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 PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATION

December 19, 2014

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STATE OF MINNESOTA
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In the Matter of the Request of Minnesota Power for a Certificate of Need for the Great Northern Transmission Line Project	**FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION**

An evidentiary hearing was held before Administrative Law Judge ("ALJ") Ann O'Reilly beginning on November 12, 2014 at 9:30 a.m. in the Large Hearing Room at the offices of the Minnesota Public Utilities Commission ("Commission" or "MPUC") in St. Paul, Minnesota, and continuing on November 14, 2014. Public Hearings were held in: Roseau and Baudette, Minnesota on October 7, 2014; Littlefork, Minnesota on October 8, 2014; Kelliher and Bigfork, Minnesota on October 14, 2014 and Grand Rapids, Minnesota on October 15, 2014. Written public comments were received until December 3, 2014.

Post hearing briefs were filed on December 19, 2014, and responsive briefs were filed on January 16, 2015.

The following appearances were made:

David Moeller, Senior Attorney, Minnesota Power, 30 West Superior Street, Duluth, Minnesota 55802 and Eric F. Swanson, Winthrop & Weinstine, P.A., 225 South Sixth Street, Suite 3500, Minneapolis, Minnesota 55402, appeared on behalf of Minnesota Power, an operating division of ALLETE, Inc. ("Minnesota Power" or "Company").

Peter Madsen, Assistant Attorneys General, 1800 Bremer Tower, 445 Minnesota Street, St. Paul, Minnesota 55101, appeared on behalf of the Department of Commerce Division of Energy Resources ("Department" or "DOC-DER").

Linda Jensen, Assistant Attorney General, 1800 Bremer Tower, 445 Minnesota Street, St. Paul, Minnesota 55101, appeared on behalf of the Department of Commerce Energy Environment Review and Analysis ("DOC-EERA").

Andrew Moratzka, 33 South Sixth Street, Suite 4200, Minneapolis, Minnesota 55402 and Chad Marriott, 900 SW Fifth Avenue, Suite 2600, Portland, Oregon 97204, Stoel Rives LLP, appeared on behalf of the Large Power Intervenors ("LPI").

Carol Overland, Legalectric, Inc., 1110 West Avenue, Red Wing, Minnesota 55066, appeared for Residents and Ratepayers Against Not-so-Great-Northern Transmission ("RRANT")

Commission Staff Michael Kaluzniak appeared for the Commission.

NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Minnesota Public Utilities Commission and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed according to the schedule which the Commission will announce. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions, and Recommendations should be included, and copies thereof shall be served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the ALJ's recommendation who request such argument.

The Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the ALJ's recommendation and that said recommendation has no legal effect unless expressly adopted by the Commission as its final order.

STATEMENT OF ISSUES

1. Has Minnesota Power satisfied the requirements of Minn. Stat. § 216B.243 and the criteria of Minn. R. 7849.0120 and other applicable legal requirements for a Certificate of Need for the Great Northern Transmission Line?

SUMMARY OF RECOMMENDATIONS

The ALJ concludes that Minnesota Power has satisfied the criteria set forth in Minnesota law for a Certificate of Need ("CON") for the Great Northern Transmission Line and that the Commission should GRANT the CON, consistent with the Findings of Fact and Conclusions of Law below.

Based on the information in the Certificate of Need Application ("CON Application"), the Environmental Report, the testimony at the public hearings and evidentiary hearing, written comments, exhibits received in this proceeding, and other evidence in the record, the ALJ makes the following:

FINDINGS OF FACT

I. APPLICANT AND OTHER PARTIES

1. Minnesota Power, the Applicant in this proceeding, provides retail electric service subject to the jurisdiction of the Commission. Minnesota Power is also a Transmission Owner in the Midcontinent Independent System Operator ("MISO"), subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

2. The DOC-DER is statutorily authorized to intervene in CON proceedings and to participate in Commission matters involving utility rates and the adequacy of utility services.

3. The DOC-EERA is not a party to this proceeding but prepared the Environmental Report for the Commission's consideration.

4. LPI, consists of several of Minnesota Power's largest retail customers, and includes ArcelorMittal USA (Minorca Mine); Boise, Inc.; Enbridge Energy, Limited Partnership; Hibbing Taconite Company; Mesabi Nugget Delaware, LLC; NewPage Corporation; PolyMet Mining, Inc.; Sappi Cloquet, LLC; UPM – Blandin Paper Company; USG Interiors, LLC; United States Steel Corporation (Keewatin Taconite and Minntac Mine); and United Taconite, LLC.

5. RRANT consists of potentially affected landowners, farmers, residents and ratepayers within the vicinity of the proposed Great Northern Transmission Line and in the service territory of Minnesota Power.

II. PROCEDURAL SUMMARY

A. Filings and Contested Case Hearing Process

6. On October 29, 2012, Minnesota Power filed a notice plan under Minn. R. 7849.2550 and on November 20, 2012, it filed a request for an exemption from certain data requirements under Minn. R. 7849.0200, subp. 6. These were filed in anticipation of the Company's CON Application for a high-voltage transmission line project (the "Project").

7. On November 19, 2012, the Commission received comments on the notice plan from the DOC-DER and from Carol Overland.

8. Minnesota Power filed reply comments on its notice plan on December 10, 2012. The Company provided clarifying information and stated that it added two additional newspapers in Itasca County to its notice list based on requests it received at open house meetings it held to discuss the potential Project with the public.

9. On December 17, 2012, the DOC-DER filed comments on the Company's exemption request, recommending that the Commission approve it in part and deny it in part.

10. Minnesota Power filed reply comments on its exemption request on January 16, 2013, to address the DOC-DER comments.

11. On January 16, 2013, filing in her individual capacity as an interested person, Carol Overland filed comments recommending that the Company's exemption requests be denied.

12. On January 23, 2013, the DOC-DER filed additional comments on both the proposed notice plan and exemption request, recommending that the Commission approve both, as clarified and modified.

13. The Commission met to consider the notice plan and exemption request on January 31, 2013 and on February 28, 2013, the Commission issued its Order Approving Notice Plan, Granting Variance Request, and Approving Exemption Request.

14. As required by the notice plan, on August 5, 2013 Minnesota Power provided notice of the Project, its intent to file for a CON, and associated matters to landowners, stakeholders, government officials and elected representatives.[1]

15. On October 21, 2013, Minnesota Power filed its Application for a CON for the construction of the Great Northern High Voltage Transmission Line project in northern Minnesota.

16. On October 22, 2013, Minnesota Power filed additional materials related to Part 3 of Appendix O to its petition.

17. LPI filed comments on November 19, 2013, recommending that the Commission find the CON Application complete and refer the case for contested case proceedings.

18. On November 19, 2013, the DOC-DER filed comments stating that the CON Application was complete and recommending that the Commission refer the petition to the Office of Administrative Hearings for contested case proceedings.

19. On November 19, 2013, filing in her individual capacity as an interested person, Carol Overland filed comments recommending that the Commission refer the petition to the Office of Administrative Hearings for contested case proceedings.

