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

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

IN THE MATTER OF THE REQUEST OF MINNESOTA POWER FOR A CERTIFICATE OF NEED FOR THE GREAT NORTHERN TRANSMISSION LINE PROJECT	Docket No. E015/CN-12-1163 OAH Docket No. 65-2500-31196

DIRECT TESTIMONY AND ATTACHMENTS OF DR. STEPHEN RAKOW

ON BEHALF OF

THE DIVISION OF ENERGY RESOURCES OF
THE MINNESOTA DEPARTMENT OF COMMERCE

SEPTEMBER 19, 2014

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I. INTRODUCTION

Q. What are your name, business address, and occupation?

A. My name is Dr. Steve Rakow. My business address is 85 Seventh Place East, Suite 500, St. Paul, Minnesota 55101-2198. I am employed as a Public Utilities Rates Analyst with the Minnesota Department of Commerce, Division of Energy Resources, Energy Regulation and Planning unit (Department).

Q. What is your educational and professional background?

A. A summary of these items is included as DOC Ex. ___ at SR-1 (Rakow Direct).

Q. What are your responsibilities in this proceeding?

A. I am submitting testimony on behalf of the Department that:

- summarizes Minnesota Power, an operating division of ALLETE, Inc.'s (MP or the Company) *Application for a Certificate of Need* (Petition) to construct the Minnesota/Manitoba border—Blackberry 500 kV transmission line and associated facilities, referred to as the Great Northern Transmission Line;
- presents the criteria established by Minnesota Statutes and Minnesota Rules that the Minnesota Public Utilities Commission (Commission) will use to decide whether to approve the Petition;
- introduces the other witnesses sponsoring testimony on behalf of the Department in this proceeding;
- provides the Department's analysis of alternatives and policy; and

- summarizes the Department's overall conclusions and recommendations at this time.

II. SUMMARY OF CERTIFICATE OF NEED

A. THE PROJECT

Q. Please summarize the facilities proposed by MP.

A. In Minnesota, MP proposes to:

- construct a new 500 kV transmission line from the United States/Canadian border to MP's Blackberry Substation near Grand Rapids, Minnesota—approximately 235 to 270 miles depending upon the route selected;[1]
- install 500 kV series compensation, the preferred location is at the midpoint of the 500 kV line between the Dorsey and Blackberry substations;[2] and
- expand the existing Blackberry 230/115 kV substation to accommodate the 500 kV line, 500/230 kV transformation, and all associated 500 kV and 230 kV equipment. (Great Northern Transmission Line or GNTL)

Q. How much does MP testify that the proposed facilities will cost?

A. The Direct Testimony and Exhibits of Michael H. Donahue updates MP's cost estimates, indicating that the proposed GNTL now is estimated to cost between

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[1] *See* MP Ex. ___ at 2 (Petition).
[2] *See* the MP Ex. ___ at 7 (Winter Direct), which describes "compensation" as including "the 500 kV series capacitor banks necessary for the reliable operation and optimal performance of the Project, and all associated 500 kV equipment."

$557.9 million and $710.1 million (2013 dollars).[3] MP Ex. ___ at 5 (Donohue Direct). Compared to MP's initial estimate, MP's current estimate is $100.8 million to $151.7 million higher than the Company's initial estimate. MP Ex. ___ at 27 (Petition). The proposed in-service date for the proposed GNTL is June 1, 2020, which did not change from the date MP initially indicated. MP requests that the Commission approve a certificate of need (CN) for the proposed GNTL.

Q. Are there any other facilities related to the proposed GNTL?

A. Yes, in Canada related transmission facilities have been proposed by Manitoba Hydro, a Crown Corporation (MH). These facilities include:

- a new 500 kV transmission line in southeastern Manitoba from the Dorsey Converter Station[4] to the United States/Canadian border–approximately 95 to 130 miles depending upon the route selected;
- upgrades to the Riel[5] and Dorsey converter stations; and
- modifications to the Glenboro substation. MP Ex. ___ at Schedule 3, page 31 of 33 (Hoberg Direct) and MP Ex. ___ at 24 (Petition).

In addition to the new transmission facilities MH has proposed new generation facilities that are related to the proposed GNTL. MH started construction of the new

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[3] See the Company's response to Department Information Request No. 23 for the dollar units.
[4] MH's Dorsey Converter Station, (located in Rosser, approximately 10 miles northwest of Winnipeg, Manitoba) is the southern terminus for MH's high voltage direct current (HVDC) transmission lines known as Bipole I and Bipole II.
[5] The Riel Converter Station (located east of Winnipeg, Manitoba) is the southern terminus for MH's Bipole III HVDC transmission line, currently under construction.

695 MW Keeyask generating station on July 16, 2014.[6] Keeyask's first unit is scheduled to be on-line in 2019.[7] Keeyask is needed, in part, to supply the power for MP's agreements with MH.[8] The construction of the Keeyask generating station will result in MH having significant surpluses of firm energy in the aftermath of Keeyask being placed in-service.[9] MH can either lock in sales of that surplus energy through contracts with utilities (such as the contract with MP) or sell the energy into short term markets such as MISO. Note that MH plans its system so that the system is capable of supplying sufficient dependable energy to meet firm energy requirements in the event of a repeat of the lowest historic hydraulic system inflow conditions. Firm energy requirements are measured by forecasted requirements in Manitoba and existing export contracts. This means that, even if MH does not have firm contracts for export, there is non-firm energy that also is available for export in most years—years where the system is not experiencing low water levels.[10] Thus the line will might be used by MH for non-firm energy sales even if there are insufficient firm energy sales.[11] On the whole, it would be helpful if MP would provide an update

[6] See: https://www.hydro.mb.ca/projects/keeyask/index.shtml?WT.mc_id=2613.
[7] MP Ex. ___ at 4 (Petition).
[8] MP Ex. ___ at 70 (Petition).
[9] For MH's estimated energy sources and requirements from MH's proposed development plan as filed in MH's regulatory process, see pages 22, 26, 30, 34, and so forth of the following file:
http://www.hydro.mb.ca/projects/development_plan/bc_documents/appendix_04_2_manitoba_hydro_supply_and_demand_tables.pdf
[10] For a discussion of MH's energy planning criteria see page 5 of the following file:
http://www.hydro.mb.ca/projects/development_plan/bc_documents/appendix_04_1_generation_planning_criteria.pdf
[11] Note that, as discussed elsewhere in this testimony, MH is paying a significant share of the costs for MP's proposed GNTL and is responsible for the portion of the line in Manitoba. Thus, MH has an incentive to find PPAs to recover their sunk transmission and generation costs. Further, the lack of firm contracts is one reason the Manitoba Public Utilities Board recommended (and the Manitoba government agreed) to delay the in-service date of the proposed Conawapa dam until additional contracts were in hand. See:
http://news.gov.mb.ca/news/index.html?item=31611&posted=2014-07-02

regarding the status in Manitoba of the Keeyask dam, Conawapa dam, and related transmission projects in rebuttal testimony.

Q. Who is the applicant for the certificate of need in this proceeding?

A. MP requests a CN for facilities located in Minnesota.[12] Thus, MP is the applicant. While MP has a contract with MH for new energy and capacity and, at this time MH would be a minority owner of the proposed GNTL, MH is not an applicant.[13]

Q. Does MP propose to have full ownership of the proposed GNTL?

A. No, not at this time. MP, in partnership with MH, proposes to construct the transmission line. At this time MP has majority ownership (51 percent) of the proposed GNTL. The Direct Testimony and Exhibits of David J. McMillan at page 13 line 20 to page 14 line 3 explained that the remaining 49 percent of the proposed GNTL would be owned by a subsidiary of MH. However, MH may transfer all or a portion of its share of the proposed GNTL to another party.

Such potential future changes in ownership do not need to be addressed at this time, since Minnesota Rules part 7849.0400 addresses requirements for ownership changes as follows:

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[12] MP is an operating division of ALLETE, Inc. Other ALLETE businesses include:

- BNI Coal in North Dakota;
- Superior Water, Light & Power in Superior, Wisconsin;
- ALLETE Clean Energy, a developer of energy projects with limited environmental impact;
- ALLETE Renewable Resources, which operates wind generation facilities in North Dakota; and
- ALLETE Properties, which owns real estate in Florida.

[13] See MP Ex. ___ at 16 (Petition).

> Subp. 2. **Proposed changes in size, type, and timing.**
>
> Changes proposed by an applicant to the certified size, type, or timing of a proposed facility before the facility is placed in service must conform to the following provisions:
>
> ... C. A change in power plant ownership smaller than the lesser of 80 megawatts or 20 percent of the capacity approved in a certificate of need issued by the commission does not require recertification.

Q. Which entity proposes to maintain the proposed GNTL after construction is complete?

A. The Petition at page 16 stated that MP will maintain the proposed GNTL.

Q. Which entity proposes to operate the proposed GNTL after construction is complete?

A. The Petition at page 16 stated that, once in-service, functional control of the proposed GNTL will be turned over to the Midcontinent Independent System Operator, Inc. (MISO).

Q. Is there a distinction between issues of ownership, financial responsibility to invest, and rate recovery?

A. Yes, the Direct Testimony of Mr. Donahue at page 9, lines 3 to 4 explained that, while MP will own 51 percent of the proposed GNTL, MP will be responsible for funding 46 percent of the construction costs. Under the proposal, MP will receive the difference

51 percent minus 46 percent) from MH via a Contribution in Aid of Construction (CIAC).[14]

Mr. McMillan's Direct Testimony at page 15 line 15 to page 16 line 3 clarified that MP's customers would be financially responsible for 28.3 percent of the Company's revenue requirements related to the investment.[15] MP's remaining revenue requirements related to the investment (51 percent minus 5 percent CIAC minus 28.3 percent ratepayers) are proposed to be paid by MH via a "Monthly Must Take Fee" contained in the terms of a 133 MW Renewable Optimization Agreement (ROA),[16] which MP has not yet filed for approval by the Commission. All of these issues are discussed in detail below in the section on financial background.

Q. According to MP, what needs would be addressed by the proposed GNTL?

A. In sections 2.1.1 and 2.1.2 of the Petition MP discussed two main needs for the proposed GNTL:

- to deliver the power called for under:
  - the Commission-approved *250 MW System Power Sale Agreement*[17] (SPSA) and *Energy Exchange Agreement*[18] (EEA) between MP and MH; and

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[14] This issue is covered in the *Facilities Construction Agreement*. See MP Ex. ___ at MD, Schedule 5 page 2 of 3 (Donahue Direct).

[15] The 250 MW for MP's purchased power agreement (PPA) divided by the 883 MW transfer capability of the proposed GNTL equals 28.3 percent; thus, ratepayers will pay for the share of the line that they are using—assuming no other costs flow through to ratepayers.

[16] A copy of the ROA is included as MP Ex. ___ at AJR, Schedule 2 (Rudeck Direct). See also MP's response to Large Power Intervenors' Information Request No. 28.

[17] The SPSA requires MP to purchase 250 MW of capacity and energy; MP's petition in Docket No. E015/M-11-938 indicates that the energy is purchased 16 hours per day, 7 days per week. The Petition at page 100 indicates that the SPSA and EEA are for the period 2020 through 2035.

- o the yet-to-be-filed ROA.[19]
- state and regional needs:
  - o delivery of the power called for in other power purchase agreements that MH is pursuing;
  - o provision of economic benefits to the entire MISO footprint; and
  - o provision of reliability benefits during outages of the existing 500 kV line between Manitoba and Minnesota.

Q. How significant are imports from MH to Minnesota and neighboring states?

A. Reports available at Canada's National Energy Board show that, between 2005 and 2013 MH was a net exporter of energy to Minnesota and North Dakota to a significant degree; exporting between 8.0 million and 11.5 million MWh annually (net of MH's imports from Minnesota and North Dakota). To put that amount into perspective, it equals:

- 11.1 to 17.0 percent of annual energy sales for Minnesota;
- 9.1 to 14.6 percent of annual energy sales for Minnesota and North Dakota; or
- 3.6 to 5.6 percent of annual energy sales for Minnesota and the 4 neighboring states.[20]

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[18] MP's petition in Docket No. E015/M-11-938 indicates that the EEA would allow MP 250 GWh per year of annual energy storage. Note that 1,000 GWh per year total minus 750 GWh per year (from the ROA) leaves 250 GWh per year from the EEA. MP Ex. ___ at 16–17 (Rudeck Direct).
[19] The yet-to-be-filed ROA includes a proposed additional 750 GWh of annual wind storage credit. MP Ex. ___ at 16–17 (Rudeck Direct).
[20] For U.S. retail sales, see http://www.eia.gov/electricity/data/browser/ For MH's export data, see http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/lctrctyxprtmprt/lctrctyxprtmprt-eng.html#s1

This fact is illustrated in Figure 1 below, which also includes the drought years of 2002 to 2004. Figure 1 shows that MH's net exports were significantly reduced during the drought years, with MH actually becoming a net importer in 2003.

Figure 1: Manitoba Hydro's Exports to the Region

Q. What is the regional situation regarding capacity needs?

A. Every six months MISO and the Organization of MISO States (OMS) perform a resource adequacy survey. This survey indicates that the recent capacity surplus is expected to largely be gone by the summer of 2016. For details see DOC Ex. ___ at SR-5 (Rakow Direct).

Q. How significant are MH exports to MP expected to be when the proposed GNTL goes in-service?

A. The Petition at page 3 estimated that the SPSA and EEA are expected to provide over 1.5 million MWh annually to MP starting in 2020. At that time the annual electric consumption by ultimate consumers on MP's system is forecasted to be about 10.4 million MWh.[21] Thus, MP estimated that the percent of MP's energy requirements supplied by MH would be about 14.4 percent in 2020.

B. THE COMMISSION PROCESS

Q. Please summarize the overall Commission process for evaluating the proposed GNTL.

A. DOC Ex. ___ at SR-2 (Rakow Direct) presents a graphical representation of the standard four step regulatory process applicable to new electric generation and transmission facilities. The proposed GNTL will go through the standard regulatory process.

Q. Please summarize the criteria to be used by the Commission in the CN proceeding regarding the proposed GNTL.

A. There are several factors to be considered by the Commission in making a determination regarding a CN for the proposed GNTL. These criteria are located in different sections of Minnesota Statutes. Some of the statutory criteria are reflected in a more specific way in Minnesota Rules part 7849.0120, which presents the main

[21] *See* MP Ex. ___ at Appendix H, page 85 (Petition).

criteria for evaluation of a transmission CN application. However, other statutory criteria do not appear to be reflected in rules (for example, the "innovative energy project" language of Minnesota Statutes §216B.1694, subd. 2). A comprehensive list of the criteria is provided in DOC Ex. ___ at SR-3 (Rakow Direct).

C. DEPARTMENT INVESTIGATION

Q. Please introduce the witnesses sponsored by the Department in this proceeding and summarize the issues on which they will testify.

A. In addition to myself, the Department is sponsoring one other witness in this proceeding, Mr. Sachin Shah, who addresses issues regarding need and forecasting under Minnesota Rules part 7849.0120 A (1).

Q. Which of the CN decision criteria are you addressing?

A. I am addressing:

- Minnesota Rules part 7849.0120 A (2) through (4);
- Minnesota Rules part 7849.0120 B (1) through (3);
- Minnesota Statutes § 216B.2422, subd. 3 (a): Environmental costs;
- Minnesota Statutes § 216B.2422, subd. 4: Preference for renewable energy facility;
- Minnesota Statutes § 216B.243, subd. 3 (9): Showing required for construction; and
- Minnesota Statutes § 216B.2426: Opportunities for distributed generation.

III. ANALYSIS

A. BACKGROUND

Q. Is a CN required for the proposed GNTL?

A. Yes. Facilities with a length greater than 1,500 feet and a capacity greater than 200 kV qualify as a large energy facility (LEF) under Minnesota Statutes § 216B.2421, subd. 2 (2). Facilities with a capacity greater than 100 kV that cross a state border qualify as a LEF under Minnesota Statutes § 216B. 2421, subd. 2 (3). Minnesota Statutes § 216B.243, subd. 2 requires that LEFs obtain a CN. Since the proposed GNTL greater than 200 kV, is longer than 1,500 feet, and crosses a state border the proposed GNTL requires a CN.

Q. How does the Department assess whether the proposed transmission line is needed?

A. Mr. Shah discusses the proceedings before the Commission (to date) that have given rise to MP's proposed transmission line. In addition, I discuss both the no-build alternative to MP's proposal and the alternative of building a smaller transmission facility.

Q. Please list the criteria that should be used in the screening analysis for the no-build alternative.

A. Minnesota Rules 7849.0120 A (4) states that the Commission must consider the ability of current facilities and planned facilities not requiring certificates of need to meet the future demand.

Q. Are current and planned facilities not requiring certificates of need a reasonable alternative to the proposed GNTL?

A. No. The interface between Manitoba and the United States is unable to accommodate increased transfer of energy from Manitoba into the United States. MP Ex. ___ at 107-108 (Petition). Not building the proposed GNTL or an alternative would not change that fact. Thus, the no-build alternative does not pass a screening test.

Q. Hasn't Manitoba Hydro promoted use of their power, in violation of Minnesota Rule 7849.0120 A (3)?

A. First, as discussed elsewhere MH is not an applicant. Second, it is true that Manitoba Hydro has been promoting use of their hydro power. However, Minnesota Rule 7849.0120 A (3) states more broadly that the Commission should consider "the effects of promotional practices of the applicant that may have given rise to the increase in the energy demand." I do not see that Manitoba Hydro has been promoting increased demand for energy overall; instead, they are marketing their brand of energy. I discuss below the alternative of demand-side management to meet the need identified in this proceeding.

Further, given that the Mercury Air Toxics Standard (MATS) will take effect soon and is expected to affect the availability of coal-fired, baseload power in the MISO region, and given that generation plants in Minnesota and the region continue to age, it is fair to conclude that power from Manitoba Hydro will be needed in Minnesota and surrounding states.

Q. What is the status of the proposed GNTL in the regional transmission planning process?

A. The regional transmission planning process is run by MISO. MISO's process results in an annual report, the *MISO Transmission Expansion Plan* (MTEP). In the current version of MTEP the proposed GNTL is targeted for Appendix B.[22] The current draft of MTEP14 defines projects in Appendix B as follows:

> Projects in Appendix B have been analyzed to ensure they effectively address one or more documented transmission issues. In general, MTEP Appendix B contains projects still in the Transmission Owners' planning processes or still in the MISO review and recommendation process. Appendix B may contain multiple solutions to a common set of transmission issues. Projects in Appendix B are not yet recommended or approved by MISO, so they are not evaluated for cost sharing. Any designation of project type (Baseline Reliability Projects, Market Efficiency Projects or Multi-Value Projects) for projects in Appendix B are preliminary. Thus, while some projects may eventually become eligible for cost-sharing, the target date does not require a final recommendation for the current MTEP cycle. The project will likely be held in Appendix B until the review process is complete and the project is moved to Appendix A.

Q. What is the status of the proposed GNTL in Minnesota's transmission planning process?

A. The state's transmission planning process involves a filing every two years by every transmission owner in Minnesota at the Commission. The most recent plan included the proposed GNTL under tracking number 2013-NE-N13.[23]

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[22] Further details are available at: https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP14.aspx

[23] Further details are available at: http://www.minnelectrans.com/report-2013.html

B. SCREENING ANALYSIS

Q. Please list the overall criteria that should be used in the screening analysis.

A. First, Minnesota Rules part 7849.0120 B (1) requires consideration of "the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives." Second, Minnesota Statutes §216B.2426 requires consideration of distributed generation:

> The Commission shall ensure that opportunities for the installation of distributed generation, as that term is defined in section 216B.169, subdivision 1, paragraph (c), are considered in any proceeding under section 216B.2422, 216B.2425, or 216B.243.

Third, Minnesota Statutes §216B.2422, subd. 4 requires consideration of renewable energy generating facilities:

> The Commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the Commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest.

