OAH 65-2500-31196
MPUC E-015/CON-12-1163

BEFORE THE STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

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

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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**

On October 21, 2013, Minnesota Power filed an Application for a Certificate of Need for its proposed Great Northern Transmission Line with the Minnesota Public Utilities Commission (Commission).

By Order issued January 8, 2014, the Commission referred this matter to the Office of Administrative Hearings for public hearings and a contested case proceeding.[1]

Public hearings were held on October 7, 8, 14, and 15, 2014, in six communities within the project area: Roseau, Baudette, Littlefork, Kelliher, Bigfork, and Grand Rapids, Minnesota.

This matter came before Administrative Law Judge Ann O'Reilly for an evidentiary hearing on November 12 and 14, 2014, at the Commission's office in Saint Paul, Minnesota.

David Moeller, Senior Attorney for Minnesota Power, and Eric F. Swanson, Winthrop & Weinstine, P.A., appeared on behalf of Minnesota Power, an operating division of ALLETE, Inc. (Minnesota Power).

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

Linda Jensen, Assistant Attorney General, appeared on behalf of the Department of Commerce -- Energy Environmental Review and Analysis Division (DOC-EERA).

Andrew Moratzka and Chad Marriott, Stoel Rives L.L.P., appeared on behalf of the Large Power Intervenors (LPI).

Carol Overland, Legalectric, Inc., appeared on behalf of the group Residents and Ratepayers Against Not-so-Great-Northern Transmission (RRANT).

[1] ORDER ACCEPTING FILING, VARYING TIME LINES, AND NOTICE AND ORDER FOR HEARING (January 8, 2014) (eDocket No. 20141-95218-01).

Michael Kaluzniak, Senior Facilities Planner for the Commission, and Tracy Smetana, the Commission's Public Advisor, were also present at the hearings.

The hearing record closed upon the filing of post-hearing reply briefs on January 16, 2015.

STATEMENT OF THE ISSUES

Has Minnesota Power satisfied the requirements of Minnesota Statutes section 216B.243 (2014), the criteria set forth in Minnesota Rule 7849.0120 (2013), and other applicable legal requirements for a Certificate of Need for the Great Northern Transmission Line?

SUMMARY OF RECOMMENDATIONS

The Administrative Law Judge concludes that Minnesota Power has satisfied the criteria set forth under Minnesota law for a Certificate of Need for the Great Northern Transmission Line. Therefore, the Administrative Law Judge respectfully recommends the Commission **GRANT** Minnesota Power's Application for a Certificate of Need, subject to the conditions set forth below.

Based on information in the Certificate of Need Application submitted by Minnesota Power, the Environmental Report prepared by the DOC-EERA, information presented during the public hearings, testimony and evidence presented at the evidentiary hearing, written comments received, exhibits received during this proceeding, and other evidence in the record, the Administrative Law Judge makes the following:

FINDINGS OF FACT

I. APPLICANT AND OTHER PARTIES

1. The Applicant for the subject Certificate of Need (CON) is Minnesota Power, an operating division of ALLETE, Inc.[2] Minnesota Power provides retail electric service in the state of Minnesota.

2. The CON Application filed by Minnesota Power entails the construction of a new 500 kV transmission line, spanning approximately 220 miles from the United States/Canadian border to Grand Rapids, Minnesota (Project).[3] The line is referred to herein as the "Great Northern Transmission Line" or the "GNTL."

[2] Ex. 9 (Application for Certificate of Need).
[3] *Id.;* Ex. 42 at 3-4 (Winter Direct)

3. The DOC-DER is statutorily authorized to intervene in CON proceedings and participate in Commission matters involving utility rates and the adequacy of utility services.[4]

4. The DOC-EERA is not a party to this proceeding but prepared the Environmental Report for the Commission's consideration.[5]

5. LPI consists of several of Minnesota Power's largest retail customers, including 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.[6]

6. 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.[7]

II. PROCEDURAL SUMMARY

A. Application Filings and Contested Case Hearing Process

7. On October 29, 2012, Minnesota Power filed a Notice Plan addressing the Project, pursuant to Minn. R. 7849.2550 (2013).[8] On November 20, 2012, Minnesota Power filed a request for an exemption from certain data requirements pursuant to Minn. R. 7849.0200, subp. 6 (2013).[9] These documents were filed in anticipation of Minnesota Power's Certificate of Need Application (CON Application) for the Project.

8. On November 19, 2012, the Commission received comments on the Notice Plan from both the DOC-DER and Carol Overland, in her individual capacity.[10]

9. Minnesota Power filed reply comments to its Notice Plan on December 10, 2012.[11] In the reply comments, Minnesota Power provided clarifying information and added two additional newspapers in Itasca County to its notice list based upon requests received at open house meetings.[12]

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[4] Minn. R. 7829.0800, subp. 3 (2013).
[5] *See* Ex. 6 (Environmental Report).
[6] PETITION TO INTERVENE (January 16, 2014) (eDocket 20141-95521-01).
[7] PETITION TO INTERVENE (January 10, 2014) (eDocket20141-95324-01).
[8] NOTICE PLAN FOR GREAT NORTHERN TRANSMISSION LINE (October 29, 2012) (eDocket Nos. 201210-80007-01, 201210-80007-02).
[9] EXEMPTION REQUEST (November 20, 2012) (eDocket No. 201211-80907-01).
[10] COMMENTS (November 19, 2012) (eDocket Nos. 201211-80801-01, 201211-80859-01).
[11] REPLY COMMENTS (December 10, 2012) (eDocket No. 201212-81592-01).
[12] *Id.*

10. On December 17, 2012, the DOC-DER filed comments to Minnesota Power's exemption request, recommending the Commission approve it in part and deny it in part.[13]

11. Minnesota Power filed reply comments to its exemption request on January 16, 2013, to address the DOC-DER's concerns.[14]

12. On January 16, 2013, Carol Overland, in her individual capacity, filed comments recommending Minnesota Power's exemption request be denied.[15]

13. On January 23, 2013, the DOC-DER filed additional comments on both the proposed Notice Plan and exemption request, recommending the Commission approve both as clarified and modified.[16]

14. The Commission met to consider the Notice Plan and exemption request on January 31, 2013.[17] On February 28, 2013, the Commission issued its Order approving the Notice Plan, granting the variance request, and approving the exemption request.[18]

15. As required by the Notice Plan, on August 5, 2013, Minnesota Power provided notice of the Project, including its intent to file for a CON, to landowners, stakeholders, government officials, and elected representatives.[19]

16. On October 21, 2013, Minnesota Power filed its CON Application for the Great Northern Transmission Line Project.[20]

17. On October 22, 2013, Minnesota Power filed additional materials related to Part 3 of Appendix O for the CON Application.[21]

18. Upon receipt, the Commission issued a Notice of Comment Period for the CON Application.[22] The initial comment period closed on November 19, 2013, and the time for reply comments closed on December 3, 2013.[23]

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[13] COMMENTS (December 17, 2012) (eDocket Nos. 201212-81883-01, 201212-81894-01).
[14] REPLY COMMENTS (January 16, 2013) (eDocket No. 20131-82827-01).
[15] EXEMPTION REPLY COMMENTS (January 16, 2013) (eDocket No. 20131-82847-01).
[16] LETTER (January 23, 2013) (eDocket Nos. 20131-83079-01, 20131-83075-01).
[17] MINUTES JANUARY 31, 2013 AGENDA MEETING (February 28, 2013) (eDocket No. 20132-84298-08)
[18] ORDER ACCEPTING FILING, VARYING TIME LINES, AND NOTICE AND ORDER FOR HEARING (January 8, 2014) (eDocket No. 20141-95218-01).
[19] Ex. 63 (Mailed Notice Plan).
[20] Exs. 8-31 (CON Application and Appendices).
[21] Exs. 25-28 (CON Application Appendix O parts 1-4).
[22] NOTICE OF COMMENT PERIOD (October 22, 2013) (eDocket No. 201310-92832-01).
[23] *Id.*

19. Several public comments were filed addressing the CON Application.[24] These comments addressed: devalued property; population density; lost tax revenue; noise; efficiency; safety; cost; conservation; transmission alternatives; health risks; future power needs; economic beneficiaries; diminished scenery and water quality; the impact on plants, animals, and trees; the loss of valuable crop and pasture land; and decreased tourism.[25]

20. Northern States Power Company, d/b/a Xcel Energy, Missouri River Energy Services, Great River Energy, and Ottertail Power Company also filed comments, urging the Commission to consider system alternatives as part of the contested case proceeding.[26]

21. On November 19, 2013, LPI and Carol Overland (in her individual capacity) filed comments recommending the Commission refer the CON Application for a contested case proceeding at the Office of Administrative Hearings.[27]

22. The DOC-DER filed comments on November 19 and 21, 2013, confirming completion of the CON Application and recommending the Commission refer the CON Application to the Office of Administrative Hearings for a contested case proceeding.[28]

23. On December 3, 2013, Minnesota Power filed reply comments related to the completeness of its CON Application.[29]

24. The Commission met on December 19, 2013.[30] On January 8, 2014, the Commission issued an Order Accepting Filing and Varying Time Lines, as well as a Notice and Order for Hearing, which named Minnesota Power and the DOC-DER as parties.[31]

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[24] PUBLIC COMMENT (October 28, 2013) (eDocket No. 201310-92996-01); PUBLIC COMMENT (November 4, 2013) (eDocket No. 201311-93253-01); PUBLIC COMMENT (November 12, 2013) (eDocket No. 201311-93612-01); PUBLIC COMMENT (November 18, 2013) (eDocket 201311-93786-01); PUBLIC COMMENT (November 25, 2013) (eDocket No. 201311-94056-01); PUBLIC COMMENT (December 9, 2013) (eDocket No. 201312-94461-01); PUBLIC COMMENT (December 16, 2013) (eDocket No. 201312-94616-01).
[25] PUBLIC COMMENT (October 28, 2013) (eDocket No. 201310-92996-01); PUBLIC COMMENT (November 4, 2013) (eDocket No. 201311-93253-01); PUBLIC COMMENT (November 12, 2013) (eDocket No. 201311-93612-01); PUBLIC COMMENT (November 18, 2013) (eDocket 201311-93786-01); PUBLIC COMMENT (November 25, 2013) (eDocket No. 201311-94056-01); PUBLIC COMMENT (December 9, 2013) (eDocket No. 201312-94461-01); PUBLIC COMMENT (December 16, 2013) (eDocket No. 201312-94616-01).
[26] COMMENTS (November 19, 2013) (eDocket No. 201311-93834-01).
[27] COMMENTS (November 19, 2013) (eDocket No. 201311-93829-01); COMMENTS (November 19, 2013) (eDocket No. 201311-93819-01); *see also* COMMENTS (December 10, 2013) (eDocket No. 201312-94468-01).
[28] COMMENTS (November 19, 2013) (eDocket No. 201311-93825-01); COMMENTS (November 21, 2013) (eDocket No. 201311-93930-01).
[29] REPLY COMMENTS (December 3, 2013) (eDocket No. 201312-94238-01).
[30] BRIEFING PAPERS DECEMBER 19, 2013 AGENDA (December 12, 2013) (eDocket No. 201312-94525-01).
[31] ORDER ACCEPTING FILING, VARYING TIME LINES, AND NOTICE AND ORDER FOR HEARING (January 8, 2014) (eDocket No. 20141-95218-01).

25. On January 10, 2014, RRANT filed a Petition to Intervene.[32]

26. Shortly thereafter, on January 14, 2014, LPI filed a Petition to Intervene.[33]

27. A Prehearing Conference was held at the Commission office in Saint Paul, Minnesota, on January 17, 2014. On January 29, 2014, the Administrative Law Judge issued the First Prehearing Order in this case, establishing the procedural schedule for this proceeding and granting the Petitions to Intervene of LPI and RRANT.[34]

III. ENVIRONMENTAL REVIEW

28. The environmental review for this proceeding was conducted by the DOC-EERA.[35] The DOC-EERA acts as an advisor to the Commission on environmental matters related to the CON Application.[36]

29. On January 15, 2014, the Commission issued a Notice of Public Information and Environmental Report Scoping Meetings.[37]

30. The 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, Minnesota, on February 18, 2014; Sanford Center, Bemidji, Minnesota, on February 19, 2014; and Sawmill Inn, Grand Rapids, Minnesota, on February 20, 2014.[38]

31. Approximately 90 people attended the meetings, and approximately 20 people offered comments on the record.[39]

32. The DOC-EERA received an additional 28 written comments regarding the scope of the Environmental Report during the comment period.[40]

33. Overall, comments from members of the public fell into three categories: comments directed exclusively at the route, which the DOC-EERA forwarded to the route permit docket;[41] comments directed at both the route and need, which the DOC-EERA forwarded to the route permit docket but also addressed in the current docket; and comments directed at need. The comments related to need addressed: safety

[32] PETITION TO INTERVENE (January 10, 2014) (eDocket20141-95324-01).
[33] PETITION TO INTERVENE (January 16, 2014) (eDocket 20141-95521-01).
[34] FIRST PREHEARING ORDER (January 29, 2014) (eDocket No. 20141-95906-01).
[35] Ex. 6 (Environmental Report).
[36] *Id*.
[37] Ex. 1 (Notice of Public Information and Environmental Report Scoping Meetings).
[38] MEETING PRESENTATIONS (February 4, 2014) (eDocket No. 20142-96153-01).
[39] Ex. 2 (Oral public comments).
[40] Ex. 3 (Written public comments).
[41] *In the Matter of the Application of Minnesota Power for a Route Permit for the Great N. Transmission Line Project in Roseau, Lake of the Woods, Beltrami, Koochiching, and Itasca Counties,* PUC Docket No. E-015/TL-14-21.

hazards; health implications; technological impacts; infrastructural, economic, and environmental effects; noise; project design; transmission and no-build alternatives; and justifications, timing, efficiency, and aesthetics.

34. On March 14, 2014, Xcel Energy filed written comments regarding development of the record and representation of its customers should any costs from the planned transmission line be allocated to them.[42] RRANT also submitted comments insisting that an Environmental Impact Statement be completed and include specific factors to be described and analyzed.[43]

35. Minnesota Power served its Notice Plan on stakeholders and local governments on March 14, 2014.[44]

36. On April 22, 2014, the DOC-EERA issued its Scoping Decision for the Environmental Report.[45]

37. On July 14, 2014, the DOC-EERA issued a Notice of Availability of Environmental Report[46] and the Environmental Report.[47] The Notice was also published in the Environmental Quality Board Monitor.[48]

38. On August 15, 2014, RRANT filed Comments on the Environmental Report Scoping Decision.[49] According to RRANT, the Environmental Report should describe, characterize, and analyze numerous factors including: the purpose, design, timing, and security risks of the Project; the justification for such a large project; the inherent inefficiency of transmission over long distances; whether eminent domain is an option for this Project; the cultural resources affected by the construction of another dam in Manitoba; and the health impacts on humans and animals related to high voltage transmission lines.[50]

A. Public Hearings and Comments

39. On September 9, 2014, the Commission issued the Notice of Public Hearings for the CON Application.[51]

40. Seven public hearings were held 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,

[42] COMMENTS (March 14, 2014) (eDocket No. 20143-97356-01).
[43] COMMENTS (March 14, 2014) (eDocket No. 20143-97345-01).
[44] Ex. 63 (Mailed Notice Plan).
[45] Ex. 4 (Scoping Decision for Environmental Report).
[46] Ex. 5 (Notice of Availability of Environmental Report).
[47] Ex. 6 (Environmental Report).
[48] Ex. 7 (Notice published in EQB Monitor).
[49] COMMENTS (August 15, 2014) (eDocket No. 20148-102312-01).
[50] *Id.*
[51] NOTICE OF PUBLIC HEARING (September 9, 2014) (eDocket No. 20149-102936-01).

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. All public hearings were presided over by the Administrative Law Judge.

41. Approximately 20 members of the public provided oral comments during the public hearings, with a majority of the comments involving route questions and objections.[52] Members of the public also asked questions of Minnesota Power related to the cost of the Project, its relationship to other Minnesota Power facilities, and Minnesota Power's contracts with Manitoba Hydro, a Canadian company with whom Minnesota Power proposes to construct the GNTL.[53]

42. Additional public comments submitted in writing were received by the deadline of December 3, 2014, and included in the record.[54]

43. The written comments received from Minnesota residents related primarily to route permit issues. Minnesota residents expressed concern with the placement of power lines on private land, decreased property values, and environmental and community impacts, including forest and deer-stand destruction.[55] James Johnson and Jeff Johnson, both landowners near Roosevelt, suggested alternate routes for the Project.[56] Buddy Savich, owner of a farm in Itasca County, objected to placement of any power lines across his farmland.[57] Laura Imax, a former Roseau resident, expressed concern that a route damaging natural resources will be selected over a route damaging farmland, which she considers to be compensable damage.[58] John and Marty Licke, Bigfork residents, requested reconsideration of "the proposed routing of the new transmission line, and instead include full utilization of the existing highline corridors."[59]

44. Midcontinent Independent System Operator, Inc. (MISO) submitted a public comment in the form of a letter.[60] MISO is the regional transmission organization that provides open-access transmission service and monitors the high voltage transmission system throughout the Midwest area in the United States and Manitoba,

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[52] *See* Littlefork Public Hearing Transcript (November 3, 2011) (eDocket No. 201411-104368-03); 201411-104368-01 (Roseau); Grand Rapids Public Hearings Transcripts (November 3, 2011) (eDocket Nos. 201411-104368-07, 201411-104368-06); Baudette Public Hearing Transcript (November 3, 2014) (eDocket No. 201411-104368-02); Kelliher Public Hearing Transcript (November 3, 2011) (eDocket No. 201411-104368-04); Bigfork Public Hearing Transcript (November 3, 2014) (eDocket No. 201411-104368-05).
[53] *See id.*
[54] PUBLIC COMMENT (December 3, 2014) (eDocket No. 201412-105151-01); PUBLIC COMMENTS (December 4, 2014) (eDocket Nos. 201412-105176-01, 201412-105176-02, 201412-105176-03, 201412-105176-04, 201412-105176-05, 201412-105176-06).
[55] PUBLIC COMMENTS at Exs. A, B, E-I (December 4, 2014) (eDocket Nos. 201412-105176-01).
[56] PUBLIC COMMENTS at Exs. A, G, I (December 4, 2014) (eDocket Nos. 201412-105176-01).
[57] PUBLIC COMMENTS at Exs. E-F (December 4, 2014) (eDocket Nos. 201412-105176-01).
[58] PUBLIC COMMENTS at Ex. H (December 4, 2014) (eDocket Nos. 201412-105176-01).
[59] PUBLIC COMMENTS at Ex. B (December 4, 2014) (eDocket Nos. 201412-105176-01).
[60] *Id.*

Canada.[61] Minnesota Power is a transmission owner within MISO, which is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).[62] In its letter, MISO stated that the Project is the result of "sound execution of MISO's collaborative Transmission Planning process."[63] According to MISO, the Project is appropriate "to address system needs and opportunities" and "will enable a series of long-term, firm transmission service requests to be accepted.[64]

45. A letter submitted by John Dunn, a resident of Wisconsin, contends that hydropower from Manitoba is not "clean" energy.[65] Mr. Dunn believes conservation, energy efficiency, load management, and locally-produced solar power would provide greater benefits for the cost.[66]

46. Minnesota Power submitted two documents as part of the public comment period: (1) a copy of the FERC Order approving the Facilities Construction Agreement (FCA);[67] and (2) a copy of a letter from Gary Doer, the Canadian Ambassador to the United States, to the United States Environmental Protection Agency discussing the Project and its ability to lower emissions related to Minnesota Power's energy supply portfolio.[68]

47. Finally, Luis Contreras, an Arkansas resident, submitted several letters contending the Project is about corporate greed, not public need.[69] Mr. Contreras asserted that a power purchase agreement does not "prove public need."[70] He believes transmission lines are hazardous to human health and therefore advocated for local solar power generation as "the best solution."[71]

B. Evidentiary Hearing

48. In preparation for the evidentiary hearing in this matter, and in conformity with the First Prehearing Order, Minnesota Power, the DOC-DER, and LPI pre-filed the testimony of their witnesses.

