the potential economic effects of replacing the proposed 250 MW NTEC purchase with wind and solar generation.⁵⁷⁶

382. Mr. Brick created his base case of Minnesota Power's existing system based on the Company's Strategist inputs.⁵⁷⁷ His analysis then added various resources including the 250 MW NTEC purchase and varying amounts of wind generation.⁵⁷⁸ He examined replacing the NTEC purchase with three additional wind scenarios: 1.50, 1.75, and 2.0 times Minnesota Power's forecasted 2025 wind generation.⁵⁷⁹

383. Mr. Brick's analysis showed that "as wind penetration increases, surplus generation increases much faster than" demand on Minnesota Power's system.⁵⁸⁰ Mr. Brick asserted that "Minnesota Power's market exposure grows when NTEC is dropped and wind increases."⁵⁸¹ Mr. Brick claimed that adding more wind on Minnesota Power's system in place of the NTEC purchase "would expose Minnesota Power's ratepayers to additional market risk: the sales risk of marketing the surplus electricity and the purchase risk of filling a larger open position from the wholesale market."⁵⁸² On this basis, he concluded that "adding more wind is not a reasonable replacement for the NTEC 250 MW Purchase."⁵⁸³

384. According to Mr. Brick, the addition of battery storage does not change this equation because the battery cost is an additional cost of producing the electricity, beyond the cost of the wind resource.⁵⁸⁴ In addition, he maintained that battery storage

⁵⁷⁴ Ex. MP-19 at 3-4 (Brick Direct).

⁵⁷⁵ Minnesota Power's Initial Br. at 41.

⁵⁷⁶ Ex. MP-19 at 13 (Brick Direct).

⁵⁷⁷ *Id.*

⁵⁷⁸ *Id.* at 13, Table 1.

⁵⁷⁹ *Id.* at 13.

⁵⁸⁰ *Id.* at 14.

⁵⁸¹ *Id.*

⁵⁸² *Id.* at 13-14, 21.

⁵⁸³ *Id.* at 21.

⁵⁸⁴ *Id.* at 15-16.

“is designed to address short-term swings in production ... [and it] would be highly unusual for battery storage to be utilized for energy stored for weeks or months.” He asserted that it “is not technically feasible for battery storage to operate over such long periods of time.”⁵⁸⁵

385. He also concluded that solar generation plus battery storage is not cost effective for similar reasons.⁵⁸⁶

386. With regard to demand response, Mr. Brick maintained that demand response is usually used as emergency capacity and would not be an adequate substitute for the NTEC project, which is designed to provide capacity, energy, and ancillary services.⁵⁸⁷ In addition, he noted that Minnesota Power already has “significant demand response in place.”⁵⁸⁸

387. Further, Mr. Brick contended that the 250 MW NTEC purchase provides “system flexibility,” “maximizes the use of already significant amounts of variable renewable generation, and avoids over-reliance on remote generation or transmission to serve its customers.”⁵⁸⁹

i. The CEOs’ Review of Mr. Brick’s Analysis

388. The CEOs maintained that the analysis provided by Minnesota Power’s witness Stephen Brick is flawed and cannot be relied upon to demonstrate that NTEC is needed to balance Minnesota Power’s system.⁵⁹⁰ The CEOs raised several concerns with Mr. Brick’s diagnostic model and his analysis.⁵⁹¹

389. The CEOs emphasized that Mr. Brick’s methodology has never been used in any other public utility docket, either in Minnesota or anywhere else in the United States.⁵⁹²

390. The CEO’s witness Michael Jacobs also pointed out that there have been three studies in Minnesota to quantify the operating impacts of renewable energy production variability, including: the 2004 Xcel Energy and Minnesota Department of Commerce Wind Integration Study; the 2006 Minnesota Wind Integration Study; and the 2014 Minnesota Renewable Energy Integration and Transmission Study (MRITS Report).⁵⁹³

⁵⁸⁵ *Id.* at 19-20. Mr. Brick does not cite any studies to support these assertions regarding the limitations of battery storage capability. *Id.*

⁵⁸⁶ *Id.* at 21.

⁵⁸⁷ *Id.*

⁵⁸⁸ *Id.*

⁵⁸⁹ Ex. MP-20 at 4 (Brick Rebuttal).

⁵⁹⁰ *Id.* at 31.

⁵⁹¹ CEO Initial Br. at 31-37.

⁵⁹² *Id.* at 32 (citing Tr. at 156) (Brick).

⁵⁹³ Ex. CEO-2 at 5 (Jacobs Direct); see *also* Tr. at 154 (Brick).

391. Mr. Jacobs asserted that “Minnesota’s wind integration studies show that geographically dispersed renewable energy resources can reduce the variability of energy supplied from these resources.”⁵⁹⁴

392. The CEOs criticized Mr. Brick’s modeling because it does not take into account the effects of geographic diversity.⁵⁹⁵ The CEOs noted that Mr. Brick’s model assumes that additional wind will have the same hour-by-hour generation profile as Minnesota Power’s existing wind resources.⁵⁹⁶

393. In addition, the CEOs claimed that Mr. Brick’s model is flawed because it is “restricted to the Minnesota Power footprint,” and does not consider whether other resources in MISO might serve to balance renewable energy in Minnesota Power’s system.⁵⁹⁷

394. The CEOs emphasized that the Company itself recognized the importance of considering the regional market in its Petition:

[T]he presence of an energy market in resource planning allows for the optimization of power supply needs on a more granular level. . . . When considering the integration of intermittent generation into the supply portfolio . . . it is appropriate to have a wholesale market available. . . . Not having the regional market available during long-term expansion planning to help with the intermittency of renewable generation would promote overbuilding of a single utility’s system and not account for existing regional support.⁵⁹⁸

395. The CEOs also maintained that Mr. Brick’s analysis is incomplete because he does not consider whether a portfolio of resource alternatives—including wind, solar, hydro, demand response, energy storage, MISO sales, transmission and curtailment—could work together to provide any of the identified flexibility needs.⁵⁹⁹ Instead, Mr. Brick only looked at each resource alternative in isolation, and analyzed whether that alternative could independently replace the entire proposed NTEC purchase.⁶⁰⁰

396. The CEOs maintained that even if Minnesota Power needs a new resource or resources to balance renewables on to its system, Mr. Brick’s analysis has failed to show that NTEC is a reasonable option for that purpose.⁶⁰¹

ii. Minnesota Power’s Response to the CEOs’ Critique

397. Minnesota Power disagreed with the CEOs critique. First, Minnesota Power asserted that the CEOs are drawing conclusions from the MRITS Study that are

⁵⁹⁴ Ex. CEO-6 at 12 (Jacobs Rebuttal).

⁵⁹⁵ CEO Initial Br. at 33.

⁵⁹⁶ *Id.* at 33 (citing Tr. at 158-59) (Brick).

⁵⁹⁷ CEO Initial Br. at 34 (citing Tr. at 157, 164) (Brick).

⁵⁹⁸ *Id.* at 34-35 (citing MP-5, App. I. at I-13).

⁵⁹⁹ *Id.* at 35.

⁶⁰⁰ *Id.* at 35-36.

⁶⁰¹ *Id.* at 28.

not warranted in this context. According to Minnesota Power, the MRITS Study focused on what is theoretically possible to achieve from an engineering perspective, while Mr. Brick's work focused on the economic consequences of resource choices.⁶⁰²

398. Next, in response to the CEOs' concern that Mr. Brick's analysis failed to include wind generation from geographically diverse sources, the Company noted that Mr. Brick included all of Minnesota Power's wind in his analysis, including generation located on the Iron Range, North Dakota, and extreme southwestern Minnesota.⁶⁰³

399. The Company noted that these wind generation resources sit in an area with a radius of over 2,000 miles and represent generation across the MISO Zone 1 footprint.⁶⁰⁴

400. Finally, Minnesota Power argued that Mr. Brick addressed the availability of the regional market and assumed the ability for the regional transmission system to absorb renewable generation from diverse locations. Mr. Brick noted that the ability to sell surplus wind in the region (especially given the broad coincidence of peak wind production) is in no way guaranteed, and that Minnesota Power's customers would bear the financial risk of that excess.⁶⁰⁵

iii. Conclusions Regarding Mr. Brick's Analysis

401. The Administrative Law Judge concludes that Mr. Brick's analysis is not particularly helpful in terms of analyzing whether NTEC is needed and reasonable for dispatchability purposes because his model results are very general in nature.⁶⁰⁶ Mr. Brick does not include a meaningful quantification of the "market risk" that he claims will result from replacing the NTEC purchase with additional wind generation resources.⁶⁰⁷ For example, Mr. Brick only presents the estimated "open position" under each scenario but does not include any analysis of when the resulting "open position" hours are likely to occur.⁶⁰⁸ As shown by the Department's analysis, which is discussed below, price spikes are much more likely during on-peak hours than off-peak hours.⁶⁰⁹ Thus, in terms of market risk, the potential timing of the open position is important to consider. As a result, Mr. Brick's modeling and analysis are of minimal use in comparing the costs and benefits of adding NTEC rather than wind generation or other resources (or a combination thereof). Given the preference for renewable generation resources in state law, a more meaningful quantification of the risk is important.⁶¹⁰

⁶⁰² Tr. at 165-66 (Brick).

⁶⁰³ Minnesota Power's Reply Br. at 41-42.

⁶⁰⁴ *Id.* at 42.

⁶⁰⁵ *Id.* at 44.

⁶⁰⁶ See Ex. 19 at 13-14 (Brick Direct).

⁶⁰⁷ *Id.* at 13-15.

⁶⁰⁸ Compare Ex. 19 at 13-15 (Brick Direct) with Ex. DER-8, SRR-4 at 10-20 (Rakow Direct, Review of Minnesota Power's Dispatchable Capacity Needs).

⁶⁰⁹ Ex. DER-8, SRR-4 at 11 (Rakow Direct, Review of Minnesota Power's Dispatchable Capacity Needs).

⁶¹⁰ See Minn. Stat. §§ 216B.2422, 216B.243, subd. 3a.

402. In addition, Mr. Brick's model uses the Company's base case from its Strategist modeling as his starting point.⁶¹¹ As discussed above, the Company's base case is not reasonable because its estimate of energy efficiency is unreasonably low and the amount of demand response included in the Base Case is unreasonably low as well. Thus, Mr. Brick's analysis is of limited value because it starts with unreasonable assumptions.

403. Third, the CEOs have raised a number of other concerns regarding Mr. Brick's model that further call into question the usefulness of the model for analyzing whether NTEC is necessary for dispatch purposes to balance the system and limit market exposure as claimed by the Company.⁶¹²

C. The Department's Analysis of the Company's Need for Dispatchable Resources

404. The Department conducted its own review of Minnesota Power's dispatchable capacity needs to address variability in wind generation.⁶¹³ In its review, the Department analyzed the extent to which the 250 MW NTEC purchase is needed to mitigate the risks posed by large quantities of wind generation resources on Minnesota Power's system.⁶¹⁴

405. The Department stated that, "[i]n essence, [Minnesota Power] claims that the [NTEC] combined cycle unit is needed to provide a cap on [Minnesota Power's] exposure to spot market prices in a manner that cannot be provided by intermittent resources such as wind and solar."⁶¹⁵

406. The Department's analysis focused on 2025 because 2025 is expected to be the first full year for operation of the proposed NTEC plant.⁶¹⁶

407. The first step in the Department's analysis was to determine an hourly load shape for 2025.⁶¹⁷ The Department estimated the Company's hourly load shape in 2025 by increasing the Company's 2011 load curve (a typical year) by five percent to approximate the peak demand and energy in 2025 as forecasted by the 2017 AFR.⁶¹⁸

408. The second step was to determine the firm resources available to meet the demand on an hourly basis in 2025. Using information provided by the Company, the Department identified resources that were dispatchable, would not be retired in 2025, and that had firm fuel supply. The Department also considered the Company's power purchase agreement with Manitoba Hydro. "The result of the analysis was that 1,097.9 MW of dispatchable resources with firm fuel arrangement could be assumed to

⁶¹¹ Ex. MP-19 at 13 (Brick Direct).

⁶¹² See Ex. CEO-6 at 13 (Jacobs Rebuttal); CEO Initial Br. at 31-37.

⁶¹³ Ex. DER-8, SRR-4 (Rakow Direct, Review of Minnesota Power's Dispatchable Capacity Need).

⁶¹⁴ *Id.*

⁶¹⁵ *Id.* SRR-4 at 2.

⁶¹⁶ *Id.*, SRR-4 at 5.

⁶¹⁷ *Id.*

⁶¹⁸ *Id.*

be available year round.”⁶¹⁹ The Department did not consider any intermittent resources such as wind or solar generation.⁶²⁰

409. The third step subtracted hourly demand, calculated in step one, from the hourly supply, calculated in step two, to arrive at an initial estimate of the size (MW) and timing (hour of the year) of MP’s exposure to spot market prices, prior to any potential mitigation measures.⁶²¹

410. The Department then analyzed the Company’s projected hourly capacity surpluses and deficits, and determined that the largest deficits are concentrated in off-peak hours. The Department also found that “[g]enerally speaking, as the size of the deficit goes down the percentage of observations in the on-peak hours increases. Thus, overall [Minnesota Power] is much more exposed to price spikes during off-peak hours than on-peak hours.”⁶²²

411. In addition, the Department analyzed pricing data for the “Minnesota Hub” of the MISO spot market for energy from 2012 to 2017.⁶²³ The Department found on-peak hours were significantly more likely to exhibit price spikes than off-peak hours in Minnesota.⁶²⁴ Thus, on-peak hours are a greater concern than off-peak hours.⁶²⁵ With regard to season, the Department found the data showed less clarity, but summer and winter had a greater share of price spikes than spring or fall.⁶²⁶

412. The Department concluded that “the data demonstrates that [Minnesota Power’s] actions so far have substantially mitigated the size and quantity of the on-peak deficits relative to the off-peak deficits.”⁶²⁷ In addition, the Department concluded that to date Minnesota Power “has managed its exposure to market price spikes during on-peak hours so that it occurs during the seasons that are perceived to be less risky.”⁶²⁸

413. Based on the 2017 AFR and the resources that the Department considered, the Department summarized the Company’s exposure to prices spikes from MISO market purchases as forth in Table 5 of its report, set forth below:⁶²⁹

⁶¹⁹ *Id.* SRR-4 at 6.

⁶²⁰ *Id.*

⁶²¹ *Id.*, SRR-4 at 7.

⁶²² *Id.*, SRR-4 at 14.

⁶²³ *Id.*, SRR-4 at 9.

⁶²⁴ *Id.*, SRR-4 at 11.

⁶²⁵ *Id.*, SRR-4 at 13.

⁶²⁶ *Id.*, SRR-4 at 12-13.

⁶²⁷ *Id.*, SRR-4 at 14.

⁶²⁸ *Id.*, SRR-4 at 16.

⁶²⁹ *Id.*

**Table 5: MP's On-peak, Hourly Capacity Surplus / (Deficit) by Season
(Number of Observations)**

| Hourly Surplus / (Deficit) | Winter, On-peak | Spring, On-peak | Summer, On-peak | Fall, On-peak |
|-------------------------------|--------------------|--------------------|--------------------|------------------|
| (801 MW) or more | - | - | - | 1 |
| (601 MW) to (800 MW) | - | 8 | - | 44 |
| (401 MW) to (600 MW) | 2 | 281 | - | 64 |
| (201 MW) to (400 MW) | 297 | 53 | 102 | 55 |
| (1 MW) to (200 MW) | 720 | 425 | 720 | 761 |
| Surplus—all sizes | 5 | 257 | 202 | 83 |
| Total | 1,024 | 1,024 | 1,024 | 1,008 |

414. Because the Department's analysis showed that the Company has a projected capacity deficit of at least 401 MW during approximately 400 hours in 2025, the Department considered measures available to the Company to mitigate exposure to price spikes.⁶³⁰ The Department identified intermittent generation facilities (solar and wind), non-dispatchable hydro generation facilities, load management resources, and the Company's energy exchange agreement (EEA) with Manitoba Hydro as potential mitigation measures.⁶³¹

415. In its review, the Department did not consider solar resources to be a significant mitigation measure for spot market prices. The Department noted that the Company is planning to add only about 33 MW of solar by 2025, and "solar generation is greater than 20 percent of installed capacity in only 178 of the 400 hours."⁶³² In other words, Minnesota Power would have only about 7 MW of solar resources "actually producing energy during more than half of the on-peak hours with a capacity deficit of at least 401 MW."⁶³³

416. The Department estimated the Company would have about 875 MW of wind capacity but indicated that "wind production can vary in an unpredictable manner."⁶³⁴ "Therefore, the Department did not compare wind production patterns to MP's capacity deficits."⁶³⁵ While the Department did not consider wind generation to be a viable mitigation measure, the Department did recognize that the Company's wind resources "potentially offer a price spike mitigation measure if the wind is blowing."⁶³⁶

417. The Department also did not consider non-dispatchable hydro power because of its limited size on the Company's system.⁶³⁷ The Department noted that

⁶³⁰ *Id.*, SRR-4 at 16-18

⁶³¹ *Id.*, SRR-4 at 18.