20. On December 3, 2013, Minnesota Power filed reply comments.

21. The Commission met to consider the matter on December 19, 2013, and on January 8, 2014 issued its Order Accepting Filing, Varying Time Lines, and Notice and Order For Hearing, naming Minnesota Power and DOC-DER as parties.

22. On January 10, 2014, RRANT filed a Petition to Intervene.

23. On January 14, 2014, LPI filed a Petition to Intervene.

24. On January 17, 2014, a Prehearing Conference was held in the Large Hearing Room at the MPUC.

[1] *See* Exhibit ("Ex.") 63.

25. On January 29, 2014, the ALJ issued the First Prehearing Order in this matter, establishing the procedural schedule and, as no objections were filed, granting the Petitions to Intervene of LPI and RRANT.

26. On August 8, 2014, Minnesota Power filed its Direct Testimony in this matter.

27. On September 19, 2014, DOC-DER and LPI filed their Direct Testimony.

28. On October 24, 2014, Minnesota Power and DOC-DER filed Rebuttal Testimony.

29. On November 7, 2014, Minnesota Power, DOC-DER and LPI filed Surrebuttal Testimony.

30. RRANT did not file testimony in this proceeding.

31. On November 12 and November 14, 2014, the ALJ presided over the contested case hearings in this matter.

32. On December 5, 2014, Minnesota Power, DOC-DER, LPI and RRANT ("Parties") submitted an Issues Matrix.

33. On December 19, 2014, the Parties submitted Initial Briefs and Minnesota Power submitted its Proposed Findings of Fact, Conclusions of Law and Recommendation.

34. On January 16, 2015, the Parties submitted their Reply Briefs and DOC-DER, LPI and RRANT submitted their Proposed Findings of Fact, Conclusions of Law and Recommendation.

B. Environmental Review

35. The environmental review for this proceeding was conducted by DOC-EERA. DOC-EERA was not a party to the proceeding but acted in an advisory role on environmental matters related to the CON Application.

36. On January 15, 2014, DOC-EERA and Commission Staff issued the Notice of Public Information and Environmental Report Scoping Meetings.[2]

37. DOC-EERA and Commission Staff held Public Information and Environmental Report Scoping Meetings at the following locations on the dates indicated: Roseau Civic Center, Roseau, Minnesota on February 11, 2014; Baudette Ambulance Garage, Baudette, Minnesota on February 12, 2014; AmericInn, International Falls, Minnesota on February 13, 2014; Ralph Engelstad Arena, Thief River Falls,

[2] Ex. 1 (Notice of Public Information and Environmental Report Scoping Meetings).

Minnesota on February 18, 2014; the Sanford Center, Bemidji, Minnesota on February 19, 2014; and Sawmill Inn, Grand Rapids, Minnesota on February 20, 2014.

38. At those hearings, approximately 90 people attended and approximately 20 people spoke on the record.[3] The Public Hearing Transcripts were received as Exhibit 2.

39. DOC-EERA also received 28 written comments regarding the Environmental Report Scoping, during the comment period, which was open until March 14, 2014.[4] The written comments were received as Exhibit 3.

40. The comments received fell into three categories: comments directed exclusively at the route, which DOC-EERA forwarded to the Route Permit docket (E-015/TL-14-21); comments directed at both the route and need, which DOC-EERA forwarded to the route permit docket but also addressed in the current docket; and comments directed at need.[5]

41. On April 22, 2014, DOC-EERA issued its Scoping Decision for the Environmental Report.[6]

42. On July 14, 2014, DOC-EERA issued its Notice of Availability of Environmental Report[7] and the Environmental Report.[8] Notice of the Availability of the Environmental Report was also published in the Environmental Quality Board Monitor.[9]

C. Public Hearings and Comments

43. On September 9, 2014, the Commission issued its Notice of Public Hearing on the CON Application.

44. Seven public hearings were held, presided over by the ALJ, in the following locations and on the dates indicated: Roseau Civic Center, Roseau, Minnesota on October 7, 2014; Lake of the Woods School, Baudette, Minnesota on October 7, 2014; Littlefork Community Center, Littlefork, Minnesota on October 8, 2014; North Beltrami Community Center, Kelliher, Minnesota on October 14, 2014; Bigfork School Edge Center, Bigfork, Minnesota on October 15, 2014; and Timberlake Lodge, Grand Rapids, Minnesota on October 15, 2014.

45. Approximately 20 members of the public spoke at the public hearings, with the majority of the comments directed at routing questions. Commenters also asked

[3] Evidentiary Hearing Transcript Volume ("V.") 2, p. 13.
[4] V. 2, p. 13.
[5] V. 2, pp. 13-16.
[6] Ex. 4.
[7] Ex. 5.
[8] Ex. 6.
[9] Ex. 7.

questions of Minnesota Power related to the cost of the facility, its relationship to other Minnesota Power facilities and regarding Minnesota Power's contracts with Manitoba Hydro.

46. Public Comments were received by the public comment deadline of December 3, 2014, and were marked as Public Comment Exhibits A through P.

47. The only comments received from Minnesota residents, Public Comments A, B and E through I, all related to route permit issues.

48. Public Comments C and J are two copies of a letter submitted by the MISO and indicating that MISO considers the Project to be a result of "sound execution of MISO's collaborative Transmission Planning process" and that the Project is appropriate "to address system needs and opportunities."

49. Public Comment Exhibit D is a letter from a resident of Wisconsin addressing need and issues related to Manitoba Hydro.

50. Public Comment Exhibit K is a copy of correspondence from Minnesota Power attaching the FERC Order approving the Facilities Construction Agreement ("FCA") between Minnesota Power and Manitoba Hydro and also in the record as Exhibit 64.

51. Public Comment Exhibit L is a copy of correspondence from Canadian Ambassador to the United States Gary Doer to the United States Environmental Protection Agency discussing the Project and its ability to lower emissions related to Minnesota Power's energy supply portfolio.

52. Public Comment Exhibits M through O were filed by a resident of Arkansas and address need and MISO related issues.

III. THE PROJECT

A. Facilities

53. 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").[10]

54. At the time of the CON 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.[11]

[10] Ex. 9, p. 24; Ex. 42, p. 3 (Winter Direct).
[11] Ex. 42, p. 3 (Winter Direct).

55. 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, 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.[12]

56. 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.[13]

57. 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 of the combined Manitoba and United States transmission line.[14]

58. 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. [15]

59. 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.[16]

B. Ownership and Financial Responsibility

60. The Great Northern Transmission Line constitutes the United States portion of a joint effort with Manitoba Hydro to construct a new Canada-United States transmission interconnection.