49. On August 8, 2014, Minnesota Power filed its Direct Testimony.[72]

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[61] *See* https://www.misoenergy.org/Pages/Home.aspx.
[62] CERTIFICATE OF NEED APPLICATION at 31 (October 21, 2013) (eDocket No. 201310-92766-02).
[63] PUBLIC COMMENTS at Exs. C, J (December 4, 2014) (eDocket Nos. 201412-105176-01).
[64] *Id.*
[65] PUBLIC COMMENTS at Ex. D (December 4, 2014) (eDocket Nos. 201412-105176-01).
[66] *Id.*
[67] PUBLIC COMMENTS at Ex. K (December 4, 2014) (eDocket Nos. 201412-105176-01).
[68] PUBLIC COMMENTS at Ex. L (December 4, 2014) (eDocket Nos. 201412-105176-01).
[69] PUBLIC COMMENTS at Exs. M-P (December 4, 2014) (eDocket Nos. 201412-105176-01).
[70] *Id.*
[71] *Id.*
[72] Ex. 34 (McMillan Direct); Ex. 37 (Atkinson Direct); Ex. 38 (Donahue Direct); Ex. 39 (Donahue Direct Attachment); Ex. 41 (Hobert Direct); Ex. 42 (Winter Direct); Ex. 43 (Rudeck Direct); Ex. 44 (Rudeck Direct Attachment).

50. On September 19, 2014, the DOC-DER and LPI filed their Direct Testimony.[73]

51. On October 24, 2014, Minnesota Power and the DOC-DER filed Rebuttal Testimony.[74]

52. On November 7, 2014, Minnesota Power, the DOC-DER and LPI filed Surrebuttal Testimony.[75]

53. RRANT did not file any testimony in this proceeding.

54. On November 10, 2014, the DOC-DER filed an errata sheet to the Surrebuttal testimony of Dr. Stephen Rakow.[76]

55. On November 12 and 14, 2014, the Administrative Law Judge presided over the evidentiary hearing in this matter.

56. On December 5, 2014, Minnesota Power, the DOC-DER, LPI, and RRANT (Parties) submitted an Issues Matrix summarizing the contested issues in this proceeding.[77]

57. On December 19, 2014, Minnesota Power, the DOC-DER, and RRANT submitted initial post-hearing briefs, and Minnesota Power also submitted its proposed findings of fact and conclusions of law.

58. On December 22, 2014, LPI filed its initial post-hearing brief along with a motion for permission to file the brief one business day after the set deadline.[78] The other parties did not oppose LPI's motion, and the Administrative Law Judge granted LPI's motion on January 9, 2015.

59. On January 16, 2015, the Parties submitted their reply briefs, and the DOC-DER and LPI submitted revisions to Minnesota Power's proposed findings of fact and conclusions of law. RRANT did not submit proposed findings or revisions to Minnesota Power's proposed findings.

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[73] Ex. 49 (Kollen Direct - Public); Ex. 50 (Kollen Direct – Trade Secret); Ex. 52 (Shah Direct); Ex. 53 (Rakow Direct - Public); Ex. 54 (Rakow Direct – Trade Secret).
[74] Ex. 35 (McMillan Rebuttal); Ex. 40 (Donahue Rebuttal); Ex. 55 (Rakow Rebuttal).
[75] Ex. 36 (McMillan Surrebuttal); Ex. 45 (Rudeck Surrebuttal); Ex. 46 (Rudeck Surrebuttal Attachment - Public); Ex. 47 (Rudeck Surrebuttal Attachment – Trade Secret); Ex. 51 (Kollen Surrebuttal); Ex. 56 (Rakow Surrebuttal); Ex. 57 (Johnson Surrebuttal).
[76] Ex. 58 (Rakow Surrebuttal Errata Sheet).
[77] ISSUES MATRIX (December 5, 2014) (eDocket No. 201412-105220-01).
[78] MOTION (December 22, 2014) (eDocket No. 201412-105600-02).

IV. PROJECT DESCRIPTION

A. Company Description

60. Minnesota Power, a division of ALLETE, was incorporated in 1906 and serves approximately 144,000 retail electric customers and 16 municipal systems across a 26,000 square mile service area in central and northeastern Minnesota.[79]

61. More than half of Minnesota Power's total energy supply is sold to industrial customers, including five taconite producing facilities, one iron nugget plant, and four paper and pulp mills.[80] These industrial customers operate around-the-clock, giving Minnesota Power a uniquely high load factor as well as a load profile with less variation than most utilities.[81]

62. Minnesota Power generates the majority of its electricity from coal-fired units at its Boswell, Laskin, and Taconite Harbor Energy Centers in Minnesota, supplemented by a long-term purchase from Square Butte's Milton R. Young 2 lignite coal generating station in North Dakota.[82]

63. In January 2013, Minnesota Power announced its Energy*Forward* resource strategy to reduce dependence on coal and fossil-based energy sources.[83] Under the Energy*Forward* plan, Minnesota Power seeks to shift its power supply from a predominantly coal-based energy mix to a balanced supply of approximately one-third renewable resources, one-third natural gas, and one-third coal-fired generation by the end of the decade.[84] The Project, which is the subject of this proceeding, is an integral piece of the Company's Energy*Forward* plan.[85]

64. Over the past several years, Minnesota Power has undertaken a systematic effort to increase its deployment of renewable energy.[86] In 2006 and 2007, Minnesota Power began purchasing wind power from wind farms in North Dakota.[87] In 2008, Minnesota Power built Taconite Ridge, the first commercial wind generating facility in northern Minnesota.[88] Most recently, in 2010 and 2012, Minnesota Power completed three phases of the Bison Wind Energy Center in North Dakota.[89] In total,

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[79] *In the Matter of Minnesota Power's Application for Approval of its 2013-2027 Resource Plan*, PUC Docket No. E015/RP-13-53, INITIAL FILING – RESOURCE PLAN (March 1, 2013).
[80] *Id.*
[81] *Id.*
[82] *Id.*
[83] Ex. 9 at 1 (CON Application).
[84] Ex. 45 at 1-2 (Rudeck Surrebuttal).
[85] Ex. 34 at 24 (McMillan Direct).
[86] *In the Matter of Minnesota Power's Application for Approval of its 2013-2027 Resource Plan*, PUC Docket No. E015/RP-13-53, INITIAL FILING – RESOURCE PLAN (March 1, 2013).
[87] *Id.*
[88] *Id.*
[89] *Id.*

the wind projects added more than 400 MW of renewable electricity to Minnesota Power's system.[90]

65. One of the primary purposes of the proposed Project is to incorporate additional hydropower into Minnesota Power's resource system, consistent with the Company's Energy*Forward* plan.[91] In addition to providing access to and the transmission of hydropower from Canada, the proposed Project will enable Minnesota Power to exchange some of the purchased hydropower with wind energy generated in Minnesota Power's North Dakota wind facilities.[92]

66. The proposed Project would not, however, fulfill the renewable energy mandates set forth in Minn. Stat. § 216B.1691, subd. 2a (2014).[93] The Company acknowledges that one of the purposes of the Project is to support the export of Canadian hydropower to other states:

> [W]hile 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.[94]

B. Proposed Facilities

67. The Project involves the construction of a new 500 kV transmission line in Minnesota from the United States/Canadian border to Minnesota Power's Blackberry Substation in the Grand Rapids, Minnesota area.[95]

68. At the time of the CON Application, Minnesota Power anticipated the Project would provide at least 750 MW of transfer capability.[96] However, subsequent analysis indicates that once completed, the Project will provide approximately 883 MW of transfer capability.[97]

69. Given the route alternatives as presented to date in the Route Permit proceeding, the 500 kV Line will be approximately 220 miles in length and constructed on a 200-foot-wide right-of-way likely in the following Minnesota counties: Beltrami, Itasca, Koochiching, Lake of the Woods, and Roseau.[98]

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[90] *Id.*
[91] Ex. 34 at 5, 24 (McMillan Direct).
[92] Ex. 45 at 1-2 (Rudeck Surrebuttal).
[93] Ex. 9 at 12 (CON Application).
[94] *Id.*
[95] Ex. 9 at 24 (CON Application); Ex. 42 at 3 (Winter Direct).
[96] Ex. 9 at 24 (CON Application).
[97] Ex. 42 at 3 (Winter Direct).
[98] Ex. 42 at 3-4 (Winter Direct); *see also In the Matter of the Request by Minnesota Power for a Route Permit for the Great Northern Transmission Line,* PUC Docket No. E015/TL-14-21, INITIAL FILING – EXECUTIVE SUMMARY (April 15, 2014).

70. The 500 kV transmission line is proposed as part of a new international transmission interconnection between Manitoba, Canada and the United States.[99] Under the proposal, Manitoba Hydro, a Crown Corporation, will be constructing the Canadian portion of this new international interconnection.[100]

71. In addition to the 500 kV transmission line, the Project includes expansion of the Blackberry Substation near Grand Rapids, Minnesota, as well as a 500 kV Series Compensation Station located near the midpoint of the combined Manitoba and United States transmission line.[101]

72. Minnesota Power anticipates using three-conductor bundle 1192.5 kcmil Aluminum Steel Conductor Reinforced (ASCR) "bunting" with 18-inch sub-spacing as the phase conductor for the Project.[102] This conductor is the same as that used on the existing Dorsey - Chisago 500 kV transmission line.[103] Final conductor selection for the Project will be based on a conductor optimization study.[104]

73. Minnesota Power continues to evaluate several structure types and configurations of towers to be used for the Project, including a self-supporting lattice tower, a lattice guyed "V" structure, and a lattice guyed delta structure.[105] 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.[106]

C. Ownership of Project

74. 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.[107]

75. Manitoba Hydro proposes to construct and have sole ownership of the Canadian portion of the new interconnection.[108]

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[99] Ex. 9 at 24 (CON Application).
[100] Ex. 42 at 3-4 (Winter Direct).
[101] Ex. 38 at 5 (Donahue Direct).
[102] Ex. 42 at 4 (Winter Direct).
[103] *Id.*
[104] *Id.*
[105] *Id.*
[106] *Id*.
[107] Ex. 34 at 13 (McMillan Direct).
[108] *Id.*

76. On the United States side, Minnesota Power proposes to have 51 percent ownership of the Project initially.[109] Manitoba Hydro's subsidiary, 6690271 Manitoba, Ltd. (Manitoba Ltd.),[110] will own 49 percent of the Project.[111] Minnesota Power and Manitoba Ltd. will own the Project as tenants in common.[112]

77. Manitoba Ltd. does not intend to be a co-owner of the Project past mid-year 2016.[113] Manitoba Ltd. plans to sell all or a portion of its share in the Project to one or more United States utilities before, during, or after construction, or at the latest by mid-2016.[114]

D. Timing

78. Construction of the Project is anticipated to begin in 2016, with an in-service date of June 1, 2020.[115]

79. In order to maintain the projected construction schedule and to achieve the contractually required in-service date, Minnesota Power began its outreach efforts for permitting and routing in mid-2012.[116]

80. Minnesota Power continues to make progress on its milestones to achieve the in-service date, including the filing of the Presidential Permit Application required for an international border crossing.[117]

81. Minnesota Power's Route Permit Application is currently pending under a separate docket.[118] Public and evidentiary hearings for the route are tentatively scheduled to occur in late July and early August 2015.

E. Estimated Costs

82. Minnesota Power has provided several estimates for the total cost of the Project since filing its CON Application in October 2013.[119]

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[109] Ex. 34 at 13-14 (McMillan Direct); Ex. 38 at 8 (Donahue Direct).
[110] Throughout this proceeding, Manitoba Hydro has referred to Manitoba Ltd. as "Manitoba Hydro." Therefore, it is difficult to decipher which entity is responsible for various obligations, including the contribution of construction payments and Must Take Fees provided for in the various agreements described in this Report.
[111] Ex. 38 at 8 (Donahue Direct).
[112] *Id.*
[113] *Id.*
[114] Ex. 34 at 13-14 (McMillan Direct); Ex. 38 at 8 (Donahue Direct).
[115] Ex. 9 at 2, 35 (CON Application); Ex. 34 at 11 (McMillan Direct); Ex. 38 at 5 (Donahue Direct).
[116] Ex. 9 at 78 (CON Application).
[117] *See* Office of Energy Docket No. PP-398, 79 Fed. Reg. 27,587 (May 14, 2014); Office of Energy Docket Nol. PP-398, 79 Fed. Reg. 68,673 (Nov. 18, 2014).
[118] *In the Matter of the Application of Minnesota Power for a Route Permit for the Great Northern Transmission Line Project in Roseau, Lake of the Woods, Beltrami, Koochiching, and Itasca Counties,* PUC Docket No. E-015/TL-14-21.
[119] Ex. 49 at 5-6 (Kollen Direct – Public).

83. In its CON Application, Minnesota Power provided an initial range of estimated costs for the Project between \$406 million and \$609 million.[120] At that time, Minnesota Power had a number of potential routes still under consideration, so the estimate used a "proxy" route based on information available.[121]

84. When Minnesota Power filed its Route Permit Application, route alternatives and segment options were identified.[122] Minnesota Power then re-examined and refined its prior cost range estimate to reflect the new route data.[123] In addition, Minnesota Power refined its estimate related to expected construction costs, including the use of matting in wetlands to mitigate potential wetland impacts.[124]

85. Based on preliminary engineering considerations of the route alternatives and segment options, Minnesota Power estimated the construction of the Project would cost between \$495.5 million and \$647.7 million in 2013 dollars.[125]

86. In July of 2014, a facility study report sponsored by MISO concluded that the 500 kV Series Compensation Station, originally budgeted at the expanded Blackberry Substation, should be a separate facility located at the midpoint of the 500 kV transmission line.[126] Incorporating that change and accounting for property taxes assessed against Project assets before the in-service date of June 1, 2020, Minnesota Power estimated construction of the Project would cost between \$557.9 million and \$710.1 million.[127]

87. In September 2014, Minnesota Power entered into a multi-party Facilities Construction Agreement (FCA) with MISO, which gave an estimate for the Project of \$676,947,930 (in 2013 dollars).[128]

88. While the FCA sets forth a more specific cost estimate, Minnesota Power continues to assert the estimated cost of the Project will be between \$557.9 million and \$710.1 million (in 2013 dollars).[129]

89. As emphasized by LPI, all of the cost estimates provided by Minnesota Power are stated in 2013 dollars and not in "as-spent" dollars.[130] Thus, none of the estimates include construction cost inflation.[131] For accounting purposes, Minnesota

[120] Ex. 9 at 27 (CON Application); Ex. 38 at 4 (Donahue Direct).
[121] Ex. 38 at 4 (Donahue Direct).
[122] *In the Matter of the Application of Minnesota Power for a Route Permit for the Great Northern Transmission Line Project in Roseau, Lake of the Woods, Beltrami, Koochiching, and Itasca Counties,* PUC Docket No. E-015/TL-14-21, INITIAL FILING – EXECUTIVE SUMMARY (April 15, 2014).
[123] Ex. 38 at 4-5 (Donahue Direct).
[124] *Id.*
[125] Ex. 38 at 4-5, Schedule 4 (Donahue Direct).
[126] Ex. 38 at 5 (Donahue Direct).
[127] *Id.*
[128] Ex. 40, Schedule 1 at 154 (Donahue Rebuttal)
[129] Ex. 40 at 6 (Donahue Rebuttal); Evidentiary Hearing Transcript Volume (Tr. Vol.) 1 at 113 (Donahue).
[130] Ex. 50 at 8-9 (Kollen Direct – Trade Secret).
[131] *Id.*

Power will incur and record costs in "as-spent" dollars, not in 2013 dollars.[132] Thus, when it comes to cost recovery, Minnesota Power will seek to recover the "as-spent" dollars from ratepayers.[133]

90. In addition, LPI asserted that none of the cost estimates provided by Minnesota Power include financing costs to be incurred during construction.[134] Minnesota Power will likely seek to recover the financing costs from customers either by: (1) capitalizing the financing costs as allowance for funds used during construction (AFUDC) and then recovering the costs, along with all other construction work in progress (CWIP) costs, over the service life of the assets; or (2) by recovering a current return on CWIP during the construction period.[135]

91. Given the terms of the agreements discussed below, Minnesota Power represents that ratepayers will only be responsible for 28.3 percent of the Project's capital costs.[136] Based upon Minnesota Power's current cost estimate of between $557.9 million and $710.1 million (in 2013 dollars), Minnesota Power asserts ratepayers will be responsible for between $158 million and $201 million (in 2013 dollars), exclusive of construction inflation and financing costs.[137]

92. Regarding operating and maintenance (O&M) costs, the primary annual maintenance expense for a transmission line is aerial inspection.[138] Aerial inspections look for broken insulators or other defects that could compromise the transmission line.[139] If issues are identified, ground crews are dispatched to correct the defect.[140]

93. In addition to structural maintenance, the right-of-way must be kept clear of vegetation.[141] Vegetation control is performed on a scheduled and routine basis, as well as when the aerial inspection uncovers issues.[142]

94. 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.[143] Using the $1,600 per mile estimate for 250 miles results in $400,000 annually in maintenance costs for the Project.[144]

[132] *Id.*
[133] *Id.*
[134] Ex. 50 at 9 (Kollen Direct – Trade Secret).
[135] Ex. 50 at 10-11 (Kollen Direct – Trade Secret).
[136] Ex. 38 at 5 (Donahue Direct).
[137] *Id.*
[138] Ex. 9 at 28 (CON Application).
[139] *Id.*
[140] *Id.*
[141] Ex. 9 at 28 (CON Application).
[142] *Id.*
[143] *Id.*
[144] Ex. 56 at 6 (Rakow Surrebuttal).

