BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
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FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
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In the Matter of the Application of Xcel Energy and ITC Midwest LLC for a Certificate of Need for the Huntley-Wilmarth 345 kV Transmission Line Project	MPUC Docket No. ET6675/CN-17-184 OAH Docket No. 82-2500-35157

INITIAL BRIEF OF THE MINNESOTA DEPARTMENT OF COMMERCE, DIVISION OF ENERGY RESOURCES

March 22, 2019

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INTRODUCTION

The Minnesota Department of Commerce, Division of Energy Resources (DOC DER) respectfully submits this initial brief to provide the Administrative Law Judge (ALJ) and the Minnesota Public Utilities Commission with an analysis of the facts and law pertaining to the Application for a Certificate of Need (CN) for the Huntley-Wilmarth 345 kV Transmission Line Project (CN Application), filed by Northern States Power Company, d/b/a Xcel Energy, and ITC Midwest LLC (Applicants).

The Applicants' proposal includes the construction of an approximately 50-mile, 345 kilovolt (kV) transmission line between Xcel's Wilmarth Substation north of Mankato, Minnesota and ITC Midwest's Huntley Substation south of Winnebago, Minnesota (Project).[1] The Applicants would also make modifications to the Wilmarth and Huntley substations to accommodate the new line.[2] Xcel and ITC Midwest would own the transmission line jointly as tenants in common, with Xcel and ITC Midwest maintaining sole ownership of any improvements to their respective substations.[3] Depending on the route chosen for the proposed Project, costs are estimated to range from $104.8 million to $160.7 million.[4] If approved, the Applicants estimate that the proposed Project would be in-service by the end of 2021.[5]

The Midcontinent Independent System Operator (MISO) identified the proposed Project to address congestion in the area in its 2016 MISO Transmission Expansion Plan (MTEP16), and MISO designated the proposed Project as a Market Efficiency Project (MEP).[6] Designation as an MEP allows for 20 percent of project costs to be allocated to each pricing zone in MISO

[1] Ex. XC-6 at 2 (Initial Filing – Certificate of Need Application) (hereinafter CN Application).
[2] *Id.*
[3] Ex. XC-22 at 4 (Neidermire Direct).
[4] Ex. DER-1 at 5 (Johnson Direct); Ex. XC-22 at 8 (Neidermire Direct).
[5] CN Application at 8.
[6] *Id.* at 1; Ex. DER-5 at 10 (Rakow Direct).

Classic[7] based on load ratio share, with the remaining 80 percent of project costs to be allocated to pricing zones based on the distribution of positive Adjusted Project Cost (APC) savings to the Local Resource Zones (LRZs).[8]

Overall, DOC DER concluded that Applicants satisfied the criteria in parts A and B of Minn. R. 7849.0120 and showed that denial of the proposed Project would adversely affect the future adequacy, reliability or efficiency of energy supply to the Applicants, Applicants' customers, or to the people of Minnesota and neighboring states and that a more reasonable and prudent alternative to the proposed Project was not demonstrated on the record.[9] If the ALJ and Commission find that the CN criteria has been met, then DOC DER requests that ratepayers' interests be protected by capping costs included in Xcel's Transmission Cost Recovery (TCR) rider for the proposed Project based on the cost estimate determined in this matter.

ISSUE

The main issue to be addressed is whether the Applicants have shown that the proposed transmission line Project meets the applicable statutory and rule criteria for a CN.[10]

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[7] MISO Classic generally refers to the northern half of the MISO footprint, including Local Resource Zones (also referred to as Cost Allocation Zones) 1-7. Ex. DER-1 at 7 (Johnson Direct).

[8] *Id.* at 6-7 (Johnson Direct) (citing CN Application at 37).

[9] DOC DER did not offer testimony specifically regarding part C of Minn. R. 7849.0120, but notes that many of these considerations are included in the Environmental Impact Statement (EIS) or in testimony relating to other criteria. Regarding whether the design, construction, or operation of the proposed facility would fail to comply with relevant policies, rules and regulations of other state and federal agencies and local governments, part D of Minn. R. 7849.0120, DOC DER notes that state agencies and local governments have been involved in the proceedings and defers to these governmental units regarding their own policies, rules, and regulations.

[10] *See* Order Finding Applications Complete and Notice and Order for Hearing at 4 (Mar. 28, 2018) (eDocket No. 20183-141450-02).

BURDEN OF PROOF

The Applicants bear the burden of proof to demonstrate by a preponderance of the evidence that they have satisfied Minnesota's legal criteria for a CN.[11] Also, a more reasonable and prudent alternative must not have been demonstrated by a preponderance of the evidence on the record.[12]

ANALYSIS

Minnesota law provides that before a large energy facility may be constructed, the applicant must show that "demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified need."[13] Minn. Stat. § 216B.243, subd. 1, directs the Commission to adopt, through rulemaking, criteria to determine need for large energy facilities.[14]

DOC DER concluded that the Applicants have met their burden to show that the proposed Project is needed under parts A and B of the CN Rule criteria laid out in Minn. R. 7849.0120. In addition, the proposed Project complies with several additional statutory requirements. If the Commission approves the proposed Project, DOC DER recommended that it should protect ratepayers by 1) requiring Xcel to wait until the first rate case after the proposed Project is in service to recover any cost overruns from Minnesota ratepayers and 2) requiring Xcel to justify fully the reasonableness of recovering any cost overruns from Minnesota ratepayers.

[11] Minn. Stat. § 216B.243, subd. 3 (2018); Minn. R. 7849.0120 (2017).
[12] Minn. R. 7849.0120 B.
[13] Minn. Stat. § 216B.243, subd. 3 (2018).
[14] "Large energy facility" is defined to include "any high-voltage transmission line with a capacity of 200 kilovolts or more and greater than 1,500 feet in length," and "any high-voltage transmission line with a capacity of 100 kilovolts or more with more than ten miles of its length in Minnesota or that crosses a state line." Minn. Stat. § 216B.2421, subd. 2(2)-(3) (2018).

I. CN RULE CRITERIA

Under the Commission's rules, to grant a CN it must make determinations on four criteria, considering several sub-factors. First, the Commission must determine that "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," taking into account five sub-factors.[15] Second, the Commission must determine that "a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record," considering four sub-factors.[16] Third, the Commission must determine that the proposed facility, or a suitable modification, "will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health," considering four sub-factors.[17] Last, the Commission must find that "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."[18]

A. Minn. R. 7849.0120 A: The Probable Result of Denial Would Be An Adverse Effect Upon the Adequacy, Reliability, and Efficiency of Energy Supply

To obtain a CN, Minn. R. 7849.120 A requires an applicant to show that "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."

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[15] Minn. R. 7849.0120 A.
[16] Minn. R. 7849.0120 B.
[17] Minn. R. 7849.0120 C.
[18] Minn. R. 7849.0120 D.

The CN Application states that several needs would be addressed by the proposed Project. First, the proposed Project would improve efficiency by relieving transmission-system congestion along the Minnesota/Iowa border.[19] Congestion can prevent the lowest-priced energy from flowing freely across the electrical system, causing more expensive generators to come on-line or increase output.[20] Second, the proposed Project would improve the deliverability of wind generation by reducing curtailments, which "improves energy delivery, reduces system generation costs and provides environmental benefits in the form of lower carbon emissions."[21] Third, the proposed Project would improve the robustness of the regional backbone transmission system, which helps the system address unplanned system outages and enables access to a diverse mix of generation resources.[22] In addition, expected closures of coal generation north of the Minneapolis/St. Paul area, such as Sherburne County Generating Station (Sherco) Units 1 and 2 and Boswell Energy Center Units 1 and 2, are driving the need for the proposed Project by increasing the need for power to flow from northern Iowa to the Twin Cities.[23]

1. Accuracy of the Applicants' Forecast of Demand

To make a determination under A of the CN rule, the Commission must consider "the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility."[24]

In this case, the claimed need is to relieve congestion identified by MISO to more efficiently deliver low-cost energy to load centers, such as the Twin Cities, and throughout the

[19] CN Application at 6-7; Ex. DER-5 at 4-5 (Rakow Direct).
[20] CN Application at 6.
[21] *Id.* at 7-8.
[22] *Id.* at 8; Ex. DER-5 at 5 (Rakow Direct).
[23] CN Application at 13; Ex. DER-5 at 5 (Rakow Direct).
[24] Minn. R. 7849.0120 A(1).

MISO region and to improve the robustness of the regional transmission system.[25] As part of its transmission-system planning, MISO develops the MTEP each year in an 18-month overlapping cycle of model building, stakeholder input, reliability analysis, economic analysis, and resource assessments.[26] As part of the MTEP process, MISO conducts the Market Congestion Planning Study to focus exclusively on transmission-system congestion that limits access to low-cost generation resources, and MISO evaluates transmission improvements that may relieve congestion and increase market efficiency under a variety of future scenarios (MTEP Futures).[27] Although congestion in the Project area had been identified for some time, the MTEP16 report approved the proposed Project as an MEP.[28]

Broadly, the generation mix in Minnesota and surrounding states has shifted to include increasing amounts of renewable energy, particularly wind, which requires additions and changes to the electrical system to ensure that this added generation can be efficiently and economically delivered to load centers.[29] To accomplish this goal MISO in its MTEP analyses takes into account in its future scenarios load forecasts, generation expansion and retirements, including retirements of coal fired power plants, and uses these analyses to assess and identify transmission needed to deliver the necessary energy reliably and efficiently from generators to customers.[30]

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[25] *See* CN Application at 10, 65-66.
[26] *Id.* at 67.
[27] *Id.*
[28] *See id.* at 71-72.
[29] *Id.* at 47.
[30] *See* CN Application at 72-78, App. F at 98-100 (discussing MISO's development of the MTEP16 Futures).

a. MISO's MTEP process

The MISO MTEP process provides a solid foundation for the determination of the proposed Project's relationship to the adequacy, reliability, and efficiency of the energy supply. The MISO MTEP process is thorough and considers load (demand) forecasts, generation forecasts, potential policy scenarios, and stakeholder input. MISO's witness Dr. Zheng Zhou broadly described MISO's development of the MTEP plans as using a "bottom-up, top-down" approach: "The 'bottom-up' portion relies on the ongoing responsibilities of the individual transmission owners to continuously review and plan to reliably and efficiently meet the needs of their local systems."[31] After reviewing these local planning activities with stakeholders, MISO then performs a "top-down" review of the adequacy of and appropriateness of the local plans in coordination with all other local plans to ensure that needs are met cost effectively.[32]

As part of its review, MISO examines congestion and considers improvements that may be needed to meet forecasted energy requirements.[33] MISO engages stakeholders to develop a wide range of future scenarios, which form the basis for forecasts of resources and load that would be economical and consistent with policy.[34] The Department's witness Dr. Steve Rakow described that these futures consider various levels of several key variables—including the demand for electricity, unit retirements, natural gas prices, and integration of renewable power—with the goal of providing "bookends," or highest and lowest potentials, for future developments.[35]

[31] Ex. MISO-1 at 6 (Zhou Direct).
[32] *See id.* Dr. Zhou emphasized that it is crucial that the transmission system be adequately planned to accommodate load growth and/or changes in load and load growth patterns, as well as changes in generation and generation dispatch patterns. *See id.* at 8.
[33] *See id.* at 7.
[34] *See id.*
[35] Ex. DER-5 at 11 (Rakow Direct).