1. Transmission Alternatives

Q. Please describe MP's screening analysis for lower voltages.

A. The Petition at pages 75-77 contains MP's screening of lower voltages. MP reviewed two lower voltages, 230 kV and 345 kV. First, MP concluded that a 230 kV alternative would not:

- meet the long-term needs of the region because:
  - small, less efficient coal units will continue to retire;

- MH has several potential customers that may request transmission service; and
- interest in MH's hydropower is expected to continue as utilities seek to increase their use of low- or no-emission renewable energy sources;

- prove to be cost-effective for customers;[24] and
- be environmentally preferable over the long-term.[25]

Second, MP screened out a 345 kV alternative based upon the assumption that a project equivalent to a 500 kV line would need to be a double-circuit 345 kV line. A double-circuit 345 kV line would have similar or higher construction cost (compared to a 500 kV line) and lower surge impedance loading and thus would not be as desirable.[26] Finally, the Winnipeg area does not have 345 kV equipment. Thus, MP indicates that expensive new substation equipment would be required at the Canadian end point. However, MP did not provide an estimate for that cost.

Q. Please describe MP's screening analysis for higher voltages.

A. The Petition at page 77 contains MP's screening of higher voltages. MP concluded that the fact that there is no 765 kV transmission in the region means that expensive transformation would be required at each substation to interconnect with existing

[24] Essentially MP states that a 500 kV transmission facility would be cheaper per unit of electricity transmitted due to the larger size and resulting "economies of scale."
[25] Building a higher voltage project now limits the proliferation of new transmission line corridors in the future.
[26] The surge impedance loading or SIL of a transmission line is the MW loading of a transmission line at which reactive power is balanced. For further information see: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshop%20Materials/JCSP%20Fundamentals%20Workshop/20080429-30%20JCSP%20Fundamentals%20Workshop%20Item%2005%20Transmission%20Design.pdf

500 kV and/or 230 kV systems. MP did not provide an estimate of the cost of transforming the power but indicated that a 765 kV transmission line would also have increased construction costs and added operational complexity. MP decided that the higher cost and increased complexity outweigh the additional capacity gained by a 765 kV build, compared to a 500 kV build.

Q. Do you have any comment on MP's screening of higher and lower voltages?

A. Yes, generally MP's screening analysis of higher and lower voltages in the Petition is reasonable. However, since the 230 kV alternative is sufficient for purposes of MP's Commission-approved SPSA, I also considered the 230 kV alternative in a more detailed analysis, as discussed below.

Q. Please describe MP's screening analysis for different end points.

A. The Petition at page 77 contains MP's screening of different end points. In many transmission study scenarios, a Fargo area end point (at times Barnesville is substituted for Fargo) exhibits similar performance and benefits. However, MP concluded that the Fargo area end point is flawed for several reasons.

First, MP argued that there are technical engineering issues. For example, MP notes that in some of the most stressed study scenarios an end point in the Fargo area would aggravate the North Dakota—Manitoba loop flow phenomenon by introducing a new low-impedance path between North Dakota and Manitoba. As a result, MP indicated that additional transmission upgrades would be required to relieve constrained generation outlet capability for North Dakota, Manitoba, or both. MP did not provide the costs of these upgrades.

Second, MP argued that, under North Dakota law, a transmission facility that transmits hydroelectric power produced outside the United States, and crosses any portion of North Dakota, must have the approval of the legislative assembly. MP argued that the practical impact of this provision in North Dakota law is that the end point for a Fargo area end point would have to be on the Minnesota side of the Red River.

Third, MP indicated that a Fargo area end point cannot achieve the timeline required by MP's SPSA and EEA agreements. MP stated that, even if a utility stepped forward today to begin public outreach efforts, it is highly improbable that the Fargo area end point could achieve a June 1, 2020 in-service date.

Q. Do you agree with MP's screening of different end points?

A. While I cannot confirm MP's statement that North Dakota's law effectively prohibits the possibility of the line using an end-point in the Fargo area, in general I agree with the results of MP's screening analysis. I note that a Fargo area end point would have additional issues regarding inappropriate cost allocations, as discussed further below in the section on financial background.

2. Generation Alternatives

Q. Please outline MP's screening analysis for generation alternatives.

A. On pages 69 to 73 of the Petition MP discussed generation alternatives. At pages 71-72 of the Petition MP stated that:

> [I]n the 938 Docket [E015/M-11-938], the Department and Commission specifically examined whether "the

> resources proposed in the [purchased power agreement] PPA represent the most appropriate resources to meet [Minnesota Power's] resource needs over the period 2020 through 2035." The Department and Commission both answered that question in the affirmative.

The Direct Testimony of Mr. Rudeck at page 29 line 17 to page 30 line 2 clarified that the Company reviewed numerous generation alternatives before signing the EEA and SPSA. Thus, MP did not reconsider whether alternative generation sources should be pursued for this proceeding. The only question addressed by MP is how to deliver the capacity and energy called for under the SPSA and EEA. In this case, new generation resources would not be able to deliver the capacity and energy called for under the SPSA and EEA.

Q. Please summarize MP's screening analysis for distributed generation alternatives.

A. On page 72 of the Petition MP stated that "while distributed generation resources may play a role in the Company's overall resource strategy going forward, they cannot displace the need for the GNTL and the substantial energy and capacity deliveries it makes available to Minnesota Power's customers." Further, as Mr. Rudeck's Direct Testimony stated regarding new generation resources in general, new distributed generation resources would not be able to deliver the capacity and energy called for under the SPSA and EEA. MP Ex. ___ at 30-31 (Rudeck Direct).

Q. Please summarize MP's screening analysis for Community-Based Energy Development (C-BED) alternatives.

A. In the Petition MP explained that the Company has continually reviewed C-BED project proposals, including during the Company's early 2013 RFP for up to 210 MW of wind. MP Ex. ___ at 72-73 (Petition). Again, as Mr. Rudeck's Direct Testimony stated regarding new generation resources in general, C-BED generation resources would not be able to deliver the capacity and energy called for under the SPSA and EEA. MP Ex. ___ at 29-31 (Rudeck Direct).

Q. Do you agree with MP's screening of generation alternatives?

A. I agree with MP that new generation, distributed generation, and C-BED alternatives all fail to pass a screening test in that there is no reason to conclude that such alternatives could meet the claimed need to deliver the energy and capacity called for under the SPSA and EEA. Therefore, I agree that the generation alternatives do not need to be considered further.

3. Other Alternatives

Q. Please list the criteria that should be used in the screening analysis for conservation alternatives.

A. Minnesota Rules 7849.0120 A (2) states that the Commission must consider the effects of the applicant's existing or expected conservation programs and state and federal conservation programs.

Q. Are existing or expected conservation programs a reasonable alternative to the proposed GNTL?

A. No. First, conservation programs were weighed as an alternative to the SPSA and EEA before the Commission approved those agreements. Second, the interface between Manitoba and the United States is unable to accommodate increased transfer of energy from Manitoba into the United States. MP Ex. ___ at 107-108 (Petition). Conservation (lower demand) on the U.S. side of the border would not change that fact. Thus, the conservation alternative does not pass a screening test.

C. Review of Transmission Studies

Q. Has the proposed GNTL been analyzed in any transmission studies?

A. Yes, the proposed GNTL has been analyzed in several transmission studies. I briefly reviewed several transmission studies that evaluated the proposed GNTL:

- *Northern Area Study* (NAS);
- *MH-US TSR Sensitivity Analysis Draft Report* (TSR Report);
- *Manitoba Hydro Wind Synergy Study* (Synergy Study);
- *Dorsey—Iron Range 500 kV Project Preliminary Stability Analysis Draft Report* (Stability Report); and
- *Manitoba—United States Transmission Development Wind Injection Study* (Wind Report).

I reviewed these studies, not to evaluate the engineering analysis, but only to see how the studies might impact the economic comparison of alternatives.

Q. Can you provide the general location for the various substations discussed by the transmission studies?

A. Yes, the substations locations are shown in Table 1 below.

Table 1: Substation Locations

Substation	Location	Map
Arrowhead	Duluth	http://wikimapia.org/#lang=en&lat=46.749506&lon=-92.348328&z=11&m=b&tag=16500&show=/12322101/Square-Butte-Adolph-HVDC-Static-Inverter-Plant
Barnesville	Barnesville	no maps available (potential new substation)
Bison	Fargo	http://www.capx2020.com/routemaps/FSC-ND-07.2013/FSC-ND-tilemap1.pdf
Blackberry	Grand Rapids	http://wikimapia.org/#lang=en&lat=47.228042&lon=-93.313086&z=17&m=b&show=/19748096/Substation
Dorsey	Winnipeg	http://www.hydro.mb.ca/projects/gif/riel_location.jpg
Maple River	Fargo	http://wikimapia.org/10697533/Maple-River-Transmission-Substation
Monticello	Monticello	http://capx2020.com/routemaps/MSC-7-9-2010/MSC_7.09.2010_Monticello_Township.pdf
Riel	Winnipeg	http://www.hydro.mb.ca/projects/gif/riel_location.jpg
Shannon	Hibbing	http://wikimapia.org/26496673/Shannon-Substation

1. Overview of the NAS

Q. Does the NAS provide information to help distinguish among the economics of the alternatives to be evaluated in this proceeding?

A. No. The NAS, authored by the MISO and provided in Appendix M of the Petition, cannot be used to compare the alternatives being reviewed in this proceeding. The NAS states at page 11:

> The Northern Area Study provides no indication or comparison between Manitoba to MISO tie-line options. Tie-lines and new hydro generation were inputs to the Northern Area Study to determine economic development opportunities after the tie lines and generating units are built and in-service – essentially answering what build-out is required for MISO's entire northern footprint to realize the benefits of new Manitoba imports.

Q. What did the NAS conclude about "what build-out is required for MISO's entire northern footprint to realize the benefits of new Manitoba imports"?

A. The NAS concluded at page 99 that "Production cost savings benefits for MISO from new potential MH to MISO tie-lines could be realized with minimal incremental transmission investment." Thus, significant costs beyond those being evaluated in this proceeding (the proposed GNTL is the tie-line) should not be expected to be incurred to realize the benefits of new imports from Manitoba.

2. Overview of the TSR Report

Q. What alternatives did the TSR Report analyze?

A. The TSR Report, authored by MISO and provided in Appendix Q of the Petition, is broken down into two draft reports, one for the eastern alternative and one for the western alternative. Regarding the eastern alternative, the TSR Report studied:

- a Riel—Shannon 230 kV line for a 250 MW request;
- a Dorsey—Blackberry 500 kV line for a 750 MW request; and
- a Dorsey—Blackberry 500 kV line plus Blackberry—Arrowhead 345 kV double circuit line for a 1,100 MW request.

Regarding the western alternative, the TSR Report studied a Dorsey—Barnesville 500 kV line and Barnesville—Monticello 345 kV second circuit at all three levels (250 MW, 750 MW, and 1,100 MW).

Q. What did the TSR Report conclude about the economics of the two alternatives?

A. The results of the TSR Report for the eastern alternative were:

- no added cost for a 250 MW request;

- $2.16 million cost (to improve the Blackberry—Nashwauk 115 kV line for a 750 MW request); and
- no added cost for a 1,100 MW request. MP Ex. ___ at 4 (Petition, Appendix Q)

The results of the TSR Report for the western alternative were:

- no added cost for a 250 MW request; and
- $8 million cost (to improve two transformers ($4 million each) at the Maple River substation) for the 750 MW and 1,100 MW requests. MP Ex. ___ at 14 (Petition, Appendix Q)

The TSR Report summarized these results by stating that the proposed transmission lines "do not impact the existing transmission system in an adverse way" and "the estimated costs associated with these mitigations are relatively small." Thus, the TSR Report does not indicate an economic preference for either alternative.

3. Overview of the Synergy Study

Q. What alternatives did the Synergy Study review?

A. The Synergy Study, authored by MISO and provided in Appendix I of the Petition, evaluated three alternatives referred to as the western alternative, the central alternative, and the eastern alternative. The eastern alternative consisted of:

- a Winnipeg—Grand Rapids 500 kV line; and
- a Grand Rapids—Duluth 345 kV double circuit line.

The central alternative consisted of:

- a Winnipeg—Bemidji—Grand Rapids 500 kV line;
- a Bemidji—Fargo 345 kV double circuit line; and
- a Grand Rapids—Duluth 345 kV double circuit line.

The western alternative consisted of:

- a Winnipeg—Barnesville 500 kV line; and
- a second (345 kV) circuit added to the Fargo—Monticello 345 kV line. MP Ex. ___ at 29 (Petition, Appendix I)

Q. What did the Synergy Study conclude about the economics of the alternatives?

A. The Synergy Study was performed in several stages. During the course of the analysis MISO determined that "the central option did not provide enough benefits to justify the construction cost." Therefore, the central alternative was removed from the later stages of the analysis in the Synergy Study.

The eastern and western alternatives were compared in numerous ways on pages 44 to 55 of the Synergy Study. A summary of the economic comparison is:

- the cost estimate was $685 million for the east option and $598 for the west option (both 2012 dollars);
- both alternatives show similar benefits for both modified and unmodified production cost savings, the difference being less than $2 million[27] in the weighted average;

[27] The difference between the alternatives is less than 1 percent of the total benefits.

- load cost savings are nearly identical, the difference being $1 million in the weighted average;
- reserve cost savings are very small (less than $1 million);
- coal unit cycling costs are also very small (less than $1 million);
- wind curtailment reductions are small (the difference being less than 1 MW at a 40 percent capacity factor); and
- benefit-to-cost (B/C) ratios range from 1.7 to 3.8, with the western option performing slightly better than the eastern option under each scenario.[28]

Regarding the eastern and western alternatives the final conclusion of the Synergy Study was that:

> …the projects show large benefits to MISO and exceed the cost to build the line, thus final recommendation from this study is to include both the East and West 500 kV transmission options in the MTEP13 Appendix B.

MP Ex. ___ at 59 (Petition, Appendix I)

4. Overview of the Stability Report

Q. What alternatives did the Stability Report study?

A. The Stability Report, authored by MP and provided in Appendix N of the Petition, reviewed an eastern alternative and a western alternative at 1,100 MW of generation. Regarding the eastern alternative, the Stability Report studied:

- a Dorsey—Blackberry (Grand Rapids) 500 kV line;
- a Blackberry—Arrowhead (Duluth) 345 kV double circuit line; and

[28] This result is caused by same benefits being divided by a lower cost.

- three transformers at the Blackberry substation, two for 500/345 kV and one for 500/230 kV; and
- 60 percent series compensation at the midpoint of the line.

Regarding the western alternative, the Stability Report studied:

- a Dorsey—Bison (Fargo) 500 kV line;
- a second circuit on the Bison—Monticello 345 kV line;
- two 500/345 kV transformers at Bison; and
- 60 percent series compensation at the midpoint of the line. MP Ex. ___ at 4 (Petition, Appendix N)

Q. What did the Stability Report conclude about the economics of the two alternatives?

A. The Stability Report did not draw economic conclusions. Instead the conclusions discussed engineering issues such as loop flow, dynamic performance, and transient voltage performance which may have economic consequences.

5. Overview of the Wind Report

Q. What alternatives did the Wind Report study?

A. The Wind Report, authored by Excel Engineering on behalf of MP and provided in Appendix O of the Petition, reviewed an eastern alternative and a western alternative at 1,100 MW of generation. There were several variations on each alternative. Generally, the variations on the western alternative included:

- a Dorsey—Bison (Fargo) 500 kV line; and
- a second circuit on the Bison—Monticello 345 kV line.

Generally, the variations on the eastern alternative included:

- a Dorsey—Blackberry (Grand Rapids) 500 kV line; and
- a Blackberry—Arrowhead (Duluth) 345 kV double-circuit line. MP Ex. ___ at 12-13 (Petition, Appendix O)

Q. What did the Wind Report conclude about the economics of the two alternatives?

A. The Wind Report compared the eastern and western alternatives based upon the mitigation costs required to inject additional wind in two scenarios: at Fargo and at both Fargo and Brookings. All scenarios assumed 1,100 MW of new Manitoba-to-U.S. power transfers.

The results showed that, for the eastern option, 500 MW of additional wind could be injected without any costs. *Id*. at 3, 25-37. Further, in most cases, at least 1,000 MW of additional wind can be injected before substantial mitigation costs (at least $100 million) are incurred. *Id*. at 3, 25-37. In comparison, the western option the results show that, in most cases, substantial mitigation costs (at least $100 million) are incurred before 400 MW of additional wind can be injected. *Id*. at 3, 25-37.

6. Summary of Review of Transmission Studies

Q. What do you conclude regarding the economics of the two alternatives from your review of these studies?

A. I conclude that, generally, only the Wind Report showed significant differences between the eastern and western alternatives in terms of economic performance. All of the other studies found minimal economic differences between the eastern and western alternatives.

D. COST ANALYSIS OF ALTERNATIVES

1. Evolution of Construction Cost Estimate

Q. Please summarize MP's cost estimates for the proposed GNTL.

A. Mr. Donahue's Direct Testimony at page 4 line 4 to page 5 line 16 summarized the evolution of MP's capital cost estimate for the proposed GNTL as follows:

> **Page 4, lines 4-5:** In Section 4.3.1 of the [Certificate of Need] Application, the Company provided a range of estimated cost of between $406 million and $609 million.[29]
>
> **Page 4, lines 17-20:** as of April 15, 2014 Minnesota Power estimated the construction of the Project on the Route Alternatives (including any combination of proposed Segment Options), including substation facilities, to cost between $495.5 million and $647.7 million in 2013 dollars.
>
> **Page 5, lines 7, 13-16:** Power Engineers completed a MISO sponsored facility study report in early July 2014 … These two items will increase the Project cost to between $557.9 million and $710.1 million. However, Minnesota Power ratepayers will be responsible for only 28.3 percent of the Project cost, equating to $158 million to $201 million.
>
> **Page 10, lines 3-5:** Please refer to the table below [Table 2] which has been prepared using the estimates included in Appendix A of the MISO Facilities Construction Agreement as submitted to MISO for their review.

[29] Note that the Petition was filed October 22, 2013.

Table 2: Cost Estimate in MISO Facilities Construction Agreement

Funding Option	Total GNTL Cost	MP Responsibility	MH-CIAC	MH-Assignee
100 percent MP Ownership	$676,242,900	$311,071,700	$365,171,200	
Assignment	$676,242,900	$311,071,700	$33,812,100	$331,359,100

Q. Please summarize MP's cost estimates for the 230 kV alternative.

A. Mr. Donahue's Direct Testimony at page 12 line 12 to page 12 line 20 summarized as follows the evolution of MP's capital cost estimate for the 230 kV alternative:

> **Page 12, lines 13-17:** Minnesota Power estimated in the Application that a 230 kV transmission option … would cost Minnesota Power (and by extension, its customers) from $200 to $240 million (2020 dollars).
>
> **Page 12, lines 19-20:** These revisions [for environmental considerations] now indicate that the cost of a 230 kV line will range from $277 million to $355 million (2013 dollars).

2. Financial Background

Q. Please outline which entities have financial responsibility for the construction of the proposed GNTL.

A. MP's response to Large Power Intervenors' Information Request Nos. 3 and 4[30] clarified the investment responsibilities. Appendix A of the MISO Facilities Construction Agreement (FCA) estimates that the total GNTL cost will be

[30] All information request responses referred to are included in is included as Department Ex. __ SR-4 (Rakow Direct). *See also* MP Ex. ___ at MD, Schedule 5 (Donahue Direct).

$676,242,900 (2013 dollars).[31] MP would be responsible for financing 46 percent of the total construction costs or $311,071,700 using the FCA estimate. MH would be responsible for financing 5 percent of the total construction costs or $33,812,100. MH would be responsible because MH would have to pay to MP 5 percent of the construction cost as a CIAC. Note that the 46 percent MP responsibility plus MH's 5 percent CIAC equals MP's 51 percent ownership share.

