BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

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

ISSUE DATE: January 24, 2019

DOCKET NO. E-015/AI-17-568

ORDER APPROVING AFFILIATED-INTEREST AGREEMENTS WITH CONDITIONS

PROCEDURAL HISTORY

I. 2015 Integrated Resource Plan

On September 1, 2015, Minnesota Power (the Company) filed its 2015 Integrated Resource Plan (2015 IRP) under Minn. Stat. § 216B.2422 and Minn. R. ch. 7843.[1]

The Company projected a mid-2020s capacity deficit on its system as a result of the idling or retirement of a number of its coal-fired generating units. To address this deficit, the Company proposed, among other things, to begin a competitive procurement process for 200–300 megawatts (MW) of natural-gas-fired generation for implementation by 2024.

On July 18, 2016, the Commission issued its *Order Approving Resource Plan with Modifications*.

The Commission allowed Minnesota Power to investigate the possible procurement of natural-gas-fired generation as part of a portfolio of resources to replace its coal-fired generators. It also required the Company to initiate competitive-bidding processes to procure both wind and demand-response capacity, and to acquire sufficient solar capacity to meet its obligations under the state Solar Energy Standard.

The Commission ordered Minnesota Power to file its next resource plan on February 1, 2018.

II. Energy*Forward* Resource Package

On July 28, 2017, Minnesota Power filed a petition for approval of an "Energy*Forward* resource package" in the current docket. The Energy*Forward* package included three generation resources intended to meet the need the Company identified in its 2015 IRP:

[1] *See In the Matter of Minnesota Power's 2016–2030 Integrated Resource Plan*, Docket No. E-015/RP-15-690.

1. A power purchase agreement (PPA) with a 250 MW wind farm in southwestern Minnesota;
2. A PPA with a 10 MW solar farm in central Minnesota; and
3. Agreements dedicating to the Company 48% of the capacity of the Nemadji Trail Energy Center (NTEC), a proposed 525 MW natural gas combined-cycle power plant in Superior, Wisconsin.[2]

Because NTEC is being developed by an affiliate of Minnesota Power, the related agreements must be approved under Minnesota's affiliated-interest statute, Minn. Stat. § 216B.48.

III. Referral for Contested-Case Proceedings

On September 19, 2017, the Commission issued its *Order Referring Gas Plant for Contested Case Proceedings, and Notice and Order for Hearings* (Referral Order).

The Commission referred the petition to the Office of Administrative Hearings for contested-case proceedings to determine whether Minnesota Power's proposed purchase of capacity from NTEC was needed and reasonable and whether the affiliated-interest agreements should be approved. It directed the Company to refile an updated petition limited to the NTEC purchase, with a revised demand forecast.[3]

Finally, the Commission extended the deadline for the Company to file its next resource plan to October 1, 2019, to accommodate full consideration of the NTEC proposal.

IV. The Parties and Their Representatives

The following parties appeared in this case:

- Minnesota Power, represented by Michael C. Krikava and Elizabeth M. Brama, Briggs and Morgan, P.A., and David R. Moeller, Senior Attorney, Minnesota Power.

- Minnesota Department of Commerce, Division of Energy Resources (the Department), represented by Peter E. Madsen, Assistant Attorney General.

- Office of the Minnesota Attorney General – Residential Utilities and Antitrust Division (the OAG), represented by Ian Dobson, Assistant Attorney General.

---

[2] A combined-cycle power plant produces electricity using one or more combustion turbines and a steam turbine. Waste heat from the combustion turbine(s) is captured and used to power the steam turbine, increasing the plant's overall energy efficiency.

[3] The Commission observed that it had already approved Minnesota Power's acquisition of additional wind and solar resources and directed the Company to refile its wind and solar PPAs for approval in a separate docket. Referral Order, at 5.

- Clean Energy Organizations (CEOs),[4] represented by Leigh Currie and Gretel Lee, Minnesota Center for Environmental Advocacy, and S. Laurie Williams, Sierra Club.

- Large Power Intervenors (LPI),[5] represented by Sarah Johnson Phillips, Andrew P. Moratzka, Sara Bergan, and Jennifer Mersing, Stoel Rives LLP.

V. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Jeanne M. Cochran to hear the case.

On October 24, 2017, Minnesota Power resubmitted its petition, limited to the portions relevant to the NTEC purchase, along with a revised demand forecast.

Between November 1 and December 12, 2017, the ALJ issued four prehearing orders addressing various evidentiary and procedural matters.

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of the evidentiary hearing. The ALJ held an evidentiary hearing on March 26, 2018, at the Commission's offices in Saint Paul. After the hearing, the parties filed initial briefs, reply briefs, and proposed findings of fact and conclusions of law.

VI. Public Comments

On February 28, 2018, the ALJ held a public hearing in Duluth. Representatives of Minnesota Power, the Department, and the CEOs attended.

Approximately 65 members of the public attended the hearing, with 21 offering oral comments. In addition, more than 1,500 written comments were received by the March 23, 2018, deadline. The ALJ summarized the public comments in a 20-page attachment to her report.

The majority of commenters opposed Minnesota Power's proposed purchase of capacity from the NTEC plant. Many argued that the purchase was not needed to meet electricity needs, and that the Company could meet demand by increasing energy efficiency and investing in renewable energy. Others objected based on the potential environmental impacts of natural-gas extraction or of the NTEC plant itself.

However, a number of comments in support of the NTEC purchase were filed by businesses, organized labor, and economic-development interests. These commenters argued that natural gas is a clean-burning fuel and a better alternative than coal. They maintained that the proposed purchase would diversify Minnesota Power's energy options and that the plant's construction and operation would bring jobs as well as tax revenue.

[4] The CEOs are Minnesota Center for Environmental Advocacy, Sierra Club, Fresh Energy, and Clean Grid Alliance (f/k/a Wind on the Wires).

[5] LPI consists of ArcelorMittal USA (Minorca Mine); Blandin Paper Company; Boise Paper, a Packaging Corporation of America company; Gerdau Ameristeel US Inc.; Hibbing Taconite Company; Mesabi Nugget Delaware, LLC; Sappi Cloquet, LLC; USG Interiors, LLC; United States Steel Corporation (Keetac and Minntac Mines); United Taconite, LLC; and Verso Corporation.

VII. The Administrative Law Judge's Report

On July 2, 2018, the ALJ filed her *Findings of Fact, Conclusions of Law, and Recommendation* (ALJ's Report).

The ALJ concluded that Minnesota Power had failed to establish that the NTEC purchase was needed and reasonable, finding the Company's alternatives analysis inadequate and biased in favor of NTEC. She therefore recommended that the Commission deny the Company's request for approval of the affiliated-interest agreements necessary to effectuate the purchase.

VIII. Proceedings Before the Commission

The following parties filed exceptions to the ALJ's Report under Minn. Stat. § 14.61 and Minn. R. 7829.2700: Minnesota Power, the Department, the CEOs, and LPI.

On October 16, 2018, the Commission received a letter from the Minnesota Environmental Quality Board (EQB) stating that nonprofit Honor the Earth had requested a review of the NTEC proposal under the Minnesota Environmental Policy Act,[6] and that EQB believed that the Commission was the appropriate governmental unit to conduct this review.

On October 18 and 29, 2018, the Commission heard oral argument from and asked questions of the parties and Honor the Earth. On October 29, the record closed under Minn. Stat. § 14.61, subd. 2.

Having examined the entire record in this case, and having heard the arguments of the parties, the Commission makes the following findings, conclusions, and order.

FINDINGS AND CONCLUSIONS

I. Summary of Commission Action

The Commission has examined the record, reviewed the report of the Administrative Law Judge, considered the exceptions to that report, and heard oral argument from the parties. Based on the entire record, the Commission concurs in many of the ALJ's findings and conclusions. However, the Commission's view of the evidence leads it to different conclusions on certain issues.

In particular, the Commission disagrees with the ALJ's conclusion that the NTEC purchase is not needed and reasonable. This conclusion rested on her finding that Minnesota Power's alternatives analysis was defective in certain respects. The Department, however, conducted an independent analysis of the NTEC purchase using the economic model developed in the Company's 2015 resource plan and found the purchase needed and reasonable. The Commission concludes that the Department's modeling assumptions were reasonable and that its analysis supports the need for the NTEC purchase.

[6] Minn. Stat. §§ 116D.01–.11.

The Commission adopts the ALJ's Report, modified as proposed by the Department in its corrected exceptions and as necessary to be consistent with this order, and approves the NTEC affiliated-interest agreements with the conditions described in this order and in Attachment A.

II. Request for MEPA Review

Before turning to the merits of Minnesota Power's petition, the Commission addresses whether approving the NTEC agreements requires environmental review under the Minnesota Environmental Policy Act (MEPA).[7]

A. Introduction

MEPA requires that "[w]here there is potential for significant environmental effects resulting from any major governmental action, the action shall be preceded by a detailed environmental impact statement prepared by the responsible governmental unit."[8] In certain cases, an environmental assessment worksheet (EAW) may first be prepared to determine whether the potential for significant environmental effects exists.[9]

Under the MEPA rules, "governmental action" means "activities including projects wholly or partially conducted, permitted, assisted, financed, regulated, or approved by governmental units."[10] "Project" is defined somewhat circularly as "a governmental action, the results of which would cause physical manipulation of the environment, directly or indirectly."[11]

On October 16, 2018, the Minnesota Environmental Quality Board notified the Commission that, in its opinion, "[MEPA] appl[ies] to the proposed governmental action being considered by the PUC" and that the Commission is the appropriate responsible governmental unit to make the decision on the need for an EAW.

B. Positions of the Parties

Minnesota Power argued that there is no MEPA "project" in the current proceeding because the Company's petition does not request permission to build or operate NTEC. It merely requests approval of the affiliated-interest agreements that will allow the Company to purchase a share of NTEC's capacity, similar to a power purchase agreement.

Moreover, the Company argued that because NTEC will be entirely owned by Wisconsin entities, built in Wisconsin, and operated in Wisconsin, it will be subject to Wisconsin's siting and environmental regulations, not MEPA, and that applying MEPA to the project would violate the Commerce Clause of the federal Constitution.

---

[7] Minn. Stat. §§ 116D.01–.11.

[8] Minn. Stat. § 116D.04, subd. 2a.

[9] *See* Minn. R. 4410.1000.

[10] Minn. R. 4410.0200, subp. 33.

[11] *Id.*, subp. 65.

Honor the Earth argued that NTEC's construction would have significant environmental impacts in Minnesota, and that the fact that the plant would be located in another state does not exempt the Commission's approval of the affiliated-interest agreements from MEPA review. It contended that if the Legislature or the EQB had intended to limit MEPA jurisdiction to projects located within the boundaries of Minnesota, they would have expressly done so in the MEPA statute or rules.