For the five MTEP16 Futures, differing amounts of demand and energy growth were modeled, along with coal generation retirements and various policy and regulatory standards.

- *Business as Usual*: Demand and energy growth are modeled at 0.9 percent. Assumes retirement of 12.6 gigawatts (GW) of coal generation and age-related generation retirements. Current state-level renewable portfolio standards (RPS) and energy efficiency resource standards (EERS) mandates are modeled.[36]
- *High-Demand*: Same as the Business as Usual future regarding the issues discussed above, but demand and energy growth are modeled at 1.6 percent.[37]
- *Low-Demand*: Same as the Business as Usual future regarding the issues discussed above, but demand and energy growth are modeled at 0.2 percent.[38]
- *Regional Clean Power Plan Compliance*: Demand and energy growth are modeled at 0.9 percent. Assumes retirement of 12.6 gigawatts (GW) of coal generation and age-related generation retirements, along with 14 GW of additional coal unit retirements, coupled with $25/ton carbon costs, and state renewables mandates.[39]
- *Sub-Regional CPP Compliance*: Demand and energy growth modeled at 0.9. Assumes retirement of 12.6 gigawatts (GW) of coal generation and age-related generation retirements, along with 20 GW of additional coal unit retirements, coupled with $40/ton carbon cost, and state mandates for renewables.[40]

To develop the demand and energy growth rates in each Future, the MTEP proposed an aggregated, footprint-wide demand and energy growth rate based on historical load growth in

[36] CN Application at 73.
[37] *Id.*
[38] *Id.*
[39] *Id.*
[40] *Id.*

demand.[41] The growth rates in each Future are referenced as 50/50, 10/90, or 90/10, with the midrange 50/50 forecast representing an equal chance that the forecast could be higher or lower than the stated growth rate.[42]

The demand and energy growth numbers stated in the Futures assumptions represent an aggregated average of the Local Balance Areas (LBA) within MISO, meaning that the load growth input into the Futures models are based on local growth projections instead of a footprint-wide average being applied across the board. MISO then aggregates the LBA values into a Local Resource Zone level and aggregates again to the level of the MISO footprint, to represent a 10-year compound annual growth rate.[43] "In MTEP16, these projections were applied to the base Module E load forecast data provided by the MISO Load Serving Entities through year 10, and then the forecast assumptions for demand and energy growth were utilized to project beyond year 10."[44] Figure 18 of the CN Application shows the breakdown of the 50/50 load forecast for MTEP16 used in the Business as Usual, Regional CPP Compliance, and Sub-regional CPP Compliance Futures.[45]

The MTEP process also accounts for new generation. As Dr. Rakow explained, given that MISO is analyzing potential futures for the transmission system, the quantity of new

[41] CN Application at 74.
[42] *Id.*
[43] *Id.* at 74-75.
[44] *Id.* at 75. The MTEP16 Report describes the difficulty of developing accurate information on the composition of load data and differences in end-use load can be viewed on a footprint-wide, regional, or load serving entity level. CN Application, Appx. F at 191 (MTEP16 Report). "To keep up with changing end-use consumption, MISO relies on the data submitted to the Module E Capacity Tracking (MECT) tool." *Id.* The MECT data is used for all of the long term forecasting. *Id.*
[45] CN Application at 75.

generation to expect and where it will be located must be estimated.[46] MISO uses a capacity expansion model to determine the size, type, and timing of future generation additions, which for MTEP 16 was run for the years 2015 to 2034.[47] Many of the locations for new generation are in the Project area.[48]

As the congestion to be addressed by the proposed Project is being driven, in part, by wind generation, the MTEP16 Futures included an assumed amount of new wind generation.[49] The new (incremental) renewable generation across the MISO footprint for each future is: Limited demand—3,600 MW wind and 1,375 MW solar; Business as Usual—5,400 MW wind and 1,500 MW solar; Regional CPP—5,400 MW wind and 20,700 MW solar; High Demand—8,700 MW wind and 1,700 MW solar; Sub-Regional CPP—25,800 MW wind and 23,100 MW solar.[50] The data on new generation, along with load forecasts and other data is then input to another model to analyze the transmission system.[51]

b. Dr. Rakow's wind capacity forecast

Dr. Rakow noted that while MISO certainly considered expected loads, the Applicants stated that the proposed Project is needed to reduce congestion, which will improve the efficiency of MISO's energy market resulting in lower wholesale energy costs.[52]

The CN Application explains, "Congestion happens when either the generators of electricity want to put more power on a line than the existing transmission facilities are able to accommodate or when consumers of electricity want to use more power than can be delivered

[46] Ex. DER-5 at 11 (Rakow Direct).
[47] *Id.*; CN Application, App. F, at App. E2 at 18 (MTEP16 Appendix E2).
[48] Ex. DER-5 at 11 (Rakow Direct); CN Application, App. F at App. E2 at 30-32, 33-37.
[49] Ex. DER-5 at 11 (Rakow Direct).
[50] CN Application, App. F at 103 (MTEP16 Report).
[51] Ex. DER-5 at 12 (Rakow Direct).
[52] *Id.* at 9; CN Application at 1.

from the most cost-effective generators." More broadly, congestion is a situation that causes an excess of supply of or demand for the most cost-effective generation.[53]

The MTEP16 determined that "the area with the most congestion, and therefore highest potential benefit, is on the border of Iowa and Minnesota."[54] The specific element of the transmission system that experiences significant congestion is the Huntley–Blue Earth 161 kV line.[55] MISO identified the cause of the congestion in the Project area as (1) the existing wind capacity and coal generation in northern Iowa; (2) the increase in wind capacity in Iowa forecast for the next 15 years; and (3) expected coal retirements near the Minneapolis/Saint Paul area.[56] The Applicants concluded that not all available wind energy can be delivered to load centers, such as the Twin Cities, given expected changes in generation.[57]

Because the retirements of coal generation facilities are known factors, Dr. Rakow focused his analysis on forecasting the amount of wind capacity expected to be added in Minnesota and Iowa.[58] Dr. Rakow provided this forecast for comparison to the levels of new wind assumed in the MTEP16 Futures, to help assess whether future wind projects in Minnesota and Iowa are sufficient to economically justify the proposed Project.[59]

Particularly, the amount of wind expected to be added affects the benefit-to-cost ratio of the proposed Project. At a 2016 meeting of the Economic Planning Users Group (EPUG), MISO illustrated that the proposed Project is estimated to have a benefit-to-cost ratio of 1.07 when MISO's Definitive Planning Phase (DPP) queue wind is modeled at 3.7 GW level, and a benefit-

[53] Ex. DER-5 at 10 (Rakow Direct).
[54] *See* CN Application, App. F at 105 (MTEP16 Report).
[55] Ex. DER-5 at 12 (Rakow Direct).
[56] CN Application, Appx. F at 110 (MTEP 16); Ex. DER-5 at 12-13 (Rakow Direct).
[57] CN Application at 65-66; Ex. DER-5 at 13 (Rakow Direct).
[58] Ex. DER-5 at 13 (Rakow Direct).
[59] *Id.*

to-cost ratio of 1.25 when DPP queue wind is modeled at 4.3 GW level.[60] These effects on the benefit-to-cost ratio are particularly important because a project must have a benefit-to-cost ratio of at least 1.25 to qualify as an MEP.[61]

Dr. Rakow explained the process that MISO uses to connect new generation, including new wind projects, to the transmission system.[62] First, MISO aggregates all potential generation projects by region and studies them in groups.[63] From 2013 to 2017, MISO formed two study groups per year in the West region,[64] which are designated as the year plus February or August (e.g. DPP-2015-Feb or DPP-2015-Aug).[65] For 2018, MISO formed only one study group, which is designated as DPP-2018-Apr.[66] Each study group undergoes an analysis divided into three phases, with the entire study process being referred to as the DPP.[67] Projects can withdraw from consideration at the end of each DPP phase.[68] If successful, the DPP process ends with a Generator Interconnection Agreement (GIA).[69] The GIA specifies the characteristics of the generation project, how it will interconnect to the transmission system, the type of transmission

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[60] *See id.* at 13, SRR-3 (Rakow Direct). MISO's EPUG presentation refers to the wind as being in Iowa and Minnesota. *Id.* at 14, SRR-3.
[61] *Id.* at 13-14.
[62] *See id.* at 14.
[63] *See* Ex. DER-5 at 14 (Rakow Direct).
[64] Portions of Minnesota, Iowa, North Dakota, South Dakota, and Montana that are in MISO make up the MISO West region, but because some transmission owners in the West region own facilities that run into neighboring states, occasionally there are projects in the West group located in Wisconsin and Missouri. *Id.* at 14 n.1.
[65] *See id.* at 14.
[66] *Id.*
[67] *Id.*
[68] Ex. DER-5 at 14 (Rakow Direct).
[69] *Id.* at 15.

service being requested, the transmission system upgrades that must be completed, cost responsibility, and so forth.[70]

To forecast new wind capacity, Dr. Rakow first determined the amount of wind projects that entered the DPP study and signed a GIA after the cutoff for inclusion in the MTEP16 Report.[71] Specifically, beginning with the DPP-2015-Feb West study group, Dr. Rakow obtained MISO's information on the projects in that group, including information on which projects completed the DPP, which were still active, and which had withdrawn.[72] Dr. Rakow then sorted the projects into generation categories (wind, solar, etc.) and into three regions (Minnesota/Iowa; Montana/North Dakota/South Dakota; and Missouri/Wisconsin). Dr. Rakow then repeated this process for the six study groups following DPP-2015-Feb West and ending with DPP-2018-Apr West.[73] These seven West study groups are in various phases of analysis.[74] As of September 17, 2018,[75] 1,803 MW of wind projects in Minnesota and Iowa had signed a GIA since the MTEP16 draft was published, and 16,697.5 MW[76] of wind in Minnesota and Iowa had joined the various

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[70] *Id.*
[71] *See id.*
[72] *Id.* at 16.
[73] These study groups are DPP-2015-Aug West study group; DPP-2016-Feb West study group; DPP-2016-Aug West study group; DPP-2017-Feb West study group; DPP-2017-Aug West study group; DPP-2018-Apr West study group. Ex. DER-5 at 16 (Rakow Direct).
[74] At the time of Dr. Rakow's Direct Testimony, the DPP-2015-Feb West and DPP-2015-Aug West study groups had been completed with all projects either having signed a GIA or withdrawn. The DPP-2016-Feb West study group is in the GIA negotiation phase. The DPP-2016-Aug West study group and the DPP-2017-Feb West study group are in different DPP phases. The remaining study groups (DPP-2017-Aug and DPP-2018-Apr) have not started. *Id.*
[75] This is the date Dr. Rakow accessed MISO's publically available generation interconnection queue. *Id.* at 17. The data, as of September 17, 2018, is located in a schedule to Dr. Rakow's testimony. *See id.* at SRR-5.
[76] Of the 16,697.5 MW, a total of 14,851.0 are still active and 1,846.5 MW have withdrawn. *Id.* at 17 n.12.

