BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, Minnesota 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St. Paul, Minnesota 55101-2147

In the Matter of the Request of Minnesota Power
for a Certificate of Need for the
Great Northern Transmission Line Project

OAH Docket No. 60-2500-30782
MPUC Docket No. E-015/CN-12-1163

MINNESOTA POWER INITIAL BRIEF

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LIST OF ACRONYMS AND TERMS

AC	Alternating Current
AFR	Annual Electric Utility Forecast Report
AFUDC	Allowance for Funds Used During Construction
C-BED	Community Based Energy Development
CIP	Conservation Improvement Program
CON	Certificate of Need
CON Rules	Minnesota Rules Chapter 7849
CON Statute	Minnesota Statutes §216B.243
CWIP	Construction Work in Progress
DC	Direct Current
DOC-DER	Department of Commerce – Division of Energy Resources
DOC-EERA	Department of Commerce – Energy Environmental Review and Analysis
DOE	United States Department of Energy
EEA	Energy Exchange Agreement
ER	Environmental Report
ESA	Energy Sale Agreement
FCA	Facilities Construction Agreement
FERC	Federal Energy Regulatory Commission
GNTL	Great Northern Transmission Line

IRP	Integrated Resource Plan
kV	kilovolt
LPI	Large Power Intervenors
Manitoba Hydro Agreements	250 MW Agreements and 133 MW ROAs
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt hours
PPA	Power Purchase Agreement
Project	Great Northern Transmission Line, consisting of the 500 kV transmission line and associated facilities
ROAs	133 MW Renewable Optimization Agreements (133 MW ESA and EEA)
ROE	Return on Equity
TCR	Transmission Cost Recovery
TSR	Transmission Service Request
250 MW Agreements	250 MW PPA and EEA
938 Docket	MPUC Docket No. E-015/M-11-938, approving the 250 MW Agreements
960 Docket	MPUC Docket No. E-015/M-14-960, Petition for Approval of 133 MW ROAs, currently pending
1088 Docket	MPUC Docket No. E-015/RP-09-1088, accepting Minnesota Power's 2010 IRP

INTRODUCTION

The Great Northern Transmission Line ("Project") provides a unique opportunity.

For Minnesota Power ("Minnesota Power" or "Company") and its customers, the Project represents the next step in transforming Minnesota Power's energy supply portfolio in a manner that will assure the continued adequacy, reliability, efficiency and cost effectiveness of its power supply, while also lowering emissions and optimizing the value of Minnesota Power's renewable energy resources. The Project does so by providing access to needed hydropower resources – resources already approved by the Minnesota Public Utilities Commission ("MPUC" or "Commission"). Moreover, the Project will deliver these resources with Minnesota Power and its ratepayers paying only a portion of the Project cost. As such, Minnesota Power and its ratepayers stand to benefit from the Project for decades to come.

For the State and the region, the Great Northern Transmission Line represents the culmination of an extensive and collaborative transmission planning and outreach effort. The Project, fully funded by the Project participants, will provide hundreds of millions of dollars in economic benefit to northern Minnesota. Additionally, once constructed, the Project will provide a new large transmission interconnection between Canada and the United States, addressing a major contingency in the current transmission system. The Project will also provide other Minnesota and regional utilities the ability to access these same hydropower resources, providing additional benefits related to lower emissions and the integration of wind and hydropower resources.

Opportunities such as the Great Northern Transmission Line rarely present themselves. They must be seized when they do.

I. BACKGROUND

A. Minnesota Power's Energy*Forward* Resource Strategy

Through the implementation of its **Energy*Forward*** resource strategy, Minnesota Power is transforming it energy supply portfolio, from a coal-dominant power supply to a more diverse, flexible, efficient and lower emission power supply that protects affordability and preserves reliable electric service for the Company's customers.[1] As recently as 2005, Minnesota Power's supply portfolio consisted of approximately 95 percent coal fired generation.[2] However, as discussed in Minnesota Power's recent Integrated Resource Plan ("IRP") and other dockets before the Commission, the Company has made substantial progress in rebalancing its supply portfolio to one consisting of about 25 percent renewable energy by the end of 2014, including 600 MW of wind energy resources.[3]

Going forward, the Company's **Energy*Forward*** resource strategy calls for Minnesota Power's portfolio to move to a balanced supply of one-third renewable energy, one-third natural gas and one-third coal – all while ensuring that the Company meets three key goals: preserving reliability, improving environmental performance and

[1] Ex. 43, p. 4 (Rudeck Direct).
[2] *Id.*
[3] *Id.*, pp. 4, 7; *see also* Ex. 20, pp. 4-16 (Minnesota Power 2013 IRP filing, Plan Summary).

protecting affordability.[4] As Mr. Rudeck explained, "many efforts will help [the Company] achieve these goals, but two are particularly relevant to this proceeding – Minnesota Power's substantial investments in wind energy resources and the construction of the Great Northern Transmission Line, enabling Minnesota Power to take delivery of carbon-free Manitoba Hydro hydropower under agreements that also maximize the value of our wind energy assets" through unique energy storage provisions in those agreements.[5]

B. Minnesota Power Agreements With Manitoba Hydro

Manitoba Hydro has a long history of energy trading relationships with United States utilities, including Minnesota Power.[6] The Company's relationship with Manitoba Hydro – and the recent agreements memorializing and reaffirming it – forms a key component of **Energy*Forward***.[7] For the purposes of this docket, two sets of energy trading agreements have central importance: (1) the 250 MW Power Purchase Agreement ("PPA") and Energy Exchange Agreement ("EEA") between Minnesota Power and Manitoba Hydro (collectively, "250 MW Agreements"), signed in 2011 and approved by the Commission in 2012;[8] and (2) the 133 MW Energy Sale Agreement ("ESA") and EEA (together the Renewable Optimization Agreements ("ROAs")) (together with the

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[4] Ex. 43, pp. 4-5 (Rudeck Direct).
[5] *Id.*, p. 5.
[6] *Id.*, p. 18.
[7] *Id.*, p. 8.
[8] MPUC Docket No. E-015/M-11-938 ("938 Docket").

250 MW Agreements, the "Manitoba Hydro Agreements"), currently before the Commission for approval.[9]

A third agreement between the two companies, the Facilities Construction Agreement ("FCA") recently approved by Federal Energy Regulatory Commission ("FERC"),[10] also has importance to this Docket.

1. The 250 MW Agreements

Beginning with Minnesota Power's 2010 IRP docket,[11] Minnesota Power identified significant capacity and energy needs in the 2020 to 2035 timeframe, with those needs driven by customer load growth and diversification of the Company's power supply.[12] To address these load and supply changes, the Company included action in its 2010 IRP with the intent to pursue both the 250 MW Agreements with Manitoba Hydro and associated new transmission to deliver that power, with power deliveries beginning in the 2020 timeframe.[13] The inclusion of the Manitoba Hydro hydropower and the new transmission to deliver that power was part of the Company's least cost system-wide long term supply plan and the Commission accepted the Company's 2010 IRP in 2011.[14]

In pursuit of this approved least cost plan, Minnesota Power negotiated the 250 MW Agreements and filed for Commission approval in the 938 Docket.[15] Collectively, the 250 MW Agreements act to optimize Minnesota Power's resources, by allowing

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[9] MPUC Docket No. E-015/M-14-960 ("960 Docket").
[10] *See* Ex. 64.
[11] MPUC Docket No. E-015/RP-09-1088 ("1088 Docket").
[12] Ex. 43, p. 9 (Rudeck Direct).
[13] *Id.*, pp. 9-10.
[14] *Id.*, p. 10.
[15] *Id.*, p. 14.

Minnesota Power to sell off-peak excess wind energy to Manitoba Hydro and then "buy back" this energy from Manitoba Hydro when needed on the Minnesota Power system.[16]

In reviewing and approving the 250 MW Agreements, the DOC-DER and Commission affirmed that Minnesota Power "will need a significant amount of capacity and energy" in the 2020 to 2035 timeframe.[17] The DOC-DER and Commission further affirmed that the 250 MW Agreements "provide the most appropriate resources for [Minnesota Power] to meet its resource needs" over this time period.[18] Finally, the Commission recognized that "both [Manitoba Hydro] and [Minnesota Power] must construct their own new transmission facilities (in Canada and the USA respectively) to allow Manitoba Hydro to sell the contracted power to MP."[19] Given the importance of these new transmission facilities, the Commission specifically requested that Minnesota Power update it on the progress on the milestones achieved regarding the "new major transmission facilities" necessary to deliver the capacity and power contracted for under the approved 250 MW Agreements.[20] The Project provides these necessary new major transmission facilities.

2. The Renewable Optimization Agreements

The 133 MW ROAs bring additional zero emission supply resources to Minnesota Power and further optimize the Company's wind power resources – benefits that will

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[16] *Id.*, pp. 7-8; Ex. 12, DOC-DER Comments, p. 20; Transcript Vol. ("V.") 1, p. 186 (Rudeck).
[17] Ex. 12, DOC-DER Comments at p. 4.
[18] Ex. 12, DOC-DER Comments at pp. 5, 25.
[19] Ex. 12, DOC-DER Comments, p. 13.
[20] *Id.*, Ordering Paragraph 2.

again be made possible by completion of the Project.[21] Regarding wind power optimization, upon completion of the Project, Minnesota Power would schedule additional energy from the Company's wind-generating facilities to Manitoba Hydro when wind production is high and is not needed for customer load.[22] When Manitoba Hydro uses this Minnesota Power wind power to serve customer load in Manitoba, Manitoba Hydro would be able to temporarily reduce their hydropower generation by decreasing the flow of water through their hydropower plants.[23] The water "stored" during that process would be used later to generate electricity to schedule to Minnesota when wind energy production is low or customer needs are high.[24]

This arrangement optimizes the use of both wind-generated energy and hydropower, which brings benefits to customers and allows Minnesota Power to further enhance the carbon-free portion of its long term supply portfolio.[25] In fact, through the combined Manitoba Hydro Agreements, Minnesota Power has procured a total of over 1.5 million megawatt hours ("MWh") of hydropower annually, and the ability annually to store 1 million MWh of wind power in Manitoba Hydro's system,[26] bringing substantial economic benefits for Minnesota Power's customers.[27]

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21 *See* Ex. 34, pp. 7-8 (McMillan Direct).
22 Ex. 43, pp. 15-16 (Rudeck Direct).
23 *Id.*, p. 16.
24 *Id.*
25 *Id.*
26 Ex. 34, p. 7 (McMillan Direct).
27 *See* Ex. 43, p. 17-18 (Rudeck Direct).

The energy taken by Minnesota Power under the ROAs is priced at market and includes the associated environmental attributes.[28] This structure provides optionality for Minnesota Power to either take the energy, if needed for least cost customer supply, or to resell it to the market.[29] In either case, Minnesota Power receives the environmental attributes as part of the transaction – another valuable component of the ROAs.[30]

The ROAs further benefit Minnesota Power and its ratepayers, by having Manitoba Hydro pay for the transmission delivery costs for the energy associated with the 133 MW ESA through a "must take fee" provision in the EEA. This "must take fee" credits Minnesota Power and its customers for the capital costs associated with 133 MW of the transfer capability of the Project.[31] As a result, while the Project is sized at 500 kV and will provide 883 MW of transfer capability, Minnesota Power and its customers receive the benefits of the economies of scale associated with the Project and will receive 383 MW of hydropower resources, while paying for just 250 MW of transfer capability.[32] As discussed further below, this "must take fee" provision of the ROAs, combined with an additional contribution in aid of construction ("CIAC") provided in the FCA, results in a revised capital cost range for Minnesota Power and its ratepayers of $158 to $201 million, which is lower than the transmission cost estimate contemplated as part of the original 250 MW Agreements.[33]

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[28] *Id.*
[29] *Id.*
[30] *Id.*
[31] Ex. 45, pp. 3, 18 (Rudeck Surrebuttal).
[32] Ex. 43, p. 18 (Rudeck Direct); Ex. 34, p. 13 (McMillan Direct).
[33] Ex. 43, pp. 18-19 (Rudeck Direct).

The ROAs are currently being reviewed by the Department and Commission, with Minnesota Power having filed its Petition for Approval in the 960 Docket on November 6, 2014.[34]

3. The Facilities Construction Agreement

On September 23, 2014 Minnesota Power, Manitoba Hydro and the Midcontinent Independent System Operator, Inc. ("MISO") executed the FCA for the Project,[35] setting forth the ownership percentages and financial responsibilities for the Project, among other terms. Importantly, the FCA includes provisions requiring Manitoba Hydro to provide a five percent CIAC to Minnesota Power[36] and requires Minnesota Power's full consent if Manitoba Hydro ultimately wishes to assign its interest in the Project to another transmission owner.[37] As discussed further below, the CIAC payment, together with the "must take fee" in the ROAs, brings Minnesota Power and its ratepayers financial responsibility for the capital costs of the Project down to 28.3 percent of the Project costs.[38]

On November 25, 2014, the FERC approved the FCA.[39] With that approval, MISO considers the Project an approved project under the MISO tariff and MISO has

[34] Ex. 45, pp. 2-3 (Rudeck Surrebuttal); Ex. 46 and 47 (Public and Trade Secret versions, respectively, of the Petition and ROAs).
[35] Ex. 40 (MD-R), Schedule 1 (FCA).
[36] *Id.*; Ex. 35, p. 9 (McMillan Rebuttal).
[37] Ex. 40, pp. 3-4 (Donahue Rebuttal).
[38] *Id.*, p. 5.
[39] Ex. 64 (FERC Docket No. ER14-2950-000, Order dated November 25, 2014).

moved the Project to Appendix A of the MISO Transmission Expansion Plan 14 ("MTEP14").[40]

C. Procedural History

Minnesota Power provides the procedural history for this matter in its Proposed Findings of Fact, Conclusions of Law and Recommendation, filed concurrently with this Initial Brief.

D. Public And Stakeholder Engagement

Throughout its work on the Project, Minnesota Power has actively engaged the public and interested stakeholders. As detailed in its Certificate of Need ("CON") Application and the testimony of Mr. Atkinson, Minnesota Power has led four different rounds of public open house meetings across the Project area.[41] In addition, Minnesota Power has published and distributed newsletters, established a hotline for messages, taken website comments, and mailed comments and met with private associations to discuss the Project.[42] The Company has also extensively engaged with federal, State and local government stakeholders, beginning in June of 2012 and continuing throughout the permitting process.[43] Those efforts have resulted in a broad understanding and widespread recognition of the need for the Project, as reflected by the paucity of opposition shown in the public comment record.

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[40] https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP14.aspx
[41] *See* Ex. 9, pp. 8-9; Ex. 37, pp. 3-5 (Atkinson Direct).
[42] *Id.*
[43] *Id.*

II. PROJECT DESCRIPTION

A. Facilities

The Project includes the construction of a new 500 kV transmission line in Minnesota from the United States/Canadian border to the Minnesota Power Blackberry Substation in the Grand Rapids, Minnesota area (the "500 kV Line").[44] At the time of the Application, Minnesota Power stated that the Project would provide at least 750 MW of transfer capability. However, subsequent analysis indicates that once completed, the Project will provide approximately 883 MW of transfer capability.[45]

Given the route alternatives as presented to date in the Route Permit proceeding, MPUC Docket No. E-015/TL-14-21, the 500 kV Line will be approximately 220 miles in length in the United States, and will be constructed on a 200 foot wide right of way likely in the following Minnesota counties: Beltrami, Itasca, Koochiching, Lake of the Woods, and Roseau.[46]

The 500 kV Line will be part of a new 500 kV international transmission interconnection (the "500 kV Interconnection") between Manitoba and the United States. Manitoba Hydro will be constructing the Canadian portion of this new international interconnection.[47]

In addition to the transmission line, the Project includes expansion of the Blackberry Substation and a series compensation station, to be located near the midpoint

[44] Ex. 9, p. 24; Ex. 42, p. 3 (Winter Direct).
[45] Ex. 42, p. 3 (Winter Direct).
[46] *Id.*, pp. 3-4 and MPUC Docket No. E-015/TL-14-21.
[47] *Id.*

of the 500 kV Interconnection.[48] Minnesota Power anticipates using 3-conductor bundle 1192.5 kcmil Aluminum Steel Conductor Reinforced ("ASCR") "Bunting" with 18 inch sub-spacing as the phase conductor for the Project. This conductor is the same as that used on the existing Dorsey - Chisago 500 kV transmission line. Final conductor selection for the Project will be based on a conductor optimization study. Minnesota Power continues to evaluate several structure types and configurations of towers that will be used for the line, including a self-supporting lattice tower, a lattice guyed-V structure and a lattice guyed delta structure. Minnesota Power currently estimates approximately four to five structures per mile of line, with the type of structure in any given section of line dependent on land type and land use.[49]

B. Ownership And Financial Responsibility

The Great Northern Transmission Line constitutes the United States portion of a joint effort with Manitoba Hydro to construct a new Canada-United States 500 kV Interconnection. Manitoba Hydro will construct and have sole ownership of the Canadian portion of this new interconnection. On the United States side, Minnesota Power will have majority ownership (51 percent) of the Project. The balance of the Project (49 percent) will initially be owned by a subsidiary of Manitoba Hydro, although the subsidiary may sell all or a portion of its share to one or more United States utilities, before, during or after construction.[50]

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[48] Ex. 38, p. 5 (Donahue Direct).
[49] Ex. 24, pp. 24-25; Ex. 42, p. 4 (Winter Direct).
[50] Ex. 34, p. 13 (McMillan Direct).