95. Based upon the terms of the agreements discussed below, Minnesota Power asserts ratepayers will only be responsible for 33.3 percent of the O&M expenses associated with the Project each year.[145]

V. MINNESOTA POWER'S AGREEMENTS WITH MANITOBA HYDRO

96. Various contracts between Manitoba Hydro and Minnesota Power form the basis for Minnesota Power's CON Application. These contracts: (1) provide for the exchange of wind and hydro energy intended for transmission by the Project; and (2) establish the relative financial responsibilities of the two utilities.

A. The 250 MW Agreements

97. In October 2009, Minnesota Power filed a Petition for Approval of its 2010 Integrated Resource Plan (2010 IRP) with the Commission.[146] In its 2010 IRP, Minnesota Power identified a predicted increase in energy needs as well as an expected capacity deficit in the 2020 to 2035 timeframe due to customer load growth and diversification of its power supply.[147]

98. To address the anticipated load and supply changes, and to diversity its energy resources, Minnesota Power intended to pursue a 250 MW power purchase agreement with Manitoba Hydro and build a new transmission line to deliver the power purchased.[148] Minnesota Power intends to have power delivery available through these sources by 2020.[149]

99. The inclusion of 250 MW of hydropower from Manitoba Hydro, and the new transmission to deliver that power, is part of Minnesota Power's least cost system-wide long-term supply plan.[150]

100. The DOC-DER analyzed and the Commission ultimately approved Minnesota Power's 2010 IRP in 2011.[151] According to the DOC-DER, the Commission's approval of Minnesota Power's 2010 IRP established Minnesota Power's need for additional capacity and energy.[152]

101. Minnesota Power did not present specific evidence of increased need for energy or capacity in this proceeding, relying instead on the Commission's approval of its 2010 IRP.

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[145] Ex. 38 at 5-6 (Donahue Direct).
[146] *In the Matter of Minnesota Power's Application for Approval of its 2010-2024 Resource Plan*, PUC Docket No. E015/RP-09-1088, PETITION (October 5, 2009).
[147] *Id.*
[148] Ex. 43 at 9 (Rudeck Direct).
[149] *Id.*
[150] Ex. 43 at 10 (Rudeck Direct).
[151] *Id.*
[152] Ex. 52 at 6-8 (Shah Direct).

102. In furtherance of its 2010 IRP, Minnesota Power negotiated a 250 MW Power Purchase Agreement (PPA) and a 250 MW Energy Exchange Agreement (EEA) with Manitoba Hydro (collectively referred to as the 250 MW Agreements).[153]

103. The 250 MW Agreements require Minnesota Power to purchase 250 MW of capacity and energy (250 MW during 16 hours each day) from Manitoba Hydro during June 1, 2020, through May 31, 2035.[154] The agreements also allow Minnesota Power to sell 250,000 MWh per year to Manitoba Hydra and later buy back the energy during June 1, 2020, through May 31, 2035.[155] This arrangement creates energy "banking" or what Manitoba Hydro describes as a "storage" element as part of the transaction.

104. According to Minnesota Power, the 250 MW Agreements optimize Minnesota Power's resources by allowing Minnesota Power to sell off-peak excess wind energy from its wind farms to Manitoba Hydro and then "buy back" the energy from Manitoba Hydro when needed by Minnesota Power customers.[156]

105. The 250 MW Agreements were approved by the Commission in 2012.[157] Minnesota Power relies on the Commission's approval of its 2010 IRP and the 250 MW Agreements to establish the accuracy of its forecast of demand as well as the need for more electricity and capacity for its customers.

106. In reviewing and approving the 250 MW Agreements, the DOC-DER and the Commission noted that given Minnesota Power's projected capacity and energy deficits during the 2020 to 2035 timeframe, Minnesota Power "will need a significant amount of capacity and energy."[158] The DOC-DER based this conclusion on the forecast scenarios presented within Minnesota Power's 2011 Annual Forecast Report.[159]

107. The DOC-DER and the Commission further concluded that the 250 MW Agreements "provide the most appropriate resources for [Minnesota Power] to meet its resource needs" over the time period of 2020 to 2035.[160]

108. The DOC-DER and the Commission recognized that "both [Manitoba Hydro] and [Minnesota Power] must construct their own new transmission facilities (in

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[153] *See In the Matter of Minnesota Power's Petition for Approval of a 250 MW Power Purchase Agreement with Manitoba Hydro*, PUC Docket No. E015/M-11-938, PETITION (September 16, 2011); Ex. 13 (Appendix D to CON Application).
[154] Ex. 52 at 5-6 (Shah Direct).
[155] *Id.*
[156] Ex. 43 at 7-8 (Rudeck Direct).
[157] *In the Matter of Minnesota Power's Petition for Approval of a 250 MW Power Purchase Agreement with Manitoba Hydro*, PUC Docket No. E015/M-11-938, ORDER (February 1, 2012).
[158] Ex. 12 at 4 (Appendix C to CON Application).
[159] *Id.*
[160] Ex. 12 at 5, 25 (Appendix C to CON Application).

Canada and the USA respectively) to allow Manitoba Hydro to sell the contracted power to [Minnesota Power]."[161]

109. The Commission specifically ordered Minnesota Power to provide updates on the progress of milestones achieved regarding the "new major transmission facilities" necessary to deliver the capacity and power contracted for under the approved 250 MW Agreements.[162]

B. The 133 MW Renewable Optimization Agreements

110. On July 30, 2014, Minnesota Power executed a 133 MW Energy Sale Agreement (ESA) and a 133 MW Energy Exchange Agreement (EEA) with Manitoba Hydro (collectively referred to as Renewable Optimization Agreements or ROAs).[163]

111. Minnesota Power filed a Petition for Approval of the ROAs with the Commission in November 2014.[164]

112. The ROAs provide for the purchase of an additional 133 MW of energy from Manitoba Hydro, as well as an exchange of wind and hydro energy between Minnesota Power and Manitoba Hydro.[165] According to Minnesota Power, the 133 MW ROAs bring 230,000 megawatt hours (MWh) of additional annual carbon-free energy to Minnesota Power customers when the Manitoba Hydro hydroelectric system is in surplus.[166] In addition, the agreements optimize Minnesota Power's wind power resources by allowing it to exchange wind power with Manitoba Hydro's water power in an efficient manner.[167]

113. Under the ROAs, Minnesota Power is able to send additional energy from its wind-generating facilities to Manitoba Hydro when wind production is high and not needed for its customer load.[168] In turn, when Manitoba Hydro is using Minnesota Power's wind power for their customer load, Manitoba Hydro is able to temporarily reduce hydropower generation by decreasing the flow of water through its plants.[169] The energy "saved" during that process can be used later to generate electricity sent to Minnesota Power when wind energy production is low or customer needs are high.[170]

114. In addition to helping meet its capacity and energy needs, Minnesota Power asserts that the ROAs optimize the value of its wind energy investments,

[161] Ex. 12 at 13 (Appendix C to CON Application).
[162] *In the Matter of Minnesota Power's Petition for Approval of a 250 MW Power Purchase Agreement with Manitoba Hydro*, PUC Docket No. E015/M-11-938, ORDER (February 1, 2012).
[163] Ex. 43, Schedule 2 (Rudeck Direct).
[164] Ex. 46, Schedule 1 (Rudeck Surrebuttal).
[165] *Id.*
[166] Ex. 43 at 15 (Rudeck Direct).
[167] *Id.*
[168] *Id.*
[169] Ex. 43 at 16 (Rudeck Direct).
[170] *Id.*

diversify its energy portfolio, and lessen its reliance on coal-fired energy.[171] According to Minnesota Power, "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."[172]

115. Through the 250 MW Agreements and the 133 MW ROAs (collectively referred to as the Manitoba Hydro Agreements), Minnesota Power has procured a total of over 1,500,000 MWh of hydropower annually, as well as the ability to "store" or "bank" 1,000,000 MWh[173] of wind power annually in Manitoba Hydro's system.[174]

116. The energy purchased by Minnesota Power under the ROAs is priced at market rates and includes associated environmental benefits of renewable energy.[175] Minnesota Power asserts that this structure provides optionality for Minnesota Power to either take the energy if needed for least-cost customer supply, or to resell the energy in the market.[176] In either case, Minnesota Power receives the environmental attributes of the renewable power as part of the transaction.[177] These attributes are in furtherance of Minnesota Power's Energy*Forward* plan of reducing its reliance on coal-fired energy sources, and diversifying its resources.[178]

117. Because the energy provided by the ROAs is in excess of the amount needed by Minnesota Power, the ROAs require Manitoba Hydro to pay for the additional transmission delivery costs for the energy associated with the 133 MW ESA through a monthly fee for the term of the EEA.[179]

118. The 133 MW ESA provides that during the 20-year contract term, Manitoba Hydro shall pay a monthly fee (Must Take Fee) to Minnesota Power for all components of the transmission revenue requirements associated with the 133 MW portion of the Project.[180] According to Minnesota Power, the Must Take Fee is equal to 17.7 percent of the Project's total O&M and capital expenses.[181] Minnesota Power arrives at the 17.7 percent figure by dividing the 133 MW available through the ROAs by the 750 MW transmission capacity of the Project, as it was originally proposed under the 250 MW Agreements (i.e. 133 is 17.7% of 750).[182]

119. When the 17.7 percent Must Take Fee is added to Manitoba Hydro's 49 percent financial obligation for the Project, Minnesota Power claims Manitoba Hydro will

[171] Ex. 34 at 7 (McMillan Direct).
[172] Ex. 43 at 16 (Rudeck Direct)
[173] According to Minnesota Power's Petition for Approval of the 133 MW ROAs, the ROAs enable Minnesota Power to store 750,000 MWh per year of wind energy. Ex. 46 at 2-3 (Rudeck Surrebuttal).
[174] Ex. 34 at 7 (McMillan Direct).
[175] Ex. 43 at 17 (Rudeck Direct).
[176] *Id.*
[177] *Id.*
[178] Ex. 34 at 24 (McMillan Direct).
[179] Ex. 43 at 18 (Rudeck Direct).
[180] Ex. 43 at 18 (Rudeck Direct); Ex. 44 at 32-38 (Rudeck Direct Attachment).
[181] Ex. 38 at 13 (Donahue Direct).
[182] *Id*.

be paying 66.7 percent of the Project's total costs (49% + 17.7% = 66.7%), leaving Minnesota Power responsible for only 33.3 percent of those costs (100% - 66.7% = 33.3% or 51% - 17.7% = 33.3%).[183]

120. At the beginning of each contract year, Minnesota Power and Manitoba Hydro will determine the amount of the monthly Must Take Fee.[184] Manitoba Hydro will then pay the determined amount to Minnesota Power each month.[185]

121. For the portion attributable to capital costs, the monthly Must Take Fee equals the capital costs of the 133 MW portion of the Project divided by 20 years (the contract term) and then split into 12 monthly payments.[186] Minnesota Power will apply the Must Take Fee received "as a credit towards its retail revenue requirements and MISO Attachment O revenue requirement subject to applicable regulatory approvals."[187] In other words, Minnesota Power will record the full cost of the Project in any rider and rate proceedings.[188] Then, Minnesota Power will apply the portion of the Must Take Fee attributable to capital costs of the 133 MW portion of the Project as an off-setting credit toward its revenue requirements.[189]

122. On January 30, 2015, the Commission approved the ROAs, but noted that:

> This action does not prejudge any issue in the pending applications for a certificate of need and site permit for the Great Northern Transmission Line, docket numbers E-015/CON-12-1163 and E-015/TL-14-21. Should either application be denied, the Company must make a filing within 90 days of such order detailing the effect of the denial on this PPA and the course of action proposed by the Company.[190]

123. Therefore, the Commission acknowledged that its approval of the ROAs does not necessarily establish the "need" required in the CON Application process.

C. The Facilities Construction Agreement

124. On September 23, 2014, Minnesota Power, Manitoba Hydro, and MISO executed the FCA for the Project, setting forth the ownership percentages and financial responsibilities for the Project.[191]

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183 Ex. 43 at 18 (Rudeck Direct).
184 Ex. 44 at 33-38 (Rudeck Direct Attachment).
185 Ex. 44 at 33-34 (Rudeck Direct Attachment).
186 Ex. 44 at 37 (Rudeck Direct Attachment).
187 Ex. 40, Schedule 1 at 4 (Donahue Rebuttal).
188 Ex. 56 at 3-4 (Rakow Surrebuttal).
189 *Id.*
190 *In the Matter of Minnesota Power's Petition for Approval of a 133 MW Power Purchase Agreement with Manitoba Hydro,* PUC Docket No. E015/M-14-960, ORDER (January 30, 2015).
191 Ex. 40, Schedule 1 (Donahue Rebuttal).

125. In acknowledgement of the additional capacity associated with the Project due to the addition of the 133 MW ROAs (resulting in a total transmission capacity of 883 MW as opposed to the original estimate of 750 MW), the FCA includes provisions requiring Manitoba Hydro to provide an additional five percent Contribution in Aid of Construction (CIAC) payment to Minnesota Power.[192]

126. In addition, the FCA addresses the issue of the transfer of ownership from Manitoba Ltd., likely to occur in 2016. The FCA requires Minnesota Power's "full consent" when Manitoba Ltd. seeks to assign its interest in the Project to another transmission owner.[193] The effect of this provision is discussed in more detail below.

127. On November 25, 2014, FERC approved the FCA.[194]

128. Based on FERC's approval, MISO considers the Project to be approved under the MISO tariff, and has moved the Project to Appendix A of the MISO Transmission Expansion Plan 14 (MTEP14).[195]

D. Allocation of Project Costs

129. Since the time the CON Application was filed, three events have occurred and impacted the final allocation of revenue responsibility between Minnesota Power and Manitoba Hydro. First, the total transfer capacity of the line was determined by MISO to be 883 MW, not 750 MW, thereby changing Minnesota Power's proportionate share of the Project.[196] Second, Minnesota Power and Manitoba Hydro finalized the 133 MW ROAs approved by the Commission on January 29, 2015.[197] Third, Minnesota Power and Minnesota Hydro executed the FCA, including a requirement that Manitoba Hydro pay CIAC in the amount of five percent of the Project's capital costs.[198]

130. In order for Minnesota Power to retain a 51 percent ownership of the Project while not bearing more revenue responsibility than associated with 250 MW of transfer capability, the final agreements between Minnesota Power and Manitoba Hydro are structured to allow Minnesota Power to retain only 28.3 percent responsibility for the capital costs of the Project.[199] The 28.3 percent figure is computed by comparing the 250 MW transfer capacity Minnesota Power needs to the 883 MW total capacity of the Project (250 MW divided by 883 MW total capacity = .283 or 28.3 percent).[200]

131. Minnesota Power reduced its financial obligation for capital costs in the Manitoba Hydro Agreements through two contractual provisions. First, under the 133

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[192] Ex. 40, Schedule 1 (Donahue Rebuttal); Ex. 35 at 9 (McMillan Rebuttal).
[193] Ex. 40 at 3-4 (Donahue Rebuttal).
[194] Ex. 64 (FERC Order).
[195] *See* MTEP14, MISO (March 11, 2015), https://misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP14.
[196] Ex. 42 at 3-4 (Winter Direct).
[197] Ex. 34 at 14 (McMillan Direct); Ex. 43 at 3 (Winter Direct).
[198] Ex. 40, Schedule 1 (Donahue Rebuttal).
[199] Ex. 34 at 14-16 (McMillan Direct).
[200] *Id.*

MW ROAs, Manitoba Hydro is responsible for a Must Take Fee, which Minnesota Power asserts is equal to 17.7 percent of the Project's total capital and O&M costs.[201] Second, in recognition of the additional transfer capacity, Manitoba Hydro agreed to provide a five percent CIAC payment to Minnesota Power, further reducing Minnesota Power's total financial obligation.[202]

132. As a 51 percent owner of the Project, Minnesota Power would normally be expected to pay 51 percent of both the Project's capital costs as well as on-going O&M costs. However, as a result of Manitoba Hydro's five percent CIAC obligation provided for in the FCA, Minnesota Power's financial responsibility for the Project's capital costs is reduced from 51 percent to 46 percent (51% - 5% CIAC = 46%).[203]

133. Minnesota Power's financial obligations are further reduced by the Must Take Fee included in the ROAs, which require Manitoba Hydro to pay all costs associated with the 133 MW portion of the Project. As set forth above, the Must Take Fee equates to 17.7 percent of the Project's total capital and O&M costs.[204]

134. Thus, when Minnesota Power's 51 percent ownership obligation is reduced by the five percent CIAC and the 17.7 percent Must Take Fee, Minnesota Power's total financial obligation for the Project is reduced to 28.3 percent (i.e., 51% - 5% CIAC = 46% - 17.7% Must Take Fee = 28.3%).[205] Conversely, when Manitoba Hydro's share is increased by the 5 percent CIAC and the 17.7 percent Must Take Fee, its financial obligation for the Project is 71.7 percent (49% + 5% CIAC + 17.7% Must Take Fee = 71.7%).