DPP study groups.[77] These amounts compare to 2,503 MW of wind projects signing GIAs in the entire West region, and 27,321.4 MW of wind projects in the entire West region having joined the various DPP study groups.[78]

To forecast the amount of wind in Minnesota and Iowa that may actually go into service, Dr. Rakow determined the historical percentage of wind capacity in completed DPP study groups that actually signed GIAs. Dr. Rakow reviewed the MISO DPP West study groups for 2012 to 2014 in the same manner as for the MISO DPP West study groups for 2015 to 2018.[79] For the 2012 to 2014 DPP study groups, 82.8 percent of the wind capacity in Minnesota and Iowa eventually signed a GIA, while 85.7 percent of the wind capacity in the 2012 to 2014 DPP West study groups eventually signed a GIA.[80] For the 2015 DPP study groups, which were the only completed study groups following MTEP16, 79.4 percent of the wind capacity in Minnesota and Iowa eventually signed a GIA, and 84.2 percent of the wind capacity in the DPP West study groups eventually signed a GIA.[81] Dr. Rakow, therefore, concluded that it would be reasonable to assume that, on average, about 80 to 85 percent of wind projects that enter a DPP study group would eventually sign a GIA.[82]

Dr. Rakow concluded that the overall forecast for future wind is 14,786 MW, which was arrived at by taking the known amount of wind capacity that signed GIAs from the DPP-2015-

[77] Ex. DER-5 at 17 (Rakow Direct).
[78] *Id.* at 17-18.
[79] *Id.* at 18.
[80] *Id.* at 20.
[81] *Id.*
[82] Ex. DER-5 at 20 (Rakow Direct). Dr. Rakow noted, however, that the GIA is not a perfect proxy to construction because it is possible for a wind project to sign a GIA but not be constructed, and conversely, it is also possible for a wind project to be constructed prior to signing a GIA. *Id.* Dr. Rakow explained the limited effect that these occurrence would have on MISO's data and the MTEP16 report in his Direct Testimony. *See id.* at 20-22.

Feb West and DPP-2015-Aug West study groups (1,803 MW) and adding 80 percent of the West study groups for DPP-2016-Feb to DPP-2018-Apr of wind in Iowa and Minnesota estimated to sign GIAs (12,983 MW).[83] Dr. Rakow also provided an alternative forecast assuming a much lower percentage of wind projects, in MW, entering a DPP study group to sign a GIA.[84] Dr. Rakow concluded that even if only 50 percent of the wind in Minnesota and Iowa for DPP-2016-Feb to DPP-2018-Apr signs a GIA and is constructed, the result would be 9,917 MW of wind (1,803 MW plus 8,114 MW) added in Minnesota and Iowa since MTEP16.[85]

Dr. Rakow's 14,786 MW base forecast and the 9,917 MW lower bound of wind in Iowa and Minnesota would exceed the amounts assumed for all of MISO by 2030 for four of the five MTEP16 Futures.[86] Dr. Rakow noted, however, that his forecast does not consider wind facilities that might enter the yet-to-be-formed study groups and still be in-service by 2030.[87]

Dr. Rakow concluded that a reasonable forecast of new wind capacity will exceed by a significant margin the 4,300 MW amount necessary to achieve a 1.25 benefit to cost ratio.[88] Dr. Rakow's forecast indicates that new wind capacity will continue to increase congestion in the Project area, thus supporting a conclusion that the probable result of denial would be an adverse

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[83] *Id.* at 22.
[84] *Id.*
[85] *Id.* Dr. Rakow explained that even though all of these wind facilities would be added far in advance of the 2030 cutoff date used in the MTEP16 analysis, because even the lower estimate of 9,917 MW of wind far exceeds the 4,300 MW threshold established by MISO at EPUG to meet a 1.25 benefit-to-cost ratio, wind that might enter the DPP process in the future does not need to be considered. *Id.* at 23.
[86] *Id.* at 23. Dr. Rakow's forecast would exceed the amounts of wind in the Limited Demand, Business as Usual, High Demand and Regional CPP Futures, while the forecast would be less than the assumed amount in the Sub-Regional CPP future. *Id.*
[87] Ex. DER-5 at 23 (Rakow Direct).
[88] *Id.*

effect upon the future adequacy, reliability, and efficiency of energy supply to the Applicants, the Applicants' customers, or the people of Minnesota and neighboring states.

2. Effects of the Applicants' existing or expected conservation programs and state and federal conservation programs

Minn. R. 7849.0120 A(2) requires consideration of "the effects of the applicant's existing or expected conservation programs and state and federal conservation programs." The CN Application shows that flow reductions in the Mankato area would have to range from 120 MW to 373.33 MW in order to alleviate the congestion.[89] The Applicants also calculated the load reduction—conservation and load management—necessary to achieve the necessary flow reductions using a shift factor, which represents the percentage change that additional load at one point would have on an identified constraint.[90] Assuming a shift factor of 0.3,[91] a significant amount of load reduction, between 400 and 1,244.43 MW, would be required under all three MTEP17 Futures.[92] The CN Application states that a shift factor of 0.3 would require that the load reductions occur "in a limited area on the north side of the identified congestion," particularly in and around the Mankato area.[93]

To provide a comparison for these levels of load reduction, Dr. Rakow explained that targeted demand-side management was explored as an alternative to transmission in Xcel's CN for the Hollydale 115 kV Transmission Line Project.[94] In that docket, Xcel indicated that in a 10

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[89] CN Application at 123, Table 26; Ex. DER-5 at 24 (Rakow Direct).
[90] CN Application at 123; Ex. DER-5 at 24 (Rakow Direct).
[91] In response to a DOC DER information request, the Applicants clarified that Table 27 of the CN Application should read 0.3, instead of 0.2, as it does in the associated text in the CN Application at 123-124. *See* Ex. DER-5 at 24 n.18 (Rakow Direct).
[92] *Id.* at 24-25; CN Application at 124 (Table 27).
[93] CN Application at 123; Ex. DER-5 at 25 (Rakow Direct).
[94] Ex. DER-5 at 25 (Rakow Direct).

month period it achieved about 4.5 MW of savings.[95] Dr. Rakow observed that the levels of load reduction that would be needed to reduce the congestion are far in excess of what might be expected from a targeted load management and conservation alternative.[96]

Therefore, the Applicants' existing or expected conservation programs and state and federal conservation programs cannot be expected to address the congestion and provide the reliability and efficiency of the proposed Project.

3. Effects of the Applicants' promotional practices that may have given rise to an increase in energy demand

Minn. R. 7849.0120 A(3) requires consideration of the effects of an applicant's promotional practices that may have increased energy demand in determining the need for a proposed facility.[97] Similarly, Minn. Stat. § 216B.243, subd. 3(4) requires evaluation of "promotional activities that may have given rise to demand for this facility."

The CN Application stated that "[n]either Xcel Energy nor ITC Midwest has conducted any promotional activities or events that have triggered the need for the Project," which stems from "the large amount of wind capacity in southern Minnesota and northern Iowa coupled with transmission constraints [and] . . . the expected coal generation retirements north of the

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[95] *See In re Certificate of Need for the Hollydale 115-kV Transmission-Line Project in the Cities of Plymouth and Medina*, MPUC Docket. No. E002/CN-12-113, Corrected Annual Compliance Filing at 4 (Apr. 10, 2018); Ex. DER-5 at 25 (Rakow Direct). These savings were from 206 business participants and 1,503 residential participants in the Hollydale Focused Study Area, which consists of customers served by 13 distribution feeds that experience overload conditions.

[96] Ex. DER-5 at 25 (Rakow Direct).

[97] In accordance with Minn. R. 7849.0200, subd. 6, which allows for exemptions from certain data requirements in CN Applications, the Applicants requested that ITC Midwest be exempted from providing "an explanation of the relationship of the proposed facility to … promotional activities that may have given rise to the demand for the facility," because ITC Midwest "does not directly serve end-users of electric service and has not engaged in promotional activities that could have given rise to the need for the proposed Project." *See* Request for Exemptions for the Huntley Wilmarth 345 kV Transmission Line Project at 8 (July 14, 2017) (eDocket No. 20177-133882-01). The Commission granted this exemption. *See* Order at 2 (Sept. 1, 2017) (eDocket 20179-135212-01).

Minneapolis/St. Paul area."[98] Dr. Rakow agreed that the need for the proposed Project was not created by any promotional activities and instead is due to the lower cost of wind resources and changes in existing generation resources.[99] Therefore, promotional practices did not cause the stated need for the proposed Project.

4. Ability of current facilities and planned facilities not requiring certificates of need to meet future demand

Minn. R. 7849.0120 A(4) requires consideration of "the ability of current facilities and planned facilities not requiring certificates of need to meet the future demand." Dr. Rakow explained that in developing transmission models, MISO includes all projects that it has approved.[100] Therefore, due to the proposed Project's extensive consideration and analysis particular to the MISO transmission planning process, adequate consideration of current and planned facilities' (other than the proposed Project) ability to meet future demand has occurred at the MISO planning level and been determined not to be sufficient or as efficient at meeting the need for the proposed Project.

5. Effect of the proposed facility, or a suitable modification thereof, in making efficient use of resources

Minn. R. 7849.0120 A(5) requires consideration of "the effect of the proposed facility, or a suitable modification thereof, in making efficient use of resources." The CN Application stated that one of the benefits of the proposed Project is the greater deliverability of wind resources by reducing curtailments of wind generation.[101] The Applicants explained that when existing wind generation is curtailed, other generation, typically higher cost fossil fuel generation, must be

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[98] CN Application at 13.
[99] *See* Ex. DER-5 at 26 (Rakow Direct).
[100] *Id.* at 27. In addition, DOC DER witness Matthew Landi analyzed various alternatives to the proposed Project, including alternatives not requiring certificates of need such as the Applicants' proposed No Build Alternatives, which are addressed below.
[101] CN Application at 93.

relied on, which increases costs and reduces the potential economic benefits of wind generation.[102] Applicants' witness Mr. Siebenaler testified that the proposed Project reduced wind curtailments in Minnesota, North Dakota, South Dakota, and Iowa, in all four futures under MTEP17 models.[103]

Dr. Rakow agreed that the proposed Project would reduce curtailment of wind generation and reduce line losses and concluded that the proposed Project would enable MISO to use generation resources more efficiently.[104] This consideration, therefore, weighs in favor of granting a CN for the proposed Project.

B. Minn. R. 7849.120 B: A More Reasonable and Prudent Alternative to the Proposed Facility Has Not Been Demonstrated by a Preponderance of the Evidence on the Record.