⁶³² *Id.*

⁶³³ Ex. DER-11 at 52 (Rakow Surrebuttal).

⁶³⁴ *Id.* The Department does not cite any studies to support its assertion that "wind production can vary in an unpredictable manner." *Id.* While this proposition seems logical, the record would be improved with a citation to a study for support.

⁶³⁵ Ex. DER-8, SRR-4 at 18.

⁶³⁶ *Id.*

⁶³⁷ *Id.*

Minnesota Power has about 35 MW of non-dispatchable hydro power generation on its system currently and further additions are unlikely.⁶³⁸

418. The Department also considered the Company's two EEAs with Manitoba Hydro. Because of the nature of the agreements, power from Manitoba Hydro may not be available when needed.⁶³⁹ Thus, the Department concluded that the EEAs had very limited mitigation value for spot market price spikes.⁶⁴⁰

419. Finally, the Department considered interruptible demand response resources available on the Company's system. The Department concluded that the Rider for Large Power Incremental Production Service (10 to 15 MW) and Replacement Interruptible Service (100 to 260 MW) could provide mitigation potential during the hours of Minnesota Power's greatest exposure to price spikes.⁶⁴¹

420. The Department considered these two demand response measures as the only viable mitigation measures during the times when the Company has the greatest exposure to price spikes.⁶⁴²

421. To provide a gauge of the mitigation that could be provided by these two demand response measures, the Department re-calculated its Table 5, set forth above, but assuming the midpoint (192.5 MW) of demand response was available when needed.⁶⁴³ The results are included in Table 6 on page 20 of the Department's report, which is set forth below:⁶⁴⁴

**Table 6: MP's On-peak, Hourly Capacity Surplus / (Deficit) by Season After Mitigation
(Number of Observations)**

| Hourly Surplus / (Deficit) | Winter, On-peak | Spring, On-peak | Summer, On-peak | Fall, On-peak |
|-------------------------------|--------------------|--------------------|--------------------|------------------|
| (801 MW) or more | - | - | - | - |
| (601 MW) to (800 MW) | - | - | - | 1 |
| (401 MW) to (600 MW) | - | 10 | - | 48 |
| (201 MW) to (400 MW) | 4 | 285 | - | 62 |
| (1 MW) to (200 MW) | 345 | 48 | 121 | 61 |
| Surplus—all sizes | 675 | 681 | 903 | 836 |
| Total | 1,024 | 1,024 | 1,024 | 1,008 |

⁶³⁸ *Id.*

⁶³⁹ *Id.*

⁶⁴⁰ *Id.*, SRR-4 at 18-19.

⁶⁴¹ *Id.*, SRR-4 at 19.

⁶⁴² *Id.*

⁶⁴³ *Id.*

⁶⁴⁴ *Id.*, SRR-4 at 20.

422. This table shows that when 192.5 MW of demand response is included as a mitigation measure, the Company is “estimated to have a capacity deficit exceeding 401 MW in 59 hours or about 1.5 percent of the on-peak hours during 2025.” Further, the Company is “estimated to have a deficit exceeding 200 MW in 410 hours or about 10 percent of the on-peak hours during 2025.”

423. Based on these quantitative results, the Department concluded that the Company’s proposed 250 MW NTEC purchase “will have some value in mitigating exposure to price spikes.”⁶⁴⁵ The Department also noted that “the level of risk appears to be manageable with the current resource mix” but that could change if volatility in the spot market increases, the Company removes further dispatchable capacity, or load increases significantly from that projected in 2025.⁶⁴⁶

i. The CEO’s Review of the Department’s Analysis

424. The CEOs raised concerns about the Department’s risk analysis. The CEOs asserted that the Department’s analysis should be considered “very conservative as it excludes nearly 900 MW of Minnesota Power’s resources from consideration, and also fails to consider battery storage as a potential resource.”⁶⁴⁷

425. The CEOs noted that the Department did not consider wind, solar, demand response, and non-dispatchable hydro power as resources in its comparison of the Company’s forecasted supply and demand.⁶⁴⁸ Instead, the Department considered whether these resources could be used to mitigate exposure to price spikes from buying power on the MISO market and only demand response was considered a viable mitigation measure by the Department.⁶⁴⁹

426. The CEO’s witness, Mr. Jacobs, disagreed with the Department’s decision to exclude wind, solar, and non-dispatchable hydro power from its calculation of available generation resources. Mr. Jacobs noted that the wind integration studies show there are methodologies for assessing the contribution of variable resources to meeting loads that are relevant to Minnesota Power’s potential exposure to spot market prices.⁶⁵⁰

427. With regard to solar and non-dispatchable hydro power, Mr. Jacobs disputed the Department’s assessment that the size of these resources was too small to consider in the analysis. Mr. Jacobs pointed out that these “small” resources add up and could potentially have a large cumulative impact on the Department’s analysis.⁶⁵¹ When the Department added 192.5 MW of large power interruptible services as a “mitigation measure” in the last step of his analysis, the impact was to reduce the number of hours

⁶⁴⁵ *Id.*

⁶⁴⁶ *Id.*

⁶⁴⁷ CEO Initial Br. at 37. Unlike Mr. Brick’s analysis, the Department’s analysis is based on quantitative results.

⁶⁴⁸ *Id.* at 39-40.

⁶⁴⁹ Ex. DER-8, SRR-4 at 18-20.

⁶⁵⁰ Ex. CEO-6 at 5-6 (Jacobs Rebuttal)

⁶⁵¹ *Id.* at 4.

with a capacity deficit of 400 MW or more by 85 percent.⁶⁵² Mr. Jacobs pointed out that this means the results of the Department's analysis are highly sensitive to the inclusion of additional resources.⁶⁵³

428. In addition, Mr. Jacobs emphasized that the Department did not consider energy storage as a potential mitigation measure for managing exposure to the MISO spot market.⁶⁵⁴

429. In summary, the CEOs maintained the Department "[f]ails to properly analyze and quantify the role that variable resources and energy storage can play in balancing Minnesota Power's supply and demand."⁶⁵⁵

430. Even with these alleged shortcomings, the CEOs asserted that the Department's analysis shows that "there is no reasonable justification for pursuing a project such as NTEC on the basis of mitigating market price exposure."⁶⁵⁶

ii. The Department's Response to the CEOs

431. The Department disagreed with the criticisms raised by the CEOs.

432. The Department emphasized that its analysis considered MP's existing system and explored the potential for the proposed NTEC to mitigate the risk associated with exposure to spot market prices.⁶⁵⁷

433. The Department recognized that it did not discuss energy storage as a risk-mitigation measure, other than the discussion about the effects of storage on increasing demand during off-peak periods and decreasing demand during on-peak periods.⁶⁵⁸

434. The Department maintained that it considered an appropriate range of resources in its analysis considering the purpose of its analysis.⁶⁵⁹ In the Department's view, a broader consideration of alternatives, as proposed by the CEOs, would be more appropriate for an IRP proceeding.⁶⁶⁰

⁶⁵² *Id.*

⁶⁵³ CEO Initial Br. at 41 (citing Ex. CEO-4 at 4).

⁶⁵⁴ Ex. CEO-6 at 12 (Jacobs Rebuttal).

⁶⁵⁵ *Id.* at 2.

⁶⁵⁶ CEO Initial Br. at 42.

⁶⁵⁷ Ex. DER-11 at 61 (Rakow Surrebuttal).

⁶⁵⁸ *Id.*

⁶⁵⁹ *Id.*

⁶⁶⁰ *Id.*

435. The Department also noted that its Strategist analysis considered the need to “balance” the system to reflect the variable nature of wind.⁶⁶¹ The Department asserted that pairing up energy storage with wind resources would not be reasonable because, by definition, it would lead to a higher-cost outcome.⁶⁶² Instead, with the appropriate costs added to Strategist, the model will determine which resources address MP’s overall system needs to cover the hours when wind resources are not available.⁶⁶³

436. In summary, the Department emphasized that the purpose of its risk analysis was to provide, in simple terms, a comparison of the cost Minnesota Power might incur due to market exposure during price spikes with the cost of the proposed NTEC facility, using Minnesota Power’s existing resources.⁶⁶⁴

D. Analysis of Need for Dispatchable Resources

437. The Administrative Law Judge concludes that the Company has failed to demonstrate that the 250 MW NTEC purchase is needed and reasonable as a dispatchable, flexible resource to balance its system and mitigate exposure to energy markets.

438. First, as discussed above, Minnesota Power’s has overstated its need to have additional resources available for ramping purposes and has failed to demonstrate that NTEC is needed and reasonable for that purpose.

439. Second, Mr. Brick’s analysis fails to provide a meaningful comparison of NTEC to wind and other resources.

440. Finally, the Department’s analysis of market exposure shows that the Company’s market risk in 2025 appears to be manageable with its existing resource mix.⁶⁶⁵ The Department reached this conclusion even with conservative assumptions that excluded a number of resources that could provide additional mitigation to market exposure. As such, the Department’s analysis suggests that the addition of the 250 MW NTEC purchase is not necessary for dispatch purposes in 2025 as claimed by the Company.

⁶⁶¹ See *id.* at 62. The “balancing” costs imposed on MP’s system due to wind were included in the Department’s Strategist analysis. Dr. Rakow added charges to new wind units to represent the integration costs and the cycling costs created by additional wind facilities. These costs were obtained from analysis performed by Northern States Power Company d/b/a Xcel Energy (Xcel) in Xcel’s most recent IRP, Docket No. E002/RP-15-21. The specific cost inputs were taken from Appendix J of Xcel’s most recent IRP petition, were imposed on new wind units, and were \$0.41 per MWh in 2015 for wind integration and \$1.22 per MWh in 2015 for unit cycling (the cost were escalated going forward). Thus, the costs attributable to the claimed need to balance wind were included in the Department’s Strategist modeling. *Id.* at 62–63 (Rakow Surrebuttal).

⁶⁶² *Id.*

⁶⁶³ *Id.* at 63–64.

⁶⁶⁴ *Id.* at 59.

⁶⁶⁵ Ex. DER-8, SRR-4 at 20 (Rakow Direct).

441. For these reasons, the Administrative Law Judge concludes that the Company has failed to demonstrate that the NTEC 250 MW purchase is needed as a flexible, dispatchable resource to help balance the Company's system and reduce market risk.

XI. The NTEC RFP Process

442. Minnesota Power selected the proposed NTEC 250 MW purchase through a competitive bidding process.⁶⁶⁶

443. On October 15, 2015, Minnesota Power issued an RFP for up to 400 MW of Capacity and Energy (Dispatchable Capacity RFP).⁶⁶⁷ The RFP was subsequently updated on December 15, 2015, to clarify the Company's preference for use of the local prevailing wage to determine labor costs.⁶⁶⁸

444. Proposals in response to the Dispatchable Capacity RFP were due by January 7, 2016, and entailed the bidder's development, ownership, and operation of an eligible project, with all or a share of the facility's generation to be sold to Minnesota Power over a long-term agreement.⁶⁶⁹

445. Among the Dispatchable Capacity RFP's requirements were that offers must:

- be based on a natural gas-fired resource;
- use firm transportation service by at least one major natural gas pipeline;
- provide MISO accredited or accreditable capacity (including Zonal Resource Credits) of no less than 200 MW and up to a maximum of 400 MW of summer and/or winter capacity; and
- be available to start delivery in the 2022 to 2024 timeframe.⁶⁷⁰

446. Minnesota Power's solicitation process was open to all interested parties and parties were provided with the same information. The Dispatchable Capacity RFP specified that Minnesota Power intended to consider self-build as part of its evaluation of options.⁶⁷¹

⁶⁶⁶ Ex. DER-8 at 21 (Rakow Direct). The Department's witness, Dr. Rakow, provided a history of the bidding process in his Direct Testimony. Ex. DER-8 at 21-37 (Rakow Direct).

⁶⁶⁷ See MP-7, Appendix R (Request for Proposals for Up to 400 MW of Capacity and Energy).

⁶⁶⁸ Ex. MP-23 at 3 (Frederickson Direct).

⁶⁶⁹ *Id.* at 2.

⁶⁷⁰ *Id.* at 4.

⁶⁷¹ *Id.* at 3.

447. To ensure fair and consistent treatment of all bidders, and because the Company anticipated that it would receive a proposal from an affiliate, Minnesota Power assembled an independent internal team to review the proposals and also retained an independent expert, Sedway Consulting, to oversee the Dispatchable Capacity RFP process and provide an independent evaluation of all bids.⁶⁷²

448. The Department raised some concerns about the RFP process.⁶⁷³

449. The Department believed that the duration required by Minnesota Power to complete negotiations for NTEC with South Shore was too long.⁶⁷⁴ The Department stated that Minnesota Power's inability to complete negotiations in a timely manner twice caused it to revise its estimated need for a new resource.⁶⁷⁵

450. The Department stated that Minnesota Power reacted to the determination of revised needs by pursuing discussions only with a single source rather than issuing a new RFP, consistent with the revised needs, or allowing all bidders the opportunity to address the new need.⁶⁷⁶

451. After review of Minnesota Power's rebuttal testimony, however, the Department's concerns were largely addressed.⁶⁷⁷

452. In general, the Department agreed with Minnesota Power that whether to focus on South Shore's revised proposals relative to information that was already in hand or return to the market for more bids was a judgment call. The Department's judgment, however, differed from the Company's judgment.⁶⁷⁸

453. While the Department suggested that the Company's RFP process took a long time and could have been revised, the Department also concluded that alternative offers likely would not have been competitive with the 250 MW NTEC purchase.⁶⁷⁹

454. Finally, while recognizing that the Commission has not established a bidding process that Minnesota Power must use in this case,⁶⁸⁰ the Department recommended that Minnesota Power improve its bidding process.⁶⁸¹ In response, the Company committed to take several steps for supply-side purchases of 200 MW or more.⁶⁸² The Department agreed that these steps are a reasonable outline for improving the bidding process and recommended that the Commission require Minnesota Power

⁶⁷² *Id.*

⁶⁷³ See Ex. DER-8 at 36-37 (Rakow Direct).

⁶⁷⁴ Ex. DER-8 at 36 (Rakow Direct).

⁶⁷⁵ *Id.*

⁶⁷⁶ *Id.*

⁶⁷⁷ Initial Brief of the Minnesota Department of Commerce, Division of Energy Resources (Department Initial Br.) at 40.

⁶⁷⁸ *Id.* at 35, n. 208.

⁶⁷⁹ Ex. DER-11 at 35-36 (Rakow Surrebuttal).

⁶⁸⁰ Ex. DER-11 at 16 (Rakow Surrebuttal).

⁶⁸¹ Ex. DER-8 at 55 (Rakow Direct).

⁶⁸² Ex. MP-24 at 14-16 (Frederickson Rebuttal).

to include, in its next IRP, a proposed bidding process for the Commission's consideration and potential approval under Minn. Stat. § 216B.2422, subd. 5.⁶⁸³

455. LPI also raised concerns with the Company's RFP process. LPI asserted that Minnesota Power should update and reissue its Dispatchable Capacity RFP to obtain updated information on a broader scope of dispatchable resources and market short-term options available to meet its projected needs.⁶⁸⁴

456. LPI cited three reasons in favor of its recommendation: (1) the Company's needs have changed multiple times since release of the Dispatchable Capacity RFP; (2) the parameters of the Dispatchable Capacity RFP are not a good match for the Company's current identified needs; and (3) because the Company selected an affiliate bidder in the Dispatchable Capacity RFP, transparency for customers is especially important to ensure that the best and lowest cost option was identified.⁶⁸⁵

457. In response to LPI, Minnesota Power argued that it utilized a thorough RFP competitive bidding process to solicit bids for specific resources to meet its identified need and to select the proposed 250 MW NTEC purchase.⁶⁸⁶

458. Minnesota Power argued that it has demonstrated that the updated information regarding projected need and timing did not necessitate reissuance of the RFP: the analysis conducted both in the 2015 Plan, updated subsequent information during negotiations, the indicia of the 2017 AFR, and the subsequent analysis of the RFP outcome all underscore that the RFP results are reasonable.⁶⁸⁷

459. Minnesota Power stated that competitive resource procurement is an important yet time-consuming step in the process of developing and constructing utility infrastructure. Minnesota Power argued that the record developed in this proceeding demonstrates that Minnesota Power designed and implemented an RFP in a reasonable manner to probe the market and to obtain a competitive and least-cost resource.⁶⁸⁸

460. In the view of the Administrative Law Judge, it is not necessary to determine whether the RFP process was reasonable. Because the Administrative Law Judge concluded that the Company has failed to demonstrate that the proposed 250 MW NTEC purchase is needed and reasonable, there is no need to make a determination regarding the reasonableness of the RFP or LPI's request that Minnesota Power be required to update and reissue its RFP.