135. Based upon Minnesota Power's current Project cost estimate of between $557.9 million and $710.1 million, Minnesota Power estimates ratepayers will be responsible for between $158 million and $201 million for the capital costs of the Project.[206] Using the estimate provided by Minnesota Power in the FCA ($676,947,930), Minnesota Power estimates ratepayers will be responsible for approximately $191,576,264 of the Project's capital costs.[207]

136. With respect to O&M expenses, Minnesota Power could identify no change in operating expenses associated with the increase in capacity from 750 MW to 883 MW.[208] Therefore, Minnesota Power agreed to retain its 33.3 percent responsibility for these O&M expenses.[209]

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[201] *Id.*
[202] Ex. 24 at 14-15 (McMillan Direct); Ex. 40 at 5 (Donahue Rebuttal).
[203] Ex. 34 at 15-16 (McMillan Direct).
[204] *Id.*
[205] *Id.*
[206] Ex. 38 at 5 (Donahue Direct).
[207] Ex. 40, Schedule 1 at 154 (Donahue Rebuttal).
[208] Ex. 40 at 5 (Donahue Rebuttal).
[209] Ex. 40 at 5-6 (Donahue Rebuttal).

137. The estimated annual O&M cost for the Project is $400,000 (estimated at 250 miles of line at $1,600 per mile).[210]

138. The percentage of financial responsibility Minnesota Power has for the overall Project is a material part of its justification for building a new 500 kV line as opposed to a smaller transmission facility.

E. Sale of Manitoba Ltd. Shares and Cost Allocation Implications

139. As set forth above, Manitoba Hydro's subsidiary, Manitoba Ltd., intends to divest itself of some or all of its shares in the Project by mid-2016.[211] According to Minnesota Power, if Manitoba Hydro does not identify another MISO transmission owner to assume Manitoba Ltd.'s share of the Project by 2016, Minnesota Power will assume 100 percent of the ownership of the Project.[212]

140. For the purpose of this proceeding, it is important for the Commission to ensure that when Manitoba Ltd. divests itself of its shares, Minnesota Power ratepayers are not left liable for any more than 28.3 percent of the Project's capital costs or any more than 33.3 percent of the O&M expenses of the Project. Otherwise, all of the financial justifications presented by Minnesota Power in support of the Project are meaningless.

141. To clarify the effect of Manitoba Ltd.'s divestiture of its shares in the Project, Minnesota Power provided the table set forth below.[213] The table explains the respective financial responsibilities for the Project, depending on whether: (1) Manitoba Ltd. assigns its interest in the Project to Minnesota Power or (2) Manitoba Ltd. assigns its ownership rights to an independent third party:

[210] Ex. 9 at 28 (CON Application)
[211] Ex. 9 at 8 (CON Application).
[212] Ex. 38 at 8 (Donahue Direct).
[213] Ex. 40 at 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%

142. As summarized below, the testimony provided by Minnesota Power witnesses was not entirely consistent with this table.

i. Five percent CIAC Contribution to Capital Costs

143. Minnesota Power's witnesses confirmed that regardless of whether Minnesota Power or a third party assumes Manitoba Ltd.'s 49 percent share of the Project, Manitoba Hydro will still be required to pay the five percent CIAC payment to Minnesota Power as required by the FCA.[214] Therefore, regardless of the entity assuming Manitoba Ltd.'s shares in the Project, Manitoba Hydro will remain liable for five percent of the Project's capital costs.

ii. Manitoba Ltd.'s 49 percent Share of Capital Costs and O&M Expenses

144. If Minnesota Power assumes Manitoba Ltd.'s shares in the Project, Manitoba Ltd.'s 49 percent share of the capital costs will be converted into a CIAC payment payable from Manitoba Hydro to Minnesota Power.[215] Minnesota Power will

[214] *Id.*
[215] Ex. 40 at 4-5, 8 (Donahue Rebuttal).

record all of the CIAC payments as credits to the construction work in progress, and when the Project is placed into service, the net value will be transferred to plant in-service.[216]

145. Minnesota Power's representative explained that "this accepted accounting treatment [will] maintain the pricing zone neutrality of the Manitoba Hydro assignment to Minnesota Power *and [will] ensure that Minnesota Power retail ratepayers are held harmless for this transaction*."[217] In other words, Minnesota Power claims Manitoba Hydro will remain contractually required to continue to pay Manitoba Ltd.'s 49 percent share of the Project's capital costs, even if Minnesota Power assumes all of Manitoba Ltd.'s share of the Project.[218]

146. What is less clear in the record, however, is what happens with Manitoba Ltd.'s 49 percent share of the O&M expenses upon a transfer of all shares of the Project to Minnesota Power. Minnesota Power appears to assert, but no witness testified to the fact that, Manitoba Hydro will remain liable for 49 percent of the expenses.

147. To address this contingency, the DOC-DER made the following recommendation:

> To ensure that the cost responsibility for [Minnesota Power's] ratepayers is clarified further, I recommend, if the Commission decides to approve the GNTL, that the Commission require [Minnesota Power] to receive prior approval from the Commission if [Minnesota Power] proposes to charge its ratepayers for O&M costs higher than 33%. For example, if [Minnesota Power] or [Minnesota Power's] affiliate, Allete Clean Energy, becomes the assignee, then [Minnesota Power] would need to receive prior approval from the Commission if [Minnesota Power] proposes to charge higher O&M costs to [Minnesota Power's] ratepayers as a result of such an arrangement.[219]

148. The Administrative Law Judge adopts this recommendation as a reasonable one, given the representations made by Minnesota Power in this proceeding and the ambiguity in its witnesses' testimony.

149. A material justification for this Project is that Minnesota Power ratepayers will not be responsible for more than 28.3 percent of the Project's capital costs and 33.3 percent of the O&M expenses. Therefore, Minnesota Power must be held accountable for the representations made in this proceeding.

150. If Minnesota Power ratepayers are suddenly responsible for more than 33.3 percent of the O&M expenses attributable to this Project as a result of a transfer of shares from Manitoba Ltd. to Minnesota Power (or another entity), the financial

[216] *Id.*
[217] Ex. 40 at 5 (Donahue Rebuttal).
[218] *Id.*
[219] Ex. 56 at 7-8 (Rakow Surrebuttal).

justification of the Project would substantially change. Accordingly, a condition in the CON is required to prevent this from occurring.

151. A similar condition should be considered with respect to the transfer of shares from Manitoba Ltd. to a third party.

152. If Manitoba Ltd. transfers all or part of its 49 percent interest in the Project to another MISO transmission owner, Manitoba Hydro has no responsibility for the corresponding shares or financial obligations. In that scenario, Minnesota Power must ensure the new assignee will assume Manitoba' Ltd.'s 49 percent share of both the capital and O&M expenses as part of the transaction.

153. Under the FCA, Minnesota Power retains the right to consent to any transfers by Manitoba Ltd. of its shares in the Project to a third party.[220] Minnesota Power representatives testified that any third party to whom Manitoba Ltd. transfers its shares will have to assume Manitoba Ltd.'s financial obligations for the Project, as well as agree to hold Minnesota Power's pricing zone neutral in order to receive consent from Minnesota Power.[221] As explained by Michael Donahue, Minnesota Power's Transmission Project Development Manager:

> In the event of a transfer of minority interest from Manitoba Hydro to another entity, the FCA requires Minnesota Power's full consent to any such transfer. If Manitoba Hydro was to assign its ownership percentage to another MISO Transmission Owner, the revenue requirements associated with the new minority owner position in the Project would be assigned to the Minnesota Power pricing zone under the MISO tariff and cause a significant increase in the MISO rates … Minnesota Power would find this unacceptable and would not agree to the assignment. Any potential new minority owner will have to agree to hold the Minnesota Power pricing zone neutral as a condition to any consent by Minnesota Power.[222]

154. According to Minnesota Power, the FCA's consent requirement is sufficient to protect Minnesota Power ratepayers from assuming Manitoba Hydro's 49 percent of the Project costs when Manitoba Ltd. transfers its ownership to another entity.[223]

155. Minnesota Power represents to the Commission in this proceeding that it will not consent to any transfer of shares from Manitoba Ltd. to a third party unless the third party assumes all of Manitoba Ltd.'s 49 percent share in the Project expenses (both capital costs and O&M expenses). This is a material representation that Minnesota Power must be held accountable for in the future. Otherwise, Minnesota Power could be saddled with financial liability for the Project well in excess of the 28.3

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[220] *Id.*
[221] *Id.*
[222] *Id.*
[223] Ex. 40 at 8-9 (Donahue Rebuttal).

percent of capital costs and the 33.3 percent of O&M costs asserted in this case. Such a change in financial circumstances would negate the justifications articulated by Minnesota Power for the Project itself.

156. The DOC-DER is also concerned about the impact on ratepayers when Manitoba Ltd. divests its shares.[224] According to Stephen Rakow, Ph.D., the DOC-DER's Public Utilities Rates Analyst:

> I conclude that there is a potential for a rate increase due to a change in ownership. However, since [Minnesota Power] states that the company would object to such an event and because any transfer in ownership would require Commission approval under Minnesota Rules [sic] 7849.0400 to ensure that any rate increase is just and reasonable, I conclude that this issue will be satisfactorily addressed in the future should such an ownership transfer occur.[225]

157. Based upon the representations made by Minnesota Power in this proceeding, the DOC-DER is apparently satisfied that Minnesota Power will fulfill its promises and not consent to a transfer of interest unless the successor assumes full financial responsibility for the transferred shares. As a result, DOC-DER witness Stephen Rakow did not recommend a related condition to be included in the CON.

158. To protect ratepayers if Minnesota Power seeks approval from the Commission for a transfer of ownership of under the CON, the Commission should ensure that the new transmission owner assumes all financial obligations associated with Manitoba Ltd.'s shares in the Project. Otherwise, Minnesota Power could be held liable for a much larger portion of the Project's costs than represented in this proceeding.

iii. 17.7 percent Must Take Fee

159. Minnesota Power affirmatively represents that regardless of a transfer of shares from Manitoba Ltd. to Minnesota Power or another assignee, Manitoba Hydro (the parent company) will continue to be responsible for the monthly Must Take Fee for the duration of the 133 MW ROAs' 20-year contract term.[226] The Must Take Fee due under the 133 MW ROAs represents 17.7 percent of the Project's capital costs and O&M expenses.[227]

160. Both the DOC-DER and the Administrative Law Judge are satisfied with the evidence supporting this representation.

161. In sum, Minnesota Power's representations regarding its percentage of financial obligation for the Project, both in capital costs (28.3 percent) and O&M

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[224] Ex. 56 at 5, 7-8 (Rakow Surrebuttal).
[225] Ex. 56 at 7-8, 10, 11 (Rakow Surrebuttal).
[226] Ex. 40 at 8, Table 3 (Donahue Rebuttal).
[227] Ex. 40 at 7-8 (Donahue Rebuttal).

expenses (33.3 percent), before and after an assignment by Manitoba Ltd., are central to the reasonableness and cost-effectiveness of the Project. Therefore, the Commission should ensure that any future rate or rider proceedings hold Minnesota Power to its representations regarding the potential shift of financial obligations for the Project.

VI. CRITERIA FOR GRANTING A CERTIFICATE OF NEED

162. 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.

163. The CON Statute provides that "[n]o proposed large energy facility shall be certified for construction unless the applicant can show that the demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need."[228]

164. The CON Statute 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 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;

[228] Minn. Stat. § 216B.243, subd. 3 (2014).

> (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.[229]

165. The CON Statute requires the Commission to adopt rules setting forth criteria to be used when determining whether there is a need for such facilities.[230] These rules are set forth in Minnesota Rules Chapter 7849 (CON Rules).[231]

166. The CON Rules provide that a certificate of need must be granted to an applicant if the Commission determines 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:

[229] Minn. Stat. § 216B.243, subd. 3 (2014). In this case, the Parties agreed that sections (10) and (12) of the CON Statute do not apply to the current proceeding. *See* ISSUES MATRIX (December 5, 2014) (eDocket No. 201412-105220-01).
[230] Minn. Stat. § 216B.243, subd. 1 (2014).
[231] Minn. R. ch. 7849 (2013).

(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;

(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.
>
> 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.[232]

167. All four criteria (A-D) set forth in the CON Rule must be established by the applicant.[233]

VII. APPLICATION OF CERTIFICATE OF NEED CRITERIA

A. Adequacy, Reliability or Efficiency of Energy Supply

168. The first criteria Minnesota Power must establish is that the probable result of denial of the CON Application would have an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to Minnesota Power, Minnesota Power's customers, or to the people of Minnesota and neighboring states.[234] In applying this criteria, the Commission must consider the accuracy of Minnesota Power's forecast of demand for the type of energy that would be supplied by the proposed project; the effects of conservation programs on reducing demand; the effects of promotional practices that may have given rise to the increase in energy demand; the ability of current facilities to meet the future demand; and the effect of the proposed project to make efficient use of resources.[235]

1. Accuracy of Forecast for Demand

169. No specific evidence or testimony was presented by Minnesota Power in this proceeding to demonstrate a projected increase in the need for energy or capacity. Rather, the Company relies upon the analyses presented to the Commission in its 2010 Integrated Resource Plan,[236] 2013 Integrated Resource Plan,[237] Petition for Approval of the 250 MW Agreements,[238] and Petition for Approval of the 133 MW ROAs.[239]

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[232] Minn. R. 7849.0120 (2013).
[233] *Id*.
[234] *Id.*
[235] *Id.*
[236] *In the Matter of Minn*esota *Power's Application for Approval of its 2010-2024 Resource Plan*, PUC Docket No. E015/RP-09-1088, PETITION (October 5, 2009).
[237] *In the Matter of Minnesota Power's Application for Approval of its 2013-2027 Resource Plan*, PUC Docket No. E015/RP-13-53, INITIAL FILING – RESOURCE PLAN (March 1, 2013).
[238] *In the Matter of Minnesota Power's Petition for Approval of a 250 MW Power Purchase Agreement with Manitoba Hydro*, PUC Docket No. E015/M-11-938, PETITION (September 16, 2011).
[239] *In the Matter of Minnesota Power's Petition for Approval of a 133 MW Power Purchase Agreement with Manitoba Hydro,* PUC Docket No. E015/M-14-960, PETITION (November 6, 2014).

170. No evidence was presented by the other Parties to this proceeding to negate the accuracy of the forecasts for demand presented by Minnesota Power in the other dockets.

171. Beginning with the Company's 2010 IRP, Minnesota Power's IRPs and Advanced Forecast Reports (AFRs) have indicated the need for additional capacity and energy during the 2020 to 2035 timeframe due to planned mining and industrial expansion on the Iron Range, a portion of the area serviced by Minnesota Power.[240]

172. In its 2010 IRP, Minnesota Power identified capacity and energy needs starting in 2020 driven by customer load growth and diversification of its power supply.[241]

173. To address the anticipated needs, Minnesota Power included action in its 2010 IRP to pursue agreements with Manitoba Hydro and build the new associated transmission to deliver the power by 2020.[242] The purchase of 250 MW of hydropower from Manitoba Hydro and the construction of new transmission systems to transport the power was part of Minnesota Power's least cost, system-wide, long-term supply plan.[243]

174. Upon the Commission's approval of Minnesota Power's 2010 IRP, Minnesota Power entered into the 250 MW Agreements with Manitoba Hydro.[244]

175. The Commission reviewed and approved the 250 MW Agreements in 2012.[245] In its order approving the 250 MW Agreements, the Commission concurred with and adopted the DOC-DER's conclusion that:

> Given [Minnesota Power's] projected capacity and energy deficits over the period 2020 - 2035, it is clear that [Minnesota Power] would need a significant additional amount of peaking capacity and energy to meet its future capacity and energy needs.[246]

176. The Commission also concurred with and adopted the DOC-DER's determination that the 250 MW Agreements "provide the most appropriate resources for [Minnesota Power] to meet its resource needs."[247]

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240 Ex. 43 at 9 (Rudeck Direct).
241 *Id.*
242 *Id.*
243 Ex. 43 at 9-10 (Rudeck Direct).
244 *See In the Matter of Minnesota Power's Petition for Approval of a 250 MW Power Purchase Agreement with Manitoba Hydro*, PUC Docket No. E015/M-11-938, PETITION (September 16, 2011); Ex. 13 (Appendix D to CON Application – Public); Ex. 14 (Appendix D to CON Application – Trade Secret).
245 Ex. 12 at 4 (Appendix C to CON Application).
246 Ex. 12 at 4 (Appendix C to CON Application); Ex. 52 at 4-8 (Shah Direct).
247 Ex. 12 at 5, 25 (Appendix C to CON Application).