While Minnesota Power will own 51 percent of the Project, under the terms of the Manitoba Hydro Agreements and the FCA, <u>Minnesota Power's ratepayers will be financially responsible for only 28.3 percent of the Project's capital revenue requirements</u> – the equivalent of the revenue requirements associated with 250 MW of the Project's total estimated transfer capability of 883 MW.[51] As Mr. McMillan explained, this distinction between "ownership" of the Project and "financial responsibility" for the cost of the Project is critical to understanding the full benefits of the Project (and the Manitoba Hydro Agreements) to Minnesota Power and its ratepayers.[52]

In its CON Application, Minnesota Power indicated that it would be responsible for 33.3 percent of the Project's revenue requirements, with the 17.7 percent differential between this responsibility share and the Company's ownership share covered by Manitoba Hydro under a "must take fee" to be included in the 133 MW ROAs, which were then still being finalized.[53] At that time, the Project was assumed to have a total transfer capability of 750 MW.[54] However, Minnesota Power agreed to be financially responsible for only the 250 MW of transfer capability necessary to take delivery under the 250 MW Agreements, thus the 33.3 percent share of the capital cost responsibility at

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[51] Ex. 34, p. 13 (McMillan Direct).
[52] *Id.* pp. 13-15.
[53] Ex. 9, p. 16.
[54] *Id.*

that time.[55] Operations and maintenance expenses were handled similarly, with Minnesota Power again responsible for a 33.3 percent share of the costs.[56]

Since the Application was filed, Minnesota Power continued to ensure that its customers would only bear the financial responsibility associated with 250 MW of transfer capability.[57] However, three subsequent events changed – and lowered – Minnesota Power and its ratepayers' percentage share of the overall revenue responsibility. First, the total transfer capacity of the line was estimated to be 883 MW, not 750 MW.[58] Second, Minnesota Power and Manitoba Hydro finalized the 133 MW ROAs.[59] Third, MISO, the Company, and Manitoba Hydro executed the FCA. In order for Minnesota Power to retain a 51 percent ownership in the line, while not bearing more revenue responsibility than that associated with 250 MW of transfer capability, the final agreements between the Company and Manitoba Hydro call for: (1) Minnesota Power to ultimately bear 28.3 percent responsibility for the capital costs of the Project, (2) the "must take fee" included in the 133 MW ROAs to continue covering 17.7 percent of the capital cost financial responsibility, and (3) Manitoba Hydro to provide a five percent CIAC payment to the Company – collectively totaling the 51 percent ownership held by Minnesota Power.[60] Together, these agreements allow Minnesota Power and its

[55] *Id.*
[56] *See*, Ex. 40, p. 5 (Donahue Rebuttal).
[57] *Id.*, p. 14.
[58] *Id.*; Ex. 42, pp. 3-4 (Winter Direct).
[59] Ex. 24, p. 14 (McMillan Direct); Ex. 43, p. 3 (Winter Direct).
[60] Ex. 24, pp. 14-15 (McMillan Direct); Ex. 40, p. 5 (Donahue Rebuttal). Minnesota Power maintained a 33 percent operating and maintenance expense ("O&M") allocation,

customers to gain the benefits of not just the energy deliveries called for in the Manitoba Hydro Agreements, but also to enjoy the benefits of the economies of scale, optionality and energy storage that are only available with a 500 kV line, while bearing the capital cost revenue responsibility associated with 250 MW of transfer capability.[61]

Regarding operating and maintenance expenses, Minnesota Power could identify no change in operating expenses associated with the incremental increase in capacity.[62] Therefore, the Company agreed to retain its 33.3 percent responsibility for these expenses.[63]

Finally, while the Manitoba Hydro subsidiary will have an initial 49 percent ownership interest in the Project, Manitoba Hydro has stated it does not intend to maintain a long-term interest in the Project. Thus, the FCA provides for Manitoba Hydro to assign its interest to another MISO Transmission Owner or, if it does not find another owner, to Minnesota Power.[64] In order to ensure that any such assignment cannot negatively impact Minnesota Power and its ratepayers, Minnesota Power retained full consent rights to any transfer to a third party.[65] In order for Minnesota Power to consent to a new minority owner, that owner would have to not only assume Manitoba Hydro's financial obligations, but would have to agree to hold the Minnesota Power pricing zone

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since it could identify no additional O&M expenses associated the incremental increase in capacity from 750 MW to 883 MW. Ex. 40, p. 5 (Donahue Rebuttal).

[61] Ex. 24, p. 15 (McMillan Direct).

[62] Ex. 40, p. 5 (Donahue Rebuttal).

[63] *Id.*, pp. 5-6.

[64] Ex. 40, pp. 3-5 (Donahue Rebuttal); V. 1, pp. 110-111 (Donahue).

[65] *Id.*

neutral for ratepayers.[66] Additionally, if Manitoba Hydro chooses to assign its ownership interest to Minnesota Power, the Company will still bear only 28.3 percent of the capital cost responsibility and 33.3 percent of the operations and maintenance costs, with the remainder covered by Manitoba Hydro, either through the "must take fee" or through a CIAC.[67] Thus, the full financial responsibility picture for the Project can be represented as follows[68]:

	Final Structure	
Responsibility For:	Under 100% MP ownership	Under 51% MP / 49% Other ownership
Investment:		
MP	46.00%	46.00%
MH (CIAC)	54.00%	5.00%
MH or Assignee	NA	49.00%
Total	100.00%	100.00%
Revenue Req. - Capital Cost:		
MP Ratepayer	28.30%	28.30%
MH (ROA Must Take Fee)	17.70%	17.70%
MH (CIAC)	54.00%	5.00%
MH or Assignee	N/A	49.00%
Total	100.00%	100.00%
Revenue Req. - O&M:		
MP Ratepayer	33.30%	33.30%
MH (ROA Must Take Fee)	17.70%	17.70%
MH (CIAC)	49.00%	0.00%
MH or Assignee	N/A	49.00%
Total	100.00%	100.00%

[66] *Id.*
[67] *Id.* pp. 3-7.
[68] Ex. 40, p. 8, Table 3 (Donahue Rebuttal).

C. Timing

Minnesota Power anticipates that Project construction will begin in 2016, with an in-service date of June 1, 2020 as required under the 250 MW Agreements.[69] In order to maintain this schedule and to achieve the contractually required in-service date, Minnesota Power began its outreach efforts for permitting and routing in mid-2012.[70] The Company continues to make progress on its milestones to achieve this in-service date, including the filing of the Presidential Permit application, required for an international border crossing.[71]

D. Cost Estimates

In its CON Application, the Minnesota Power provided an initial range of estimated costs for the Project.[72] At that time, the Company had a number of potential routes still under consideration, so the estimate used a "proxy" route and was based on the information then available to the Company.[73]

When the Company filed its Route Permit Application,[74] Route Alternatives and Segment Options were identified. Therefore, the Company re-examined and refined its prior cost range estimate to reflect the route data then available. In addition, Minnesota Power refined its estimate related to expected construction costs, including the use of

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[69] Ex. 9, pp. 2, 35; Ex. 34, p. 11 (McMillan Direct); Ex. 38, p. 5 (Donahue Direct).
[70] Ex. 9, p. 78.
[71] Office of Energy OE Docket No. PP-398, 79 Fed. Reg. 27,587 (May 14, 2014); 79 Fed. Reg. 68,673 (Nov. 18, 2014).
[72] Ex. 9, p. 27; Ex. 38, p. 4 (Donahue Direct).
[73] *Id.*
[74] MPUC Docket No. E-015/TL-14-21.

matting in wetlands to mitigate potential wetland impacts.[75] Based on preliminary engineering considerations of the Route Alternatives and Segment Options, as of April 15, 2014 Minnesota Power estimated the construction of the Project on the Route Alternatives (including any combination of proposed Segment Options), including substation facilities, to cost between roughly $500 million and $650 million in 2013 dollars.[76]

Finally, in July of 2014, a MISO-sponsored facility study report concluded that the 500 kV Series Compensation Station originally budgeted at the expanded Blackberry Substation should now be a separate facility located at the midpoint of the 500 kV transmission line. Incorporating that change and accounting for property taxes that will be assessed against Project assets before the in-service date of June 1, 2020, Minnesota Power now estimates that the Project will cost between $557.9 million and $710.1 million.[77] However, given the terms of the ROAs and FCA, Minnesota Power ratepayers will be responsible for only 28.3 percent of the Project's capital costs, equating to $158 million to $201 million.[78]

Regarding operating and maintenance costs, primary annual maintenance expense for transmission line is aerial inspection.[79] These inspections look for broken insulators or other defects which could compromise the line.[80] If issues are identified, ground crews

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[75] Ex. 38, pp. 4-5 (Donahue Direct).
[76] *Id.*; Schedule 4 and Ex. 32 (Section 5 of Route Permit Application).
[77] *Id.*, p. 5; V. 1, p. 113 (Donahue).
[78] Ex. 38, p. 5 (Donahue Direct).
[79] *Id.*, p. 6.
[80] *Id.*

will be dispatched to correct the defect.[81] In addition to structural maintenance, the right-of-way must be kept clear of vegetation.[82] Vegetation control is performed on a scheduled and routine basis and when the aerial inspection discovers issues.[83] The cost for routine maintenance will depend on the topology and the type of maintenance required, but typically runs from $1,100 to $1,600 per mile.[84]

As discussed above and shown in the table, Minnesota Power and its ratepayers will be responsible for only 33.3 percent of the operating and maintenance expenses associated with the Project.[85]

III. APPLICABLE LAW

Minnesota Statutes Section 216B.243 ("CON Statute") governs the granting of a CON for large energy facilities, including high voltage transmission lines such as the Great Northern Transmission Line. The CON Statute requires the Commission to adopt rules setting forth the criteria to be used in its determination of need for such facilities, which the Commission has done for high voltage transmission lines in Minnesota Rules Chapter 7849 ("CON Rules"). The CON Statute further identifies certain factors for the Commission to evaluate in its determination of need, specifically:

> (1) the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based;

[81] *Id.*
[82] *Id.*
[83] *Id.*
[84] *Id.*
[85] Ex. 39, pp. 5-6 (Donahue Rebuttal).

(2) the effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand;

(3) the relationship of the proposed facility to overall state energy needs, as described in the most recent state energy policy and conservation report prepared under section 216C.18, or, in the case of a high-voltage transmission line, the relationship of the proposed line to regional energy needs, as presented in the transmission plan submitted under section 216B.2425;

(4) promotional activities that may have given rise to the demand for this facility;

(5) benefits of this facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region;

(6) possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation;

(7) the policies, rules, and regulations of other state and federal agencies and local governments;

(8) any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically;

(9) with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota;

(10) whether the applicant or applicants are in compliance with applicable provisions of sections 216B.1691 and 216B.2425, subdivision 7, and have filed or will file by a date certain an application for certificate of need under this section or for certification as a priority electric transmission project under section 216B.2425 for any transmission facilities or upgrades identified under section 216B.2425, subdivision 7;

(11) whether the applicant has made the demonstrations required under subdivision 3a [regarding use of renewable resources]; and

> (12) if the applicant is proposing a nonrenewable generating plant, the applicant's assessment of the risk of environmental costs and regulation on that proposed facility over the expected useful life of the plant, including a proposed means of allocating costs associated with that risk.[86]

The Commission's CON Rules incorporate these statutory factors into four criteria the Commission utilizes in determining if a CON must be granted.[87] Those Rules provide that:

> A certificate of need must be granted to the applicant on determining that:
>
> A. the probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states . . . ;
>
> B. a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record . . . ;
>
> C. by a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health . . . ; and
>
> D. the record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.[88]

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[86] Minn. Stat. § 216B.243, subd. 3. The Parties agree that sections (10) and (12), above, do not apply to the current proceeding. *See* Issues Matrix, December 5, 2014. The remainder of the statutory factors correspond to provisions in the Commission's CON criteria and will be discussed in this Brief under those criteria.

[87] *See In the Matter of the Application of ITC Midwest LLC for a Certificate of Need for the Minnesota – Iowa 345 kV Transmission Line Project in Jackson, Martin, and Faribault Counties;* MPUC Docket No. ET-6675/CN-12-1053, Order Granting Certificate Of Need With Conditions, November 25, 2014, pp. 3-4.

[88] Minn. R. 7849.0120.

As the Applicant, Minnesota Power bears the burden of demonstrating the need for the Project,[89] with the specific burden being proof by a preponderance of the evidence.[90]

With respect to alternatives to the Project, Minnesota Power meets this burden by showing that the Project is a reasonable and prudent way to satisfy the articulated and demonstrated needs. It is <u>not</u> Minnesota Power's burden to disprove other potential alternatives or to prove the absence of theoretical alternatives. As articulated by the Commission's CON Rules and upheld by the Courts, the burden falls squarely on other parties to introduce alternatives into the record for consideration and then to establish that any such alternatives provide a more reasonable and prudent means of meeting the articulated needs than does the Project. In examining the Commission's CON Rules for natural gas pipelines,[91] whose criteria mirror the criteria in the high voltage transmission line CON Rules, the Court of Appeals stated:

> Under the certificate-of-need process established by statute and rule, an applicant bears the burden of proving the need for a proposed facility. An applicant fails to meet this burden when *another* party demonstrates that there is a more reasonable and prudent alternative to the facility proposed by the applicant. Minn. Stat. § 216B.243, subd. 3; Minn R. 7851.0120, subp. 8. This regulatory scheme is simply a practical way to prevent the issuance of a certificate of need when there is a more reasonable and prudent alternative to the proposed facility without requiring an applicant to face the extraordinary difficulty of proving that there is not a more reasonable and prudent alternative.[92]

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[89] *See* Minn. Stat. § 216B.243, subd. 3.
[90] *See* Minn. R. 1400.7300, subp. 5 and Minn. R. 7849.0120.
[91] Minn. R. 7851.0120.
[92] *In the Matter of the Application of the City of Hutchinson (Hutchinson Utilities Commission) for a Certificate of Need to Construct a Large Natural Gas Pipeline*, Minn.

IV. <u>THE RECORD ESTABLISHES THE NEED FOR THE PROJECT.</u>

Minnesota Power and the Department agree that the Commission should issue a CON for the Great Northern Transmission Line.[93] Moreover, no party provided testimony challenging the need for the Project.[94] A simple reason explains this lack of dispute over the need for this new transmission line – the record conclusively demonstrates that the Great Northern Transmission Line Project meets each of the Commission's four criteria for receiving a CON, in that: (1) denial would adversely affect the future energy supply to Minnesota Power, Minnesota and the region; (2) no more reasonable and prudent alternative has been demonstrated by a preponderance of the evidence; (3) the Project will meet Minnesota Power, State and regional needs in a manner compatible with the natural and socioeconomic environments; and (4) Minnesota Power will comply with all applicable federal, State and local policies, rules and regulations.[95]

App. A03-99, September 23, 2003, p. 11 (citing *State v. Paige*, 256 N.W.2d 298, 304 (Minn. 1977) (emphasis added). (Slip opinion attached as Appendix A).

[93] *See* V. 1, p. 30 (McMillan); V. 1, p. 190 (Rudeck); Ex. 56, p. 11 (Rakow Surrebuttal).

[94] Large Power Intervenors ("LPI") witness Mr. Kollen made no recommendation as to whether or not a CON should be granted. Rather, Mr. Kollen testified that "if the Commission grants Minnesota Power's certificate of need proceeding in this proceeding" then it should condition that grant on five conditions, one of which has been agreed to and four of which remain disputed as discussed in Section V., below. *See* Ex. 50, pp. 2-5 (Kollen Direct). RRANT, the only other party to the proceeding, filed no testimony.

[95] *See* Minn. R. 7849.0120

A. Minnesota Power, Minnesota And The Region Need The Project To Support The Future Adequacy, Reliability, Or Efficiency Of Energy Supply.

The first of the four criteria established by the Commission for the granting of a CON calls for an examination of whether:

> the probable result of denial [of the Certificate of Need] would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states.[96]

Under this criterion, the Commission considers: (1) an applicant's forecast of demand for energy; (2) its conservation programs; (3) its promotional practices; (4) the ability of current or planned facilities to meet the future demand; and (5) the facility's ability to make an efficient use of resources.[97] Given full consideration to these factors, the record demonstrates the severe adverse impact that denial of the CON would have on the future adequacy, reliability and efficiency of energy supply to Minnesota Power, the State and the region.

1. The Project Delivers Needed Capacity And Energy To Minnesota Power And Its Customers.

Minnesota Power is somewhat unique among regional utilities in consistently showing the need for additional electric capacity and energy resources in the future, in part due to planned mining and industrial expansion on the Iron Range.[98] Indeed, beginning with the Company's 2010 IRP, Minnesota Power's IRPs and Advanced

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[96] Minn. R. 7849.0120 (A).
[97] *Id.*; these specific considerations correspond to factors (1) – (4), (8) and (9) as set forth in Minn. Stat. § 216B.243, subd. 3 and listed at pp. 19-20, above.
[98] Ex. 43, p. 23 (Rudeck Direct).

Forecast Reports ("AFRs") have shown the need for additional capacity and energy in the 2020 to 2035 timeframe and the Commission has already approved the 250 MW Agreements, requiring construction of new major transmission facilities, as one part of meeting those needs.[99]

a. The Commission Approved the 250 MW Agreements, Finding a Need for Capacity and Energy Along with a Need for New Transmission to Deliver That Power.

In its 2010 IRP, accepted by the Commission in the 1088 Docket, Minnesota Power identified significant capacity and energy needs in the 2020 to 2035 timeframe driven by customer load growth and diversification of its power supply.[100] To address these needs, the Company included action in its 2010 IRP with the intent to pursue agreements with Manitoba Hydro and associated new transmission to deliver that power, with power deliveries beginning in the 2020 timeframe.[101] The inclusion of 250 MW of Manitoba Hydro hydropower and new transmission (now provided for by the Project) was part of the Company's least cost system-wide long term supply plan.[102]

Following the 1088 Docket, Minnesota Power entered into the 250 MW Agreements with Manitoba Hydro to meet a portion of its future supply needs. In reviewing and approving the 250 MW Agreements, the Department and Commission found, consistent with the 2010 IRP, that Minnesota Power "will need a significant

[99] *Id.*, p. 9.
[100] *Id.*
[101] *Id.*
[102] *Id.*, pp. 9-10.

amount of capacity and energy" in the 2020 to 2035 timeframe.[103] The Department and Commission then specifically affirmed that the 250 MW Agreements "provide the most appropriate resources for [Minnesota Power] to meet its resource needs" over this time period.[104] Additionally, the Commission recognized that "both [Manitoba Hydro] and [Minnesota Power] must construct their own new transmission facilities (in Canada and the USA respectively) to allow Manitoba Hydro to sell the contracted power to MP."[105] In fact, given the importance of these new transmission facilities to the 250 MW Agreements, the Commission specifically requested that Minnesota Power update the Commission on the progress on the milestones achieved regarding the completion of these new transmission facilities.[106] This Project represents these needed new transmission facilities.

b. Minnesota Power's Advance Forecasts and Resource Plans Further Demonstrate the Need for the Project.