⁶⁸³ Ex. DER-11 at 37 (Rakow Surrebuttal).

⁶⁸⁴ LPI Initial Br. at 18.

⁶⁸⁵ *Id.*

⁶⁸⁶ Ex. MP-23 at 2 (Frederickson Direct).

⁶⁸⁷ Minnesota Power's Reply Br. at 65.

⁶⁸⁸ Ex. MP-24 at 13-14 (Frederickson Rebuttal); Ex. MP-22 at 7-13 (Taylor Rebuttal).

XII. The NTEC Affiliated Interest Agreements

461. As discussed above, the NTEC plant is proposed to be owned jointly by South Shore and Dairyland. These entities have entered into two agreements to establish a 50/50 partnership and to place South Shore in the role of project and plant manager.⁶⁸⁹

462. Subject to Commission approval of the NTEC affiliated interest agreements discussed below, South Shore would assign its role as project and plant manager to Minnesota Power, thereby putting the overall responsibility for successful and timely completion of the plant on Minnesota Power. South Shore would also dedicate 48 (or 50) percent of the plant capacity to Minnesota Power through the CDA.⁶⁹⁰

463. While Minnesota Power initially proposed taking a 48 percent share of the NTEC capacity, both Minnesota Power and the Department considered whether Minnesota Power should instead take the entire 50 percent share that South Shore has available.⁶⁹¹ The Department maintained that the difference between 48 and 50 percent is within the margin of error⁶⁹² and taking South Shore's entire position would make the transaction more straightforward and easier to administer.⁶⁹³ While Minnesota Power remains willing to complete the transaction either way, the Company prefers the 50 percent alternative.⁶⁹⁴

464. Minnesota Power also emphasized that this transaction has been structured to replicate the regulatory treatment of a rate-based asset for Minnesota Power and to comply with the generation ownership requirements mandated by Wisconsin law.⁶⁹⁵ Under the transaction structure, South Shore, a Wisconsin-based affiliate, is the nominal "owner" of the Wisconsin-based power plant asset, and all indicia of control and responsibility of the asset will reside with Minnesota Power on the same basis as if the asset were owned by Minnesota Power.⁶⁹⁶

465. In this proceeding, Minnesota Power has requested Commission approval of three affiliated interest agreements effectuating the 250 MW NTEC purchase — an

⁶⁸⁹ Ex. MP-2 at 1-1, 4-18 (Petition); Ex. MP-5, Apps. F-G (Development and Construction Management Agreement between Dairyland and Southshore, Ownership and Operating Agreement between Dairyland and South Shore).

⁶⁹⁰ Ex. MP-5, App. H (Unit Contingent Capacity Dedication Agreement between South Shore and Minnesota Power).

⁶⁹¹ Ex. MP-2 at 1-4, n.10 (Petition); Ex. MP-26 at 10 (Supinski Rebuttal); Ex. MP-14 at 30-31 (Pierce Rebuttal); Ex. MP-28 at 1 (Pierce Opening Statement); Ex. DER-8 at 6 (Rakow Direct); Ex. DER-4 at 40 (Campbell Direct); Ex. DER-6 at 28-30 (Campbell Surrebuttal).

⁶⁹² Ex. DER-8 at 6 (Rakow Direct).

⁶⁹³ Ex. DER-4 at 40 (Campbell Direct).

⁶⁹⁴ Ex. MP-28 at 1 (Pierce Opening Statement).

⁶⁹⁵ Ex. MP-26 at 22-23 (Supinski Rebuttal); Wis. Stat. § 196.53. The legality of this state statutory restriction was upheld in *Alliant Energy Corp. v. Bie*, 330 F.3d 904 (7th Cir. 2003).

⁶⁹⁶ Ex. MP-13 at 12 (Pierce Direct).

Assignment of Rights Agreement (Construction Agent),⁶⁹⁷ an Assignment of Rights Agreement (Operating Agent),⁶⁹⁸ and the CDA.⁶⁹⁹

466. Minnesota Power asserted that the proposed affiliate interest agreements contain provisions to reasonably protect Minnesota Power's customers from the financial and operational risks related to the 250 MW NTEC purchase, and are in the public interest.⁷⁰⁰

467. In Surrebuttal Testimony, the Department agreed with Minnesota Power that the overall transaction is consistent with the public interest and recommended that the Company's proposed transaction be approved.⁷⁰¹ The Company and the Department also reached agreement on the Department's proposed conditions and reporting requirements with respect to the proposed transaction and with respect to the proposed mechanisms for recovery of the costs associated with the project. Attachment B to Minnesota Power's Initial Brief lists all of the Department's suggested conditions and compliance requirements and Minnesota Power's commitment to comply.

468. The CEOs and LPI did not contest any portion of the Assignment of Rights Agreements (Construction Agent or Operating Agent). However as discussed below, LPI argued that Minnesota Power has not demonstrated that the CDA is in the public interest. In addition, as discussed in the preceding sections, both the CEOs and LPI disagreed that the Minnesota Power has shown that the proposed 250 NTEC purchase is needed and reasonable.

A. The Assignment of Rights Agreement (Construction Agent)

469. Under the Assignment of Rights Agreement (Construction Agent), South Shore assigns to Minnesota Power all of the obligations of the Construction Agent as defined in the Development and Construction (D&C) Agreement between South Shore and Dairyland.⁷⁰² The Assignment of Rights Agreement (Construction Agent) indicates that this assignment means Minnesota Power must perform all of the duties of the Construction Agent under the D&C Agreement as if Minnesota Power had executed the D&C Agreement in its own name.⁷⁰³

⁶⁹⁷ The Assignment of Rights Agreement (Construction Agent), dated July 28, 2017, is between South Shore and Minnesota Power. Under this agreement, South Shore assigns to Minnesota Power the right to act as the Operating Agent for NTEC pursuant to Section 3.7.5 of the D&C Agreement. Ex. MP-4 at Appendix D (Petition).

⁶⁹⁸ The Assignment of Rights Agreement (Operating Agent), dated July 28, 2017, is between South Shore and Minnesota Power. Under this agreement, South Shore assigns to Minnesota Power the right to act as the Operating Agent for NTEC pursuant to Section 4.7.5 of the O&O Agreement. Ex. MP-4 at Appendix E (Petition).

⁶⁹⁹ Ex. MP-5 at App. H (Unit Contingent Capacity Dedication Agreement between South Shore and Minnesota Power).

⁷⁰⁰ Ex. MP-26 at 11-12, 23-24 (Supinski Rebuttal); Ex. DER-8 at 41 (Rakow Direct); Ex. DER-1 at 13, 19 (Amit Direct); Minnesota Power's Initial Br. at 72-89.

⁷⁰¹ Ex. DER-11 at 66-67 (Rakow Surrebuttal).

⁷⁰² Ex. MP-2 at 4-41 (Petition).

⁷⁰³ Ex. DER-8 at 38 (Rakow Direct).

470. According to the Petition, the Construction Agent “has primary responsibility and authority to manage the planning, permitting, design, construction, acquisition and procurement, completion, startup, and commissioning of NTEC, subject to the terms of the D&C Agreement and the direction of the NTEC Management Committee.”⁷⁰⁴

471. By acting as Construction Agent for the NTEC facility, Minnesota Power will have significant control to ensure that construction of the project proceeds on schedule and within budget to the fullest extent possible.⁷⁰⁵ Minnesota Power stated that it has a positive track record of bringing projects in on time and on or under budget.⁷⁰⁶ The Company argued that the Assignment of Rights Agreement (Construction Agent) is in the public interest because it provides protections for Minnesota Power as Construction Agent; benefits Minnesota Power customers by ensuring an experienced construction manager; and provides the Commission with regulatory oversight.⁷⁰⁷

472. Additionally, during the course of this proceeding, Minnesota Power committed that the amount of installed capacity dedicated to it under the CDA will not be lower than 250 MW, thereby ensuring customers receive, at a minimum, the amount of capacity assumed during the evaluation of bids.⁷⁰⁸

473. The reimbursements to the Construction Agent specified in Section 3.3.1 of the D&C Agreement are intended to compensate Minnesota Power for the actual costs it incurs in its role as Construction Agent, including overheads and general and administrative expenses, and no more. Half of the reimbursement will be paid by Dairyland and the other half by South Shore. Minnesota Power’s share of South Shore’s half will be passed through to Minnesota Power without mark-up as part of the CDA.⁷⁰⁹ Minnesota Power has acknowledged that it will need to demonstrate the reasonableness of any costs it proposes to charge its customers for its role as Construction Agent in future rate case proceedings.⁷¹⁰

⁷⁰⁴ Ex. MP-2 at 4-37 (Petition). The Management Committee will be composed of a primary and alternate representative of each NTEC Owner. The Management Committee is responsible for providing oversight of the planning, permitting, design, construction, acquisition and procurement, completion, renewal, addition, replacement, modification, operation, maintenance, repair and decommissioning of NTEC. Ex. MP-2 at 4-37 to 4-38 (Petition).

⁷⁰⁵ Ex. MP-26 at 13 (Supinski Rebuttal).

⁷⁰⁶ *Id.* at 13, n.5; (LSS) Rebuttal Schedule 8 (Supinski Rebuttal).

⁷⁰⁷ *Id.* at 13.

⁷⁰⁸ *Id.* at 15, 21; Ex. DER-11 at 27 (Rakow Surrebuttal).

⁷⁰⁹ Ex. MP-26 at 13 (Supinski Rebuttal). The amount passed from South Shore to Minnesota Power depends on whether the Commission approves a 48 or 50 percent share of NTEC for Minnesota Power’s customers. If the Company ultimately purchases 48 percent of NTEC’s capacity, then the reimbursement will be 48 percent without markup. *Id.*

⁷¹⁰ *Id.* at 12-13.

B. The Assignment of Rights Agreement (Operating Agent)

474. Under the Assignment of Rights Agreement (Operating Agent), South Shore assigns to Minnesota Power all of the obligations of the Operating Agent as defined in the Ownership and Operating (O&O) Agreement between South Shore and Dairyland.⁷¹¹ This Assignment of Rights Agreement (Operating Agent) indicates that this assignment means that Minnesota Power must perform all of the duties of the Operating Agent under the O&O Agreement as if Minnesota Power had executed the O&O Agreement in its own name.⁷¹²

475. According to the Petition, the Operating Agent:

[H]as primary responsibility for the operation and maintenance of NTEC; the planning, permitting, design, construction, acquisition and procurement, and completion of any capital improvements; the scheduling, dispatch, sale, or other disposition of energy and ancillary services; decommissioning of NTEC; and any other matters set forth in the project agreements or otherwise determined by the Management Committee.⁷¹³

476. By acting as Operating Agent for the NTEC facility, Minnesota Power will have significant control to ensure that operation of the NTEC plant is in accordance with prudent utility practice. Minnesota Power stated that it has extensive experience operating and maintaining power plant assets and will care for the NTEC unit to the same high standards as it does its other units.⁷¹⁴ Minnesota Power argued that the Assignment of Rights Agreement (Operating Agent) is in the public interest because it provides protections for Minnesota Power as Operating Agent; benefits Minnesota Power customers by ensuring an experienced operator for the NTEC facility; and provides the Commission with regulatory oversight.

477. The Company stated that the terms of the O&O Agreement are intended to reasonably and appropriately allocate the risks of the project among the Operating Agent and NTEC Owners.⁷¹⁵ As with the Assignment of Rights Agreement (Construction Agent), the provisions of the O&O Agreement and Assignment of Rights Agreement (Operating Agent) ensure Minnesota Power will be fairly compensated for its role as Operating Agent. Minnesota Power has also acknowledged that it will need to demonstrate the reasonableness of any costs it proposes to charge its customers for its role as Operating Agent in future rate case proceedings.⁷¹⁶

⁷¹¹ Ex. MP-2 at 4-41 (Petition).

⁷¹² *Id.*; Ex. DER-8 at 43 (Rakow Direct).

⁷¹³ Ex. MP-2 at 4-39 (Petition); see Ex. MP-5 at Appendix G (Petition).

⁷¹⁴ Ex. MP-26 at 19 (Supinski Rebuttal) (Public and Nonpublic).

⁷¹⁵ *Id.* at 21.

⁷¹⁶ *Id.* at 18-19.

C. The CDA

478. The CDA is an agreement between Minnesota Power and South Shore.⁷¹⁷ The CDA has a 40-year term.⁷¹⁸ Under the CDA, South Shore initially dedicated to Minnesota Power 48 percent of NTEC's: (1) capacity (approximately 250 MW); (2) associated energy; (3) ancillary services; and (4) all other attributes.⁷¹⁹ In exchange, the CDA also defines Minnesota Power's cost responsibility.⁷²⁰

479. Development of NTEC is described in Article III of the CDA. Transmission interconnection requirements are discussed in Article IV. Sale and purchase obligations are outlined in Article V. The CDA pricing details are contained in Article VI. Billing and payment procedures are in Article VII. O&M procedures are contained in Article VIII.⁷²¹

480. Under the CDA, Minnesota Power will pay a \$/kW per month charge for the installed costs of its 48 percent interest in the total NTEC baseline capacity on the same basis as if Minnesota Power was the owner of that capacity, as well as its proportional share of the MISO network upgrade costs. This "capacity pricing" concept is contained in Section 6.1 of the CDA and includes separate components for the cost of the plant and the cost of the network upgrades.⁷²²

481. Minnesota Power stated that this pricing essentially converts the installed cost of NTEC into a revenue requirement based on assumed construction costs, assumed cost of capital, and other inputs and applies those values to 48 percent of the overall plant. The costs are then translated into a payment stream on a \$/kW per month basis for each of the plant costs and the network upgrade costs. The Company stated that because this pricing stream is designed to replicate a revenue requirement, the key inputs of cost of capital are designed after the first contract year to be based on Minnesota Power's authorized rate of return, capital structure, depreciation schedule, and the like. In addition, Minnesota Power has designed the pricing to replicate a revenue requirement on a rate-based asset, meaning that the per-unit cost decreases over time as the asset depreciates.⁷²³

482. A comparable formula is utilized for the network upgrade costs, where the Company has stated a specified amount of potential network upgrades and designed a \$/kW per month payment to reflect recovery of that cost.⁷²⁴

483. Largely due to accounting and cost recovery concerns, the Department recommended that Minnesota Power consider increasing the Company's share of the

⁷¹⁷ See generally Ex. MP-5 at Appendix H (Petition).

⁷¹⁸ Ex. MP-2 at 4-42 (Petition).

⁷¹⁹ *Id.*

⁷²⁰ *Id.* at 4-42 to 4-47.

⁷²¹ *Id.* at 4-43 to 4-44.

⁷²² *Id.* at 4-43.

⁷²³ *Id.*

⁷²⁴ *Id.* at 4-44.

dedicated capacity from 48 to 50 percent.⁷²⁵ As discussed above, Minnesota Power agreed to do so.⁷²⁶

484. In addition, the CDA addresses other costs. Sections 6.1.1 and 6.1.2 of the CDA provide the formulas for calculating the monthly charge for capital-related costs (depreciation, taxes, and cost of capital related to the power plant and transmission network upgrades). Section 6.1.3(a) clarifies that changes in capital structure, cost of capital, and depreciation schedule only happen based upon Commission orders applicable to Minnesota Power's rates.⁷²⁷ Therefore, under the proposed CDA, South Shore's capital charges to Minnesota Power would mimic rate-based treatment.⁷²⁸

485. Section 6.2.2 of the CDA notes that the O&O Agreement establishes a Market Operations Account to pay for variable costs (fuel commodity costs, variable fuel transportation costs, and other MISO charges). Section 6.2.2 states that Minnesota Power would receive and pay the Company's share of the Market Operations Account's revenues and costs.⁷²⁹

486. Section 6.2.3 of the CDA establishes a funding mechanism for Minnesota Power's share of the Trust Account, Working Capital Account, and Market Operations Account; these accounts are required by the O&O Agreement to be funded by NTEC's Owners. Section 6.2.3 requires Minnesota Power to provide funds for its share to South Shore.⁷³⁰

487. Under Section 15.2.3, South Shore provides Minnesota Power the right to purchase the Company's share of NTEC at a price equal to the undepreciated net book value. The CDA acknowledges that such a purchase would be subject to Commission and Federal Energy Regulatory Commission approval.⁷³¹

⁷²⁵ Ex. DER-4 at 40 (Campbell Direct). The Department also noted that, in terms of resource planning, the 10 to 15 MW difference between the proposed 48 percent share of NTEC and the suggested increase from a 48 to 50 percent share of NTEC is not significant—these amounts are well within the margin of error of the forecasts and modeling results that were used in Minnesota Power's IRP. Ex. DER-8 at 6 (Rakow Direct).