177. Given the need for new transmission to deliver this power, the Commission specifically requested that Minnesota Power update the Commission on the progress of new transmission facilities.[248]

178. After the Commission approved the 250 MW Agreements, Minnesota Power's 2013 and 2014 AFRs indicated it still needed to add more capacity to meet the growing energy needs of customers.[249]

179. Due to Minnesota Power's industrial load concentration, the AFRs include multiple industrial load growth scenarios, the Moderate Growth scenario in both the 2013 and 2014 AFR submittals providing the most relevant information for the purpose of this proceeding.[250] According to the 2013 AFR, Minnesota Power projected average annual energy sales growth and average annual peak demand growth of 1.5 percent and 1.2 percent, respectively, from 2013 through 2017.[251] In Minnesota Power's 2014 AFR, it projected annual energy sales and peak demand would grow approximately 1.1 percent on average per year from 2014 through 2028.[252] Based upon these projections, Minnesota Power determined that its need for more energy and capacity exceeded that provided by the 250 MW Agreements.[253]

180. In March 2013, Minnesota Power filed for approval of its 2013 Integrated Resource Plan (2013 IRP) with the Commission.[254] The 2013 IRP documented the Company's plan to: (1) remove Taconite Harbor Unit 3 from the system by 2015; and (2) refuel Laskin Units 1 and 2 to operate on natural gas by 2015.[255]

181. The Commission determined that as a result of Minnesota Power's proposed retirement of Taconite Harbor Unit 3, Minnesota Power would need an additional 50 MW of capacity in 2015 and an additional 100 MW of capacity by 2019.[256] Therefore, the Commission determined that Minnesota Power's capacity and energy needs would exceed that provided for in the 250 MW Agreements.[257] The Commission ordered:

> Minnesota Power shall obtain approximately 200 MW, subject to need, of intermediate capacity (and associated energy) in the 2015 – 2017 timeframe by constructing the resource itself, by sharing in the ownership

[248] *Id*.
[249] Ex. 18 (Appendix H to CON Application); Ex. 43, Schedule 1 (Rudeck Direct).
[250] Ex. 43 at 10-13 (Rudeck Direct).
[251] Ex. 18 at 1 (Appendix H to CON Application).
[252] Ex. 43, Schedule 1 at 1 (Rudeck Direct)
[253] Ex. 43 at 10-13 (Rudeck Direct).
[254] *In the Matter of Minnesota Power's Application for Approval of its 2013-2027 Resource Plan*, PUC Docket No. E015/RP-13-53, INITIAL FILING – RESOURCE PLAN (March 1, 2013).
[255] *Id.*
[256] *In the Matter of Minnesota Power's Application for Approval of its 2013-2027 Resource Plan*, PUC Docket No. E015/RP-13-53, ORDER APPROVING RESOURCE PLAN, REQUIRING FILINGS, AND SETTING DATE FOR NEXT RESOURCE PLAN (November 12, 2013).
[257] *Id.*

of the resource, or by procuring the resource through bilateral contracts, whichever option is most cost-effective.[258]

182. The Company's 2013 IRP did not identify the need for the 133 MW ROAs.

183. It is unclear from the record whether the execution of the 133 MW ROAs is in response to the need for additional energy cited in the Commission's order approving Minnesota Power's 2013 IRP.[259]

184. Nonetheless, the Commission approved the 133 MW ROAs in January 2015, adopting the DOC-DER's recommendation and ultimate conclusion that the 133 MW ROAs are needed to meet Minnesota Power's need for additional energy and capacity.[260]

185. In this proceeding, the DOC-DER did not perform an analysis of the 2010 AFR or 2013 AFR, nor did it develop alternative forecasts to determine if Minnesota Power has a need for energy and capacity. Rather, the DOC-DER concluded that the issue of need has been adequately reviewed and accepted by the Commission in the 2010 Resource Plan Docket, 250 MW PPA Docket, and 2013 Resource Plan Docket.[261] Therefore, the DOC-DER summarily concurs with Minnesota Power that a need exists for the proposed Project.[262]

186. Neither LPI nor RRANT presented testimony or evidence negating Minnesota Power's forecast of demand or Minnesota Power's stated need for additional energy and capacity starting in 2020.

187. Based upon the evidence presented, Minnesota Power has established, by a preponderance of the evidence, that there is a need for additional energy and capacity in the 2020 - 2035 timeframe, and that a denial of the CON Application would likely adversely affect the future adequacy of the energy supply to Minnesota Power and its customers.

2. Effect of Conservation Programs to Meet Need

188. According to the DOC-DER, conservation programs were "weighed as an alternative to the [250 MW Agreements] before the Commission approved those agreements."[263] During the proceeding to approve the 250 MW Agreements, the DOC-DER determined that conservation programs would not be sufficient to negate the need for Minnesota Power to procure additional energy and capacity.[264] Therefore, the DOC-

[258] *Id.*
[259] Ex. 43 at 15-16 (Rudeck Direct).
[260] *In the Matter of Minnesota Power's Petition for Approval of a 133 MW Power Purchase Agreement with Manitoba Hydro,* PUC Docket No. E015/M-14-960, ORDER (January 30, 2015).
[261] Ex. 52 at 3-11 (Shah Direct).
[262] *Id.*
[263] Ex. 53 at 20-21 (Rakow Direct).
[264] *Id.*

DER did not conduct additional review of a conservation alternative in this proceeding.[265]

189. The DOC-DER further explained that the interface between Manitoba and the United States is unable to accommodate the increased transfer of energy contemplated by the 250 MW Agreements, which is required under the Commission-approved Manitoba Hydro Agreements.[266] Therefore, the DOC-DER concludes that conservation is essentially irrelevant to the need for additional facilities to transport the power being purchased from Manitoba Hydro.[267]

190. Minnesota Power contends that its conservation programs are insufficient to reduce the demand for additional energy and capacity currently being faced. According to Minnesota Power, its Conservation Improvement Program (CIP) is "an integral part of its resource planning."[268] Minnesota Power'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.[269]

191. Since 2010, Minnesota Power's CIP efforts have led to results surpassing the 1.5 percent annual savings goal set by Minnesota law, saving 77,630 MWh in 2013.[270] Minnesota Power asserts that these conservation levels are built into Minnesota Power's IRPs, AFRs, and other resource acquisition proceedings, including the Commission docket approving the 250 MW Agreements.[271]

192. Minnesota Power represents that it will continue to implement conservation programs to maximize efficient use of electricity.[272] Minnesota Power asserts, however, that these programs cannot slow load growth sufficiently to mitigate Minnesota Power's need for additional capacity and energy from Manitoba Hydro.[273]

193. The DOC-DER concurs with Minnesota Power's determination,[274] and neither LPI nor RRANT provided evidence disputing the Company's claims. Therefore, Minnesota Power has established that conservation programs will not reduce the Company's current need for additional electricity and capacity.

3. Effect of Promotional Activities on Need

194. There was no evidence presented to show that Minnesota Power has engaged in promotional activities to encourage the use of more power.[275] Rather the

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[265] *Id.*
[266] *Id.*
[267] *Id.*
[268] Ex. 43 at 32 (Rudeck Direct).
[269] Ex. 21 (Appendix K to CON Application).
[270] Ex. 43 at 32 (Rudeck Direct).
[271] Ex. 21 (Appendix K to CON Application); Ex. 53 at 21 (Rakow Direct).
[272] Ex. 9 at 107 (CON Application).
[273] Ex. 21 (Appendix K to CON Application); Ex. 9 at 107 (CON Application).
[274] Ex. 53 at 20-21 (Rakow Direct).
[275] Ex. 9 at 15 (CON Application).

evidence demonstrates that the Project is a response to an increased need for capacity and energy due, in part, to economic growth on the Iron Range and, in larger part, to Minnesota Power's overall strategy of incorporating more renewable energy into its portfolio.[276]

195. The Project is an integral part of Minnesota Power's Energy*Forward* strategy of lessening dependence on coal-fired facilities, diversifying its supply portfolio, and integrating significant additions of wind and other renewable energy resources.[277] This approach minimizes Minnesota Power's and its customers' exposure to the risk of future emissions regulations.[278]

196. The DOC-DER did not evaluate whether Minnesota Power has engaged in promotional practices that have given rise to the increase in energy demand. Instead, the Department addressed whether Manitoba Hydro has engaged in promotional activities that have given rise to the need for the Project.[279] The Department concluded that, first, Manitoba Hydro is not an applicant for the CON, and hence its promotional activities are irrelevant.[280] Second, the Department notes that while Manitoba Hydro "may have marketed their brand of energy," it has not promoted increased demand overall.[281] Thus, the Department concluded that promotional practices have not created the need for the Project.[282]

197. Neither LPI nor RRANT presented specific evidence that Minnesota Power's promotional activities have given rise to the increased demand for energy in the region.

198. Therefore, the evidence presented in this case does not establish that Minnesota Power's promotional activities have given rise to the increased demand for energy in the state or region.

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[276] *Id.*
[277] *Id.*
[278] Ex. 43 at 13-14 (Rudeck Direct).
[279] Ex. 53 at 13 (Rakow Direct).
[280] *Id.*
[281] *Id.*
[282] *Id.*

4. Ability of Current Facilities to Meet State and Regional Energy Needs

199. Minnesota Power determined that its current transmission resources cannot facilitate the energy exchanges contemplated by the Manitoba Hydro Agreements.[283] As a result, Minnesota Power examined whether upgrades to its current transmission facilities, or double circuiting existing lines, would enable it to service the additional energy and capacity provided for in the Manitoba Hydro Agreements.[284] It concluded that neither option was an acceptable alternative.[285]

200. The current interface between Manitoba and the United States consists of three 230 kV lines and the Dorsey-Forbes 500 kV line.[286] The three 230 kV lines from Manitoba to the United States are: (1) the G82R Line from Glenboro, Manitoba, to Rugby, North Dakota; (2) the L20D Line from Letellier, Manitoba, to Drayton, North Dakota; and (3) the R50M Line from Richer, Manitoba, to Moranville, Minnesota.[287] The 500 kV line is the Dorsey-Forbes Line (also known as the D602F Line), which originates at the Dorsey Substation near Winnipeg, Manitoba, and connects to the Forbes Substation near Duluth, Minnesota.[288] Another 500 kV line continues from the Forbes Substation to the Chisago Substation near the Minneapolis/St. Paul metropolitan area.[289]

201. According to Minnesota Power, the current Manitoba to United States interface is unable to accommodate the increased transfer capacity resulting from the Manitoba Hydro Agreements without upgrades or new transmission development to alleviate overload on the Roseau series capacitors.[290]

202. 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.[291] Because the Forbes-Dorsey 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, thereby requiring increased capacity on the line.[292]

203. The current intact capability on the Manitoba-United States interface is 2,175 MW.[293] Studies have shown that above the 2,175 MW transfer level, overloads will occur on the Roseau series capacitors.[294] The Roseau capacitors are an element

[283] Ex. 34 at 10 (McMillan Direct).
[284] Ex. 9 at 73-75 (CON Application).
[285] *Id.*
[286] Ex. 42 at 9 (Winter Direct).
[287] Ex. 42 at 11 (Winter Direct).
[288] *Id.*
[289] *Id.*
[290] *Id.*
[291] Ex. 42 at 11 (Winter Direct).
[292] Id.
[293] Ex. 42 at 9-10 (Winter Direct).
[294] *Id.*

of the existing Dorsey-Forbes 500 kV Line, required for the reliable and efficient operation of the line.[295]

204. Currently, the flow limit on the Forbes-Dorsey Line is based on the 2,000 amp (1,732 MVA) rating of the Roseau series capacitors and line terminal equipment.[296] According to Minnesota Power:

> While it is technically feasible to increase the rating of D602F from 2,000 amps to 2,500 amps (2165 MVA) by upgrading the Roseau series capacitors, this 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 D602F beyond its existing capacity.[297]

205. Moreover, an unplanned outage of the Forbes-Dorsey 500 kV tie line is the second largest contingency in the entire MISO footprint.[298] Increasing the total Manitoba to United States transfer capability by increasing the capacity of the Forbes-Dorsey Line exacerbates this contingency.[299] Therefore, upgrading current facilities to accommodate the energy and capacity needed as a result of the Manitoba Hydro Agreements would likely decrease the reliability of the system as a whole.[300]

206. With respect to double circuiting the existing lines, Minnesota Power explained there are only two lines that could be double circuited: the Richer-Morganville 230 kV Line (R50M) and the Dorsey-Forbes Line.[301] From a reliability perspective, "double circuiting is typically avoided because a common structure failure could result in the loss of both lines."[302]

207. Double circuiting also creates maintenance constraints if only one line can be de-energized at a given time.[303] Since both the R50M and Dorsey-Forbes Lines are tie lines between Manitoba and the United States, it would not be acceptable to de-energize both at the same time for maintenance purposes.[304]

208. Furthermore, because double circuiting an existing line is typically proposed as a method of limiting the proliferation of new transmission corridors, double circuiting often requires an extended outage of the existing line to construct the new double circuited line in its place.[305] According to Minnesota Power, an extended outage

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[295] *Id.*
[296] *Id.*
[297] Ex. 42 at 11-12 (Winter Direct).
[298] *Id.*
[299] *Id.*
[300] *Id.*
[301] Ex. 42 at 17 (Winter Direct).
[302] *Id.*
[303] Ex. 42 at 17 (Winter Direct).
[304] *Id.*
[305] Ex. 42 at 17-18 (Winter Direct).

of one of the four existing Manitoba tie lines during the 48 months it will take to construct the Project would not be acceptable.[306] Therefore, a new double circuited 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.[307] Either of these options would add cost to the Project and defeat the environmental purpose for double circuiting.[308]

209. Neither LPI nor RRANT presented evidence to show that current facilities or other facilities not requiring certificates of need could be used to meet the energy demand or facilitate the energy exchanges contemplated by the Manitoba Hydro Agreements.

210. Therefore, Minnesota Power has established by a preponderance of the evidence that its current facilities cannot meet the future demand, and that the construction of facilities not requiring a CON are similarly insufficient to meet the demand.

5. Effect of Project in Making Efficient Use of Resources and Meeting State and Regional Energy Needs

211. The evidence presented in this case demonstrates that the Project will make efficient use of resources by allowing Minnesota Power to exchange wind energy for hydro energy and reduce Minnesota Power's reliance on coal-based energy, while at the same time giving Minnesota Power the ability to meet future regional energy needs.

212. 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.[309]

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[306] *Id.*
[307] *Id.*
[308] *Id.*
[309] PUBLIC COMMENTS at EXS. C, J (December 4, 2014) (eDocket No. 201412-105176-01).

213. By increasing transfer capability between Canada and the United States, the Project will provide Minnesota, as well as regional utilities, increased access to Manitoba Hydro hydropower.[310]

214. Manitoba Hydro has a history of energy trading with multiple state and regional utilities, including Xcel Energy, Great River Energy, and Wisconsin Public Service.[311] Manitoba Hydro is currently engaged in a significant development plan that will support increased energy trading with Minnesota Power and other United States utilities.[312] Manitoba Hydro's approved development plan includes construction of the 695 MW Keeyask Generating Station, which began in July 2014.[313] This development plan also includes the Manitoba Hydro transmission facilities necessary to meet the Project at the United States – Canada border, providing the transmission capacity for new export sales.[314]

215. The Project, together with the Canadian portion of the new interconnection being constructed by Manitoba Hydro, would 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.[315]

216. There are various Transmission Service Requests (TSRs) between MISO and Manitoba Hydro involving Minnesota Power and Wisconsin Public Service (WPS). The WPS TSRs indicate the potential need for more transmission capacity in addition to the capacity required for the Manitoba Hydro Agreements.[316]

217. The Project will facilitate the addition of new wind generation and reduce curtailment of those wind resources. According to 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, meaning increased efficiency of the energy supply system as a whole.[317]

218. 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."[318] 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.[319]

[310] Ex. 43 at 28-29 (Rudeck Direct).
[311] *See* Ex. 34 at 8-9, 21 (McMillan Direct).
[312] Ex. 34 at 10-12 (McMillan Direct).
[313] *Id.*
[314] *Id.*
[315] *Id.*
[316] Ex. 52 at 12 (Shah Direct)
[317] Ex. 41 at 7-8 (Hoberg Direct); Ex. 19 (Appendix I to CON Application).
[318] Ex. 34 at 9 (McMillan Direct).
[319] *Id.*

219. By facilitating more energy trading, the Project has the potential to bring more load balancing benefits, thereby increasing the efficiency of the overall supply system while also reducing state and regional utilities' need to depend on carbon-emitting natural gas resources.[320]

220. The Project will further provide incremental export capability for hydroelectric resources generated in Manitoba, without inherently limiting potential transmission outlet capability for other resources.[321] The Project will alleviate the main thermal constraint associated with the North Dakota – Manitoba "loop flow" phenomenon, and thereby facilitate less interaction between power generated in North Dakota and power generated in Manitoba.[322] As a result, the Project will enable the wind-hydropower synergy described in the MISO Manitoba Hydro Wind Synergy Study[323] without creating other adverse consequences.[324]

221. Minnesota Power asserts no other significant transmission project addressing the United States – Manitoba interconnection currently exists that can provide the state and regional benefits provided by the Project.[325]

222. Neither LPI nor RRANT directly challenged the ability of the proposed Project to make efficient use of resources. RRANT argued, however, that the proposed Project is only part of a larger project modeled and studied by MISO.[326] RRANT asserts that the regional benefits claimed by Minnesota Power are only possible if the line extends to the Arrowhead Substation in Duluth or into Michigan.[327] However, RRANT provided no evidence and offered no testimony in support of its claim that the Project will not provide the regional benefits described by Minnesota Power's witnesses.

223. The only evidence presented related to efficient use of resources and the ability of the Project to meet larger, regional energy needs was presented by Minnesota Power and its witnesses. Therefore, Minnesota Power has established by a preponderance of the evidence that the effect of the proposed Project will make efficient use of resources.

B. Analysis of Reasonable and Prudent Alternatives

224. As required by Minnesota Rule 7849.0120, subpart B, Minnesota Power and the DOC-DER evaluated whether there is a more reasonable and prudent alternative to the proposed Project. Minnesota Power and the DOC-DER evaluated energy generation alternatives, alternative voltages for the proposed line, alternative endpoints for the line, double circuiting existing lines, installing a direct circuit (DC) line,

[320] *Id.*
[321] Ex. 42 at 8 (Winter Direct); Ex. 62 (Response to DOC IR 8).
[322] *Id.*
[323] Ex. 19 (Appendix I to CON Application).
[324] Ex. 42 at 8 (Winter Direct); Ex. 62 (Response to DOC IR 8).
[325] Ex. 43 at 28-29 (Rudeck Direct).
[326] RRANT Initial Post Hearing Brief at 5-14.
[327] *Id.*

and undergrounding a new line. Both Minnesota Power and the DOC-DER concluded that none of the alternatives examined were a more reasonable or prudent alternative to the proposed Project.[328]

1. Generation Alternatives

225. The primary basis for the Project's need is to allow Minnesota Power to accept the power provided for under the Manitoba Hydro Agreements. The Company entered into the 250 MW Agreements after conducting analyses considering market purchases, advanced coal-fired generation, combustion gas turbines, and combined cycle gas turbines, other renewable generation; and demand-side management and conservation across a wide range of future energy industry assumptions and sensitivities.[329]

226. Using a Strategist Model for the screening of reasonable alternatives, Minnesota Power concluded that a natural gas-fired combined cycle unit is the only reasonable alternative to the hydropower provided under the 250 MW Agreements.[330] That analysis, however, did not incorporate the financial benefits to Minnesota Power and its ratepayers of the 133 MW ROAs and the FCA because Minnesota Power and Manitoba Hydro had not yet entered into those transactions.