The CEOs agreed, and argued that since a "project" is defined as a "governmental action" under the MEPA rules, the relevant project in this case is the Commission's approval of the NTEC agreements. This "project" will occur in Minnesota and will result in physical manipulation of the environment, and therefore MEPA applies.

C. Commission Action

The Commission agrees with Minnesota Power that MEPA does not permit the type of bootstrapping analysis used by Honor the Earth and the CEOs.

Honor the Earth and the CEOs assert that MEPA expands the Commission's jurisdiction over power plant siting, allowing it to conduct duplicative environmental review of a Wisconsin power plant. But the Commission's siting and certificate-of-need statutes make clear that its jurisdiction over power plants is limited to facilities proposed to be built in Minnesota.[12]

While there may be situations in which MEPA's reach extends into neighboring states, such as cross-border projects, this case does not present such a situation.[13] The NTEC facility will be built entirely within Wisconsin, more than two miles from the Minnesota border. It is therefore subject to that state's permitting and environmental-review regulations, not Minnesota's.

MEPA review of NTEC is not authorized for the further reason that there is no MEPA "project" before the Commission. A project is a governmental action, "the results of which would cause physical manipulation of the environment."[14] Minnesota Power is not seeking a permit to construct or operate NTEC; it is seeking approval of agreements effectuating its purchase of capacity from the plant. The requested "governmental action" pertains only to these agreements, and their approval will not grant permission to construct or operate the plant. That permission will have to be obtained from Wisconsin regulators before any physical manipulation of the environment can occur.

[12] *See* Minn. Stat. §§ 216E.02, subd. 2 (giving the Commission authority over the siting of power plants in the state); 216B.243, subd. 2 (requiring the Commission to issue a certificate of need before a power plant is "sited or constructed *in Minnesota*" (emphasis added)). *See also* Minn. R. 4410.4300, subp. 3, .4400, subp. 3 (requiring that environmental review of power plants over 50 MW be conducted according to the Commission's siting and certificate-of-need rules).

[13] *Cf. Joint Powers Auth. v. U.S. Army Corps of Eng'rs*, 2015 WL 2251481, at *12 (D. Minn. May 13, 2015) (concluding that MEPA applied to a cross-border flood-diversion project in the Fargo–Moorhead area of North Dakota and Minnesota).

[14] Minn. R. 4410.0200, subp. 65. *Accord* Minn. Stat. § 116D.04, subd. 2a (providing that "[w]here there is potential for significant environmental effects *resulting from* any major governmental action," environmental review is required (emphasis added)).

In summary, Honor the Earth and the CEOs ask that the Commission undertake environmental review of a Wisconsin power plant over which the Commission has no jurisdiction. Minnesota Power is not seeking a permit for NTEC itself, and approval of the affiliated-interest agreements will not result in physical manipulation of the environment. For these reasons, their approval is not a governmental action that requires environmental review under MEPA.[15]

For all these reasons, the Commission will deny the request for MEPA review.

III. Background

A. Minnesota Power's Changing Resource Mix

Minnesota Power has traditionally relied on coal-fired generation to provide much of its baseload power-supply needs. In recent years, however, the Company has begun transitioning its power supply to a less carbon-intensive resource mix.[16]

By 2020, the Company will have removed nearly 700 MW of coal-fired generation from its power supply by retiring or repowering its plants and by phasing out long-term capacity purchases from other utilities. To replace the baseload energy supplied by these coal-fired resources, the Company plans to construct or purchase more than 850 MW of wind generation by 2020, sign long-term agreements to purchase 250 MW of hydroelectricity from the Manitoba Hydro-Electric Board beginning in 2020, and add a small amount of solar generation to its fleet. The net result will be a power supply that includes significant new variable renewable generation and increasingly less baseload generation.

B. Projected Energy and Capacity Deficits

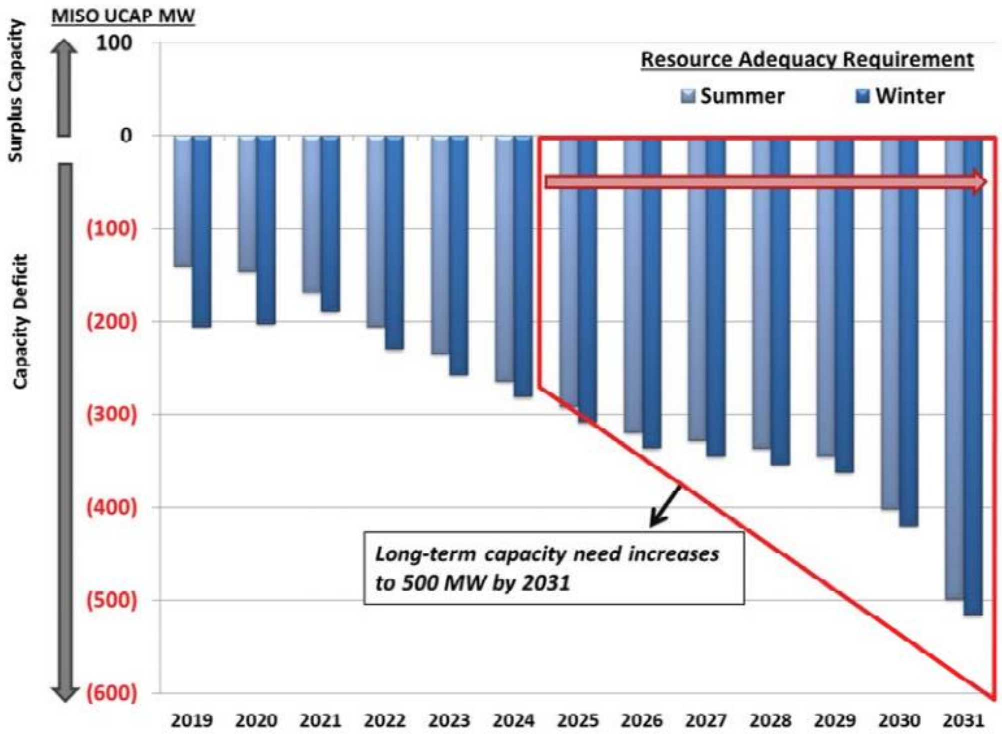
Based on these ongoing efforts to reduce coal-fired generation, changing hourly energy requirements, increased renewable generation, and projected load growth, Minnesota Power anticipates a growing need for capacity and energy in the mid-2020s.[17] As shown below in Figure 1, in the absence of any resource additions, the Company forecasts a capacity deficit that will reach 300 MW by 2025 and grow to 500 MW by 2031.

[15] The Commission also notes that, taken to their logical conclusion, Honor the Earth and the CEOs' arguments would require MEPA review every time the Commission approved a Minnesota utility's power purchase agreement with a large generating facility near the state, an absurd result.

[16] A utility's "base load" is the minimum level of demand on its power system over time. A baseload power plant is one that serves this base level of demand by producing power at or near the plant's maximum output more or less continuously. Historically, coal-fired power plants have often been used as baseload plants, since they produce energy inexpensively but cannot be ramped up or down quickly to follow the day-to-day fluctuations in system load.

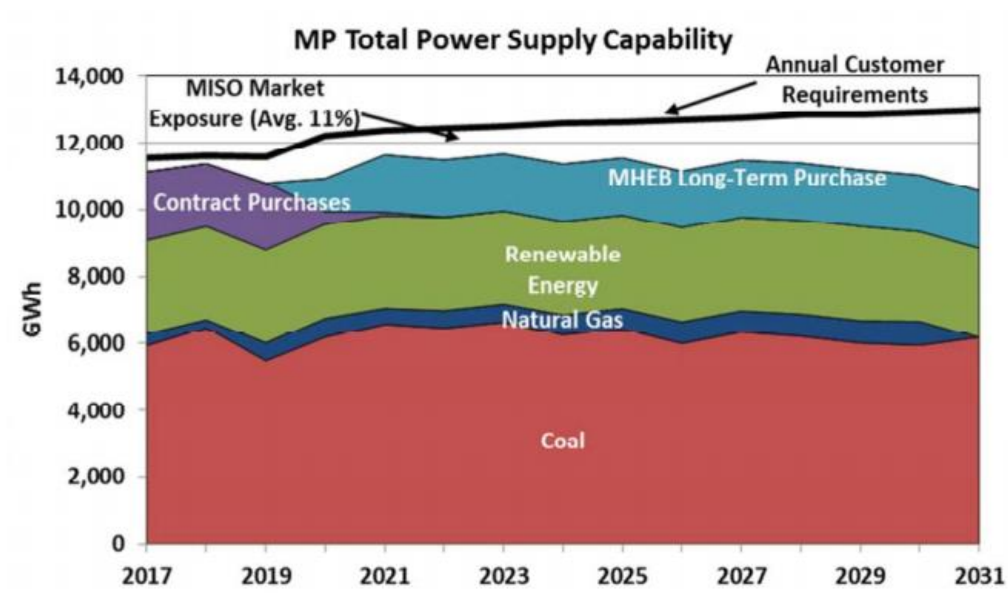
[17] Capacity and energy are related but distinct concepts. A generator's capacity is its maximum output, typically measured in megawatts. Energy is the amount of electricity that a generator produces over a period of time, measured in megawatt–hours. In planning for future resource additions, a utility must account for both capacity and energy needs to ensure a reliable, cost-effective electric system.

Figure 1: Minnesota Power's Projected Capacity Deficit[18]



Along with this capacity deficit, the Company also predicts growing energy needs of about 1,000 gigawatt–hours (GWh) annually by 2020, increasing to 2,400 GWh by 2031, as coal-fired energy is removed from the power supply and customer needs increase. Figure 2 below shows Minnesota Power's projected energy needs through 2031.

Figure 2: Minnesota Power's Projected Energy Deficit[19]



[18] Pierce Direct, at 54.

[19] Pierce Direct, at 57.

According to Minnesota Power, higher system levels of renewable generation will create additional planning challenges for the Company. By 2020, the Company will have more than 850 MW of renewable generation on its system. As a result, it projects significant energy-supply variability and claims a corresponding need for dispatchable capacity and flexible energy to help mitigate exposure to energy-market prices.[20]

C. Natural Gas RFP

In several of its recent resource plans, Minnesota Power has identified an intermediate natural-gas-fired resource as potentially cost-effective for replacing some of the energy and capacity from its coal-fired plants.[21]

In October 2015, the Company issued a request for proposals (RFP) for 200–400 MW of natural-gas-fired capacity and associated energy delivered into its MISO load zone starting in 2022–2024.[22] Minnesota Power selected two of the most cost-competitive proposals, including a bid from its affiliate South Shore Energy, LLC, for further negotiations. South Shore's initial bid was to supply 300 MW with an in-service date in the 2022–2024 timeframe.