61. Manitoba Hydro will construct and have sole ownership of the Canadian portion of this new interconnection.

62. 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

[12] *Id.*, pp. 3-4 and MPUC Docket No. E-015/TL-14-21.
[13] *Id.*
[14] Ex. 38, p. 5 (Donahue Direct).
[15] Ex. 42, p. 4 (Winter Direct).
[16] *Id*.

portion of its share to one or more United States utilities, before, during or after construction.[17]

63. 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 Renewable Optimization Agreements ("ROAs"), which were then still being finalized.[18]

64. At that time, the Project was assumed to have a total transfer capability of 750 MW.[19] However, Minnesota Power agreed to be 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 that time.[20]

65. Operations and maintenance expenses were handled similarly, with Minnesota Power again responsible for a 33.3 percent share of the costs.[21]

66. Since the CON Application was filed, Minnesota Power continued to ensure that its customers would only bear the financial responsibility associated with 250 MW of transfer capability.[22] However, three subsequent events impacted the final allocation of revenue responsibility between Minnesota Power and Manitoba Hydro. First, the total transfer capacity of the line was estimated to be 883 MW, not 750 MW.[23] Second, Minnesota Power and Manitoba Hydro finalized the 133 MW ROAs.[24] Third, the Company and Minnesota Hydro executed a FCA.

67. 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 (250 MW/883 MW), (2) for the "must take fee" included in the 133 MW ROAs to continue covering 17.7 percent of the responsibility for both the capital costs and the operating and maintenance costs, and (3) for Manitoba Hydro to provide a

[17] Ex. 34, p. 13 (McMillan Direct).
[18] Ex. 9, p. 16.
[19] *Id.*
[20] *Id.*
[21] *See*, Ex. 40, p. 5 (Donahue Rebuttal).
[22] Ex. 34, p. 14 (McMillan Direct).
[23] *Id.*; Ex. 42, pp. 3-4 (Winter Direct).
[24] Ex. 24, p. 14 (McMillan Direct); Ex. 43, pp. 3 (Winter Direct).

five percent Contribution In Aid of Construction ("CIAC") payment to the Company – collectively totaling the 51 percent ownership held by Minnesota Power.[25]

68. Regarding operating and maintenance expenses, Minnesota Power could identify no change in operating expenses associated with the incremental increase in capacity.[26] Therefore, the Company agreed to retain its 33.3 percent responsibility for these expenses.[27]

69. 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.[28]

70. In order to ensure that any such assignment cannot negatively impact Minnesota Power and its ratepayers, Minnesota retained full consent rights to any transfer to a third party.[29]

71. Minnesota Power testified that in order for it 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 neutral.[30]

72. If Manitoba Hydro chooses to assign its ownership interest to Minnesota Power, the Company will still bear only 33.3 percent of the operations and maintenance costs, with the remainder covered by Manitoba Hydro through the "must take fee" and through a CIAC.[31]

73. Given the various contractual agreements between Minnesota Power and Manitoba Hydro, the financial responsibility for the Project breaks down as follows, depending on whether Manitoba Hydro assigns its interest to Minnesota Power or Manitoba Hydro or an assignee retain 49 percent ownership [32]:

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[25] 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, 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).
[26] Ex. 40, p. 5 (Donahue Rebuttal).
[27] *Id.*, pp. 5-6.
[28] Ex. 40, pp. 3-5 (Donahue Rebuttal); V. 1, pp. 110-111 (Donahue).
[29] *Id.*
[30] *Id.*
[31] *Id.* pp. 3-7.
[32] Ex. 40, p. 8, Table 3 (Donahue Rebuttal).

	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-Assignee	NA	49.00%
Total	100.00%	100.00%
Revenue Req. - Capital Cost:		
MP Ratepayer	28.30%	28.30%
MH (ROA 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 Fee)	17.70%	17.70%
MH (CIAC)	49.00%	0.00%
MH or Assignee	N/A	49.00%
Total	100.00%	100.00%

C. Timing

74. Project construction is anticipated to begin in 2016, with an in-service date of June 1, 2020 as required under the 250 MW Agreements.[33]

75. 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.[34]

76. 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.[35]

D. Costs

77. In its CON Application, the Minnesota Power provided an initial range of estimated costs for the Project of $406 million and $609 million.[36] At that time, the

[33] Ex. 9, pp. 2, 35; Ex. 34, p. 11 (McMillan Direct); Ex. 38, p. 5 (Donahue Direct).
[34] Ex. 9, p. 78.
[35] *See* Office of Energy OE Docket No. PP-398, 79 Fed. Reg. 27,587 (May 14, 2014); 79 Fed. Reg. 68,673 (Nov. 18, 2014).

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.[37]

78. When the Company filed its Route Permit Application,[38] 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 matting in wetlands to mitigate potential wetland impacts.[39]

79. 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.[40]

80. 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 assessed against Project assets before the in-service date of June 1, 2020, Minnesota Power estimated that the Project will cost between $557.9 million and $710.1 million. That remains the Company's current cost estimate.[41]

81. 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 a range of $158 million to $201 million.[42]

82. Regarding operating and maintenance costs, primary annual maintenance expense for a transmission line is aerial inspection.[43] These inspections look for broken insulators or other defects which could compromise the line.[44] If issues are identified, ground crews will be dispatched to correct the defect.[45] In addition to structural maintenance, the right-of-way must be kept clear of vegetation.[46] Vegetation control is performed on a scheduled and routine basis and when the aerial inspection discovers

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[36] Ex. 9, p. 27; Ex. 38, p. 4 (Donahue Direct).
[37] *Id.*
[38] MPUC Docket No. E-015/TL-14-21.
[39] Ex. 38, pp. 4-5 (Donahue Direct).
[40] *Id.*; Schedule 4.
[41] *Id.*, p. 5; V. 1, p. 113 (Donahue).
[42] Ex. 38, p. 5 (Donahue Direct).
[43] *Id.*, p. 6.
[44] *Id.*
[45] *Id.*
[46] *Id.*

issues.[47] 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.[48]

83. Given the terms of the ROAs, Minnesota Power and its ratepayers will be responsible for only 33.3 percent of the operating and maintenance expenses associated with the Project.[49]

IV. MINNESOTA POWER'S AGREEMENTS WITH MANITOBA HYDRO

84. Contracts between Manitoba Hydro and Minnesota Power have particular relevance to this proceeding, since those contracts both provide for the exchange of energy intended to be transmitted over the Project and they establish the relative financial responsibilities of these two entities.

A. The 250 MW Agreements

85. The 250 MW Power Purchase Agreement ("PPA") and 250 MW Energy Exchange Agreement ("EEA") between Minnesota Power and Manitoba Hydro (collectively, "250 MW Agreements") were signed in 2011 and approved by the Commission in 2012.[50]

86. The 250 MW Agreements followed Minnesota Power's 2010 Integrated Resource Plan ("IRP") docket,[51] where the Company 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.[52]

87. 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.[53]

88. The inclusion of the 250 MW of 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.[54]

89. The 250 MW Agreements act to optimize Minnesota Power's resources, by allowing Minnesota Power to sell off-peak excess wind energy to Manitoba Hydro and

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[47] *Id.*
[48] *Id.*
[49] Ex. 39, pp. 5-6 (Donahue Rebuttal).
[50] MPUC Docket No. E-015/M-11-938 ("938 Docket").
[51] MPUC Docket No. E-015/RP-09-1088 ("1088 Docket").
[52] Ex. 43, p. 9 (Rudeck Direct).
[53] *Id.*, pp. 9-10.
[54] *Id.*, p. 10.

then "buy back" this energy from Manitoba Hydro when needed on the Minnesota Power system.[55]

90. 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.[56]

91. 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.[57]