Minnesota Power's need for the additional capacity and energy to be delivered pursuant to the Manitoba Hydro Agreements – and therefore the need for the Project – continues to be demonstrated in Minnesota Power's 2013 and 2014 AFRs.[107] As Mr. Rudeck discussed, due to Minnesota Power's industrial load concentration, the AFRs include multiple industrial load growth scenarios, with the Moderate Growth scenario in both the 2013 and 2014 AFR submittals providing the most relevant information for the

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[103] Ex. 12, Department Comments at p. 4 (incorporated by reference in the Commission Order in the 938 Docket at Ex. 12, p. 1).
[104] Ex. 12, Commission Order and Department Comments at pp. 5, 25.
[105] Ex. 12, Commission Order and Department Comments, p. 13.
[106] *Id.*, Ordering Paragraph 2.
[107] Ex. 18 (2013 AFR); Ex. 43 (AJR), Schedule 1 (2014 AFR).

purpose of this proceeding.[108] Given the anticipated new load in Minnesota Power's service territory being projected for the 2020 time period, the AFR process continues to support Minnesota Power's need for the additional capacity and energy to be purchased from Manitoba Hydro.[109]

Finally, the Company's 2013 IRP, approved by the Commission in November of 2013,[110] further supports Minnesota Power's need for the capacity and energy to be purchased from Manitoba Hydro. As Department witness Mr. Shah noted, in that proceeding the Commission determined that "even after approval of the 250 MW PPA in [the 938 Docket], the Commission determined that [Minnesota Power] needed to add capacity to its system."[111]

The 2013 IRP represented a significant step in Minnesota Power's **Energy*Forward*** resource strategy.[112] As Mr. Rudeck explained, the **Energy*Forward*** strategy "is reshaping the Company's power supply from a predominantly coal-based energy mix to a diverse supply that minimizes customer costs, retains reliability, allows the Company to meet applicable air quality regulations in an economically and environmentally beneficial manner, and minimizes risks associated with potential further State or federal regulations that may restrict carbon emissions or penalize generators of those emissions."[113] The Company has already made substantial progress in

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[108] Ex. 43, p. 10-13 (Rudeck Direct).
[109] *Id.* pp. 10-11.
[110] MPUC Docket No. E-015/RP-13-53.
[111] Ex. 52, p. 11 (Shah Direct).
[112] Ex. 43, p. 13 (Rudeck Direct).
[113] *Id.*, pp. 13-14.

implementing this strategy, in large part due to the successful implementation of the Company's renewable energy plan, including the Bison wind farms, as well as the Manitoba Hydro Agreements and decisions made on thermal fleet transformation, including declining Square Butte coal generation off-take, retirement of Taconite Harbor Unit 3, and refueling of Laskin Units 1 and 2 from coal to natural gas.[114]

This combination of load growth and supply side transformation demonstrates Minnesota Power's need for the hydroelectric energy and capacity in the Manitoba Hydro Agreements as a critical element of its long term resource strategy.[115] And, as the Commission has already determined in the 938 Docket, without major new transmission facilities, Minnesota Power cannot take delivery of this needed energy and capacity.[116] As such, denial of the CON for the Project would adversely affect the adequacy of energy supply to Minnesota Power and its customers.

Denial of the CON for the Project would also harm the reliability of power supply to the Company and its customers. As the record shows, the existing interface between Manitoba and the United States, consisting of three 230 kV lines and the Dorsey-Forbes 500 kV line, is unable to accommodate increased transfer of energy from Manitoba into the United States.[117] In fact, historical studies of the Manitoba – United States transmission interface have identified that attempting to significantly increase transfers of energy on the current system would cause overloads on capacitors which are an element

[114] *Id.*, p. 14.
[115] *Id.*
[116] Ex. 12, Department Comments, p. 13 (incorporated by reference in the Commission Order in the 938 Docket at Ex. 12, p. 1).
[117] Ex. 9, p. 13; Ex. 42, p. 9 (Winter Direct).

of the existing 500 kV Line and are required for the reliable and efficient operation of the line.[118] Moreover, an unplanned outage of this existing 500 kV tie line is the second largest contingency in the entire MISO footprint.[119] Thus, in addition to enabling delivery of needed energy resources, development of a second 500 kV tie line from Manitoba to the Iron Range will reduce loading on the existing 500 kV tie line and improve the performance of the transmission system during this contingency – improving system reliability to the benefit of Minnesota Power, its customers and the broader State and regional markets.[120]

c. State and Regional Needs Further Support the Project.

In public comments filed November 20, 2014, MISO confirmed what the record demonstrates – that the Project is appropriate from a broader perspective than focusing solely on Minnesota Power and its needs. MISO stated, in part:

> As the result of MISO's work with the Applicant in the above-captioned case and its independent review of the proposed transmission project, <u>MISO considers the Great Northern Transmission Line Project a result of sound execution of MISO's collaborative Transmission Planning process.</u> This Project was reviewed under both the transmission service request process found in Module B of MISO's Tariff, and as a targeted study under a technical study task force exploring the value added by this transmission Project to the MISO footprint as described in Attachment FF, Transmission Expansion Planning Protocol, of MISO's Tariff. <u>Both studies confirmed the appropriateness of the Project to address system needs and opportunities</u>.[121]

[118] Ex. 9, pp. 9-10 (Winter Direct).
[119] *Id.*, p. 12.
[120] Ex. 9, p. 13; Ex. 42, pp. 9-13.
[121] OAH Public Comment Ex. C, MISO Comment Letter, November 20, 2014, p. 1 (eDocket Document ID 201411-104808-01).

Indeed, the record demonstrates that, in addition to meeting the needs of Minnesota Power and its customers, the Project supports the future adequacy, reliability and efficiency of supply to Minnesota and the region in multiple ways, including: (1) increasing access to a reliable, affordable and non-emitting energy resource; (2) supporting other renewable resources such as wind; (3) pairing with United States resources through seasonal energy exchanges; and (4) increasing the efficiency and reliability of the regional transmission system.

First, by increasing transfer capability between Canada and the United States the Project enables State and regional utilities increased access to hydropower. Manitoba Hydro has a long history of energy trading with multiple State and regional utilities, including Xcel Energy, Great River Energy and Wisconsin Public Service.[122] As the record demonstrates, Manitoba Hydro is currently engaged in a significant development plan that will support increased energy trading with Minnesota Power and other United States utilities.[123] Manitoba Hydro's approved development plan includes construction of the 695-megawatt Keeyask Generating Station – construction which began in July 2014.[124] In addition, the plan includes the Manitoba Hydro transmission facilities that will meet the Project at the United States – Canada border, providing the transmission capacity for these new export sales.[125] The Project, together with this Canadian portion of the new interconnection being constructed by Manitoba Hydro, will have enough

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[122] *See* Ex. 34, pp. 8-9, 21 (McMillan Direct).
[123] *Id.*, pp. 10-12.
[124] *Id.*
[125] *Id.*

capacity to deliver the 383 MW contracted for in the Manitoba Hydro Agreements, as well as 500 MW of additional hydropower to other utilities in Minnesota and the region, thereby meeting future State and regional energy needs.[126] In fact, while large hydropower transfers like this do not satisfy the current renewable energy mandates in Minnesota, such a new hydropower transfer could also support compliance with renewable energy requirements for utilities in Wisconsin and other states.[127]

Second, not only will the Project facilitate these additional energy exchanges, it will also facilitate significant addition of new wind generation and reduce the curtailment of those wind resources. As demonstrated by the MISO Manitoba Hydro Wind Synergy Study, Manitoba Hydro's hydroelectric power can work with MISO wind resources to provide benefits to electric customers within MISO.[128] The study found that a new 500 kV interconnection with Manitoba will provide "significant benefits" to the entire MISO footprint, including substantial reductions in wind curtailments and better utilization of both wind and hydro resources,[129] meaning increased efficiency of the energy supply system as a whole. These benefits over 20 years were valued at approximately $1.6 billion in 2012 dollars for the northern MISO region.[130]

Third, because Manitoba Hydro's customer needs peak in the winter and many Minnesota and other regional utilities face their peak needs in the summer, Manitoba

[126] *Id.*
[127] *See, e.g.,* Wis. Stat. § 196.378, as amended by 2011 Wis. Act 34.
[128] Ex. 41, pp. 7-8 (Hoberg Direct); Ex. 19 (MISO Hydro Wind Synergy Study).
[129] *Id.*
[130] *Id.*

Hydro and United States utilities have engaged in "seasonal diversity exchanges."[131] In these exchanges Manitoba Hydro supplies surplus power from its system in the summer and United States utilities supply surplus power in the winter, lessening the need for utilities on either side of the border to build additional peaking resources.[132] By facilitating more energy trading, the Project can bring more such load balancing benefits, again increasing the efficiency of the overall supply system while also reducing State and regional utilities' need to depend on price volatile and carbon-emitting natural gas resources.[133]

Finally, the Project supports the reliability of the overall transmission system in the region, as discussed above, by addressing a major contingency in the current system and adding a second 500 kV interconnection between Manitoba and the United States.

2. Conservation Programs Have Been Fully Considered In The Assessment Of Need.

Minnesota Power's Conservation Improvement Program ("CIP") is an integral part of its resource planning.[134] The Company's CIP efforts focus on increased efficiencies that reduce the amount of energy needed for certain uses and include eligible residential, commercial, and small scale renewable programs.[135] Since 2010, Minnesota Power's CIP efforts have resulted in surpassing the 1.5 percent annual savings goal set by State statute, saving 77,630 MWh in 2013 and these conservation levels are built in to

[131] Ex. 34, p. 9 (McMillan Direct).
[132] *Id.*
[133] *Id.*
[134] Ex. 43, p. 32 (Rudeck Direct).
[135] *Id.*; Ex. 21 (Executive Summary, Minnesota Power 2014-2016 Triennial Conservation Improvement Plan filing).

Minnesota Power's IRPs, AFRs and other resource acquisition proceeding, including the 938 Docket approving the 250 MW Agreements.[136] Conservation programs will continue to be implemented by Minnesota Power to maximize efficient use of electricity; however, these programs cannot slow load growth sufficiently to mitigate Minnesota Power's need for additional capacity and energy from Manitoba Hydro, and the Project which enables the delivery of that power.[137] The Department agreed that conservation does not lessen the need for the Project or serve as an alternative to it.[138]

3. Promotional Practices Have Not Given Rise To The Need For The Project.

Minnesota Power has engaged in no direct promotional activities to encourage the use of more power.[139] In fact, as just discussed, Minnesota Power engages in significant demand-side management and conservation programs. Therefore, the Project does not respond to any growth in demand due to promotional activities. Rather, the Project responds to increased need for capacity and energy, in part due to economic growth on the Iron Range.[140] In addition, the Project helps to fulfill the Company's **Energy*Forward*** strategy of lessening dependence on coal-fired facilities, diversifying its supply portfolio and successfully integrating significant additions of wind and other renewable energy resources.[141]

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[136] *See Id.*; Ex. 53, p. 21 (Rakow Direct) (noting conservation was considered in the approval of the 250 MW Agreements).
[137] *Id.*; Ex. 9, p. 107.
[138] Ex. 53, pp. 20-21 ((Rakow Direct).
[139] Ex. 9, p. 15.
[140] *Id.*
[141] *Id.*

The Department also examined whether Manitoba Hydro has engaged in promotional activities that have given rise to the need for the Project.[142] As the Department noted, while Manitoba Hydro may market "their brand of energy," it has not promoted increased demand overall.[143] Thus, the Department also concluded that promotional practices have not created the need for the Project.

4. Current And Planned Facilities Not Requiring Certificates Of Need Cannot Meet The Need Met By The Project.

As the Commission recognized in the 938 Docket, existing facilities cannot meet the needs covered by the Manitoba Hydro Agreements. In fact, the 938 Docket specifically recognized that both Manitoba Hydro and Minnesota Power would need to construct new transmission facilities and the Commission required updates on the status of Minnesota Power's efforts in that regard.[144] The record of this proceeding verifies those findings. As Mr. Winter succinctly stated, "the existing interface between Manitoba and the United States, consisting of three 230 kV lines and one 500 kV line, is <u>unable to accommodate increased transfer of energy</u> from Manitoba into the United States."[145] The Department agreed.[146]

The record also demonstrates that upgrades of existing facilities cannot meet the need met by the Project. As Mr. Winter explained, to increase transfer levels from Manitoba to the United States with no new transmission tie lines across the interface

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[142] Ex. 53, p. 13 (Rakow Direct).
[143] *Id.*
[144] Ex. 12 at Ordering Paragraph 2.
[145] Ex. 42, p. 9 (Winter Direct).
[146] Ex. 53, p. 12 (Rakow Direct).

would require additional capacity on some or all of the existing tie lines. Since the current 500 kV line is the largest, lowest impedance line on the interface, the majority of incremental transfers from Manitoba to the United States would flow on this line, requiring increased capacity on the line.[147] While it is technically feasible to increase the rating of this line, the upgrade would be highly complex and raise a number of potential issues relating to the operation of the line and terminal equipment as well as the reliability of the regional transmission system, resulting from the electrical inefficiencies of increasing utilization of the line.[148] Finally, upgrading existing facilities would certainly not enable increases in hydroelectric power imports from Manitoba to the United States in excess of the Manitoba Hydro Agreements, and potentially would not even facilitate the full 383 MW needed to fulfill those Agreements.[149] The record demonstrates that appropriate long-term capacity for the interface between Manitoba and the United States can only be achieved efficiently, economically, and reliably with a single new transmission line build large enough to facilitate the Manitoba Hydro Agreements and additional energy exchanges to meet the energy needs of Minnesota Power and the region.[150]

5. The Project Makes Efficient Use Of Resources.

As already discussed, the Project makes efficient use of resources in a number of ways, not just for Minnesota Power and its customers but for the State and region as well.

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[147] Ex 42, p. 11 (Winter Direct).
[148] *Id.*, pp. 11-12.
[149] *Id.*, p. 12.
[150] *Id.*

The Project allows for the optimization of Minnesota Power's wind resources and creates the possibility for other state and regional utilities to achieve this same benefit. The Project results in reduced wind curtailments in the northern region of MISO. By being sized at 500 kV, the Project avoids the need to "build twice" as additional transfer capability becomes necessary. Finally, and critically for Minnesota Power and its ratepayers, the Project provides the benefits of the economies of scale of a large project and facilitates the delivery of 383 MW of power from Manitoba Hydro, while Minnesota Power and its ratepayers only bear the financial responsibility for 250 MW of that capacity. As Mr. McMillan explained:

> Manitoba Hydro, with the approval of its PUB, is shouldering the bulk of the construction costs and a majority of the long-term operations expenses and risk associated with building and owning a 500 kV asset. Manitoba Hydro is also enabling Minnesota Power to utilize the Manitoba Hydro system for energy storage as well as allowing Minnesota Power to keep the value of environmental attributes associated with energy purchases. Minnesota Power's customers stand to benefit over the next four decades from this opportunity.[151]

For all of the reasons discussed above, delay or denial of a CON for the Project would adversely impact Minnesota Power, its customers, the State and the region. As Mr. Rudeck summarized:

> For Minnesota Power, the most direct impact of denial would be the inability to take delivery of power from Manitoba Hydro under the Commission-approved 250 MW Agreements and under the 133 MW [ROAs]. Delay or denial of a Certificate of Need for the Project, and the resulting inability for Minnesota Power to take delivery of the contracted hydropower, would leave Minnesota Power with significant unmet needs beginning in 2020. Loss of the contract for and ability to access hydropower would come with an economic cost, as well as a cost in

[151] Ex. 34, pp. 12-13 (McMillan Direct).

> diversification of generation resources and a loss of the synergies possible through the coordination of wind and hydropower contemplated by Minnesota Power and Manitoba Hydro.
>
> Additionally, denial of a Certificate of Need would mean the loss of the State and regional benefits that can be brought about by the Project, including the additional ability to take advantage of the wind-hydro synergies, the ability to meet regional needs with emission-free hydropower, building a more reliable system by reinforcing the connections between Minnesota and Manitoba, and increasing the transfer capability between Manitoba and the United States while simultaneously reducing wind curtailments.
>
> Projects such as the Great Northern Transmission Line represent a once-in-a-generation opportunity, as large transmission projects that provide renewable energy, regional reliability enhancements, and mutually beneficial outcomes for so many stakeholders only are developed very infrequently. Synchronized development of and long term resource need solutions with Manitoba Hydro as represented by the Project in the State of Minnesota are unique opportunities that if not seized at this time, may be forever lost.
>
> Minnesota Power and Manitoba Hydro have made significant commitments to the Project and have already made substantial progress toward making the Project a reality. Once in service, the Project will bring substantial benefits to Minnesota Power, our customers, the State and the region. Delay or denial of the Certificate of Need surrenders those benefits and no other significant transmission project addressing the United States – Manitoba interconnection currently exists which can recover them.[152]

B. No Party Presented An Alternative To The Project And The Record Does Not Demonstrate A More Reasonable And Prudent Alternative.

The second criterion used by the Commission in assessing need calls for the Commission to grant a CON if:

> a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record.[153]

[152] Ex. 43, pp. 28-29 (Rudeck Direct).
[153] Minn. R. 7849.0120(B) (emphasis added).

To determine whether such a preferred alternative has been established, the Commission examines: (1) the size, type, and timing of the proposed facility compared to those of reasonable alternatives; (2) the cost of the proposed facility compared to the costs of reasonable alternatives; (3) the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; and (4) the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives.[154] The record conclusively demonstrates that no more reasonable and prudent alternative exists for Minnesota Power and its ratepayers. In fact, no party even proposed an alternative.

1. The Project Provides The Appropriate Size, Type, And Timing Of Facility To Meet Minnesota Power, Customer, State And Regional Need.

The record includes a thorough analysis of multiple alternatives to the Project, including generation alternatives, transmission alternatives, and "no build" alternatives.[155] None of these provides a more reasonable and prudent alternative to the Project. As the Department summarized:

> Considering the cost of the proposed GNTL and the cost of energy to be supplied by the proposed GNTL compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives, I conclude that <u>the proposed GNTL is the preferred alternative</u>. Also, the proposed GNTL has a minimal impact in the near term when considering the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota.[156]

[154] *Id.*; these specific considerations correspond to factors (5), (6) and (8) as set forth in Minn. Stat. § 216B.243, subd. 3, listed at pp. 19-20, above.
[155] *See, e.g.,* Ex. 9, pp. 63-110.
[156] Ex. 53, p. 42 (Rakow Direct) (emphasis added).

a. Generation Alternatives.