In April 2016, Minnesota Power selected South Shore as the winning bidder, and negotiations continued throughout the remainder of 2016. During that period, the Company revised its demand forecast downward and sought a new offer from South Shore for a 150 MW gas-fired resource with an in-service date of 2024.[23] South Shore responded with two revised offers, one for 200 MW and the other for 250 MW. Ultimately, Minnesota Power determined that it needed 250 MW and selected NTEC.

D. The Nemadji Trail Energy Center (NTEC)

The Nemadji Trail Energy Center is a proposed natural gas combined-cycle power plant being jointly developed by Minnesota Power's affiliate South Shore Energy, LLC and Dairyland Power Cooperative, a Wisconsin utility.

As proposed, NTEC will consist of one gas turbine generator, a heat-recovery steam generator with duct firing, and a steam turbine generator, with a total generating capacity of 525–550 MW, dependent on final turbine selection. The plant will be sited in Superior, Wisconsin near existing

---

[20] Utilities typically do not meet customer demand solely with their own generation facilities, but will procure capacity and energy on the regional energy market if doing so is cheaper than self-generating. Minnesota utilities have access to the regional energy market run by the Midcontinent Independent System Operator (MISO). MISO dispatches all generators in the MISO footprint to meet all load in the MISO footprint.

[21] *See, e.g.*, 2015 IRP, at 16–17 (describing plans to procure "200 to 300 MW of intermediate natural gas generation resource"). An intermediate or *load-following* power plant is one that adjusts its output throughout the day to meet shoulder demand. A load-following plant is typically less efficient than a baseload plant, but more efficient than a peaking plant.

[22] July 28, 2017 Energy*Forward* Petition, Appendix U.

[23] July 28 Petition, Appendix V, at 8.

gas-pipeline infrastructure and will have access to a firm supply of natural gas. It is expected to begin commercial operation in 2024.

NTEC will be jointly owned by South Shore and Dairyland. Minnesota Power will not have an ownership interest in NTEC because Wisconsin statutes only permit residents of that state to obtain a license, permit, or franchise to own or operate a generation facility there. Minnesota Power's parent company, ALLETE, Inc., created South Shore to own ALLETE's share of NTEC.

Each NTEC owner will have the right to 50% of NTEC's capacity. While Minnesota Power will not be a project owner, South Shore and Dairyland have agreed that the Company will take the lead in developing, constructing, operating, and maintaining NTEC, subject to Commission approval. South Shore has also agreed to dedicate 48% of NTEC's capacity (approximately 250 MW) to Minnesota Power and its customers.

E. The NTEC Transaction

The NTEC transaction involves two agreements between South Shore and Dairyland, three proposed affiliated-interest agreements between South Shore and Minnesota Power, and a guaranty agreement between Minnesota Power and Dairyland.

The two agreements between South Shore and Dairyland are a Development and Construction (D&C) Agreement and an Ownership and Operating (O&O) Agreement. These agreements establish a 50/50 partnership between South Shore and Dairyland and place South Shore in the role of project and plant manager.

The three affiliated-interest agreements between South Shore and Minnesota Power (collectively, "the NTEC agreements") are:

- An **Assignment of Rights Agreement (Construction Agent)** 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;
- An **Assignment of Rights Agreement (Operating Agent)** 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; and
- A **Capacity Dedication Agreement (CDA)** between South Shore and Minnesota Power, by which South Shore would dedicate 48% of NTEC's capacity (approximately 250 MW) and the associated energy to Minnesota Power in exchange for monthly payments from the Company.

Finally, under the Guaranty Agreement, Minnesota Power guarantees to Dairyland the performance of South Shore's obligations under the D&C and O&O Agreements.

F. Minnesota Power's Petition

On October 24, 2017, Minnesota Power filed the revised petition now before the Commission. The Company requests that the Commission:

1. Approve the two assignment-of-rights agreements that authorize Minnesota Power to act as a construction agent and operating agent for South Shore;
2. Approve the CDA allocating 48% of NTEC's output to the Company; and
3. Grant a rule variance, and approve related tariff amendments, to allow fuel costs charged to Minnesota Power under the CDA to be recovered from ratepayers through the Company's Fuel and Purchased Energy Rider, and to allow revenues realized under the CDA to flow back to customers.

IV. The Legal Standard

In Minnesota, a public utility must obtain Commission approval of transactions worth more than $50,000 with an affiliated entity.[24] The Commission may 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."[25]

Because the NTEC purchase involves resource-planning and resource-acquisition considerations, the Commission's determination of whether the affiliated-interest agreements are "reasonable and consistent with the public interest" is guided by relevant factors from Minnesota's resource-planning and certificate-of-need statutes, Minn. Stat. §§ 216B.2422 and .243.

In its Referral Order, the Commission determined that approval of the NTEC agreements turns on whether the 250 MW NTEC purchase is needed and reasonable, and that the Company bears the burden of proving that the proposed purchase is needed and reasonable based on all relevant factors.[26] The Commission drew on Minn. Stat. §§ 216B.2422 and .243 to specifically identify several factors relevant to the ultimate question of NTEC's need and reasonableness:

- An updated forecast of demand;[27]
- Socioeconomic and environmental costs, including the most recent environmental externality values established by the Commission;[28]
- Alternatives to some or all of NTEC's energy and capacity, including but not limited to alternatives such as additional wind and solar resources, storage, demand response, and additional energy efficiency;[29] and

---

[24] Minn. Stat. § 216B.48, subd. 4.

[25] *Id.*, subd. 3.

[26] Referral Order, at 5.

[27] *See* Minn. Stat. § 216B.2422, subd. 1(d) (defining "resource plan" as "a set of resource options that a utility could use to meet the service needs of its customers over a forecast period").

[28] *See* Minn. Stat. § 216B.2422, subd. 3 (requiring utilities to apply environmental cost values in evaluating and selecting resource options).

[29] *See* Minn. Stat. § 216B.243, subd. 3(6) (requiring evaluation of alternatives to a proposed facility).

- "The renewable resource requirements set forth in Minn. Stat. § 216B.2422, and Minn. Stat. § 216B.243, subd. 3a."[30]

In her second prehearing order, the ALJ identified additional factors that guided her decision on the ultimate question of need.[31]

V. The Need for the NTEC Purchase

A. Summary

Both the Company and the Department conducted resource-planning analyses of the NTEC purchase and concluded that the purchase was needed, though for different reasons. Minnesota Power contended that NTEC was needed primarily as a source of dispatchable capacity, while the Department found NTEC to be an economic source of energy compared to other options.

The CEOs and LPI argued that neither the Company's nor the Department's analysis should be relied on to support the need for the NTEC purchase, and that the Company in particular had made assumptions that biased its model in favor of NTEC.

The Commission, however, concludes that the Department's analysis included a robust range of scenarios and establishes the need for the NTEC purchase as a least-cost resource for supplying Minnesota Power's customers' energy requirements.

B. The Company's Strategist Analysis

Minnesota Power used Strategist, modeling software that is commonly used by utilities in resource planning, to compare alternatives for meeting forecasted energy and capacity needs.

Strategist estimates the costs of different resource mixes by accounting for factors such as energy demand, fuel costs, environmental regulations, and capital costs. By doing so, the model can help a utility identify least-cost expansion plans that satisfy its specified energy and capacity requirements.

1. Base-Case Assumptions

Minnesota Power began by developing a "base case," a set of assumptions about the factors that will affect its power supply in the future. The Company took several steps to refine the base assumptions and inputs from its 2015 IRP, including:

- Updating its demand forecast;
- Updating its power supply to reflect recent changes, such as the removal of coal-fired generating units;

---

30 Referral Order, at 9. *See* Minn. Stat. §§ 216B.2422, subd. 4 (establishing a preference for renewable energy facilities over nonrenewable facilities), .243, subd. 3a (requiring a demonstration that the proposed facility is less expensive than renewable alternatives).

31 *See* Second Prehearing Order, Final Issues List (December 12, 2017).

- Updating existing generators' capacity values based on their accredited capacity as determined by MISO;
- Assuming 150 MW of industrial demand-response capacity;[32]
- Using the most recent industry data, including costs, for demand-side management programs, generation technologies, storage technologies, natural gas, coal, and other key power-supply drivers;
- Assuming a regulatory penalty of $21.50 per ton of carbon dioxide (CO_2) emitted after 2021 in four base-case scenarios and assuming no CO_2-regulation costs in four other scenarios;[33] and
- Using the latest environmental cost values for power plant emissions established by the Commission under Minn. Stat. § 216B.2422, subd. 3.[34]

Minnesota Power developed incremental energy-efficiency assumptions using the same methodology as in its 2015 IRP. Specifically, the Company tested three different scenarios of incremental energy-efficiency savings: 11, 15, and 30 GWh per year. These amounts were in addition to 46 GWh embedded in the demand forecast.

Using base-case assumptions, Minnesota Power projected an approximately 100 MW capacity deficit in 2025. The Company projected that this need would grow to about 150 MW between 2026 and 2029. In 2031, the projected capacity deficit under the Company's base case was approximately 300 MW.

2. Alternatives Analysis

After establishing its base case, Minnesota Power compiled a list of system resources and the associated unit cost of electricity for each resource type. After screening out the most costly options, the Company arrived at the following list of resource alternatives to make available to Strategist's capacity-expansion model:

- 250 MW share of a natural-gas-fired combined-cycle plant (NTEC)
- 525 MW natural-gas-fired combined-cycle plant
- 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

[32] "Demand response" refers to changes in customer usage in response to incentive payments or other price signals. Interruptible service—under which customers agree to reduce their usage at times of high system demand in exchange for a discounted electricity rate—is a common form of demand response.

[33] *See generally In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06*, Docket No. E-999/CI-07-1199.

[34] *See generally In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subd. 3*, Docket No. E-999/CI-14-643. In rebuttal testimony, the Company provided an updated RFP-selection analysis reflecting the new values established by the Commission's January 3, 2018 order in that docket.

- 100 MW solar farm located in central Minnesota
- 50 MW bilateral bridge transaction[35]
- Air conditioning load control and hot-water load control

Next, in "Step 1" of its analysis, the Company used Strategist to estimate what resource portfolios would meet its energy and capacity needs at the lowest cost over the 14-year period ending in 2031. The Company limited Strategist's ability to select resources before 2025, focusing the model's analysis on the growing capacity and energy needs anticipated in the mid-2020s.