227. LPI presented evidence that, over 40 years, the estimated cost of a natural gas-fired combined cycle alternative would be approximately $52.90/MWh and the estimated cost of the 250 MW Agreements would be approximately $51.30/MWh, in 2011 dollars.[331] Therefore, the costs of the two alternatives are relatively close.

228. According to Minnesota Power, in comparison to a natural gas plant, the 250 MW Agreements will provide more price certainty and mitigate carbon risks in Minnesota Power's future power supply.[332] Additionally, when combined with Minnesota Power's wind supply portfolio, the 250 MW Agreements will bring a flexible energy supply with base load characteristics.[333]

229. In reviewing the 250 MW Agreements, the DOC-DER and the Commission found that the agreements "provide the most appropriate resources for [Minnesota Power] to meet its resource needs" during the 2020 to 2035 time period.[334]

230. Minnesota Power also examined the potential for distributed generation or community-based energy development (C-BED) projects to meet the needs addressed by the Project.[335] While Minnesota Power is exploring distributed generation and C-BED opportunities, it asserts that any resources Minnesota Power or its customers may

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[328] Ex. 6 at 29 (Environmental Report).
[329] Ex. 43 at 29-30 (Rudeck Direct).
[330] Ex. 43 at 30 (Rudeck Direct).
[331] Ex. 50 at 8 (Kollen Direct – Trade Secret).
[332] Ex. 43 at 30 (Rudeck Direct).
[333] Ex. 43 at 29-30 (Rudeck Direct).
[334] Ex. 12 at 5, 25 (Appendix C to CON Application).
[335] Ex. 43 at 31-32 (Rudeck Direct); Ex. 53 at 19-20 (Rakow Direct)

develop cannot displace the need for the Project and the 383 MW of hydropower it enables Minnesota Power to receive.[336]

231. The DOC-DER 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 [Manitoba Hydro Agreements]. . . . Therefore, the generation alternatives do not need to be considered further" in this proceeding.[337]

2. Transmission Alternatives

a. Alternative Voltages

232. Minnesota Power evaluated three alternative voltage scenarios to replace the proposed 500 kV line: (1) a 230 kV line; (2) a 345 kV line; and (3) a 765 kV line.[338] For the reasons discussed below, each of the voltage alternatives failed to provide a preferable alternative to the proposed Project.[339]

233. RRANT argues that the proposed Project is "grossly oversized" to meet the 383 MW need presented by the Manitoba Hydro Agreements, which form the basis for Minnesota Power's CON Application.[340]

i. 230 kV Line Alternative

234. According to the DOC-DER, a 230 kV line would likely be sufficient to accommodate the additional power transmissions required by the Manitoba Hydro Agreement.[341] Minnesota Power asserts, however, that a 230 kV line may not be able to provide sufficient transmission capacity for Minnesota Power to support the Manitoba Hydro Agreements.[342] The evidentiary record is unclear with respect to this claim.

235. According to the 2013 "MH-US TSR Sensitivity Analysis Draft Report (Eastern Plan)" prepared by MISO, 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.[343] However, it is unclear from the record whether or not the 230 kV line could facilitate the total incremental transfer capability required by the 383 MW to be delivered under the Manitoba Hydro Agreements.[344] It is also unclear from the record

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[336] Ex. 43 at 31 (Rudeck Direct); Ex. 9 at 72-73 (CON Application).
[337] Ex. 53 at 20 (Rakow Direct).
[338] Ex. 42 at 13-15 (Winter Direct).
[339] *Id.*
[340] RRANT Initial Post-Hearing Brief at 1, 16-17.
[341] Ex. 53 at 17 (Rakow Direct).
[342] Ex. 41 at 14 (Hoberg Direct).
[343] Ex. 42 at 14 (Winter Direct), Ex. 30 (Appendix Q to CON Application).
[344] *Id.*

whether or not stability constraints would exist at either the 250 MW or 383 MW incremental transfer levels.[345]

236. But even assuming a 230 kV line would be sufficient from an operational perspective, Minnesota Power explained that a 230 kV alternative would not be cost effective for customers, would not meet the long-term needs of the region, and would not be environmentally preferable over the long-run.[346]

237. A major part of Minnesota Power's justification for the Project is that ratepayers would only be responsible for 28.3 percent of the capital costs of the Project (estimated to be between $158 million and $201 million in 2013 dollars), as well as for a third of the O&M costs of the new 500 kV line.[347] The reduction in Minnesota Power's responsibility for capital expenses and O&M costs is due to agreements with Manitoba Hydro which are premised upon Minnesota Power building a 500 kV line, as opposed to a 230 kV line, capable of transmitting 883 MW of power.[348]

238. Under Minnesota Power's analysis, a 230 kV line would cost between $277 million and $355 million.[349] However, unlike the proposed 500 kV line, Minnesota Power and its customers would bear 100 percent responsibility for the capital costs of a 230 kV line, as well as full responsibility for the operations and maintenance costs.[350] Presumably, this is because Manitoba Hydro would not agree to additional cost contributions if the Project could not increase its ability to transfer energy beyond that needed by Minnesota Power.

239. Based upon Minnesota Power's most recent cost estimates, the Project will add $30.1 million in MISO revenue requirements in the first year of operation.[351] In contrast, a stand-alone 230 kV line would add $52.2 million in additional revenue requirements to Minnesota Power's MISO rates.[352] Thus, a 500 kV line has lower MISO revenue requirements than a 230 kV line due to the specific financial agreements reached between Manitoba Hydro and Minnesota Power requiring the construction of a 500 kV line.[353]

240. The DOC-DER concurred that the Project "would have far lower revenue requirements than a stand-alone 230 kV transmission line" due to Manitoba Hydro's contractual contributions to capital costs of the 500 kV line provided for in the Manitoba Hydro Agreement[354] With respect to operation and maintenance costs for a 230 kV line, the DOC-DER concluded that the cost differential between the Project and a 230

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[345] *Id.*
[346] Ex. 53 at 15-16 (Rakow Direct).
[347] Ex. 34 at 19 (McMillan Direct).
[348] Ex. 38 at 12-13 (Donahue Direct); Ex. 34 at 19 (McMillan Direct).
[349] Ex. 38 at 12-13 (Donahue Direct).
[350] *Id.*
[351] Ex. 38 at 15 (Donahue Direct).
[352] *Id.*
[353] *Id.*
[354] Ex. 53 at 38 (Rakow Direct).

kV are "too small to change the overall conclusion" that the 500 kV line is the more reasonable alternative.[355]

241. The DOC-DER further opined that "a 500 kV transmission line would have a lower internal cost and lower line losses, and thus [lower] societal cost, than the 230 kV alternative."[356] As a result, the DOC-DER determined that 500 kV is "the preferred voltage" for the proposed Project.[357]

242. Finally, the evidence presented establishes that a 230 kV line could not provide the same long-term benefits that a 500 kV line can offer. According to Minnesota Power, the demand for power in certain areas of the Upper Midwest will increase over the next decade.[358] Interest in Canadian hydropower is expected to continue as utilities like Minnesota Power seek to decrease their reliance on fossil-based energy and increase their use of renewable energy sources.[359] Developing a transmission solution now that can deliver substantial hydropower to northern Minnesota and 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.[360]

243. From an environmental perspective, building a higher voltage project now will reduce the need for future transmission expansions and should limit the proliferation of new transmission line corridors in the future, both of which have human and environmental impacts.[361]

244. Accordingly, a preponderance of the evidence establishes that a 230 kV is not a more reasonable and prudent alternative to the proposed 500 kV line.

ii. 345 kV Line Alternative

245. With respect to a 345 kV alternative, Minnesota Power did not explain whether a new 345 kV line would meet its needs under the Manitoba Hydro Agreement. Instead, Minnesota Power determined that a 345 kV line would be inferior simply because it does not have the same capacity as a single 500 kV line.[362] Minnesota Power asserts that it would have to double circuit a 345 kV line to obtain the same benefits of a 500 kV line, and would therefore have similar construction costs to a 500 kV line.[363] Minnesota Power further notes there is no existing 345 kV equipment in the Winnipeg area where the line originates, resulting in the need for new substation equipment at the Canadian endpoint.[364] Because the 500kV line is compatible with the

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[355] Ex. 53 at 38-39 (Rakow Direct).
[356] Ex. 53 at 38-42 (Rakow Direct); Tr. Vol. 2 at 80-81 (Rakow).
[357] *Id.*
[358] Ex. 42 at 13 (Winter Direct).
[359] Ex. 9 at 76 (CON Application).
[360] Ex. 42 at 13 (Winter Direct).
[361] Ex. 9 at 76 (CON Application).
[362] Ex. 42 at 14-15 (Winter Direct).
[363] *Id.*
[364] *Id.*

Canadian facilities, a new substation at the Canadian endpoint is not required for the Project.[365]

iii. 765 kV Line Alternative

246. A 765 kV alternative also fails to provide a reasonable alternative. Because there is currently no 765 kV transmission infrastructure in MISO north of Illinois, expensive transformation would be required at each substation to interconnect a 765 kV line with existing transmission facilities systems in Manitoba and Minnesota.[366] 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 case as compared to a 500 kV line build.[367] In addition, a 765 kV line is substantially larger than is necessary to accommodate Minnesota Power's needs under the Manitoba Hydro Agreements.[368]

247. The DOC-DER did not independently evaluate the use of a 345 kV or 765 kV line. Instead, the DOC-DER merely concluded that Minnesota Power's "screening analysis of higher and lower voltages in the Petition is reasonable."[369]

b. Alternative Endpoints

248. In its CON Application, Minnesota Power provided a detailed discussion of the Fargo Area Study Concept (Concept), a hypothetical transmission line traveling a more westerly route than the Project.[370] The end point of the line under the Concept would be in Barnesville, Minnesota, and a different Canadian border crossing point would be used.[371]

249. The transmission line proposed within the Concept would be sited entirely in Otter Tail Power Company's (OTP's) MISO pricing zone, causing utilities in OTP's zone to be responsible for payment of the costs.[372] These utilities include OTP, Missouri River Energy Services (MRES), and Great River Energy (GRE), but not Minnesota Power.[373]

250. Because none of the ratepayers from OTP, MRES, and GRE are triggering the need for the line, the DOC-DER believes the Concept would represent "a significant misallocation of costs."[374] In addition, because the Concept would interconnect with the CapX Fargo line, GRE, MRES, Xcel Energy, and OTP could all

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[365] *Id.*
[366] Ex. 42 at 15 (Winter Direct).
[367] *Id.*
[368] *Id.*
[369] Ex. 53 at 17 (Rakow Direct).
[370] Ex. 9 at 77-104 (CON Application).
[371] Ex. 53 at 47-49 (Rakow Direct).
[372] *Id.*
[373] *Id.*
[374] Ex. 53 at 47-49 (Rakow Direct).

eventually elect to own a share of the line.[375] Therefore, ownership of a line with a Barnesville end point would not be known until after MISO approves the project and ownership elections are finalized.[376]

251. According to Minnesota Power, the Concept 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 not required for the Project.[377]

252. Moreover, it is 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 in-service on June 1, 2020 because no entity has yet indicated a willingness to develop and fund such a line.[378]

253. Given the utility service territories traversed by the Concept's transmission line, the DOC-DER concluded:

> [T]he [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.[379]

254. Minnesota Power also considered terminating the Project's 500 kV Line at either the Shannon or Forbes substations in Minnesota.[380] The Company's engineering and siting review found that both the Shannon and Forbes Substations would be inferior long-term solutions compared to the Blackberry Substation.[381]

255. Neither the Shannon nor the Forbes Substation provide as much 230 kV transmission line outlet capacity as the Blackberry Substation, and neither substation performed as well electrically as the Blackberry Substation in preliminary power flow studies.[382] Moreover, the locations of the Shannon and Forbes Substations present impediments to the Project. The Shannon Substation is located adjacent to an active mine on leased property, and investing in a significant new infrastructure on leased land is a risky undertaking.[383] The Forbes Substation is located south of the Iron Range formation, among active mines.[384] As a result, the most feasible locations for crossing the Iron Range formation would be further west near Grand Rapids.[385] Consequently, a

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[375] *Id.*
[376] *Id.*
[377] Ex. 42 at 15-16 (Winter Direct).
[378] Ex. 42 at 16 (Winter Direct).
[379] Ex. 53 at 49 (Rakow Direct).
[380] Ex. 9 at 104-105 (CON Application); Ex. 42 at 16 (Winter Direct).
[381] Ex. 42 at 16 (Winter Direct).
[382] *Id.*
[383] *Id.*
[384] Ex. 42 at 16-17 (Winter Direct).
[385] *Id.*

Forbes endpoint would increase the overall length of the line, thereby increasing the overall human and environmental impacts as well as the cost of the Project.[386]

c. Other Transmission-Related Alternatives

256. Minnesota Power also evaluated double circuiting existing lines, installing a DC Line, and undergrounding the new line. The evidence presented in this case establishes that each of these alternatives is a less reasonable alternative than a new 500 kV line as proposed in the Project.

257. As discussed above, the unrefuted evidence in the record establishes that double circuiting the existing lines would not be a reasonable or prudent alternative to the Project because it would be less reliable, create maintenance constraints, present a higher risk of line loss, and require an extended outage.[387] In addition, double circuiting in this situation could be more costly from both a monetary and environmental perspective.[388]

258. Minnesota Power also considered a high voltage DC line as they typically have lower line losses than AC lines of the same length.[389] According to Minnesota Power's expert witness, 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.[390] Given the costs of DC transmission, the break-even line length at which DC becomes economically feasible compared to AC transmission is generally between 400 and 500 miles.[391] The total length of the Project plus its Canadian counterpart will be less than 400 miles.[392] Accordingly, Minnesota Power determined that a DC alternative would not be economically justified and could add to the total cost of the Project.[393]

259. Moreover, Minnesota Power asserts that a new DC line into Manitoba could create technical issues for Manitoba Hydro.[394] Given the additional cost of a DC line and the potential technical issues related to connection with foreign facilities, a DC line would not provide a more reasonable and prudent alternative than the Project.[395]

260. Finally, Minnesota Power evaluated building the proposed 500 kV line underground.[396] According to Minnesota Power's expert witness, underground high voltage transmission lines can often impose higher engineering and construction costs

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[386] *Id.*
[387] *Id.*
[388] *Id.*
[389] Ex. 42 at 18 (Winter Direct).
[390] *Id.*
[391] *Id.*
[392] *Id.*
[393] *Id.*
[394] Ex. 42 at 19 (Winter Direct).
[395] *Id.*
[396] Ex. 42 at 19 (Winter Direct).

than overhead lines, especially for a line of this size and length.[397] 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.[398] Given these drawbacks, Minnesota Power determined that undergrounding the entire line does not provide a preferable alternative to the Project.[399]

261. No other party presented evidence that double circuited lines, a DC line, or an underground line would be a more prudent or reasonable alternative to the 500 kV line proposed in the Project.

3. Analysis of Alternatives Considering External and Internal Costs

262. Minnesota Rule 7849.0120, subpart B(3), requires that the Commission consider "the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives."

263. Minnesota Power did not include the Commission's existing environmental externality values when it compared the cost calculations for the various alternatives.[400]

264. According to the DOC-DER, application of the Commission's externality values slightly improves the economics of the proposed Project in comparison with other options.[401] Therefore, the DOC-DER does not oppose Minnesota Power's analysis.[402] However, the DOC-DER recommended that the Commission order Minnesota Power to use the Commission's externality values in all future CON proceedings.[403] Minnesota Power agreed to this recommendation.[404]

265. The DOC-DER further recommended that the Commission's CO_2 regulation cost estimates, developed pursuant to Minnesota Statutes section 216H.06, be applied to the cost calculations in all future transmission CON proceedings to ensure CO_2 and other emission costs are reasonably considered in resource selections.[405]

266. Consideration of the Commission's externality and CO_2 regulation cost estimates indicates a slight benefit for the Project but does not materially change the analysis of line losses.[406]

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397 *Id.*
398 *Id.*
399 *Id.*
400 Ex. 53 at 43 (Rakow Direct).
401 *Id.*
402 *Id.*
403 *Id.*
404 Ex. 35 at 8-9 (McMillan Rebuttal).
405 Ex. 53 at 43–44 (Rakow Direct).
406 Ex. 53 at 44-45 (Rakow Direct).

267. In sum, no other party presented evidence that a more reasonable and prudent alternative to the proposed Project exists. Therefore, the Administrative Law Judge concludes that a more reasonable and prudent alternative to the proposed Project has not been established by a preponderance of the evidence.

C. Evaluation of the Environmental and Socioeconomic Impacts of the Proposed Project

268. Minnesota Rule 7849.0120C requires that the Commission consider whether an applicant has established, by a preponderance of the evidence, that the proposed project will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health. In making this determination, the Commission must consider the relationship of the proposed project to the overall state energy needs; the effects of the proposed project upon the natural and socioeconomic environments compared to the effects of not building the facility; the effects of the proposed project in inducing future development; and the socially beneficial uses of the output of the proposed facility, including its uses to protect or enhance environmental quality.[407]

269. The Project was the subject of a thorough and coordinated environmental review by the DOC-EERA.[408] As part of the current proceeding, the DOC-EERA created an Environmental Report (ER).[409] The ER examined potential issues related to air quality; biological resources; cultural, archaeological and historic resources; soils, geology, and physiography; human health and safety; radio and telecommunication interference; land use; noise; socioeconomics; property values; aesthetics; and water resources.[410] According to the ER, the Project will be compatible with the human and natural environment.[411]

270. The ER concluded that there will be minimal air quality impacts and minor impact to biological resources in the Project area as a result of the transmission line construction and operation.[412] While a small amount of vegetation will be permanently removed at each structure location and some wildlife temporarily displaced or impacted (such as birds), the DOC-EERA concluded these impacts can be appropriately mitigated as part of the Project.[413] In addition, the impact to soils will be temporary and can be adequately minimized.[414]

271. With respect to human impacts, the ER identified no specific cultural, historic, or archeological impacts associated with the Project.[415] The ER addressed the general impact of high voltage transmission lines to human health and safety, including

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[407] Minn. R. 7849.0120C (2013).
[408] Ex. 6 (Environmental Report)
[409] *Id.*
[410] *Id.*
[411] Ex. 37 at 11-12 (Atkinson Direct).
[412] Ex. 6 at 32-36 (Environmental Report).
[413] *Id.*
[414] Ex. 6 at 37-39 (Environmental Report).
[415] Ex. 6 at 36-37 (Environmental Report).

the exposure to electromagnetic fields (EMFs) and stray voltage.[416] The ER concluded that research has not been able to establish a cause and effect relationship between exposure to EMFs and adverse health effects.[417] With respect to stray voltage, the ER noted it can be reduced or eliminated through mitigation.[418]

272. The ER discussed the potential for an increase in noise caused by large transmission facilities.[419] In addition, the ER evaluated the potential for interference with radio and television frequencies as well as global positioning systems.[420]

273. The ER acknowledged that large transmission lines often impact private land owners, as well as public lands, when property is used for transmission facilities.[421] The ER evaluated the various ways that private land owners are impacted, the remedies available to those landowners, and the public natural resources that could be affected by the Project.[422] These impacts include visual and aesthetic changes, effects on the State's water resources, including wetlands, and impacts on land use and land-based industries.[423]

274. In addition, the ER discussed the visual and aesthetic impacts that large power lines have on their natural environments, as well as the potential impact the Project could have on the State's water resources, including wetlands.[424] Land use, including various industries, can also be impacted by the construction and operation of transmission facilities.[425] Overall, however, the ER identified no basis for denying Minnesota Power's CON Application.