⁷²⁶ Ex. MP-14 at 30–31 (Pierce Rebuttal).

⁷²⁷ See Ex. MP-5, App. H (Unit Contingent Capacity Dedication Agreement between South Shore and Minnesota Power).

⁷²⁸ Ex. DER-8 at 49 (Rakow Direct).

⁷²⁹ See Ex. MP-5, App. H.

⁷³⁰ *Id.* As indicated above, Minnesota Power agreed to increase this share to 50 percent.

⁷³¹ *Id.* The Department stated that this clause is not an issue at this time. The Commission would be able to determine the reasonableness of the purchase price if and when such a purchase is proposed. Ex. DER-8 at 50 (Rakow Direct).

488. The Company maintained that, overall, the CDA is structured to effectively mimic utility ownership of a rate-based generation asset.⁷³² Additionally, the CDA provides that Minnesota Power is giving the Commission authority over the contract and relationship on the same basis as if Minnesota Power owned the NTEC plant in its own name as a rate-based asset.⁷³³

489. Minnesota Power asserted that two features of the CDA provide important customer protections. The first feature is an overall soft cap on two capital cost components: (1) a cap on the capital cost attributable to the power plant; and (2) a cap on the capital cost attributable to network upgrades. Under the CDA, costs can be moved from the power plant to network upgrades, allowing Minnesota Power to manage cost overruns for individual items within the overall project budget. The Company agreed that the costs to deploy the NTEC resource will not exceed specified “capped” levels without Commission approval. Because unforeseen circumstances can arise, Minnesota Power may request Commission approval for recovery of costs in excess of the soft cap, recognizing that the Company would bear the burden of proving the reasonableness of those costs.⁷³⁴

490. The second feature was a “true up” feature, designed to ensure that customers are only responsible for the 48 (or 50) percent share of NTEC that is being dedicated to them.⁷³⁵ In addition, the Company claimed that this true-up feature would ensure that Minnesota Power does not “over-recover” for things like the capital costs, cost of capital, taxes, or depreciation, and that all costs incurred in procuring the capacity are adjusted to actual cost levels, all of which would be subject to the “soft cap.”⁷³⁶

491. The Department identified several potential issues with the CDA that could expose Minnesota Power’s customers to risk. Those issues included: the proposed soft cap, the true-up mechanism, the 250 MW capacity commitment, potential abandoned plant costs, and potential errors in operation or maintenance.⁷³⁷ In response to

⁷³² Ex. MP-2, 4-41 to 4-47 (Petition); Ex. MP-25 at 30-31 (Supinski Direct); Ex. MP-26 at 22-23 (Supinski Rebuttal). The Company noted that the CDA operates in a manner substantially similar to Minnesota Power’s offtake agreement with Square Butte Electric Cooperative for the purchase of a portion of the capacity and associated energy from Young 2. Under that agreement, Minnesota Power is obligated to make payments for its proportional share of Young 2 on the same basis as if it was an owner of the plant and all of those costs are recovered from customers as if Minnesota Power owned the asset directly to the full extent of its capacity purchase. Ex. MP-2 at 4-42 (Petition).

⁷³³ Ex. MP-26 at 24 (Supinski Rebuttal).

⁷³⁴ *Id.* at 23-24.

⁷³⁵ Ex. MP-25 at 35 (Supinski Direct).

⁷³⁶ Ex. MP-26 at 23-24 (Supinski Rebuttal). It appeared to the Department that Minnesota Power believed that the CDA would allow the Company to establish a rider outside of Minnesota Power’s rate case for the Company to recover NTEC costs. Ex. DER-6 at 19 (Campbell Surrebuttal). However, as discussed in greater detail below, Minnesota Power states that it is not proposing to true-up the costs under the CDA outside of a rate case, but will true-up the assumptions and inputs in future rate case filings to ensure all costs and assumptions are up to date and accurate. See Minnesota Power Initial Br. at 80, n.301, Attachment B at 8.

⁷³⁷ Ex. DER-4 at 10-15 (soft cap), 32-33 (true-up) (Campbell Direct); Ex. DER-6 at 6-7, 16, 32 (soft cap), 15-16 (true-up) (Campbell Surrebuttal); Ex. DER-8 at 50 (250 MW capacity commitment, abandoned plant

concerns raised by the Department, the Company clarified its position on each issue and made further commitments. The Department's concerns were resolved by these steps and none of these issues remain in dispute between the Department and the Company.⁷³⁸

492. In addition to the issues identified above, LPI and the Department raised concerns with regard to the proposed revenue requirements pricing structure and questioned whether a levelized pricing alternative should be evaluated.⁷³⁹

493. The Department initially expressed concern with South Shore's incentive to continue to perform in the later years under the CDA pricing structure.⁷⁴⁰ The Department questioned whether the proposed declining \$/kW per month capacity charges would reduce the incentive to continue performing in the contract's later years, absent sufficient posted security or Commission authority to reject costs and impose penalties related to imprudent actions by South Shore and Dairyland as NTEC Owners, or Minnesota Power as Construction Agent and Operating Agent.⁷⁴¹

494. In response to concerns raised by the Department, the Company provided information indicating that Minnesota Power will continue to have reasonable incentives to operate the plant in later years, citing the agreement with Dairyland, its past experience with jointly-administered power plants, and acknowledging that the Commission could deny Minnesota Power recovery of costs if the Company is unable to justify proposed cost recovery due to Minnesota Power's future implementation of the transaction.⁷⁴² Given that Minnesota Power made clear that the Commission will have on-going regulatory oversight over Minnesota Power's actions and cost recovery, the Department concluded that this issue was reasonably resolved between the Company and the Department.⁷⁴³

495. Additionally, the Department expressed concern that the Company had not provided a comparison of a revenue requirement ownership-type method with a levelized fixed-cost PPA pricing method for establishing the cost cap for capacity and fixed and variable operations and maintenance costs. As a result, the parties were not able to fully compare the options of the PPA method to the revenue requirement

costs, and potential errors in operations or maintenance) (Rakow Direct); Ex. DER-11 at 32 (abandoned plant costs) (Rakow Surrebuttal).

⁷³⁸ Ex. MP-26 at 15, 32-35, 41-42 (Supinski Rebuttal); Ex. DER-6 at 6-7, 13 (Campbell Surrebuttal); Ex. DER-11 at 32 (Rakow Surrebuttal); see *generally* Minnesota Power Initial Br. at Attachment B.

⁷³⁹ Ex. DER-8 at 52 (Rakow Direct); Ex. DER-6 at 22-24 (Campbell Surrebuttal); Ex. LPI-5 at 22-24 (Gorman Direct); LPI Initial Br. at 28-31, 33.

⁷⁴⁰ Ex. DER-8 at 52 (Rakow Direct).

⁷⁴¹ *Id.*

⁷⁴² Ex. MP-14 at 31-32 (Pierce Rebuttal) (citing Minnesota Power's joint ownership of Boswell 4 with its partner Wisconsin Public Power, Inc. and its arrangement with Square Butte Electric Cooperative for the joint operation and supply from Young 2).

⁷⁴³ Ex. DER-11 at 6 (Rakow Surrebuttal) ("I agree with Ms. Pierce that the following both provide evidence that MP will have incentive to adequately operate and maintain the unit over the long run: [1] the partnership with Dairyland Power Cooperative, [2] MP's experience with the jointly-owned Boswell unit 4; and [3] the fact that MP has made clear that the Commission will have on-going regulatory oversight over MP's actions and cost recovery.").

method.⁷⁴⁴ Nonetheless, the Department concluded that it was not particularly concerned about whether the rate recovery in Minnesota Power's future rate cases will occur using a PPA method or a revenue requirement method.⁷⁴⁵

496. LPI was also concerned that the Company had not provided a levelized cost analysis for the 250 MW NTEC purchase, which would have allowed the parties to compare the Company's proposed declining balance cost structure to a levelized cost structure.⁷⁴⁶ LPI asserted that without such an analysis there is no basis upon which to find that the CDA structure is reasonable and in the public interest.⁷⁴⁷

497. In addition, LPI analyzed the Company's proposed declining balance pricing structure and concluded that the proposal will result in higher prices for customers in the early years of NTEC (e.g., the 2025-2030 period) when the Company has the least demonstrated need for NTEC capacity.⁷⁴⁸

498. As a result, LPI recommended that alternative pricing structures should be considered that provide a better balance for customers while still fully compensating the Company for NTEC costs.⁷⁴⁹

499. Specifically, LPI recommended that, if the Commission ultimately determines that the 250 MW NTEC purchase is needed and reasonable, then the Commission should require further analysis and potentially modification of the CDA to provide for a more economic cost structure.⁷⁵⁰

500. Minnesota Power made several arguments to support its position that modeling a levelized pricing structure is neither warranted under the circumstances, nor would it result in a lower overall cost for customers.

501. First, Minnesota Power stated that the declining balance rate-based pricing structure under the CDA results in overall cost savings for Minnesota Power customers while also capturing the proposed rate-base treatment of the 250 MW NTEC purchase for the benefit of Minnesota Power's customers.

502. Second, Minnesota Power noted that no levelized NTEC proposal was bid into the Dispatchable Capacity RFP and to develop a levelized pricing alternative that would provide meaningful comparison to the proposed CDA revenue requirements pricing structure, it would be necessary to create a new South Shore levelized bid proposal based on the risk profile and assumptions of a levelized pricing option.⁷⁵¹

⁷⁴⁴ Ex. DER-6 at 22-25 (Campbell Surrebuttal).

⁷⁴⁵ Ex. DER-4 at 35 (Campbell Direct); Ex. DER-6 at 18 (Campbell Surrebuttal).

⁷⁴⁶ Ex. DER-4 at Ex. NAC-19 (Campbell Direct).

⁷⁴⁷ LPI Initial Br. at 29-30.

⁷⁴⁸ Ex. LPI-5 at 22 (Gorman Direct).

⁷⁴⁹ LPI Initial Br. at 29.

⁷⁵⁰ *Id.*

⁷⁵¹ Ex. MP-26 at 28-29 (Supinski Rebuttal); see Evid. Hearing Tr. at 197-98 (Supinski) (maintaining that the net present value of the levelized pricing stream would be substantially higher because it would be

503. Third, Minnesota Power asserted a levelized pricing alternative would have been significantly more expensive on a net present value basis as compared to the CDA because of how South Shore, or any other bidder, would have needed to structure such a PPA-style proposal to accommodate risk shifts.⁷⁵²

504. Ultimately, the Company stated that it declined to engage in such an exercise for two primary reasons. First, it was clear that such updated assumptions would result in an overall more expensive proposal on a net present value basis, which would be less beneficial to customers. Second, because no levelized NTEC proposal was bid into Minnesota Power's Dispatchable Capacity RFP, it would be necessary to develop new cost inputs and assumptions based on such levelized pricing outside the context of a competitive bidding process.⁷⁵³

505. Lastly, the Company argued that LPI is merely seeking more analysis for the sake of further delay, and is ignoring Minnesota Power's explanations why the levelized cost structure proposal is neither helpful nor necessary.⁷⁵⁴

D. Public Interest Analysis

506. The three affiliated interest agreements, discussed above, are intended to effectuate the construction and operation of the NTEC plant as well as Minnesota Power's proposed 250 MW NTEC purchase.

507. Pursuant to Minn. Stat. § 216B.48, subd. 3, these affiliated interest agreements can only be approved by the Commission if Minnesota Power demonstrates that the agreements are "reasonable and consistent with the public interest."

508. Approval of these affiliated interest agreements is only consistent with the public interest if the Company has demonstrated that the proposed 250 MW NTEC purchase is needed and reasonable.

509. Because the Administrative Law Judge concluded above that the Company has not met its burden to demonstrate that the proposed 250 MW NTEC purchase is needed and reasonable, the Administrative Law Judge concludes that the Company has failed to demonstrate that the proposed affiliated interest agreements are consistent with the public interest.⁷⁵⁵

necessary to import different assumptions because of the risk shifting that exists in a levelized pricing stream); Minnesota Power Initial Br. at 81.

⁷⁵² Ex. MP-26 at 28-29 (Supinski Rebuttal); see Tr. at 197-98 (Supinski).

⁷⁵³ Minnesota Power's Initial Br. at 82.

⁷⁵⁴ Minnesota Power's Reply Br. at 5.

⁷⁵⁵ To the extent the Commission reaches a different conclusion as to whether the Company has demonstrated that the proposed NTEC purchase is needed and reasonable, the Administrative Law Judge recommends that the Commission find that the Affiliated Interest Agreements are in the public interest with the Department's Suggested Conditions and Compliance Requirements set forth in Attachment B to Minnesota Power's Initial Brief.

XIII. Other Issues

A. Development of a Demand Response Rider

510. In Minnesota Power's 2016 Rate Case Order dated March 12, 2018, the Commission directed Minnesota Power, LPI, and other stakeholders to develop a demand response rider and corresponding methodology for cost recovery, based on stakeholder input, for submission to the Commission. The Commission directed that the demand response issue be addressed either in the instant docket or in a new miscellaneous docket.⁷⁵⁶

511. The record in this proceeding is not sufficiently developed to make a determination on a demand response rider and corresponding methodology for cost recovery.⁷⁵⁷

512. In addition, both Minnesota Power and LPI have acknowledged that since the 2016 Rate Case Order referral, the parties have continued to engage in thoughtful informal discussions outside of this proceeding. Both parties acknowledged each party's commitment to continue working on this developing a demand response product.⁷⁵⁸

513. Moreover it is possible there are other persons and organizations beyond the parties to this proceeding who may wish to provide input on such a proposal.

514. For these reasons, the Administrative Law Judge recommends that the issue be addressed in a new miscellaneous docket.

B. Honor The Earth's Request for an Environmental Impact Statement

515. As discussed above in the summary of public comments, Honor the Earth requested that an Environmental Impact Statement be prepared for the proposed 250 MW NTEC purchase before any decision is made approving the affiliated interest agreements.⁷⁵⁹

516. The Administrative Law Judge makes no determination on the question of whether an Environmental Impact Statement is legally required for the proposed affiliated interest agreements because the issue not within the scope of this contested case proceeding. The issues in the proceeding were defined by the Notice and Order for Hearing issued on September 19, 2017 and by the Second Prehearing Order issued on December 12, 2017. To extent Honor the Earth wished to raise this legal issue, it could have filed a petition to intervene by the November 17, 2017 deadline and requested that the issue be considered during the prehearing process in early December 2017 when the issues for the proceeding were finalized.⁷⁶⁰ It chose not do

⁷⁵⁶ 2016 Rate Case at 115 (Order Point 72) (eDocket No. 20183-140963-01).

⁷⁵⁷ See MP-14 at 53-57 (Pierce Direct); Ex. MP-15 at 13-15 (Pierce Surrebuttal).

⁷⁵⁸ See LPI Initial Br. at 23-24; Minnesota Power's Initial Br. at 11-12.

⁷⁵⁹ Public Comment by Honor the Earth at 3-15 (eDocket No. 20185-143144-01).

⁷⁶⁰ See First Prehearing Order at 2, 3-5 (setting deadline for intervention and timing for finalizing the issues to be heard in this proceeding).

so. Instead, the group waited until March 23, 2018 to raise this legal issue in its public comment. As such, the issue was not raised in a timely manner and is outside the scope of this contested case proceeding.⁷⁶¹

517. Any Conclusions of Law more properly designated as Findings of Fact are hereby adopted as such.

Based on these Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS OF LAW

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. §§ 14.50, 216B.08, 216B.48 (2016).

2. The parties and the public received proper and timely notice of the hearings in this matter.

3. Minnesota Power is a “public utility” as defined by Minn. Stat. § 216B.02, subd. 4 (2016), because it operates facilities for furnishing electric service to the public in Minnesota.⁷⁶²

4. Public utilities are required to obtain Commission approval of contracts and arrangements with “affiliated interests” for “the furnishing of management, supervisory, construction, engineering, accounting, legal, financial, or similar services” and “for the purchase, sale, lease, or exchange of any property, right, or thing, or for the furnishing of any service, property, right, or thing, other than those above enumerated, . . .”⁷⁶³

5. An “affiliated interest” agreement is not valid or effective without written approval of the Commission.⁷⁶⁴

6. The Commission “shall approve [an affiliated interest agreement] only if it clearly appears and is established upon investigation that it is reasonable and consistent with the public interest.”⁷⁶⁵

7. The term “affiliated interests” includes an unregulated affiliate of the public utility.⁷⁶⁶

⁷⁶¹ See Second Prehearing Order, Final Issues List.