Briefly, the Step 1 modeling process involved calculating and comparing the present-value cost of various combinations of the above-listed resources under eight different futures:

Table 1: Eight Futures Considered in Alternatives Analysis

	Season	CO_2 Penalty	Excess Energy Sold Into Wholesale Market
Future 1	Summer	No	Yes
Future 2	Summer	No	No
Future 3	Summer	Yes	Yes
Future 4	Summer	Yes	No
Future 5	Winter	No	Yes
Future 6	Winter	No	No
Future 7	Winter	Yes	Yes
Future 8	Winter	Yes	No

The Company also varied a number of other key inputs under each of these futures—including fuel costs, CO_2-regulation costs, capital costs, environmental costs, and customer-load outlooks—to test the cost of each portfolio under different scenarios. The Step 1 analysis indicated that the most cost-effective portfolio was the set of resources that Minnesota Power ultimately included in its Energy*Forward* package—including the 250 MW NTEC purchase.

Finally, in Step 2 of its alternatives analysis, the Company conducted a "swim lane" comparison of the Energy*Forward* package side by side with three other viable resource portfolios:

[35] This resource represents, essentially, a 50 MW power purchase agreement. "Bilateral" signifies a transaction with a single counterparty, as opposed to MISO market purchases. "Bridge" refers to the fact that the purpose of such a transaction would be to supply capacity and energy until the resource need is great enough to justify building a new power plant, wind farm, etc.

Table 2: Swim Lane Alternatives

Energy*Forward* Resource Package: 250 MW of wind added in 2020, 10 MW of solar added in 2020, and an approximately 250 MW share of the NTEC combined-cycle gas turbine added in 2025.[36]

75% Renewable Capacity Portfolio: 1,950 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.

50% Renewable Capacity Portfolio: 1,350 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.

Large Combustion Turbine Portfolio: 456 MW of gas peakers, the first 228 MW added in 2025 and the second in 2031, and 250 MW of wind added in 2020.

Similar to Step 1, Minnesota Power used Strategist to "stress test" these four preselected portfolios under eight futures while varying key inputs and cost drivers. The Company then compared the present-value cost of the portfolios under each of the 264 unique scenarios (or "sensitivities") that it modeled.

The Energy*Forward* package was selected as providing the lowest-cost power supply in over 90% of the sensitivities considered.

3. Updated Alternatives Analysis

After these proceedings commenced, Minnesota Power conducted an additional, revised Strategist analysis to address criticisms raised by the CEOs and LPI. First, the Company updated its demand forecast to account for a paper mill that closed after the forecast was conducted.

Minnesota Power also added two new futures to the original eight. In the two new futures, the Company included environmental costs as a base-case assumption. The Company then ran these ten futures through Strategist assuming incremental efficiency values of 11 GWh and 30 GWh, which resulted in a total of 20 unique futures.

In Step 1 of its revised analysis, Minnesota Power made an additional resource available to the model: 300 MW of industrial demand response, selectable in 150 MW blocks starting in 2025. While a 150 MW block of demand response was selected in approximately 78% of the sensitivities modeled, in almost all cases, the model selected it post-2025, after selecting the 250 MW NTEC purchase.

Finally, in Step 2, the Company added two new swim lanes at the request of LPI:

---

[36] This package assumes that another 12 MW of solar is added in 2025 to comply with the Solar Energy Standard, and that a 100 MW combustion turbine is added in 2031 to meet capacity needs. However, Minnesota Power is not seeking approval of these additional resources at this time.

- **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 installed in 2031, and 300 MW of industrial demand response with limitations and pricing based on LPI's demand-response proposal in the Company's recent rate case.

- **Swim Lane 6** reduced the size of the proposed NTEC purchase from 250 to 200 MW and increased the size of the combustion turbine added in 2031 to 150 MW.

Even with these additional swim lanes, the 250 MW NTEC purchase was selected as the least-cost resource more than 90% of the time. Minnesota Power maintained that these results demonstrated that, combined with the other resources in its Energy*Forward* package, the proposed NTEC purchase is the best and least-cost resource option for meeting its energy needs in the mid-2020s.

4. Criticism of the Company's Modeling

The CEOs and LPI criticized several aspects of Minnesota Power's modeling, arguing that the assumptions used by the Company impacted the results in a way that favored the NTEC purchase. As a result, they maintained that the Company had failed to meet its burden to fully analyze alternatives to the proposed purchase.

The CEOs and LPI argued that Minnesota Power's modeling unreasonably constrained the timing of when resources could be selected in a way that favored the selection of NTEC. They contended that the Company did this, in part, by only allowing NTEC to be selected in one year—2025—and limiting the model's ability to select other resources before that year.

LPI and the CEOs also maintained that the Company's analysis was not sufficiently robust because it did not consider a broad enough range of resources both in terms of type and size. For example, the CEOs argued that Minnesota Power should have included smaller blocks of solar generation to give the model more flexibility in matching this resource to the energy and capacity need in a given year.

The CEOs, further, argued that Minnesota Power had biased the model against selecting solar and wind generation by failing to recognize the capacity credit attributable to these resource types[37] and, in the case of wind, overstating its price. They contended that the capacity-credit values used by the Company conflicted with MISO guidance. And they argued that the Company's assumption that the price of new wind generation would be $45 per MWh throughout the planning period was not reasonable because wind costs have been declining over the last decade.

The CEOs also argued that the Company had underestimated its ability to use energy-efficiency measures to minimize the need for new generation. In particular, they asserted that the Company's forecasted energy savings were significantly lower than what it had achieved in recent years, and that it assumed unreasonably high prices for additional efficiency programs.

[37] "Capacity credit" is the portion of a generator's nameplate capacity that counts toward MISO's resource-adequacy requirements.

Finally, the CEOs and LPI argued that the 150 MW of base industrial demand-response capacity assumed by the Minnesota Power was too low. They noted that this figure is smaller than the Company's contracted demand-response capacity for 2017, smaller than its three-year historical average, and smaller than the five-year average based on the latest available data.

To demonstrate that the Company's assumptions impacted its modeling results, the CEOs conducted their own, more limited modeling, adjusting the inputs to reflect the CEOs' preferred assumptions. The CEOs concluded that Minnesota Power has very little need for capacity if different energy-efficiency and demand-response assumptions are used. They contended that 300 MW of wind and 100 MW of solar added between 2025 and 2030 would meet the actual need more cost-effectively than NTEC, while better aligning with statutory preferences for energy efficiency and renewable resources and Minnesota's greenhouse gas goals.[38]

5. The ALJ's Conclusions

The ALJ agreed with the CEOs and LPI that Minnesota Power used 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. As a result, she concluded that the Company's alternatives analysis failed to demonstrate that the NTEC purchase is the best and least-cost resource alternative to meet its customers' capacity and energy needs in 2025.

The ALJ found that the CEOs' limited modeling was not a substitute for the full analysis that should precede a size, type, and timing decision for a utility's resource selection. However, she concluded that their modeling results suggested that NTEC was not the most economic choice to meet the Company's resource needs in the late 2020s, and that a more robust alternatives analysis is necessary.

C. The Company's Analysis of Its Dispatchable-Capacity Need

1. Summary of Analysis

In addition to the above alternatives analysis, Minnesota Power analyzed the extent to which increased variable wind generation on its system would create a need for a dispatchable resource for reliability purposes and to mitigate its exposure to the energy market.

The Company estimated that its existing resource mix can only provide about 20 MW of "ramp"—the ability increase or decrease output quickly to match rapid changes in load or variable generation—and that its dispatchable resources would fall short of the ramping need approximately 18.5% of the time in 2025. But with NTEC, the Company projected that it would be able to meet the ramping needs of its own load more than 99% of the time.

Minnesota Power maintained that it has an obligation to plan for its system needs and develop a diverse and flexible power supply. And the Company argued that, while some of its ramping

[38] *See* Minn. Stat. §§ 216B.243, subd. 3a (requiring utility to explore using renewable energy when seeking certificate of need for nonrenewable facility), .2401 (establishing preference for cost-effective energy savings over other energy resources), 216H.02, subd. 1 (establishing greenhouse gas goals).

needs could potentially be met by the MISO market, if all utilities were to rely exclusively on MISO to meet their individual system needs, the broader regional power system would no longer be able to function reliably.

Minnesota Power also presented an outside consultant's economic analysis supporting its claim that the NTEC purchase was needed for flexibility and to mitigate exposure the energy market. Beginning with the base case from the Company's Strategist model, he compared NTEC's ability to meet the projected 2025 capacity deficit with that of three different wind-generation scenarios: 1.5, 1.75, and 2 times its forecasted 2025 wind generation. His analysis suggested that adding more wind in place of NTEC would expose Minnesota Power's ratepayers to additional market risk—both of having surplus electricity to sell into the market when prices are low and, at other times, of having to purchase electricity from the market when prices are high.

2. Responses to the Company's Analysis

a. CEOs

The CEOs criticized Minnesota Power's analysis of its ramping capability, arguing that the Company understated or excluded the ramping capability of resources already on its system, and overlooked potential new ramping resources besides NTEC.

The CEOs argued that Minnesota Power overstated its obligation to balance load and generation in real time, stating that the Company's generators, like other utilities in the region, are dispatched and ramped by MISO. They contended that, in the context of a modern, regional power system like MISO's, an individual utility rarely needs to rely exclusively on its own resources to meet supply and demand variability.

The CEOs also raised several concerns with the outside consultant's analysis. In particular, they argued that:

- The consultant used an inappropriate methodology;
- Other studies have shown that geographically dispersed renewable energy sources can mitigate these sources' variability;
- His study did not take into account the effects of geographical diversity; and
- His study did not consider whether renewable resources outside of the utility's geographic footprint, or a portfolio of renewable resources in combination, could serve to balance the variability of renewable resources.

b. Department

The Department conducted its own review of Minnesota Power's dispatchable-capacity needs, analyzing the extent to which the NTEC purchase was needed mitigate the risks posed by large quantities of wind generation resources on Minnesota Power's system.

The Department framed the issue as whether "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."

Focusing on 2025, the Department compared forecasted load to available power supply to estimate the Company's exposure to the spot market for each hour of the year. The Department concluded that the level of market exposure appears to be manageable with the Company's current resource mix, but that this could change based on various factors. The Department also concluded that the proposed NTEC purchase would have some value in mitigating exposure to market-price spikes.

3. The ALJ's Conclusions

The ALJ concluded that Minnesota Power had failed to demonstrate that the 250 MW NTEC purchase was needed and reasonable as a dispatchable, flexible resource to balance its system and mitigate exposure to energy markets.

She determined that Minnesota Power had overstated its ramp need in 2025 by ignoring existing dispatchable resources on its system and failing to consider new ramping alternatives other than NTEC. Nor did she find the outside consultant's analysis of market exposure particularly helpful for determining whether NTEC was needed and reasonable for dispatchability purposes. She found that his model results were fairly general and did not meaningfully quantify the market risk that would result from replacing NTEC with wind generation.

Finally, the ALJ noted that the Department's analysis of market exposure showed that the Company's market risk in 2025 appears to be manageable with its existing resource mix. She concluded that the Department's analysis suggests that the addition of the NTEC purchase is not necessary for dispatch purposes in 2025.