275. As fully discussed above, the Project will enable Minnesota Power to meet a stated growing need for additional energy and capacity by allowing it to take delivery of additional energy under the Manitoba Hydro Agreements. The hydro energy offered by Manitoba Hydro will allow Minnesota Power to reduce its dependence on coal-based energy sources and to diversify its resource mix in furtherance of its Energy*Forward* plan. While the Project will not enable Minnesota Power to meet its renewable energy requirements set forth in law, the Project should reduce overall emissions compared to coal-based alternatives, as well as reduce Minnesota Power's exposure to the cost of potential future emission reduction requirements.

276. According to Minnesota Power, the Project will also optimize the value of its wind resources.[426] A new 500 kV transmission interconnection between Manitoba and the Iron Range has the potential to bring benefits in the form of reduced wind

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[416] Ex. 6 at 39-47 (Environmental Report).
[417] Ex. 6 at 46 (Environmental Report).
[418] Ex. 6 at 47 (Environmental Report).
[419] Ex. 6 at 56-60 (Environmental Report).
[420] Ex. 6 at 47-49 (Environmental Report).
[421] Ex. 6 at 49-50, 61-65 (Environmental Report).
[422] *Id.*
[423] Ex. 6 at 60-71 (Environmental Report).
[424] *Id.*
[425] Ex. 6 at 49-56 (Environmental Report).
[426] Ex. 41 at 7-8 (Hoberg Direct); Ex. 19 (Appendix I to CON Application).

curtailment and better utilization of both wind and hydro resources, enhancing affordability and further enabling non-carbon emitting energy to reach the market.[427]

277. The Project also directly and indirectly replaces coal generation as well as natural gas generation in Minnesota. As addressed in the 2013 IRP, Minnesota Power is planning to shut down Taconite Harbor Unit 3 and refuel Laskin Units 1 and 2 (switching from coal to natural gas).[428] The Manitoba Hydro Agreements are part of Minnesota Power's plan to replace this lost energy and capacity with renewable hydropower.[429]

278. The indirect impact of the Project will be to enable the addition of hydro resources to the MISO dispatch stack.[430] To the extent that coal units are on the margin (the load following unit), and Manitoba Hydro's generation has a lower variable cost (dispatched first) or is must run, hydro generation will replace coal generation.[431] The same consideration applies to natural gas generation: to the extent that natural gas units are on the margin and Manitoba Hydro's generation has a lower variable cost (dispatched first), hydro generation will replace natural gas generation. [432]

279. Finally, Minnesota Power presented evidence that the Project will provide economic benefit in the form of property tax revenue to the impacted areas. Property taxes are estimated to provide $40,000 to $60,000 per mile in annual revenues to local governments.[433] During construction, the Project would provide construction and maintenance jobs as well as increased business for hotels, restaurants, and other services along the final route.[434] In total, the Project could generate over $850 million of economic impact in northern Minnesota for the design and construction period of 2016 through 2020.[435]

280. In sum, a preponderance of the evidence in the record establishes that the proposed Project will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health.

D. Compliance with Federal, State and Local Regulations

281. Minnesota Rule 7849.0120D requires the Commission to consider whether the record demonstrates that the design, construction, or operation of the proposed facility will comply or fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

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427 *Id.*
428 Ex. 53 at 46 (Rakow Direct).
429 *Id.*
430 *Id.*
431 *Id.*
432 *Id.*
433 Ex. 44 at 25-26 (Rudeck Direct Attachment – Trade Secret).
434 *Id.*
435 Ex. 44 at 25 (Rudeck Direct Attachment – Trade Secret); Ex. 22 (Appendix L to CON Application).

282. Minnesota Power asserted a commitment to continue to work with all federal, state and local governmental authorities to obtain the necessary permits, and noted it "is fully committed to compliance with those permits."[436]

283. No evidence was presented to show that the design, construction, or operation of the proposed Project will violate or fail to comply with any relevant policies, laws, rules, or regulations. Therefore, the record does not demonstrate that the design, construction, or operation of the proposed Project will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

VIII. CONDITIONS

284. While not disputing the need for the Project, LPI recommended the Commission impose several conditions on the CON if granted.

A. Approval of the 133 MW ROAs and the FCA

285. First, LPI witness Lane Kollen recommended approval of the CON be made contingent upon approval of the 133 MW ROAs as well as FERC approval of the FCA.[437] No party objected to this recommendation.

286. On November 25, 2014, after the conclusion of the evidentiary hearing, FERC approved the FCA.[438] Thus, there is no need to condition the CON on FERC's approval of the FCA.

287. On November 6, 2014, Minnesota Power filed its Petition with the Commission seeking approval of the 133 MW ROAs.[439]

288. On January 30, 2015, after the conclusion of the evidentiary hearing, the Commission approved the 133 MW ROAs.[440] Therefore, there is no need to condition the CON on the Commission's approval of the 133 MW ROAs.

B. "Capping" Minnesota Power's Cost Recovery

289. LPI also recommended the Commission prohibit cost recovery for the Project above the $676,947,930 cost estimate cited in the FCA, including contingencies.[441] LPI's recommendation is referred to as a "hard cap" in this

[436] Ex. 34 at 26 (McMillan Direct).
[437] Ex. 50 at 3 (Kollen Direct).
[438] Ex. 64 (FERC Approval of FCA).
[439] Ex. 46, Schedule 1 (Rudeck Surrebuttal Attachment).
[440] *In the Matter of Minnesota Power's Petitioner for Approval of a 133 MW Power Purchase Agreement with Manitoba Hydro*, PUC Docket No. E-014/M-14-960, ORDER (January 30, 2015).
[441] Ex. 49 at 3, 11 (Kollen Direct); Ex. 50 at 11-12 (Kollen Direct – Trade Secret Version); Ex. 51 at 10 (Kollen Surrebuttal).

proceeding because it would limit the total dollar amount Minnesota Power can recover for the Project.

290. LPI maintained that a "hard cap" is necessary to ensure Minnesota Power's customers benefit from the claimed value of the Project, the 250 MW Agreements, the 133 MW ROAs, and the FCA.[442] In support of its recommendation, LPI noted that Minnesota Power has revised the estimated Project cost upward several times since Minnesota Power first filed its Application.[443] In addition, LPI asserted the cost of the Project along with the 250 MW Agreements is similar to the cost of a natural gas fired combined cycle alternative.[444] LPI's position is based on a cost analysis completed by its expert, Lane Kollen.[445]

291. In response to LPI's recommendation, the DOC-DER asserted it is not necessary to address the issue of a cost cap at this time because cost recovery is typically addressed in rider or rate case proceedings. Nonetheless, the DOC-DER does not oppose "making clear to [Minnesota Power] the terms of their future cost recovery."[446]

292. In the alternative, the DOC-DER recommended adoption of a "soft cap" rather than a "hard cap." Specifically, the DOC-DER suggested the Commission order that: (1) Minnesota Power be limited to recover in riders only the amount of costs proposed in this proceeding; (2) Minnesota Power be allowed to request recovery of costs above this amount only in a rate case where costs will be subject to full prudence review; and (3) Minnesota Power be required to carry the burden of demonstrating the prudence of those additional costs and why it would be reasonable to recover them from ratepayers.[447]

293. The DOC-DER noted the Commission adopted a similar "soft cap" approach in a 2010 proceeding regarding cost recovery of energy facilities owned by Northern States Power Company, d/b/a, Xcel Energy. In that case, the Commission specified:

> The Commission will allow Xcel to recover, through its RES rider, only the costs up to the amounts of the initial estimates at the time the projects are approved as eligible projects. No amounts above what Xcel initially indicated the projects would cost will be allowed to flow through the RES rider. Nor will additional cost overruns be eligible for deferred accounting. However, Xcel will be allowed to seek recovery, on a prospective basis, of additional costs at the time of its next rate case, upon a showing that it is reasonable to require ratepayers to pay for any such additional costs. This approach allows Xcel to recover the majority of the costs for projects

[442] Ex. 49 at 11-12 (Kollen Direct).
[443] Ex. 49 at 5-6 (Kollen Direct).
[444] Ex. 49 at 7-8 (Kollen Direct).
[445] Ex. 49 at 5-8 (Kollen Direct).
[446] Ex. 55 at 2-3 (Rakow Rebuttal).
[447] Ex. 55 at 3 (Rakow Rebuttal); Ex. 56 at 10-11 (Rakow Surrebuttal).

> eligible for RES rider recovery promptly, while providing at least some incentive for Xcel to minimize costs and help protect ratepayers."[448]

294. Minnesota Power agreed to the DOC-DER's recommendation of imposing a "soft cap" on cost recovery.[449] Minnesota Power noted that a "soft cap" 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.[450]

295. The Commission very recently used a similar "soft cap" approach in a transmission CON proceeding involving ITC Midwest, LLC.[451] In its November 25, 2014 Order approving the ITC Midwest CON, the Commission stated:

> The Commission recognizes that the ALJ's Findings with respect to the cost of the proposed Project contain little certainty, noting that the final cost of the Project is dependent on a number of factors that are outside of ITC Midwest's control, including the final route (which impacts final design); the timing of construction; the availability of construction crews; and the cost of materials.
>
> Nonetheless, the Commission agrees with the DOC DER's recommendation to condition its approval of the certificate of need by imposing the cost recovery limitation set forth below. The Commission concurs with the Department that it should continue its practice of limiting utilities seeking to recover transmission costs <u>through transmission cost recovery riders</u> to the costs put forward by applicants in certificate of need proceedings -- here, $284,000,000. The Commission continues to believe 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.[452]

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[448] Ex. 55 at 3 (Rakow Rebuttal) (quoting *In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation, for Approval of the 2010 Renewable Energy Standard Cost Recovery Rider and 2009 Renewable Energy Standard Tracker Report*, PUC Docket No. E002/M-09-1083, ORDER APPROVING 2010 RES RIDER AND 2009 RES TRACKER REPORT, ESTABLISHING 2010 RES CHARGE, AND REQUIRING REVISED TARIFF at 5 (April 22, 2010)).
[449] Minnesota Power Initial Brief (Br.) at 59.
[450] *Id.*
[451] *In the Matter of the Application of ITC Midwest L.L.C. for a Certificate of Need for the Minnesota-Iowa 345 kV Transmission Line Project in Jackson, Martin, and Faribault Counties,* PUC Docket No. ET-6675/CN-12-1053, ORDER GRANTING CERTIFICATE OF NEED WITH CONDITIONS at 6 (November 25, 2014) ("ITC Midwest Order").
[452] *Id.* (emphasis added).

296. For the reasons set forth by the Commission in the ITC Midwest Order, the Administrative Law Judge concludes it is reasonable to adopt a "soft cap" for this Project as well. A "soft cap" will provide an incentive to Minnesota Power to control its costs without denying it the opportunity to recover any prudently incurred costs that exceed its current cost estimate.

297. A "hard cap" is not reasonable because the Project still has to go through the routing process, and conditions could be added which would have the effect of increasing the cost of the Project. In addition, as the Commission recognized in the ITC Midwest Order, there can be unforeseen circumstances for any project that can lead to prudently incurred cost overruns. Thus, imposing a "hard cap" as a condition of the CON could preclude Minnesota Power from recovering its reasonable and prudent costs of service. Such a result would be contrary to Minnesota Statutes section 216B.16, subdivision 6, which requires the Commission to set rates at a level allowing the utility the opportunity to recover its "reasonable and prudent costs" of providing utility service.

298. Moreover, LPI's recommendation for a "hard cap" is based on a faulty cost comparison by its expert. In doing the cost comparison, LPI witness Lane Kollen compared the 250 MW Agreements and the Project with a natural gas-fired alternative.[453] This analysis does not include the economic and environmental benefits Minnesota Power ratepayers are expected to receive from the recently approved 133 MW ROAs. In addition, the analysis fails to consider that the Commission has already approved the 250 MW Agreements and the 133 MW ROAs. Cancellation of these contracts and substitution of a natural gas-fired facility would be inconsistent with the resource decisions already made by the Commission, and would likely involve contract cancellation costs that have not been included in LPI's analysis.

299. For these reasons, the Administrative Law Judge recommends that the Commission reject the "hard cap" proposed by LPI and instead adopt the "soft cap" recommended by the DOC-DER.

300. The Administrative Law Judge further recommends the Commission cap Minnesota Power's rider requests at the lesser of: (1) 28.3 percent of the Project's total capital costs; or (2) $201 million (in 2013 dollars), the high end of Minnesota Power's current estimate of the amount customers will pay for the Project.[454]

301. If Minnesota Power experiences capital cost increases beyond the $201 million amount, it can request recovery of amounts beyond the "soft cap" amount in a rate case subject to review by the Commission for prudence and reasonableness. As part of any such request, the Administrative Law Judge recommends Minnesota Power be required to demonstrate that it is not seeking recovery of more than 28.3 percent of the total capital costs for the Project.[455]

[453] *Id.*
[454] Ex. 34 at 19 (McMillan Direct).
[455] Ex. 34 at 19 (McMillan Direct); *see also* Minnesota Power Initial Br. at 40.

302. Adopting a "soft cap" and requiring Minnesota Power to honor its commitment that ratepayers will be responsible for only 28.3 percent of the Project costs will help ensure the Project does not result in unreasonable rates for Minnesota Power's customers. Moreover, the "soft cap" will ensure the financial justifications for the Project and representations made by Minnesota Power in this proceeding actually materialize.

C. Other Cost Recovery and Cost Allocation Recommendations

303. LPI made three additional recommendations regarding cost recovery and cost allocation issues: (1) mandating that Minnesota Power accumulate an allowance for funds used during construction (AFUDC) for the Project and allow recovery of those funds only after the Project is placed into service; (2) mandating rider recovery of all Project costs; and (3) determining the allocation of Project costs among customer groups.[456] Both Minnesota Power and the DOC-DER claimed these issues are not usually addressed in CON proceedings and are more appropriately addressed in future proceedings, after notice to all potentially interested parties is given.[457]

304. The Administrative Law Judge agrees. These three issues are generally addressed in ratemaking or rider proceedings rather than CON proceedings. It is not necessary to address these rate-related issues in order to determine whether the criteria for a CON have been met in this case.[458] Therefore, the Commission need not decide these issues in the current docket.

305. If the Commission does address the issues, however, LPI's recommendations should be denied for the reasons set forth below.

1. AFUDC Treatment

306. LPI asks the Commission to mandate that Minnesota Power accumulate an allowance for funds used during construction (AFUDC) for the Project, and allow recovery of the funds only after the Project is placed into service.[459]

307. The Minnesota Legislature has specifically addressed cost recovery for transmission assets, providing substantial detail and direction to the Commission.[460] In 2005, the Legislature enacted "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.[461]

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[456] Ex. 49 at 4-5 (Kollen Direct).
[457] Ex. 35 at 12-15 (McMillian Rebuttal); Ex. 57 at 5-6, 11-12, 14 (Johnson Surrebuttal).
[458] *See* Minn. Stat. § 216B.243 (2014); Minn. R. 7849.0120 (2013).
[459] Ex. 49 at 4, 19-23 (Kollen Direct).
[460] Minn. Stat. § 216B.16, subd. 7b (2014).
[461] 2005 Minn. Laws ch. 97, art. 1, § 2 at 490; Ex. 35 at 12 (McMillan Rebuttal).

308. The traditional ratemaking approach for major construction projects allows for AFUDC, but defers any utility recovery of costs until the asset is "used and useful" and placed into the utility's rate base.[462]

309. For new transmission projects, Minnesota law provides that a utility may file for a transmission cost adjustment which "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."[463]

310. The Commission has consistently approved transmission cost recovery (TCR) filings that provide for "a current return on construction work in progress" (CWIP). To deny Minnesota Power the ability to make such a filing would mark a significant departure from Commission precedent as detailed below.[464]

311. On July 12, 2007, Minnesota Power requested Commission approval of a Transmission Cost Recovery Rider (TCR Rider) consistent with Minn. Stat. § 216B.16, subd. 7b (2014).[465] The DOC-DER recommended approval of Minnesota Power's petition.[466] The DOC-DER also agreed with Minnesota Power's proposed methodology.[467] In its order issued on December 7, 2007, the Commission approved Minnesota Power's 2007 TCR Rider and allowed Minnesota Power to begin collecting rates that included a current return on CWIP effective January 1, 2008.[468]

312. Similarly, on June 23, 2009, the Commission issued an order approving Minnesota Power's 2009 TCR Rider;[469] on May 11, 2011, the Commission issued an order approving Minnesota Power's 2010 TCR Rider;[470] and on November 12, 2013, the Commission granted Minnesota Power's petition for approval of its 2011 TCR Rider.[471]

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[462] Ex. 35 at 12 (McMillan Rebuttal).
[463] Minn. Stat. § 216B.16, subd. 7b (b)(5) (2014).
[464] Ex. 57 at 6 (Johnson Surrebuttal).
[465] *In the Matter of Minnesota Power's Petition for Approval of a Transmission Cost Recovery Rider,* PUC Docket No. E-015/M-07-965, PETITION (July 12, 2007).
[466] *In the Matter of Minnesota Power's Petition for Approval of a Transmission Cost Recovery Rider,* PUC Docket No. E-015/M-07-965, COMMENTS at 6 (October 12, 2007).
[467] *Id.*
[468] *In the Matter of Minnesota Power's Petition for Approval of a Transmission Cost Recovery Rider,* PUC Docket No. E-015/M-07-965, ORDER (December 7, 2007).
[469] *In the Matter of Minnesota Power's Request for Approval of its 2009 Rate Adjustment Mechanism under its Transmission Cost Recovery Ride,* PUC Docket No. E-015/M-08-1176, ORDER (June 23, 2009).
[470] *In the Matter of Minnesota Power's Petition for Approval of its Transmission Cost Recovery Rider,* PUC Docket No. E-015/M-10-799, ORDER (May 11, 2011).
[471] *In the Matter of Minnesota Power's Petition for Approval of its 2011 Transmission Cost Recovery Rider Factor,* PUC Docket No. E-015/M-11-695, ORDER (November 12, 2013).