⁷⁶² See Minn. Stat. § 216B.02, subd. 4 (2016).

⁷⁶³ Minn. Stat. § 216B.48, subd. 3 (2016).

⁷⁶⁴ *Id.*

⁷⁶⁵ *Id.*

⁷⁶⁶ *Id.*, subd. 1.

8. The Assignment of Rights Agreement (Construction Agent),⁷⁶⁷ the Assignment of Rights Agreement (Operating Agent),⁷⁶⁸ and the CDA⁷⁶⁹ are contracts between Minnesota Power and an affiliate, South Shore. These affiliated interest agreements require Commission approval to be effective because they involve the furnishing of applicable services by and to Minnesota Power and South Shore, and the purchase of capacity from NTEC.

9. Minnesota Power has failed to establish that approval of these affiliated interest agreements is consistent with the public interest because it has failed to demonstrate that the underlying 250 MW NTEC purchase is needed and reasonable.⁷⁷⁰

10. As explained in detail above, the Company's consideration of alternatives was inadequate to demonstrate that the proposed 250 MW NTEC purchase is needed and reasonable for meeting its customers' capacity and energy needs.

11. The Company has also failed to establish that the 250 MW NTEC purchase is needed and reasonable for dispatchability purposes.

12. Nor has the Company established that the proposed 250 MW NTEC purchase is consistent with the requirements of Minn. Stat. § 216B.2422 and Minn. Stat. § 216.243, subd. 3a because its alternatives analysis was biased in favor of NTEC.

13. Any Findings of Fact more properly designated as Conclusions of Law are hereby adopted as such.

Based upon these Conclusions of Law, and for the reasons explained in the accompanying Memorandum, the Administrative Law Judge makes the following:

⁷⁶⁷ The Assignment of Rights Agreement (Construction Agent), dated July 28, 2017, is between South Shore and Minnesota Power. Under this agreement, South Shore assigns to Minnesota Power the right to act as the Operating Agent for NTEC pursuant to Section 3.7.5 of the D&C Agreement. Ex. MP-4, App. D (Petition).

⁷⁶⁸ The Assignment of Rights Agreement (Operating Agent), dated July 28, 2017, is between South Shore and Minnesota Power. Under this agreement, South Shore assigns to Minnesota Power the right to act as the Operating Agent for NTEC pursuant to Section 4.7.5 of the O&O Agreement. Ex. MP-4, App. E (Petition).

⁷⁶⁹ Ex. MP-5, App. H (Unit Contingent Capacity Dedication Agreement between South Shore and Minnesota Power).

⁷⁷⁰ Because the Administrative Law Judge has concluded that the affiliated interest agreements are not consistent with the public interest, there is no need to address whether the related, proposed revisions to Minnesota Power's FPE Rider are in the public interest under Minn. Stat. § 216B.16, subd. 7(3) or whether the proposed variances to the FPE Rider are consistent with Minn. R. 7829.3200. Similarly, there is no need to address whether the guaranties by Minnesota Power referenced in the O&O are subject to the requirements of Minn. Stat. § 216B.40. Or, whether the affiliated interest agreements are subject to the requirements of Minn. Stat. § 216B.50. See Second Prehearing Order, Final Issues List, Issues 3-5.

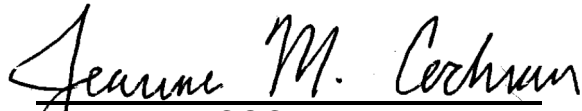
RECOMMENDATION

Based on the Findings of Fact and Conclusions of Law, the Administrative Law Judge respectfully recommends:

1. The Commission issue an order denying Minnesota Power's request for approval of the Assignment of Rights Agreement (Construction Agent), the Assignment of Rights Agreement (Operating Agent), and the CDA because the Company has not demonstrated that these affiliated interest agreements are consistent with the public interest.

2. Minnesota Power, LPI, and other stakeholders continue to work to develop a demand response rider and corresponding methodology for cost recovery for submission to the Commission. The Commission open a new miscellaneous docket to address the issue.

Dated: July 2, 2018


JEANNE M. COCHRAN
Administrative Law Judge

Reported: Transcribed

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the time frames established in the Commission's rules of practice and procedure, Minn. R. 7829.2700, .3100 (2017), unless otherwise directed by the Commission. Exceptions should be specific and stated and numbered separately. Oral argument before a majority of the Commission will be permitted pursuant to Minn. R. 7829.2700, subp. 3. The Commission will make the final determination of the matter after the expiration of the period for filing exceptions, or after oral argument, if an oral argument is held.

The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge's recommendations. The recommendations of the Administrative Law Judge have no legal effect unless expressly adopted by the Commission as its final order.

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Petition
for Approval of the Energy*Forward*
Resource Package

**ATTACHMENT A:
SUMMARY OF PUBLIC COMMENTS**

A public hearing was held on February 28, 2018, in Duluth, Minnesota, to take public comment on the proposed project. The following persons appeared at the public hearing on behalf of the parties and the Commission:

David R. Moeller and Julie I. Pierce, Minnesota Power, appeared on behalf of Petitioner Minnesota Power (MP or the Company).

Peter E. Madsen, Assistant Attorney General, appeared on behalf of the Department of Commerce, Division of Energy Resources (Department or DOC-DER).

Leigh Currie and Gretel Lee, Minnesota Center for Environmental Advocacy, appeared on behalf of Fresh Energy, Sierra Club, Wind on the Wires, and the Minnesota Center for Environmental Advocacy (collectively, the Clean Energy Organizations or CEOs).

Sean Stalpes, Commission Staff, was present on behalf of the Commission.

There was no appearance by the Office of the Attorney General, Residential Utilities and Antitrust Division, or the Large Power Intervenors (LPI).

In addition to the public hearing, the public had an opportunity to submit written public comments. The public comment period closed on March 23, 2018 at 4:30 p.m. as provided in the Notice of Public Hearing issued by the Commission on February 20, 2018.⁷⁷¹ Written comments were filed in the Commission's electronic docket (eDocket) system.

SUMMARY OF PUBLIC COMMENT

1. Over 1,500 written public comments were received by the March 23, 2018 deadline set by the Public Utilities Commission. In addition, over 20 individuals provided oral comments at the public hearing held on February 28, 2018.

⁷⁷¹ Notice of Public Hearing (Feb. 20, 2018) (eDocket No. 20182-140293-01).

2. All comments made at the public hearings or submitted in writing were fully considered. The following accurately summarizes the topics raised, although not all persons raising the topic are individually identified.⁷⁷²

I. General Opposition to the Proposed Plant and the Company's Proposed 250 Megawatt (MW) Purchase

3. The majority of the comments received were in opposition to the Nemadji Trail Energy Center (NTEC) natural gas plant and MP's proposed 250 MW purchase from the NTEC plant. Many people commented that the purchase is not needed to meet electricity needs. These commenters maintain that MP could meet demand by increasing energy efficiency and investing in renewable energy alternatives, such as wind and solar.

4. The majority of comments urged MP to move more aggressively toward 100 percent renewable energy by investing in wind, solar and energy savings, instead of a new fossil fuel plant.

5. Many of those who commented object to the fact that the gas will be derived from hydraulic fracturing (fracking). These commenters maintain that fracking damages the environment by contributing to water and air pollution.

6. Over 1,400 people submitted written comments using language from a form letter drafted by the Sierra Club in opposition to the proposed plant.⁷⁷³ The letter asserts that the proposed "fracked gas plant" is "risky for Minnesotans' health, climate and pocketbooks." The letter maintains that communities impacted by fracking have seen flammable water from toxic chemicals, increases in earthquakes from mining, and increased air pollution. The letter states that instead of investing in more "dirty fuels," MP should invest in renewable energy, like wind and solar along with energy savings, to meet Minnesota's greenhouse gas reduction goals. The letter also contends that MP has not shown that the gas plant is needed to meet electricity needs and warns that customers will be on the hook for \$350 million for a plant that may not be needed. The letter urges the Commission to reject the proposal to protect MP's customers and the environment.⁷⁷⁴

7. Of the approximately 1,400 people who submitted letters using the Sierra Club language, approximately 273 added personal notes.

⁷⁷² The citations in the footnotes below are to written comments filed in the Commission's eDockets system except where a public hearing transcript citation is provided. Most of the written comments received were in email format. A relatively small number of mailed letters were received. Written comments were efiled in the eDockets system either by the Commission or the Office of Administrative Hearings.

⁷⁷³ See Public Comments filed on March 22, 2018 and March 23, 2018 (eDockets Nos. 20183-141286-01, 20183-141288-01, 20183-141291-01, 20183-141292-01, 20183-141322-01, 20183-141298-01).

⁷⁷⁴ See, e.g., Public Comments filed on March 22, 2018 (eDockets No. 20182-141288-01).

A. Need for the Plant/Purchase Not Demonstrated

8. Several people stated that they believe the plant is unnecessary.⁷⁷⁵ For example, Andrew Streitz stated that he opposes MP's proposed new gas plant because "it appears to be unnecessary due to excess capacity."⁷⁷⁶ Mr. Streitz also expressed concern that making such a large investment in gas now will preclude MP from investing in lower-cost, long-term renewable resources, such as wind and solar.⁷⁷⁷ Similarly, Sharon Kutter objected to the proposed plant based on the CEOs' expert opinion that MP will be in a position of "extreme excess capacity" if it acquires 250 mw capacity from the plant.⁷⁷⁸ Ms. Kutter stated that energy conservation, renewable energy, and energy storage are better options than the proposed plant.⁷⁷⁹

9. Ellyn Wiens also commented that the proposed gas plant is not needed to produce power at this time.⁷⁸⁰ She urged the Commission to reject the proposal.⁷⁸¹ Similarly, Doretta Reisenweber stated that the proposed plant is not needed because MP has the option of obtaining energy from the regional grid until more renewable sources become available.⁷⁸² Ms. Reisenweber maintained that MP is overstating how much energy it needs and she criticized MP for failing to adequately consider cheaper and cleaner renewable options, such as wind and solar.⁷⁸³

10. Chad Thomas commented that MP's data in support of the need for the plant is "dubious."⁷⁸⁴ He urged the Commission to reject the proposal. Mr. Thomas contended that approval of the proposed plant would benefit only the Company's shareholders and not MP's customers, the citizens of Minnesota, or the environment.⁷⁸⁵

11. The Citizens Utility Board of Minnesota (CUB) submitted written comments in opposition to the proposed plant.⁷⁸⁶ CUB advocates on behalf of Minnesota's residential and small business utility customers.⁷⁸⁷

12. CUB stated that ratepayer funds should only be invested in a large, long-term asset, such as this proposed plant, if the asset is absolutely necessary.⁷⁸⁸ CUB maintained, based on the testimony of witnesses for the Large Power Intervenors and the Clean Energy Organizations, that MP has not demonstrated a need for the power plant and has not adequately examined alternative resources that may be less

⁷⁷⁵ See, e.g., Comments by Jerry Pults, Jackie Holmbeck, Terry Olso, Askia Luminae (Mar. 23, 2018)(eDocket No. 20183-141298-01).

⁷⁷⁶ Comment by Andrew Streitz (Mar. 3, 2018) (eDocket No. 20183-140968-01).

⁷⁷⁷ *Id.*

⁷⁷⁸ Comment by Sharon Kutter (Mar. 10, 2018)(eDocket No. 20183-140968-01).

⁷⁷⁹ *Id.*

⁷⁸⁰ Comment by Ellyn Wiens (Feb. 28, 2018) (eDocket No. 20183-14047-01).

⁷⁸¹ *Id.*

⁷⁸² Comment by Doretta Reisenweber (Mar. 1, 2018) (eDocket No. 20183-140826-01).

⁷⁸³ *Id.*

⁷⁸⁴ Comment by Chad Thomas (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁷⁸⁵ *Id.*

⁷⁸⁶ Comment by CUB (Mar. 22, 2018) (eDocket No. 20183-41280-01).

⁷⁸⁷ *Id.*

⁷⁸⁸ *Id.*

expensive.⁷⁸⁹ According to CUB, with the continued cost decline of renewable energy and energy storage, it is likely alternative energy resources will prove less costly than natural gas within the expected useful life of the proposed power plant, running the risk that the plant will become a stranded asset.⁷⁹⁰

13. In November 2017, CUB conducted a poll to gauge public opinion about the proposed NTEC plant and the Company's requested general rate increase.⁷⁹¹ Of a random sample of 552 MP customers, 77 percent said they were not inclined to support building the plant, and 92 percent said they want MP to do a full analysis of energy options.⁷⁹² CUB stated that the poll also showed that MP customers are very sensitive to bill increases. Therefore, because the estimated \$350 million cost of the plant will be passed through to customer rates, CUB urges the Commission not to approve the proposed plant unless MP adequately demonstrates it is necessary.⁷⁹³

14. Linda Herron, a resident of Duluth, spoke at the public hearing in opposition to the proposed plant.⁷⁹⁴ Ms. Herron believes the proposed plant is not needed. Ms. Herron asserted that MP has overstated its electricity needs, over-estimated the cost of increased renewable energy, and failed to implement the energy savings opportunities of efficiency programs, such as the strategic energy management program used by large industrial customers.⁷⁹⁵ Ms. Herron maintained that MP must do more than just transition from coal to natural gas in order to meet Minnesota's greenhouse gas reduction goals.⁷⁹⁶ She stated that the plant will threaten clean air and water, and compromise Minnesota's greenhouse gas emission reduction goals by using fracked gas, a fossil fuel.⁷⁹⁷ According to Ms. Herron, MP must begin transitioning to renewable energy sources immediately.⁷⁹⁸ For all of these reasons, Ms. Herron urged the PUC to reject the proposed gas plant.⁷⁹⁹

15. Dennis Szymialis also spoke at the public hearing in opposition to the proposed plant.⁸⁰⁰ Mr. Szymialis believes that the plant is not needed.⁸⁰¹ He maintained that energy conservation policies and energy storage are the best ways to meet energy needs.⁸⁰² Mr. Szymialis expressed concern that the proposed gas plant is being built to power special projects such as the proposed PolyMet copper-nickel mine and not for the purpose of meeting the energy needs of the community.⁸⁰³ Mr.

⁷⁸⁹ *Id.*

⁷⁹⁰ *Id.*

⁷⁹¹ *Id.*

⁷⁹² *Id.*

⁷⁹³ *Id.*

⁷⁹⁴ Linda Herron, Public Hearing (Public Hrg.) Transcript (Tr.) at 37-39 (Feb. 28, 2018).

⁷⁹⁵ *Id.* at 38.

⁷⁹⁶ *Id.*

⁷⁹⁷ *Id.* at 37.

⁷⁹⁸ *Id.*

⁷⁹⁹ *Id.*

⁸⁰⁰ Dennis Szymialis, Public Hrg. Tr. at 39-41 (Feb. 28, 2018).

⁸⁰¹ *Id.* at 40.

⁸⁰² *Id.*

⁸⁰³ *Id.*

Szymialis also asserted that wind energy is not truly a “clean energy” given the large amount of copper used to generate wind turbine systems.⁸⁰⁴

16. Bill Mittlefehldt, a resident of Duluth and member of Minnesota Interfaith Power and Light, spoke at the public hearing in opposition to the proposed gas plant.⁸⁰⁵ Like others, Mr. Mittlefehldt believes MP has failed to demonstrate a need for the energy at this time.⁸⁰⁶ In addition, Mr. Mittlefehldt maintained that it is better for the environment and for future generations to invest in renewable energy sources instead of investing \$700 million in a gas power plant.⁸⁰⁷

17. Bret Pence, a member of Minnesota Interfaith Power and Light and resident of Duluth, also spoke at the public hearing in opposition to the proposed plant.⁸⁰⁸ Mr. Pence questioned whether there is a need for the plant. If it is determined that there is a need, Mr. Pence maintained that energy storage, energy efficiency and renewable energy options, such as wind and solar, can adequately meet the need.⁸⁰⁹ Mr. Pence also objected to expanding fossil fuel infrastructure in light of Minnesota’s greenhouse gas reduction goals.⁸¹⁰

B. Environmental Concerns/Desire for Increased Renewable Energy

18. Many people submitted comments in opposition to the proposed plant based on concerns about the environmental risks associated with fossil fuel energy and fracking in particular.⁸¹¹

19. Several people stressed the importance of protecting the environment by investing in clean renewable energy options such as wind and solar, instead of fracked gas.⁸¹² For example, Barb Kwam stated “there are good, viable, renewable energy

⁸⁰⁴ *Id.*

⁸⁰⁵ Bill Mittlefehldt, Public Hrg. Tr. at 45-48 (Feb. 28, 2018).

⁸⁰⁶ *Id.* at 45.

⁸⁰⁷ *Id.* at 46.