92. In the 938 Docket, the DOC-DER and 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."[58]

93. Given the importance of these new transmission facilities, the Commission specifically requested Minnesota Power to update the Commission 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.[59]

B. The 133 MW Renewable Optimization Agreements

94. On July 30, 2014, Minnesota Power and Manitoba Hydro signed the 133 MW Energy Sale Agreement ("ESA") and 133 MW EEA (collectively, the "Renewable Optimization Agreements" or "ROAs") (together with the 250 MW Agreements, the "Manitoba Hydro Agreements").[60]

95. The 133 MW ROAs bring additional zero emission supply resources to Minnesota Power and further optimize the Company's wind power resources by allowing Minnesota Power to 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.[61]

96. When Manitoba Hydro uses this Minnesota Power wind power to serve customer load in Manitoba, Manitoba Hydro would be able to temporarily reduce their

[55] *Id.*, pp. 7-8; Ex. 12, Department Comments, p. 20; V. 1, p. 186 (Rudeck).
[56] Ex. 12, Department Comments at p. 4.
[57] Ex. 12, Department Comments at pp. 5, 25.
[58] Ex. 12, Department Comments, p. 13.
[59] *Id.*, Ordering Paragraph 2.
[60] Ex. 43, Schedule 2 (Rudeck).
[61] Ex. 43, pp. 15-16 (Rudeck Direct).

hydropower generation by decreasing the flow of water through their hydropower plants.[62]

97. 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.[63]

98. 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.[64]

99. 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.[65]

100. The energy taken by Minnesota Power under the ROAs is priced at market and includes the associated environmental attributes.[66] 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.[67] In either case, Minnesota Power receives the environmental attributes as part of the transaction.[68]

101. The ROAs also require 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.[69]

102. The ROAs were filed with the Commission for approval and are currently pending Commission action.[70]

C. The Facilities Construction Agreement

103. On September 23, 2014, Minnesota Power, Manitoba Hydro and the Midcontinent Independent System Operator, Inc. ("MISO") executed the Facilities

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[62] *Id.*, p. 16.
[63] *Id.*
[64] *Id.*
[65] Ex. 34, p. 7 (McMillan Direct).
[66] *Id.*
[67] *Id.*
[68] *Id.*
[69] Ex. 45, pp. 3, 18 (Rudeck Surrebuttal).
[70] MPUC Docket No. E-015/M-14-960 ("960 Docket").

Construction Agreement ("FCA") for the Project,[71] setting forth the ownership percentages and financial responsibilities for the Project, among other terms.

104. The FCA includes provisions requiring Manitoba Hydro to provide a five percent CIAC to Minnesota Power[72] and requires Minnesota Power's full consent if Manitoba Hydro ultimately wishes to assign its interest in the Project to another transmission owner.[73]

105. On November 25, 2014, FERC approved the FCA.[74]

106. With that approval, MISO considers the Project an approved project under the MISO tariff and MISO has moved the Project to Appendix A of the MISO Transmission Expansion Plan 14 ("MTEP14").[75]

V. CRITERIA FOR GRANTING A CERTIFICATE OF NEED

107. 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.

108. 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").

109. 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;
>
> (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

[71] Ex. 40 (MD-R), Schedule 1 (FCA) (Donahue Rebuttal).
[72] *Id.*; Ex. 35, p. 9 (McMillan Rebuttal).
[73] Ex. 40, pp. 3-4 (Donahue Rebuttal).
[74] Ex. 64 (FERC Docket No. ER14-2950-000, Order dated November 25, 2014).
[75] https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP14.aspx

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.[76]

[76] Minn. Stat. § 216B.243, subd. 3. The Parties agreed that sections (10) and (12), above, do not apply to the current proceeding. *See* Issues Matrix, December 5, 2014. The

110. The Commission's CON Rules incorporate these statutory factors into four criteria the Commission utilizes in determining if a CON must be granted.[77] 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, considering:
>
> (1) the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility;
>
> (2) the effects of the applicant's existing or expected conservation programs and state and federal conservation programs;
>
> (3) the effects of promotional practices of the applicant that may have given rise to the increase in the energy demand, particularly promotional practices which have occurred since 1974;
>
> (4) the ability of current facilities and planned facilities not requiring certificates of need to meet the future demand; and
>
> (5) the effect of the proposed facility, or a suitable modification thereof, in making efficient use of resources;
>
> B. a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record, 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;

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remainder of the statutory factors correspond to provisions in the Commission's CON criteria and will be discussed in these Findings under those criteria.

[77] *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.

(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;

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, considering:

(1) the relationship of the proposed facility, or a suitable modification thereof, to overall state energy needs;

(2) the effects of the proposed facility, or a suitable modification thereof, upon the natural and socioeconomic environments compared to the effects of not building the facility;

(3) the effects of the proposed facility, or a suitable modification thereof, in inducing future development; and

(4) the socially beneficial uses of the output of the proposed facility, or a suitable modification thereof, including its uses to protect or enhance environmental quality; 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.[78]

111. As the Applicant, Minnesota Power bears the burden of demonstrating the need for the Project,[79] with the specific burden being proof by a preponderance of the evidence.[80]

112. With respect to alternatives to the Project, Minnesota Power meets its burden by showing that the Project is a reasonable and prudent way to satisfy the articulated and demonstrated needs. Minnesota Power fails to meet this burden if *another* party demonstrates that there is a more reasonable and prudent alternative to the facility proposed by the applicant.[81]

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[78] Minn. R. 7849.0120.
[79] *See* Minn. Stat. § 216B.243, subd. 3.
[80] *See* Minn. R. 1400.7300, subp. 5 and Minn. R. 7849.0120.
[81] *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.

VI. APPLICATION OF CERTIFICATE OF NEED CRITERIA

A. Adequacy, Reliability or Efficiency of Energy Supply

1. Minnesota Power Energy Supply

113. Beginning with the Company's 2010 IRP[82], Minnesota Power's IRPs and Advanced Forecast Reports ("AFRs") have consistently shown the need for additional capacity and energy in the 2020 to 2035 timeframe.[83]

114. In its 2010 IRP 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.[84]

115. 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.[85] 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.[86]

116. Following the 2010 IRP, Minnesota Power entered into the 250 MW Agreements with Manitoba Hydro to meet a portion of its future supply needs.

117. 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 amount of capacity and energy" in the 2020 to 2035 timeframe.[87]

118. The Department and Commission determined that the 250 MW Agreements "provide the most appropriate resources for [Minnesota Power] to meet its resource needs" over this time period.[88]

119. Given the need for new transmission to deliver this power, 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.[89]

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

[82] MPUC Docket No. E-015/RP-10-1088 ("1088 Docket")

[83] Ex. 43, p. 9 (Rudeck Direct).

[84] *Id.*

[85] *Id.*

[86] *Id.*, pp. 9-10.

[87] Ex. 12, Commission Order and Department Comments at p. 4.

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

[89] *Id.*, Ordering Paragraph 2.

The Company filed the CON Application for the Project to gain approval for these news transmission facilities.