For now, MH is also responsible for financing the remaining 49 percent of the total construction costs or $331,359,100. However, MP has made clear that the 49 percent share is likely to be transferred to another Minnesota MISO transmission owner or MP will assume 100 ownership (its own 51 percent share plus the 49 percent minority share).[32] If the minority ownership were to be transferred to another Minnesota MISO transmission owner, presumably the entity receiving MH's ownership share would be responsible for financing the 49 percent (or $331,359,100). However, all issues regarding the new owner can be addressed at the time any change in ownership is known.

Q. What would happen if MH does not sell its ownership share?

A. If a sale does not happen, then MP would become 100 percent owner of the proposed GNTL by mid-year 2016. MP Ex. ___ at 8 (Donahue Direct). If MP were to assume 100 percent ownership MH would provide 49 percent ($331,359,100) to MP as another CIAC. In that case, all of the costs of the GNTL would be attributable to MP. However, 49 percent of the costs would be offset by this CIAC (in addition to

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[31] For further information regarding the $676 million cost estimate see MP's response to Large Power Intervenors' Information Request No. 24.

[32] *See* MP Ex. __ at 13–14 (McMillan Direct); MP Ex.__ at 8 (Donahue Direct).

the 5 percent CIAC discussed above). Effectively, this structure means that MH would be financially responsible for 49 percent of the costs of the line even though MP would be the owner. I discuss below protections for MP's ratepayers.

Q. Please outline how MP's recovery of the capital costs of the proposed GNTL is proposed to work.

A. MP's responses to Large Power Intervenors' Information Request Nos. 3 and 4 and the Petition clarified cost recovery. MP proposed to have a 51 percent ownership share of GNTL, or $344,883,800 (using the FCA's $676,242,900 cost estimate); those are the costs that MP must recover. MP's costs would be offset by MH's 5 percent CIAC payment, assumed to be $33,812,100. That leaves 46 percent of total costs or $311,071,700 yet to be recovered.

The 46 percent can be broken down into two parts:

- 17.7 percent of total costs, or $119,695,000, attributable to the yet-to-be-filed ROA; and
- 28.3 percent of total costs, or $191,376,700, attributable to the SPSA.

The costs attributable to the SPSA (again 28.3 percent of the total or $191,376,700 using the FCA estimate) would be recovered through MP's Transmission Cost Recovery Rider (TCR), potentially base rates after a rate case for retail customers, and through formula rates set by the Federal Energy Regulatory Commission (FERC) in MISO's Attachment O process for MP's/Allete's wholesale customers.

MP expects to recover the costs attributable to the future ROA (17.7 percent of the total or $119,695,000 using the FCA estimate) from MH through a scheduling fee arrangement (also referred to as a “Monthly Must Take Fee”) expected to be included in the proposed ROA. At this time, I understand that MP expects to propose that the 17.7 percent share of investment for the proposed GNTL be placed into MP’s ratebase or TCR with the Monthly Must Take Fee paid by MH as an offset.

Q. How would the remaining 49 percent of the proposed GNTL’s capital costs be recovered?

A. Without knowledge of the entity assuming the minority ownership it is not possible to answer in detail. However, in general the costs of minority ownership of the proposed GNTL (49 percent or $331,359,100) would be assigned to MP’s load zone and thus ratepayers in MP’s load zone would be subject to paying the minority owner’s costs. MP’s response to Department Information Request No. 17 indicated that MP’s load share is 90.1 percent and Great River Energy’s load share is 9.9 percent. Thus, presumably, MP’s ratepayers would be responsible for approximately 90.1 percent of the new minority owner’s costs.

However, the wide disparity in impact between MP assuming the minority ownership (MH CIAC payment) or another Minnesota MISO transmission owner assuming the ownership (charges to ratepayers in MP’s load zone) indicates that it would helpful if MP would clarify in rebuttal testimony how the Company envisions cost recovery working for the minority owner if MH assigns the minority ownership to another Minnesota MISO transmission owner.

Q. How will the operations and maintenance (O&M) costs of the proposed GNTL be recovered?

A. The Petition at page 29 stated that MP's ratepayers "will also be responsible for only one-third of the maintenance costs." Since the petition was filed it has become clear that the GNTL's transfer capability is greater than initially estimated; the transfer capability assumed in the Petition (at page 13) to be about 750 MW. This was updated to be 883 MW in MP's direct testimony (see MP Ex. ___ at 15 (McMillan Direct) and MP Ex. ___ at 3 (Winter Direct)) and that the SPSA uses 28.3 percent of the total transfer capacity rather than one-third. Thus, the share of O&M costs to be recovered from MP's ratepayers should be somewhat less than stated in the Petition. It would be helpful if MP were to clarify in rebuttal testimony the specifics of the amount of O&M costs to be charged to MP's customers.

The Petition at page 16 stated: "Minnesota Power, through an Operation and Maintenance agreement will invoice the minority owner monthly for its 49 percent pro rata share of Operation and Maintenance expenses." Thus, the Petition explicitly accounts for 82 percent (49 percent plus 33 percent) or 77.3 percent using the updated estimate of transfer capability (49 percent plus 28.3 percent). The remaining O&M costs should be recovered from MH via the ROA; either 17.7 percent (100 minus 49 minus 33.3) if ratepayers are responsible for one-third or, if the updated transfer capability is used to calculate ratepayers' share, 22.7 percent (100 minus 49 minus 28.3). However, it would be helpful if MP were to clarify in rebuttal testimony the remaining O&M cost recovery.

Q. Can you summarize the outstanding issues regarding cost recovery at this time?

A. MP should clarify four items in rebuttal testimony. First, will MP propose that the 17.7 percent share of costs for the proposed GNTL be placed into MP's rate base or

TCR with the MH scheduling fees as an offset or if some other treatment is planned? Second, how does the Company envision recovery of the investment costs for the minority owner working? That is:

- does MP receive a CIAC payment from MH if a transfer to another Minnesota MISO transmission owner is arranged?
- are the costs of the new minority owner (a Minnesota MISO transmission owner) charged to MP's zone with no MH CIAC offset? or
- is there some other impact?

Third, the Company should explain whether or not MP's ratepayers are to be responsible for one-third or 28.3 percent of O&M costs or some other amount. Fourth, MP should clarify how the unaccounted for O&M cost recovery (either 17.7 percent [100 minus 49 minus 33.3] if ratepayers are responsible for one-third of O&M costs or, if the updated transfer capability is used, 22.7 percent [100 minus 49 minus 28.3]) would be recovered. My understanding of MP's proposed recovery of costs is illustrated in Table 3 below; I request that MP provide corrections or clarifications to Table 3 in the Company's rebuttal testimony.

Table 3: Summary of Financial Background

Responsibility For:	Final Ownership Structure: 100 % MP	Final Ownership Structure: 51 % MP / 49 % Other
Investment		
MP	46.0%	46.0%
MH (CIAC)	54.0%	5.0%
MH-Assignee	NA	49.0%
Total	100.0%	100.0%
Rev. Req.–Capital Cost		
MP Ratepayer	28.3%	28.3%
MH (ROA Fee)	17.7%	17.7%
MH (CIAC)	54.0%	5.0%
Undefined	0.0%	49.0%
MH-Assignee	NA	0.0%
Total	100.0%	100.0%
Rev. Req.–O&M		
MP Ratepayer	28.3%	28.3%
MH (ROA Fee)	17.7%	17.7%
MH (CIAC)	0.0%	0.0%
Undefined	54.0%	5.0%
MH-Assignee	NA	49.0%
Total	100.0%	100.0%

3. Analysis of Internal Costs

Q. Please list the criteria used in the analysis of alternatives, considering internal costs only.

A. Minnesota Rules 7849.0120 B (2) states that the Commission must consider "the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives."

Also, Minnesota Statutes § 216B.243, subd. 3 (9) states that the Commission must evaluate 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.[33]

Q. Where is the Company's most recent cost analysis located?

A. Mr. Donahue's Direct Testimony at page 5 lines 7 to 14 provided updated construction cost estimates for the proposed GNTL. Mr. Donahue's Direct at page 12 lines 17 to 20 provided updated construction cost estimates for the 230 kV alternative.

Q. Please summarize MP's current cost analysis for the proposed GNTL.

A. The proposed GNTL is now estimated to cost between $557.9 million and $710.1 million (2013 dollars, see the response to Department Information Request No. 23). Further, Mr. Donahue's Direct Testimony at page 13 lines 3 to 4 stated that MP's ratepayers would be responsible for 28.3 percent of the proposed GNTL (equivalent to paying for 250 MW of the 883 MW of incremental transmission capacity). Thus, it appears that MP's ratepayers would be responsible for between $158 million and $201 million of construction costs. Specifically, Mr. Donahue's Direct Testimony at page 10 lines 4 to 5 provided a point estimate of $676,242,900 from Appendix A of a MISO Facilities Construction Agreement, submitted to MISO for review. Using the 28.3 percent allocator means that MP's ratepayers would be responsible for $191.4

[33] If a renewable generation facility had passed the screening analysis, Minnesota Statutes § 216B.2422, subd. 4 would also apply. However, in this instance no renewable generation facility passed the screening analysis.

million of construction costs estimated in the FCA. I request that MP confirm this number in their rebuttal testimony.

Q. Please summarize MP's current cost analysis for the 230 kV alternative.

A. The cost of a 230 kV alternative is now estimated to range from $277 million to $355 million (2013 dollars). Mr. McMillan's Direct Testimony at page 19 lines 12 to 14 confirmed that MP's ratepayers would be responsible for 100 percent of the costs of the 230 kV alternative.

Q. Please compare the results of MP's current cost analysis.

A. Mr. Donahue's Direct Testimony at page 15 lines 4 to 9 summarized the revenue requirements of MP's capital cost estimate for the proposed GNTL and the 230 kV alternative:

For the proposed GNTL:

> **Page 15, lines 4-7:** Based on Minnesota Power's revised cost estimate as updated in this testimony, the Project will add $30.1 million in MISO revenue requirements in the first year of operation to the Minnesota Power load zone

For the 230 kV alternative:

> **Page 15, lines 8-9:** that stand-alone project would add $52.2 million in additional revenue requirements to Minnesota Power's MISO rates.

Thus, the proposed GNTL would have far lower revenue requirements than a stand-alone 230 kV transmission line.

Q. Could consideration of O&M costs change this conclusion?

A. No, for the following reasons. First, MP's supplemental responses to Department Information Request Nos. 9 and 10 showed that the O&M revenue requirements are already included in MP's cost estimates and that the O&M revenue requirements for the 230 kV alternative are lower by about $107,000. This O&M cost differential, even if separate consideration were appropriate, is far too small to change the overall conclusion in the alternatives analysis in MP's supplemental responses to Department Information Request Nos. 9 and 10.

Second, Mr. Donahue's Direct Testimony at page 6 lines 9 to 11 estimated O&M costs for the proposed GNTL to be $1,100 to $1,600 per mile. Assuming a length of 240 miles and assuming that MP's ratepayers would be responsible for 33 percent of O&M costs,[34] MP's ratepayers would be responsible for between $87,100 and $126,700 annually in O&M costs. Even if no O&M costs were attributed to the 230 kV alternative, the O&M cost differential between the proposed GNTL and the 230 kV alternative is far too small to change the overall conclusion. That is, O&M costs of about $100,000 per year are too small to change the overall economic conclusion because the rate impact of the difference in construction costs (230 kV alternative minus GNTL proposal) would equal millions of dollars in the first year; see Mr. Donahue's Direct Testimony at page 15 and summarized above.

Q. Could consideration of line losses change the overall conclusion?

A. No. On pages 33-34 of the Petition MP provided line loss information. MP estimated that the proposed GNTL would result in a reduction in line losses of 21.1 MW and

[34] *See* MP Ex. ___ at 29 (Petition).

79,849 MWh. Table 4 below calculates the annual economic benefit of the proposed GNTL's line loss savings. Table 4 shows that the annual economic benefit associated with line-loss savings is about $4.2 million.

Table 4: Economic Benefit of Line Loss Savings[35]

Amount	Item	Amount	Item
79,849	**MWh Saved**	21.1	**MW Saved**
$29.23	**$/MWh**	$89,500	**$/MW-yr**
$2,333,986	**Energy Savings**	$1,888,450	**Demand Savings**

In general, lower voltage alternatives have a poorer performance in terms of line losses. Thus, the 230 kV alternative would be expected to have a lower level of demand and energy savings. Further, the revenue requirement differential (500kV minus 230 kV) is about $22.1 million. To offset the line loss benefit of the proposed GNTL ($4.2 million) and the revenue requirement difference ($22.1 million) would require $26.3 million in benefits or about 131 MW of line loss savings (assuming $0.2 million[36] per MW). Thus, consideration of line losses would improve the economics of the proposed GNTL relative to the 230 kV alternative.

Q. What is the potential for the GNTL to lower costs for electric consumers in Minnesota?

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[35] The MW and MWh savings are taken from the Petition at pages 33-34. The $/MWh value is the average locational marginal price (LMP) at MISO's Minnesota Hub for January 1, 2014 to August 17, 2014. (LMP Source: https://www.misoenergy.org/Library/MarketReports/Pages/MarketReports.aspx) The $/MW value is MISO's cost of new entry (CONE) for planning year 2014/15 in MISO's load resource zone (LRZ) 1; note that LRZ1 consists of the following balancing authorities: DPC, GRE, MDU, MP, NSP, OTP, and SMMPA (CONE Source: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2013/20130905/20130905%20SAWG%20Item%2007%20CONE%20Filing.pdf)

[36] $4.2 million divided by 21.1 MW line loss savings equals about $0.2 million per MW of line loss savings.

A. MP's response to Department Information Request No. 3 provided an analysis of locational marginal prices (LMPs) and production costs. The result of the LMP analysis is a slight decrease in Minnesota LMPs in 2022 (either 4¢ in the business as usual (BAU) case or 1¢ in the high growth case) and a larger decrease in Minnesota LMPs in 2027 (either 78¢ in the BAU case or 30¢ in the high growth case). Retail sales of electricity in Minnesota are about 67 or 68 million MWh annually.[37] Applying the LMP decrease shown in MP's response to Department Information Request No. 3 to the retail sales of electricity provides the upper bound of the savings (if all retail sales were priced at LMP). If MP's estimates are accurate, the decreases would translate into the following maximum savings levels:

- A decrease of 4¢ per MWh (2022 BAU) equals a savings of $2.68 million;
- A decrease of 1¢ per MWh (2022 high growth) equals a savings of $0.67 million;
- A decrease of 78¢ per MWh (2027 BAU) equals a savings of $52.26 million; and
- A decrease of 30¢ per MWh (2027 high growth) equals a savings of $20.10 million.

The result of the production cost analysis would be a slight increase in Minnesota production cost in 2022:

- either $0.2 million in the BAU case; or

[37] For Minnesota's annual energy consumption see: http://www.eia.gov/electricity/data/browser/#/topic/5?agg=0,1&geo=000004&endsec=vg&linechart=ELEC.SALES.MN-ALL.A&columnchart=ELEC.SALES.MN-ALL.A&map=ELEC.SALES.MN-ALL.A&freq=A&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=

- $3.0 million in the high growth case.

The result of the production cost analysis estimates a decrease in Minnesota production cost in 2027:

- either $3.3 million in the BAU case; or
- $1.6 million in the high growth case.

I agree with MP's response to Department Information Request No. 3 that the near term impact is not material. The longer term impact, while subject to significant uncertainties, indicates the potential for savings for the region attributable to the proposed GNTL.

Q. Please summarize your analysis of internal costs.

A. Considering the cost of the proposed GNTL and the cost of energy to be supplied by the proposed GNTL compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives, I conclude that the proposed GNTL is the preferred alternative. Also, the proposed GNTL has a minimal impact in the near term when considering the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota. However, there is uncertainty about the effects of the proposed GNTL in the longer term; it is hoped that the proposed GNTL will decrease costs for electric consumers in Minnesota in the longer term.

4. Analysis of Societal Cost

Q. Please explain what statutory or rule criteria are used to guide the analysis of alternatives considering external and internal costs.

A. Minnesota Rules 7849.0120 B (3) states that the Commission must consider "the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives." Also, Minnesota Statutes §216B.2422, subd. 3 (a) states:

> The commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.

This is a certificate of need proceeding where resource options will be selected. Thus, MP should have used the Commission's externality values but MP did not discuss the values in the Petition. As indicated further below, application of externality values slightly improves the economics of the proposed GNTL. However, I recommend that the Commission order MP to use the Commission's externality values in future CN proceedings.

Q. Is the Commission's estimated range of the cost of future CO_2 regulation, pursuant to Minnesota Statutes § 216H.06, required to be used in this proceeding?

A. No. Since Minnesota Statutes § 216H.06 states that the range of costs of future CO_2 regulation applies to "electricity generation resource acquisition proceedings," it would appear that Minnesota Statutes do not require the CO_2 regulation range of costs be used in this transmission proceeding. However, in economic terms, it does not matter if an increase in emissions (and thus emissions costs) is caused by selecting a high-emission generation alternative or a high-loss transmission alternative. Thus, despite section 216H.06's language, the Commission's CO_2 regulation cost estimates should be applied to the cost calculations in all transmission CN proceedings so that CO_2 and other emission costs are reasonably considered in resource selections.

Q. What impact does the addition of the Commission's externality values and cost of future CO_2 regulation have on the internal cost results?

A. In Docket No. E002/CN-11-826 I calculated a cost per MWh using the Commission's externality values, CO_2 internal cost value, and the estimated cost of SO_2 emissions credits. Since the cost of SO_2 emissions credits are an existing internal cost they should already be included in the LMP data used here. Thus, I removed the SO_2 emissions cost from my prior calculations. The result is an estimated cost of $20.05 per MWh in 2017. Table 5 below presents the same data as in Table 1 but adds the externality and CO_2 regulatory cost values. Table 5 shows that the annual economic benefits (including externalities and Carbon cost) associated with the line-loss savings are $5.8 million.

Table 5: Economic Benefit of Line Loss Savings with Externalities

Amount	Item	Amount	Item	Total Benefit
79,849	**MWh Saved**	21.1	**MW Saved**	
$49.28	**$/MWh**	$89,500	**$/MW-yr**	
$3,934,959	**Energy Savings**	$1,888,450	**Demand Savings**	**$5,823,409**

In summary, consideration of the Commission's externality and CO_2 regulation cost estimates indicates a slight benefit of the GNTL but does not materially change the analysis of line losses.

Q. Did MP analyze the addition of the Commission's externality values or estimated range of the cost of future CO_2 regulation?

A. Yes, in response to Department Information Request No. 3, MP adjusted the Company's analysis to include the Commission's cost of future CO_2 regulation value. The result of the LMP analysis with CO_2 values included was:

- A decrease of 1¢ per MWh (2022 BAU) equals a savings of $0.67 million;
- A decrease of 52¢ per MWh (2027 BAU) equals a savings of $34.8 million;

The result of the production cost analysis with CO_2 values included was:

- either $0.6 million increase (2022 BAU case); or
- $1.5 million decrease (2027 BAU case).

In summary, inclusion of the Commission's CO_2 values is relatively minor. Consideration of the impact of CO_2 values on the LMP makes the proposed GNTL slightly less beneficial as the LMP decreases by a lower amount. The production cost impact is similar, with production costs increasing by a larger amount with CO_2 values than without CO_2 values in the 2022 BAU case ($0.6 million versus $0.2 million) and decreasing by a smaller amount in the 2027 BAU case ($3.3 million versus $1.5 million).

5. Other Issues

a. Impact on Fossil Fuel Generation

Q. What is the expected impact of the proposed GNTL on coal generation in Minnesota and the region?

A. There are two impacts. First, as decided in MP's prior resource plan (Docket No. E015/RP-13-53), the direct impact is that MP is planning on shutting down Taconite Harbor unit 3 and refueling Laskin units 1 and 2 (switching from coal to natural gas). The SPSA is part of MP's plan to replace the lost energy and capacity. Thus, the GNTL is directly enabling a decrease in coal generation.