First, it is important to remember that the Project is required for Minnesota Power to meet its need for additional capacity and energy by taking delivery of the power provided for under the Manitoba Hydro Agreements. The Company entered into those Agreements only after conducting analyses that also considered market purchases; advanced coal-fired generation, combustion gas turbines and combined cycle gas turbines; other renewable generation; and incorporating demand side management and conservation across a wide range of future energy industry assumptions and sensitivities. As discussed in the 938 Docket, using its Strategist model for screening of reasonable alternatives, the Company concluded that a natural gas-fired combined cycle unit may be the only reasonable alternative to the Manitoba Hydro hydropower.[157] However, the Manitoba Hydro Agreements provide more price certainty and mitigate carbon risks in Minnesota Power's future power supply, compared to a gas-fired facility. Additionally, when combined with Minnesota Power's wind supply portfolio, the Manitoba Hydro Agreements bring a flexible energy supply with base load characteristics.

In reviewing the 250 MW Agreements, the Department and Commission agreed that those Agreements "provide the most appropriate resources for [Minnesota Power] to meet its resource needs" over the 2020-2035 time period.[158] Since that time, Minnesota

[157] Ex. 43, pp. 29-30 (Rudeck Direct). Of course, the analysis in the 938 Docket did not reflect the substantial additional benefits to Minnesota Power and its ratepayers of the 133 MW ROAs and the FCA as those additional agreements had not yet been negotiated and signed..

[158] Ex. 12, Commission Order and Department Comments at pp. 5, 25.

Power has advanced its **Energy*Forward*** Resource Strategy to reduce emissions and deliver a more balanced system, with both the Project and the Manitoba Hydro Agreements, as well as at least 200 MW of new combined cycle generation being added sometime beyond 2020.[159] If the Project were not built, Minnesota Power's **Energy*Forward*** vision for a balanced power supply would not be able to be realized, and could become over-reliant on a natural gas generation portfolio.[160]

Minnesota Power also examined the potential for distributed generation[161] or community based energy development ("C-BED")[162] projects to meet the needs met by the Project. While the Company is exploring distributed generation and C-BED opportunities, any such resource the Company or its customers may develop cannot displace the need for the Project and the 383 MW of hydropower it enables Minnesota Power to receive.[163]

The Department also considered generation alternatives and agreed that "new generation, distributed generation, and C-BED alternatives all fail to pass a screening test in that there is no reason to conclude that such alternatives could meet the claimed need to deliver the energy and capacity called for under the [250 MW Agreements]. Therefore, the generation alternatives do not need to be considered further" in this proceeding.[164]

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[159] Ex. 43, p. 30 (Rudeck Direct).
[160] *Id.*
[161] Minn. Stat. § 216B.169.
[162] Minn. Stat. § 216B.1612.
[163] Ex. 43, p. 31 (Rudeck Direct); Ex. 9, pp. 72-73.
[164] Ex. 53, p. 20 (Rakow Direct).

b. Transmission Alternatives.

The record contains extensive discussion of transmission alternatives, including alternative voltages, alternative endpoints, and alternative configurations.[165] None of these provides a reasonable or prudent alternative than the Project.

(i) Alternative Voltages.

Compared to the 500 kV Project, a 230 kV transmission line fails on cost, resource adequacy, and environmental and socioeconomic grounds. Regarding cost, the record demonstrates that due to the structure of the Manitoba Hydro Agreements and FCA, resulting in Minnesota Power ratepayers bearing only a portion of the cost of the Project, Minnesota Power customers would actually pay <u>more</u> for a smaller 230 kV line than for the Project.[166] In fact, using the current cost estimates and revenue requirements responsibilities, the additional costs that would be imposed on Minnesota Power customers from a smaller line have grown from the time of the Application.[167]

For the Project, Minnesota Power ratepayers will be responsible for only 28.3 percent of the capital costs, estimated to equate to $158 million to $201 million.[168] In contrast, the 230 kV alternative is estimated to cost between $277 million and $355 million.[169] Moreover, Minnesota Power and its customers would bear 100 percent responsibility for those costs and 100 percent responsibility for the operations and maintenance costs, meaning the 230 kV alternative would be substantially more

[165] Ex. 9, pp. 73-107; Ex. 42, pp. 13-19 (Winter Direct).
[166] Ex. 9, pp. 28-29; Ex. 34, p. 19 (McMillan Direct).
[167] Ex. 34, p. 19 (McMillan Direct).
[168] *Id.*
[169] Ex. 38, pp. 12-13 (Donahue Direct).

expensive for Minnesota Power and its customers than the Project.[170] Thus, as the Department correctly summarized, the Project "would have far lower revenue requirements than a standalone 230 kV transmission line."[171]

In addition, a 230 kV alternative does not adequately meet Minnesota Power's needs and cannot meet the long-term needs of the region and would not be environmentally preferable over the long-term.[172] As demonstrated by the Manitoba Hydro Transmission Service Request ("TSR") Sensitivity Analysis July 2013 Draft Report, a 230 kV line from the Riel Substation in southern Manitoba to Minnesota Power's Shannon Substation on the Iron Range could facilitate 250 MW of incremental Manitoba to United States transfer capability with no thermal constraints.[173] However, it is unclear whether or not the same project could facilitate the total incremental transfer capability required by the 383 MW to be delivered under the Manitoba Hydro Agreements.[174] Additionally, since the MISO study only covers thermal analysis, it is unclear whether or not stability constraints would exist at either the 250 MW or 383 MW incremental transfer level.[175] Given these uncertainties, a 230 kV alternative cannot provide a more reasonable and prudent alternative than the Project. The Department agreed, stating that "a 500 kV transmission line would have a lower internal cost and

[170] *Id.*; Ex. 34, p. 19 (McMillan Direct); Vo. 1, p. 26 (McMillan).
[171] Ex. 53, p. 38 (Rakow Direct).
[172] Ex. 42, p. 11 (Winter Direct).
[173] Ex. 42, p. 14 (Winter Direct); Ex. 30 (MISO MH-US TSR Sensitivity Analysis Draft Report (Eastern Plan), July 13, 2013).
[174] *Id.*
[175] *Id.*

lower line losses, and thus societal cost, than the 230 kV alternative and is the preferred voltage."[176]

Selection of a 230 kV alternative would create other adverse impacts, beyond those to Minnesota Power and its customers. Demand for power in certain areas of the Upper Midwest is expected to increase over the next decade.[177] Given the favorable characteristics of hydropower resources and the risks associated with carbon-emitting fuel sources, Manitoba Hydro has had several customers and potential customers request transmission service for delivery of energy and capacity of its hydropower in the recent past.[178] Developing a transmission solution now that can deliver substantial hydropower to northern Minnesota, and that also has sufficient capacity to deliver additional hydropower to other utilities in the Upper Midwest will help meet the future energy needs of the region.[179] In contrast, constructing a new 230 kV transmission line now would not provide an optimal long-term solution for an interface poised to see significant growth over the next 15 to 20 years and would simply require further construction in the future – adding significant financial and environmental costs and impacts.[180]

A 345 kV line also fails to meet Minnesota Power's and its customers' needs more reasonably and prudently that the Project. First, a 345 kV alternative fails to provide a reasonable alternative since it would not be capable of the same capacity as a single

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[176] V. 2, p. 80-81 (Rakow) (emphasis added).
[177] Ex. 42, p. 13 (Winter Direct).
[178] *Id.*
[179] *Id.*
[180] *Id.*, pp. 13-14.

500 kV line.[181] An equivalent project to a single 500 kV line would be a double circuit 345 kV line, which would be similar in construction cost or more expensive than the Project.[182] Moreover, there is no existing 345 kV equipment in the Winnipeg area where the line originates, meaning that expensive new substation equipment would be required at the Canadian endpoint that is not required for the Project.[183]

Finally, the record discusses the possibility of a 765 kV alternative. However, since there is currently no 765 kV transmission in MISO north of Illinois, expensive transformation would be required at each substation to interconnect with existing transmission facilities systems in Manitoba and Minnesota.[184] Combined with the increased construction costs of a higher voltage line, the overall cost increase and operational complexity would not more reasonably and prudently meet the needs identified in this docket, compared to a 500 kV build.[185]

(ii) Alternative Endpoints.

The record also examines three alternative end points for a new transmission line none of which more reasonably and prudently meets the needs of Minnesota Power, its customers, the State and the region when compared to the Project. In its Application, Minnesota Power provided a detailed discussion of the Fargo Area Study Concept ("Concept") – a hypothetical line traveling a more westerly route than the Project.[186]

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[181] Ex. 42, pp. 14-15 (Winter Direct).
[182] *Id.*
[183] *Id.*
[184] *Id.*, p. 15.
[185] *Id.*
[186] Ex. 9, pp. 77-104.

That discussion demonstrated that the Concept, if built, would result in regional transmission system inefficiencies that would constrain generation outlet capability for North Dakota, Manitoba, or both, requiring potentially large-scale transmission system upgrades that would not be required for the Project.[187] Moreover, it is highly improbable that the Concept could be turned into a reality in time to meet Minnesota Power's contractual obligation in the Manitoba Hydro Agreements of an in-service date of June 1, 2020, since no entity has yet indicated a willingness to develop and fund such a line.[188] Despite the time, attention and analysis given this Concept by a variety of entities, to date no entity has indicated a willingness to develop and fund the construction of such a transmission line.

The Department raised significant concerns with this conceptual western line as well, stating that it "failed for several reasons."[189] As Dr. Rakow testified, given the utility service territories traversed by such a line: "the [Concept] would likely result in a significant misallocation of costs, might transfer responsibility for revenue requirements from [Manitoba Hydro] to ratepayers in Minnesota, and would result in the entire ownership structure of the [project] not being known for quite some time. The misallocation of costs is a significant economic issue."[190]

[187] Ex. 42, pp. 15-16 (Winter Direct).
[188] *Id.*, p. 16.
[189] Tr. 2, p. 81 (Rakow).
[190] Ex. 53, p. 49 (Rakow Direct).

Minnesota Power also considered terminating the Project's 500 kV Line at either the Shannon or Forbes substations.[191] As Mr. Winter Explained: "Upon engineering and siting review, the Company determined that the Shannon Substation is an inferior long-term solution compared to the Blackberry Substation for several reasons. First, the Shannon Substation does not provide as much 230 kV transmission line outlet capability as the Blackberry Substation, and did not perform as well electrically as the Blackberry Substation in preliminary power flow studies. Second, the Shannon Substation is located adjacent to an active mine on property leased from the mine. Since the lease agreement for the Shannon Substation has an infrastructure relocation provision, there would be considerable risk in making significant new critical infrastructure investments on leased land."[192]

The Forbes Substation endpoint also has limited outlet capacity and inferior electrical performance when compared to the Blackberry Substation.[193] Additionally, the Forbes Substation is located south of the Iron Range formation, among active mines. Therefore, the most feasible locations for crossing the Iron Range formation appear to be further west, near Grand Rapids, meaning a Forbes endpoint would increase the overall length of the line, thereby increasing the overall human and environmental impact and cost of the Project.[194]

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[191] Ex. 9, pp. 104-105 ; Ex. 42, p. 16 (Winter Direct).
[192] *Id.*
[193] *Id.*
[194] *Id.*, pp. 16-17.

(iii) Other Transmission-Related Alternatives.

Minnesota Power also examined three other transmission related alternatives – double circuiting, a Direct Current ("DC") line, and undergrounding the transmission facilities.[195] None of the three provides a more reasonable and prudent alternative than the Project.

With respect to double circuiting, the only existing double circuit opportunities for the Project are two existing tie lines from Manitoba: the Richer – Moranville 230 kV line (R50M), which extends all the way to the Shannon 230 kV Substation on the Iron Range, and the Dorsey – Forbes 500 kV line (D602F), which extends all the way to the Forbes 500 kV Substation on the Iron Range.[196] As Mr. Winter explained: "From a reliability perspective, double circuiting is typically avoided because a common structure failure could result in the loss of both lines. Double circuiting also creates maintenance constraints if only one line can be de-energized at a given time. Since both lines in this case would be tie lines between Manitoba and the United States, it would not be acceptable to de-energize both at the same time for maintenance purposes."[197]

Additionally, double circuiting often requires an extended outage of the existing line to construct the new double circuit line in its place. Since an extended outage of any of the four existing Manitoba tie lines would not be acceptable from an overall system reliability and adequacy perspective, the new double circuit line would have to be built adjacent to the existing line or in a completely new corridor to allow the existing line to

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[195] *See* Ex. 9, pp. 105-107; Ex. 42, pp. 17-18 (Winter Direct).
[196] Ex. 42, p. 17 (Winter Direct).
[197] *Id.*

stay in service during construction. Either of these options would add substantial cost to the Project and effectively defeat the main environmental purpose for double circuiting the line.[198] For these reasons, double circuiting is not a reasonable and prudent alternative to the Project.

The Company also considered a DC line, since DC lines typically have lower line losses than an AC line of the same length.[199] However, while the loss savings associated with a DC line may be a positive factor, DC lines also require expensive conversion stations at each delivery point because the DC power must be converted to AC power before it can be interconnected to the AC transmission system and delivered to customers.[200] Given these benefits and costs of DC transmission, the break-even line length at which DC becomes economically feasible compared to AC transmission is usually between 400 and 500 miles. Since the total length of the Project plus its Canadian counterpart will be less than 400 miles, a DC alternative would not be economically justified.[201] Rather, it would add to the total cost of the Project. Finally, a new DC line into Manitoba could create serious technical issues for Manitoba Hydro.[202] Therefore, a DC line does not provide a more reasonable and prudent alternative than the Project.

Finally, Minnesota Power examined the possibility of undergrounding the line. Underground high voltage transmission lines impose significantly higher engineering and

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198 *Id.*, pp. 17-18.
199 *Id.*, p. 18.
200 *Id.*
201 *Id.*
202 *Id.*, p. 19 and Schedule 3.

construction costs than overhead lines. In addition, underground lines suffer higher line losses and additional maintenance expenses throughout their useful life and present serious operating and maintenance challenges due to the relative inaccessibility of the underground conductors.[203] Given these drawbacks, undergrounding does not provide a preferable alternative to the Project.

(iv) Transmission Alternatives Summary.

As discussed above, no transmission alternative provides a more reasonable and prudent alternative than the Project. The alternatives presented fail for a combination of reasons, including economic, resource adequacy, reliability, environmental and timing grounds. In comparison to these alternatives, the Project presents a once-in-a-generation opportunity to meet the needs of Minnesota Power, its customers, the State and the region with a highly economic, non-emitting resource that optimizes Minnesota Power's other renewable energy investments.

c. "No Build" Alternatives.

For all of the reasons discussed in Sections II, A and II, B, 1, a, above, "no build" alternatives do not provide a more reasonable and prudent alternative than the Project. Rather, the record demonstrates that denial of the CON would adversely impact the future resource adequacy, efficiency and reliability for Minnesota Power, its customers, the State and the region. Neither conservation, distributed generation, nor projects not requiring a CON can meet these needs. Moreover, as the Commission has already determined, Minnesota Power has substantial need for capacity and energy beginning in

[203] *Id*., p. 19.

2020 and the Project provides access to the most appropriate means of meeting at least a portion of that that need.

2. The Project Cost Is Reasonable.

As discussed in the Project Description, Minnesota Power now estimates that the Project will cost between \$557.9 million and \$710.1 million.[204] This estimate includes updates to reflect a recent MISO-sponsored study that determined the series compensation station should now be a separate facility located at the midpoint of the 500 kV transmission line, rather than being located at Blackberry, adding cost to the Project. It also includes accounting for property taxes that will be assessed against Project assets before the in-service date of June 1, 2020.[205] No party has challenged the accuracy of these estimates. Additionally, given the terms of the ROAs and FCA, Minnesota Power ratepayers will be responsible for only 28.3 percent of the Project's capital costs, equating to \$158 million to \$201 million.[206]

In contrast, not only would a 230 kV line alternative fail to deliver the resource adequacy, efficiency and reliability benefits of the Project, it would cost Minnesota Power ratepayers <u>more</u> than the 500 kV Project. Minnesota Power would have full responsibility for both the capital and ongoing costs of a 230 kV alternative, and the Company currently estimates such a project would have capital costs of between \$277

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[204] Ex. 38, p. 5 (Donahue Direct); V. 1, p. 113 (Donahue).
[205] *Id.*
[206] *Id*.

million and $355 million.[207] Therefore, as the Department stated, the Project "would have far lower revenue requirements than a stand-alone 230 kV transmission line."[208]

3. The Project Is Compatible With The Natural And Socioeconomic Environments.

As discussed further in Section IV, C, below, the Project is not just compatible with the natural and socioeconomic environments when compared to alternatives, it stands out in this regard. The Project forms a key piece of Minnesota Power's **Energy*Forward*** strategy, through which the Company is diversifying its energy mix by increasing the use of renewable energy sources and reducing reliance on fossil fuel fired generation generally and by significantly reducing reliance on coal fired generation in particular.[209] None of the alternatives addressed in the record bring these same levels of benefits.