D. The Department's Strategist Analysis

1. Summary of Modeling

The Department conducted its own Strategist modeling in reviewing the NTEC purchase. Rather than use the base case prepared by Minnesota Power for this proceeding, the Department relied on an update to the base case that it had vetted during the Company's 2015 IRP proceeding. The Department made four significant updates to the 2015 IRP base case:

- Updated the demand forecast;
- Updated the prices for generic wind units;
- Updated the prices for generic solar units; and
- Made a new 250 MW natural gas combined-cycle resource (NTEC) available for selection in 2025.

The Department retained a generic 200 MW natural gas combined-cycle unit from the 2015 IRP model and made it available for selection in each year of the new study period. NTEC was the first combined-cycle gas generator to be selected by Strategist in the Department's modeling. When two intermediate units were selected, NTEC was selected first, followed by the 200 MW option.

The Department's model consistently selected NTEC as part of the least-cost expansion plan, irrespective of the levels of forecasted demand, energy storage, and demand response, or application of environmental costs. In general, under the Department's model, Strategist added NTEC to the Company's system because its energy output reduced overall societal costs, not because NTEC fills a capacity need.

The Department concluded that its modeling supported adding a 250 MW intermediate resource by 2025. The Department also noted that the need for an approximately 200 MW combined-cycle resource was consistent with the conclusions of its prior analyses in Minnesota Power's recent resource plans.

2. Criticism of the Department's Modeling

The CEOs raised concerns about the Department's approach of updating the last IRP base case and questioned a number of assumptions used by the Department in its modeling. They asserted that the Department's alternatives analysis was unreasonable because NTEC could only be selected in 2025, predetermining the timing of that option.

In addition, the CEOs argued that:

- the wind prices used by the Department were too high;
- the demand-response level the Department used was less than that used by the Company in its modeling and far less than the 194 MW level recommended by the CEOs;
- the Department's use of contingency bands in its forecast was not a reasonable substitute for separately modeling variations in demand response or storage; and
- the Department did not include the Nobles 2 wind farm in its calculation of the firm capacity available to the Company.

3. The ALJ's Conclusions

The ALJ agreed with the CEOs that the Department's Strategist modeling included some unreasonable assumptions. In particular, she concluded that the Department's results were biased in favor of NTEC because the Department only allowed NTEC to be selected in 2025. She reasoned that since the Commission has not made a decision that a resource of this type is needed in 2025, the Department's modeling unreasonably constrained the resource options.

In addition, the ALJ agreed with the CEOs that the levels of demand response and energy efficiency modeled by the Department were too low. Because these underlying assumptions were not reasonable, she concluded, the Department's Strategist modeling is not sufficiently robust or reliable for purposes of determining whether the 250 MW NTEC purchase is needed and reasonable.

E. Commission Action

Having carefully reviewed the record, the Commission finds that the NTEC purchase, as proposed, is needed and reasonable based on all relevant factors, including those identified by the Commission in its Referral Order and by the ALJ in her Second Prehearing Order.

The Department's Strategist modeling established that NTEC, in conjunction with the other elements of the Energy*Forward* resource package, is a cost-effective resource for meeting

Minnesota Power's energy needs in the wake of the Company's retirement of 700 MW of baseload coal-fired generation. Even if Minnesota Power experiences no capacity needs, it will be purchasing energy from the MISO market, and NTEC provides a hedge against spikes in market prices and reduces overall costs by providing an economic source of energy.

The Department's model consistently selected NTEC as least-cost under scenarios with various ranges of customer demand, energy storage, and demand response, and with or without environmental costs. Moreover, by comparing NTEC's impact on overall system costs to that of wind and solar resources, the Department's analysis met the renewable-resource requirements of Minn. Stat. §§ 216B.2422 and 216B.243, subd. 3a.

Because the NTEC purchase is cost-effective, and to simplify the accounting, the Department recommended that Minnesota Power consider increasing its share of NTEC's capacity from 48% to 50%, and the Company agreed to do so. The Commission agrees that it is reasonable for Minnesota Power to take 50% of NTEC's capacity. A 50% share is within the margin of reasonableness in light of the identified need and will simplify the accounting and reporting related to the transaction.

The CEOs criticized several of the assumptions the Department used in its modeling. However, to the extent these criticisms have merit, correcting the assumptions would likely not have changed the outcome. The Commission therefore disagrees with the ALJ's conclusion that the Department's modeling was not sufficiently robust or reliable for purposes of determining whether the NTEC purchase is needed and reasonable.

The ALJ relied on the CEOs' claim that the Department limited its model's selection of an NTEC-like resource to 2025, prejudging the timing of the resource need. However, the Department made a generic 200 MW combined-cycle resource available for selection in each year of the planning period. What was limited to 2025 was the selection of a combined-cycle resource with NTEC's specific characteristics. This was reasonable: there is nothing in the record to suggest that NTEC is available in any other year.

The ALJ also credited the CEOs' claims that the Department modeled insufficient demand response and energy efficiency. Resource-planning assessments are necessarily imprecise; they involve evaluating multiple future scenarios to account for uncertainty. In this case, the Department's modeling captured the effect of a wide range of both demand response and energy efficiency by varying customer demand and energy efficiency levels. In other words, even assuming the CEOs are correct that greater levels of demand response and energy efficiency should have been evaluated, their preferred assumptions are still within the range of forecast contingencies evaluated by the Department.

In sum, the Department evaluated reasonable ranges for key variables, and its Strategist results are sufficiently robust and reliable for purposes of determining whether the NTEC energy purchase is needed and reasonable. And since the Department's analysis independently established a need for the NTEC purchase, the Commission does not reach the issue of whether the Company's Strategist modeling was sufficient.

VI. NTEC Agreements Approved with Conditions

Having determined that the NTEC purchase is needed and reasonable based on all relevant factors, the Commission will approve the affiliated interest agreements needed to effectuate the purchase, with the conditions discussed below.

A. The Commission approves the affiliated-interest agreements with the conditions recommended by the Department.

In addition to its analysis of the need for NTEC, the Department closely scrutinized all other aspects of the NTEC transaction, including the RFP process, project cost estimates, and the pricing structure reflected in the Capacity Dedication Agreement. Based on its review, the Department recommended that the Commission find the NTEC agreements reasonable and in the public interest, subject to a number of conditions.[39]

The Commission concurs and will approve the NTEC agreements, finding them reasonable and the public interest under the affiliated-interest statute and rules, Minn. Stat. § 216B.48 and Minn. R. 7825.1900–.2300. This approval will be subject to the conditions recommended by the Department, which are set forth in Attachment A and incorporated herein.

In addition, approval of the NTEC agreements will be subject to the following conditions and understandings:

B. The Commission makes no determination that the CDA's declining-balance pricing structure is necessarily appropriate for rate recovery.

Under the CDA, Minnesota Power will pay South Shore a monthly charge representing its share of NTEC's installed costs and MISO network-upgrade costs computed on the same basis as if the Company itself were the owner of NTEC.

According to Minnesota Power, the CDA's pricing structure essentially converts the installed cost of NTEC into a revenue requirement based on assumed construction costs, assumed cost of capital, and other inputs. The costs are then translated into a payment stream on a dollars per kilowatt per month basis for each cost component. The CDA's pricing is designed to simulate a rate-base asset, with the per-unit cost decreasing over time as NTEC depreciates.

LPI argued that the CDA's declining-balance pricing structure would result in higher costs for customers in the early years of the CDA when Minnesota Power has the least need for NTEC's capacity. LPI recommended that, if the Commission finds the NTEC purchase to be needed and reasonable, it require the Company to undertake further analysis and potentially modify the CDA to provide for a more economic cost structure—for example, a levelized payment structure like that typically used in power purchase agreements.

While structuring the NTEC purchase to mimic a rate-base asset appears reasonable in general, the record in this case is not sufficiently developed on the issue of whether costs associated with a declining-balance pricing structure are appropriate for rate recovery. Accordingly, in any future

[39] The Department and the Company reached agreement on these conditions. *See* Minnesota Power Initial Brief, Attachment B (listing agreed conditions).

proceeding involving the recovery of NTEC costs, there will be no presumption that the costs inherent in the CDA's pricing structure are necessarily appropriate for rate recovery. Instead, the Company will be required to establish the propriety of these costs as compared to other cost structures that Minnesota Power chose not to use, which would include a levelized payment structure.[40]

C. Minnesota Power shall continue to develop a demand-response rider to be filed in a new docket.

On March 12, 2018, the Commission issued its *Findings of Fact, Conclusions, and Order* in Minnesota Power's 2016 rate case (Rate Case Order).[41] The Commission directed Minnesota Power to work with LPI and other stakeholders to develop a demand-response rider and corresponding cost-recovery methodology to submit to the Commission.[42] The Commission directed that the demand-response rider be addressed either in the Energy*Forward* docket or in a new docket.

LPI proposed a demand-response rider that would allow for up to 300 MW of total interruptible load. Minnesota Power expressed concern that LPI's proposal does not provide any assurance that customers would curtail their demand when needed, or explain how the cost of the program would be recovered.

The ALJ concluded that the record was not sufficiently developed to make a decision on a demand-response rider in this docket. However, she noted that Minnesota Power and LPI have continued to engage in informal discussions on the development of a demand-response rider, and are committed to continuing these efforts. She recommended that the issue be addressed in a new miscellaneous docket.

The Commission agrees with the ALJ that demand-response options must be better developed before a rider is approved. Minnesota Power, LPI, and other stakeholders should continue to develop a demand-response rider and corresponding methodology for cost recovery in a new miscellaneous-docket filing; and this filing should be submitted for Commission approval within six months after the date of the final written order in the Company's 2016 rate case.

---

[40] In addition, the Company and the Department agreed that rate recovery of CDA costs would be subject to a "soft cap" based on NTEC's estimated costs, escalated according to the Handy-Whitman index. The Commission finds that it is reasonable to use an escalator for the soft cap and that, as a beginning baseline, the Handy-Whitman index is reasonable. However, this will not preclude introduction of evidence by the Department or other parties of a different escalation amount or mechanism in a future rate case.

[41] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-16-664.

[42] Rate Case Order, at 115.

D. Minnesota Power's next resource plan will include a detailed plan for the early retirement of its remaining coal-fired generators.

Minnesota's Next Generation Energy Act establishes goals for reducing statewide greenhouse gas emissions to a level at least 15% below 2005 levels by 2015, at least 30% below 2005 levels by 2025, and at least 80% below 2005 levels by 2050.[43]

Minnesota Power projects that it will exceed its pro-rata share of the 2025 goal, achieving a 42% reduction by 2025. After 2025, however, carbon-dioxide emissions on the Company's system are expected to remain steady, meaning that further measures will be needed to meet the 80% reduction goal for 2050. The CEOs stressed that the electricity sector will likely need to achieve carbon-emission reductions *higher* than those of other sectors if Minnesota is to meet its greenhouse gas emissions-reduction goals.