Second, the indirect impact of the proposed GNTL is to enable the addition of resources (MH's generation to meet the SPSA) to the MISO dispatch stack. Thus, to the extent that coal units are on the margin (the load following unit) and MH's generation has a lower variable cost (and thus would be dispatched first) or is must run, coal generation will be replaced by hydro generation imported via the GNTL. The same consideration applies to natural gas generation; to the extent that natural gas units are on the margin and MH's generation has a lower variable cost (would be dispatched first), natural gas generation will be replaced by hydro generation imported via the GNTL.

In summary, the proposed GNTL is directly (in MP's IRP) and indirectly (in MISO dispatch) replacing coal generation and the proposed GNTL is indirectly replacing natural gas generation.

Q. Could the hydro generation enabled by the proposed GNTL replace wind generation?

A. In terms of the MISO dispatch order the answer is no. Wind has little to no variable cost and is often operated as a "must run" unit. Thus, wind is unlikely to be the load following unit and MH is unlikely to replace wind via the dispatch order. However, in MP's IRP hydro and wind are both resources that must compete with each other to serve the Company's energy needs. It is possible that, if MH had not been selected additional wind (presumably accompanied by natural gas capacity and energy) would have been selected.

b. Barnesville Alternative End Point

Q. Could selection of the Barnesville end point impact who pays for the line?

A. Yes, a project constructed to a Barnesville end point likely would be sited entirely in Otter Tail Power Company's (OTP's) MISO pricing zone—a different border crossing point would be used. Second, a project with a Barnesville end point still would not qualify for cost sharing within MISO (treatment as multi-value project, market efficiency project, etc.). Thus, the project being in OTP's pricing zone, utilities in OTP's zone would be responsible to pay for the costs. OTP is about 73.7 percent of the zone, Missouri River Energy Services (MRES) is 11.6 percent, and Great River Energy (GRE) is 15.7 percent. Thus, ratepayers of OTP, MRES, and GRE would have to pay the costs of the line. Since none of these ratepayers are triggering the need for the line this cost allocation would represent a significant misallocation of costs. While it is possible that a cost sharing agreement could be negotiated between the load in the OTP zone (OTP, MRES, and GRE) and MP, it would not be prudent to assume that such an agreement could be negotiated. Furthermore, it has not been shown that a Barnesville end point, with (potentially) a completely different set of owners (see below) would be able to obtain cost sharing agreements similar to the cost sharing in MP's SPSA, EEA, and ROA.

Q. Could selection of the Barnesville end point impact who owns the line?

A. Yes, ownership of the Barnesville alternative would be unknown for some time. Specifically, Minnesota Statutes § 216B.246, subd. 2 states:

> An incumbent electric transmission owner has the right to construct, own, and maintain an electric transmission line that has been approved for construction in a federally registered planning authority transmission plan and connects to facilities owned by that incumbent electric transmission owner.

The Direct Testimony of Laura McCarten at page 16 in Docket No. ET2, E002/CN-06-1115 indicated that the Fargo—St. Cloud line was scheduled to be owned as follows:

- Great River Energy—25.0 percent;
- Minnesota Power—14.7 percent;
- Missouri River Energy Services—11.0 percent;
- Xcel Energy—36.1 percent; and
- Otter Tail Power Company—13.2 percent.

Thus, since the Barnesville alternative would interconnect with the CapX Fargo line, it appears that GRE, MRES, Xcel and OTP all could eventually elect to own a share of a Barnesville alternative. Therefore, ownership of the entire GNTL, with a Barnesville end point would not be known until after MISO (a federally registered planning authority) approves a project in its MISO transmission expansion plan (MTEP) and the ownership elections of the utilities are finalized. Currently, a majority (51 percent) of the ownership is known with the minority (49 percent) being unknown.

Q. Please summarize these other considerations.

A. In summary, the Barnesville alternative would likely result in a significant misallocation of costs, might transfer responsibility for revenue requirements from MH to ratepayers in Minnesota, and would result in the entire ownership structure of the GNTL not being known for quite some time. The misallocation of costs is a significant economic issue.

IV. RECOMMENDATION

Q. Please provide your conclusion and recommendation at this time.

A. First, I recommend that the Commission order MP to use the Commission's externality values in all certificates of need and put MP on notice that failure to do so would result in CN filings being found to be incomplete in the future.

Second, I recommend that MP clarify whether MP expects to propose that the 17.7 percent share of costs for the proposed GNTL be placed into MP's ratebase with the MH scheduling fees as an offset or if some other ratemaking treatment is planned.

Third, I recommend that MP clarify how the Company envisions recovery of the investment costs for the minority owner working. That is:

- does MP receive a CIAC payment from MH if a transfer to another Minnesota MISO transmission owner is arranged?
- are the costs of the new minority owner (a Minnesota MISO transmission owner) charged to MP's zone with no MH CIAC offset? or
- is there some other impact?

Fourth, I recommend that the Company explain if MP's ratepayers are to be responsible for one-third or 28.3 percent of O&M costs or some other amount.

Fifth, I recommend that the Company fully explain the source for the unaccounted for O&M cost recovery (either 18 percent [100 minus 49 minus 33] if ratepayers are responsible for one-third of O&M costs or, if the updated transfer capability is used, 22.7 percent [100 minus 49 minus 28.3]).

Sixth, I recommend that the Company confirm that the most recent point estimate is that MP's ratepayers would be responsible for $191.4 million of construction costs.

Seventh, I recommend that MP provide an update regarding the status in Manitoba of the Keeyask dam, Conawapa dam, and related transmission projects in rebuttal testimony.

Lastly, I recommend that MP provide corrections or clarifications to my Table 3 above.

Q. Does this conclude your direct testimony?

A. Yes.

Steve Rakow
Minnesota Department of Commerce
85 7th Place East, Suite 500
St. Paul, MN 55101-2145

Professional Background

1996 to present Public Utilities Rates Analyst • Minnesota Department of Commerce. Analyze resource plans, certificates of need, and miscellaneous public policy issues. Testify before the Minnesota Public Utilities Commission in contested-case proceedings. A list of related filings analyzed and testimony presented is included below.

1999 to 2005 Board of Governors • MinforMed, L.L.C. Wrote portions of and advised on the economic and business sections of several grant proposals and the 2002 business plan. Named to Board of Directors, March, 2000.

1995 Instructor • University of Nebraska-Omaha. Taught Principles of Macroeconomics.

1993 to 1994 Instructor and Academic Assistant to the Rector • Concordia International University-Estonia. Taught Introduction to Economics. Wrote Student Handbook and Faculty Introduction to Tallinn Handbook.

1993 Instructor • Concordia University-Nebraska. Taught Principles of Microeconomics.

1989 to 1993 Graduate Teaching Assistant • University of Nebraska. Taught Introduction to Economics, Principles of Microeconomics, Principles of Macroeconomics, Current Economic Issues and Intermediate Macroeconomics. Specialized in public policy, economic history and comparative economics.

Education

Doctor of Philosophy, Economics, University of Nebraska, December 1994

Master of Arts, Economics, Mankato State University, March 1989

Bachelor of Arts, Economics, Moorhead State University, May 1987

Bachelor of Science, Accounting, Moorhead State University, May 1987

Testimony in Contested Case Proceedings

Docket No.	Company	Description	Subjects
ET6675/CN-12-1053	ITC Midwest	Minnesota-Iowa 345 kV Project	Alternatives, Policy
E002/CN-12-1240	Xcel Energy	Competitive Resource Acquisition	Alternatives
E002/CN-12-0113	Xcel Energy	Hollydale 115 kV	Alternatives, Policy
E017/M-10-1082	OTP	Big Stone AQCS	Alternatives
E017/GR-10-239	OTP	Rate Case	Big Stone II Background
E015/PA-09-526	MP	Purchase DC Line	Alternatives
E002/CN-08-0510	Xcel Energy	Prairie Island ISFSI	Planning, Alternatives, Policy
E002/CN-08-0509	Xcel Energy	Prairie Island EPU	Planning, Alternatives, Policy
E002/CN-08-0185	Xcel Energy	Monticello EPU	Planning, Alternatives, Policy
E002, ET2/ CN-06-1115	Xcel Energy, GRE	CapX 161/230/345 kV	Planning Background, Alternatives, Policy
E002, ET3/ CN-04-1176	Xcel, Dairyland	Chisago-Apple R. 115/161 kV	Planning Background, Alternatives, Policy
E017 et al/ CN-05-0619	OTP et al	Big Stone-Morris 230 kV Big Stone-Granite F. 345 kV	Planning Background, Alternatives, Policy
E002/CN-05-0123	Xcel Energy	Monticello ISFSI	Alternatives, Policy
E002/CN-04-0076	Xcel Energy	Blue Lake CT	Alternatives
IP6339/CN-03-1841	Trimont LLC	Trimont Wind	Settlement-Alternatives
E001/GR-03-767	Interstate	Rate Case	Rate of Return
IP6202/CN-02-2006	MMPA	Faribault CC	Settlement, Enviro. Report
ET2/CN-02-0536	GRE	Plymouth-Maple Gr. 115 kV	Forecasting
E002/CN-01-1958	Xcel Energy	SW Minn. 115/161/345 kV	Forecasting
PL9/CN-01-1092	Lakehead	Clearbrook-Superior Pipeline	Alternatives, Social Consequences
E002/CN-99-1815	NSP	Black Dog CC	Alternatives, Forecasting
ET2/CN-99-0976	GRE	Pleasant Valley CT	Social Consequences, Forecasting, Enviro. Report
IP3/CN-98-1453	Tenaska NRG	Lakefield Junction CT	Alternatives, Enviro. Report Social Consequences
PL9/CN-98-0327	Lakehead	Clearbrook-Donaldson Pipeline	Alternatives, Social Consequences

Comments in Planning and Need Proceedings

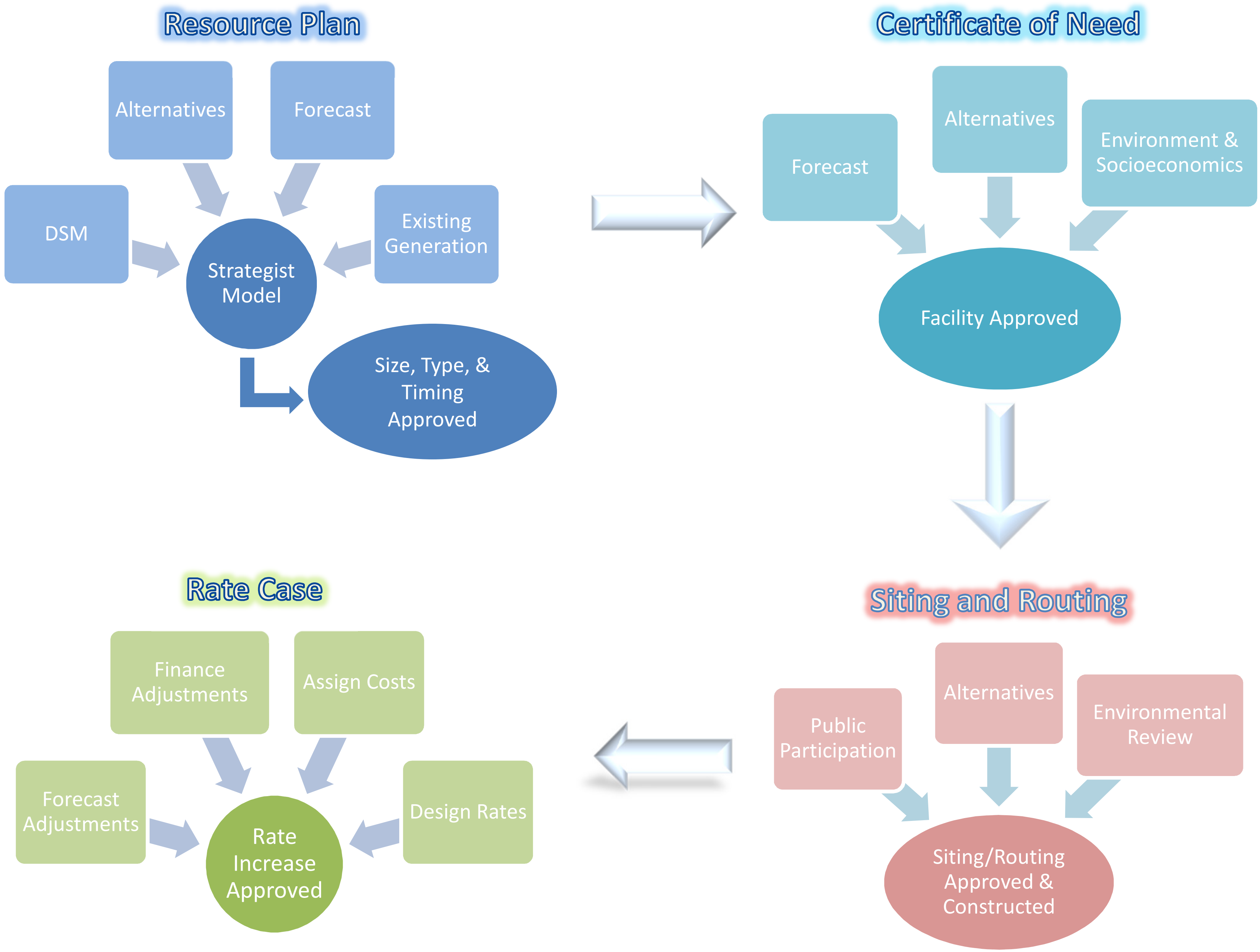
Docket No.	Company	Type	Subjects
E001/RP-14-77	Interstate Power	Resource Plan	Modeling
ET2/CN-12-1235	GRE	Need-Trans.	All Areas
E015/RP-13-0053	Minnesota Power	Resource Plan	Modeling
E015/M-12-1349	Minnesota Power	Resource Purchase	Modeling
E002, ET2/CN-11-0826	Xcel Energy, GRE	Need-Trans.	Alternatives, Policy
E017/RP-10-0623	Otter Tail Power	Baseload Study	Modeling
E002/CN-11-0332	Xcel Energy	Need-Trans.	Alternatives, Policy
E002/RP-10-0825	Xcel Energy	Resource Plan	Modeling
E015/RP-09-1088	Minnesota Power	Baseload Study	Modeling
ET3/RP-11-0918	Dairyland	Resource Plan	Supply
IP6853,6866/CN-11-0471	Black Oak & Getty	Need-Wind	All Areas
E999/M-11-0445	All Utilities	Trans. Plan	All Areas
ET6133/RP-11-0771	MMPA	Resource Plan	Supply
E001/RP-08-0673	Interstate Power	Resource Plan	Modeling
E017/RP-10-0623	Otter Tail Power	Resource Plan	Modeling
E002/CN-09-1390	Xcel Energy	Need-Trans.	Alternatives, Policy
E002/CN-10-0694	Xcel Energy	Need-Trans.	Alternatives, Policy
ET6/RP-10-0782	Minnkota	Resource Plan	Modeling
ET6838/CN-10-0080	Geronimo Wind	Need-Wind	All Areas
IP6701/CN-09-1186	National Wind	Need-Wind	All Areas
IP6830/CN-09-1110	Geronimo Wind	Need-Wind	All Areas
E015/RP-09-1088	Minnesota Power	Resource Plan	Modeling
E999/M-09-0602	All Utilities	Trans. Plan	All Areas
ET9/RP-09-0536	SMMPA	Resource Plan	Modeling
E002/CN-08-0992	Xcel Energy	Need-Trans.	All Areas
IP6688/CN-08-0961	EcoHarmony Wind	Need-Wind	All Areas
ET6125/RP-08-0846	Basin	Resource Plan	Supply
ET2/RP-08-0784	Great River	Resource Plan	Supply
E002/RP-07-1572	Xcel Energy	Resource Plan	Modeling, Nuclear
E017 et al/CN-07-1222	MP, OTP, Minnkota	Need-Trans.	Alternatives, Policy
E999/M-07-1028	All Utilities	Trans. Plan	All Areas
E017/CN-06-0677	Otter Tail	Need-Trans.	All Areas
ET9/RP-06-0605	SMMPA	Resource Plan	Supply

Comments in Planning and Need Proceedings-Continued

Docket No.	Company	Type	Subjects
E999/TL-05-1739	GRE, MP	Need-Trans.	All Areas
E001/RP-05-2029	Interstate Power	Resource Plan	Supply
E999/TL-05-1739	All Utilities	Trans. Plan	All Areas
ET10/RP-05-1102	Missouri River	Resource Plan	Modeling
ET2/RP-05-1100	Great River	Resource Plan	Supply
E017/RP-05-0968	Otter Tail Power	Resource Plan	Supply
E015/RP-04-0865	Minnesota Power	Resource Plan	DSM, Supply
E002/RP-04-1752	Xcel Energy	Resource Plan	Modeling, Nuclear, Bids
E999/TL-03-1752	All Utilities	Trans. Plan	All Areas
ET2/RP-03-0974	Great River	Resource Plan	DSM
E002/RP-02-2065	Xcel Energy	Resource Plan	DSM, Nuclear
ET6/RP-02-1145	Minnkota	Resource Plan	Forecasting, Contingency
E999/TL-01-0961	All Utilities	Trans. Plan	All Areas
ET2/RP-01-0160	Great River	Resource Plan	DSM
ET3/RP-00-1619	Dairyland	Resource Plan	All Areas
E002/RP-00-0787	Xcel Energy	Resource Plan	DSM, Nuclear
ET9/RP-00-0863	SMMPA	Resource Plan	Forecasting
E015/RP-99-1543	Minnesota Power	Resource Plan	DSM, Forecasting
E017/RP-99-0909	Otter Tail Power	Resource Plan	Rate Design
ET10/RP-98-0938	Missouri River	Resource Plan	Supply, Rate Design
ET2,3/RP-98-0366	CPA/Dairyland	Resource Plan	Supply
E002/RP-98-0032	NSP	Resource Plan	Supply, Nuclear
E015/RP-97-1545	Minnesota Power	Resource Plan	DSM
E001/RP-97-0955	Interstate Power	Resource Plan	Supply
ET9/RP-97-0954	SMMPA	Resource Plan	Forecasting
ET7/RP-97-0001	United Power	Resource Plan	DSM

Docket No. E015/CN-12-1163

Department Ex. __ SR-2


Resource Plan
Alternatives
Forecast
DSM
Existing Generation
Strategist Model
Size, Type, & Timing Approved
Certificate of Need
Alternatives
Forecast
Environment & Socioeconomics
Facility Approved
Siting and Routing
Alternatives
Public Participation
Environmental Review
Siting/Routing Approved & Constructed
Rate Case
Finance Adjustments
Assign Costs
Forecast Adjustments
Design Rates
Rate Increase Approved

RESOURCE PLAN (Minn. Stat. 216B.2422, Minn. Rules 7843)

•DOES identify generic size, type, and timing of plants needed.
•DOES NOT identify specific power plants that would supply the deficit.
•Filed by every electricity provider (or its wholesale provider) with 100 MW of capacity and supplying electric service to 10,000 Minnesota customers.
•Consists of a 15-year forecast of projected power needs, existing energy supplies, and generic new additions to provide power to those projected customers.
•Results in a Commission determination of any projected deficits in supply on a generic basis i.e., identifies the size (how many MW), type (whether baseload, intermediate, peaking, wind, etc), and timing (which year) of resource needs.
•May substitute for a certificate of need process in circumstances prescribed by Minnesota Statute.

CERTIFICATE OF NEED (Minn. Stat. 216B.243, Minn. Rules 7849, 7851, 7853, and 7855)

•DOES identify specific large energy facilities.
•Filed by every electric provider (or its wholesale provider) for generation facilities above 50 MW and transmission facilities above 100 kV and 10 miles long or above 200 kV and 1,500 feet long.
•Consists of forecast of resource needs (the deficit to be addressed) and alternative projects to provide power to customers (supply).
•Starts with a resource plan-determined size, type, and timing of a need, confirms a specific need exists, and evaluates the economic, environmental, and social consequences of the alternatives to fulfill the need.
•Results in a Commission determination of the specific facility needed to fulfill demand (if any).