The Commission's rules provide that a CN may be granted to an applicant if "a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record."[105] Minnesota statutes also require consideration of renewable energy alternatives and distributed generation in CN proceedings.[106]

Alternatives to the proposed Project have been extensively considered. Before MISO designated the proposed Project as an MEP, the MTEP16 study performed a screening analysis identifying 23 possible solutions designed to relieve congestion in the Blue Earth area.[107] Of these 23 solutions, 16 were shown to have a one-year benefit-to-cost ratio (BC ratio) equal to or

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[102] *Id.*
[103] Ex. XC-24 at 23 (Siebenaler Direct).
[104] Ex. DER-5 at 28 (Rakow Direct).
[105] Minn. R. 7849.0120 B.
[106] *See* Minn. Stat. §§ 216B.2422, subd. 4, 216B.2426 (2018).
[107] Ex. DER-3 at 3-4 (Landi Direct).

greater than 0.9.[108] MISO then grouped these 16 alternatives into four groups of solutions based on voltage level and design approach.[109] The best performer in each group underwent a full 20-year Net Present Value (NPV) calculation to determine its BC ratio.[110] The remaining three solutions with a BC ratio of one or more were then subjected to engineering analyses of their ability to mitigate the congestion through 2031.[111] Of these three solutions, only one relieved 100% of the congestion through 2031. This solution, referred to as solution I-02, is the proposed Project.[112]

In addition to MISO's screening analysis described above, to determine the appropriate solution to the congestion, the Applicants analyzed the proposed Project with MTEP17 assumptions and data.[113] DOC DER's witness Mr. Matthew Landi reviewed the Applicants' analysis and concluded that overall the Applicants' analysis sufficiently considered reasonable alternatives to the proposed Project and demonstrated that the proposed Project is the best available choice for the Applicants to address the congestion.[114] Mr. Landi most intensively compared the proposed Project to a 161 kV alternative, which was the most viable of the analyzed alternatives. Mr. Landi concluded that the proposed Project outperformed the 161 kV alternative with respect to the 20-Year NPV Benefit, curtailment reductions, reduced system losses, congestion relief, externalities benefits, and cost allocation.[115]

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[108] CN Application at 79; Ex. DER-3 at 4-5 (Landi Direct). A project must have a BC ratio of 1.25 to qualify as an MEP in Attachment FF of the MISO Tariff. *See* Ex. MISO-1, sched. 1 at 21 (MTEP16 Report at 100) (Zhou Direct).
[109] Ex. DER-3 at 5 (Landi Direct).
[110] CN Application at 81; Ex. DER-3 at 5 (Landi Direct).
[111] CN Application at 82-83; Ex. DER-3 at 5 (Landi Direct).
[112] CN Application at 82-83; Ex. DER-3 at 5 (Landi Direct).
[113] Ex. DER-3 at 6 (Landi Direct).
[114] Ex. DER-3 at 20 (Landi Direct); Ex. DER-4 at 13 (Landi Rebuttal).
[115] *See* Ex. DER-3 at 46-48 (Landi Direct).

1. The record does not demonstrate that reasonable alternatives are more appropriate than the proposed facility regarding size, type and timing.

Minn. R. 7849.0120 requires that the Commission consider "the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives," in determining need.

Mr. Landi analyzed the alternatives to the proposed Project considered by the Applicants including: size alternatives, type alternatives, generation alternatives (renewable energy resources and distributed generation resources), and energy conservation and demand side management (DSM) programs (referred to by Applicants as "No Build Alternatives"). Mr. Landi's analysis shows that the record does not demonstrate a more reasonable and prudent alternative to the proposed facility in terms of size, type, or timing under Minn. R. 7849.0120 B(1), and considering renewable energy alternatives and distributed generation as required by Minn. Stat. §§ 216B.2422, subd. 4, 216B.2426 (2018).[116]

a. Size alternatives

As in past proceedings, DOC DER interprets "size," in the context of Minn. R. 7849.0120 B(1), as the quantity of power transfers that the transmission line enables.[117] Applicants agree that this interpretation is correct in this context.[118]

Mr. Landi concluded that the Applicants' analysis of both higher and lower voltage size alternatives to the proposed Project was appropriate.[119] Specifically, the Applicants appropriately

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[116] Minn. R. 7849.0120 B (2017); Ex. DER-3 at 20 (Landi Direct); Ex. DER-4 at 13 (Landi Rebuttal).
[117] *See In re Application for a Certificate of Need for the Upgrade of the Sw. Twin Cities Chaska Area 69 kV Transmission Line to 116 kV Capacity*, MPUC Docket No. E002/CN-11-826, Comments of DOC DER at 15 (Jan. 28, 2013); Ex. DER-3 at 7 (Landi Direct).
[118] Ex. DER-3 at 7-8, ML-2 (Landi Direct).
[119] Ex. DER-3 at 10 (Landi Direct); *see also* CN Application at 99-100.

concluded that the higher costs of higher voltage lines, 765 kV and 500 kV, were not justified because the proposed 345 kV line would sufficiently alleviate the congestion.[120] Regarding lower-voltage alternatives, the Applicants excluded from further consideration 230 kV and 138 kV lines, because substations in the area would require costly upgrades to accommodate these voltages,[121] and 69 kV and 115 kV lines for technical and cost considerations.[122] Mr. Landi agreed that excluding these alternatives was reasonable.[123]

The Applicants and DOC DER provided additional analysis of the 161 kV alternative, but both concluded that it had significant limitations, such as not sufficiently addressing the congestion, not sufficiently reducing wind curtailments, and not qualifying as an MEP.[124]

First, under both MTEP17 and MTEP18 modeling, the 161 kV alternative would provide less congestion relief over the life of the transmission line. While the proposed Project is expected to relieve 100% of the congestion over the ten-year study period using both MTEP17 and MTEP18 assumptions, the 161 kV alternative would alleviate only 85% of the congestion by 2032 under MTEP18 and 80% of the congestion under MTEP17 by 2031.[125] Although the 161 kV alternative fairs better in the near term at relieving the congestion under MTEP17 modeling

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[120] *See* Ex. DER-3 at 8-9 (Landi Direct). The Applicants similarly determined that a double-circuit 345 kV/345 kV line would increase the project costs without identifiable additional benefits, because a single 345 kV line relieved 100% of the congestion through 2031. CN Application at 113; Ex. DER-3 at 10 (Landi Direct).
[121] These upgrades would cost approximately $31.2 million for the 230 kV line and $28.9 for the 138 kV line. *See* Ex. DER-3 at 9, ML-3 at 3 (Landi Direct).
[122] *See* CN Application at 99-102.
[123] *See* Ex. DER-3 at 9-10 (Landi Direct); CN Application at 101. Also, the lower capacity of 69 kV and 115 kV lines provide even less of a power transfer path than the 161 kV alternative, and therefore would also be insufficient to relieve the congestion. Ex. DER-3, ML-4 (Landi Direct).
[124] Mr. Landi also examined the Applicants' analysis of the expected reduction in system losses resulting from the proposed Project versus the 161 kV alternatives, which is discussed in Section B.4 below. *See* Ex. DER-3 at 43-46 (Landi Direct).
[125] *See* Ex. DER-3 at 47, ML-14, ML-15 (Landi Direct); Ex. DER-4 at 6 (Landi Rebuttal); Ex. XC-24 at 40 (Siebenaler Direct).

assumptions, providing 100% of congestion relief in 2021, it was only able to provide 75% and 80% of congestion relief in 2026 and 2031 respectfully.[126] Similarly under MTEP18, the 161 kV alternative would reduce 99% of the congestion in 2022, but would only relieve 94% and 85% of the congestion by 2027 and 2032.[127]

Second, the proposed Project is expected to reduce curtailments of wind resources better, compared to the 161 kV alternative. Reducing these curtailments would likely put downward pressure on MISO prices due to the generally lower variable costs of wind resources.[128] Under MTEP17 Futures, Mr. Landi's analysis showed a 18.7% reduction in wind resource curtailments for the proposed Project with only a 9.9% reduction for the 161 kV alternative by 2026.[129] While the margin between the alternatives would be reduced by 2031, the proposed Project was still projected to reduce 15.8% of curtailments versus 161 kV alternative's 11.5%.[130] Overall, Mr. Landi concluded that under the MTEP17 Futures the proposed Project would reduce wind resource curtailments by an additional 86,000 MWh in 2026, and by an additional 150,000 MWh in 2031, compared to the 161 kV alternative.[131] Under MTEP18 modeling assumptions, Mr. Siebenaler testified that the proposed Project would reduce curtailments by between 2.6% and 18.4%, whereas the 161 kV alternative would reduce curtailments by between 1.4% and 12.1%.[132] Mr. Landi agreed that the proposed Project would better reduce wind resource curtailments under MTEP18 modeling assumptions compared to the 161 kV alternative.[133]

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[126] Ex. DER-3 at 45 (Landi Direct).
[127] Ex. XC-24 at 40 (Siebenaler Direct); Ex. DER-4 at 6 (Landi Rebuttal).
[128] Ex. DER-3 at 43 (Landi Direct).
[129] *Id.*
[130] *Id.*
[131] *See id.* at 43, 47.
[132] Ex. XC-24 at 40-41 (Siebenaler Direct).
[133] Ex. DER-3 at 43, 46, 48-49 (Landi Direct); Ex. DER-4 at 7 (Landi Rebuttal).

Third, the 161 kV alternative, due to its lower voltage, could not qualify as an MEP, which allows for cost sharing across the MISO region.[134] As an MEP, Minnesota ratepayers would pay a lower share of the cost of the proposed Project, whereas the full costs of the 161 kV alternative would be assigned to the local resource zone in MISO.[135]

Therefore, the size alternatives in the record have not been shown to be more appropriate than the proposed 345 kV line.[136] However, because it is the most viable of analyzed size alternatives, the 161 kV alternative is discussed further below regarding internal and external economic costs.

b. Type alternatives

Minn. R. 7849.0120 B(1) also requires the Commission to consider the type of the proposed facility compared to reasonable alternatives. As in past proceedings, DOC DER interprets "type," in the context of Minn. R. 7849.0120 B(1), as referring to the transmission line's nominal voltage, rated capacity, surge impedance loading (SIL), and the nature of power transported (AC or DC).[137]

The Applicants considered several type alternatives to the proposed Project: (1) constructing a transmission project with different end points; (2) reconductoring or rebuilding the existing transmission facilities currently connecting the Huntley and Wilmarth substations; (3) double-circuiting of existing transmission lines; (4) employing high-voltage direct current

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[134] Ex. DER-3 at 48 (Landi Direct).
[135] *Id.* at 24, 48.
[136] *See* Ex. DER-2 at 10 (Landi Direct).
[137] *See In re Application for a Certificate of Need for the Upgrade of the Sw. Twin Cities Chaska Area 69 kV Transmission Line to 116 kV Capacity*, MPUC Docket No. E002/CN-11-826, Comments of DOC DER at 15 (Jan. 28, 2013); Ex. DER-3 at 11 (Landi Direct).