120. Minnesota Power's need for the additional capacity and energy to be delivered pursuant to the Manitoba Hydro Agreements continues to be demonstrated in Minnesota Power's 2013 and 2014 AFRs.[90]

121. 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 purpose of this proceeding.[91]

122. 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.[92]

123. The Company's 2013 IRP, approved by the Commission in November of 2013,[93] further supports Minnesota Power's need for the capacity and energy to be purchased from Manitoba Hydro.

124. In that proceeding, the Commission determined that even after approval of the 250 MW Agreements, Minnesota Power needs to add capacity to its system.[94]

125. The 133 MW ROAs provide additional needed resources and will also be delivered to Minnesota Power via the Project.[95]

126. The Project provides the benefits of the economies of scale of a large project and facilitates the delivery of the full 383 MW of power from Manitoba Hydro, while Minnesota Power and its ratepayers only bear the financial responsibility for 250 MW of that capacity, because Manitoba Hydro will bear 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.[96]

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[90] Ex. 18 (2013 AFR); Ex. 43 (AJR), Schedule 1 (2014 AFR).
[91] Ex. 43, p. 10-13 (Rudeck Direct).
[92] *Id.*, pp. 10-11.
[93] MPUC Docket No. E-015/RP-13-53.
[94] Ex. 52, p. 11 (Shah Direct).
[95] Ex. 43, pp. 15-16 (Rudeck Direct).
[96] Ex. 34, pp. 12-13 (McMillan Direct).

127. Minnesota Power's Conservation Improvement Program ("CIP") is integral part of its resource planning.[97] 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.[98] 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 into Minnesota Power's IRPs, AFRs and other resource acquisition proceeding, including the 938 Docket approving the 250 MW Agreements.[99]

128. 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.[100]

129. The Department agreed that conservation does not lessen the need for the Project or serve as an alternative to it. [101]

130. Minnesota Power has engaged in no direct promotional activities to encourage the use of more power.[102] Rather, the Project responds to increased need for capacity and energy, in part due to economic growth on the Iron Range.[103]

131. The Project also 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.[104] This minimizes Minnesota Power's and its customers' exposure to the risk of future emissions regulations.[105]

132. The Department examined whether Manitoba Hydro has engaged in promotional activities that have given rise to the need for the Project.[106] The Department stated that, while Manitoba Hydro may market "their brand of energy," it has not

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[97] Ex. 43, p. 32 (Rudeck Direct).
[98] *Id.*; Ex. 21 (Executive Summary, Minnesota Power 2014-2016 Triennial Conservation Improvement Plan filing).
[99] *See Id.*; Ex. 53, p. 21 (Rakow Direct) (noting conservation was considered in the approval of the 250 MW Agreements).
[100] *Id.*; Ex. 9, p. 107.
[101] Ex. 53, pp. 20-21 ((Rakow Direct).
[102] Ex. 9, p. 15.
[103] *Id.*
[104] *Id.*
[105] *Id.*; Ex. 43, pp. 13-14 (Rudeck Direct).
[106] Ex. 53, p. 13 (Rakow Direct).

promoted increased demand overall.[107] Thus, the Department also concluded that promotional practices have not created the need for the Project.

133. 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.[108]

134. An unplanned outage of this existing 500 kV tie line is also the second largest contingency in the entire MISO footprint.[109] 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. This will improve system reliability to the benefit of Minnesota Power, its customers and the broader State and regional markets.[110]

135. The existing transmission interface between Manitoba and the United States, consisting of three 230 kV lines and one 500 kV line, is unable to accommodate increased transfer of energy from Manitoba into the United States.[111]

136. Upgrades of existing facilities also cannot meet the need met by the Project. To increase transfer levels from Manitoba to the United States with no new transmission tie lines across the interface 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.[112]

137. 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.[113] 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 facilitate the full 383 MW needed to fulfill those Agreements.[114]

138. In the 938 Docket, the Commission recognized that both Manitoba Hydro and Minnesota Power would need to construct new transmission facilities for Minnesota

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[107] *Id.*
[108] Ex. 9, p. 13; Ex. 42, p. 9 (Winter Direct).
[109] Ex. 42, p. 12 (Winter Direct).
[110] Ex. 9, p. 13; Ex. 42, pp. 9-13.
[111] Ex. 42, p. 9 (Winter Direct); Ex. 53, p. 12 (Rakow Direct).
[112] Ex. 42, p. 11 (Winter Direct).
[113] *Id.*, pp. 11-12.
[114] *Id.*, p. 12.

Power to take delivery of the capacity and energy provided by the 250 MW Agreements.[115]

139. Denial of the CON for the Project would not allow Minnesota Power to take delivery of the power called for under the Manitoba Hydro Agreements, leaving Minnesota Power with significant unmet needs beginning in 2020 and adversely impacting the adequacy, reliability and efficiency of energy supply to Minnesota Power and its customers.[116]

2. State and Regional Energy Supply

140. In public comments filed November 20, 2014, 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, MISO considers the Great Northern Transmission Line Project a result of sound execution of MISO's collaborative Transmission Planning process. 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. Both studies confirmed the appropriateness of the Project to address system needs and opportunities.[117]

141. By increasing transfer capability between Canada and the United States, the Project enables State and regional utilities increased access to Manitoba Hydro hydropower.[118]

142. 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.[119]

143. Manitoba Hydro is currently engaged in a significant development plan that will support increased energy trading with Minnesota Power and other United States utilities.[120] Manitoba Hydro's approved development plan includes construction of the 695 MW Keeyask Generating Station – construction which began in July 2014.[121] This

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[115] Ex. 12, Ordering Paragraph 2 and Department Comments, p. 13.
[116] Ex. 43, p. 28 (Rudeck Direct).
[117] MISO Comment Letter, November 20, 2014, p. 1 (eDocket Document ID 201411-104808-01), Public Comment Exhibit C.
[118] Ex. 43, pp. 28-29 (Rudeck Direct).
[119] *See* Ex. 34, pp. 8-9, 21 (McMillan Direct).
[120] *Id.*, pp. 10-12.
[121] *Id.*

development plan also includes the Manitoba transmission facilities that will meet the Project at the United States – Canada border, providing the transmission capacity for new export sales.[122]

144. The Project, together with this Canadian portion of the new interconnection being constructed by Manitoba Hydro, will have enough 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.[123]

145. 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.[124]

146. The Project 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, 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,[125] 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.[126]

147. 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 Hydro and United States utilities have engaged in "seasonal diversity exchanges."[127] 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.[128]

148. By facilitating more energy trading, the Project can bring more load balancing benefits, 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.[129]

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[122] *Id.*
[123] *Id.*
[124] *See, e.g.,* Wis. Stat. § 196.378, as amended by 2011 Wis. Act 34.
[125] Ex. 41, pp. 7-8 (Hoberg Direct); Ex. 19 (MISO Hydro Wind Synergy Study).
[126] *Id.*
[127] Ex. 34, p. 9 (McMillan Direct).
[128] *Id.*
[129] *Id.*

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, the State and the region.[130]

150. 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.[131] 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 Manitoba.[132] As a result, the Project enables the wind-hydropower synergy described in the MISO Wind Synergy Study,[133] without creating other adverse consequences.[134]

151. No other significant transmission project addressing the United States – Manitoba interconnection currently exists which can provide the State and regional benefits provided by the Project.[135]

152. Denial of the CON for the Project would not allow State or regional utilities increased access to Manitoba Hydro hydropower and would not address the regional reliability concerns with the current United States – Canada interface, adversely impacting the adequacy, reliability and efficiency of energy supply to the State and the region.