SITING AND ROUTING (Minn. Stat. 216E, Minn. Rules 7850, 7852, and 7854)

•Determines the location for new large energy facilities.
•Filed by every electric provider (or its wholesale provider) for generation facilities above 50 MW and transmission facilities above 100 kV and 1,500 feet long.
•May take place without a certificate of need for transmission facilities above 100 kV and between 1,500 feet and 10 miles in length.
•For other facilities, may take place simultaneously (at the same time as the certificate of need) or sequentially (after the certificate of need).
•Consists of a specific facility and one or more alternative locations.
•Starts with a certificate of need-determined facility and evaluates the economic, environmental, and social consequences of the alternative locations for the facility.
•Results in Commission determination of the specific location for a specific facility.

RATE CASE (Minn. Stat. 216B.16, Minn. Rules 7825)

•Determines the charges applied to customer bills for all utility services.
•Filed by every investor-owned retail electricity provider.
•Generally, new large energy facilities may only be included in a rate case only after they are constructed.
•Consists of one year’s data on sales, utility costs, and customer rates on a forecasted or historic basis.
•Starts with the costs incurred and evaluates the prudence of the utility’s costs.
•Results in specific rates being charged to specific customer classes.

Minnesota Rules 7849.0120 **Criteria.**

A certificate of need must be granted to the applicant on determining that:

A. the probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states, considering:

(1) the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility;
(2) the effects of the applicant's existing or expected conservation programs and state and federal conservation programs;
(3) the effects of promotional practices of the applicant that may have given rise to the increase in the energy demand, particularly promotional practices which have occurred since 1974;
(4) the ability of current facilities and planned facilities not requiring certificates of need to meet the future demand; and
(5) the effect of the proposed facility, or a suitable modification thereof, in making efficient use of resources;

B. a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record, considering:

(1) the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives;
(2) the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives;
(3) the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; and
(4) the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives;

C. by a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health, considering:

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

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

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

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

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

Minnesota Statutes §216B.1694, subd. 2 (a) (4). **Regulatory incentives.**

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

Minnesota Statutes § 216B.2422, Subd. 3. (a). **Environmental costs.**

The commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.

Minnesota Statutes § 216B.2422, subd. 4. **Preference for renewable energy facility.**

The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f.

Minnesota Statutes §216B.243, subd. 3 (9). **Showing required for construction.**

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

Minnesota Statutes §216B.243 subd. 3 (10) **Showing required for construction.**

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

Minnesota Statutes §216B.243, subd. 3 (12). **Showing required for construction.**

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

Minnesota Statutes §216B.243 subd. 3a. **Use of renewable resource.**

The commission may not issue a certificate of need under this section for a large energy facility that generates electric power by means of a nonrenewable energy source, or that transmits electric power generated by means of a nonrenewable energy source, unless the applicant for the certificate has demonstrated to the commission's satisfaction 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. For purposes of this subdivision, "renewable energy source" includes hydro, wind, solar, and geothermal energy and the use of trees or other vegetation as fuel.

Minnesota Statutes §216B.2426**. Opportunities for distributed generation.**

The commission shall ensure that opportunities for the installation of distributed generation, as that term is defined in section 216B.169, subdivision 1, paragraph (c), are considered in any proceeding under section 216B.2422, 216B.2425, or 216B.243.

Minnesota Statutes §216H.03 Subd. 3. **Long-term increased emissions from power plants prohibited.**

Unless preempted by federal law, until a comprehensive and enforceable state law or rule pertaining to greenhouse gases that directly limits and substantially reduces, over time, statewide power sector carbon dioxide emissions is enacted and in effect, and except as allowed in subdivisions 4 to 7, on and after August 1, 2009, no person shall:

(1) construct within the state a new large energy facility that would contribute to statewide power sector carbon dioxide emissions;

(2) import or commit to import from outside the state power from a new large energy facility that would contribute to statewide power sector carbon dioxide emissions; or

(3) enter into a new long-term power purchase agreement that would increase statewide power sector carbon dioxide emissions. For purposes of this section, a long-term power purchase agreement means an agreement to purchase 50 megawatts of capacity or more for a term exceeding five years.

Minnesota Statutes §216H.06. **Emissions consideration in resource planning.**

By January 1, 2008, the Public Utilities Commission shall establish an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation. The estimate, which may be made in a commission order, must be used in all electricity generation resource acquisition proceedings. The estimates, and annual updates, must be made following informal proceedings conducted by the commissioners of commerce and pollution control that allow interested parties to submit comments.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: E015/CN-12-1163 Date of Request: April 7, 2014

Requested From: David R. Moeller / Senior Attorney Response Due: April 17, 2014

Analyst Requesting Information: Steve Rakow

Type of Inquiry:	[ ]..... Financial	[ ]..... Rate of Return	[ ]..... Rate Design
	[ ]..... Engineering	[ ]..... Forecasting	[ ]..... Conservation
	[ ]..... Cost of Service	[ ]..... CIP	[ ]..... Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
3	Please provide an estimate of the impact of the proposed project on locational marginal prices (LMPs).

Response:

Based on the analysis completed by Ventyx and summarized in the report *"Economic Analysis of the Great Northern Transmission Line 2022 and 2027"* the Project will slightly decrease the locational marginal price (LMP) within the state of Minnesota across both scenarios (Business as Usual and High Growth) and both timeframes (2022 and 2027) as shown in table 4.1 of the report.

Response by: Scott Hoberg

List sources of Information:

Title: Engineer Senior

Ventyx GNTL Economic Analysis

Department: System Performance & Transmission Planning

Telephone: 218-355-2618

Economic Analysis of the Great Northern Transmission Line 2022 & 2027

Prepared for:
Minnesota Power

Ventyx project no.: US-V00001330A
Final Report

Date:

4/9/2014

Prepared by:
Ventyx, an ABB company

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AN ABB COMPANY

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Table of Contents

1 Introduction

1.1 Executive Summary

Minnesota Power retained Ventyx, an ABB company (Ventyx) to perform detailed hourly nodal market simulation and forecasts to examine the benefits of constructing a new 500 kV transmission line from Manitoba to Minnesota.

The primary goal of this analysis was to quantify changes, caused by interconnecting this new line, in:

1. the estimated cost to serve demand for market participants in MISO and in Minnesota
2. the Locational Marginal Price (LMP) within the State of Minnesota

The metric "Adjusted Production Cost" (APC) as defined by the Midcontinent ISO (MISO) was used to estimate cost.

Based on the analysis it has been shown that for the two years studied (2022 and 2027) and two future scenarios (Business-As-Usual and High Growth) analyzed the impact of the Great Northern Transmission Line (GNTL) caused a decrease in LMPs within Minnesota. Also it is shown that the new transmission line causes no material change in the calculated Adjusted Production Cost based on MISO's APC methodology.

1.2 Scope

In early 2013, MISO performed its Northern Area Study (NAS), assessing the potential benefits of a variety of transmission projects – including the GNTL - that have been proposed to address the needs of MISO's northern tier of states, including Minnesota. That study was performed using the PROMOD IV market simulation model, analyzing the economic impacts in the years 2022 and 2027, and using MISO's MTEP 2012 database.

For this GNTL study, Ventyx considered using MISO's MTEP 2013 database for PROMOD IV. However, that database was still under revision by MISO at the time Ventyx undertook the GNTL study. Consequently, Ventyx obtained from MISO the NAS database, which was based on the MTEP 2012 data assumptions.

Ventyx compared the key assumptions, such as gas price forecasts, load growth, generator retirements, and new generation expansion, between the NAS data and the work-in-progress MTEP 2013 database. These data assumptions were reviewed with Minnesota Power staff, and they – along with Ventyx – agreed that the differences in key assumptions between MTEP 2012 and MTEP 2013 were minor, and that the GNTL study would proceed using the NAS database.

For this GNTL study, two futures were analyzed. The first was MISO's **Business-As-Usual** (BAU) future, representing mid-range economic assumptions. The second was MISO's **High Growth** (HG) future, representing assumptions of higher economic growth, including higher demand growth and higher gas prices.

Taking full advantage of the NAS database, Ventyx simulated the years 2022 and 2027 to capture the impact of additional generation resource development by Manitoba Hydro.

The generation schedules from hydro plants in Manitoba are as represented in MISO's NAS analysis, which was in turn derived by MISO and Manitoba Hydro as part of their joint "Manitoba Hydro Wind Synergy Study".

Note that these hydro generation schedules are assumed to be static between the pre-GNTL and post-GNTL cases. Consequently, the analysis presented here will not capture possible benefits deriving from modifications to Manitoba Hydro's generation scheduling practices that might be implemented when GNTL is in service. These simulations dispatch hydropower hourly schedules at a very low offer price, so that the energy will generally be taken by the market unless transmission limitations constrain its delivery. Except when it is curtailed by such congestion, this Manitoba Hydro export energy is a "price-taker", bought by the market at the local LMP.

1.3 About PROMOD IV software

PROMOD IV provides valuable information on the dynamics of the marketplace through its ability to determine the effects of transmission congestion on key system flowgates. PROMOD IV captures the constraints and limitations inherent in electric power transmission using a DC load flow algorithm. All major transmission equipment is modeled, including transformers, phase-angle regulators, DC ties, generation buses, load buses, and transmission lines with reactance and resistance inputs.

Transmission system modeling is fully integrated with the commitment and dispatch algorithm so that generators are scheduled, started, and cycled while enforcing transmission flow constraints.

PROMOD IV simultaneously optimizes transmission, generation, and ancillary service requirements for all 8760 hours to provide a robust security-constrained unit commitment and economic dispatch solution with bus-level LMP reporting. This study employed PROMOD IV, version 10.1.3.

2 Input Assumptions

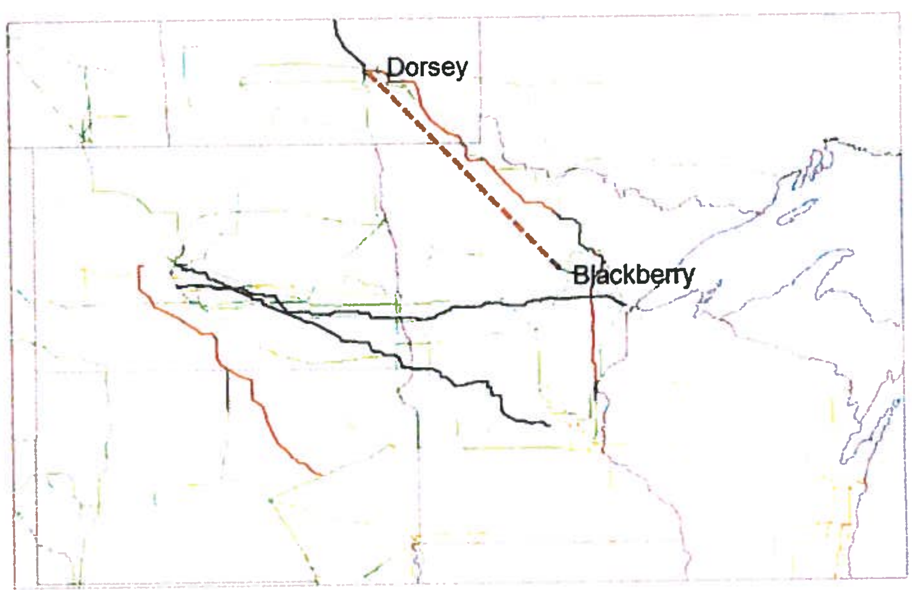
The majority of input assumptions were defined by Midcontinent ISO for their Northern Area Study.

2.1 Project Description

Minnesota Power, in partnership with Manitoba Hydro, proposes to construct a 500 kV transmission line from the International border that would terminate at the Blackberry substation in Itasca County (spanning an estimated 235 to 270 miles). The GNTL itself was modeled using MISO's data from NAS which was originally submitted by Minnesota Power. The project comprises the 500 kV branch from the Dorsey substation in Manitoba to the Blackberry substation in northwestern Minnesota, rated at 1732 MVA, plus additional system changes and upgrades at the Blackberry substation to feed these flows into the 230kV transmission system. Figure 1 below shows the general geographic arrangement of the project and is not representative of the project's actual route.

MISO's NAS analysis included as part of the project a 345kV extension from the Blackberry substation to the Arrowhead bus. This extension to the Arrowhead bus has not been represented in this Ventyx study.

Figure 1 -- Great Northern Transmission Line Path



2.2 Transmission Network

The scope of this database includes the entire Eastern Interconnect electric grid, excluding New England, Florida, Hydro-Quebec and the Canadian Maritime Provinces. These exclusions are sufficiently remote from Minnesota that they may be adequately represented by scaling their generation to meet their load and holding their net import or export constant.

The same network model is used for both 2022 and 2027. Therefore the only transmission difference examined is the presence or absence of the GNTL.

Two modifications were made to the MISO NAS data. First, the MISO ISO footprint was expanded to include the companies in the Entergy transmission region, which were to become integrated into the MISO market in December 2013. Second, the two futures were modified to include two conceptual transmission projects that were identified in the NAS study as significantly surpassing MISO's benefit/cost criterion:

- Hankinson – Wahpeton 230 kV upgrade
- Big Stone – Morris 115 kV upgrade

These two potential upgrades were determined by MISO to substantially increase the deliverability of wind generation from the Dakotas into Minnesota.

2.3 Generation

Table 2.1 presents the installed capacity of generation by fuel and type in MISO and in the companies that serve Minnesota load. Note the increase from 2022 to 2027 in wind, combined-cycle and combustion turbine capacity. These figures represent generic expansion and not specific proposals. There is no difference in the generation capacity mix between the Business As Usual and High Growth futures.

The schedule of hydropower from Manitoba was modeled per agreement between MISO and Manitoba Hydro for the Northern Area Study. Hydro energy is mostly represented as scheduled for peak-shaving (concentrated in higher-demand hours each day) with some flexibility to respond to market prices. This model mimics profit-maximizing bidding behavior without requiring that an offer price be assigned to the energy.

In the MISO NAS data, the hydro energy is offered to the MISO market at 0 $/MWh, shifting the supply curve to the right, with the expected effect of slightly lowering market clearing prices by displacing higher-cost generation in the receiving market. (Results of this study support this conjecture. Refer to Table 4.1.) However, the hydro energy is not free of charge; it is paid for at market clearing price. This study does not include the contract price for the energy, but it is supposed that the contract price is tied somehow to the market prices.

Table 2.1 – MISO and MN Generation Mix by Technology, 2022 and 2027

MISO - High Growth and Business As Usual				
Fuel	Technology	MW Capacity, 2022	MW Capacity, 2027	Change, 2022 to 2027
COAL	ST -Coal	60,496	60,496	-
	IGCC	1,077	1,077	-
GAS	CC	28,021	35,221	7,200
	CT -Gas	35,705	41,105	5,400
	ST -Gas	16,788	16,780	(8)
	ICE -Gas	109	109	-
OIL	CT -Oil	4,486	4,486	-
	ST -Oil	158	158	-
	ICE -Oil	381	381	-
	CT -Kerosene	67	67	-
RENEWABLES	CT -Renewable	36	36	-
	ST -Renewable	844	844	-
	ICE-Renewable	215	215	-
	ST -Other	167	167	-
WATER	Hydro	1,527	1,400	(127)
	Pumped-Storage	2,518	2,518	-
URANIUM	Nuclear	14,796	14,796	-
WIND	Wind	13,053	31,053	18,000
SUN	Solar PV	1,041	1,481	440
DEMAND RESPONSE	Interruptible Loads	9,169	9,169	-

Minnesota - High Growth and Business As Usual				
Fuel	Technology	MW Capacity, 2022	MW Capacity, 2027	Change, 2022 to 2027
COAL	ST -Coal	9,032	9,032	-
	IGCC	-	-	-
GAS	CC	2,897	4,097	1,200
	CT -Gas	7,315	7,315	-
	ST -Gas	267	259	(8)
	ICE -Gas	15	15	-
OIL	CT -Oil	1,690	1,690	-
	ST -Oil	-	-	-
	ICE -Oil	188	188	-
	CT -Kerosene	47	47	-
RENEWABLES	CT -Renewable	-	-	-
	ST -Renewable	452	452	-
	ICE-Renewable	26	26	-
	ST -Other	51	51	-
WATER	Hydro	375	350	(25)
	Pumped-Storage	-	-	-
URANIUM	Nuclear	2,366	2,366	-
WIND	Wind	6,583	11,286	4,703
SUN	Solar PV	220	320	100
DEMAND RESPONSE	Interruptible Loads	2,259	2,259	-

2.4 Demand

Demand in each area follows a synthetic hourly schedule which has been determined from load data for the years 2003-2009. This schedule is scaled so as to match the peak and annual energy figures assumed as in the table below.

Table 2.2 presents demand figures, described by annual peak and energy for MISO and for the companies that serve Minnesota load. The latter account for about 10 percent of MISO demand.

Table 2.2 – MISO and MN (weighted by sales) Demand, 2022 and 2027

		2022 BAU	2027 BAU	Growth Rate	2022 HG	2027 HG	Growth Rate
MISO	Peak MW	132,079	140,247	1.2%	141,857	156,279	2.0%
	Energy GWh	736,160	796,278	1.6%	802,554	907,110	2.5%
Minnesota Companies	Peak MW	13,923	15,019	1.5%	14,990	16,804	2.3%
	Energy GWh	80,695	86,895	1.5%	87,964	99,021	2.4%

2.5 Fuel Prices

Table 2.3 presents fuel prices for the Business as Usual and High Growth futures. Note that fuel prices are generally about 10% higher in the High Growth future.

Table 2.3 – Fuel Prices (nominal $/MBtu)

Business as Usual		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas (Henry Hub)	2022	$ 4.95	$ 4.93	$ 4.87	$ 4.66	$ 4.65	$ 4.67	$ 4.71	$ 4.74	$ 4.75	$ 4.79	$ 4.89	$ 5.05
	2027	$ 5.40	$ 5.38	$ 5.32	$ 5.09	$ 5.08	$ 5.11	$ 5.15	$ 5.18	$ 5.19	$ 5.24	$ 5.34	$ 5.51
Oil #6	2022	$ 13.30	$ 12.96	$ 12.99	$ 13.27	$ 13.64	$ 13.93	$ 14.21	$ 14.35	$ 14.37	$ 14.26	$ 13.99	$ 13.62
	2027	$ 14.50	$ 14.13	$ 14.16	$ 14.47	$ 14.87	$ 15.19	$ 15.49	$ 15.65	$ 15.66	$ 15.54	$ 15.25	$ 14.85
Oil #2	2022	$ 20.00	$ 19.76	$ 19.58	$ 19.50	$ 19.44	$ 19.42	$ 19.63	$ 20.28	$ 21.04	$ 21.23	$ 20.88	$ 20.36
	2027	$ 21.81	$ 21.54	$ 21.35	$ 21.26	$ 21.19	$ 21.17	$ 21.39	$ 22.11	$ 22.93	$ 23.14	$ 22.76	$ 22.19
Kerosene	2022	$ 21.17	$ 21.03	$ 21.02	$ 21.09	$ 21.17	$ 21.39	$ 21.70	$ 22.29	$ 22.91	$ 22.89	$ 22.34	$ 21.51
	2027	$ 23.08	$ 22.93	$ 22.91	$ 22.98	$ 23.08	$ 23.32	$ 23.65	$ 24.29	$ 24.97	$ 24.95	$ 24.35	$ 23.45

Business as Usual		Average	Min	Max
Coal (MN units)	2022	$ 2.31	$ 1.48	$ 3.48
	2027	$ 2.52	$ 1.61	$ 3.79

High Growth		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas (Henry Hub)	2022	$ 5.55	$ 5.53	$ 5.46	$ 5.22	$ 5.21	$ 5.24	$ 5.28	$ 5.31	$ 5.32	$ 5.38	$ 5.48	$ 5.66
	2027	$ 6.41	$ 6.38	$ 6.31	$ 6.04	$ 6.03	$ 6.07	$ 6.11	$ 6.15	$ 6.16	$ 6.22	$ 6.33	$ 6.54
Oil #6	2022	$ 14.91	$ 14.53	$ 14.56	$ 14.88	$ 15.30	$ 15.62	$ 15.93	$ 16.09	$ 16.11	$ 15.99	$ 15.68	$ 15.27
	2027	$ 17.21	$ 16.77	$ 16.81	$ 17.17	$ 17.66	$ 18.03	$ 18.39	$ 18.58	$ 18.59	$ 18.45	$ 18.10	$ 17.62
Oil #2	2022	$ 22.43	$ 22.16	$ 21.95	$ 21.86	$ 21.80	$ 21.77	$ 22.00	$ 22.74	$ 23.59	$ 23.80	$ 23.40	$ 22.82
	2027	$ 25.89	$ 25.57	$ 25.34	$ 25.24	$ 25.16	$ 25.13	$ 25.40	$ 26.24	$ 27.22	$ 27.47	$ 27.01	$ 26.34
Kerosene	2022	$ 23.74	$ 23.58	$ 23.57	$ 23.64	$ 23.74	$ 23.98	$ 24.33	$ 24.99	$ 25.68	$ 25.66	$ 25.04	$ 24.12
	2027	$ 27.40	$ 27.22	$ 27.20	$ 27.28	$ 27.40	$ 27.68	$ 28.08	$ 28.84	$ 29.65	$ 29.62	$ 28.90	$ 27.83

High Growth		Average	Min	Max
Coal (MN units)	2022	$ 2.59	$ 1.66	$ 3.90
	2027	$ 2.99	$ 1.91	$ 4.50

2.6 Emissions Prices

All emissions (SO_2, NO_X, CO_2) were assigned zero cost in 2022 and 2027.