(HVDC) transmission lines; (5) using alternative conductor arrays, which affects the capacity of the transmission line; and (6) installing underground transmission lines.[138]

The Applicants provided several reasons why these alternatives were not appropriate, including reliability and cost-effectiveness.[139] Mr. Landi concluded that the Applicants sufficiently explained their reasonable conclusion that these alternatives are not appropriate.[140] The type alternatives in the record, therefore, have not been shown to be more appropriate than the proposed Project.

c. Timing

Minn. R. 7849.0120 B(1) also requires that the Commission consider the timing of the proposed facility compared to reasonable alternatives. As in past proceedings,[141] DOC DER interprets "timing," in the context of Minn. R. 7849.0120 B(1), as referring to the proposed on-line date for a project.[142] The Application explains that the congestion is likely to become more severe as time passes.[143] For example, in 2016 and 2017 alone "more than 6,600 MW of new wind generation to be located in Minnesota or Iowa entered the MISO queue."[144] Mr. Landi concluded that due to the existing congestion and the likelihood that it will become more severe until the proposed on-line date in 2021, the proposed on-line date appears reasonable.[145]

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[138] CN Application at 113-121; Ex. DER-3 at 12, ML-5 (Landi Direct).
[139] Ex. DER-3 at 12-13 (Landi Direct); CN Application at 113-121.
[140] Ex. DER-3 at 13 (Landi Direct).
[141] *See In re Application for Sw. Twin Cities Chaska Area 69 kV Transmission Line to 116 kV Capacity*, MPUC Docket No. E002/CN-11-826, Comments of DOC DER at 15 (Jan. 28, 2013).
[142] Ex. DER-3 at 13 (Landi Direct).
[143] CN Application at 58; Ex. DER-3 at 14 (Landi Direct).
[144] CN Application at 58; Ex. DER-3 at 14 (Landi Direct).
[145] Ex. DER-3 at 14 (Landi Direct).

d. No Build Alternatives

The Applicants also considered two No Build Alternatives, which would attempt to reduce congestion through (1) load growth, and (2) conservation and DSM programs.[146]

Regarding the load growth alternative, the Applicants stated that because the congestion is due in part to generation levels exceeding the amount of load in the area, if the area's load grew sufficiently, congestion would ameliorate.[147] The Applicants determined, however, that to reduce current congestion, load in the area would need to increase between 120 MW and 373.33 MW, while it is only projected to grow by 58 MW by 2027.[148] The Applicants and Mr. Landi agreed that the projected load growth is insufficient to reduce congestion.[149]

Regarding conservation and DSM program alternatives, the Applicants examined the effects of load reductions in the congested area.[150] The Applicants' technical analysis suggests that, in order to alleviate current congestion, load reduction through conservation and DSM would need to occur in and near Mankato and reach between 240 MW and 600 MW, if only the existing generation fleet remains, and between 700 MW and 1,800 MW, if no new facilities were constructed.[151] The Applicants and Mr. Landi agreed that the conservation and DSM programs alternatives would not alleviate the congestion.[152]

e. Renewable generation and distributed generation

Minnesota law requires that the Commission consider additional factors related to alternatives in all CN proceedings. First, the Commission cannot approve a nonrenewable

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[146] CN Application at 121-24; Ex. DER-3 at 14-15 (Landi Direct).
[147] CN Application at 122.
[148] *See id.* at 122-23, App. M.
[149] *Id.* at 122; Ex. DER-3 at 16 (Landi Direct).
[150] CN Application at 122-24; Ex. DER-3 at 16 (Landi Direct).
[151] CN application at 123; Ex. DER-3 at 16 (Landi Direct).
[152] Ex. DER-3 at 16 (Landi Direct).

energy facility in a CN proceeding "unless the utility has demonstrated that a renewable energy facility is not in the public interest."[153] Second, the Commission must ensure that opportunities for distributed generation are considered in CN proceedings.[154]

The Applicants generally concluded that adding new generation resources, renewable or otherwise, would not be a reasonable alternative given that existing generation and planned new wind energy generation are inducing the need for the proposed Project.[155] Nevertheless, the Applicants stated that in order for a generation alternative to reduce the congestion, it "would need to be of equal or lower cost to the wind generation that is currently being constrained," would need to be north of the congestion, and would need to generate approximately 120 MW and 370 MW at minimum during times when congestion is present.[156] The Applicants noted the difficulty of siting new large-scale wind generation facilities on the north side of the congestion because of existing development and other considerations near the City of Mankato.[157] Also, due to decreased wind speeds north of the Iowa border a large quantity of wind turbines would need to be constructed—15 to 30 percent more nameplate capacity.[158] Mr. Landi concluded that the Applicants reasonably demonstrated that additional renewable generation resources would be

[153] Minn. Stat. § 216B.2422, subd. 4 (2018). This determination requires that the Commission consider impacts on local and regional grid reliability, along with utility and ratepayer impacts resulting from the intermittent nature of renewable energy facilities and reduced exposure to "fuel price volatility, changes in transmission costs, portfolio diversification, and environmental compliance costs." *Id.*

[154] Minn. Stat. § 216B.2426 (2018). For the purpose of this requirement, "distributed generation" is defined as "a distributed generation facility of no more than ten megawatts of interconnected capacity that is certified by the commissioner . . . as a high-efficiency, low-emissions facility." Minn. Stat. § 216B.169, subd. 1(c) (2018).

[155] CN Application at 118-21.

[156] *Id.* at 119.

[157] *Id.* at 119-20.

[158] *Id.*

either insufficient or not cost-effective alternatives.[159] In this specific instance, a renewable generation alternative to the proposed transmission line does not appear to be a more reasonable and prudent alternative to the proposed Project on the current record.

Although the Applicants did not address distributed generation alternatives in the CN Application, they did so in response to DOC DER information requests.[160] The Applicants looked at three distributed generation resources: (1) rooftop solar and community solar gardens; (2) distributed thermal resources; and (3) distributed wind resources.[161] The Applicants' analysis indicated that available distributed generation resources would be highly unlikely to resolve the congestion, and that even if such resources could do so, each of these distributed energy resource alternatives would be either insufficient or not cost-effective.[162] Overall, Mr. Landi concluded that the Applicants reasonably considered distributed generation alternatives and demonstrated that these alternatives would either be insufficient or not cost-effective.[163]

2. The costs of the proposed facility compared to the costs of energy supplied by the proposed facility versus reasonable alternatives

In determining whether a more reasonable and prudent alternative has been demonstrated, Minn. R. 7849.0120 B(2) requires consideration of "[t]he 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."

The Applicants evaluated the performance of the 161 kV alternative using MTEP17 models and Future assumptions.[164] The Applicants stated that the proposed 345 kV line resulted

[159] Ex. DER-3 at 20 (Landi Direct).
[160] *See id.*, ML-6.
[161] *Id.*
[162] *See id.* at 18, ML-6.
[163] *Id.* at 19-20.
[164] CN Application at 104.

in a higher 20-year net present value (NPV) Benefit.[165] To reach this conclusion, the Applicants performed a PROMOD[166] analysis for the proposed 345 kV Project and the 161 kV alternative using the three MTEP17 Futures.[167] The Applicants then estimated project benefits under each Future by calculating the Adjusted Projection Cost (APC) savings over a 20-year period.[168] Applicants subsequently calculated the benefit-to-cost (BC) ratio for the 161 kV alternative, using only the costs for the shortest proposed route (Green Route) and a single-circuit steel monopole design, against the 345 kV line with a similar route and design selection.[169]

Mr. Landi conducted additional analysis of the weighted Present Value (PV) benefit and weighted BC ratio of the proposed Project versus reasonable alternatives, as these measures estimate the expected economic benefits.[170] In response to DOC DER information requests, the Applicants detailed the economic analysis performed on PV benefit-to-cost analysis using APC savings and provided updated economic analysis of the proposed Project and 161 kV alternative.[171] Overall, Mr. Landi observed that the Applicants' analysis appeared to be a standard economic analysis of a project that accrues benefits and costs for many years in the future.[172]

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[165] *Id.*
[166] The Applicants' witness Mr. Siebenaler explained at the evidentiary hearing that PROMOD, computer software, is used to enable the production cost analysis to calculate the benefits of a project. Evid. Hr. Tr. at 27 (Siebenaler).
[167] CN Application at 106.
[168] *Id.* at 106; Ex. DER-3 at 20 (Landi Direct).
[169] CN Application at 106. Although changes to the federal tax code would affect the benefit-to-cost ratio for the proposed Project, the Applicants explained that these changes would likely decrease project costs and increase the benefit-to-cost ratio for all alternatives on a comparable basis. *See* Evid. Hr. Tr. at 31-32 (Siebenaler).
[170] Ex. DER-4 at 3 (Landi Rebuttal).
[171] *See* Ex. DER-3 at 21-22, ML-7 (Landi Direct).
[172] *Id.* at 24-25. DOC DER also requested the same level of benefit-cost analysis as was done for the proposed Project and alternatives in the CN Application in response to the EIS scoping
(Footnote Continued on Next Page)

The CN Application stated that the proposed Project had a weighted 20-year PV benefit of approximately $273.11 million, which the Applicants updated in response to an information request to $275.83 million.[173] Following the Environmental Impact Statement (EIS) Scoping Decision, Applicants estimated that the updated costs for the proposed Project range from $104.8 million to $160.7 million, resulting in a BC ratios from 1.42 to 2.18.[174] Mr. Landi emphasized that these project costs were not the same as the value of the annual costs of the proposed Project.[175]

In response to an informal inquiry, the Applicants explained that, for each of the 20 years analyzed, the annual costs included a 20.76% "adder" to the construction cost estimate for each route and design to account for annual revenue requirements,[176] the discount rate, and the inflation rate.[177] The PV of project costs was then determined by summing the PV of the annual project costs each year over the 20-year period.[178] Mr. Landi verified that once the 20.76% adder was factored into the analysis of 20-year PV of costs, the weighted PV benefits

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decision. Although the Applicants did not provide such an analysis for the 161 kV alternative, Mr. Landi ultimately concluded that foregoing this analysis was reasonable because the 161 kV alternatives would not sufficiently address congestion and would not qualify as an MEP. *Id.* at 23-34.

[173] Ex. DER-3 at 26, ML-7 at 6 (Landi Direct).

[174] *See id.* ML-9.

[175] *Id.* at 26.

[176] The annual revenue requirements, found in Attachment GG of the MISO Tariff, are posted for each transmission owner for a 20-year period. *See id.*, ML-7.

[177] *Id.* at 26. The Applicants' response to the DOC DER's informal inquiry is attached to Mr. Landi's Direct Testimony. *See id.* at ML-10.

[178] Ex. DER-3 at 26 (Landi Direct).

corresponded approximately to the updated weighted PV benefits provided by the Applicants.[179] This analysis allowed Mr. Landi to confirm the Applicants' updated figures.[180]

The Applicants provided an updated weighted 20-year PV benefit of $200.7 million (2016$).[181] Using data provided by the Applicants with the updated cost estimates, Mr. Landi provided an analysis of the low- and high-cost estimates for the proposed Project using the MTEP17 Futures, compared to the least cost option of the 161 kV alternative, as shown in the table below:[182]

Table 4 Landi Direct – DOC DER Analysis of Internal Costs of Proposed Project and 161 kV Alternative

Project	Applicants' Project Cost Estimate (2016$)	PV Benefits (2016$, Millions)				PV Costs (2016$, Millions)				BC Ratios (2016$, Millions)			
		AAT	*EF*	*PR*	*Weighted*	*AAT*	*EF*	*PR*	*Weighted*	*AAT*	*EF*	*PR*	*Weighted*
161 kV Huntley-Wilmarth Transmission Line Alternative	$80.9 Million	$557,465,361.19	$ 8,561,537.02	$123,544,753.43	$200,719,314.36	$97,697,020.39				5.71	0.09	1.26	2.05
345 kV Huntley-Wilmarth Transmission Line *Purple Low Route*	$104.8 Million	$816,043,675.29	$ 13,917,740.86	$138,009,303.50	$275,829,855.75	$126,559,304.54				6.45	0.11	1.09	2.18
345 kV Huntley-Wilmarth Transmission Line *Purple-E-Red High Route*	$160.7 Million	$816,043,675.29	$ 13,917,740.86	$138,009,303.50	$275,829,855.75	$194,065,651.14				4.20	0.07	0.71	1.42

Applicants' witness Mr. Siebenaler also analyzed the internal costs of the 161 kV alternative and the proposed Project based the modeling assumptions in the final draft of the MTEP18 Report and compared the costs, weighted BC ratios, and the 20-year weighted PV benefits under MTEP18 and MTEP17.[183] Mr. Landi confirmed that Mr. Siebenaler's updated internal cost analysis used the same methodology as the Applicants' original internal costs

[179] *Id.* at 27.
[180] *Id.*
[181] *Id.*, ML-7 at 7.
[182] *Id.* at 29.
[183] Ex. XC-24 at 38-42 (Siebenaler Direct). Table 8 of Mr. Siebenaler's Direct Testimony provides this comparison. *Id.* at 39.

analysis.[184] Although the economic benefits of both the proposed Project and the 161 kV alternative were reduced when analyzed under the modeling assumptions of MTEP18, as opposed to MTEP17, Mr. Landi concluded that the proposed Project is still superior to the 161 kV alternative.[185]

Overall, Mr. Landi concluded that although the benefits varied depending on the route chosen, even if the highest cost route is chosen, the overall net PV benefit of the proposed Project would still be higher compared to the 161 kV alternative.[186] Mr. Landi concluded that the Applicants reasonably determined that the 161 kV alternative was not more economical than the proposed Project.[187] Therefore, the 161 kV alternative is not a more reasonable and prudent alternative than the proposed Project, in terms of costs.

3. Effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives

Minn. R. 7849.0120 B(3) requires consideration of "the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives." To assess the effects of policies and projects on natural and socioeconomic environments in Commission proceedings, the legislature required the Commission to "quantify and establish a range of environmental costs associated with each method of electricity generation," to the extent practicable, and required utilities to "use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when

[184] Ex. DER-4 at 4 (Landi Rebuttal).
[185] *Id.* at 5.
[186] Ex. DER-3 at 29 (Landi Direct).
[187] *Id.* at 29-30; Ex. DER-4 at 13 (Landi Rebuttal).

evaluating and selecting resource options."[188] To this end, the Commission developed and updated environmental costs for CO_2, sulfur dioxide (SO_2), and nitrogen oxides (NO_x).[189]

In a previous CN proceeding, the Commission ordered ITC Midwest to "work with the Department to develop a spreadsheet . . . ITC can use to calculate the cost of alternatives, including the Commission's CO_2 internal cost and externality values, in future certificate of need proceedings."[190] The Applicants developed a spreadsheet to evaluate environmental externalities of two system configurations—the proposed 345 kV Project and the 161 kV alternative—and included it as Appendix I to the CN Application.[191] Mr. Landi reviewed and analyzed Appendix I, which includes an "Economic Benefit," and a "Public Policy Benefit," to examine the effects of the proposed facility and 161 kV alternative on both the socioeconomic and natural environments.[192]

The Economic Benefit was calculated as the modified Adjusted Projection Cost (APC) savings for each of three MTEP17 study years (2021, 2026, and 2031).[193] The Public Policy Benefit seeks to quantify and compare the environmental impact of the proposed Project versus the 161 kV alternative by comparing the changes in the emissions of CO_2, NO_x, and SO_2 resulting from changes in electricity generation in MISO Load Resource Zones (LRZ) 1, 2, and

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[188] Minn. Stat. § 216B.2422, subd. 3(a) (2018).
[189] *In re Further Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, subd. 3*, MPUC Docket No. E-999/CI-14-643, Order Updating Environmental Cost Values (Jan. 3, 2018) (hereinafter "Externalities Order").
[190] *In re Application of ITC Midwest LLC for a Certificate of Need for the Minn. – Iowa 345 kV Transmission Line Project in Jackson, Martin, and Faribault Ctys.*, MPUC Docket No. ET-6675/CN-12-1053, Order Granting Certificate of Need with Conditions at 10 (Nov. 25, 2014).
[191] *See* XC-18 at 2-3 (Abing Direct); CN Application, App. I.
[192] *See* Ex. DER-3 at 30-41 (Landi Direct).
[193] Ex. XC-18 at 4 (Abing Direct).

3, induced by these two alternatives.[194] For CO_2 externality costs, the Applicants used a low and high value to provide a range of public policy benefits, while for SO_2 and NO_x, the Applicants used the median value of the rural location approved by the Commission.[195] Mr. Landi concluded that the Applicants' approach was reasonable due to the relatively small change in SO_2 and NO_x emission changes as a result of the proposed Project or the 161 kV alternative relative to one another.[196]

The Applicants' witness Mr. Abing testified that, regarding Appendix I, "[t]he key takeaway is the 345 kV Project provides greater estimated avoided emissions reductions for SO_2, NO_x, and CO_2 than the 161 kV alternative," using the Commission's approved externality values.[197] Mr. Landi concluded that the Applicants' externalities analysis appropriately used the Commissions externality values and cost of CO_2 regulation values and employed reasonable methodology.[198]

Over a 63-year evaluation period, matching the assumed life of the transmission assets, the Applicants quantified the total benefits by summing the Economic Benefits and the Public

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[194] *Id.*; Ex. DER-3 at 31 (Landi Direct). In analyzing Applicants' externalities analysis, Mr. Landi noted that the APC "Benefits" were different than the APC "Savings" used in the economic analysis for both the proposed Project and 161 kV alternative. Ex. DER-3 at 35 (Landi Direct). The Applicants explained that because the MTEP Futures also capture emissions of SO_2, NO_x, and CO_2, they removed the change in emission costs from the APC Benefit for all MISO North-Central resources to avoid double counting emissions reductions. Ex. DER-3 at 35, ML-12 at 2-3 (Landi Direct). A chart showing the difference between the original APC Benefits and those modified for the externalities analysis is contained in Mr. Landi's Direct Testimony. *See id.* at 35-36.

[195] Ex. DER-3 at 31-33 (Landi Direct); Externalities Order at 57-58 (establishing low, median, and high ranges for environmental cost values for criteria pollutants for three categories: Rural, Metropolitan Fringe, and Urban).

[196] Ex. DER-3 at 32-33 (Landi Direct).

[197] Ex. XC-18 at 6 (Abing Direct).

[198] Ex. DER-3 at 40-41 (Landi Direct).

Policy Benefits.[199] Next, the Applicants subtracted the present value of the annual revenue requirements from the present value of the annual total benefits to determine the present value of the annual net benefit of the three route options of the proposed Project and the 161 kV alternative.[200] Simply put, the figure below illustrates the Applicants calculation of net benefits in a simplified formula to compare benefits to costs:

$$\sum_{t\,=\,2022}^{63} \boldsymbol{Economic\ Benefits_t + Public\ Policy\ Benefits_t\ - Revenue\ Requirements_t}$$

Both Appendix I and the Applicants' response to a DOC DER information request, which provided a range of net benefits for the proposed Project and the 161 kV alternative, were calculated prior to the EIS Scoping Decision. Therefore, the Applicants relied on the original project cost estimates from the Application in calculating the annual revenue requirement, not the updated project cost estimates incorporating the scoped route alternatives.[201]

To update the Applicants' externalities analysis to account for the updated cost estimates, Mr. Landi adjusted the underlying project cost assumptions,[202] to match the Applicants' post-scoping project cost assumptions.[203] Mr. Landi used the following routes and respective costs to update the externalities analysis: (1) High Cost: high-end cost estimate of the Purple-E-Red Route ($160.7 million); (2) Medium Cost: low-end cost estimate of the Red Route ($134.4 million); and (3) Low Cost: low-end cost estimate of the Purple Route ($104.8

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199 *See* CN Application, App. I.
200 Ex. DER-3 at 34-35 (Landi Direct).
201 *Id.* at 36. Specifically, the EIS Scoping decision considered an additional route, the Purple-E-Red Route, which, at estimated costs ranging from $157.0 million to $160.7 million, has costs that exceed the range considered in Appendix I. *Id.* at 36-37.
202 *Id.* at 37. The Applicants provided a live spreadsheet of Appendix I and updated cost assumptions to all routes, route segments, and alignment alternatives following the EIS Scoping Decision in response to DOC DER information requests. *See id.*
203 *Id.*

million).[204] Mr. Landi testified that although updating the project cost assumptions changed the overall net benefits of the proposed Project, regardless of which route option is selected, its net benefits are still higher than the net benefits of the 161 kV alternative.[205] Also, Mr. Landi's update did not have an appreciable effect on the proposed Project's Economic Benefits or Public Policy Benefits.[206]

Mr. Landi concluded that his investigation and update of Applicants' externalities analysis confirmed that the proposed Project is superior to the 161 kV alternative due to its higher net benefits.[207] Particularly, the net benefits for the proposed Project range between $38.8 million to $137.6 million more than the 161 kV alternative for the highest cost proposed Project route; for the lowest cost proposed Project route its net benefits range from approximately $121.3 million to $220 million higher than the 161 kV alternative.[208]

Considering the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives, no alternative has been demonstrated on the record to be more reasonable than the proposed facility.

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[204] *Id.* at 27.

[205] *Id.* at 38-39. The Applicants' witness Mr. Abing also provided an updated externalities analysis incorporating the Purple-E-Red route, the highest cost route of those in the scoping decision, but did not provide an updated analysis of low and medium project cost estimates using the scoping decision routes, which included alignment and segment alternatives. Ex. DER-4 at 10-11 (Landi Rebuttal). Mr. Landi confirmed that Mr. Abing's updated externalities analysis of the highest cost route matched his own analysis, indicating that the same methodology was used. Ex. DER-4 at 11 (Landi Rebuttal).

[206] Ex. DER-3 at 38 (Landi Direct). Mr. Landi summarized his updated analysis in Table 7 of his Direct Testimony. *See id.*

[207] *Id.* at 41.

[208] *Id.*

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

Several parties provided information regarding the reliability of reasonable alternatives and the proposed Project. First, MISO's witness Mr. Zhou testified that the proposed Project underwent a reliability analysis during the MEP process to "ensure that the selected transmission projects do not degrade system reliability."[209] This process resulted in a finding that the proposed Project causes "no harmful reliability impacts on the transmission system in the MISO footprint or neighboring transmission systems."[210]

In the CN Application, the Applicants raised a number of reasons why some alternatives were not reliable.[211] For example, the Applicants stated that generation alternatives, particularly citing new wind generation on the north side of the congestion, may have system consequences such as reliability violations.[212] Mr. Landi testified that the Applicants' explanations regarding the viability of the type alternatives showed that they reasonably concluded that these alternatives are not appropriate.[213]

Also Mr. Landi analyzed the difference in system losses between the proposed Project and the 161 kV alternative, because reducing system losses "puts a downward pressure on electricity prices and improves the 'robustness' of the system by improving system reliability."[214] While the 161 kV alternative would better reduce system losses during summer

[209] Ex. MISO-1 at 21 (Zhou Direct).
[210] *Id.* at 22.
[211] CN Application at 113-121.
[212] *Id.* at 119-21.
[213] Ex. DER-3 at 13 (Landi Direct).
[214] *Id.* at 44.

peak conditions, the proposed Project would more effectively reduce system losses during off-peak, high wind conditions, which would allow for greater deliverability of wind resources.[215]

C. Minn. R. 7849.0120 C: The Record Contains Information on Whether the Proposed Facility Will Provide Benefits to Society in a Manner Compatible with Protecting the Natural and Socioeconomic Environments, Including Human Health.