⁸⁰⁸ Bret Pence, Public Hrg. Tr. 65-67 (Feb. 28, 2018).

⁸⁰⁹ *Id.* at 65-66.

⁸¹⁰ *Id.* at 66.

⁸¹¹ See Comments by Barbara Edson, Dulcie Berkman, Patricia Wasser, Bonnie Dawson, Echo Brueberg, Karen Weiberg, Paula Kwakenat, Wendy O’Leary, Jane Moe, Cheryl Downey, Christine Nohre, Erin Enger, Joe Culver, Abbey Feola, Marla Vagts, Judy Helgen, Dakota Hoska, Laura Ross, Stephen Wiley, Myranda Zeglin, Cindy Bickel, Barbara Kaufman, Shirley Schwarze, Arlene and Paul Renshaw, Therese Jacobson, Sister Joy Barth (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸¹² See Comments by Evan Gedlinske, Gail Matthews, Margaret Parks, Meg Lee, Nick Stevens, Elaine Alcock, Karen McElrath, Pat Ament, Ben Wolfe, Neil Hall, Kelly Shaffer, Kimberly Ditz, James Faraday, Heidi Fletcher, Jennifer Paterson, Everett Dennis, Brielle Bierman, Cynthia Klinksiek Alexandra Berg, Lisa Arrowood, Nancy Root, Lucille Altemus, Jack Bohnhoff, Diane Glorvigen, Shawn Gardner, Lyle Goebel, Carol Roback, Amy Albert, Ann Miller, Elizabeth Weberg, Constance Jerome, Lori Knosalla, Nancy Peterson, Lisa Hensel, Matthew Smith, Peter Melka, Courtney Werk, Carol Dines, Martha Mueller, Douglas Westby, Sara Van De Veer, Cheri Roshon, Helen Paul, Kathleen McQuillan, Arlene and Paul Renshaw, Kevin Windhauser, Therese Jacobson, Nett Hart (Mar. 23, 2018)(eDocket 20183-141298-01); Abi Evans, Lori Dundek, Barbara Akre, Mary Maltese, Cindy Mueller, Chris Erickson, Yvette Schultenover, Karen Olson, Jeanne Wingenter, Laurel Zaepfel, Dorothy Hachmann, Pdon Pinkham, Nick Stevens, Julie Martin, Carol Roback, William Bennett, Terry McCarthy, Helen Paul, Andrew Larson

sources to tap without endangering our lakes and our water resources. There are too many risky unknowns with fracking. We don't want it here.”⁸¹³ Thomas Brinkman said: “Instead of planning more investments in dirty fossil fuels that will continue to threaten our health, climate and pocketbooks, Minnesota Power’s long term plan for generating electricity should include renewable energy and energy conservation.”⁸¹⁴

20. Brad Snyder, a science teacher and environmental educator, strongly urged the PUC to reject the proposed plant.⁸¹⁵ Mr. Snyder maintained that the plant will be bad for customers, human health and the environment.⁸¹⁶ Mr. Snyder asserted that the United States is reducing its dependence on fossil fuels and the PUC should likewise focus on environmentally friendly and cost-effective options, such as renewable energy and energy efficiency.⁸¹⁷

21. Jo Haberman, a resident of Duluth, spoke at the public hearing in opposition to the proposed plant.⁸¹⁸ Ms. Haberman stated that MP should be moving more quickly toward a goal of 100 percent renewable energy in order to address the climate crisis.⁸¹⁹ Ms. Haberman also maintained that the need for the plant has not been demonstrated.⁸²⁰ She contends that customers should not be stuck paying for a \$350 million dollar gas plant when renewable energy is becoming less expensive.⁸²¹ Ms. Haberman urged the PUC to reject the gas plant proposal to meet Minnesota’s greenhouse gas reduction goals and protect the safety of the environment and the health of the community.⁸²²

22. Norm Herron also spoke at the public hearing in opposition to the proposed plant.⁸²³ Mr. Herron objected to the fact that the proposed plant will be powered primarily by natural gas, a fossil fuel derived from hydraulic fracturing.⁸²⁴ Mr. Herron noted that methane, a main component of natural gas, is 25 times more potent in trapping heat in the atmosphere than carbon dioxide.⁸²⁵ Mr. Herron asserted that a recent study of gas wells in Weld County, Colorado by the National Oceanic and Atmospheric Administration (NOAA) found that four percent of the methane produced by the gas wells escaped into the atmosphere.⁸²⁶ According to Mr. Herron, the NOAA scientists found the emissions from the Weld County gas wells to be equal to the carbon

(Mar. 23, 2018) (eDocket No. 20183-141298-01); Christy Hammer (Mar. 12, 2018) (eDocket No. 20183-140968-01).

⁸¹³ Comment by Barb Kwam (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸¹⁴ Comment by Thomas Brinkman (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸¹⁵ Comment by Brad Snyder (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸¹⁶ *Id.*

⁸¹⁷ *Id.*

⁸¹⁸ Jo Haberman, Public Hrg. Tr. at 34-35 (Feb. 28, 2018).

⁸¹⁹ *Id.* at 35.

⁸²⁰ *Id.*

⁸²¹ *Id.*

⁸²² *Id.* at 35.

⁸²³ Norm Herron, Public Hrg. Tr. 42-44 (Feb. 28, 2018).

⁸²⁴ *Id.* at 42.

⁸²⁵ *Id.*

⁸²⁶ *Id.* at 43.

emissions of one to three million cars.⁸²⁷ Mr. Herron expressed concern about the other pollutants released by fracking, including benzene, and the effect these pollutants have on people's health.⁸²⁸ Given the pollution and health risks associated with natural gas fracking, Mr. Herron urged the PUC to reject the NTEC proposal. Mr. Herron maintained that storage of excess energy can meet energy demand and smooth out the variability of wind and solar power.⁸²⁹

23. Ray Skip Sandman, a resident of Duluth, spoke at the public hearing in opposition to the proposed plant.⁸³⁰ Like many others who commented, Mr. Sandman opposes the proposed plant for climate and environmental reasons.⁸³¹ Mr. Sandman also objected to the fact that the plant will be built in Wisconsin. Mr. Sandman maintained that Wisconsin Governor Scott Walker and the corporations that support him, are anti-environment and anti-union.⁸³² Mr. Sandman urged the PUC to reject the proposal and instead support renewable energy options in Minnesota.⁸³³ In addition, Mr. Sandman believes that the temporary construction jobs that will be created are not enough to support approving the project.⁸³⁴ Instead, he urged the PUC to invest in a green energy economy.⁸³⁵

24. Like Mr. Sandman, Mike Kuitu, objected to the proposed plant being built in Wisconsin.⁸³⁶ Mr. Kuitu stated at the public hearing that he opposes the proposed plant for environmental reasons, but that he also resents MP's proposal to invest in a plant in Wisconsin.⁸³⁷ Mr. Kuitu suggested that MP is proposing to construct the plant in Wisconsin in order to avoid tougher environmental regulations in Minnesota.⁸³⁸

25. Bruno Giovannoni, a resident of Duluth, spoke at the public hearing in opposition to the proposed plant.⁸³⁹ Mr. Giovannoni stated that MP's long-term plan for generating electricity includes a majority investment in dirty fossil fuels and fracked gas that will continue to harm the environment and customers' health.⁸⁴⁰ Mr. Giovannoni urged the PUC to reject the proposed plant and to instead plan for a 100 percent renewable energy future.⁸⁴¹

⁸²⁷ *Id.*

⁸²⁸ *Id.*

⁸²⁹ *Id.*

⁸³⁰ Ray Skip Sandman, Public Hrg. Tr. at 51-52 (Feb. 28, 2018).

⁸³¹ *Id.* at 51.

⁸³² *Id.*

⁸³³ *Id.* at 52.

⁸³⁴ *Id.*

⁸³⁵ *Id.*

⁸³⁶ Mike Kuitu, Public Hrg. Tr. at 52-54 (Feb. 28, 2018).

⁸³⁷ *Id.* at 53.

⁸³⁸ *Id.*

⁸³⁹ Bruno Giovannoni, Public Hrg. Tr. at 60-62 (Feb. 28, 2018).

⁸⁴⁰ *Id.* at 60.

⁸⁴¹ *Id.*

26. The Northern Minnesota Volunteers of the Citizens' Climate Lobby (Volunteers) submitted a letter signed by 20 individuals.⁸⁴² The Citizens' Climate Lobby is a national non-profit organization with volunteers who meet regularly with elected officials across the country to encourage bipartisan cooperation toward enactment of carbon fee and dividend legislation to address climate change.⁸⁴³ In its letter, the Volunteers maintained that the proposed plant is contrary to MP's stated goal of reducing carbon emissions and is environmentally irresponsible.⁸⁴⁴ According to the Volunteers, there is no valid argument to justify increased greenhouse gas emissions when environmentally responsible and cost-effective wind and solar alternatives are available.⁸⁴⁵ The Volunteers urged the PUC to reject the proposed plant and to direct MP to focus on alternatives that eliminate greenhouse gas emissions in future proposals.⁸⁴⁶

27. Jeffrey Schroeder conceded that a gas plant is better than a coal powered plant, but objected to the proposal's long term commitment to using more fossil fuels.⁸⁴⁷ Mr. Schroeder suggested that the PUC require MP to decommission its coal plants before approving the proposed gas plant.⁸⁴⁸

C. Honor the Earth Comments

28. In written comments submitted on March 23, 2018, Honor the Earth urged the PUC to deny MP's petition for approval of its gas plant proposal and affiliated interest agreements.⁸⁴⁹ If the Commission does not deny MP's petition, Honor the Earth requested the Commission complete an Environmental Impact Statement (EIS) to fully inform the record on the environmental impacts of the proposed plant, as well as any alternatives considered by the Commission.⁸⁵⁰

29. Honor the Earth asserted that the PUC may not approve the affiliated interest agreements without first requiring that an EIS be prepared.⁸⁵¹ Honor the Earth noted that the Minnesota Environmental Policy Act (MEPA)⁸⁵² requires a detailed EIS "[w]here there is potential for significant environmental effects resulting from any major government action."⁸⁵³ Honor the Earth contends that the proposed gas plant is "a major government action" that will have "significant environmental effects."⁸⁵⁴

⁸⁴² Comment by Northern Minnesota Volunteers of the Citizens' Climate Lobby (Mar. 14, 2018) (eDocket No. 20183-141015-01).

⁸⁴³ See Public Hrg. Tr. at 70 (Eric Enberg) (Feb. 28, 2018).

⁸⁴⁴ Comment by Northern Minnesota Volunteers of the Citizens' Climate Lobby (Mar. 14, 2018) (eDocket No. 20183-141015-01).

⁸⁴⁵ *Id.*

⁸⁴⁶ *Id.*

⁸⁴⁷ Comment by Jeffrey Schroeder (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁴⁸ *Id.*

⁸⁴⁹ Comment by Honor the Earth (Mar. 23, 2018) (eDocket No. 20185-143144-01).

⁸⁵⁰ *Id.* at 21.

⁸⁵¹ *Id.* at 3.

⁸⁵² Minn Stat. ch. 116D (2016).

⁸⁵³ Comment by Honor the Earth at 3 (citing Minn. Stat. § 116D.04, subd. 2a) (eDocket No. 20185-143144-01).

⁸⁵⁴ *Id.* at 4.

Specifically, Honor the Earth asserted that construction and operation of the proposed plant, located six miles from Duluth, will significantly and adversely impact: the air and water of the Duluth and Lake Superior area; the physical wellbeing of the people of Minnesota via health impacts caused by air pollution; the socioeconomic wellbeing of the people of Minnesota by directing ratepayer resources towards a major out-of-state power plant rather than to clean electric generation facilities and electricity storage facilities in Minnesota; and the climate of Minnesota due to the long-term commitment to a natural gas-fired facility that will produce significant greenhouse gas emissions for decades.⁸⁵⁵

30. Honor the Earth maintained that the fact that the proposed plant is located in Wisconsin does not exempt it from MEPA review.⁸⁵⁶ Honor the Earth noted that the MEPA defines “environment” broadly to include physical conditions existing “in the area that may be affected by a proposed project.”⁸⁵⁷ In addition, Honor the Earth pointed out that Minn. Stat. § 216B.48, subd. 3 (2017) requires the PUC to determine if approval of the affiliated interest agreements is “consistent with the public interest.”⁸⁵⁸ According to Honor the Earth, it would be inconsistent for the Commission to investigate whether approval of the affiliated agreements is in the public interest without analyzing the impacts of the proposed plant on Minnesota’s environment.⁸⁵⁹ Moreover, Honor the Earth maintained that both the Commission and MP have tacitly agreed that the proposed plant will have quantifiable adverse environmental impacts on Minnesota.⁸⁶⁰ In support of this claim, Honor the Earth noted the Commission’s September 19, 2017, decision requiring consideration of socioeconomic and environmental costs pursuant to the Commission’s externality process,⁸⁶¹ as well as MP’s assertions in its Petition that the proposed plant will reduce carbon emissions relative to coal-fired power.⁸⁶² Honor the Earth maintained that, based on the Commission’s actions and MP’s representations, it is appropriate for the Commission to consider the environmental impacts within Minnesota of the proposed out-of-state power plant.⁸⁶³

31. Honor the Earth further asserted that the PUC must evaluate alternatives to the proposed gas plant under the MEPA.⁸⁶⁴ Honor the Earth noted that the MEPA requires comparison of the environmental effects of reasonable alternatives to a proposed action as part of the EIS.⁸⁶⁵

32. Honor the Earth concluded that the PUC should not approve the affiliated interest agreements.⁸⁶⁶ Honor the Earth stated that MP has failed to demonstrate that

⁸⁵⁵ *Id.* at 5.

⁸⁵⁶ *Id.* at 7.

⁸⁵⁷ *Id.* at 7 citing Minn. R. 4410.0200, subp. 23 (2017).

⁸⁵⁸ *Id.* at 11.

⁸⁵⁹ *Id.* at 11 and 12.

⁸⁶⁰ *Id.* at 12.

⁸⁶¹ *Id.* at 12 (citing Commission’s externality order contained in Docket No. E999/CI-14-643).

⁸⁶² *Id.* (citing MP’s October 24, 2017, Petition for Approval of Gas Plant Proposal).

⁸⁶³ *Id.* at 12-13.

⁸⁶⁴ *Id.* at 14.

⁸⁶⁵ *Id.* at 15.

⁸⁶⁶ *Id.*

the proposed 250 MW NTEC purchase is needed or in the best interest of its customers.⁸⁶⁷ Honor the Earth agrees with LPI witness Brian Andrews that MP's modeling is flawed, biased, and exaggerates MP's need for capacity.⁸⁶⁸

33. Finally, Honor the Earth urged the Commission to investigate the potential impact of future pipeline expansions on MP's forecast of need given the large and frequently fluctuating pipeline power demands in Minnesota.⁸⁶⁹ Specifically, Honor the Earth suggested that the Commission evaluate the potential impact of Enbridge's Lines 3 and 61 Twin on MP and consider how these pipelines affect the regional grid and the need for generation or storage to follow pipeline loads.⁸⁷⁰

D. Proposed Plant's Effect on North Shore and Tourism

34. Several people urged the PUC to reject the proposal in order to protect Lake Superior and to maintain Northern Minnesota's pristine environment now and for future generations.⁸⁷¹ Kristine Sieger stated that "Lake Superior is a natural beauty and must be protected."⁸⁷² Brandy Norman-Wiebenga called the plant proposal "disgraceful" and urged the PUC to protect "our cherished natural resources."⁸⁷³ Likewise, Myranda Zeglin implored the PUC not to ruin the beauty of Minnesota by approving the proposed fracked gas plant.⁸⁷⁴ And Mary Steponkus expressed concern that approval of the plant "will have disastrous effects on the loveliness that we call Lake Superior."⁸⁷⁵

35. Some commenters expressed concern about the effect the proposed plant may have on Northern Minnesota's tourism industry.⁸⁷⁶ For example, Sarah Strain said: "Lake Superior and the North Shore is a major tourist destination and helps support many small towns on and around the North Shore. A fracked gas plant along the North Shore would detract from the area's appeal, hurting the growing tourism industry. Please do not jeopardize the livelihoods of hundreds of North Shore Minnesotans by building this plant. Help keep the North Shore a Minnesota tourism destination by

⁸⁶⁷ *Id.* at 16.

⁸⁶⁸ *Id.*

⁸⁶⁹ *Id.* at 17.

⁸⁷⁰ *Id.* at 21.