3 Methodology

This analysis of the GNTL looks at the benefits to MISO and Minnesota in two ways:

1. Savings due to reduced Adjusted Production Costs (APC)
2. Changes in locational marginal prices (LMPs)

3.1 Adjusted Production Cost

APC is a common measure of energy production costs, used by the various ISOs to represent the net effect of market settlements when determining the cost to serve load. It is basically the cost of market purchases less revenues from market sales, modified by imports from and exports to neighboring markets.

Since it is impractical to try to capture the details of an ISO settlement statement, given uncertainty in the allocation of hedges, in the net impacts of market uplift charges, and in any particular market participant's bidding and scheduling policies, APC looks at the ISO settlement statement from the perspective of a vertically integrated utility (the predominant corporate structure of major market participants in MISO). In this view, the ISO market settlement simply represents a pricing mechanism for net purchases from, or sales to, the market.

In PROMOD IV simulations, a market participant ("company") will buy or sell among the other companies within its local market ("pool", such as MISO or PJM), depending on the state of the security-constrained dispatch each hour. The APC is calculated using the results of the PROMOD IV simulations, assuming that each company's net production is applied first to meet its own demand. Any surplus (or deficit) is sold to (or purchased from) other companies participating in the pool/market at the hourly rate.

According to MISO's APC definition, the hourly rate for sales to the pool is a blended marginal price for "net supply" by that company. It is the average of the LMPs at the company's own generator nodes, weighted by MWh production at each node. The hourly rate for energy purchased from the pool is a blend of the "net supply" prices for all companies that happen to be selling energy in the hour.

A company can also be allocated a share of economic purchases and sales that PROMOD IV schedules between pools, limited by economic hurdle rates defined between each pair of pools, and limited by the ability of the transmission system to carry these transfers. In MISO's NAS database, Manitoba Hydro is considered to be its own pool, as is the group of MRO companies that are currently neither in MISO nor in SPP[1].

MISO's definition of APC sets the price for any such inter-pool purchases and sales at the pool-wide generation-weighted LMP. Because this GNTL analysis focuses on the market interaction between Manitoba and Minnesota, Ventyx believes that it is more appropriate to price any such allocated inter-pool purchases and sales at the individual company generation-weighted LMP, and has used that pricing methodology in this analysis.

[1] The economic hurdle between MISO and Manitoba Hydro is set to zero.

This report summarizes the APC benefits of the GNTL on a MISO-wide basis and on a State of Minnesota basis. The latter Minnesota results are calculated by first multiplying the APC value for each company by the fraction of its load that is within Minnesota and then summing the result for all companies. The load fractions have been extracted from a prior study performed by Analysis Group (*"LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Supplemental Analysis"*, April 2013, Table 2, page 8).

3.2 LMP in Minnesota

An additional measure of the benefit of the GNTL is its impact on wholesale prices. PROMOD IV calculates from its nodal results the load-weighted zone LMP for each of the companies. These zone-level values are then weighted together, using load multiplied by the same factors from the Analysis Group report, to obtain a Minnesota load-weighted LMP. The company values are also averaged to obtain a MISO-wide load-weighted LMP. The change in these LMPs attributed to the GNTL being in service provides a measure of the benefits in terms of unhedged demand costs.

PROMOD IV calculates LMP including all three components: marginal energy, marginal congestion and marginal loss. It performs a Security-Constrained Unit Commitment (SCUC) and Economic Dispatch (SCED), such that the resulting output from all generators not only respects all generation operational constraints, including planned and forced outages, but also ensures that power flows on transmission facilities do not overload any facility for which a capacity limit has been provided, either in "system intact" (n-0) conditions or under the hypothetical loss of one facility (n-1). The transmission constraints are consistent with those used in the MISO NAS study.

4 Discussion of Results

Results are summarized below and interpreted.

4.1 Locational Marginal Price (LMP) in Minnesota

Table 4.1 presents the forecast change in LMP for Minnesota load, for the years 2022 and 2027 in the two future scenarios. The LMPs are load-weighted averages, expressed in nominal $/MWh.

In general, the wholesale prices show a decrease when GNTL is in service, as expected. In both scenarios, the relatively larger LMP decrease in 2027 is explained by the availability in that year of greater quantities of hydro-electric energy due to the commissioning of additional generating resources in Manitoba.

The comparatively lesser LMP decrease in the High Growth future is explained by observing that Manitoba Hydro's internal demand is forecast higher in the High Growth future, reducing the amount of energy that Manitoba Hydro has available for export, compared to the Business As Usual future.

Table 4.1 – Change in Load-Weighted LMPs Related to GNTL

	Scenario	GNTL status	LMP for Minnesota Load (Weighted-Average): Average LMP ($/MWh) On-peak	Off-peak	All hours	Change due to 500 kV GNTL line (in - out, $/MWh) On-peak	Off-peak	All hours
2022	BAU	out	$ 38.35	$ 25.91	$ 31.82	-0.08	0.00	-0.04
		in	$ 38.28	$ 25.91	$ 31.79			
	HG	out	$ 50.05	$ 34.65	$ 41.97	-0.01	0.00	-0.01
		in	$ 50.04	$ 34.65	$ 41.96			
2027	BAU	out	$ 42.29	$ 28.70	$ 35.18	-1.35	-0.26	-0.78
		in	$ 40.95	$ 28.44	$ 34.40			
	HG	out	$ 52.85	$ 39.13	$ 45.67	-0.53	-0.09	-0.30
		in	$ 52.32	$ 39.04	$ 45.37			

The change in LMP is the difference of the LMP with the GNTL in service minus the LMP without the GNTL in service, rounded to the nearest penny.

4.2 Adjusted Production Cost

Table 4.2 presents the forecast change in Adjusted Production Cost for MISO as a whole and for Minnesota only, in nominal dollars (2022$ and 2027$).

The results in Table 4.2 are given to four decimals to show clearly that the GNTL causes no material change, either increase or decrease, to the cost to serve load as computed by MISO's APC methodology.

The Adjusted Production Cost does not change despite the reduction in LMP that is enabled by the GNTL. This is because, although the cost of energy purchases may decrease for entities that are net purchasers, so too may the revenues (profits) decrease for entities that are net sellers of energy. The profits of the net sellers are further reduced because the additional energy purchased from Manitoba Hydro reduces the volume of energy that those net sellers would otherwise have produced and sold.

A vertically-integrated utility with a good balance between economic generation assets and demand would therefore see little change in its market settlement as average LMPs shift up or down.

Table 4.2 -- Change in Adjusted Production Costs Related to GNTL

	Scenario	GNTL status	Adjusted Production Cost ($Billion) MISO	Adjusted Production Cost ($Billion) Minnesota	Change due to GNTL (in - out, $Billion) MISO	Change due to GNTL (in - out, $Billion) Minnesota
2022	BAU	out	18.8001	1.6275	-0.0004	0.0002
		in	18.7996	1.6277		
	HG	out	24.0776	2.1563	0.0004	0.0030
		in	24.0780	2.1593		
2027	BAU	out	21.9331	1.9494	0.0022	-0.0033
		in	21.9354	1.9460		
	HG	out	31.5224	2.8627	0.0114	-0.0016
		in	31.5338	2.8610		

The change in cost is the difference of the adjusted production cost with the GNTL in service minus the adjusted production cost without the GNTL in service.

5 Carbon Sensitivity

As a simple sensitivity, Ventyx repeated the simulations of the Business As Usual scenarios with the assumption of the following CO2 regulation costs (in Nominal $/ton): $23.95 in 2022 and $26.70 in 2027 (Minnesota Power supplied these figures, citing the Minnesota Public Utilities Commission's Carbon Valuation Docket *(MPUC Docket Nos. E-999/CI-13-796 and E-999/CI-07-1199)*.

Penalizing CO2 production raises the marginal cost of production for gas and coal-fired power plants, approximately as shown in Table 5.1 below. The given penalties are large enough to invert the economic merit order of coal and combined-cycle units and would raise LMP correspondingly when such a generator is the marginal unit (setting the price):

Table 5.1 – Illustrative Generator Marginal Cost with and without CO2 Penalty

		With no CO2 penalty				With CO2 penalty = $23.95		
		Fuel, $/MBtu	Heat Rate (MBtu / MWh)	Variable O&M, $/MWh	**Marginal Cost, $/MWh**	lb CO2 emitted per MBtu of heat	CO2 penalty, $/MWh	**Marginal Cost, $/MWh**
Coal	Steam Turbine	3	10.5	3	**$ 35**	209	$ 26	**$ 61**
Gas	Combined Cycle	5	8	2	**$ 42**	119	$ 11	**$ 53**
	Combustion Turbine	5	12	3	**$ 63**	119	$ 17	**$ 80**

The installed capacity of Combined-cycle generation being about half that of coal-fired generation (see Table 2.1) and insufficient by itself to meet the higher levels of demand, coal would be expected either to be on the margin or be displaced by less expensive imported energy in higher-demand hours in the "carbon tax" sensitivity.

Based on the "typical" figures from Table 5.1, the marginal energy component of LMP (neglecting transmission congestion and loss pricing) in peak hours would be expected to rise by at least $11-18 relative to the case with no carbon penalty, from $35-42 (coal or gas CC on the margin) to $53 or more (gas CC or imports on the margin). The results of this study support this conjecture. (Refer to the "on-peak average LMP" column of Table 5.2, below.)

Table 5.2 presents the change in Minnesota LMP in the carbon sensitivity case and compares it with the Business As Usual scenario. Table 5.3 presents the change in Adjusted Production Cost.

Table 5.2 – Locational Marginal Prices with and without CO2 Penalty

			LMP for Minnesota Load (Weighted-Average)					
			Average LMP ($/MWh)			Change due to 500 kV GNTL line (in - out, $ / MWh)		
	Scenario	GNTL status	On-peak	Off-peak	All hours	On-peak	Off-peak	All hours
2022	BAU	out	$ 38.35	$ 25.91	$ 31.82	-0.08	0.00	-0.04
		in	$ 38.28	$ 25.91	$ 31.79			
	Carbon	out	$ 54.85	$ 45.94	$ 50.17	-0.03	0.00	-0.01
		in	$ 54.82	$ 45.95	$ 50.16			
2027	BAU	out	$ 42.29	$ 28.70	$ 35.18	-1.35	-0.26	-0.78
		in	$ 40.95	$ 28.44	$ 34.40			
	Carbon	out	$ 60.62	$ 49.62	$ 54.87	-1.04	-0.04	-0.52
		in	$ 59.57	$ 49.58	$ 54.35			

Adding the carbon penalty to the BAU scenario reduced the simulated impact that GNTL would have on LMP in Minnesota. LMPs are flatter across load levels, presumably because gas is on the margin more frequently. This reduces the opportunity for the hydro energy delivered by GNTL to moderate high prices that drive up average prices.

Table 5.3 – Adjusted Production Cost with and without CO2 Penalty

			Adjusted Production Cost ($Billion)		Change due to GNTL (in - out, $Billion)	
	Scenario	GNTL status	MISO	Minnesota	MISO	Minnesota
2022	BAU	out	18.8001	1.6275	-0.0004	0.0002
		in	18.7996	1.6277		
	Carbon	out	31.1953	2.8776	0.0010	0.0006
		in	31.1963	2.8782		
2027	BAU	out	21.9331	1.9494	0.0022	-0.0033
		in	21.9354	1.9460		
	Carbon	out	35.5899	3.3205	0.0049	-0.0015
		in	35.5949	3.3190		

Adjusted Production Cost does not change materially with the addition of a carbon penalty.

6 Conclusion

PROMOD LMP simulations were performed for 2022 and 2027, using input assumptions consistent with the 2013 MISO Northern Area Study. Significant amounts of wind, combined-cycle and even solar PV generation were modeled in MISO in the 2027 cases that were not present in the 2022 cases.

Input assumptions were established for two separate future scenarios (Business as Usual and High Growth) and 8,760-hour chronological simulations were performed for each scenario with the GNTL in service and without, as the only input change.

The salient result from this study is that interconnection of the 500 kV GNTL brings about:

1. decreased Locational Marginal Prices (LMPs) within Minnesota
2. no material change to the cost to serve load in MISO or Minnesota

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: E015/CN-12-1163 Date of Request:July 7, 2014

Requested From: David R. Moeller, Senior Attorney Response Due:July 17, 2014

Analyst Requesting Information: Stephen Rakow

Type of Inquiry:			
	[ ]......Financial	[ ]......Rate of Return	[ ]......Rate Design
	[ ]......Engineering	[ ]......Forecasting	[ ]......Conservation
	[ ]......Cost of Service	[ ]......CIP	[ ]......Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
9	Please explain how the $26.4 million in MISO revenue requirements for the Project for the MP load zone, mentioned on page 31 of the Petition, and was calculated.

Response:

The attached spreadsheet labeled "MISO Rate Impacts.xls" was used to develop the $26.4 million in MISO Revenue Requirements. The spread sheets starts with summary version the MISO Attachment O rate template, to which GNTL specific data is added. The result of the embedded calculations is the projected MISO revenue requirements of $26.4 million.

Response by: Michael H. Donahue___________ List Sources of Information:

Title: Trans. Project Development Mgr. _________________________________

Department: Trans. Regulatory Compliance and Business Support__________________

Telephone: 218-355-2617 ________________ _________________________________

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

SUPPLEMENTAL

Docket Number: E015/CN-12-1163 Date of Request: July 7, 2014

Requested From: David R. Moeller, Senior Attorney Response Due: July 17, 2014

Analyst Requesting Information: Stephen Rakow

Type of Inquiry:	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[ ] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
10	Please explain how the $34.5 million in revenue requirements for the 230 kV alternative, mentioned on page 31 of the Petition, was calculated.

Supplemental Response:

Minnesota Power has updated the MISO revenue requirements for the 230 kV alternatives that were discussed on page 31 of the Application, to reflect the latest estimated project cost of a 230 kV alternative. The new MISO revenue requirement for a 230 kV alternative is $52.2 million. A supporting work sheet is attached.

Response by: Michael H. Donahue__________ List Sources of Information:

Title: Trans. Project Development Mgr. ________________________________

Department: Trans. Regulatory Compliance and Business Support _________________

Telephone: 218-355-2617_______________ ________________________________

Minnesota Power
SUMMARY PROJECTED ATTACHMENT O
Impacts of the Great Northern Transmission Line
230 kV Option

	AC System 2014	GNTL Impacts	GNTL 230 kV Impacts Revised AC Rates 2014
RATE BASE			
Gross Plant in Service			
Transmission	340,810,833	315,895,646	656,706,479
General & Intangible	21,507,329	4,543,196	26,050,525
Total Gross Plant	362,318,162	320,438,842	682,757,004
Accumulated Depreciation			
Transmission	112,376,653	17,029,735	129,406,388
General & Intangible	12,568,363	2,654,934	15,223,297
Total Accumulated Depreciatin	124,945,016	19,684,669	144,629,685
Net Plant in Service			
Transmission	228,434,180	298,865,911	527,300,091
General & Intangible	8,938,966	1,888,262	10,827,228
Total Net Plant	237,373,146	300,754,173	538,127,319
CWIP Recovery for Incentive Rate Transmission Projects	51,506,190	-	51,506,190
Adjustments to Rate Base	(58,618,512)	(50,486,643)	(109,105,155)
Land Held for Future Use	16,748	995	17,743
Working Capital	5,153,938	1,181,936	6,335,874
Rate Base	235,431,510	251,450,461	486,881,971
		-	

REVENUE REQUIREMENT

O&M			
Transmission	33,305,291	3,508,155	36,813,446
Less: LSE included in O&M Accounts	2,581,965	-	2,581,965
Less: Account 565	16,313,064	2,087,713	18,400,777
A&G	6,980,898	1,528,564	8,509,462
Less: EPRI & Reg. Comm. Exp. & Non-safety Ad	117,182	24,753	141,935
Plus: Transmission Related Reg. Comm. Exp	124,092	26,214	150,306
Transmission Lease Payments	962,768	-	962,768
Total O&M	22,112,654	2,898,039	25,010,693
Depreciation Expense			
Transmission	8,603,670	7,962,071	16,565,741
Prefunded AFUDC Amortization	(121,712)	-	(121,712)
General	1,022,335	215,957	1,238,292
Total Depreciation Expense	9,504,293	8,178,028	17,682,321
Taxes Other Than Income			
Labor Related - Payroll	647,909	136,864	784,773
Plant Related - Property	3,744,922	4,503,760	8,248,682
Plant Related - Other	129,410	93,525	222,935
Total Taxes Other Than Income	4,522,241	4,734,149	9,256,390
Income Taxes	10,922,808	11,739,067	22,661,875
Return (inlcudes ROE plus Interest)	20,498,127	21,892,836	42,390,963
Revenue Requirement	67,560,123	49,442,119	117,002,242
Less: Attachment GG Adjustment	(21,521,790)	2,512,167	(19,009,623)
Less: Attachment ZZ Adjustment	(4,776,079)	527,040	(4,249,039)
MP Revenue Requirement to be Collected under Attachment O	41,262,254	52,481,326	93,743,580

Revenue Credits			
Account No. 454	598,118	35,514	633,632
Account No. 456	3,470,046	210,345	3,680,391
Total Revenue Credits	4,068,164	245,859	4,314,023
True Up	(445,165)	-	(445,165)
Minnesota Power Adjusted Revenue Requirement	**36,748,925**	**52,235,467**	**88,984,392**
GRE Revenue Requirement to be Collected under Attachment O Assigned to the MP Pricing Zone	12,100,304	-	12,100,304
Joint Revenue Requirement to be Collected under Attachment O	**48,849,229**	**52,235,467**	**101,084,696**
MP MISO Load (MW's)	1,535		1,535
GRE MISO Load assigned to the MP Pricing Zone (mW's)	193		193
Total MISO Load in the MP Pricing Zone	**1,728**		**1,728**
Annual 2014 MISO Joint Pricing Zone Network Rate (Schedule 9)	**28,273**		**58,505**
Monthly 2014 MISO Joint Pricing Zone Network Rate (Schedule 9)	**2,356**		**4,875**
Increase over currently posted MISO Rates			106.93%

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: E015/CN-12-1163 Date of Request: July 8, 2014

Requested From: David Moeller Response Due: July 18, 2014

Analysts Requesting Information: Steve Rakow and Mark Johnson

Type of Inquiry:	[ ]......Financial	[ ]......Rate of Return	[ ]......Rate Design
	[ ]......Engineering	[ ]......Forecasting	[ ]......Conservation
	[ ]......Cost of Service	[ ]......CIP	[ ]......Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
17	Subject: Pricing Zones and Load Share A. Please identify each MISO transmission pricing zone impacted by MP's proposed route for the Great Northern Transmission Line. B. For each transmission pricing zone identified in part A, please provide MP's estimated load ratio share. In addition, for each pricing zone identified in part A, please list all other utilities included in the pricing zone and, if available, their estimated load ratio share.