B. Alternatives

1. Generation Alternatives

153. The Project is required for Minnesota Power to take delivery of the power provided for under the Manitoba Hydro Agreements.

154. The Company entered into the Manitoba Hydro 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.

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[130] *Id.*
[131] Ex. 42, p. 8 (Winter Direct); Ex. 62 (Loop Flow Impact Study).
[132] *Id.*
[133] Ex. 19 (MISO Wind Synergy Study).
[134] Ex. 42, p. 8 (Winter Direct); Ex. 62 (Loop Flow Impact Study).
[135] Ex. 43, pp. 28-29 (Rudeck Direct).

155. 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 hydropower provided under the 250 MW Agreements.[136] That analysis did not incorporate the financial benefits to Minnesota Power and its ratepayers of the 133 MW ROAs and the FCA, since Minnesota Power and Manitoba Hydro had not yet entered into those transactions.

156. In comparison to a natural gas plant, 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.[137]

157. In reviewing the 250 MW Agreements, the Department and Commission found that those Agreements "provide the most appropriate resources for [Minnesota Power] to meet its resource needs" over the 2020 to 2035 time period.[138]

158. Minnesota Power also examined the potential for distributed generation or community based energy development ("C-BED") projects to meet the needs met by the Project. While the Company is exploring distributed generation and C-BED opportunities, any such resources 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.[139]

159. 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 [agreements with Manitoba Hydro]. Therefore, the generation alternatives do not need to be considered further" in this proceeding.[140]

2. Transmission Alternatives

a. Alternative Voltages

160. Compared to the 500 kV Project, a 230 kV transmission line would impose higher costs on Minnesota Power and its ratepayers than the Project.[141]

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[136] Ex. 43, pp. 29-30 (Rudeck Direct).
[137] *Id.*
[138] Ex. 12, Commission Order and Department Comments at pp. 5, 25.
[139] Ex. 43, p. 31 (Rudeck Direct); Ex. 9, pp. 72-73.
[140] Ex. 53, p. 20 (Rakow Direct).
[141] Ex. 9, pp. 28-29; Ex. 34, p. 19 (McMillan Direct).

161. 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.[142]

162. The 230 kV alternative is estimated to cost between $277 million and $355 million.[143] 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 expensive for Minnesota Power and its customers than the Project.[144]

163. The Department analyzed the 230 kV alternative and concluded that the Project "would have far lower revenue requirements than a standalone 230 kV transmission line."[145]

164. 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. [146]

165. 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.[147] 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.[148] It is also unclear whether or not stability constraints would exist at either the 250 MW or 383 MW incremental transfer level.[149]

166. 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.[150] 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.[151]

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[142] *Id.*
[143] Ex. 38, pp. 12-13 (Donahue Direct).
[144] *Id.*; Ex. 34, p. 19 (McMillan Direct); V. 1, p. 26 (McMillan).
[145] Ex. 53, p. 38 (Rakow Direct).
[146] Ex. 42, p. 11 (Winter Direct).
[147] Ex. 42, p. 14 (Winter Direct), Ex. 30 (MISO MH-US TSR Sensitivity Analysis Draft Report (Eastern Plan), July 13, 2013.
[148] *Id.*
[149] *Id.*
[150] Ex. 42, p. 13 (Winter Direct).
[151] *Id.*

167. 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.[152]

168. The Department analyzed the 230 kV alternative and concluded that "a 500 kV transmission line would have a lower internal cost and lower line losses, and thus societal cost, than the 230 kV alternative and is the preferred voltage."[153]

169. A 345 kV alternative fails to provide a reasonable alternative since it would not be capable of the same capacity as a single 500 kV line.[154] 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.[155] 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.[156]

170. A 765 kV alternative also fails to provide a reasonable alternative. 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.[157] 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.[158]

b. Alternative Endpoints

171. In its CON 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.[159] 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.[160]

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[152] *Id.*, pp. 13-14.
[153] V. 2, pp. 80-81 (Rakow).
[154] Ex. 42, pp. 14-15 (Winter Direct).
[155] *Id.*
[156] *Id.*
[157] *Id.*, p. 15.
[158] *Id.*
[159] Ex. 9, pp. 77-104.
[160] Ex. 42, pp. 15-16 (Winter Direct).

172. 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.[161]

173. Given the utility service territories traversed by such a line, the Department stated that: "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."[162]

174. Minnesota Power also considered terminating the Project's 500 kV Line at either the Shannon or Forbes substations.[163] Engineering and siting review found that the Shannon Substation is an inferior long-term solution compared to the Blackberry Substation[164]

175. Minnesota Power also considered the Forbes Substation endpoint. The Forbes Substation also has limited outlet capacity and inferior electrical performance when compared to the Blackberry Substation.[165] 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.[166]

c. Other Transmission-Related Alternatives

176. 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.[167]

177. 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

[161] *Id.*, p. 16.
[162] Ex. 53, p. 49 (Rakow Direct).
[163] Ex. 9, pp. 104-105; Ex. 42, p. 16 (Winter Direct).
[164] *Id.*
[165] *Id.*
[166] Ex. 42, pp. 16-17 (Winter Direct).
[167] *Id.*, p. 17.

United States, it would not be acceptable to de-energize both at the same time for maintenance purposes.[168]

178. 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 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.[169] For these reasons, double circuiting is not a reasonable and prudent alternative to the Project.

179. The Company also considered a DC line, since DC lines typically have lower line losses than an AC line of the same length.[170] DC lines 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.[171] Given these 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.[172] Rather, it would add to the total cost of the Project.

180. A new DC line into Manitoba could create serious technical issues for Manitoba Hydro.[173] Therefore, a DC line does not provide a more reasonable and prudent alternative than the Project.

181. Underground high voltage transmission lines impose significantly higher engineering and 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.[174] Given these drawbacks, undergrounding does not provide a preferable alternative to the Project.

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[168] *Id.*
[169] *Id.*, pp. 17-18.
[170] *Id.*, p. 18.
[171] *Id.*
[172] *Id.*
[173] *Id.*, p. 19 and Schedule 3.
[174] *Id.*, p. 19.

C. Environmental and Socioeconomic Impacts

182. The Project enables Minnesota Power to meet a growing customer need by taking delivery under the Manitoba Hydro Agreements. The Commission has already determined that the 250 MW Agreements provide the most appropriate resource to meet that portion of the Company's needs. In making that determination, the 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.

183. By adding the hydropower made possible by the Project to its supply portfolio, Minnesota Power is also diversifying the Company's resource mix and reducing the overall emissions that would otherwise be associated with its electric supply portfolio.

184. By doing so, the Project reduces overall emissions compared to alternatives and reduces the Company's and its ratepayers' exposure to the cost of potential future emission reduction requirements.