⁸⁷¹ See Comments by Myranda Zeglin, Cindy Bickel, Barbara Kaufman, Roslyn Hjermstad, April Narcisse, Jerry Pults, Sheila Winderlich, Susan Wick, Cheryl Engel, Corlissa Greening, Tracy Trembley, Julie Rozman, Barbara Little, Jim Adams, Lisa Arrowood, Danielle Heiny, Ann Follett, Mark Johnson, Wendi Meath-Nelson, Lisa Boland, Lisa and Rolf Lund, Ramona Moeller, Amy Goerwitz, Joey Nelson, Cindy Strelow, Paula Yankee, Suzanne Dunn, Bruce Teigen, Kevin Baierl, Susan Denio, Ben Thorp, Marjorie Huebner, Kristine Sieger, Judy Epstein, Cin Carlson, Doretta Reisenweber, Greta Gaard, Laura Ross, Pat Dokken, Sue O'Donnell, Jean Fleischhacker, Jane Nechville, Katherine Noble, Pat Steves and, Cheryl Downey, Carole Gealow, Carole Festvog, Molly Raske, Kathleen Ricketts (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁷² Comment by Kristine Sieger (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁷³ Comment by Brandy Norman-Wiebenga (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁷⁴ Comment by Myranda Zeglin (March 23, 2018) (eDocket No. 20183-141298-01).

⁸⁷⁵ Comment by Mary Steponkus (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁷⁶ See Comments by Roslyn Hjermstad, Ann Follett, Jon Hayman, Shirley Evans (Mar. 23, 2018) (eDocket No. 20183-141298-01).

rejecting the proposed gas plant.”⁸⁷⁷ Roslyn Hjermstad noted that northern Minnesota’s clean air and water are huge tourist attractions.⁸⁷⁸ She urged the PUC not to allow a fossil-fuel burning facility in “cabin country.”⁸⁷⁹ Likewise, both Cheryl Engel and Julie Rozman implored the PUC to protect northern Minnesota’s pristine environment by rejecting the proposed plant.⁸⁸⁰

36. Gail Frethem described the proposal as “terrible” and likened it to an assault on the clean Lake Superior shoreline.⁸⁸¹ Ann Follett described Minnesota’s North Shore as a “unique treasure” and asked the PUC to protect it and North Shore tourism by rejecting the proposed plant.⁸⁸²

E. Corporate Profit Motivation

37. Several people suggested that the proposal was motivated by corporate greed and would only benefit MP shareholders at the expense of the environment.⁸⁸³

38. For example, Chad Thomas commented that approval of the proposed plant would only benefit MP and its shareholders and not MP’s customers.⁸⁸⁴ Tom Carlson asserted that the only motivation for fracked gas is corporate and individual greed.⁸⁸⁵ Pamela Syverson urged the PUC to put protecting the environment ahead of corporate profits.⁸⁸⁶

F. Negative Health Effects, Risk of Accidents and Earthquakes, Lower Property Values

39. Several people object to the proposed gas plant based on concerns that fracking causes negative health effects, including asthma and increased incidences of certain cancers.⁸⁸⁷ A few others object to the proposed plant based on concerns that fracking increases the risk of earthquakes.⁸⁸⁸

⁸⁷⁷ Comment by Sarah Strain (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁷⁸ Comment by Roslyn Hjermstad (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁷⁹ *Id.*

⁸⁸⁰ Comments by Cheryl Engel and Julie Rozman (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁸¹ Comment by Gail Frethem (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁸² Comment by Ann Follett (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁸³ See Comments by Elizabeth Buchanan, Kathy Peterson, Suzanne Birch, Peggy Meisch, Margaret Brennan, Robert Johnson, Polly Calhoun, Tom Carlson, Maria Jacobson, Corlissa Greening, Pamela Novotny, Kathleen Dougherty, David Knightly, Doreen Lindahl (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁸⁴ Comment by Chad Thomas (March 23, 2018) (eDocket No. 20183-141298-01).

⁸⁸⁵ Comment by Tom Carlson (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁸⁶ Comment by Pamela Syverson (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁸⁷ See Comments by MaryPat Coyne, Janet Comer, Lucille Osojnicki, Joyce Kramer, Tracy Kugler, Carol Ashley, Danielle Heiny, Kate Dougherty, Luis Olvera, Dulcie Berkman, Mary Gleason, Wendy O’Leary, Christine Nohre (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁸⁸ See Comments by MaryPat Coyne, Hubert Hix, Deborrah Schlinger, Lila Talvitie-Zamora, Angela Hansen (Mar. 23, 2018) (eDocket No. 20183-141298-01).

40. In her comment opposing the proposed plant, Tracy Kulger cited to a recent report that examined numerous peer-reviewed articles detailing increased risks for cancer, asthma, birth defects, and other health problems related to fracking.⁸⁸⁹ Ms. Kugler maintained that the potential risks to public health and the increased greenhouse gas emissions are solid reasons to reject the proposed gas plant.⁸⁹⁰ Lucille Osojnicki also expressed concern that the proposed plant may harm public health in ways that may be worse than the harm caused by pollution from taconite mining in Minnesota's North Shore area.⁸⁹¹

41. Finally, Vickie Owens, a resident of Superior, expressed concern that the proposed plant would lower property values in the area.⁸⁹² Ms. Owens pointed out that depressed property values would offset the claimed positive impacts for residents who live near the plant.⁸⁹³ Ms. Owens also objected to the proposed plant out of concern that a serious accident or terrorist attack at the plant could kill or injure hundreds of people.⁸⁹⁴

G. Bad Investment/Outdated Technology

42. Several commenters urged the PUC to reject the proposal as a bad investment. They maintained that the future of energy lies in clean renewable sources, and they insisted that these renewable sources, such as wind and solar, are becoming more plentiful and cost effective.⁸⁹⁵

43. Julius Salinas, a resident of Esko, Minnesota, stated at the public hearing that he is opposed to the proposed plant because it is an investment in fossil fuel.⁸⁹⁶ Mr. Salinas maintained that customers' energy needs can be more economically met using energy efficiency techniques and sustainable renewable energy.⁸⁹⁷ Mr. Salinas asserted that MP needs to be more forward-looking and invest in a sustainable and secure energy infrastructure that uses wind, solar and hydro power.⁸⁹⁸ According to Mr. Salinas, the proposed gas plant's use of 100-plus-year-old technologies is "Jurassic." In addition, he maintained that the fracking procedures employed to extract the gas threaten water supplies, increase seismic events, and negatively impact citizens' health and property values.⁸⁹⁹

⁸⁸⁹ Comment by Tracy Kugler (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁹⁰ *Id.*

⁸⁹¹ Comment by Lucille Osojnicki (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁹² Comment by Vickie Owens (Mar. 1, 2018) (eDocket No. 20183-140747-01).

⁸⁹³ *Id.*

⁸⁹⁴ *Id.*

⁸⁹⁵ Comments by Gary Hanson, Emer Griffin, Tim King, Mark Fitzpatrick, Jennifer Amy-Dressler, Rebecca Krasky, Joanne Sieck, Mary Vlazny, Dean Prekker (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁸⁹⁶ Julius Salinas, Public Hrg. Tr. at 48-50 (Feb. 28, 2018).

⁸⁹⁷ *Id.* at 48-49.

⁸⁹⁸ *Id.* at 49.

⁸⁹⁹ *Id.* at 49-50.

44. Eric Enberg, a member of Citizens' Climate Lobby, spoke at the public hearing in opposition to the proposed plant.⁹⁰⁰ Citizens' Climate Lobby is a national non-profit organization with volunteers who meet regularly with elected officials across the country to encourage bipartisan cooperation toward enactment of carbon fee and dividend legislation to address climate change.⁹⁰¹ Mr. Enberg pointed out that if carbon pricing legislation prevails, the price of gas-generated power will rise, making wind and solar power more cost-effective.⁹⁰² Given this, Mr. Enberg maintained that MP should invest in renewable energy options. According to Mr. Enberg, renewable energy options combined with energy efficiency would decrease the need for greater energy capacity.⁹⁰³ Moreover, because MP makes much of its revenue from the guaranteed return granted it by the PUC on remaining depreciation, Mr. Enberg asserted that MP's shareholders would benefit by investing in renewables, which have a much high capital expense than fossil fuel plants.⁹⁰⁴ In closing, Mr. Enberg urged the PUC not to lock MP's customers into an unnecessary power plant that will become increasingly expensive and irrelevant.⁹⁰⁵

45. Several people stated that the plant is not needed and would be a bad investment.⁹⁰⁶ Harley Blake stated that the proposal "is a waste of money and resources, which would be better used for renewable energy sources . . ."⁹⁰⁷ Gary Hansen asserted that "it is totally irresponsible to consider support of fracking and to invest in additional fossil fuel energy development when solar and wind are becoming so viable!"⁹⁰⁸ Abbey Feola noted the "enormous investments needed to build a power plant, the uncertain financial future of fossil fuels, and the need to transition away from fossil fuels" as reasons to reject the proposed plant.⁹⁰⁹ Ms. Feola maintained that Minnesota is better off "investing in smaller, sustainable energy sources."⁹¹⁰

46. Several other people objected to the proposal based on what they see as an investment in an outdated technology.⁹¹¹ For example, Judy Urban stated it is irresponsible to build "an unneeded plant for soon to be obsolete technology" instead of increasing investment in renewable energy options.⁹¹² Similarly, Juan Izar stated that "sinking money into fossil fuel powered infrastructure is short-sighted and irresponsible."⁹¹³ And Janet Leadholm stated: "Leave fossil fuels behind. It's time has

⁹⁰⁰ Eric Enberg, Public Hrg. Tr. at 70-72 (Feb. 28, 2018).

⁹⁰¹ *Id.* at 70.

⁹⁰² *Id.* at 71.

⁹⁰³ *Id.* at 72.

⁹⁰⁴ *Id.* at 73.

⁹⁰⁵ *Id.*

⁹⁰⁶ See Comments by Joan Phillips, Jackie Holmbeck, Laura Nereng (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁹⁰⁷ Comment by Harley Blake (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁹⁰⁸ Comment by Gary Hanse (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁹⁰⁹ Comment by Abbey Feola (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁹¹⁰ *Id.*

⁹¹¹ See, e.g., comments by Elaine Alcock, Nick Stevens, Sara Sangiovanni, Yvette Schultenover, Terri Dugan (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁹¹² Comment by Judy Urban (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁹¹³ Comment by Juan Izar (Mar. 23, 2018) (eDocket No. 20183-141298-01).

come and gone. Now is the time to invest in renewable energy, which provides a cleaner, healthier, more sustainable future. Unlike fossil fuels, the more you invest in renewable energy, the more cost effective it becomes.”⁹¹⁴

47. Geoffrey Witrak commented that the rapidly evolving economics of renewable energy have equaled or eclipsed natural gas for electricity generation.⁹¹⁵ According to Mr. Witrak, a recent article in the *Star Tribune* stated that unsubsidized wind power in Minnesota currently yields a slightly cheaper cost per megawatt hour of electricity generation than natural gas.⁹¹⁶ Mr. Witrak maintained that this cost differential in favor of wind power will only grow greater by the time MP’s proposed gas plant is operational in 2025.⁹¹⁷ Given this, Mr. Witrak asserted that MP should invest in renewable energy sources instead of what will soon be non-competitive power generation largely paid for by residential ratepayers.⁹¹⁸ Mr. Witrak also stated that utilities are ethically obligated to invest in non-carbon based power and work towards greenhouse gas reduction for the sake of the environment and future generations.⁹¹⁹

48. Jason Tuttle submitted a comment recommending MP invest in Small Module Reactors (SMR) technology instead of natural gas.⁹²⁰ Mr. Tuttle asserted that SMRs can generate clean electrical power without having to rely on wind and sun to operate.⁹²¹

H. Increased Customer Rates

49. A number of people expressed concern that the proposed plant will result in increased customer rates. For example, JoAnn Sramek complained that MP’s rates continue to increase making it difficult for retirees and other persons on fixed incomes to afford to heat their homes.⁹²² Said Ms. Sramek, “I am very disappointed that you are even thinking of building a fracked gas plant. How are retirees supposed to survive even if they have some savings? It costs Big Bucks to live in MN’s climate.”⁹²³ Similarly, Karen Holden submitted a comment in opposition to the proposed plant stating that she can “hardly afford her [electric] bill now.”⁹²⁴ Ms. Holden urged the PUC to reject MP’s plan to add “an unnecessary gas plant at consumers’ expense.”⁹²⁵

50. Buddy Robinson spoke at the public hearing on behalf of the Minnesota Citizens Federation Northeast, formerly known as the Senior Coalition and the

⁹¹⁴ Comment by Janet Leadholm (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁹¹⁵ Comment by Geoffrey Witrak (Mar. 5, 2018) (eDocket No. 20183-140968-01).

⁹¹⁶ *Id.*

⁹¹⁷ *Id.*

⁹¹⁸ *Id.*

⁹¹⁹ *Id.*

⁹²⁰ Comment by Jason Tuttle (Mar. 1, 2018) (eDocket No. 20183-140747-01).

⁹²¹ *Id.*

⁹²² Comment by JoAnn Sramek (Mar. 23, 2018) (eDocket No. 20183-141298-01).

⁹²³ *Id.*

⁹²⁴ Comment by Karen Holden (Mar. 2, 2018) (eDocket No. 140747-01).

⁹²⁵ *Id.*

Minnesota Senior Federation Northeast.⁹²⁶ Minnesota Citizens Federation Northeast advocates on behalf of the financial interest of residential ratepayers.⁹²⁷ Mr. Robinson maintained that the proposed plant is not needed.⁹²⁸ He asserted that electricity may be purchased from the grid if needed, and that, rather than investing in fossil fuels, MP should be investing in cost-effective wind, solar and storage.⁹²⁹ Mr. Robinson objected to ratepayers having to pay for the \$350 million investment.⁹³⁰ He suggested that the investment is motivated in part to maximize profits for MP's shareholders.⁹³¹

51. Another advocacy group known as "Do Gooder" submitted copies of a form letter signed by approximately 20 customers in opposition to the proposed NTEC plant. The letter states that these customers cannot afford to pay more for electricity and the customers urges the PUC to reject the proposed plant and support investment in less expensive renewable options to help keep customers' utility bills down.⁹³²

II. General Support for the Company's Proposed Purchase of NTC 250 Megawatts

52. A number of businesses, organized labor, and economic development interests expressed support for the proposed gas plant and power purchase. These commenters maintained that gas is a clean burning resource and a better alternative than coal. They insisted that the proposed purchase will diversify the Company's energy options and will be a necessary source of generation when alternatives such as wind and solar are not available. These interest groups also extolled the number of jobs that will result from the construction and operation of the plant as well as the estimated \$1 million in annual tax revenue.

A. Comments from Mayor Jim Paine, Local Chambers of Commerce and Economic Development Groups

53. Jim Paine, Mayor of Superior, Wisconsin, spoke at the public hearing in support of the proposed plant.⁹³³ Mayor Paine asserted that the proposed plant is in the best interest of the community and that it will be good for the environment and the region's economy.⁹³⁴ Mayor Paine stated that he is satisfied the proposed plant will provide safe and affordable energy to northwest Wisconsin and northeast Minnesota.⁹³⁵ And he maintained the plant represents a move in the right direction towards providing more renewable energy to the grid.⁹³⁶ Mayor Paine also noted that the proposed

⁹²⁶ Comment by Buddy Robinson Tr. at 54-56 (Feb. 28, 2018).

⁹²⁷ *Id.* at 54.

⁹²⁸ *Id.* at 55.

⁹²⁹ *Id.* at 56.

⁹³⁰ *Id.*

⁹³¹ *Id.*

⁹³² See Comments by Lydia Goustin, Tim King, Mike and Jane Conrad, Barb Moore (Mar. 3, 2018) (eDocket No. 20183-140968-01).

⁹³³ Jim Paine, Public Hrg. Tr. at 62-6 (Feb. 28, 2018).

⁹³⁴ *Id.* at 62.

⁹³⁵ *Id.* at 63.