While the Energy*Forward* package is a step in the right direction, it does not address the biggest obstacle to Minnesota Power achieving state emission-reduction goals in the long term: the Company's continued reliance on the two coal-fired generators at its Boswell Energy Center. These two generators (Unit 3 and Unit 4) have a combined capacity of more than 800 MW, and though the units are scheduled to be fully depreciated in 2034–2035, the Company has not committed to any plan for their retirement.

In its recent rate case, the Company proposed to lengthen the depreciation schedule of Boswell Units 3 and 4 as a rate-mitigation measure. The proposal would have extended their retirement date for accounting purposes to 2050. And while the Company disclaimed any intent to operate them past 2035, it provided an engineering study stating that there was no technical reason that, with appropriate maintenance and upgrades, the plant could not be operated until 2050.

The Commission initially accepted Minnesota Power's rate-mitigation proposal and extended the Boswell units' accounting lives to 2050.[44] It also accepted the CEOs' related proposal to require the Company to file a plan to securitize any unrecovered depreciation expenses remaining when the Boswell units are retired prior to 2050. However, on reconsideration, the Commission found the Company's rate-mitigation proposal unnecessary and restored the units' previous depreciation schedule.[45]

Given this history and the need to take further steps to cut greenhouse gas emissions in the medium to long term, the Commission will require Minnesota Power to include the following information in its next IRP filing:

- A baseload retirement analysis that thoroughly evaluates and includes a plan for the early retirement of Boswell 3 and 4, individually and in combination; and

---

[43] Minn. Stat. § 216H.02, subd. 1.

[44] Rate Case Order, at 13–14.

[45] Docket No. E-015/GR-16-664, Order Granting Reconsideration in Part, Revising March 12, 2018 Order, and Otherwise Denying Reconsideration Petitions, at 3–4 (May 29, 2018). The Commission also retained a modified version of the CEOs' securitization proposal, requiring the Company to report on the securitization of stranded assets generally. *Id.* at 4–5.

- A securitization plan that could be used to mitigate potential ratepayer impacts associated with any early retirement of one or both of the Boswell 3 and 4 facilities.

In addition, the Commission will require Minnesota Power, in developing the modeling analysis to be used in its next resource plan, to consult with stakeholders, including but not limited to the Department and the CEOs, regarding the Company's modeling inputs and parameters. Consulting with stakeholders will help ensure a robust analysis and, ideally, minimize the number of disputes that arise over the assumptions used.

Finally, Minnesota Power's next resource plan is currently due on October 1, 2019. However, in light of the additional analysis required by this order, the Commission will extend the deadline to October 1, 2020. This extension will give the Company sufficient time to consult with stakeholders, conduct the necessary analysis, and file a resource plan that will provide the Commission and stakeholders with useful information.

VII. FPE Rider Changes and Automatic-Adjustment Rule Variance

A. Introduction

Under Minn. Stat. § 216B.16, subd. 7, and associated rules,[46] the Commission may allow a public utility to automatically adjust its rates to reflect changes in the cost of fuel and purchased power, as well as federally regulated wholesale rates for energy delivered through interstate facilities. The Commission has approved a "Fuel and Purchased Energy Rider" (FPE Rider) as Minnesota Power's mechanism for adjusting these costs.[47]

In this case, the Company has requested that the Commission authorize changes to its FPE Rider to ensure that fuel costs and MISO market costs related to the NTEC purchase are recovered and that MISO revenues realized under the Capacity Dedication Agreement flow back to customers through the rider. The Company also requested a variance to the Commission's automatic-adjustment rules to allow it to flow costs and revenues associated with NTEC through the FPE Rider in the same manner as if the plant were owned by the Company.

The Department agreed that the Company's proposed recovery of fuel costs and MISO costs and revenues through the FPE Rider was consistent with Minnesota regulatory requirements and appeared to be correctly reflected in the Company's proposed tariff language. No other party submitted testimony regarding, or objected to, Minnesota Power's FPE Rider proposal.

B. Commission Action

Because the ALJ concluded that the NTEC purchase was not needed, she did not address whether the proposed revisions to Minnesota Power's FPE Rider were in the public interest or whether the proposed rule variances should be granted. The Commission, however, finds the NTEC purchase needed and reasonable and must therefore address Minnesota Power's proposed FPE Rider changes and rule variances.

---

[46] *See* Minn. R. 7825.2390–.2850 (hereinafter "automatic-adjustment rules").

[47] *See* Minnesota Power's Electric Rate Book, Volume I, Section V, at 50.0–50.2.

The Commission finds that the Company's proposed FPE Rider tariff changes are in the public interest, subject to the Department's suggested conditions and compliance requirements set forth in Attachment A, because the changes are necessary to effectuate the NTEC purchase.

The Commission will also grant Minnesota Power's request for variances to the automatic-adjustment rules. Under Minn. R. 7829.3200, the Commission will vary any of its rules upon making the following findings:

1. Enforcing the rule would impose an excessive burden upon the applicant or others affected by the rule;
2. Granting the variance would not adversely affect the public interest; and
3. Granting the variance would not conflict with any standards imposed by law.

The Commission will vary the automatic-adjustment rules as requested by Minnesota Power, making the following findings:

1. Enforcing the automatic-adjustment rules would impose an excessive burden on Minnesota Power because doing so would require that the Company own NTEC to be able to pass costs through the FPE Rider, and would unreasonably delay recovery of fuel costs to serve the Company's customers.
2. Granting a variance will not adversely affect the public interest, but will further the public interest by allowing Minnesota Power's ratepayers to benefit from NTEC's low-cost generation.
3. Finally, granting the variance would not conflict with any standards imposed by Minnesota law.

For the foregoing reasons, the Commission will authorize Minnesota Power to revise its FPE Rider as proposed and will grant the requested variance to the automatic-adjustment rules under Minn. R. 7829.3200.

VIII. Other Potentially Applicable Statutes

The Department argued that, in addition to the affiliated-interest statute, three other statutes apply to the agreements by which Minnesota Power will effect the NTEC purchase: Minn. Stat. § 216B.49 (the securities statute), Minn. Stat. § 216B.50 (the property-acquisition statute), and Minn. Stat. § 216B.1694 (the innovative-energy-project statute).

A. Securities Statute

Under Minn. Stat. § 216B.49, it is unlawful for a public utility to issue securities without prior approval from the Commission.[48] A "security" includes the "assumption of any obligation or liability as a guarantor, endorser, surety, or otherwise in the security of another person."[49] The Commission must grant permission to issue a security if it finds that the proposed security

[48] Minn. Stat. § 216B.49, subd. 3.

[49] *Id.*, subd. 1.

issuance is “reasonable and proper and in the public interest and will not be detrimental to the interests of the consumers and patrons affected thereby.”[50]

Minnesota Power has provided a guaranty to Dairyland for South Shore’s obligations under the D&C and O&O agreements. According to the Company, the likelihood that the guaranty will be called upon is very low. Nevertheless, it committed not to pass on to its customers any costs incurred under the guaranty without Commission approval, and recognizes that it would bear the burden of proving both the recoverability and reasonableness of any such costs.

The Department recommended that the Commission approve the Guaranty Agreement on the following conditions:

- If Minnesota Power incurs costs under the agreement, it must not recover any such costs from its ratepayers unless and until it demonstrates to the Commission that such costs are rare, unforeseen, and reasonable to charge to its ratepayers; and
- The Company would bear the burden of demonstrating that it would be reasonable to recover any such rare and unforeseen costs from its customers.

The Department concluded that this approach would protect the Company’s ratepayers from undue exposure to risks related to its unregulated affiliate, South Shore.

The Commission agrees and finds that, subject to the Department’s proposed conditions, the Guaranty Agreement is reasonable and proper and in the public interest and will not be detrimental to the interests of the consumers and patrons affected thereby. The Commission will approve the Guaranty Agreement subject to these conditions, which are also set forth in Attachment A.

B. Property Acquisition Statute

Under Minn. Stat. § 216B.50, a public utility may not “sell, acquire, lease, or rent any plant as an operating unit or system in this state for a total consideration in excess of $100,000” without prior approval from the Commission. The Commission must grant its approval if it finds that “the proposed action is consistent with the public interest.”

The Department concluded that Minn. Stat. § 216B.50 applies to the NTEC transaction, reasoning that Minnesota Power will effectively be leasing NTEC from South Shore once the plant is operational.

Minnesota Power disagreed, contending that the CDA does not convey a property interest in NTEC itself, but instead functions like a power purchase agreement. But even if section 216B.50 applies, the Company argued, it has supplied the information necessary to establish that the transaction is consistent with the public interest.

[50] *Id.*, subd. 4.

Further, if the Commission finds that the statute applies, the Company stated that it would request a variance from certain information requirements for property-acquisition petitions.[51] The Department supported the Company's request for a variance.

The Commission agrees that section 216B.50 applies to the NTEC agreements and finds that the agreements are in the public interest for the reasons already discussed. The Commission also finds that the criteria for granting a variance have been met under Minn. R. 7829.3200, and grants the Company's requested variance.

C. Innovative Energy Project Statute

Minn. Stat. § 216B.1694 creates regulatory incentives to develop an "innovative energy project" that uses coal as the primary fuel in a combined-cycle configuration. In particular, the statute provides that such a project

> shall, prior to the approval by the commission of any arrangement to build or expand a fossil-fuel-fired generation facility, or to enter into an agreement to purchase capacity or energy from such a facility for a term exceeding five years, be considered as a supply option for the generation facility, and the commission shall ensure such consideration and take any action with respect to such supply proposal that it deems to be in the best interest of ratepayers.[52]

Because NTEC is a fossil-fuel-fired generation facility and Minnesota Power has entered into agreements to purchase capacity and energy from NTEC for a term exceeding five years, the Department reasoned that Minn. Stat. § 216B.1694 applies to the Commission's approval of the NTEC agreements. However, the Department nonetheless concluded that the NTEC purchase complies with the statute because "a coal gasification project will not pass a ratepayer benefit/cost test."[53]

Minnesota Power questioned the statute's applicability, stating that it was not aware of the existence of any proposals for innovative energy projects that would need to be considered before the NTEC purchase is approved. The Company noted that the Commission previously found that Excelsior Energy Inc.'s Mesaba Project was an "innovative energy project" under the statute. However, that project was never constructed and apparently is no longer being actively pursued.

Although it is not clear that Minn. Stat. § 216B.1694 applies to the NTEC purchase, the Commission finds that the purchase would comply with the statute in any event, since it would not be in ratepayers' best interest for Minnesota Power to acquire generation from a coal-fired plant instead of from NTEC.

For the foregoing reasons, the Commission finds that Minnesota Power has met the requirements of all applicable statutes.