Minn. R. 7849.0120 C requires that the Applicants show that the proposed facility, or a suitable modification, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health. In making this determination, the rule requires consideration of several factors. DOC DER did not submit testimony regarding these factors but notes that the draft EIS, prepared by the Department's Energy Environmental Review and Analysis (DOC EERA) unit, provides background for a determination regrading some considerations, including the effects of the proposed Project on natural and socioeconomic environments and public health.[216] Aspects of other factors, such as the relationship of the proposed facility to overall state energy needs, are provided in many parties' testimonies and the CN Application.

D. Minn. R. 7849.0120 D: DOC DER Relies on Other State and Federal Agencies and Local Governments to Demonstrate that the Design, Construction, or Operation of the Proposed Facility Will Fail to Comply with Their Own Relevant Policies, Rules, and Regulations.

Minn. R. 7849.0120 requires that the Commission determine that "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." The CN Application provides that the

[215] Ex. DER-3 at 43-44, 46, ML-13 (Landi Direct). Mr. Landi observed that while the 161 kV alternative is slightly better at reducing system losses during summer peak conditions, the amount of difference is not significant. *Id.* at 46.
[216] *See* Draft EIS at ch. 5, parts 1 & 2 (eDocket Nos. 201812-148307-12, 201812-148307-14).

"Applicants will secure all necessary permits and authorizations prior to commencing construction on the portions of the Project requiring such approvals."[217] The Application also includes a table of major permits, approvals, or consultations that may be required for the proposed Project.[218] The Draft EIS also provides a list of several potential required permits and approvals.[219] DOC DER relies upon the various agencies and local governments listed in the table to participate in the proceedings as needed to inform the Commission of any objections or complications.[220]

State agencies and local governments have filed comments regarding the proposed Project, including Minnesota Department of Natural Resources and the City of Mankato; further the City of North Mankato participated as a party in the contested case proceeding. DOC DER defers to other state and federal agencies and local governments regarding whether the proposed Project complies with their respective policies, rules, or regulations.

II. OTHER LEGAL REQUIREMENTS ADDRESSED BY DOC DER

A. Minn. Stat. § 216B.243, subd. 3(9)—Reliability, Access, and Deliverability

In high-voltage transmission line proceedings, the CN statute also requires consideration of "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."[221]

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[217] CN Application at 12.

[218] *See id.* at 176-78.

[219] *See* Draft EIS at Table 2-1. The Draft EIS also discusses the zoning and land-use compatibility of the proposed Project. *See* Draft EIS at 5.4.5.

[220] *See* Minn. Stat. § 216B.243, subd. 7 (requiring other state agencies authorized to issue permits for siting, construction or operation of large energy facilities to present their position regarding need and participate in the public hearing process prior to the issuance or denial of a certificate of need).

[221] Minn. Stat. § 216B.243, subd. 3(9) (2018).

Dr. Rakow concluded that the proposed Project would result in lower costs for electrical consumers in Minnesota and enhance the deliverability of energy.[222] To qualify as an MEP the proposed Project's benefits must exceed costs, resulting in a benefit-to-cost ratio of at least 1.25.[223] Also, Dr. Rakow observed that the distribution of benefits, what the Applicants term APC savings, were as follows: 65.0 percent in LRZ 3; 34.5 percent in LRZ 1; and 0.5 percent in LRZ 5.[224] Most utilities serving Minnesota are in LRZ 1 with the remainder in LRZ 3.[225] Therefore, DOC DER concludes that the considerations of Minn. Stat. § 216B.243, subd. 3(9) favor granting a CN for the proposed Project.

B. Minn. Stat. § 216B.243, subd. 3(11), 3a—Renewable Energy Generation

The CN statute also requires that prior to granting a CN for a large energy facility that transmits electric power generated by a nonrenewable energy source, the applicant must demonstrate that "it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source."[226] Dr. Rakow explained that because the interconnection of numerous generators is conditional upon the completion of the proposed Project, the incremental impact would be to enable the transmission of energy from all new resources.[227] Many of these new resources are expected to be renewable because some of the best wind resources in the nation are located in the Project area, and the proposed Project would reduce curtailments of wind energy.[228] Dr. Rakow concluded that the

[222] Ex. DER-5 at 31 (Rakow Direct).
[223] *Id.*
[224] *Id.* at 30.
[225] *Id.* at 30-31.
[226] Minn. Stat. § 216B.243, subd. 3(11), 3a.
[227] Ex. DER-5 at 32 (Rakow Direct).
[228] *Id.*

proposed Project would be an integral part of generating and delivering power generated by renewable energy sources and would assist in accommodating other generation changes occurring in Minnesota and in the MISO system.[229] Therefore, the Applicants have satisfied the considerations required by Minn. Stat. § 216B.243, subd. 3a.

III. PROJECT COST RECOVERY

It is important that the Commission protect ratepayers' interests by holding utilities accountable to their cost estimates for constructing large energy facilities because these costs will be rolled into rates. In this case, the best way to achieve that goal is to cap cost recovery in Xcel's transmission cost recovery (TCR) rider at the Applicants' estimated costs of the proposed Project, until the Commission can ultimately determine the reasonableness of project costs in a subsequent rate case. This approach would not apply to ITC Midwest because it is not a Minnesota rate-regulated public utility. The Applicants generally agree that this approach is reasonable.[230]

A. Proposed Project Costs, MISO Allocations, and Cost Recovery

Depending on the route chosen for the proposed Project, project costs are estimated to range from $104.8 million to $160.7 million, as seen in the following table.[231]

Johnson Direct Table 2: Revised Total Project Cost Estimates (2016 $)

Purple		Green		Red		Blue		Purple-E-Red	
Low	High	Low	High	Low	High	Low	High	Low	High
$ 104.8	$ 147.3	$ 108.2	$ 124.8	$ 134.4	$ 143.8	$ 123.7	$ 142.5	$ 157.0	$ 160.7

[229] *Id.*
[230] Ex. XC-26 at 2 (Stevenson Rebuttal).
[231] Ex. DER-1 at 5 (Johnson Direct); Ex. XC-22 at 8 (Neidermire Direct).

The Applicants' cost estimates include all transmission line costs, right-of-way costs, costs for risk contingencies for modifications to the transmission line and substations at both the Wilmarth and Huntley substations, and Allowance for Funds Used During Construction (AFUDC).[232]

1. It is Reasonable to Use the Applicants' Estimated Project Costs for Cost Recovery in Xcel's TCR Rider.

DOC DER witness Mr. Mark Johnson testified that he did not have any concerns with the Applicants' estimated Project costs.[233] Reasonableness of costs in CN and other resource acquisition proceedings can be determined in various ways, depending on the circumstances. For example, if cost information is available about similar types of resources, that information could be used as a comparison. If competitive bidding is used to procure a resource, the result of that bidding process is often considered to result in reasonable costs.[234] In CN proceedings, like this case, other stakeholders have the opportunity to file alternatives to the proposed facility.[235] Even when project alternatives are not filed, typically, an applicant introduces evidence of potential alternatives to the project that it considered in determining whether the proposed Project is more reasonable and prudent.[236] This is what the Applicants have done here.[237]

As discussed in more detail below, to give regulated utilities reasonable incentives to minimize costs and not overbuild capital projects, DOC DER and the Commission use cost caps to hold utilities accountable to their cost estimates.

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232 Ex. XC-25 at 9 (Stevenson Direct).
233 Ex. DER-1 at 5 (Johnson Direct); Ex. DER-2 at 3 (Johnson Surrebuttal).
234 Ex. DER-6 at 2 (Johnson Sur-Surrebuttal).
235 *Id.*
236 *Id.*
237 DOC DER witness Mr. Landi examined the Applicants' consideration of various alternatives and agreed that none of those alternatives were better options. Ex. DER-3 at 49 (Landi Direct). Thus, the record does not demonstrate that there is a more reasonable and prudent alternative to the proposed facility.

2. The Proposed Project's Costs Are Appropriately Allocated Across the MISO Area.

In addition to the concern as to whether estimated project costs are reasonable to use for a cost cap in the TCR rider, another concern is the requirement that project costs are appropriately allocated among those receiving the Project's benefits.[238] DOC DER agreed that the proposed Project's costs are appropriately allocated as specified under MISO's tariffs.[239] The MISO board of directors approved the proposed Project as an MEP in December 2016 as part of its MTEP16 report.[240] MEPs are projects that MISO determines are needed to reduce transmission system congestion and improve the efficiency of MISO's energy markets, which, if built, should lower wholesale energy costs. To qualify as an MEP, the proposed Project met the following criteria:

- Greater than 50 percent of the total cost of the candidate project must be attributed to facilities that operate at a 345 kV voltage level or higher;
- The benefit-to-cost ratio of the candidate project must meet or exceed 1.25; and
- The total project costs must exceed $5 million.[241]

Under the MISO tariff, Attachment GG and Schedule 26, 20 percent of the proposed Project's costs would be allocated to the Transmission Pricing Zones in MISO Classic (Zones 1-7) based on their respective load ratio share.[242] The amounts allocated to the Transmission Pricing Zones would then be allocated to each utility based on their respective load ratio share

[238] Costs in a TCR rider must be appropriately allocated between retail and wholesale customers. *See* Minn. Stat. § 216B.16, subd. 7b(b)(9) (2018).
[239] Ex. DER-1 at 6-10 (Johnson Direct).
[240] Ex. XC-22 at 5 (Neidermire Direct).
[241] *See* Ex. XC-22 at 5 (Neidermire Direct); Ex. DER-1 at 6 (Johnson Direct).
[242] Technically, project capital and operation and maintenance costs are first converted into annual revenue requirements before being allocated under MISO tariffs. For purposes of this brief, the allocation of project costs is intended to be synonymous with the allocation of revenue requirements. Ex. DER-1 at 6 n.3 (Johnson Direct); *see also* Ex. XC-6 at 37 (CN Application). For a map of the MISO pricing zones, see Ex. DER-1 at 7 (Johnson Direct).

within these zones.[243] The remaining 80 percent of project costs would be allocated to MISO Classic Zones 1, 3, and 4 based on the distribution of APC savings to the Local Resource Zones.[244] The amounts allocated to each Local Resource Zone would then be allocated to each utility based on their respective load ratio share within these zones.[245]

Specifically, because Xcel has load in six different MISO Transmission Pricing Zones, Xcel would be allocated a portion of the proposed Project costs from six different Transmission Pricing Zones based on their respective load ratio share in each.[246] The Applicants estimated that Xcel would be allocated approximately 16.96 percent of the proposed Project's costs under Schedule 26 of the MISO tariffs.[247] Further, Xcel and ITC Midwest would also receive the revenues collected under MISO Schedule 26 that are associated with their respective ownership interest in the proposed Project.[248] MISO Schedule 26 revenues are revenues that Xcel and ITC Midwest would receive from MISO for use of the proposed Project.[249] DOC DER agreed that these allocations reasonably reflect the requirements in MISO's tariff.[250]

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[243] *Id.* at 38-39.
[244] *See* Ex. DER-1 at 8 (Johnson Direct); Ex. XC-6 at 37-39 (CN Application).
[245] Ex. XC-6 at 37-39 (CN Application).
[246] Ex. DER-1 at 8 (Johnson Direct). Because ITC Midwest does not have any load in the MISO Classic area, ITC Midwest would not be allocated any of the proposed Project's costs. Moreover, any project costs that are allocated to ITC Midwest's Transmission Pricing Zone would be allocated to the utilities with load in ITC Midwest's Transmission Pricing Zone. *Id.* at 9.
[247] Ex. XC-6 at 39 (CN Application). In addition, any other Minnesota regulated utility with load located within one of the Transmission Pricing Zones would also be allocated a share of the proposed Project's costs. Other Minnesota regulated utilities' respective shares of the proposed Project's costs, however, would be significantly lower than Xcel's 16.96 percent share of the costs due to their smaller size and load. Ex. DER-1 at 9 (Johnson Direct).
[248] Ex. DER-1 at 9 (Johnson Direct).
[249] *Id.*
[250] *Id.* at 10.