⁹³⁶ *Id.*

project is the single largest private investment in northwest Wisconsin, and he emphasized the economic benefit the community will reap in the number of construction and operation jobs the plant will provide.⁹³⁷ Mayor Paine closed his remarks by urging the PUC to approve the proposed plant.⁹³⁸

54. Taylor Pedersen, President and CEO of the Superior-Douglas County Area Chamber of Commerce, submitted a letter in support of the proposed plant on behalf of the Chamber and its Board of Directors.⁹³⁹ Mr. Pedersen stated that the proposal is “a step in the right direction to use renewable energies” and he maintains the proposed plant “will strengthen our grid stabilization in the region.”⁹⁴⁰ Mr. Pedersen also asserted that the proposed plant will create jobs and improve the region’s economy.⁹⁴¹ He noted that the proposed plant is projected to have “an estimated \$1 billion impact over twenty years, 260 jobs during construction, and 25 living wage jobs during operation.”⁹⁴² Mr. Pedersen maintained that the region needs this project and he believes the proposed gas plant is a positive step toward meeting energy diversification goals.⁹⁴³

55. David Ross, President and CEO of the Duluth Area Chamber of Commerce spoke at the public hearing in support of the proposed NTEC plant.⁹⁴⁴ Mr. Ross stated that the Twin Ports area will benefit from a “successful, vibrant, and strategically well-positioned utility.”⁹⁴⁵ According to Mr. Ross, the proposed project will “fortify MP’s transformation from coal to renewables,” while keeping the lights on “when the wind is not blowing, and the sun is not shining.”⁹⁴⁶ Mr. Ross also noted that those in the building trades will benefit from the 260 construction jobs the project is expected to create.⁹⁴⁷ In conclusion, Mr. Ross urged the Commission to allow the “needed, beneficial, environmentally-friendly, job-creating private investment to proceed.”⁹⁴⁸

56. Randy Lasky spoke at the public hearing in support of the proposed NTEC plant.⁹⁴⁹ Mr. Lasky is the President of Northspan Group, a private nonprofit business and community development organization serving northeast Minnesota and northwest Wisconsin.⁹⁵⁰ Mr. Lasky asserted that approval of the plant will bring MP closer to its goal of diversifying its energy mix to reduce carbon dioxide emissions.⁹⁵¹ Mr. Lasky noted that soon MP will have completed removal of coal fired generation capacity at

⁹³⁷ *Id.* at 63.

⁹³⁸ Tr. at 64.

⁹³⁹ Comment by Taylor Pedersen (Mar. 12, 2018) (eDocket No. 20183-141015-01).

⁹⁴⁰ *Id.*

⁹⁴¹ *Id.*

⁹⁴² *Id.*

⁹⁴³ *Id.*

⁹⁴⁴ David Ross, Public Hrg. Tr. at 22-23 (Feb. 28, 2018).

⁹⁴⁵ *Id.* at 22.

⁹⁴⁶ *Id.*

⁹⁴⁷ *Id.*

⁹⁴⁸ *Id.* at 23.

⁹⁴⁹ Randy Lasky, Public Hrg. Tr. at 32-33 (Feb. 28, 2018).

⁹⁵⁰ *Id.* at 32.

⁹⁵¹ *Id.*

three locations, including units at Taconite Harbor on the north shore of Lake Superior.⁹⁵² Mr. Lasky maintained that the 250 megawatts from the proposed plant will enable MP to support the addition of more solar and wind by 2025.⁹⁵³ According to Mr. Lasky, the proposed plant is a win-win opportunity for renewables, overall clean power generation, and the continuing delivery of safe, affordable, and reliable power.⁹⁵⁴

57. Jim Caesar also spoke at the public hearing in support of the proposed plant.⁹⁵⁵ Mr. Caesar is the Executive Director of the Development Association of Superior and Douglas County, Wisconsin.⁹⁵⁶ The Development Association advocates for and assists business expansion, creation, recruitment, and retention in Superior and Douglas County.⁹⁵⁷ Speaking on behalf of the Development Association's board of directors and its 130 member companies, Mr. Caesar strongly urged the PUC to approve the proposed plant based on the number of jobs, the estimated \$1 million in annual revenue, and the reliable low-cost energy the plant will provide.⁹⁵⁸ Mr. Caesar also spoke on behalf of the Superior and Douglas County Chamber of Commerce and indicated that the Chamber's board of directors likewise fully support the project.⁹⁵⁹

58. Brian Hanson, CEO of the Area Partnership for Economic Expansion (APEX), a private sector-led business and economic development organization, spoke at the hearing in support of the proposed plant.⁹⁶⁰ Mr. Hanson stated that the proposed plant promotes investment in the region by providing 260 construction jobs and up to 25 full-time permanent positions, and estimated tax revenue of \$1 million annually.⁹⁶¹ Mr. Hanson asserted that the plant will ensure efficient reliable energy for regional employers.⁹⁶² And he contended that, by acting as a backup for the ever expanding fleet of wind and solar resources obtained by MP and Dairyland, the proposed plant will reduce carbon emissions.⁹⁶³ Mr. Hanson urged the Commission not to turn its back on the jobs, tax revenues, and balanced portfolio of energy resources the proposed plant offers.⁹⁶⁴

B. Comments from Local Businesses and Unions

59. Todd Rothe also spoke at the public hearing in support of the proposed plant.⁹⁶⁵ Mr. Rothe is the owner of JR Jensen Construction, a company that employs

⁹⁵² *Id.* at 32-33.

⁹⁵³ *Id.* at 33.

⁹⁵⁴ *Id.* at 34.

⁹⁵⁵ Jim Caesar, Public Hrg. Tr. at 67-69 (Feb. 28, 2018).

⁹⁵⁶ *Id.* at 67.

⁹⁵⁷ *Id.*

⁹⁵⁸ *Id.*

⁹⁵⁹ *Id.* at 68.

⁹⁶⁰ Brian Hanson, Public Hrg. Tr. at 26-27 (Feb. 28, 2018).

⁹⁶¹ *Id.* at 26.

⁹⁶² *Id.* at 27.

⁹⁶³ *Id.*

⁹⁶⁴ *Id.* at 28.

⁹⁶⁵ Todd Rother, Public Hrg. Tr. at 29-30.

approximately 85 people in Superior, Wisconsin.⁹⁶⁶ Mr. Rothe asserted that the economic benefit to the local community in terms of construction jobs and tax revenue makes the plant a very attractive project.⁹⁶⁷ In addition, Mr. Rothe praised the plant's ability to provide economical and efficient energy that can backup renewable energy sources.⁹⁶⁸ Mr. Rothe urged the PUC to approve the proposed plant.⁹⁶⁹

60. Norm Voorhees, President of the Northern Wisconsin Building and Construction Trades Council, spoke at the public hearing in support of the proposed plant.⁹⁷⁰ The Northern Wisconsin Building and Construction Trades Council is a labor union that represents approximately 650 men and women who earn their living in the construction trades.⁹⁷¹ Mr. Voorhees maintained that the project represents a huge economic investment in the Twin Ports area that will deliver many good paying temporary union construction jobs.⁹⁷² Mr. Voorhees also praised MP's commitment to diversify its energy portfolio by increasing renewable energy sources and decreasing carbon-based sources.⁹⁷³

61. Keith Musolf submitted a comment in favor of the proposed plant on behalf of Iron Workers Local 512.⁹⁷⁴ Mr. Musolf stated that the proposed project is a great opportunity to provide needed jobs to local construction workers.⁹⁷⁵ He also maintained that the plant will be in a prime location with much of the needed infrastructure already in place.⁹⁷⁶ Finally, Mr. Musolf asserted that the proposed plant's use of "modern clean technology" is "exactly the type of future we need in the Twin Ports."⁹⁷⁷

62. Brad Boos spoke at the public hearing in support of the proposed plant.⁹⁷⁸ Mr. Boos is the President of Hunt Electric, which is located in Duluth. Mr. Boos stated that the proposed plant is needed given that renewable energy resources are dependent on weather conditions and are not always reliable.⁹⁷⁹ Mr. Boos also questioned claims that the proposed plant is not needed.⁹⁸⁰ He noted that if the proposed PolyMet copper nickel mine gets approved, it will need a large amount of electricity.⁹⁸¹ Finally, Mr. Boos stated that the proposed plant will benefit the regional

⁹⁶⁶ *Id.* at 29.

⁹⁶⁷ *Id.*

⁹⁶⁸ *Id.* at 30.

⁹⁶⁹ *Id.* at 31.

⁹⁷⁰ Norm Voorhees, Public Hrg. Tr. at 58-60 (Feb. 28, 2018).

⁹⁷¹ *Id.* at 58.

⁹⁷² *Id.* at 59.

⁹⁷³ *Id.*

⁹⁷⁴ Comment by Keith Musolf (Mar. 20, 2018) (eDocket No. 20183-141201-01).

⁹⁷⁵ *Id.*

⁹⁷⁶ *Id.*

⁹⁷⁷ *Id.*

⁹⁷⁸ Brad Boos, Public Hrg. Tr. at 74-76 (Feb. 28, 2018).

⁹⁷⁹ *Id.* at 74.

⁹⁸⁰ *Id.* at 75.

⁹⁸¹ *Id.*

economy as well as the nation's security.⁹⁸² Mr. Boos urged the PUC to approve the proposed plant.⁹⁸³

C. Dairyland Comments in Support of the Proposed Plant

63. Dairyland submitted comments stating that it is pursuing the NTEC plant to diversify its resources and ensure reliability.⁹⁸⁴ According to Dairyland, reducing dependence on coal, adding renewables, modernizing its grid, and adding the NTEC plant are all key elements of its strategic vision or "Preferred Plan." Dairyland stated that its goal is to diversify its system from one that was 98% coal in 2000 to one that, by approximately 2025, will be 25% renewable, 50% coal, and the remainder natural gas.⁹⁸⁵ Dairyland asserted that the proposed NTEC gas plant will ensure reliability by providing a flexible energy source to support the renewable sources it intends to add. Dairyland also maintained that the gas plant will be responsive to intermittent solar and wind generation. Dairyland stated the proposed plant will help meet energy needs in the region when the sun does not shine or the wind does not blow.⁹⁸⁶ Dairyland urged the Commission to approve the NTEC proposal.⁹⁸⁷

64. Rob Palmberg, Vice President of Strategic Planning for Dairyland spoke at the public hearing in support of the proposed plant.⁹⁸⁸ Echoing Dairyland's written submission, Mr. Palmberg stated that the proposed plant will help Dairyland diversify its resources and expand its options for adding renewables.⁹⁸⁹ Mr. Palmberg noted that Dairyland's local cooperatives in Minnesota and Illinois have acquired territory that will lead to a projected growth of 20 percent in the next nine years, requiring new resources like the proposed plant.⁹⁹⁰ Mr. Palmberg stressed the value of the partnership with MP and praised the location of the plant's site as being adjacent to both partners' service territories.⁹⁹¹ Mr. Palmberg believes that, with the new plant and by working together, Dairyland and MP can provide more efficient, cost-effective energy while reducing their dependence on coal.⁹⁹² According to Mr. Palmberg, the plant is a necessary and prudent investment that will be responsive to intermittent solar and wind, and help diversify the energy used to power the region.⁹⁹³

⁹⁸² *Id.*

⁹⁸³ *Id.*

⁹⁸⁴ Comment by Dairyland (Feb. 23, 2018) (eDocket No. 20183-141330-01).

⁹⁸⁵ *Id.*

⁹⁸⁶ *Id.*

⁹⁸⁷ *Id.*

⁹⁸⁸ Rob Palmberg, Public Hrg. Tr. at 23-24 (Feb. 28, 2018).

⁹⁸⁹ *Id.* at 24.

⁹⁹⁰ *Id.*

⁹⁹¹ *Id.*

⁹⁹² *Id.* at 25.

⁹⁹³ *Id.* at 26.

D. Citizen Comments in Favor of Natural Gas Plant

65. Aaron Mielke submitted a comment urging the PUC to approve the proposed plant.⁹⁹⁴ Mr. Mielke stated that natural gas is a clean burning domestic resource that will help keep utility costs down.⁹⁹⁵ He also asserted the proposed plant will provide needed jobs to the region.⁹⁹⁶ Don Wagner also submitted a comment urging the PUC to support of the proposed gas power plant.⁹⁹⁷

66. Fritz Hinzmann submitted comments in support of the proposed plant.⁹⁹⁸ According to Mr. Hinzmann, a natural gas plant is “the perfect environmental compromise between coal and renewables” and “an excellent economical compromise.”⁹⁹⁹

67. Eric Wendlandt, who works for Enbridge, also submitted a comment in support of the proposed plant.¹⁰⁰⁰ Mr. Wendlandt stated that he has worked on a number of gas power plant projects in Minnesota and can say with certainty that natural gas is a clean, efficient, and reliable power.¹⁰⁰¹ In addition, Mr. Wendlandt asserted that natural gas power is a “great bridge until renewables can provide reliable power at an affordable price.”¹⁰⁰²

68. Dave Updegraff submitted a comment in support of the construction of the proposed plant.¹⁰⁰³ Mr. Updegraff maintained that a new gas plant, especially one designed to take advantage of current technological advances and efficiencies, should accelerate the shutdown of coal burning facilities.¹⁰⁰⁴ Mr. Updegraff also asserted that that the ability to generate electricity locally with local labor is important to him.¹⁰⁰⁵

69. Chris Thacker strongly urged the PUC to approve the proposed plant.¹⁰⁰⁶ Mr. Thacker stated that, while he hopes utility companies eventually transition to 100 percent renewable resources, until that time comes, he believes a gas power plant will reduce carbon emissions.¹⁰⁰⁷

⁹⁹⁴ Comment by Aaron Mielke (Mar. 3, 2018) (eDocket No. 20183-14096801).

⁹⁹⁵ *Id.*

⁹⁹⁶ *Id.*

⁹⁹⁷ Comment by Don Wagner (Mar. 1, 2018) (eDocket No. 20183-140747-01).

⁹⁹⁸ Comment by Fritz Hinzmann (Mar. 1, 2018) (eDocket No. 20183-140747-01).

⁹⁹⁹ *Id.*

¹⁰⁰⁰ Comment by Eric Wendlandt (Mar. 6, 2018) (eDocket No. 20183-140968-01).

¹⁰⁰¹ *Id.*

¹⁰⁰² *Id.*

¹⁰⁰³ Comment by Dave Updegraff (Mar. 6, 2018) (eDocket No. 20183-140968-01).

¹⁰⁰⁴ *Id.*

¹⁰⁰⁵ *Id.*

¹⁰⁰⁶ Comment by Chris Thacker (Mar. 1, 2018) (eDocket No. 20183-140968-01).

¹⁰⁰⁷ *Id.*

July 2, 2018

See Attached Service List

**Re: In the Matter of Minnesota Power's 2015-2029 Integrated Resource
Plan {RP-15-690 and AI-17-568}**

**OAH 68-2500-34672
MPUC E-015/AI-17-568**

To All Persons on the Attached Service List:

Enclosed and served upon you is the Administrative Law Judge's **FINDINGS OF
FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION** in the above-entitled
matter.

If you have any questions, please contact my legal assistant Sheena Denny at
(651) 361-7881 or sheena.denny@state.mn.us, or facsimile at (651) 539-0310.

Sincerely,



JEANNE M. COCHRAN
Administrative Law Judge

JMC:sd
Enclosure
cc: Docket Coordinator

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
PO BOX 64620
600 NORTH ROBERT STREET
ST. PAUL, MINNESOTA 55164

CERTIFICATE OF SERVICE

| | |
|---|---|
| In the Matter of Minnesota Power's 2015-2029 Integrated Resource Plan {RP-15-690 and AI-17-568} | OAH Docket No.: 68-2500-34672 MPUC E-015/AI-17-568 |
|---|---|

Sheena Denny, certifies that on July 2, 2018 she served the true and correct

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION by

eService, and U.S. Mail, (in the manner indicated below) to the following individuals:

| | | | | | |
|--------------------|----------------|--------------------------------------|---|--------------------|-----|
| Bergan | Sara | sebergan@stoel.com | Stoel Rives LLP | Electronic Service | Yes |
| Berninger | Carolyn | cberninger@mncenter.org | Minnesota Center for Environmental Advocacy | Electronic Service | Yes |
| Brama | Elizabeth | ebrama@briggs.com | Briggs and Morgan | Electronic Service | Yes |
| Cochran | Jeanne | Jeanne.Cochran@state.mn.us | Office of Administrative Hearings | Electronic Service | Yes |
| Commerce Attorneys | Generic Notice | commerce.attorneys@ag.state.mn.us | Office of the Attorney General-DOC | Electronic Service | Yes |
| Currie | Leigh | lcurrie@mncenter.org | Minnesota Center for Environmental Advocacy | Electronic Service | Yes |
| Dobson | Ian | residential.utilities@ag.state.mn.us | Office of the Attorney General-RUD | Electronic Service | Yes |
| Eknes | Bret | bret.eknes@state.mn.us | Public Utilities Commission | Electronic Service | No |
| Ferguson | Sharon | sharon.ferguson@state.mn.us | Department of Commerce | Electronic Service | Yes |
| Johnson Phillips | Sarah | sarah.phillips@stoel.com | Stoel Rives LLP | Electronic Service | Yes |
| Krikava | Michael | mkrikava@briggs.com | Briggs And Morgan, P.A. | Electronic Service | Yes |
| Lee | Gretel | glee@mncenter.org | Minnesota Center for Environmental Advocacy | Electronic Service | Yes |
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| Stastny | Kristin | kstastny@briggs.com | Briggs and Morgan, P.A. | Electronic Service | Yes |
| Williams | Susan | laurie.williams@sierraclub.org | Sierra Club | Electronic Service | Yes |
| Wolf | Daniel P | dan.wolf@state.mn.us | Public Utilities Commission | Electronic Service | Yes |