---

[51] *See* Minn. R. 7825.1800(B) (incorporating information requirements (A)–(J) from Minn. R. 7825.1400). Specifically, Minnesota Power requested a variance to Minn. R. 7825.1400(E)–(J).

[52] Minn. Stat. § 216B.1694, subd. 2(4).

[53] Rakow Direct, Schedule 3, at 4.

ORDER

1. The Commission adopts the ALJ's Report's findings and conclusions as modified by the July 23, 2018 Exceptions of the Department of Commerce (and the October 23, 2018 corrections to those Exceptions), and insofar as they are consistent with this order.

2. The Commission approves the NTEC agreements as reasonable and consistent with the public interest under the affiliated-interest statute and rules, Minn. Stat. § 216B.48 and Minn. R. 7825.1900–.2300, subject to the following conditions and understandings.

3. The Commission adopts and incorporates the Department's proposed conditions and compliance requirements and the Company's commitment to comply (Attachment A).

4. In any future rate case in which Minnesota Power seeks to recover costs associated with the NTEC purchase, the Company will be required to prove the propriety of the costs associated with this deal structure in contrast to other cost structures that the Company chose not to use, which would include a PPA-like levelized payment structure.

5. Minnesota Power shall continue to develop, based on stakeholder input, a demand-response rider and corresponding methodology for cost recovery and shall file the rider in a new miscellaneous docket within six months of the date of the final written order in Docket No. E-015/GR-16-664.

6. Minnesota Power shall include the following in its next resource plan:

   a. A baseload retirement analysis that thoroughly evaluates and includes a plan for the early retirement of Minnesota Power's two remaining coal plants, Boswell 3 and 4, individually and in combination;

   b. A securitization plan that could be used to mitigate potential ratepayer impacts associated with any early retirement of one or both of the Boswell 3 and 4 facilities; and

   c. A proposed bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years, as set forth in Attachment A, for Commission consideration and potential approval.

7. In developing the modeling analysis to be used in its next resource plan, Minnesota Power shall consult with stakeholders, including but not limited to the Department of Commerce and the Clean Energy Organizations, regarding the Company's modeling inputs and parameters.

8. The deadline for Minnesota Power to file its next resource plan is extended to October 1, 2020.

9. The Commission finds the Company's proposed revisions to its FPE Rider in the public interest under Minn. Stat. § 216B.16, subd. 7(3), and Minn. R. 7825.2390–.2600 and grants its requested variance to the automatic-adjustment rules.

10. The Commission approves the Guaranty Agreement, subject to the applicable conditions set forth in Attachment A.

11. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf

Daniel P. Wolf
Executive Secretary

This document can be made available in alternative formats (e.g., large print or audio) by calling 651.296.0406 (voice). Persons with hearing loss or speech disabilities may call us through their preferred Telecommunications Relay Service or email consumer.puc@state.mn.us for assistance.

Attachment A
Additional Compliance Requirements

Conditions of Approval	Comments
Affiliated Interest Statute. Recommends that the Commission "approve MP's affiliated interest agreements as being reasonable and in the public interest under Minnesota Statutes § 216B.48, subd. 3."[73]	Minnesota Power accepts this condition.
Property Acquisition Statute. Recommends that the Commission "grant MP's requested variance to Minnesota Rules part 7825.1400, Items E to J."[74] Recommends that the Commission "determine that MP has met the requirements of Minnesota Statutes § 216B.50."[75]	Minnesota Power accepts this condition if this statute is found applicable.[76]
Innovative Energy Project Statute. Recommends that the Commission "determine that MP has met the requirements of Minnesota Statutes § 216B.1694, subd. 2(4)."[77]	Minnesota Power accepts this condition if this statute is found to apply. [78]
Environmental Externality Values. Recommends that the Commission "determine that MP has met the requirements of Minnesota Statutes § 216B.2422, subd. 3(a)."[79]	Minnesota Power agrees that the requirements have been met.[80]

[73] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).
[74] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).
[75] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).
[76] *See* Ex. MP-14, at 23, 25 (Pierce Rebuttal).
[77] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).
[78] *See* Ex. MP-14, at 29 (Pierce Rebuttal).
[79] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).
[80] *See* Ex. MP-17 and MP-18, at 2, 30; (EJP) Rebuttal Schedule 2 (Palmer Rebuttal) (Public and Nonpublic).

Conditions of Approval	Comments
Bidding Process in Next IRP. Recommends that the Commission "order MP to include, in the Company's next IRP, a proposed bidding process for Commission consideration and potential approval under Minnesota Statutes § 216B.2422, subd. 5; the process should: • Apply to supply-side acquisitions of 100 MW or more and lasting longer than five years; and • Include the six reforms provided by Mr. Frederickson."[81] The six steps are: 1. Ensure that the RFP is consistent with the Commission's then-most-recent IRP order and direction regarding size, type, and timing; 2. Provide the Department and other stakeholders with notice of RFP issuances; 3. Notify the Department and other stakeholders of material deviations from those timelines; 4. Update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings; 5. Where Minnesota Power or an affiliate proposes a project, the Company will engage an independent evaluator to oversee the bid process and provide a report for the Commission; and Request that the independent evaluator specifically address the impact of material delays or changes of circumstances on the bid process.[82]	Minnesota Power accepts this condition.[83] [84]
250 MW of Dedicated Capacity. Recommends that Commission approval "should include MP's commitment regarding at least 250 MW of dedicated capacity in the approval."[85]	Minnesota Power accepts this condition and agrees "the amount of installed capacity dedicated to it under the CDA will not be lower than 250 MW."[86]

[81] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).
[82] Ex. MP-24, at 14-16 (Frederickson Rebuttal).
[83] Ex. MP-24, at 14-15 (Frederickson Rebuttal).
[84] *See* Ex. MP-28 (Pierce Opening Statement).
[85] Ex. DER-11 and DER-12, at 27, 71 (Rakow Surrebuttal) (Public and Nonpublic).
[86] Ex. MP-26 and MP-27, at 15 (Supinski Rebuttal) (Public and Nonpublic).

Conditions of Approval	**Comments**
D&C Agreement Amendments. Recommends that Commission approval should "include MP's commitment regarding amendments to the D&C Agreement in the approval."[87]	Minnesota Power agrees: "During the pendency of this contested case proceeding and prior to approval of the assignment, the Company does not anticipate that any changes to the D&C Agreement would occur. But, to address Dr. Rakow's comment, Minnesota Power will require SSE to allow the Commission to review and pre-approve any amendments if they do occur. Once the assignment becomes effective, the D&C Agreement could only be amended if Minnesota Power, as the Construction Agent, consents to such an amendment. Minnesota Power commits that, in its role as Construction Agent, it will not agree to any material changes to the D&C Agreement that adversely impact customer costs without seeking regulatory concurrence."[88]
O&O Agreement Amendments. Recommends that Commission approval should "include MP's commitment regarding amendments to the O&O Agreement in the approval."[89]	Minnesota Power agrees to the following commitment: "As with the issue of potential amendments to the D&C Agreement …, during the pendency of this contested case proceeding and prior to approval of the Assignment, the Company does not anticipate any changes to the O&O Agreement would occur. Nevertheless, Minnesota Power commits that it will require SSE to allow the Commission to review and pre-approve any amendments if they do occur. Once the assignment becomes effective, the O&O Agreement could only be amended if Minnesota Power, as the Operating Agent, consents to such amendment. Minnesota Power commits that it will not agree to any material changes to the O&O Agreement that adversely impact customer costs without seeking regulatory concurrence."[90]
Abandoned Plant. Recommends that Commission approval should "include MP's commitment regarding abandoned plant in the approval."[91]	Minnesota Power agrees that "prior to obtaining cost recovery for an abandoned investment, Minnesota Power would need to obtain Commission approval either in a rate case or another proceeding. In particular, the Company would bear the burden of requesting recovery of its share of abandoned plant costs and would be required to prove the reasonableness of such cost recovery under the circumstances."[92]

[87] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).
[88] Ex. MP-26 and MP-27, at 17 (Supinski Rebuttal) (Public and Nonpublic).
[89] Ex. DER-11 and DER-12, at 71 (Rakow Surrebuttal) (Public and Nonpublic).
[90] Ex. MP-26 and MP-27, at 22 (Supinski Rebuttal) (Public and Nonpublic).
[91] Ex. DER-11 and DER-12, at 72 (Rakow Surrebuttal) (Public and Nonpublic).
[92] Ex. MP-26 and MP-27, at 32 (Supinski Rebuttal) (Public and Nonpublic).

Conditions of Approval	Comments
CDA Amendments. Recommends that Commission approval should "require MP to make a compliance filing to address the following issues in the CDA: • the definition of ANUC in section 6.1.2; • clarification of "it" in section 11.6; • clarification of "either" in section 13.1; and • the footnotes in Appendix H[.]"[93]	Minnesota Power agrees to make a compliance filing to correct the following issues in the CDA: • the definition of ANUC in section 6.1.2; • clarification of "it" in section 11.6; and • the footnotes in Appendix H[.]"[94] However, the extraneous word "either" is in the first sentence of Section 13.1 of the O&O Agreement, not the CDA.[95] Minnesota Power agrees to correct this item as well.
Capital Costs without Escalation. Recommends that "the capital costs for the gas plant and related interconnection costs including capitalized interest and AFUDC should be approved in today's dollars without escalation," assuming either a 50% or 48% ownership.[96]	Minnesota Power accepts this condition and is willing to proceed with unescalated costs, provided that costs are escalated using a pre-agreed index, such as Handy-Whitman. [97] [98]
Handy-Whitman Index – Escalation. Agrees to the Company's "use of the Handy-Whitman index for purposes of escalation in the Company's future rate case where MP includes the total in-service costs of the gas plant and related interconnection costs."[99]	Minnesota Power accepts this condition.[100]
Decommissioning Costs. Recommends the inclusion ~~in capital costs~~ of an additional $10 million for decommissioning costs (assuming either a 50% or 48% ownership).[101] ~~Recommends that the additional $10 million for decommissioning be reflected as an increase in the soft cap.~~[102]	Minnesota Power accepts this condition.[103]
Independent Engineering Study – Decommissioning. Recommends that, for decommissioning, "MP be required to provide an independent engineering study and to use at least $10 million for decommissioning costs.[104]	Minnesota Power will provide an independent engineering study to the Department at the time of rate recovery request.[105]

[93] Ex. DER-11 and DER-12, at 72 (Rakow Surrebuttal) (Public and Nonpublic).

[94] *See* Ex. MP-25, at 3-4 (Supinksi Direct); Ex. MP-26 and MP-27, at 39-40 (Supinski Rebuttal) (Public and Nonpublic).