Response:

A. The Great Northern Transmission Line (GNTL) as proposed will only impact the Minnesota Power MISO Pricing Zone (MISO Pricing Zone 14).

B. In addition to Minnesota Power, Great River Energy is the only other utility with load in the Minnesota Power MISO Pricing Zone. The 2014 estimate load ratios for Minnesota Power and Great River Energy within the Minnesota Power MISO Pricing Zone are Minnesota Power 90.1% and Great River Energy 9.9%.

Response by: Michael H. Donahue__________ List Sources of Information:

Title: Trans. Project Development Mgr. ________________________________

Department: Trans. Regulatory Compliance and Business Support__________________

Telephone: 218-355-2617________________ ________________________________

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: E015/CN-12-1163 Date of Request:August 14, 2014

Requested From: David R. Moeller
Senior Attorney
Response Due:August 26, 2014

Analyst Requesting Information: Steve Rakow

Type of Inquiry:

[ ]......Financial	[ ]......Rate of Return	[ ]......Rate Design
[ ]......Engineering	[ ]......Forecasting	[ ]......Conservation
[ ]......Cost of Service	[ ]......CIP	[ ]......Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
23	Regarding the cost estimate by Power Engineers in a MISO sponsored facility study report, discussed in the Direct Testimony and Exhibits of Michael H. Donahue at page 5, please explain if the \$557.9 million to \$710.1 million range for total project costs is in nominal or real dollars; if real please provide the year of the dollars.

Response:

A. The value of the estimate reference above is in nominal dollars (2013).

Response by: Michael H. Donahue___________ List Sources of Information:

Title: Trans. Project Development Mgr.____ ___________________________

Department: Trans. Regulatory Compliance and Business Support

Telephone: 218-355-2617_________________ ___________________________

LARGE POWER INTERVENORS

Utility Information Request

SUPPLEMENTAL

Docket Number: E015/CN-12-1163	Date of Request: May 19, 2014
Requested From: Large Power Intervenors	Response Requested: May 30, 2014

By: Large Power Intervenors (Andrew Moratzka, Chad T. Marriott , Lane Kollen and Phil Hayet)

Request No.	
003	Please provide a detailed description of the scheduling fee arrangement that the Company claims will reduce the cost to customers from the 51.0% proposed MP ownership to 33.3% of the cost. Provide a copy of all documents, draft or otherwise, that were relied on for the concept and/or that will be used to implement the arrangement.
004	Please provide the Company's quantification of the effects of the project on customer rates, including, but not limited to, the derivation of the revenue requirement, all of the relevant class billing determinants, and the effects of the scheduling fee arrangement. Provide all assumptions, data, and computations, including electronic spreadsheets with formulas intact, e.g., revenue requirements model, class cost of service model, etc.

Supplemental Response:

Minnesota Power and Manitoba Hydro (MH) recently completed negotiation on several agreements which among other items outlines the financial responsibility for the construction and operation of the Great Northern Transmission Line (Project). The Renewable Optimization Agreements (ROA) have been executed by both companies. The MISO Facilities Construction Agreement (FCA) has been submitted to MISO for their review. Once MISO has completed their review the FCA will be executed and submitted to FERC for approval. FERC approval is expected within 60 days of submittal. The paragraphs below summaries the business structure detailed in those agreements. For ease of review, references to Manitoba Hydro also encompass its subsidiary, 6690271 Manitoba Ltd.

As agreed to in the FAC, Minnesota Power will own 51% of the Project, while MH will own the 49% balance as tenants in common. However, MH does not intend to be an owner of the Project past mid-year 2016. MH is reviewing ownership options with another Minnesota MISO Transmission Owner however if that option does not materialize, Minnesota Power will assume 100% of the Project as of mid-year 2016. MH or its Assignee will be financial responsible for 49% of all ongoing Operation and Maintenance expense associated with the Project.

While Minnesota Power is a 51% owner of the Project, Minnesota Power has only a 46% funding obligation for construction cost. MH will provide the balance (54%) of construction funds either through Contribution in Aid of Construction (CIAC) payments (if Minnesota Power becomes the 100% owner), or a 5% CIAC payment and the assignment of 49% to another Minnesota MISO Transmission Owner.

Please refer to the table below which has been prepared using the estimates included in Appendix A of the FCA.

Funding Option	Total Project Cost	MP Responsibility	MH-CIAC	MH-Assignment
100% MP Ownership	$ 676,242,900	$ 311,071,700	$ $365,171,200	
Assignment	$ 676,242,900	$ 311,071,700	$ $33,812,100	$ 331,359,100

The Minnesota Power funding obligation percentage is a product of Minnesota Powers requested capacity of the Project (383 MW) over the total requested capacity of the Project (883 MW). The Minnesota Power requested capacity consists of two capacity requests to MISO. Minnesota Power requested 250 MW of capacity to provide a transmission path for the 250 MW PPA between Minnesota Power and Manitoba Hydro (previously approved by the Commission) and a 133 MW request to provide a transmission path for the ROA.

The Minnesota Power funding obligation can be broken down as shown in the following table:

Capacity Request	Percentage of Total	Pro Rata Share
250 MW PPA	28.3%	$ 191,376,700
133 MW ROA	17.7%	$ 119,695,000
Total Minnesota Power	**46.0%**	**$ 311,071,700**

Minnesota Power plans to include all cost associated with our funding obligation in a future Transmission Cost Recovery Rider for retails rates and through our MISO Attachment O process for wholesale customers. Under the terms of the Renewable Optimization Agreements, Manitoba Hydro will provide a "Must Take Fee" which will be in excess of the pro rata revenue requirements associated with the 133 MW capacity request. This "Must Take Fee" credit will be included as an offset to revenue requirements in both the Transmission Cost Recovery Rider and the MISO Attachment O.

Details on when the applicable filings will be made has not yet been determined.

Response by:	David Moeller____________	List Sources of Information:
Title:	Senior Attorney___________	________________________________
Department:	Corporate Legal Services___	________________________________
Telephone:	218-723-3963____________	________________________________

LARGE POWER INTERVENORS

Utility Information Request

Docket Number: E015/CN-12-1163 Date of Request: August 26, 2014

Requested From: Large Power Intervenors Response Requested: September 4, 2014

By: Large Power Intervenors (Andrew Moratzka, Chad T. Marriott , Lane Kollen and Phil Hayet)

Request No.

024 Please provide a copy of the Company's most recent and most detailed cost estimate(s) for the project, separately showing each line segment and/or component of the project, and each type of cost (direct costs incurred from third parties, direct costs incurred internally, AFUDC, etc.). In addition, for all direct costs incurred internally, show labor, materials, and each other category of costs separately. Please indicate if the dollars are in current dollars (present value) or accounting dollars ("as and when spent"). If in present value dollars, please indicate the present value date.

Response:

A. Please find attached excel spreadsheet "GNTL FCA Detailed Estimate 7-10-14". This workbook represents current detailed estimate for the GNTL in 2013 dollars. The summary page should be treated as public information while all the detail tabs are labelled "Trade Secret".

Response by: Michael H. Donahue___________ List Sources of Information:

Title: Trans. Project Development Mgr. ________________________________

Department: Trans. Regulatory Compliance and Business Support__________________

Telephone: 218-355-2617________________ ________________________________

GNTL Project Estimate Summary 7/10/2014
Accumulated by MH Donahue

		Blue Route
Miles for Blue Route		222.52
		Est. (2013$)
Material & Construction	$	347,412,278
Engineering and Program Management	$	40,484,019
Construction Phase Contingency	$	34,679,164
500 kV Line Materials & Construction	$	422,575,461
MP Internal Services	$	15,168,103
Professional Permitting Support	$	8,700,000
ROW Acquisition Support	$	11,500,000
Land & Land Rights	$	28,862,000
500 kV Transmission Line	$	486,805,564

500/230 kV Substation Materials & Construction	$	38,585,800
MP Internal & Professional Services	$	-
Land & Land Rights	$	500,000
Blackberry 500/230 kV Substation	$	39,085,800

500 kV Series Compensation Materials & Construction	$	44,280,200
Land & Land Rights	$	250,000
GNTL 500 kV Series Compensation Station	$	44,530,200

230 kV Modifications Transmission Line Materials & Construction	$	3,537,919
230 kV Modifications Substation Materials & Construction	$	625,000
Land & Land Rights	$	-
Minnesota Power 230 kV Modifications	$	4,162,919

TOTAL PROJECT	$	574,584,483
Capitalize Property Taxes	$	44,200,000
PROJECT CONTINGENCY (10%)	$	57,458,448
TOTAL ESTIMATED COST (2013$)	$	676,242,932
Project Estimate with Contingency Allocated		
500 kV Transmission Line	$	535,486,121
Blackberry 500/230 kV Substation	$	42,994,380
GNTL 500 kV Series Compensation Station	$	48,983,220
Capitalized Property Taxes	$	44,200,000
Minnesota Power 230 kV Modifications	$	4,579,211
	$	676,242,932

Project Funding Sources 2013 Dollars

Minnesota Power Base Investment 28.3%	$	191,376,750
Minnesota Power Renewable Optimization Investment 17.7%	$	119,694,999
Total Minnesota Power -46%	$	311,071,749
Manitoba Hydro Portion - 54%	$	365,171,183
Total Project	$	676,242,932

NON-PUBLIC DOCUMENT
CONTAINS TRADE SECRET DATA

LARGE POWER INTERVENORS

Utility Information Request

Docket Number: E015/CN-12-1163 | Date of Request: August 26, 2014

Requested From: Large Power Intervenors | Response Requested: September 4, 2014

By: Large Power Intervenors (Andrew Moratzka, Chad T. Marriott , Lane Kollen and Phil Hayet)

Request No.

028 Refer to Exhibit___(AJR) Schedule 2, the 133 MW Energy Sale Agreement ("Agreement").

a. Please confirm that the Contract Term, as defined in the Agreement, is 20 years starting with the date that the 500 kV Transmission Interconnection in-service date.

b. Please confirm that pursuant to Section 2.6, MH is obligated to pay the monthly must-take fee only during the Contract Term, which commences on the 500 kV Transmission Interconnection in-service date and terminates 240 months later, except that MH is not required to pay the must take fee in the last month of the Contract Term. If this is not correct, then please state the term during which MH is obligated to pay the monthly must-take fee.

c. Please confirm that MH is not obligated to pay the monthly must-take fee before the Contract Term commences or after the Contract Term terminates.

d. Please indicate where in the Company's Application or testimony any witness describes the fact that this must-take fee is limited to a twenty-year period compared to the combination of the estimated four-year construction period and the 55 year life of the line and the 40 year life of the substation.

e. Please explain why the must-take fee does not apply during the construction period.

f. Please explain why the must-take fee does not apply after the 20th year of service.

g. Does the Company consider the 20-year limitation on the must-take fee an important component of the Agreement? Please explain your response.

h. Please confirm that MP customers will be responsible for 46% of the capital-related costs of the project, not 28.3% of these costs, prior to and after the Contract Term.

i. Please explain why the Contract Term of the Agreement is 20 years and not a longer period, possibly coincident with the life of the resources that will be used to supply the energy under the agreement.

Response:

a. Yes.

b. Yes.

c. Yes.

d. Mr. Rudeck's testimony stated that "Manitoba Hydro will make monthly payments to Minnesota Power during the entire term of the agreement." Minnesota Power will provide additional detail regarding the Monthly Must Take Fee in the upcoming Petition to the Commission seeking regulatory approval of the Agreement.

e. The Monthly Must Take Fee is tied to delivery of energy on the new transmission line, which cannot begin until the line is placed in-service.

f. The term of the Monthly Must Take Fee coincides with the Agreement.

g. **[TRADE SECRET BEGINS**

TRADE SECRET ENDS].

h. MP customers will be responsible for the applicable revenue requirements, offset by any available credits including those provided from Manitoba Hydro under the Monthly Must Take Fee for the Contract Term and **[TRADE SECRET BEGINS TRADE SECRET ENDS].**

i. See response to (g).

Response by:	David Moeller _____________	List Sources of Information:
Title:	Senior Attorney___________	________________________________
Department:	Corporate Legal Services ___	________________________________
Telephone:	218-723-3963_____________	________________________________

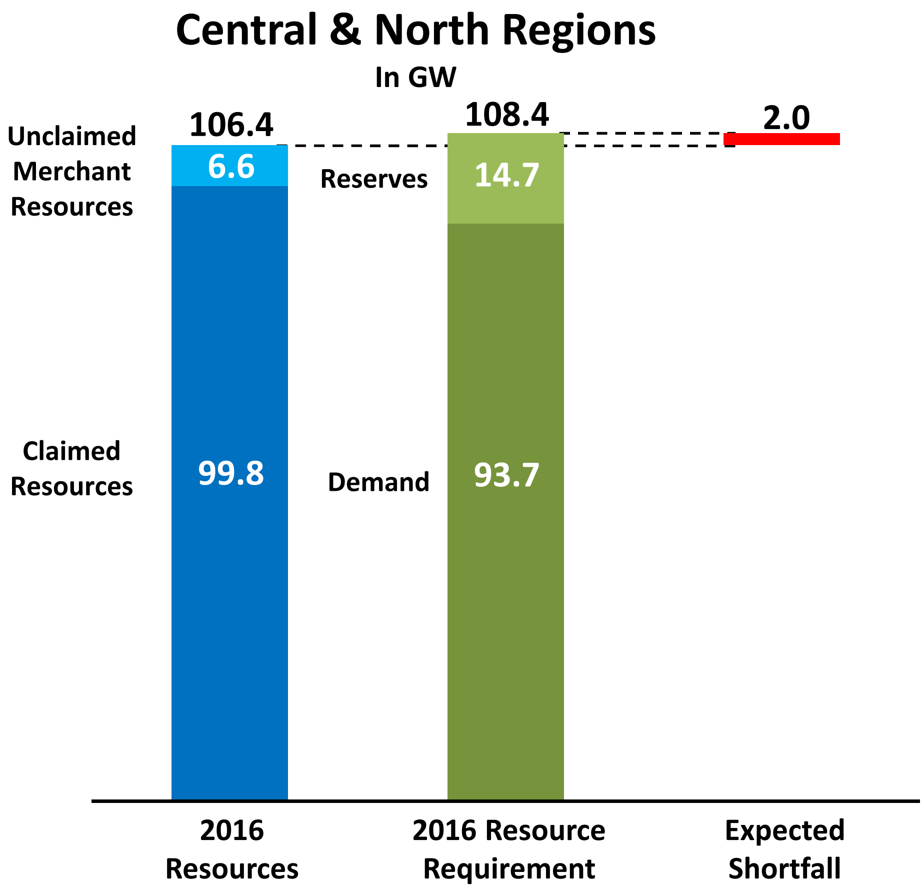
2016 Resource Adequacy Forecast

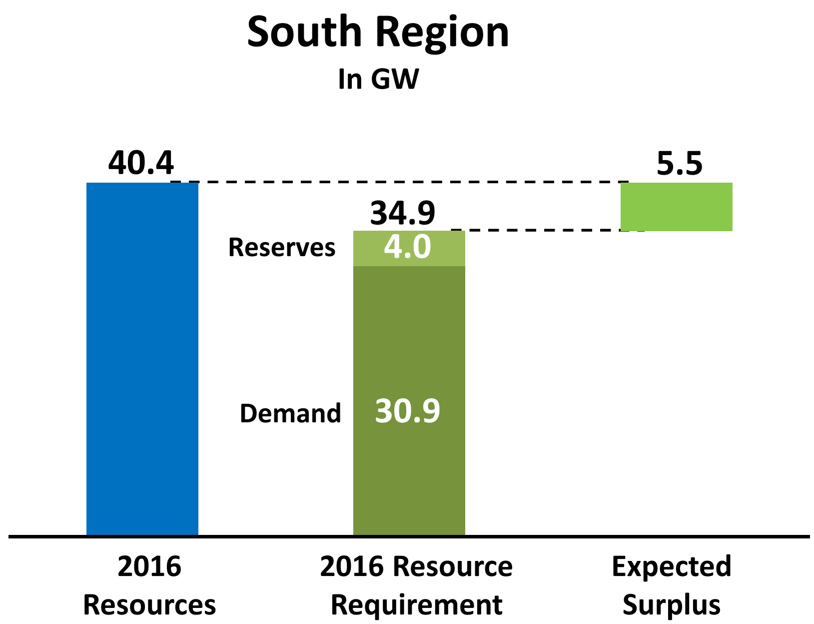
June 5, 2014

2014 OMS-MISO Survey Update

- 2016 Year Summary:
  - 2.3 GW reserve margin shortfall in North and Central regions
    - North and Central region zones: Reserve Margin shortfalls in three of seven zones; marginal surpluses in remaining zones
  - 2.5 GW reserve margin surplus in South region
- Reconciliation:
  - Reconciliation with Module E demand forecast - 0.85% annual growth rate for next three years
  - Reconciliation of generation retirements with MISO-EPA survey
- Major changes and assumptions:
  - Continued accounting of all merchant generation as MISO capacity (only exclusions of units cleared in PJM RPM)
  - 2.0 GW of generators reclassified from retirement / low confidence to high confidence
  - About 2 GWs of capacity additions – DRs, purchases, new builds