185. 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 form of reduced wind curtailment and better utilization of both wind and hydro resources, enhancing affordability and further enabling further non-emitting energy to reach the market.[175]

186. 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 to $60,000 per mile in annual revenues to local governments.[176] 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.[177]

187. The Project is subject to a thorough and coordinated environmental review. For the current proceeding, that review is reflected in the Environmental Report ("ER").[178] The ER examined potential issues related to air quality, biological resources, cultural, archaeological and historic resources, soil, health and safety and land use,

[175] Ex. 41, pp. 7-8 (Hoberg Direct); Ex. 19 (MISO Hydro Wind Synergy Study).
[176] Ex. 44, pp. 25-26 (Rudeck Direct).
[177] Ex. 44, p. 25; Ex. 22 (Labovitz School of Business and Economics economic impact study).
[178] Ex. 6 (Environmental Report)

among others. Nothing in the ER provides a basis to conclude that the Project will not be compatible with the human and natural environment.[179]

D. Compliance with Federal, State and Local Regulations

188. The record demonstrates the Company's 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.

189. Minnesota Power indicated its commitment to continue to work with all federal, State and local governmental authorities to obtain all necessary permits and is fully committed to compliance with those permits."[180]

VII. CONDITIONS

A. Approval of the 133 MW Renewable Optimization Agreements

190. LPI witness Mr. Kollen recommended 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.[181] No party objected to this recommendation.

191. On November 26, 2014, subsequent to the conclusion of the contested case hearings, FERC approved the FCA.[182] Thus, a "condition" is no longer necessary for the FERC approval.

192. On November 6, 2014, Minnesota Power filed its Petition with the Commission seeking approval of the 133 MW ROAs.[183]

193. 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.[184]

194. 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.

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[179] *See Id.*; Ex. 37, pp. 11-12 (Atkinson Direct).
[180] Ex. 34, p. 26 (McMillan Direct)
[181] Ex. 50, p. 3 (Kollen Direct).
[182] Ex. 64 (FERC Approval of FCA).
[183] MPUC Docket No. E-015/M-14-960 (Petition for Approval included in the record as Ex. 55 (ASR-S), Schedule 1 (Rudeck Surrebuttal).
[184] Ex. 35, p. 9 (McMillan Rebuttal); Ex. 45, pp. 2-3 (Rudeck Surrebuttal).

195. In addition, the ROAs include 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.[185]

196. Given the importance of the ROAs to the overall benefits of the Project for Minnesota Power and its customers, 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.[186]

B. "Capping" Minnesota Power's Cost Recovery

197. The Commission has historically addressed issues such as cost recovery for projects in the rider or rate case proceeding in which the utility first requests recovery from ratepayers, not in CON proceedings.[187]

198. Whether or not the Commission addresses cost recovery in this proceeding, it will continue to have the ability to assess the prudence of the costs incurred in developing the Project.[188]

199. 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 the Commission could specify that: (1) Minnesota Power would be limited to recover in riders 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.[189]

200. Minnesota Power agreed to the Department's recommendation of putting in place such a "soft cap" on cost recovery.[190] 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.[191]

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[185] Ex. 45, p. 2 (Rudeck Surrebuttal).
[186] Ex. 51, pp. 6-7 (Kollen Surrebuttal); Ex. 55, pp. 1-2 (Rakow Rebuttal); Ex. 35, pp. 9-10 (McMillan Rebuttal).
[187] Ex. 55, pp. 2-3 (Rakow Rebuttal); Ex. 35, pp. 10-11 (McMillan Rebuttal).
[188] *Id.*
[189] Ex. 55, pp. 2-3 (Rakow Rebuttal); Ex. 56, pp. 10-11 (Rakow Surrebuttal).
[190] Ex. 36, p. 3 (McMillan Surrebuttal).
[191] Ex. 35, pp. 10-11 (McMillan Rebuttal).

201. The Commission very recently used this same "soft cap" approach in a transmission CON proceeding involving ITC.[192] 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 through transmission cost recovery riders to the costs put forward by applicants in certificate of need proceedings -- here, $284,000,000. The Commission continues to believe 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.[193]

202. LPI witness Kollen disagreed with this approach and instead recommended a "hard cap" that would absolutely prohibit the recovery of costs above the level shown in the record to date.[194] Mr. Kollen recommended that the Commission limit in this Docket any cost recovery to the cost estimate cited in the FERC approved FCA.[195] Mr. Kollen stated that a "hard cap" was necessary to protect ratepayers and because, on cost grounds, the Project was a "close call" when compared to a natural gas fired alternative.

203. In this proceeding, as with typical CON proceedings, the Company has provided a range of capital costs.[196] This range is appropriate given that a final route and any route permit conditions for this Project will be decided in a separate docket.[197] The

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[192] MPUC Docket No. ET-6675/CN-12-1053.
[193] *Id.*, Order Granting Certificate of Need, p. 6 (emphasis added).
[194] Ex. 50, pp. 5-13 (Kollen Direct).
[195] Ex. 50, p. 11 (Kollen Direct)
[196] Ex. 35, p. 10 (McMillan Rebuttal).
[197] *Id.*

Company's cost estimates also appropriately include standard contingencies, which may prove necessary and reasonable.[198]

204. 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 need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, 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, the commission shall give due consideration to evidence of the cost of the property when first devoted to public use, 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.[199]

205. Mr. Kollen's recommendation of a "hard cap" is flawed by a false comparison. Mr. Kollen claims that such an absolute limit on cost recovery is necessary because the economics of the Project is a "close call" with the option of building a natural gas facility.[200] His analysis compared only the 250 MW Agreements and the Project with a natural gas-fired alternative.[201] This analysis does not include the substantial economic and environmental benefits Minnesota Power ratepayers will receive from the 133 MW ROAs.

206. A "hard cap" can send inappropriate signals to utilities and encourage resource decisions that are not in the best interest of ratepayers. 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.[202] 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.[203] Doing so would result in a more expensive overall system for ratepayers and an inefficient use of resources.[204]

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[198] *Id.*, p. 11.
[199] Minn. Stat. § 216B.16, subd. 6.
[200] Ex. 50, pp. 7-8 (Kollen Direct).
[201] *Id.*
[202] V. 2, pp. 92-94 (Rakow).
[203] *Id.*
[204] *Id.*

C. Other Cost Recovery and Cost Allocation Recommendations

207. LPI witness Kollen made three additional recommendations regarding cost recovery or cost allocation issues. None of these recommendations finds any precedent in past Commission decisions. Both Minnesota Power and the Department testified that these issues will be appropriately addressed in future proceedings, after notice to all potentially interested parties.

208. The Commission need not address these issues in the current docket but if it does so, Mr. Kollen's recommendations should be denied.