Moreover, Minnesota Power's work on the Project has involved "an unprecedented level of commitment and coordination with key stakeholders, including the public and governmental entities, all aimed at understanding and addressing potential environmental concerns associated with a transmission line project of this scope."[210] In the Route Permit and Presidential Permit review associated with the Project, the environmental impact of Project is being jointly reviewed by the State of Minnesota and the United States Department of Energy, with the full cooperation of the Company. In fact, as Mr. Millan testified, the White House recognized the Project for its efforts in

[207] Ex. 38, pp. 12-13 (Donahue Direct).
[208] Ex. 53, p. 38 (Rakow Direct).
[209] Ex. 34, p. 24 (McMillan Direct).
[210] Ex. 34, p. 24 (McMillan Direct).

early coordination with federal, State and local entities.[211] For the purposes of this proceeding, the Environmental Report prepared by the Department of Commerce, Energy Environmental Review and Analysis ("DOC-EERA") thoroughly and fairly evaluated the relevant environmental issues and identified no reasons to deny a CON for the Project.[212]

Finally, the Project provides significant economic benefits to northern Minnesota, including Minnesota Power's service territory, such as construction jobs, tax revenues and other benefits. In fact, construction of the Project is expected to generate over $850 million in economic impact in northern Minnesota for the design and construction period of 2016 through 2020.[213]

4. The Project Will Perform Reliably And Will Enhance The Reliability Of The Transmission System.

The record demonstrates that the Project will perform reliably and will enhance the reliability of the overall transmission system. Specifically, the Loop Flow Impact Study demonstrates that the Project will provide the needed incremental export capability for hydroelectric resources generated in Manitoba, without inherently limiting potential transmission outlet capability for other resources.[214] As Mr. Winter explained, "this is due to the fact that the Project alleviates the main thermal constraint associated with the North Dakota – Manitoba "loop flow" phenomenon, and thereby facilitates less interaction between power generated in North Dakota and power generated in

[211] *Id.*, Schedule 2.
[212] *See* Ex. 6 (Environmental Report); Ex. 37, p. 11-12 (Atkinson Direct).
[213] Ex. 34, p. 25 (McMillan Direct); Ex. 22 (Labovitz School of Business and Economics economic impact study).
[214] Ex. 42, p. 8 (Winter Direct); Ex. 62 (Loop Flow Impact Study).

Manitoba.[215] As a result, the Project enables the wind-water synergy described in the MISO Wind Synergy Study,[216] without creating other adverse consequences.[217]

Compared to alternatives, the Project also enhances the reliability of the transmission system in multiple ways, including by (1) increasing access to a reliable, affordable and non-emitting energy resource; (2) supporting other renewable resources such as wind; (3) pairing with United States resources through seasonal energy exchanges; and (4) increasing the efficiency and reliability of the regional transmission system.[218]

In summary, when compared to other alternatives in the record, the Project meets the needs of Minnesota Power, its customers, the State and the region. It will enable delivery of needed hydropower resources and do so economically, in a manner compatible with the natural environment while bringing significant socioeconomic benefits, and it will do so while enhancing the reliability of the overall transmission system.

C. The Project Meets Minnesota Power, State And Regional Needs In A Manner Compatible With Protecting The Natural And Socioeconomic Environments.

For its third criterion, the Commission states that it will grant a CON when:

> by a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a

[215] *Id.*
[216] Ex. 19 (MISO Wind Synergy Study).
[217] Ex. 42, p. 8 (Winter Direct); Ex. 62 (Loop Flow Impact Study).
[218] Discussed in detail in Section IV, A, 1, above.

> manner compatible with protecting the natural and socioeconomic environments, including human health.[219]

In analyzing this question, the Commission considers: (1) the relationship of the facility to overall State energy needs; (2) the effects of the facility on the natural and socioeconomic environments; (3) the effects of the facility in inducing future development; and (4) the socially beneficial uses of the output of the facility including its uses to protect or enhance environmental quality.[220] This Initial Brief has already addressed each of these factors, as they overlap with other criteria. However, the key attributes of the Project will be highlighted again here.

First, by adding the hydropower made possible by the Project, Minnesota Power is simultaneously diversifying the Company's resource mix and reducing the overall emissions that would otherwise be associated with its electric supply portfolio.[221] By doing so, along with the environmental benefits of reduced emissions, the Project reduces the Company's exposure to the cost of potential future emission reduction requirements and supports future economic development in the Company's service territory.[222]

Second, the Project optimizes the value of Minnesota Power's wind resources. As demonstrated in the Manitoba Wind Synergy Study, a new 500 kV transmission interconnection between Manitoba and the Iron Range brings significant benefits in the

[219] Minn. R. 7849.0120 (C).
[220] *Id.*; these considerations correspond to factors (3) and (5) of Minn. Stat. § 216B.243, subd. 3, listed at pp. 19-20, above.
[221] Ex. 44, p. 25 (Rudeck Direct).
[222] *Id.*

form of reduced wind curtailment and better utilization of both wind and hydro resources, enhancing affordability and enabling further non-emitting energy to reach the market.[223]

Third, the Project provides substantial economic benefits in the form of property tax revenue, construction and maintenance jobs, and increased business for hotels, restaurants, and other services along the final route. Property taxes alone are estimated to provide $40,000 - $60,000 per mile in annual revenues to local governments.[224] In total, the Labovitz School of Business and Economics estimated that the Project will generate over $850 million in economic impact in northern Minnesota for the design and construction period of 2016 through 2020.[225]

Fourth, the Project enables Minnesota Power to meet a growing customer need by taking delivery under the Manitoba Hydro Agreements. As the Department and Commission already affirmed, the 250 MW Agreements provide the most appropriate resource to meet that portion of the Company's needs. In making that determination, the Department and Commission considered a number of factors, including the price of the power. Affordable and reliable power is critical to Minnesota Power and its customers, and can help fuel economic activity in Minnesota Power's service territory.[226]

Finally, the Project will deliver these benefits subject to a thorough and coordinated environmental review. For the current proceeding, that review is reflected in

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[223] Ex. 41, pp. 7-8; Ex. 19 (Hydro Wind Synergy Study).
[224] Ex. 44, pp. 25-26 (Rudeck Direct).
[225] Ex. 44, p. 25; Ex. 22 (Labovitz School of Business and Economics economic impact study).
[226] Ex. 44, pp. 24-25 (Rudeck Direct).

the Environmental Report ("ER").[227] The ER examined potential issues related to air quality, biological resources, cultural, archaeological and historic resources, soil, health and safety, and land use, among others.[228] Nothing in the ER provides a basis to conclude that the Project will not be compatible with the human and natural environment. Moreover, the Project is being fully reviewed by the DOC-EERA and the United States Department of Energy in the context of the Route Permit proceeding and Presidential Permit review, as discussed above and Minnesota Power has affirmed its commitment to full compliance with all applicable permits.[229]

D. The Project Will Comply With Relevant Policies, Rules, And Regulations Of Other State And Federal Agencies And Local Governments.

The final criterion used by the Commission in determining need states that a CON will be granted if:

> the record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.[230]

The Project undeniably meets this criterion. On behalf of Minnesota Power, Mr. McMillan testified that: "Minnesota Power will continue to work with all federal, State and local governmental authorities to obtain all necessary permits and is fully committed

[227] Ex. 6.
[228] *Id.*
[229] Ex. 34, p. 26 (McMillan Direct).
[230] Minn. R. 7849.0120 (D); this criterion mirrors factor (7) as set forth in Minn. Stat. § 216B.243, subd. 3.

to compliance with those permits."[231] The record evidences the Company's commitment in this regard, including its early and frequent outreach to federal, State, and local officials and its support of a coordinated State and federal environmental review for the Route Permit and Presidential Permit for the Project.

V. CONDITIONS

While no witness testified in opposition to the granting of a CON, LPI witness Kollen recommended that the Commission attach several conditions to any such grant. The majority of his recommended conditions do not go to the need for the Project. Rather, his recommendations seek to pre-judge rate, cost recovery and cost allocation decisions which will be made in later dockets, where all ratepayers' interests have the opportunity to be heard.

A. It Is Reasonable To Condition The Certificate Of Need On Commission Approval Of The 133 MW Renewable Optimization Agreements Between Minnesota Power And Manitoba Hydro.

While Mr. Kollen did not challenge the need for the Project, he did recommend that Commission approval of the CON be "contingent" upon Commission approval of the 133 MW ROAs between Minnesota Power and Manitoba Hydro and FERC approval of the FCA. No party objected to this recommendation. However, on November 26, 2014, subsequent to the conclusion of the contested case hearings, FERC approved the FCA.[232] Thus, a "condition" is no longer necessary for the FERC approval.

[231] Ex. 34, p. 26 (McMillan Direct).
[232] Ex. 64.

Regarding the ROAs, on November 6, 2014, Minnesota Power filed its Petition with the Commission seeking approval of these agreements.[233] The record demonstrates that these agreements provide substantial benefits to Minnesota Power and its ratepayers, including the "must take fee" that credits Minnesota Power customers for the transmission revenue requirements components associated with 133 MW of the Project.[234] In combination with the FCA and other contractual provisions between Minnesota Power and Manitoba Hydro, this feature of the ROAs bring Minnesota Power's and its ratepayers' responsibility for the revenue requirements associated with the Project down to less than 30 percent of the Project cost, as discussed above. In addition, the ROAs includes the "wind storage" provisions, discussed above, that further increase the flexibility and value of the Manitoba Hydro resources as part of Minnesota Power's supply.[235] As such, the ROAs and are a central piece of the overall benefits of the Project and LPI, the Department and Minnesota Power all agree that it is reasonable to condition the granting of the CON on the Commission approval of the ROAs.[236]

B. A "Soft Cap" On Project Costs, As Agreed To By Minnesota Power And The Department, Provides Ratepayer Protections Without Creating The Potential For Adverse Impacts To The Broader Public Interest.

The record also discusses the concept of imposing a "cost cap" on Minnesota Power's recovery of costs related to the Project, whether that recovery occurs through use

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233 MPUC Docket No. E-015/M-14-960 (Petition for Approval included in the record as Ex. 55 (ASR-S), Schedule 1 (Rudeck Surrebuttal).
234 Ex. 35, p. 9 (McMillan Rebuttal); Ex. 45, pp. 2-3 (Rudeck Surrebuttal).
235 Ex. 45, p. 2 (Rudeck Surrebuttal).
236 Ex. 51, pp. 6-7 (Kollen Surrebuttal); Ex. 55, pp. 1-2 (Rakow Rebuttal); Ex. 35, pp. 9-10 (McMillan Rebuttal).

of a rider or in a general rate case. As both Minnesota Power and the Department noted, the Commission has historically addressed such issues in the rider or rate case proceeding in which the utility first requests cost recovery from ratepayers, not in CON proceedings.[237] Indeed, the Commission will continue to have the ability to assess the prudence of the costs incurred in developing the Project going forward and, therefore, does not need to address this issue or to artificially "cap" the costs at this time.[238]

Nonetheless, the Department suggested that it may be reasonable to clarify for Minnesota Power the terms of its future cost recovery. Specifically, the Department suggested that it may be reasonable to specify that: (1) Minnesota Power would be limited to recover in <u>riders</u> only the amount of costs proposed in this proceeding; (2) the Company could request recovery of costs above this amount only in a rate case, where those costs will be subject to full prudence review; and (3) Minnesota Power would have the burden of demonstrating the prudency of those additional costs and showing why it would be reasonable to recover them from ratepayers.[239] The Department noted that the Commission employed this approach in a cost recovery proceeding for certain renewable energy facilities owned by Xcel Energy, to give the utility an incentive to minimize costs.[240]

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[237] Ex. 55, pp. 2-3 (Rakow Rebuttal); Ex. 35, pp. 10-11 (McMillan Rebuttal).
[238] *Id.*
[239] Ex. 55, pp. 2-3 (Rakow Rebuttal); Ex. 56, pp. 10-11 (Rakow Surrebuttal); V. 2, p. 81 (Rakow)..
[240] *Id.* (citing MPUC Docket No. E-002/M-09-1083).

Minnesota Power agreed to the Department's recommendation of putting in place such a "soft cap" on cost recovery.[241] This approach is consistent with the Commission's decision on cost recovery regarding Minnesota Power's plan to retrofit its Boswell Unit 4 facility as part of its mercury reduction efforts.[242] In its Order in that proceeding, the Commission stated: "To protect ratepayers from potential cost overruns, the Commission will cap the total amount that Minnesota Power may recover through the Boswell 4 rider at the amount stated in the Company's petition."[243] The Commission capped only the amount Minnesota Power may recover through the rider; it did not impose a cap on total recovery, including potential rate case recovery.

Further, the Commission very recently used this same "soft cap" approach in a transmission CON proceeding involving ITC.[244] In its November 25, 2014 Order approving the CON, the Commission stated as follows:

> The Commission recognizes that the ALJ's Findings with respect to the cost of the proposed Project contain little certainty, noting that the final cost of the Project is dependent on a number of factors that are outside of ITC Midwest's control, including the final route (which impacts final design); the timing of construction; the availability of construction crews; and the cost of materials.
>
> Nonetheless, the Commission agrees with the DOC DER's recommendation to condition its approval of the certificate of need by imposing the cost recovery limitation set forth below. The Commission concurs with the Department that it should continue its practice of limiting utilities seeking to recover transmission costs <u>through transmission cost recovery riders </u>to the costs put forward by applicants in certificate of need proceedings -- here, $284,000,000. The Commission continues to believe

[241] Ex. 36, p. 3 (McMillan Surrebuttal).
[242] Ex. 35, pp. 10-11 (McMillan Rebuttal).
[243] MPUC Docket No. E-015/M-12-920, Order dated November 5, 2013, p. 7.
[244] MPUC Docket No. ET-6675/CN-12-1053.

> the fiscal discipline these limits impose benefits ratepayers and that the limits help protect the integrity of the certificate of need process.
>
> At the same time, the Commission recognizes that routing realities cannot always be foreseen with certainty, cost overruns can be prudently incurred, and that recovery over the $284,000,000 level could be justified under some circumstances. The Commission will therefore permit utilities to seek higher recovery levels in future proceedings, with proper documentation and explanation in their rider filings.[245]

In stark contrast to this consistent Commission approach to the issue, LPI argues for a "hard cap" that would absolutely prohibit the recovery of costs above the level shown in the record to date.[246]

Mr. Kollen recommended that the Commission limit in this docket any cost recovery to the cost estimate cited in the FERC approved FCA.[247] As Mr. Kollen stated during his testimony: "And what that means is that the Commission in this proceeding would fix the maximum cost that Minnesota Power can recover from customers, rather than waiting to a subsequent rate case or a rider proceeding."[248]

Such a "hard cap" runs contrary to Minnesota law, is not appropriate as part of a CON approval, goes beyond prior Commission orders, and creates perverse incentives that may harm the public interest. Mr. Kollen appears to acknowledge that the Commission has not imposed such a "hard cap" in prior proceedings.[249] The Commission has not done so for sound reasons. In this proceeding, as with typical CON

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[245] *Id.*, Order dated November 25, 2014, p. 6 (emphasis added).
[246] Ex. 50, pp. 5-13 (Kollen Direct).
[247] Ex. 50, p. 11 (Kollen Direct)
[248] V. 2, pp. 33-34 (Kollen).
[249] Ex. 51, p. 11 (Kollen Surrebuttal).

proceedings, the Company has provided a range of capital costs.[250] This range is appropriate given that a final route and any route permit conditions for this Project will be decided in a separate docket.[251] For this and other reasons, the Company's cost estimates appropriately include standard contingencies, which may prove necessary and reasonable.[252]

Of course, under Minnesota law utilities may recover the reasonable and prudent costs incurred in providing utility service. Minnesota's general ratemaking statute provides that in setting rates, the Commission:

> shall give due consideration to the public need for adequate, efficient, and reasonable service and to the <u>need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service</u>, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property. In determining the rate base upon which the utility is to be allowed to earn a fair rate of return, <u>the commission shall give due consideration to evidence of the cost of the property when first devoted to public use</u>, to prudent acquisition cost to the public utility less appropriate depreciation on each, to construction work in progress, to offsets in the nature of capital provided by sources other than the investors, and to other expenses of a capital nature.[253]

Certainly, the Commission can "disallow" costs it ultimately deems were not prudently incurred. However, prohibiting recovery today of costs which may be

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[250] Ex. 35, p. 10 (McMillan Rebuttal).
[251] *Id.*
[252] *Id.*, p. 11.
[253] Minn. Stat. § 216B.16, subd. 6; *see also*, *Senior Citizens Coalition v. Minnesota Public Utilities Commission*, 355 N.W.2d 295, 300 (Minn. 1984) ("Under section 216B.16, subd. 6, a utility is entitled to a reasonable return on its investment in 'property used and useful in rendering service to the public.'").

prudently incurred in the future violates the fundamental ratemaking principles embodied in Minnesota Statutes.

Additionally, a “hard cap” is not necessary to “protect” ratepayers. First, as discussed above, the Commission has the authority to disallow costs in the future if it determines the utility incurred them imprudently. Second, while the Commission’s past practice of limiting <u>current</u> cost recovery may provide additional incentive to the utility to manage the cost of the Project, Minnesota Power’s larger obligations to limit impacts on customers has driven the development of this Project.[254] The Company’s efforts in this regard include assuring that all benefits from the 133 MW ROAs (including environmental benefits) flow through to customers. The ROAs and FCA also allocate a significant portion of Project’s capital costs to Manitoba Hydro, lessening the impact of the Project on rates.[255] These unique contractual agreements already provide substantial ratepayer benefit and protection.[256]

Mr. Kollen’s recommendation of a “hard cap” is further flawed by a false comparison. In arguing the need for this “hard cap” Mr. Kollen claims that such an absolute limit on any cost recovery is necessary because the economics of the Project is a “close call” with the option of building a natural gas facility.[257] However, this “analysis” compared only the 250 MW Agreements and the Project with a natural gas-fired

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254 Ex. 35, p. 11 (McMillan Rebuttal).
255 *Id.*; Ex. 43, pp. 15-18 (Rudeck Direct).
256 *Id.*
257 Ex. 50, pp. 7-8 (Kollen Direct).

alternative.[258] As such, Mr. Kollen's testimony ignores the substantial economic and environmental benefits Minnesota Power ratepayers will receive from the 133 MW ROAs. This incomplete analysis cannot provide a basis for creating a new and unprecedented "hard cap" on cost recovery in this proceeding.