313. Minnesota Power's 2014 TCR Rider is currently pending before the Commission.[472]

314. In every Commission order to date, Minnesota Power has been allowed to recover a current return on CWIP for transmission projects that have not yet been placed in service, consistent with Minn. Stat. § 216B.16, subd. 7b(b)(5).

315. Requiring AFUDC treatment of Project construction costs also has the potential to have adverse impacts on ratepayers although there is insufficient information at this time to draw a definitive conclusion. Providing a current return on CWIP provides customers a lower overall capital cost of approximately $55 million in nominal dollars as compared to recording AFUDCs.[473] Given the timing delay in recovery under these two methods, the lower overall capital costs may not result in a benefit to ratepayers. A number of assumptions would be necessary to draw a conclusion as to the net impact on ratepayers.[474]

316. Requiring AFUDC treatment of construction costs could also create the possibility of "rate shock" to customers once the Project is placed into service.[475] 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.[476]

317. Requiring AFUDC treatment of Project construction costs would harm Minnesota Power's cash flow, which, in turn, can lower its financial ratings and impose additional costs on ratepayers due to the higher cost of capital.[477] The DOC-DER noted that while these harms are difficult to measure, standard recovery of Project costs through a return on CWIP may bring ratepayer benefits due to Minnesota Power's improved cash flow and stronger financial rating.[478]

318. The Administrative Law Judge concludes the record in this case fails to demonstrate that requiring AFUDC treatment of Project construction costs will result in more reasonable rates than allowing a current return on CWIP. Therefore, the Administrative Law Judge recommends that the Commission not require AFUDC treatment at this time.

[472] *In the Matter of Minnesota Power's Petition for Approval of a Transmission Cost Recovery Rider,* PUC Docket No. E-015/M-14-337, COMPLIANCE FILING (February 25, 2015).
[473] Ex. 35 at 13 (McMillan Rebuttal); Ex. 57 at 7 (Johnson Surrebuttal).
[474] Ex. 57 at 7-9 (Johnson Surrebuttal).
[475] Ex. 35 at 13 (McMillan Rebuttal); Ex. 57 at 8 (Johnson Surrebuttal).
[476] Ex. 35 at 13 (McMillan Rebuttal).
[477] Ex. 35 at 13 (McMillan Rebuttal); Tr. Vol. 1 at 68-70 (McMillan).
[478] Ex. 57 at 8-9 (Johnson Surrebuttal).

2. Rider Recovery of All Project Costs

319. Next, LPI recommended the Commission act now and require Minnesota Power to recover all Project costs through a TCR Rider.[479]

320. While Minnesota law allows recovery of transmission costs through a TCR Rider, it does 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."[480]

321. According to the DOC-DER, the Commission has never mandated recovery of transmission costs only through a TCR Rider.[481]

322. Both the DOC-DER and Minnesota Power maintain that better ratemaking outcomes may be achieved for customers by addressing Project costs through a traditional general rate case.[482] For example, a rate case would re-examine the issue of wholesale/retail allocation and may provide benefits to retail customers.[483] 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.[484]

323. If the Commission mandates recovery solely through a TCR Rider, the Commission would essentially be pre-determining how the costs are recovered over the next 55 years – the expected service life of the Project.[485]

324. In response to these concerns, LPI suggested that the Commission could require TCR Rider recovery for the first five years instead of over the life of the Project.[486]

325. The Administrative Law Judge concludes that neither LPI's original TCR Rider recovery proposal nor its alternative proposal is supported by the record in this case. It would be unreasonable to mandate recovery of Project costs through the TCR Rider, either for the lifetime of the Project or for the next five years, because recovery through base rates may prove to be a more reasonable approach at some point. The Commission should retain the ability to address the issue in future proceedings to ensure that customers do not pay unreasonable rates.

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[479] Ex. 49 at 4 (Kollen Direct).
[480] Minn. Stat. § 216B.16, subd. 7b(b)(9) (2014).
[481] Ex. 57 at 10-11 (Johnson Surrebuttal).
[482] Ex. 35 at 14 (McMillan Rebuttal); Ex. 57 at 10 (Johnson Surrebuttal).
[483] Ex. 35 at 14 (McMillan Rebuttal).
[484] Ex. 35 at 14 (McMillan Rebuttal).
[485] Ex. 57 at 10 (Johnson Surrebuttal).
[486] LPI Reply Br. at 19.

3. Cost Allocations

326. Finally, LPI recommended the Commission pre-determine the allocation of costs among classes of customers before a cost recovery proceeding has been initiated. LPI asserts such action is necessary "to partially remedy the subsidies provided by the [large power] class to other classes" that resulted from the Commission's most recent Minnesota Power general rate case decision.[487]

327. Cost allocation matters are traditionally addressed in cost recovery or rate case proceedings.[488] Cost allocation and ratemaking involve fact and policy decisions not yet fully developed in this case.

328. In addition, because the issue of cost allocation was not identified in the Notice and Order for Hearing and was not raised until after the intervention deadline, not all customer groups have received a fair opportunity to participate and develop the record on this issue.

329. For these reasons, the Administrative Law Judge concludes that the issue of cost allocation is best left to future cost recovery proceedings where all customer classes are on notice that ratemaking decisions will be made.

CONCLUSIONS OF LAW

I. JURISDICTION

1. The Commission and Administrative Law Judge have jurisdiction to consider Minnesota Power's CON Application pursuant to Minnesota Statutes sections 14.57, 216B.08, 216B.243 (2014), and Minnesota Rules 7829.1000, 7849.0010 - .2100 (2013).

II. COMPLETENESS OF APPLICATION

2. On January 8, 2014, the Commission found the CON Application to be substantially complete and accepted it.

3. The Administrative Law Judge finds the CON Application meets all requirements of Minnesota Rules 7849.0200-.0340, subject to the exemptions granted by the Commission in its Order Approving Notice Plan, Granting Variance Requirements, and Approving Exemption Request, dated February 28, 2013.

III. NOTICE AND HEARING REQUIREMENTS

4. Minnesota Rule 7829.2550 requires an applicant for a CON to submit a Notice Plan for approval by the Commission before filing a CON Application.

[487] Ex. 49 at 5, 27 (Kollen Direct).
[488] Ex. 35 at 17-18 (McMillan Rebuttal); Ex. 57 at 14 (Johnson Surrebuttal).

5. Minnesota Power filed its Notice Plan on October 29, 2012.[489] The Commission approved the Notice Plan on February 28, 2013.[490]

6. The Administrative Law Judge finds that, prior to filing its CON Application on October 21, 2013, Minnesota Power provided all notices required by the Commission-approved Notice Plan.

7. Minnesota Rule 7829.2500 sets forth certain service and notice requirements for a CON applicant and the Commission.

8. The Administrative Law Judge concludes the Applicant and the Commission fulfilled all service and notice requirements set forth in Minnesota Rule 7829.2500.

9. Minnesota Statutes section 216B.243, subdivision 4, and Minnesota Rule part 7829.2500, subpart 9, require the Commission to hold at least one public hearing on the CON Application. Minnesota Statutes section 216B.243, subdivision 4, further requires that a Commission employee be available to facilitate citizen participation at the public hearing.

10. In this case, seven public hearings were conducted in six communities throughout the proposed Project area. Members of the public were given an opportunity to appear at the public hearings and to submit written comments. The evidentiary hearing was held in St. Paul, Minnesota, and occurred over the course of two days. Tracy Smetana, the Commission's Public Advisor, was present at the public and evidentiary hearings to facilitate citizen participation. Therefore, the Commission has satisfied all requirements of Minnesota Statutes section 216B.243, subdivision 4, and Minnesota Rule part 7829.2500, subpart 9.

11. Minnesota Rules 7849.1200-.1800 set forth certain requirements for the DOC-EERA with respect to the Environmental Report. The Administrative Law Judge concludes that the DOC-EERA has satisfied all requirements set forth within the rules.

12. Therefore, the Administrative Law Judge concludes that the Applicant, the DOC-DER, and the Commission have provided all necessary notices, and complied with all applicable substantive and procedural requirements for a CON.

IV. CRITERIA FOR EVALUATING CON APPLICATION

13. The criteria for evaluating an application for a CON are set forth in Minnesota Statutes section 215B.243, and expanded upon in Minnesota Rule 7849.0120.

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[489] NOTICE PLAN FOR GREAT NORTHERN TRANSMISSION LINE (October 29, 2012) (eDocket Nos. 201210-80007-01, 201210-80007-02).

[490] ORDER ACCEPTING FILING, VARYING TIME LINES, AND NOTICE AND ORDER FOR HEARING (January 8, 2014) (eDocket No. 20141-95218-01).

14. The proposed Project constitutes a "large energy facility," as defined by Minnesota Statutes section 216B.2421, subdivision 2.

15. Minnesota Statutes section 216B.243, subdivision 3, provides that no proposed large energy facility shall be constructed unless the applicant can show that the demand for electricity cannot be met more cost effectively through energy conservation and load management measures, and unless the applicant has otherwise justified its need. In assessing need, the Commission shall evaluate:

> (1) the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based;
>
> (2) the effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand;
>
> (3) the relationship of the proposed facility to overall state energy needs, as described in the most recent state energy policy and conservation report prepared under section 216C.18, or, in the case of a high-voltage transmission line, the relationship of the proposed line to regional energy needs, as presented in the transmission plan submitted under section 216B.2425;
>
> (4) promotional activities that may have given rise to the demand for this facility;
>
> (5) benefits of this facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region;
>
> (6) possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation;
>
> (7) the policies, rules, and regulations of other state and federal agencies and local governments;
>
> (8) any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically;
>
> (9) with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota;

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

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

(12) if the applicant is proposing a nonrenewable generating plant, the applicant's assessment of the risk of environmental costs and regulation on that proposed facility over the expected useful life of the plant, including a proposed means of allocating costs associated with that risk.[491]

16. Minnesota Statutes section 216B.243 further requires the Commission to adopt rules setting forth the criteria to be used in its determination of need for such facilities.[492] These criteria are set forth in Minnesota Rule 7849.0120.

17. Minnesota Rule 7849.0120 provides that a certificate of need must be granted to the applicant if the Commission determines 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.

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[491] Minn. Stat. § 216B.243, subd. 3 (2014). In this case, the Parties agreed that sections (10) and (12) of the CON Statute do not apply to the current proceeding. *See* ISSUES MATRIX (December 5, 2014) (eDocket No. 201412-105220-01).

[492] Minn. Stat. § 216B.243, subd. 1 (2014).

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;

(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.

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.[493]

18. As the Applicant, Minnesota Power bears the burden of demonstrating, by a preponderance of the evidence, the need for the Project.[494]

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[493] Minn. R. 7849.0120 (2013).

[494] Minn. Stat. § 216B.243, subd. 3 (2014); Minn. R. 1400.7300, subp. 5 (2013); Minn. R. 7849.0120 (2013).

19. The record in this proceeding demonstrates that Minnesota Power has satisfied the criteria for a CON set forth in Minnesota Statutes section 216B.243 and Minnesota Rule 7849.0120.

20. Minnesota Power has established by a preponderance of the evidence that the increased demand for electricity projected in the 2020-2035 timeframe cannot be met more cost effectively through energy conservation or load management measures.

21. Minnesota Power has established by a preponderance of the evidence that the probable result of a denial of its CON Application would be an adverse effect upon the future adequacy, reliability, or efficiency of the energy supply to Minnesota Power, its customers, and the people of Minnesota and neighboring states.

22. In addition, a more reasonable and prudent alternative to the Project has not been demonstrated by a preponderance of the evidence in the record.

23. A preponderance of the evidence in the record 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) diversifying Minnesota Power's supply portfolio and reducing its dependence on coal-based energy sources; (4) reducing the risks of future emissions regulations; (5) supporting State and regional energy needs; and (6) enhancing the efficiency and reliability of the transmission system.

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

25. A preponderance of the evidence demonstrates that the Project will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health. These benefits include the ability to meet state and regional energy needs; a reduction in Minnesota Power's reliance on coal-based energy sources; the diversification of Minnesota Power's resource options; an increased reliance on hydro and wind power (renewable energy sources) over coal-based resources; and the optimization of Minnesota Power's wind resources;

26. Finally, the record does not demonstrate that the design, construction, or operation of the proposed Project will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

27. Therefore, the Administrative Law Judge concludes that Minnesota Power has met the criteria for the issuance of a CON, and respectfully recommends the Commission **GRANT** Minnesota Power's Application, subject to the conditions set forth below.

V. RECOMMENDED CONDITIONS

28. Pursuant to Minnesota Rule 7849.0400, subpart 1, the issuance of a CON may be made contingent upon certain conditions set by the Commission.

29. As set forth above, the Commission need not address final cost recovery or cost allocation issues in this proceeding. However, because Minnesota Power's justification for the Project is based in large part upon Minnesota Power's representations that its ratepayers will only be responsible for 28.3 percent of the Project's total capital costs, and only 33 percent of the Project's O&M costs, conditions to set limits on Minnesota Power's ability to recover expenses are warranted in this proceeding.

30. It is not consistent with Commission precedent to set a "hard cap" cost recovery limitation in a CON proceeding or to require cost recovery exclusively through a rider mechanism. However, a "soft cap" on Minnesota Power's recovery of capital costs is justified under the circumstances in this case.

31. Accordingly, the Administrative Law Judge respectfully recommends that the Commission include a condition in the CON limiting the amount Minnesota Power may recover for the Project in riders to an amount not to exceed the lesser of: (1) 28.3 percent of the capital costs of the Project; or (2) $201 million in 2013 dollars, even if this amount is less than 28.3 percent of the total costs. The condition should allow Minnesota Power to request recovery of any excess costs in a subsequent rate proceeding, where the additional costs can be subject to a full prudence review. The Administrative Law Judge further recommends that the Commission put Minnesota Power on notice that it will bear the burden to demonstrate the prudence of any such additional costs and why it would be reasonable to recover the additional costs from ratepayers given the specific representations made in this CON proceeding.

32. To ensure the cost responsibility for Minnesota Power's ratepayers remains as represented by Minnesota Power in this CON proceeding, the Administrative Law Judge respectfully recommends that the Commission also include a condition requiring Minnesota Power to obtain prior approval from the Commission if it proposes to charge ratepayers for O&M costs greater than 33 percent of the Project's total O&M costs at any time in the future. This is particularly important if Manitoba Hydro or Manitoba Ltd. transfers its ownership shares to another entity, including Minnesota Power or its parent company, ALLETE, Inc.

33. By holding Minnesota Power to the representations it has made in this proceeding, the Commission will ensure that the financial justifications for the Project materialize and Minnesota Power's ratepayers are adequately protected.

34. Finally, the Administrative Law Judge respectfully recommends that the Commission impose a condition requiring Minnesota Power to use the Commission's externality values in all future CON applications and CON proceedings.

35. Any of the foregoing Findings of Fact that should be treated as Conclusions of Law are hereby adopted as Conclusions of Law.

Based on the foregoing Findings of Fact and Conclusions of Law, the Administrative Law Judge makes the following:

RECOMMENDATION

IT IS HEREBY RECOMMENDED that the Minnesota Public Utilities Commission:

1. Grant a Certificate of Need to Minnesota Power for the construction of the Great Northern Transmission Line and associated facilities consistent with the Findings of Fact and Conclusions of Law set forth above;

2. Impose the following conditions on the Certificate of Need: (1) limit Minnesota Power's recovery in riders to an amount equal to 28.3 percent of the total capital costs of the Project or $201 million (in 2013 dollars), whichever is less; (2) allow Minnesota Power to request recovery of any excess costs only in a rate case where the costs will be subject to full prudence review; and (3) put Minnesota Power on notice that it will have the burden of demonstrating the prudence of any additional costs and show why it would be reasonable to recover the additional costs from ratepayers given the representations made in this CON proceeding;

3. Impose a condition requiring Minnesota Power to obtain prior approval from the Commission if it proposes to charge ratepayers for operation and maintenance costs greater than 33 percent of the Project's total O&M costs at any time in the future; and

4. Impose a condition requiring Minnesota Power to use the Commission's current externality values in all future CON applications and CON proceedings.

Dated: March 16, 2015

s/Ann C.O'Reilly

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ANN C. O'REILLY
Administrative Law Judge

Reported: Shaddix & Associates, transcribed

NOTICE

Under the Minnesota Public Utility Commission's Rules of Practice and Procedure, Minn. R. 7829.0100-.3200, exceptions to this Report, if any, by any party adversely affected, must be filed within 15 days of the mailing date hereof with the Executive Secretary of the Public Utilities Commission, 350 Metro Square Building, 121 Seventh Place East, St. Paul, Minnesota 55101-2147. Exceptions must be specific, relevant to the matters at issue in this proceeding, and stated and numbered separately. Proposed Findings of Fact, Conclusions of Law, and Order should be included, and copies thereof served upon all parties.

The Commission shall make its determination on the applications for the Certificate of Need after expiration of the period to file exceptions as set forth above, or after oral argument, if such is requested and had in this matter.

Notice is hereby given that the Commission may accept, modify, condition, or reject this Report of the Administrative Law Judges, and that this Report has no legal effect unless expressly adopted by the Commission.