1. Mandating AFUDC Treatment

209. Mr. Kollen recommending that the Commission mandate that the Company accumulate an allowance for funds used during construction ("AFUDC") and require the Company to recover those funds only after the Project is placed into service.[205]

210. The Minnesota Legislature has specifically addressed cost recovery for transmission assets, providing substantial detail and direction to the Commission regarding that cost recovery.[206] The Legislature enacted these "transmission cost adjustment" provisions specifically for the purpose of encouraging new transmission construction, by removing the financial disincentive to utilities of pursuing such major construction projects under traditional ratemaking.[207]

211. The traditional ratemaking approach allowed for AFUDC but deferred any utility recovery of costs until the asset was "used and useful" and placed into the utility's rate base.[208]

212. Minnesota Statutes now provide 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.[209]

213. The Commission has consistently approved transmission cost recovery ("TCR") filing that provide for "a current return on construction work in progress" and to

[205] Ex. 50, pp. 19-23 (Kollen Direct).
[206] Minn. Stat. § 216B.16, subd. 7b.
[207] Ex. 35, p. 12 (McMillan Rebuttal).
[208] *Id.*
[209] Minn. Stat. § 216B.16, subd. 7b (b) (5).

deny the ability to make such a filing would mark a significant departure from Commission precedent.[210]

214. On July 12, 2007, Minnesota Power requested Commission approval of a TCR Rider consistent with Minn. Stat. § 216B.16, subd. 7b.[211] 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. 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.[212]

215. On June 23, 2009, the Commission issued an Order approving Minnesota Power's 2009 TCR Rider.[213] On May 11, 2011, the Commission issued an Order approving Minnesota Power's 2010 TCR Rider.[214] On November 12, 2013, the Commission granted the Company's petition for approval of its 2011 TCR Rider.[215] The Company's 2014 TCR Rider is currently pending before the Commission.[216]

216. 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).

217. Requiring AFUDC treatment of Project construction costs could also have adverse impacts to ratepayers. Providing a current return on CWIP provides customers a lower overall capital cost of approximately $55 million in nominal dollars compared to recording AFUDC, meaning lower overall capital costs to ratepayers.[217] 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.[218]

218. Requiring AFUDC treatment of construction costs also creates the possibility of "rate shock" to customers once the Project is placed in service.[219]

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[210] Ex. 57, p. 6 (Johnson Surrebuttal).
[211] MPUC Docket No. E-015/M-07-965.
[212] *Id.*, p. 1.
[213] MPUC Docket No. E-015/M-08-1176
[214] MPUC Docket No. E-015/M-10-799.
[215] MPUC Docket No. E-015/M-11-695.
[216] MPUC Docket No. E-015/M-14-337.
[217] Ex. 35, p. 13 (McMillan Rebuttal); Ex. 57, p. 7 (Johnson Surrebuttal).
[218] Ex. 57, pp. 7-9 (Johnson Surrebuttal).
[219] Ex. 35, p. 13 (McMillan Rebuttal); Ex. 57, p. 8 (Johnson Surrebuttal).

Compared to AFUDC treatment, allowing a return on CWIP gradually phases in rate increases rather than creating a one-time rate adjustment for the entirety of the Project.[220]

219. Requiring 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.[221] The Department noted 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.[222]

2. Mandating Rider Recovery of All Project Costs

220. Mr. Kollen also recommended that the Commission act now to require Minnesota Power to recover all Project costs through a TCR Rider.[223]

221. 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."[224]

222. The Commission has never mandated recovery of transmission costs only through a TCR Rider.[225]

223. It is possible that better ratemaking outcomes may be achieved for customers by addressing Project costs through a traditional general rate case.[226] For example, a rate case would re-examine the issue of wholesale/retail allocation and may provide benefits to retail customers.[227] Further, the transmission rider would use Minnesota Power's last approved return on equity ("ROE") rather than re-examining and resetting an appropriate ROE going forward.[228]

224. 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.[229]

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[220] Ex. 35, p. 13 (McMillan Rebuttal).
[221] Id.; V. 1, pp. 68-70 (McMillan).
[222] Ex. 57, pp. 8-9 (Johnson Surrebuttal).
[223] Ex. 50, p. 4 (Kollen Direct).
[224] Minn. Stat. § 216B.16, subd. 7b(b)(9).
[225] Ex. 57, pp. 10-11 (Johnson Surrebuttal).
[226] Ex. 34, p. 14 (McMillan Rebuttal); Ex. 57, p. 10 (Johnson Surrebuttal).
[227] Ex. 34, p. 14 (McMillan Rebuttal).
[228] *Id.*
[229] Ex. 57, p. 10 (Johnson Surrebuttal).

3. Cost Allocations

225. Mr. Kollen also recommends that the Commission 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.[230]

226. Cost allocation matters are addressed in cost recovery or rate case proceedings.[231] 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.

CONCLUSIONS OF LAW

1. The Commission and ALJ have jurisdiction to consider Minnesota Power's Application for a CON.

2. The Commission determined that the CON Application was substantially complete and accepted the CON Application on January 8, 2014.

3. Public hearings were conducted in the proposed Project areas for the Project. The public was given an opportunity to appear at the hearings or to submit written comments. The evidentiary portion of the hearing was held in St. Paul, Minnesota.

4. DOC-EERA completed the Environmental Report, following appropriate notice and public information meetings and after receiving public comment.

5. Minnesota Power and DOC-EERA have complied with all applicable substantive and procedural requirements for a CON.

6. The record in this proceeding demonstrates that Minnesota Power has satisfied the criteria for a CON set forth in Minn. Stat. § 216B.243 and Minn. R. 7849.0120.

7. The record in this proceeding demonstrates that the Project will address multiple needs, including (1) enabling the delivery of needed capacity and energy resources to Minnesota Power and its customers; (2) optimizing Minnesota Power's wind energy resources; (3) reducing emissions from Minnesota Power's supply portfolio and minimizing the risk of future emissions regulations; (4) supporting State and regional energy needs; and (5) enhancing the efficiency and reliability of the transmission system.

[230] Ex. 50, p. 27 (Kollen Direct).
[231] Ex. 34, pp. 17-18 (McMillan Rebuttal); Ex. 57, p. 14 (Johnson Surrebuttal).

8. No party or person has demonstrated by a preponderance of the evidence that there is a more reasonable and prudent alternative to address those needs met by the Project.

9. The citations to exhibits in the Findings of Fact are not intended to indicate that all evidentiary support in the record has been cited.

10. It is appropriate to condition the CON for the Project on Commission approval of the 133 MW ROAs.

11. It is appropriate for the Commission to specify that: (1) Minnesota Power will be limited to recover in riders only the amount of Project costs proposed in this proceeding; (2) the Company can 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 will have the burden of demonstrating the prudency of those additional costs.

12. The Commission need not address cost final cost recovery or cost allocation issues in this proceeding.

13. It is not appropriate or consistent with Minnesota law and Commission precedent to set a cost recovery limitation at this time or to require cost recovery exclusively through a rider mechanism.

14. It is not appropriate to address cost allocation issues when those issues were not noticed for hearing.

15. Any of the foregoing Findings that should be treated as Conclusions are hereby adopted as Conclusions.

RECOMMENDATION

Based on the foregoing Findings and Conclusions, IT IS RECOMMENDED that the Minnesota Public Utilities Commission:

> Grant a Certificate of Need to Minnesota Power for the construction of the Great Northern Transmission Line and associated facilities, consistent with the Findings and Conclusions, above.

Dated: December 19, 2014

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