Finally, while imposition of a "hard cap" may, at first blush, appear to "protect" ratepayers, it can have exactly the opposite effect by sending perverse signals to utilities and encourage resource decisions that are not in the best interest of ratepayers. As the Department explained, if the Commission imposes a "hard cap" on a utility in one proceeding, it creates an incentive for the utility to minimize its risks and seek to recover costs through a different proceeding.[259] Specifically, imposing a "hard cap" on capital costs in a CON proceeding would encourage a utility to abandon capital intensive projects and instead pursue resource options that can receive cost recovery through the fuel clause.[260] By doing so, ratepayers end up with a more expensive overall system and an inefficient use of resources.[261]

For all of the reasons discussed above, the "soft cap" proposed by the Department and agreed to by Minnesota Power is consistent with Commission precedent, provides reasonable ratepayer protections, preserves for the Commission full authority to review and either approve or disapprove future cost recovery, and is consistent with the public interest. The "hard cap" proposed by LPI veers dramatically from Commission

[258] *Id.* (As Mr. Kollen states at page 7, his analysis "shows a slight savings for the 250 MW Agreements and GNTL project compared to the combined cycle alternative.")
[259] V. 2, pp. 92-94 (Rakow).
[260] *Id.*
[261] *Id.*

precedent, imposes unreasonable conditions on Minnesota Power, and creates unintended consequences that could harm the public interest.

C. LPI's Cost Recovery And Cost Allocation Recommendations Are Unprecedented, Contrary To Statute, And Inconsistent With The Public Interest.

As discussed further below, LPI witness Kollen makes three additional recommendations regarding cost recovery or cost allocation issues. None of these recommendations finds any precedent in past Commission decisions. The reason for the unprecedented nature of these recommendations is simple – they do not tie to the Commission's determination of need, two run contrary to legislative direction, and all of the issues raised will be addressed in future cost recovery proceedings. Perhaps Mr. Kollen offers these recommendations because, despite his substantial rate case, cost allocation and cost recovery testimony experience, a review of his resume fails to reveal a single CON proceeding in which he has participated.[262] Regardless, the fact remains that neither the Administrative Law Judge ("ALJ") nor the Commission need to address these issues in this proceeding. As both Minnesota Power and the Department testified, these issues will be appropriately addressed in future proceedings, after notice to all potentially interested parties. As Mr. McMillan testified, "while Minnesota Power has worked to be transparent about cost recovery matters, cost recovery treatment is not an issue that needs to be decided in the CON docket. Indeed, it would be premature and inappropriate to do so at this time."[263]

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[262] *See* Ex. 50 at Appendix A (Kollen Direct).
[263] Ex. 35, p. 12 (McMillan Rebuttal).

A review of transmission CONs issued by the Commission since 2005, together with a listing of any "conditions" imposed as a part of granting the CON, fails to reveal a single CON Order that has pre-emptively addressed the rate-making and cost recovery issues LPI argues for in this proceeding. The following table catalogues the results of those Orders:[264]

MPUC Docket No.	Project Applicant and Name	MPUC Order Date	Conditions Imposed on CON
ET-2, E015/TL-05-867	Great River Energy and Minnesota Power Badoura and Tower Projects	May 25, 2006	None
ET-2/CN-06-367	Great River Energy – Mud Lake-Wilson Lake 115 kV Project	February 12, 2007	None
E-017/CN-06-677	Otter Tail Power Company – Appleton-Canby 115 kV Transmission Line	April 18, 2007	None
E-002/CN-04-1176	Xcel Energy and Dairyland Power – Chisago Project	February 20, 2008	None
E017, ET-6131, ET-6130, ET-6144, ET-6135, ET-10/CN-05-619	Otter Tail Power Company and Others for the Big Stone 2 Transmission Facilities	March 17, 2009	Conditions imposed related to the Big Stone 2 coal generating plant in South Dakota. This CON extinguished in order dated February 25, 2010.

[264] This table does not include transmission projects that are pending before the Commission or where the application was withdrawn.

MPUC Docket No.	Project Applicant and Name	MPUC Order Date	Conditions Imposed on CON
ET-2, E002, et al./CN-06-1115	CapX2020 345 kV Transmission Projects	May 22, 2009	For the Brookings Project: 1) Signed PPAs or utility renewable generation and designate as network transmission. 2) Submit transmission service requests to MISO with compliance filing showing new transmission capacity. 3) Compliance filings related to MISO and federal changes that affect conditions.
E017, E015, ET-6/CN-07-1222	CapX2020 Bemidji-Grand Rapids 230 kV Transmission Project	July 14, 2009	Provide a compliance filing within 60 days on final ownership
E-002/CN-08-992	Xcel Energy – 161 kV Transmission Line Between Pleasant Valley Substation and Byron Substation	February 28, 2011	None
IP-6838/CN-10-80	Prairie Rose Wind and Associated Transmission Facilities	September 16, 2011	None
E-002/CN-09-1390	Xcel Energy and City of Glencoe – Glencoe-Waconia Upgrades	November 14, 2011	None
E-002/CN-10-694	Xcel Energy – Hiawatha Project	February 10, 2012	None

MPUC Docket No.	Project Applicant and Name	MPUC Order Date	Conditions Imposed on CON
ET-2, E-015/CN-10-973	Minnesota Power and Great River Energy – Savanna Project	March 7, 2012	None
E-002/CN-11-826	Xcel Energy and Great River Energy – Southwest Twin Cities Chaska Project	October 15, 2013	None
ET-6675/CN-12-1053	ITC Midwest MN/IA Transmission Project	November 25, 2014	1) Soft cap for recovery through their transmission cost riders 2) ITC Midwest shall work with the Department on use of MPUC CO2 and externality values 3) ITC Midwest shall use MPUC externality values in future CON proceedings

Minnesota Power strongly recommends that the ALJ and Commission continue this historical practice of not addressing rate recovery and cost allocation issues in CON proceedings, but addressing them in rate recovery and general rate proceedings, where all ratepayer interests can be heard. To the extent the ALJ and Commission nonetheless considers these issues in the current case, LPI's recommendations must be rejected.

1. Mandating AFUDC Treatment For Construction Costs Is Inconsistent With Minnesota Statutes And Past Commission Practice And Adversely Impacts The Public Interest.

LPI witness Kollen again radically departs from Commission practice, and from Minnesota law, by recommending that the Commission act now to prohibit Minnesota Power from asking – in a future cost recovery proceeding – to receive a return on construction work in progress "("CWIP"), as it incurs the substantial investment costs during the construction period on the Project. Instead, Mr. Kollen argues that the Commission should mandate that the Company accumulate an allowance for funds used during construction ("AFUDC") and be prohibited from recovering its costs until after the Project is completed and placed in service.

The Minnesota Legislature has specifically addressed cost recovery for transmission assets, providing substantial detail and direction to the Commission regarding that cost recovery.[265] The Legislature enacted these "transmission cost adjustment" provisions for the purpose of encouraging new transmission construction.[266] As part of this effort to encourage construction of needed facilities, the Legislature directed that a utility may file for a transmission cost adjustment that:

> provides a current return on construction work in progress, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism.[267]

By enacting this language, the Legislature removed the financial disincentive to utilities of pursuing such major construction projects under traditional ratemaking.[268]

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[265] Minn. Stat. § 216B.16, subd. 7b (attached as Appendix B).
[266] Ex. 35, p. 12 (McMillan Rebuttal).
[267] Minn. Stat. § 216B.16, subd. 7b (b) (5) (emphasis added).

That older paradigm, now recommended by Mr. Kollen, allowed for AFUDC treatment but deferred any utility recovery of costs until the asset was "used and useful" and placed into the utility's rate base.[269]

Given the clear direction from the Legislature, the Commission has consistently approved transmission cost recovery ("TCR") filings that provide for "a current return on construction work in progress." As Department witness Mr. Johnson testified: "In fact, if the Commission denied a request by [Minnesota Power] for current recovery of a return on CWIP in a future TCR Rider, the Commission would be making <u>a significant departure from past precedent</u>."[270] A review of past Commission Orders demonstrates the veracity of Mr. Johnson's testimony.

For example, on July 12, 2007, Minnesota Power requested Commission approval of a TCR Rider consistent with Minn. Stat. § 216B.16, subd. 7b.[271] The Department recommended approval of Minnesota Power's petition. In response to Minnesota Power's request to recover a current return on construction work in progress for two transmission projects, the Department agreed with Minnesota Power's proposed methodology. The Department stated in its October 12, 2007 comments, adopted and incorporated by reference by the Commission in its December 7, 2007 Order:

> The Department understands that MP is proposing to recover AFUDC on the CWIP balance up to the point the rider begins in 2008. Once the rider is implemented, MP proposes to discontinue AFUDC and begin recovery of a current return on CWIP. In order to ensure against double recovery of the

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[268] Ex. 35, p. 12 (McMillan Rebuttal).
[269] *Id.*
[270] Ex. 57, p. 6 (Johnson Surrebuttal).
[271] MPUC Docket No. E-015/M-07-965.

> AFUDC amount already included in CWIP, MP proposes to set up a contra AFUDC account to offset the portion of AFUDC capitalized under the TCR Rider. The Company proposed the same methodology in its recent Boswell 3 Plan (Docket No. E015/M-06-1501). The Department agrees with this approach. Based on our analysis, the Department concludes that the proposed AFUDC/CWIP calculations are reasonable.[272]

In its December 7, 2007 Order, the Commission approved Minnesota Power's Transmission Cost Recovery Rider and allowed the Company to begin collecting rates that included a current return on construction work in progress effective January 1, 2008.[273]

This Order began a consistent practice, consistent with Minnesota Statutes. On June 23, 2009, the Commission issued an Order approving Minnesota Power's 2009 TCR Rider.[274] On May 11, 2011, the Commission issued an Order approving Minnesota Power's 2010 TCR Rider.[275] On November 12, 2013 the Commission granted the Company's petition for approval of its 2011 TCR Rider.[276] The Company's 2014 TCR Rider is currently pending before the Commission.[277] In every Commission Order to date, Minnesota Power has been allowed to recover a current return on construction work in progress on transmission projects that have not been placed in-service, consistent with Minn. Stat. § 216B.16, subd. 7b(b)(5).

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[272] Id., Department Comments, p. 4 (Commission Order and Department Comments attached as Appendix C).
[273] Appendix C, p. 1.
[274] MPUC Docket No. E-015/M-08-1176
[275] MPUC Docket No. E-015/M-10-799.
[276] MPUC Docket No. E-015/M-11-695.
[277] MPUC Docket No. E-015/M-14-337.

Moreover, since Minn. Stat. § 216B.16, subd. 7b was enacted in 2005, the Commission has issued at least multiple CONs or certifications for new transmission projects under Minn. Stat. § 216B.243 and 2425. In none of those Orders has the Commission imposed any of the conditions related to the means by which costs must be recovered under a future TCR Rider or general rate case (nor has the Commission imposed a "hard cap" on the total capital dollars that can be recovered from ratepayers).

In addition to diverging from statutes and past Commission practices, Mr. Kollen's recommendation to mandate AFUDC treatment could have adverse impacts to ratepayers. In fact, providing a current return on CWIP provides customers a <u>lower</u> overall capital cost of approximately $55 million in nominal dollars compared to recording AFUDC, meaning lower overall capital costs to ratepayers.[278] Given the timing delay in recovery under these two methods, a number of assumptions would be necessary to draw any definitive conclusion as to the net impact on ratepayers.[279] However, it cannot be debated that mandating AFUDC treatment of construction costs will increase the total cost of the Project to ratepayers.

Moreover, as the Company and Department noted, mandating AFUDC treatment of construction costs creates the possibility of "rate shock" to customers once the Project is placed in service.[280] Compared to AFUDC treatment, allowing a return on CWIP

[278] Ex. 35, p. 13 (McMillan Rebuttal); Ex. 57, p. 7 (Johnson Surrebuttal).
[279] Ex. 57, pp. 7-9 (Johnson Surrebuttal).
[280] Ex. 35, p. 13 (McMillan Rebuttal); Ex. 57, p. 8 (Johnson Surrebuttal).

gradually phases in rate increases rather than creating a one-time rate adjustment for the entirety of the Project.[281]

Finally, mandating AFUDC treatment of Project construction costs would severely harm Minnesota Power's cash flow, which in turn can lower the Company's financial ratings and impose additional costs on ratepayers due to the higher cost of capital.[282] As Mr. McMillan testified, these concerns are very real and there is "a steady conversation with Wall Street about cash flow and its importance," versus later recovery through AFUDC treatment.[283] The Department agreed, noting that while these harms are difficult to measure, the now standard recovery of these costs through a return on CWIP may bring ratepayer benefits due to the Company's improved cash flow and stronger financial rating.[284] As a former Illinois Commerce Commission noted:

> Additionally, by virtue of pre-funding, utilities can obtain greater certainty of cost recovery, which provides risk assurance to the investment community. Specifically, reducing rate impacts by spreading costs over a longer timeline can significantly reduce upfront ratepayer backlash toward the needed investment, and therefore diminish regulatory uncertainty. This approach will decrease the cost of capital to both utilities and the customers they serve.[285]

For all of the reasons discussed above, the Commission should deny LPI's recommendation that the Commission turn back the hands of time and stray from statute and precedent by mandating AFUDC treatment of all Project construction costs.

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[281] Ex. 35, p. 13 (McMillan Rebuttal).
[282] *Id.*; V. 1, pp. 68-70 (McMillan).
[283] V. 1, p. 70 (McMillan).
[284] Ex. 57, pp. 8-9 (Johnson Surrebuttal).
[285] *Pre-Funding to Mitigate Rate Shock*, Sherman Elliott and Ralph Zarumba, 150 No. 9 Pub. Util. Fort. 56 (Sept. 1, 2012).

2. Mandating Rider Recovery For The Entirety Of The Project Costs Is Contrary To Statute And Commission Precedent And May Not Prove To Be In Ratepayers' Best Interests.

Mr. Kollen again recommends that the ALJ and Commission ignore statute and precedent when he asks for a mandate that Minnesota Power only be allowed recovery of Project costs through a TCR Rider.[286] While the statutes allow recovery of transmission costs through a TCR Rider, the statutes do not require such recovery in perpetuity. Rather, the transmission cost adjustment statute specifically provides that a TCR Rider shall remain in place until "costs have been fully recovered or have otherwise been reflected in the utility's general rates."[287] Thus, the statute clearly anticipates that utilities may move recovery of transmission costs from a TCR Rider to its general rates, if approved by the Commission in a general rate case.[288]

Given this clear language, the Commission has never mandated recovery of transmission costs only through a TCR Rider.[289] Again, sound public policy supports the Commission's past practice. As both Minnesota Power and the Department testified, once the Project is built and in service, better ratemaking outcomes may be achieved for customers by addressing this major new asset addition through a traditional general rate case.[290] For example, a rate case would re-examine the issue of wholesale/retail allocation and may provide benefits to retail customers.[291] Further, the transmission rider

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[286] Ex. 50, p. 4 (Kollen Direct).
[287] Minn. Stat. § 216B.16, subd. 7b(b)(9) (emphasis added).
[288] Ex. 57, p. 11 (Johnson Surrebuttal).
[289] *Id.*
[290] Ex. 34, p. 14 (McMillan Rebuttal); Ex. 57, p. 10 (Johnson Surrebuttal).
[291] Ex. 34, p. 14 (McMillan Rebuttal).

would use Minnesota Power's last approved return on equity ("ROE") rather than re-examining and resetting an appropriate ROE going forward.[292] In addition, as the Department explained, if the Commission mandates recovery solely through a TCR Rider, "the Commission would essentially be pre-determining rate recovery of the Project over the next 55 years," the expected service life of the Project.[293] For all of these reasons, the Commission should continue its past practice, consistent with statute, and not pre-emptively foreclose in this docket an option that may prove to be in the best interest of ratepayers.

3. Cost Allocation Issues Will Be Addressed In Future Proceedings.

Finally, Mr. Kollen again proposes departing from Commission precedent by asking the Commission to pre-determine the allocation of costs among classes of customers before a cost recovery proceeding has been initiated. Mr. Kollen believes such action is necessary "to partially remedy the subsidies provided by the LP class to other classes" that resulted from the Commission's most recent Minnesota Power general rate case decision.[294]

As both the Department and Minnesota Power testified, cost allocation matters are addressed in cost recovery or rate case proceedings.[295] Cost allocation and ratemaking involves both fact and policy decisions best left to those future cost recovery proceedings, where all customer classes are on notice that ratemaking decisions will be made and can

[292] *Id.*
[293] Ex. 57, p. 10 (Johnson Surrebuttal).
[294] Ex. 50, p. 27 (Kollen Direct).
[295] Ex. 34, pp. 17-18 (McMillan Rebuttal); Ex. 57, p. 14 (Johnson Surrebuttal).

then voice their opinion. The Notice Plan approved by the Commission required notice to "landowners reasonably likely to be affected by the proposed transmission line,"[296] not to Minnesota Power's 140,000 customers living outside the area proposed for the Project but would be impacted if LPI's proposed conditions are ordered by the Commission. The purpose of the current proceeding is not to set rates or to address other issues participants may have from either past or future proceedings.[297]

Despite its concerns about this LPI recommendation, the Company provided information on two alternative examples of cost allocation. For both examples, the Company allocated the revenue requirements to the Minnesota retail jurisdiction using the D-02 transmission demand allocation factor from the Company's last rate case.[298] In the first example, the jurisdictional revenue requirements are allocated to all classes using the D-02 transmission demand class allocation factors. Under this approach, the greatest percentage increase would fall on the Large Power Class.[299] As the Department testified, this example is similar to the rate design method in the Company's most recent Commission-approved TCR Rider dockets.[300]

Minnesota Power developed the second example after clarifying its understanding of Mr. Kollen's recommendation on allocating revenue requirements. Under this second

[296] Minn. R. 7829.2550, subp. 3(A).
[297] Ex. 35, pp. 17-18 (McMillan Rebuttal).
[298] *Id.*, p. 15.
[299] *Id.*, p. 15 and Schedule 2, Table 1.
[300] Ex. 57, p. 13 (Johnson Surrebuttal).

approach, the jurisdictional revenue requirements are apportioned to customer class on base revenue so that all customer classes have the same average rate increase.[301]

The Company then estimated rate impacts for all customer classes under the first and second examples for the years 2020, 2021 and 2022.[302] Under the first alternative the Company estimates the increase in years 2020, 2021 and 2022 will be 2.96 percent, 2.63 percent, and 2.53 percent for residential customers and 4.63 percent, 4.09 percent, and 3.94 percent for LP customers, respectively. In the second alternative the Company estimates the increase for the years 2020, 2021 and 2022 will be 3.98 percent, 3.54 percent, and 3.40 percent for all customer classes.[303]

Neither Minnesota Power nor the Department expressed an opinion on the "proper" rate design, recommending instead that this issue be addressed at the time the Company requests rate recovery.