3. Cost Recovery Between Rate Cases: Extraordinary Cost Recovery in the TCR Rider

Minnesota utilities are permitted by statute to charge ratepayers for transmission project costs in their annual transmission riders prior to when the facilities are used and useful, and in addition to the transmission costs charged in base rates (extraordinary ratemaking), but such costs must be offset by revenues.[251] For any Minnesota rate-regulated utility that owns a transmission project, the transmission project's capital and operation and maintenance costs are converted into Minnesota annual revenue requirements and recovered from retail ratepayers through base rates in general rate cases or TCR riders, which are then reflected on monthly utility bills for retail ratepayers.[252] Generally speaking, Minnesota's rate-regulated utilities include and recover MISO Schedule 26 costs, net of revenues, from ratepayers through transmission riders that are reflected on monthly utility bills.[253] As indicated above, the cost cap in this case would apply to Project costs included in the TCR rider.[254]

B. To Protect Ratepayers, the Commission Should Cap Cost Recovery for the Proposed Project in the Transmission Cost Recovery Rider to the Applicants' Estimated Project Costs.

DOC DER testified that it supports the Commission's use of mechanisms to protect ratepayers from being charged costs for projects that go over budget.[255] Absent cost recovery

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[251] *Id.* at 12; Minn. Stat. § 216B.16, subd. 7b(b).
[252] Ex. DER-1 at 10 (Johnson Direct).
[253] *Id.*
[254] *Id.* at 11-19.
[255] *Id.*; *see, e.g.*, *In re N. States. Power Co., a Minn. Corp., d/b/a Xcel Energy, for Approval of a Modification to its TCR Tariff, 2010 Project Eligibility, TCR Rate Factors, Continuation of Deferred Accounting and 2009 True-up Report*, MPUC Docket No. E-002/M-09-1048, Order Approving 2010 TCR Project Eligibility and Rider, 2009 TCR Tracker Report, and TCR Rate Factors (Apr. 27, 2010); *In re Otter Tail Power Co.'s Request for Approval of a Transmission Cost Recovery Rider Including the Proposed Transmission Factor for the Recovery Period from May 2, 2013 to Apr. 30, 2014*, MPUC Docket No. E-017/M-13-103, Order Capping Costs,
(Footnote Continued on Next Page)

caps tied to the evidentiary record in which the project was proposed and approved, utilities do not have a strong incentive to ensure that project costs are accurately reported in regulatory proceedings and to ensure that costs are contained and reasonable.[256] Cost caps prevent the rate-regulated utility from recovering any cost overruns in a TCR rider between rate cases.[257] In a utility's next rate case, under the cost-cap approach, a utility is required to explain and justify the reasonableness of project costs, including any cost overruns.[258] As a result, the use of cost caps incentivizes CN applicants not to exceed their cost estimates provided in a CN proceeding.[259]

As indicated above, the most likely way that costs and offsetting revenues would be charged to Minnesota ratepayers is through Xcel's TCR rider.[260] Absent the ability to recover such costs through a rider, recovery would not be allowed until the first rate case after the project goes into service (or is projected to go into service during the forecasted test year).[261] The cap for recovery in a TCR rider is set at the amount of costs the utility represented for the project in

(Footnote Continued from Previous Page)
Denying Rider Recovery of Excess Costs, and Requiring Inclusion of All MISO Schedule 26 Costs and Revenues in TCR Rider (Mar. 10, 2014).

[256] Ex. DER-1 at 12 (Johnson Direct).

[257] *Id.* at 13.

[258] *Id.* at 13-14.

[259] *See id.* at 12.

[260] Ex. DER-1 at 12 (Johnson Direct). The cost-cap approach in this matter would not apply to ITC Midwest. ITC Midwest is a wholesale transmission company with rates set by the Federal Energy Regulatory Commission (FERC) and does not directly deliver electricity to retail customers in Minnesota. As such, ITC Midwest does not have a transmission rider in Minnesota, but does charge rates set by FERC. Therefore, the Minnesota Commission does not have the same ability to protect ratepayers by holding ITC Midwest directly accountable for its CN cost estimates as it does with traditional Minnesota rate-regulated utilities.

[261] Ex. DER-1 at 12 (Johnson Direct); *see* Minn. Stat. § 216B.16, subd. 7b(a) ("Notwithstanding any other provision of this chapter, the commission may approve a tariff mechanism for the automatic annual adjustment of charges for . . . new transmission facilities that have been separately filed and reviewed and approved by the commission under 216B.243 . . . .").

the proceeding where the project was approved.[262] Utilities are allowed to charge ratepayers for inflation from the year in which costs are approved to the in-service date of the facility.[263]

An important reason to protect Minnesota ratepayers by capping costs recoverable in Xcel's TCR rider is that it is unclear that MISO would similarly hold utilities accountable for cost overruns related to projects in the MISO transmission system.[264] Rather than use a cost-cap approach, if a project's costs exceed its estimate by more than 25 percent, MISO may conduct a variance analysis.[265] According to the Applicants:

> Under Attachment FF of the MISO Tariff, if the cost of this Project exceeds or is projected to exceed 25 percent or more of the Project's baseline cost estimate, MISO is required to initiate a new process called a "variance analysis." A variance analysis for a project may also be triggered by a schedule delay or inability to complete project construction.[266]

MISO, however, has never used its variance analysis, which DOC DER concludes is concerning.[267] As a result, it is unclear to what extent MISO would require utilities to institute a mitigation plan even if costs exceed estimates by more than 25 percent.[268] In addition, it is unclear to what extent MISO would actually cancel a transmission project, especially if the project was already under construction and had incurred significant costs.[269] Finally, it is unclear whether MISO would ever disallow recovery of cost overruns.[270] Minnesota operates under the regulatory approach that just because a utility incurs a cost, that fact, while necessary, is not

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[262] Ex. DER-1 at 13 (Johnson Direct).
[263] *Id.*
[264] *See id.* at 16-19.
[265] *Id.*
[266] Ex. XC-24 at 35-36 (Siebenaler Direct).
[267] Ex. DER-1 at 17-18 (Johnson Direct); Ex. XC-24 at 36-37 (Siebenaler Direct).
[268] Ex. DER-1 at 18 (Johnson Direct).
[269] *Id.*
[270] *Id.*

sufficient to justify cost recovery from ratepayers: utilities still must show that it is reasonable to recover such costs from ratepayers.[271] By contrast, it is unclear whether MISO would ever not allow a transmission owner to recover costs, even the amounts greater than a 25 percent variance.

The Applicants generally agreed with DOC DER's cost-cap approach, but recommended that the Commission permit a filing, within 45 days of the Commission's order approving the particular route for the proposed Project, that would provide a final cost estimate based on the approved route and segments, or any design changes.[272] The Applicants also stated that "the Commission could make route or alignment adjustments to these proposed routes in its Route Permit Order" or the Commission "could include mitigation measures that were not contemplated by the Applicants in developing the Project cost estimates."[273] DOC DER agreed that this approach is reasonable.[274] To that end, DOC DER provided the following specific recommendations:

- DOC DER supports the cost estimates identified in Johnson Direct Table 2 ($104.8 million to $160.8 million) and recommend that they be used as the starting point for determining the cap amount.

- Xcel should provide a final number or cap amount within 45 days of the Commission's Order determining the route. This number should be based on the Commission's decisions in this proceeding using the costs identified for the 39 different route options identified in Schedule 2 of Mr. Stevenson's Direct Testimony and clearly identifying the cost effects of any material changes, due to the Commission's decisions.

- The Commission should permit DOC DER and other interested parties the opportunity to address whether they agree with the Applicants' final Project cost estimate; and

[271] *Id.*
[272] Ex. XC-26 at 2-3 (Stevenson Rebuttal).
[273] *Id.* at 3.
[274] Ex. DER-2 at 8 (Johnson Surrebuttal).

- If the Commission approves the Applicants' proposal, DOC DER recommends that the Commission require the Applicants to identify these costs clearly and ensure that the costs are easily trackable in future recovery in riders and rate cases.[275]

C. Summary of Cost Recovery Protections

DOC DER recommends that the Commission protect Minnesota ratepayers' interests in this proceeding by capping costs included in Xcel's TCR rider for the proposed Project based on the cost estimate determined in this matter. Once the Commission determines the cost of the proposed Project based on its decisions regarding route alternatives, the Commission should hold Xcel accountable by: 1) requiring Xcel to wait until the first rate case after the proposed Project is in service to recover any cost overruns for Minnesota ratepayers; and 2) requiring Xcel to justify fully the reasonableness of recovering any cost overruns of the proposed Project from Minnesota ratepayers. DOC DER agrees that the Commission should order the Applicants to file, within 45 days of the Commission's order approving the route for the proposed Project, a final cost estimate based on the approved route and segments. DOC DER recommends that it, and other interested parties, be permitted to respond to the Applicants' filing.

CONCLUSIONS AND RECOMMENDATIONS

DOC DER concluded that Applicants satisfied the criteria in parts A and B of Minn. R. 7849.0120 and showed that denial of the proposed Project would adversely affect the future adequacy, reliability or efficiency of energy supply to the Applicants, Applicants' customers, or to the people of Minnesota and neighboring states and that a more reasonable and prudent alternative to the proposed Project was not demonstrated on the record.[276] Thus, DOC DER recommends that the ALJ and Commission find that the CN criteria A and B have been met, with

[275] *Id.* at 9.
[276] Please see discussion above regarding parts C and D of Minn. R. 7849.0120.

the agreed-on condition to protect ratepayers' interests by capping costs included in Xcel's TCR rider for the proposed Project based on the cost estimate determined in this matter and subject to the following:

- the range cost estimates of $104.8 million to $160.8 million is the starting point for determining the cap amount;
- Xcel must provide a final number or cap amount within 45 days of the Commission's Order determining the route, reflecting the Commission's decisions in this proceeding using the costs identified for the 39 different route options identified in Schedule 2 of Mr. Stevenson's Direct testimony and clearly identifying the cost effects of any material changes, due to the Commission's decisions;
- DOC DER and other interested parties will be permitted the opportunity to address whether they agree with the Applicants' final Project cost estimate; and
- the Applicants must identify these costs clearly and ensure that the costs are easily trackable in future recover in riders and rate cases.

Dated: March 22, 2019

Respectfully submitted,

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