[95] Ex. MP-6, at G-61 (Initial Petition – Volume 4 Appendices F-J) (Nonpublic); Ex. DER-8 and DER-9, SRR-5, at 4 (Rakow Direct) (Public and Nonpublic) (DOC IR-18).

[96] Ex. DER-6 and DER-7, at 30-31 (Campbell Surrebuttal) (Public and Nonpublic).

[97] Ex. MP-26 and MP-27, at 33-36 (Supinski Rebuttal) (Public and Nonpublic).

[98] *See* Ex. MP-26 and MP-27, at 36 (Supinski Rebuttal) (Public and Nonpublic).

[99] Ex. DER-6 and DER-7, at 31 (Campbell Surrebuttal) (Public and Nonpublic).

[100] Ex. MP-26 and MP-27, at 36 (Supinski Rebuttal) (Public and Nonpublic).

[101] Ex. DER-6 and DER-7, at 31 (Campbell Surrebuttal) (Public and Nonpublic).

[102] Ex. DER-6 and DER-7, at 7, 13, 31 (Campbell Surrebuttal) (Public and Nonpublic).

[103] *See* Ex. MP-26 and MP-27, at 42 (Supinski Rebuttal) (Public and Nonpublic).

[104] Ex. DER-6 and DER-7, at 32 (Campbell Surrebuttal) (Public and Nonpublic).

[105] *See* Ex. MP-26 and MP-27, at 42 (Supinski Rebuttal) (Public and Nonpublic).

Conditions of Approval	**Comments**
Third-Party Transmission Soft Cap. Concludes that the third-party transmission amounts provided by Minnesota Power in response to DOC IR 22 "provide a reasonable soft cap amount that should be used to evaluate the costs in future rate recovery proceedings."[106] Specifically concludes that "MP's plan to reconsider the cost-effectiveness of the project, in the event that costs exceed the negotiated third-party transmission upgrades amount, appears to be reasonable."[107]	Minnesota Power accepts this condition.[108]
Updating Exhibits C-1 and D-1 (Supinski Rebuttal Testimony, Schedules 5&6). "The $10 million in decommissioning costs should be reflected and updated on Exhibit C-1 which MP should file as a corrected Exhibit C-1. I also recommend that MP provide the update Exhibit C-1 with $10 million in decommissioning costs and Exhibit D-1 electronically with formulas intact."[109]	Minnesota Power agrees to provide the electronic versions of Exhibits C-1 and D-1 with formulas intact. ~~The $10 million in decommissioning costs are already accurately shown in Exhibit C-1, which reflects 50% of the overall plant decommissioning costs.[110]~~
Future Rate Case Recovery. "[R]ate case recovery means final cost recovery including the related assumptions that will be determined in MP's future rate case. However, the capital costs approved in this docket including the soft cap and O&M costs used in the Strategist Modeling on Schedule 3 of Ms. Supinski's Rebuttal Testimony, will be the starting point for review in the rate case, and recovery of any higher costs would require MP to support that it is reasonable to charge the costs to its ratepayers."[111]	Minnesota Power accepts this condition.
FPE Rider. Minnesota Power's proposed rate recovery of fuel costs, MISO market costs, and MISO market revenues through the FPE Rider "appears to be consistent with Minnesota requirements and appears to be correctly reflected in MP's tariff language."[112] "MP also clarified that it will not be recovering its O&M costs, depreciation costs, and MISO administrative costs through its FPE Rider."[113]	Minnesota Power accepts this condition.[114]

[106] Ex. DER-6 and DER-7, at 31 (Campbell Surrebuttal) (Public and Nonpublic).
[107] Ex. DER-6 and DER-7, at 9 (Campbell Surrebuttal) (Public and Nonpublic).
[108] *See* Ex. MP-26 and MP-27, at 37-38 (Supinski Rebuttal) (Public and Nonpublic).
[109] Ex. DER-6 and DER-7, at 32 (Campbell Surrebuttal) (Public and Nonpublic).
[110] Ex. MP-26 and MP-27, at 42, 47-48, Rebuttal Schedules 5 and 6 (Supinski Rebuttal) (Public and Nonpublic).
[111] Ex. DER-6 and DER-7, at 32 (Campbell Surrebuttal) (Public and Nonpublic).
[112] Ex. DER-6 and DER-7, at 17, 33 (Campbell Surrebuttal) (Public and Nonpublic).
[113] Ex. DER-6 and DER-7, at 17, 33 (Campbell Surrebuttal) (Public and Nonpublic).
[114] *See* Ex. MP-2 and MP-3, at 4-54 to 4-61 (Initial Petition – Volume 2) (Public and Nonpublic).

Conditions of Approval	**Comments**
True-Up Mechanism. "[R]ate recovery for the gas and transmission facilities and related O&M costs should occur in a future MP rate case, which would not result in a true-up mechanism. MP has not demonstrated that any proposed recovery of capital or variable O&M costs in a rider outside of a rate case is reasonable or permitted under Minnesota law."[115] "Again, to be clear, the Department does not agree that a rider outside of MP's rate cases to recover capacity costs or non-fuel fixed or variable costs would be reasonable or permissible."[116]	Minnesota Power accepts this condition and will seek cost adjustments for capital costs and fixed and variable O&M costs through rate cases on the same basis as it does for Minnesota Power-owned generating facilities.
Revenue Requirement Method vs. PPA. "Overall, [Campbell] conclude[s] that, if this facility is approved, the rate case recovery using either a revenue requirement or PPA method would provide the necessary rigorous review and would be the best method to protect ratepayers."[117]	Minnesota Power accepts the rate case recovery mechanism proposed by the Department for review of the revenue requirement method for capacity costs and fixed and variable O&M recovery.[118]
Resource Center Accounting. Campbell is satisfied that "MP agreed to set up locational or 'resource center' accounting to track costs of this investment and allow for direct assignment and allocation of costs."[119]	"Minnesota Power agrees to set up locational or 'resource center' accounting to track costs for this investment and allow for direct assignment and allocation of costs. We are happy to work with the Department to ensure that the accounting mechanisms we propose are satisfactory to them."[120]
Full Access to MP/South Shore Books. Recommends that "MP be required to provide full access to MP's/ South Shore's books and records including all billings related to the NTEC gas facility and transmission and all related costs.[121]	Minnesota Power accepts this condition.[122]
Sharing Costs. Accepts MP's commitment to advise the Department and interested parties anytime shared costs are not divided 50/50 between Dairyland and South Shore.[123]	Minnesota Power accepts this condition.[124]
48% vs. 50% Ownership Share. The Department could support Minnesota Power's ownership share at either 48% or 50%.[125]	Minnesota Power agrees that either outcome is supported and defers to the Commission.[126]

[115] Ex. DER-6 and DER-7, at 33 (Campbell Surrebuttal) (Public and Nonpublic).
[116] Ex. DER-6 and DER-7, at 19 (Campbell Surrebuttal) (Public and Nonpublic).
[117] Ex. DER-6 and DER-7, at 22 (Campbell Surrebuttal) (Public and Nonpublic).
[118] *See* Ex. MP-25, at 32-33 (Supinksi Direct); Ex. MP-26 and MP-27, at 22-23 (Supinski Rebuttal) (Public and Nonpublic).
[119] Ex. DER-6 and DER-7, at 34 (Campbell Surrebuttal) (Public and Nonpublic).
[120] Ex. MP-14, at 33 (Pierce Rebuttal).
[121] Ex. DER-6 and DER-7, at 28, 34 (Campbell Surrebuttal) (Public and Nonpublic).
[122] Ex. MP-14, at 34 (Pierce Rebuttal).
[123] Ex. DER-6 and DER-7, at 28, 34 (Campbell Surrebuttal) (Public and Nonpublic).
[124] Ex. MP-14, at 34 (Pierce Rebuttal).
[125] Ex. DER-6 and DER-7, at 34 (Campbell Surrebuttal) (Public and Nonpublic).
[126] Ex. MP-14, at 30-31 (Pierce Rebuttal).

Conditions of Approval	Comments
Costs under the Guarantee Agreement. Dr. Amit agrees with Minnesota Power's proposal. "If MP incurs costs under the Guarantee Agreement, MP must not recover any such costs from its ratepayers unless and until the Company demonstrates to the Commission that the incurrence of such costs is rare, unforeseen, and reasonable to charge to its ratepayers. MP has the burden of demonstrating that it would be reasonable to recover any such rare and unforeseen costs from its ratepayers. This approach should protect MP's ratepayers from undue exposure to risks regarding MP's unregulated affiliate, South Shore. Thus, I believe MP and I are in agreement on all issues that I have raised in this proceeding."[127]	Minnesota Power agrees. "While Minnesota Power agrees that it would not attempt to recover any costs in the unlikely event that payment is required under the Guaranty Agreement without express Commission approval, there may be (rare and unforeseen) circumstances where it would be appropriate that such costs are collected from customers, who will receive all of the benefit of Minnesota Power's share of NTEC. Therefore, the Company recommends that instead of conditioning approval of the Guaranty Agreement on a condition that Minnesota Power's customers shall not be charged for any obligations or payments made under that agreement, the approval be conditioned on Minnesota Power not seeking to charge customers for any obligation or payments under the agreement absent express prior Commission review approval. And of course, Minnesota Power recognizes that it would bear the burden of proving the reasonableness of any such proposed charge."[128]
D&C and O&O Agreement. Dr. Amit concludes that MP's ratepayers are appropriately protected from the financial risks and business risks of the NTEC project under the D&C Agreement and the O&O Agreement.[129]	Minnesota Power agrees. "The terms of the D&C Agreement are intended to reasonably and appropriately allocate the risks of the NTEC project among the Construction Agent and NTEC Owners. Dr. Amit analyzed the various potential risks and agreement provisions addressing the allocation of those risks. The Company agrees with the conclusion that the provisions of the Agreements are reasonable and that the potential risks related to the NTEC project are reasonably and appropriately allocated among the parties."[130] "The terms of the O&O Agreement are intended to reasonably and appropriately allocate the risks of the project among the Construction Agent/Operating Agent and NTEC Owners. The Department witnesses analyzed the various potential risks and agreement provisions addressing the allocation of those risks. I agree with their conclusions, as discussed above, that the provisions of the Project Agreements and Assignment Agreements are reasonable and that the potential risks related to the NTEC project are reasonably and appropriately allocated among the parties."[131]

[127] Ex. DER-3, at 2-3 (Amit Surrebuttal).

[128] Ex. MP-26 and MP-27, at 49-50 (Supinski Rebuttal) (Public and Nonpublic).

[129] Ex. DER-1 and DER-2, at 21 (Amit Direct) (Public and Nonpublic).

[130] Ex. MP-26 and MP-27, at 16 (Supinski Rebuttal) (Public and Nonpublic).

[131] Ex. MP-26 and MP-27, at 21 (Supinski Rebuttal) (Public and Nonpublic).