CONCLUSION

As Minnesota Power Executive Vice President David McMillan summarized, the Great Northern Transmission Line presents: "a once-in-a-generation opportunity for Minnesota Power and its customers to connect to the most advantageous and complementary carbon free resource available in the Upper Midwest."[304] The record of this proceeding bears that out, demonstrating that the Project meets each of the criteria

[301] Ex. 35, pp. 15-16 and Schedule 2, Table 2 (McMillan Rebuttal).
[302] *Id.*, p. 17 and Schedule 2, Tables 3 and 4 (McMillan Rebuttal).
[303] *Id.*
[304] Ex. 34, p. 12 (McMillan Direct).

necessary for the Commission to grant a CON. In fact, no party presented testimony opposing the Project. As the record shows:

- Denial of a Certificate of Need for the Project would adversely impact the adequacy, reliability and efficiency of energy supply to Minnesota Power, its customers, the State and the region.

- No alternative analyzed meets Minnesota Power's or State and regional needs as reasonably and prudently as the Project, in part due to the unique funding of the Project which places only a portion of the Project cost responsibility on Minnesota Power and its customers.

- The Project, together with the Manitoba Hydro Agreements, offers a multitude of benefits, including: providing affordable, reliable, efficient and non-emitting energy resources while minimizing ratepayer cost; optimizing Minnesota Power's other renewable energy resources and furthering the transformation of its energy supply, minimizing future risks; and creating hundreds of jobs and spurring hundreds of millions of dollars of economic activity in northern Minnesota.

- The Project will achieve these benefits while fully complying with all applicable regulatory requirements.

The record, Minnesota Statutes and Commission precedent also demonstrate that the Commission can and will make all cost recovery and cost allocation decisions in subsequent proceedings, after appropriate notice and comment. Such issues do not go to the need determination and cannot be "pre-emptively" determined in a manner consistent with Minnesota law.

Therefore, Minnesota Power respectfully requests that the Administrative law Judge recommend to the Commission and that the Commission grant Minnesota Power a Certificate of Need for the Great Northern Transmission Line, conditioned upon: (1) Commission approval of the 133 MW Renewable Optimization Agreements; and (2) establishment of a cap on the total construction cost recovery allowed through a

Transmission Cost Recovery Rider equal to the Company's estimated construction costs in this record, while requiring the Company to bear the burden of demonstrating the prudence of any additional costs in a future general rate case.

Dated: December 19, 2014

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Court of Appeals of Minnesota.

In the Matter of the APPLICATION OF THE CITY OF HUTCHINSON (HUTCHINSON UTILITIES COMMISSION) for a Certificate of Need to Construct a Large Natural Gas Pipeline.

No. A03-99. | Sept. 23, 2003.

Minnesota Public Utilities Commission, CN011826.

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Considered and decided by PETERSON, Presiding Judge, SCHUMACHER, Judge, and STONEBURNER, Judge.

UNPUBLISHED OPINION

PETERSON, Judge.

***1** Hutchinson Utilities Commission (HUC) applied for a certificate of need in order to build a natural-gas pipeline. Relator Northern Natural Gas Company (Northern) intervened in the proceedings before the office of administrative hearings. The administrative law judge reserved for the Minnesota Public Utilities Commission (MPUC) the issue of whether Minnesota law classifies HUC's proposed pipeline as an intrastate pipeline. Nonetheless, relying on a comparative-cost analysis that assumed that the pipeline would not be considered an intrastate pipeline, the ALJ reasoned that Northern had failed to demonstrate that the alternatives it offered more reasonably meet HUC's needs than HUC's proposed pipeline and recommended that the certificate of need be issued. Pursuant to the MPUC's scheduling order, Northern filed exceptions to the ALJ findings, emphasizing that the pipeline's intrastate status is critical because if the intrastate-pipeline statute applies, HUC will lose its eligibility for favorable financing. The MPUC concluded that it did not need to determine whether the proposed pipeline, upon completion, will be an intrastate pipeline and issued an order granting HUC a certificate of need. Northern petitioned for reconsideration, and the MPUC denied the petition.

On appeal, Northern argues that (1) the MPUC erred by refusing to consider the intrastate issue; (2) the MPUC erred by removing the burden of proof from HUC; and (3) HUC failed to provide substantial evidence supporting a determination that its proposed pipeline reasonably meets any identified need of HUC. We affirm.

FACTS

The City of Hutchinson is located 55 miles west of Minneapolis and has a population of approximately 13,050 people. Between 1990 and 2000, the number of households in Hutchinson increased by about 18.95%, and growth is projected to continue through at least 2020 due to Hutchinson's close proximity to the Minneapolis area and its role as a manufacturing and retail center for the surrounding rural area.

Respondent Hutchinson Utilities Commission (HUC) provides electricity and natural-gas services to commercial and residential customers in Hutchinson. HUC uses 3.2 billion cubic feet (Bcf) of natural gas per year. Approximately 73% of the gas is used to generate electricity, and HUC's customers directly consume 27%. Since 1960, HUC has obtained its natural gas via Northern's pipeline. HUC's current contract with Northern expires in October 2003.

During winter months, the natural-gas capacity available to HUC under its contract with Northern is 17,253 dekatherms (Dth) per day, with a minimum delivery pressure of 450 pounds per square inch gauge (psig). From 1996 to 2001, HUC's peak winter load was 16,695 Dth per day, which is 97% of capacity. During summer months, the natural-gas capacity available to HUC under its contract with Northern is 14,380 Dth per day, with a minimum delivery pressure of 450 psig. From 1996 to 2001, HUC's peak summer load was 18,291 Dth per day, which is 127% of capacity. As a result, on peak summer days, HUC has had to ask its commercial/industrial customers to reduce their load. It has also had to ask 3M, one of its customers, to reduce its firm commitment on peak days. On days when natural-gas demand exceeds capacity, HUC buys capacity from other sources or, if gas is not available, pays penalties. The Northern market-area zone where Hutchinson is located is capacity constrained and fully subscribed.

***2** HUC's demand for natural gas will continue to increase. HUC anticipates adding gas-powered generators to produce electricity in 2011 and 2016.

In September 1996, HUC began seeking additional natural-gas capacity and delivery pressure from Northern, but they were unable to reach agreement. In February 2002, in response to HUC's request for an economic feasibility study for providing 40,000 Dth per day at 800 psig, Northern offered to supply that capacity and pressure provided that HUC pay an initial down payment, annual capacity reservation payments for each contract year, and maximum demand and commodity surcharges. In April 2002, Northern offered to supply a capacity of 20,000 Dth per day during the winter months and 25,000 Dth per day during the summer months, at a delivery pressure of 600 psig. The April 2002 offer would extend HUC's currently contracted firm-market-area entitlement for eight years, until 2011, and allow HUC to increase its entitlement beginning November 1, 2003 for an initial eight year term. Northern also offered to end the initial term any year between 2007 and 2011. Neither of Northern's proposals provided a detailed explanation of how Northern would meet the additional capacity and pressure requirements. Neither proposal assured additional capacity past 2011.

In December 2001, HUC submitted to the MPUC an application for a certificate of need to construct an 89-mile natural-gas pipeline connecting the Northern Border Pipeline Company pipeline near Trimont, Minnesota, to HUC's facilities in Hutchinson. The proposed pipeline capacity will be 60,000 million cubic feet (Mcf) per day through the initial 34 miles of 16-inch pipe and 40,000 Mcf per day through the remaining 55 miles of 12-inch pipe, with a delivery pressure of 800 psig. That capacity exceeds HUC's forecasted need. The total cost of the proposed pipeline would be at least $25.5 million (HUC's estimate) but may be as high as $39 million (Northern's estimate).

In January 2002, the MPUC issued an order accepting HUC's filing as substantially complete upon receipt of (1) an economic feasibility study by Northern regarding the cost of Northern expanding its system to provide more capacity and higher delivery pressure to Hutchinson and (2) a cost comparison by HUC of the Northern and HUC proposals. HUC filed those additional documents in March 2002, and the matter was referred to the Office of Administrative Hearings (OAH) for a contested-case proceeding.

Northern, Reliant Energy Minnegasco (Minnegasco), and respondent Sibley Renville Future Agricultural Interests Recognized, Inc., intervened in the OAH proceeding. Public hearings were held on May 15-16, 2002, and evidentiary hearings were held on June 5, 2002 and on July 22-23, 2002. An administrative law judge (ALJ) issued findings of fact and conclusions of law and recommended that HUC be granted a certificate of need. The ALJ did not determine whether the proposed pipeline was an intrastate pipeline requiring owners to offer available capacity to any customer on an open access, non-discriminatory basis. In a footnote, the ALJ stated:

> ***3** The ALJ makes no findings or conclusions with respect to the status of the proposed pipeline as one subject to "Open Access." The record contains the legal position of [respondent Department of Commerce (DOC)] and of [Minnegasco] on this point, but the only testimony on the issue was in respect to whether municipal bond

> financing could be used if the pipeline is not restricted to municipal users. At the close of the hearing, the [DOC] and HUC requested that this issue be addressed to the [MPUC] after a ruling on the Certificate of Need.

Northern filed exceptions to the ALJ's recommendation, arguing that HUC failed to show the need for the proposed pipeline and that the proposed pipeline was governed by Minn.Stat. § 216B.045 (2002). The MPUC adopted the ALJ's findings of fact, conclusions of law, and recommendation and issued an order granting HUC the certificate of need. The MPUC denied Northern's petition for reconsideration. This certiorari appeal from the order denying Northern's petition for reconsideration followed.

DECISION

A reviewing court may reverse or modify an agency decision if the substantial rights of the petitioners may have been prejudiced because the administrative finding, inferences, conclusion, or decisions are:

(a) In violation of constitutional provisions; or

(b) In excess of the statutory authority or jurisdiction of the agency; or

(c) Made upon unlawful procedure; or

(d) Affected by other error of law; or

(e) Unsupported by substantial evidence in view of the entire record as submitted; or

(f) Arbitrary or capricious.

Minn.Stat. § 14.69 (2002). When reviewing an agency decision,

the court must ... recognize the need for exercising judicial restraint and for restricting judicial functions to a narrow area of responsibility lest (the court) substitute its judgment for that of the agency. It must be guided in its review by the principle that the agency's conclusions are not arbitrary and capricious so long as a rational connection between the facts found and the choice made has been articulated.

....

When reviewing agency decisions we adhere to the fundamental concept that decisions of administrative agencies enjoy a presumption of correctness, and deference should be shown by courts to the agencies' expertise and their special knowledge in the field of their technical training, education, and experience. The agency decision-maker is presumed to have the expertise necessary to decide technical matters within the scope of the agency's authority, and judicial deference, rooted in the separation of powers doctrine, is extended to an agency decision-maker in the interpretation of statutes that the agency is charged with administering and enforcing. We defer to an agency's conclusions regarding conflicts in testimony, the weight given to expert testimony and the inferences to be drawn from testimony.

In re Excess Surplus Status of Blue Cross and Blue Shield of Minnesota, 624 N.W.2d 264, 277-78 (Minn.2001) (citations and quotations omitted). On appeal from an agency decision, the party seeking review bears the burden of proving that the agency's conclusions violate one or more provisions of Minn.Stat. § 14.69 (2002). *Markwardt v. State, Water Resources Bd.,* 254 N.W.2d 371, 374 (Minn.1977) (applying burden of proof to predecessor statute).

I.

***4** Northern argues that because the pipeline for which HUC sought a certificate of need is an intrastate pipeline, the MPUC erred when it refused to consider the application of Minn.Stat. § 216B.045 (2002) to the proposed pipeline. Northern also argues that application of Minn.Stat. § 216B.045 invalidates the comparative-cost analysis relied on by the ALJ and the MPUC in determining that Northern failed to demonstrate that its alternative proposals meet HUC's needs more reasonably and prudently than the proposed pipeline.

In making its first argument, Northern mischaracterizes the MPUC's decision. The MPUC did not refuse to consider the application of Minn.Stat. § 216B.045 to the proposed pipeline. In the opening paragraph of its findings and conclusions the MPUC stated, "The Commission need not and will not reach the issue of whether the proposed pipeline, upon completion, would be subject to Commission regulation under Minn.Stat. § 216B.045. The only issue considered herein is whether the certificate of need should be granted." This statement demonstrates that the MPUC considered whether Minn.Stat. § 216B.045 applies to the proposed pipeline and concluded that it was not necessary to determine whether the statute applies before deciding whether to grant a certificate of need for the pipeline.

Northern's second argument essentially disputes the MPUC's conclusion that it was not necessary to determine whether Minn.Stat. § 216B.045 applies to the proposed pipeline before deciding whether to grant a certificate of need for the pipeline. Northern contends that because Minn.Stat. § 216B.045 applies to the proposed pipeline, the MPUC had to consider the impact of Minn.Stat. § 216B.045 when deciding whether to grant HUC a certificate of need.

To understand Northern's argument, it is necessary to understand the certificate-of-need process. Under Minn.Stat. § 216B.243, subd. 2 (2002), "[n]o large energy facility shall be sited or constructed in Minnesota without the issuance of a certificate of need by the [MPUC]."[1] The statute further provides that

[n]o proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need. In assessing need, the commission shall evaluate:
(1) the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based;

(2) the effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand;

(3) the relationship of the proposed facility to overall state energy needs, as described in the most recent state energy policy and conservation report prepared under section 216C.18;

(4) promotional activities that may have given rise to the demand for this facility;

*5 (5) benefits of this facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region;

(6) possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation;

(7) the policies, rules, and regulations of other state and federal agencies and local governments; and

(8) any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically.

Minn.Stat. § 216B.243, subd. 3 (2002). In addition to these statutory factors for assessing need, Minn.Stat. § 216B.243, subd. 1 (2002), directs the MPUC to "adopt assessment of need criteria to be used in the determination of need for large energy facilities." The criteria adopted by the MPUC state, in part, that a certificate of need shall be granted if it is determined that
a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of evidence on the record by parties or persons other than the applicant, considering:

(1) the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives;

(2) the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives;

(3) the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; and

(4) the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives.

Minn. R. 7855.0120, subp. B (2001).

Minn.Stat. § 216B.045 states in relevant part:
Subdivision 1. Definition of intrastate pipeline. For the purposes of this section "intrastate pipeline" means a pipeline wholly within the state of Minnesota which transports or delivers natural gas received from another person at a point inside or at the border of the state, which is delivered at a point within the state to another, provided that all the natural gas is consumed within the state. An intrastate pipeline does not include a pipeline owned or operated by a public utility, unless a public utility files a petition requesting that a pipeline or a portion of a pipeline be classified as an intrastate pipeline and the commission approves the petition.

Subd. 2. Reasonable rate. Every rate and contract relating to the sale or transportation of natural gas through an intrastate pipeline shall be just and reasonable. No owner or operator of an intrastate pipeline shall provide intrastate pipeline services in a manner which unreasonably discriminates among customers receiving like or contemporaneous services.

***6 Subd. 3. Transportation rates; discrimination.** Every owner or operator of an intrastate pipeline shall offer intrastate pipeline transportation services by contract on an open access, nondiscriminatory basis. To the extent the intrastate pipeline has available capacity, the owner or operator of the intrastate pipeline must provide firm and interruptible transportation on behalf of any customer. If physical facilities are needed to establish service to a customer, the customer may provide those facilities or the owner or operator of the intrastate pipeline may provide the facilities for a reasonable and compensatory charge.

Subd. 4. Contracts; commission approval. No contract establishing the rates, terms, and conditions of service and facilities to be provided by intrastate pipelines is effective until it is filed with and approved by the commission. The commission has the authority to approve the contracts and to regulate the types and quality of services to be provided through intrastate pipelines. The approval of a contract for an intrastate pipeline to provide service to a public utility does not constitute a determination by the commission that the prices actually paid by the public utility under that contract are reasonable or prudent nor does approval constitute a determination that purchases of gas made or deliveries of gas taken by the public utility under that contract are reasonable or prudent.

Minn.Stat. § 216B.045, subds. 1-4. The statute regulates the operation of intrastate pipelines by requiring intrastate-pipeline owners to offer available pipeline capacity to any customer on an open-access, nondiscriminatory basis. Northern argues that because the proposed pipeline is an intrastate pipeline and HUC will have capacity available on the pipeline, the MPUC erred when it decided to grant HUC a certificate of need without considering the impact that offering the available capacity to customers will have on the operation of the pipeline. Specifically, Northern argues that if HUC provides services to a non-municipal customer, the interest rate that HUC will have to pay to finance the pipeline will increase, and the higher interest rate invalidates the MPUC's comparison between the cost of the proposed pipeline and the cost of alternatives.

Although Northern argues convincingly that the manner in which the proposed pipeline will be operated will affect the cost of the pipeline, which, in turn, should affect the MPUC's cost comparison, we are not persuaded that the MPUC's determination that it did not need to decide whether HUC's pipeline will be subject to regulation under Minn.Stat. § 216B.045 is an error of law. The MPUC did not conclude that a more reasonable and prudent alternative to the proposed pipeline had not been demonstrated solely because of the cost-comparison figures. The MPUC also concluded that each of Northern's alternative proposals failed to address HUC's long-term needs. The MPUC found that the February 22, 2002, proposal

> *7 was not specific regarding meeting anticipated demands after 2011.... The ALJ indicated that he was persuaded that the February 22, 2002 offer was not a more reasonable and prudent alternative to the proposed pipeline because of the February 22, 2002 offer's cost and its failure to address the longer term needs.

The MPUC found that the April 24, 2002, proposal

> did not provide assurance of additional supplies past 2011, when HUC anticipates placing an additional gas fired generator online....The ALJ indicated that because this proposal failed to address the likely need for increased capacity beginning in 2011, he was persuaded that this was not a more reasonable or prudent alternative.

Even if we were to assume that the proposed pipeline is an intrastate pipeline subject to Minn.Stat. § 216B.045, there is substantial evidence in the record to support the MPUC's determination that the alternatives are not reasonable and prudent alternatives to the proposed pipeline because the alternatives Northern proposed do not address anticipated increases in demand after 2011. Therefore, we conclude that the MPUC did not err when it determined that it did not need to determine whether the proposed pipeline is an intrastate pipeline under Minn.Stat. § 216B.045.

II.

Northern argues that because Minn. R. 7851.0120, subp. B, places the burden of proving the existence of a more reasonable and prudent alternative on a party other than the applicant, the rule conflicts with Minn.Stat. § 216B.243, which places the burden of proving the need for the proposed facility on the applicant. Northern contends that the statute places the burden of proof on the applicant, and a rule cannot change the burden.

We do not agree that Minn. R. 7851.0120, subp. B, changes an applicant's burden of proof. Under the certificate-of-need process established by statute and rule, an applicant bears the burden of proving the need for a proposed facility. An applicant fails to meet this burden when another party demonstrates that there is a more reasonable and prudent alternative to the facility proposed by the applicant. Minn.Stat. § 216B.243, subd. 3; Minn. R. 7851.0120, subp. 8. This regulatory scheme is simply a practical way to prevent the issuance of a certificate of need when there is a more reasonable and prudent alternative to the proposed facility without requiring an applicant to face the extraordinary difficulty of proving that there is not a more reasonable and prudent alternative. *See State v. Paige,* 256 N.W.2d 298, 304 (Minn.1977) (recognizing difficulty in "proving a negative").

III.

Substantial evidence is defined as: (1) such relevant evidence as a reasonable mind might accept as adequate to support a conclusion; (2) more than a scintilla of evidence; (3) more than some evidence; (4) more than any evidence; and (5) evidence considered in its entirety. *Cable Communications Bd. v. Nor-West Cable Communications P'ship,* 356 N.W.2d 658, 668 (Minn.1984). "If an administrative agency engages in reasoned decisionmaking, [we] will affirm, even though [we] may have reached a different conclusion had [we] been the fact-finder." *Id.* at 669.

***8** The evidence establishes that Northern has no additional capacity available on the branch line serving HUC. During the 1996-2001, HUC's peak winter load reached 97% of contracted-for capacity, and its peak summer load reached 127% of contracted-for capacity. HUC presented evidence that its demand for natural gas will continue to increase through 2016. Northern and the DOC presented evidence questioning the validity of HUC's estimates of its future need for natural gas. But "[i]t is within the peculiar expertise of the agency to evaluate the weight [and credibility] to be accorded expert evidence, [so this court] will not substitute [its] judgment for that of the agency." *In re Hutchinson,* 440 N.W.2d 171, 177 (Minn.App.1989), *review denied* (Minn. Aug. 9, 1989).

Northern argues that it showed the existence of a more reasonable and prudent alternative to the proposed pipeline. But, as we have already stated, the MPUC determined that Northern failed to prove the existence of a more reasonable and prudent alternative because Northern failed to show that its alternatives could meet HUC's capacity and pressure requirements or provide additional services beyond 2011. Northern also cites the environmental costs of constructing a new pipeline, but it does not cite evidence showing that it could meet HUC's requirements without constructing an additional facility.

We conclude that the MPUC's order granting HUC a certificate of need is supported by substantial evidence and that there is a rational connection between the facts found by the MPUC and the decision to grant HUC a certificate of need.

Affirmed.

Footnotes

1 The parties do not dispute that the proposed pipeline is a "large energy facility" as defined under Minn.Stat. § 216B.2421 (2002).

APPENDIX B

Subd. 7b. **Transmission cost adjustment.** (a) Notwithstanding any other provision of this chapter, the commission may approve a tariff mechanism for the automatic annual adjustment of charges for the Minnesota jurisdictional costs net of associated revenues of:

(i) new transmission facilities that have been separately filed and reviewed and approved by the commission under section 216B.243 or are certified as a priority project or deemed to be a priority transmission project under section 216B.2425;

(ii) new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system; and

(iii) charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system.

(b) Upon filing by a public utility or utilities providing transmission service, the commission may approve, reject, or modify, after notice and comment, a tariff that:

(1) allows the utility to recover on a timely basis the costs net of revenues of facilities approved under section 216B.243 or certified or deemed to be certified under section 216B.2425 or exempt from the requirements of section 216B.243;

(2) allows the utility to recover charges incurred under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system. These charges must be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset;

(3) allows the utility to recover on a timely basis the costs net of revenues of facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed and determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system;

(4) allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest;

(5) provides a current return on construction work in progress, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism;

(6) allows for recovery of other expenses if shown to promote a least-cost project option or is otherwise in the public interest;

(7) allocates project costs appropriately between wholesale and retail customers;

(8) provides a mechanism for recovery above cost, if necessary to improve the overall economics of the project or projects or is otherwise in the public interest; and

(9) terminates recovery once costs have been fully recovered or have otherwise been reflected in the utility's general rates.

(c) A public utility may file annual rate adjustments to be applied to customer bills paid under the tariff approved in paragraph (b). In its filing, the public utility shall provide:

(1) a description of and context for the facilities included for recovery;

(2) a schedule for implementation of applicable projects;

(3) the utility's costs for these projects;

(4) a description of the utility's efforts to ensure the lowest costs to ratepayers for the project; and

(5) calculations to establish that the rate adjustment is consistent with the terms of the tariff established in paragraph (b).

(d) Upon receiving a filing for a rate adjustment pursuant to the tariff established in paragraph (b), the commission shall approve the annual rate adjustments provided that, after notice and comment, the costs included for recovery through the tariff were or are expected to be prudently incurred and achieve transmission system improvements at the lowest feasible and prudent cost to ratepayers.

APPENDIX C

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

LeRoy Koppendrayer	Chair
David Boyd	Commissioner
Marshall Johnson	Commissioner
Phyllis Reha	Commissioner
Thomas Pugh	Commissioner

David R. Moeller
Attorney
Minnesota Power
30 West Superior Street
Duluth, MN 55802-2093

SERVICE DATE: DEC - 7 2007

DOCKET NO. E-015/M-07-965

In the Matter of Minnesota Power's Petition for Approval of a Transmission Cost Recovery Rider

The above entitled matter has been considered by the Commission and the following disposition made:

> **Approved Minnesota Power's proposed Transmission Cost Recovery Rider, with an effective date of January 1, 2008.**
>
> **Granted Company's request for a variance of Minn. Rules, part 7825.3600.**
>
> **The Company shall file revised tariff pages and listing of pages not changed before implementing recovery under the Transmission Cost Recovery Rider.**
>
> **The Company shall maintain, and shall include with future filings for rate recovery, records sufficient to ascertain on a project basis that expenditures claimed by Minnesota Power are consistent with the guiding agreements between multiple owners of the project.**
>
> **The Company shall maintain expenditure, recovery, and tracker balance information on a project basis and shall supply such information with each annual renewal filing.**

The Commission agrees with and adopts the recommendations of the Department of Commerce which are attached and hereby incorporated in the Order.

BY ORDER OF THE COMMISSION

Burl W. Haar

Burl W. Haar
Executive Secretary

(S E A L)

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October 12, 2007

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce**
Docket No. E015/M-07-965

Dear Dr. Haar:

Attached are the comments of the Energy Division of the Minnesota Department of Commerce in the following matter:

Minnesota Power's request for Approval of a Transmission Cost Recovery Rider.

The petition was filed on July 12, 2007 by:

David R. Moeller
Attorney
Minnesota Power
30 West Superior Street
Duluth, Minnesota 55802-2093

The Department recommends **approval** and is available to answer any questions the Minnesota Public Utilities Commission (Commission) may have.

Sincerely,

/s/ SUSAN L. PEIRCE
Rate Analyst

SLP/ja
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE

DOCKET NO. E015/M-07-965

I. BACKGROUND

On July 12, 2007, Minnesota Power (MP or the Company) filed a petition seeking approval of a Transmission Cost Recovery Rider (TCR Rider) to recover costs of new transmission facilities approved by the Commission under Minn. Stat. §216B.241 or 216B.2425.

In addition, the Company filed its proposed recovery under the TCR Rider for 2008.

II. SUMMARY OF THE FILING

MP requests approval of a Transmission Cost Recovery Rider for the recovery of Minnesota jurisdictional transmission costs. Specifically, the Company is requesting recovery of its share of two high-voltage transmission lines, the Tower and Badoura projects, certified as priority projects by the Minnesota Public Utilities Commission in its May 25, 2006 Order in Docket No. ET2, E015/TL-05-867. Table 1, below, summarizes the capital costs and 2008 revenue requirements for each project.

Table 1: Summary of Proposed Projects and Revenue Requirements

Project	Estimated Capital Expenditures	Estimated 2008 MN Jurisdictional Revenue Requirement
Badoura-Pequot Lakes	$ 22,000,000	625,053
Tower-Embarrass	$ 4,980,000	124,746
Total	$ 26,980,000	$ 749,799

Under MP's proposal, the TCR Rider would be applicable to electric service under all of MP's Retail Rate Schedules, including its Large Power Interruptible and Large Power Incremental Production customers except its Competitive Rate Schedules, Rate Codes, 53, 59, 73, and 79. The retail revenue requirement will be allocated to the Large Power customer class based on its portion of retail transmission demand (58.82%), with the remaining portion of the retail revenue requirement (41.18%) allocated to non-Large Power customer classes.

For Large Power customers, MP proposes to incorporate both a demand and energy rate adder by splitting the Large Power customer retail revenue requirement between demand and energy charges based on the 2006 base rate demand and energy revenue split (approximately 60% demand and 40% energy).

MP proposes only an energy rate adder for the remaining applicable customer classes determined by dividing the projected 12-month non-Large Power customer class retail revenue requirement by the non-Large power kilowatt-hour sales for the previous calendar year.

III. DEPARTMENT ANALYSIS

A. STATUTORY REQUIREMENTS

The TCR Statute, Minn. Stat. §216B.16, subd. 7b sets forth the following:

(1) allows the utility to recover on a timely basis the costs net of revenues of facilities approved under section 216B.243 or certified or deemed to be certified under section 216B.2425;

(2) allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest;

(3) provides a current return on construction work in progress, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism;

(4) allows for recovery of other expenses if shown to promote a least-cost project option or is otherwise in the public interest;

(5) allocates project costs appropriately between wholesale and retail customers;

(6) provides a mechanism for recovery above cost, if necessary to improve the overall economics of the project or projects or is otherwise in the public interest; and

(7) terminates recovery once costs have been fully recovered or have otherwise been reflected in the utility's general rates.

Minnesota Power requests approval of its TCR Rider tariff, as well as recovery under the Rider for its first two projects, the Badoura Project and Tower Project. Minn. Stat. §216B.16, subd. 7(a) provides that,

> The commission may approve a tariff mechanism for the automatic annual adjustment of charges for the Minnesota jurisdictional costs of new transmission facilities that have been separately filed and reviewed and approved by the commission under section 216B.243 or are certified as a priority project or deemed to be a priority transmission project under section 216B.2425.

The Commission certified the need and designated each project as a priority in its May 25, 2006 Order in Docket No. ET2, E015/TL-05-867. Consequently, both projects are appropriate for cost recovery under a TCR Rider.

B. TOTAL PROPOSED COSTS

MP will jointly own the Tower and Badoura Transmission projects with Great River Energy (GRE). The Department has reviewed MP's proposed costs, and finds them consistent with the costs submitted by the Company in the route permitting dockets (ET2,E015/TC-06-1624 for Tower, and ET2,E015/TL-07-76 for Badoura), and believes them to be reasonable.

Given the number of new transmission lines involving multiple owners, and the ability of utilities to recover transmission costs through a rate rider, the Commission may wish to require companies to submit a schedule detailing the allocation of costs between multiple transmission line owners, along with their ongoing tracker account balances. Requiring utilities to submit an ongoing accounting of the allocation of costs between multiple owners will assist in ensuring that the same costs are not being recovered from customers at multiple utilities.

C. ADDITIONAL REQUIREMENTS UNDER MINN. STAT. 216B.16, SUBD 7

The Department offers the following comments on the specific requirements of Minn. Stat. 216B.16, sub. 7b.

a. Rate of return on Investment

Minn. Stat. §16B.16, subd. 7b(2) allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest. MP proposes to use the pre-tax rate of return of 13.59 percent approved in its last retail rate case (Docket No. E015/GR-94-001).

b. Provides for a current return on Construction Work in Progress

Table 2, below, summarizes the proposed revenue requirement for the Badoura and Tower projects over the next three years.

Table 2: Proposed Revenue Requirement

	2008	2009	2010
Badoura-Pequot Lakes	625,053	1,990,183	2,898,315
Tower-Embarrass	124,746	421,670	634,446
Total Rev. Req.	$749,799	2,411,853	3,532,761

MP calculated its revenue requirement assuming a return on Construction Work in Progress (CWIP) based on the Company's pre-tax rate of return from its last rate case (Docket No. E015/GR-94-001) of 13.59 percent.

MP proposes to calculate and add an Allowance for Funds Used During Construction (AFUDC) amount to its CWIP balance. This CWIP balance will subsequently become the beginning balance for the calculation of the projected revenue requirements under TCR Rider. In addition, MP is seeking a recovery on the CWIP balance once the TCR Rider begins in 2008. MP states that it will set up a contra AFUDC account for the current return on CWIP to offset the retail portion of AFUDC capitalized with the TCR Rider.

The Department understands that MP is proposing to recover AFUDC on the CWIP balance up to the point the rider begins in 2008. Once the rider is implemented, MP proposes to discontinue AFUDC and begin recovery of a current return on CWIP. In order to ensure against double recovery of the AFUDC amount already included in CWIP, MP proposes to set up a contra AFUDC account to offset the portion of AFUDC capitalized under the TCR Rider. The Company proposed the same methodology in its recent Boswell 3 Plan (Docket No. E015/M-06-1501). The Department agrees with this approach. Based on our analysis, the Department concludes that the proposed AFUDC/CWIP calculations are reasonable.

MP proposes to implement a tracker account for the purpose of accounting for all retail requirements associated with the Rider. MP seeks approval of its 2008 rate adder in the current filing, and proposes to make annual filings by October 1st of subsequent years to update the rate adjustment effective January 1. The Department agrees with this approach.

c. Recovery of other expenses

While Minn. Stat. §216B.16, subd. 7b(4) allows for recovery of other expenses if shown to promote a least-cost project option or are otherwise determined to be in the public interest, MP states that it has not included any such expenses at this time.

d. Allocation between wholesale and retail customers

MP allocated its costs between wholesale and retail customers based using the transmission allocator from its last rate case. Minn. Stat. §216B.16, subd. 7(b)(1) requires that the revenue requirement be net of the revenues the Company earns from the facilities. In this case, MP will earn wholesale revenues from MISO for the use of these transmission lines under its Open Access Transmission Tariff (OATT). Under the Company's OATT tariff, transmission assets are included in the OATT revenue calculation in the year after they are placed in service. Consequently, recovery under the wholesale tariff lags the investment by approximately one year. In its March 29, 2007 Order in the Matter of Northern States Power Company d/b/a Xcel Energy for Approval of 2007 Project Eligibility, TCR Rate Factors and RCR Compliance Filing, Docket No. E002/M-05-1501, the Commission required Xcel to reflect wholesale revenues in its Transmission Cost Recovery Rider from the date of in-service rather than crediting retail customers for the receipt of wholesale revenues with a one year lag. MP has included a credit for wholesale revenues in its revenue requirement at the time the transmission lines are placed in service, consistent with the Commission's findings in Docket E002/M-05-1501.

III. RATE DESIGN

MP proposes to allocate its revenue requirement between wholesale and retail customers based on total energy sales adjusted for losses from the most current calendar year. For retail customers, MP proposes to allocate its revenue requirement across all of its retail rate classes, including its Large Power Interruptible and Large Power Incremental Production Service Customers, except its Competitive Rate Schedules (Rate Codes 53, 59, 73, and 79).

MP estimates the rate impacts as follows:

Table 3: Summary of Rate Impact by Rate Class

	2008
Total Retail Rev. Req.	$891,874
Large Power	
Avg. Rate (c/kWh)	7.139
Increase (%)	2.24
Avg. Impact ($/month)	1.15
All other Retail classes – Residential & General Service	
Avg. Rate (c/kWh)	6.953
Increase (%)	2.3
Avg. Impact ($/month)	4.36

MP's proposed rate design methodology is consistent with the methodology used in other recent Rider filings. For example, it is appropriate to exclude MP's competitive tariffs from this charge since these customers are subject to effective competition, per Minn. Stat. §216B.162, and can obtain its energy from an energy supplier not regulated by the Commission. Such issues can be addressed as needed in MP's next rate case. Thus, based on our analysis, the Department recommends approval of the Company's proposed Rider.

V. DEPARTMENT RECOMMENDATION

The Department recommends that the Commission approve Minnesota Power's request for Transmission Cost Recovery Rider.

/ja

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October 18, 2007

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
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RE: Docket No. E015/M-07-965

Dear Dr. Haar,

On October 12, 2007, the Energy Staff of the Minnesota Department of Commerce (Department) submitted comments on Minnesota Power's request for approval of cost recovery under a Transmission Cost Recovery Rider. In its comments, the Department included Table #3 summarizing the proposed rate additives. Table #3 should be corrected to read as follows:

Table 3: Summary of Rate Impact by Rate Class

	2008		
Total Revenue Req.	$891,874		
MN Retail Revenue Requirement	$749,799		
Residential		**General Service**	
Avg. Rate (c/kWh)	7.221	Avg. Rate (c/kWh)	7.095
Increase (%)	0.14	Increase (%)	0.14
Avg. Impact ($/month)	.07	Avg. Impact ($/month)	0.27
Large Light & Power		**Large Power**	
Avg. Rate (c/kWh)	5.394	Avg. Rate (c/kWh)	4.051
Increase (%)	0.19	Increase (%)	0.17
Avg. Impact ($/month)	19.24	Avg. Impact ($/month)	2,793
Municipal Pumping		**Lighting**	
Avg. Rate (c/kWh)	5.784	Avg. Rate (c/kWh)	12.30
Increase (%)	0.17	Increase (%)	0.08
Avg. Impact ($/month)	1.88	Avg. Impact ($/month)	0.04

MP appropriately allocated its costs between wholesale and retail customers using the transmission allocator from its last rate case. The rates contained in Table #3 above reflect the average rate impact of its proposal by retail customer class. The correction to Table #3 do not alter the Department's recommendation of approval.

The Department is available to answer any questions the Commission may have.

Sincerely,

/s/ SUSAN L. PEIRCE
Rate Analyst

SLP/sm