2016 Resource Adequacy Forecast
As of January 31, 2014

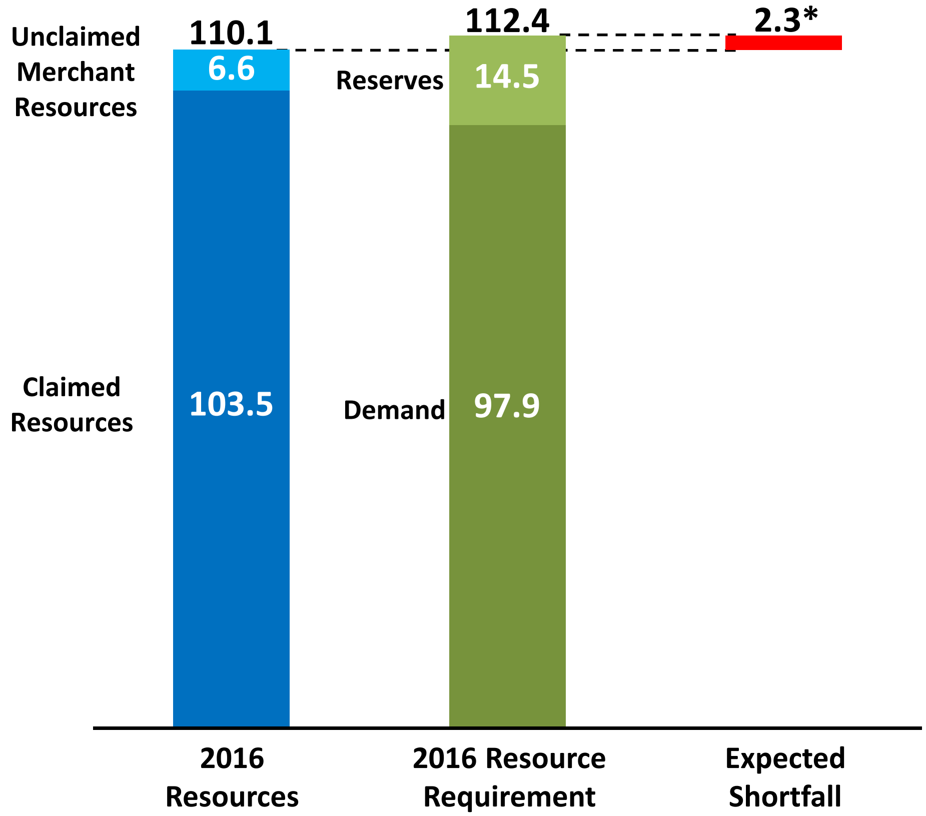




2016 Resource Adequacy Forecast As of June 2, 2014

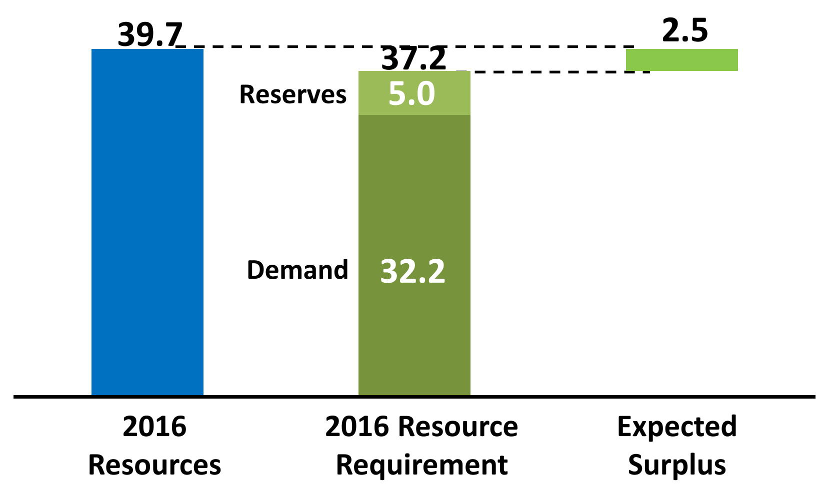
Central & North Regions

In GW



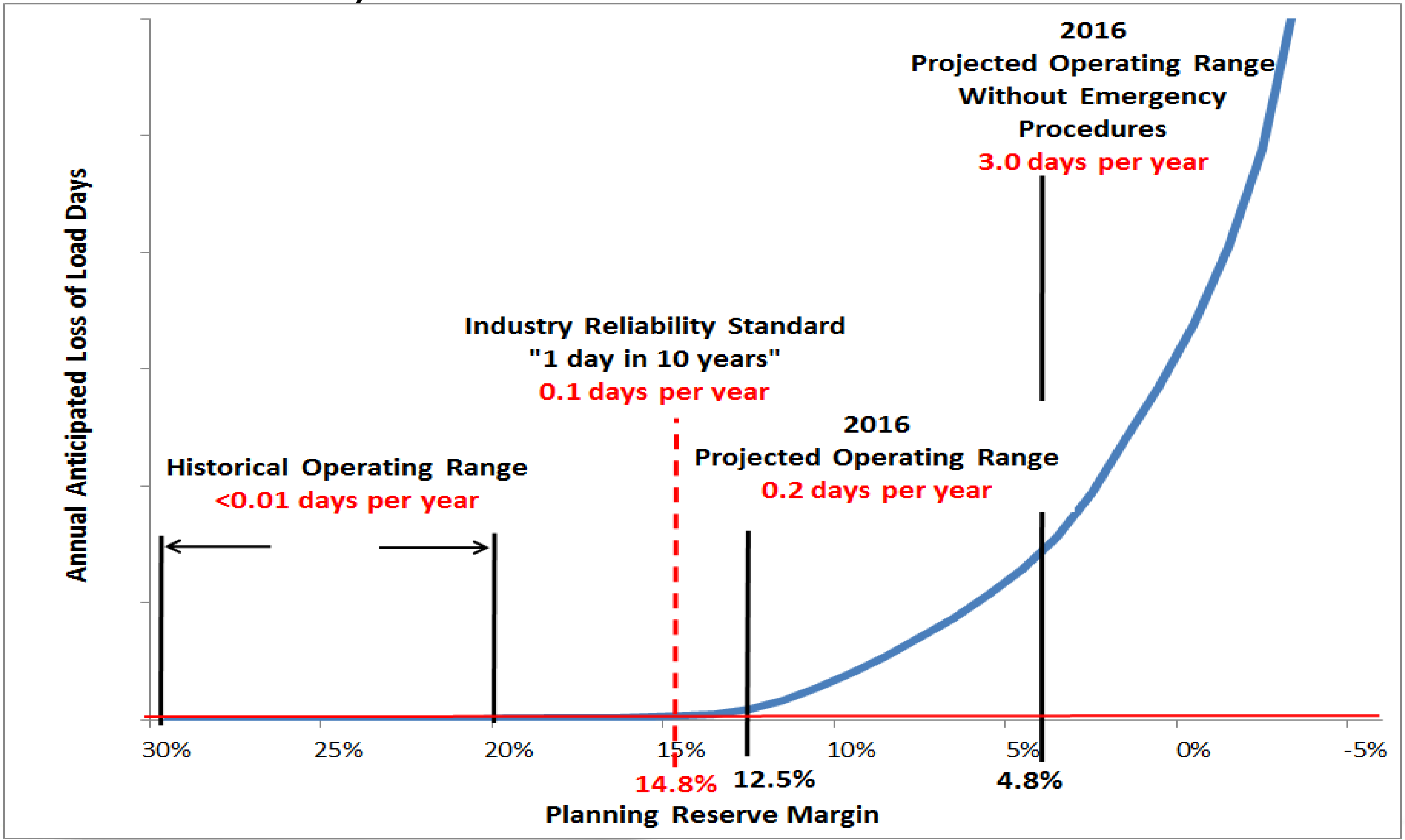
South Region

In GW

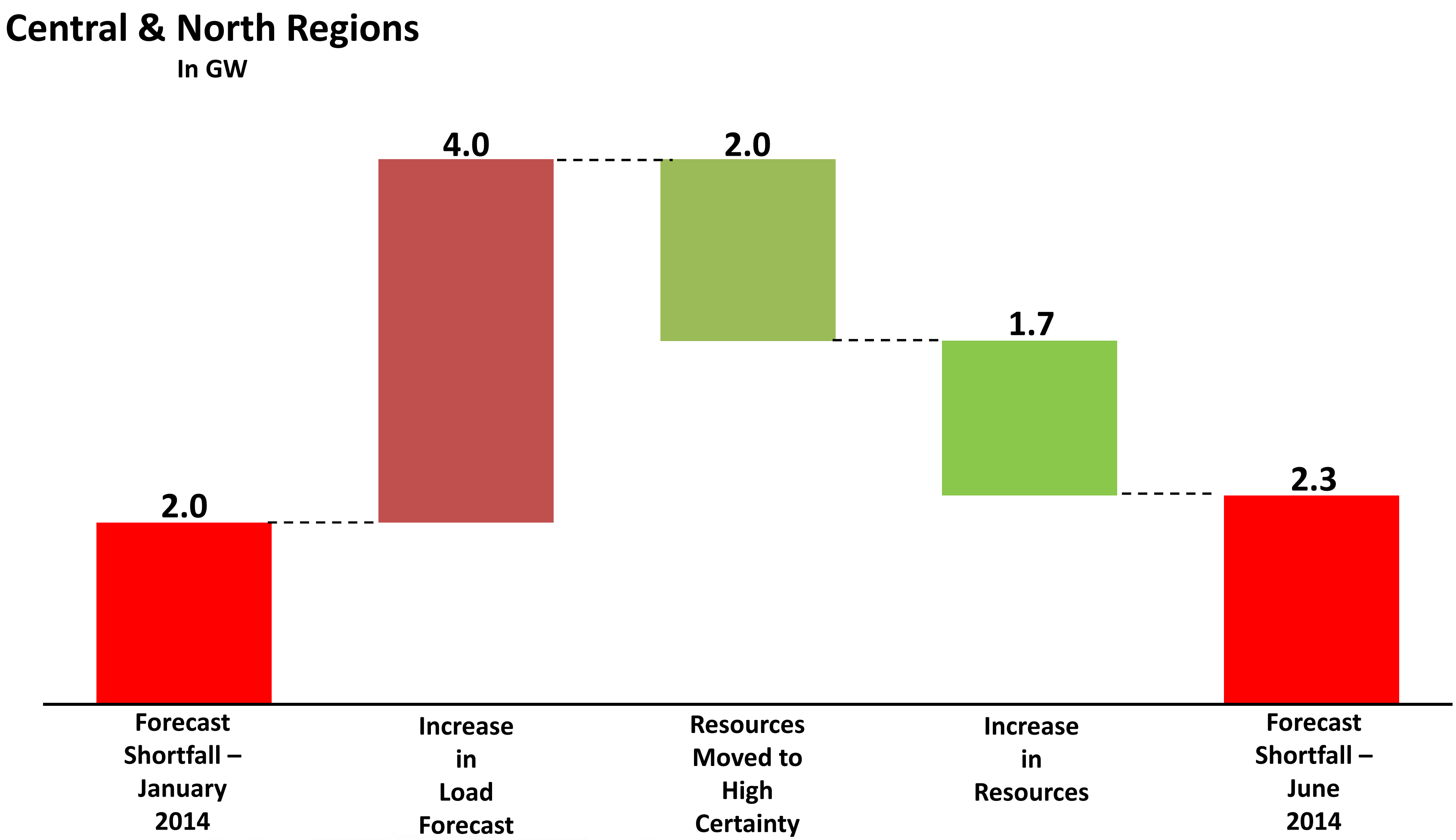


***A shortfall figure means that the probability of a loss of load event increases. A 2.3 GW shortfall would result in a 12.5% PRM, resulting in approximately a .2 day/year probability of a loss of load event. See the graph on Slide #4 for more detail.**

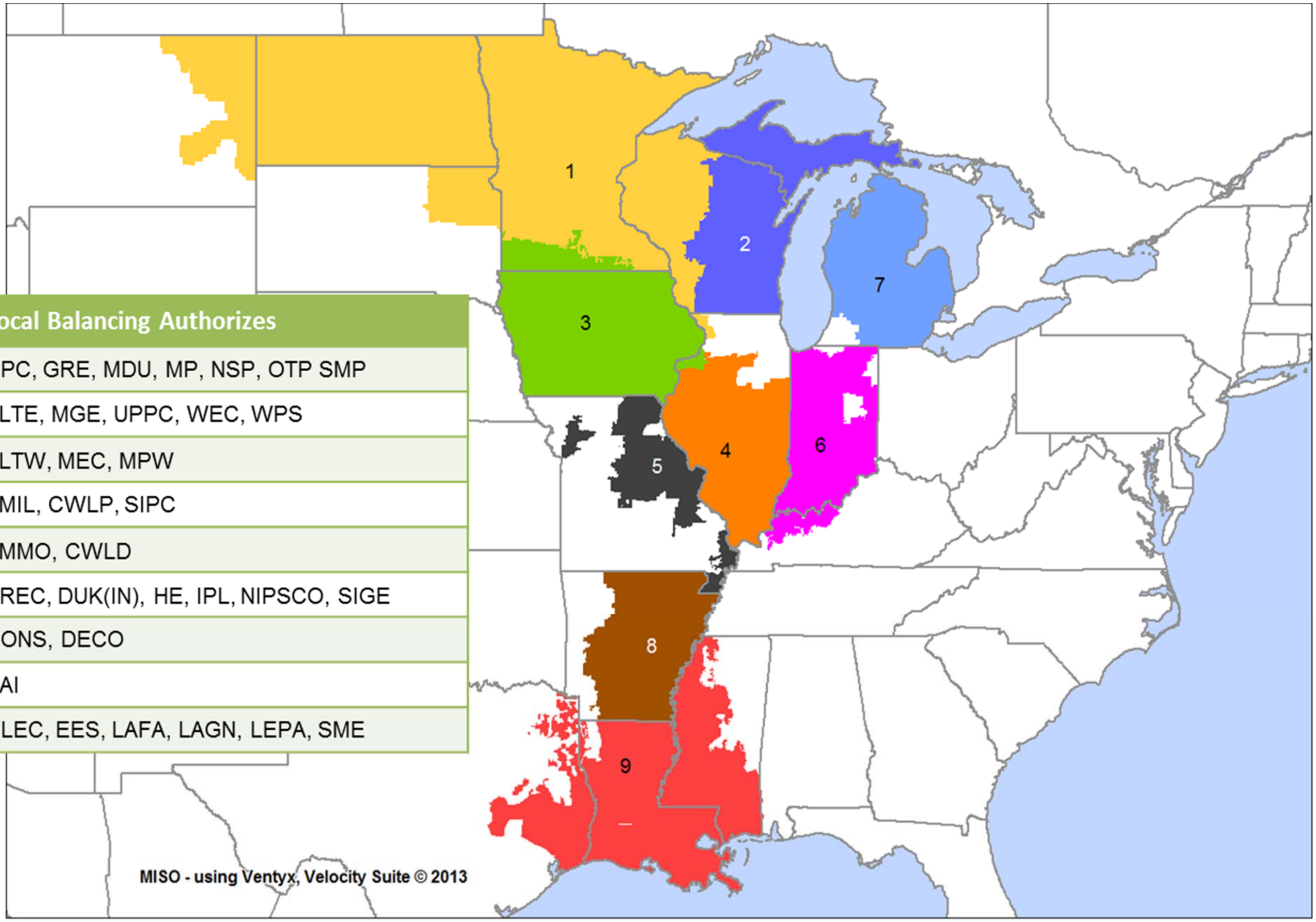
As planning reserves erode, the probability of loss of load and reliance on Emergency Operating Procedures will increase
- As of June 2, 2014



2016 Resource Adequacy Forecast Reconciliation from January to June

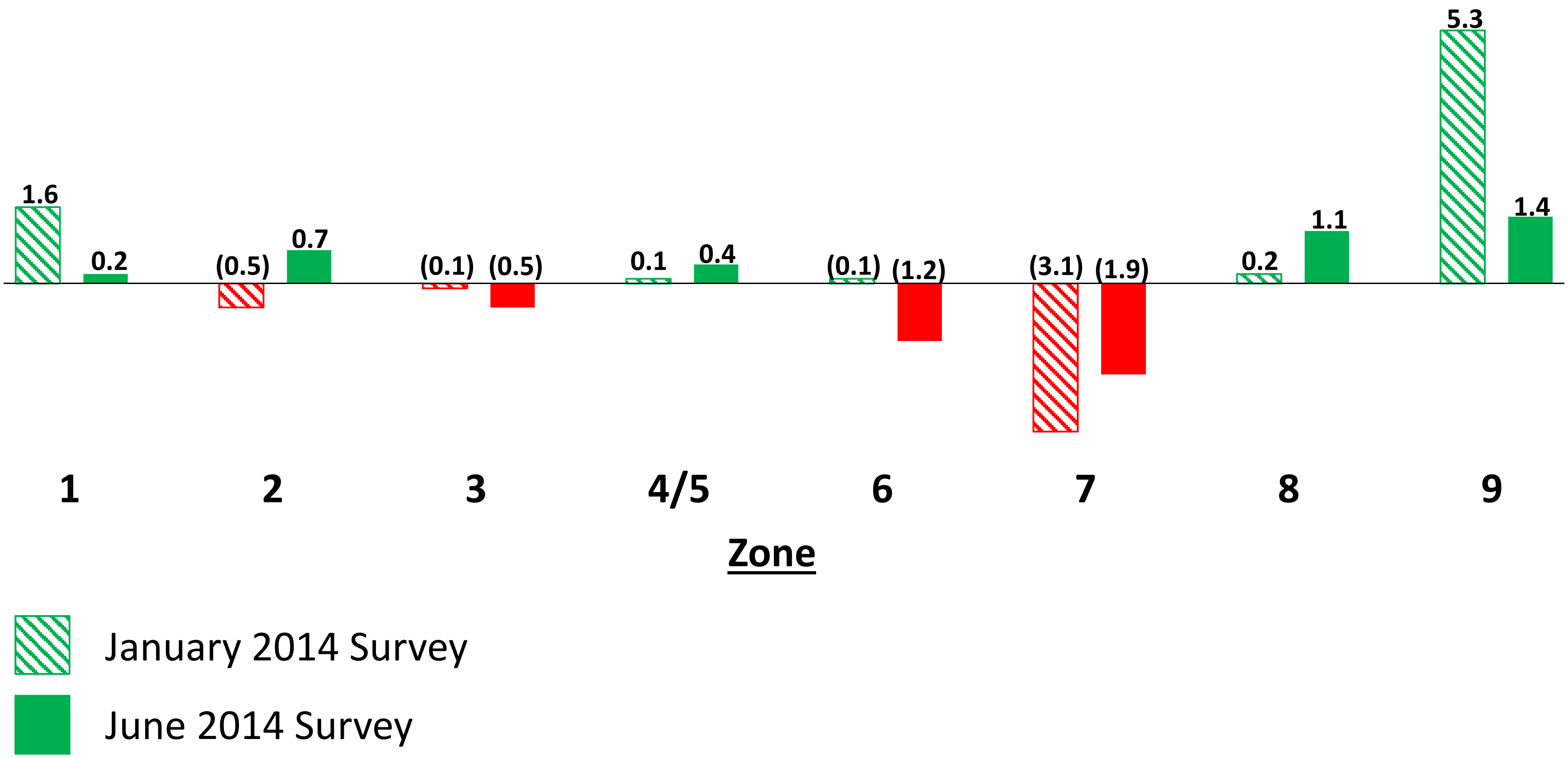


MISO Local Resource Zones

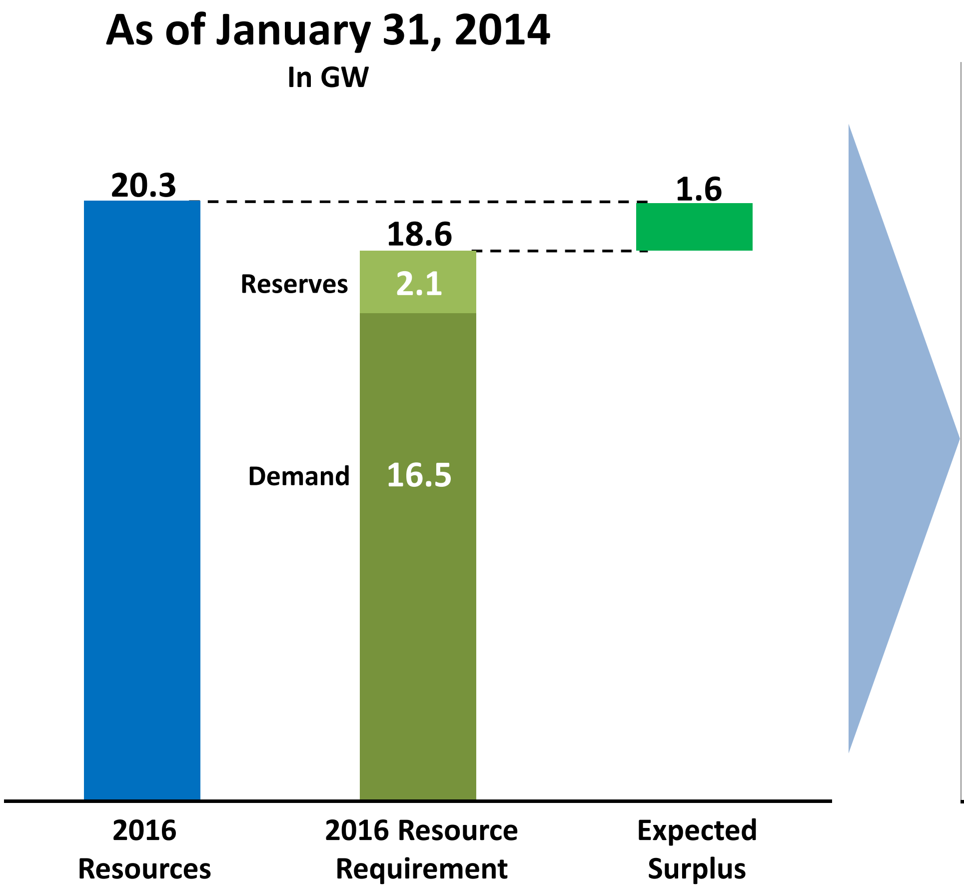


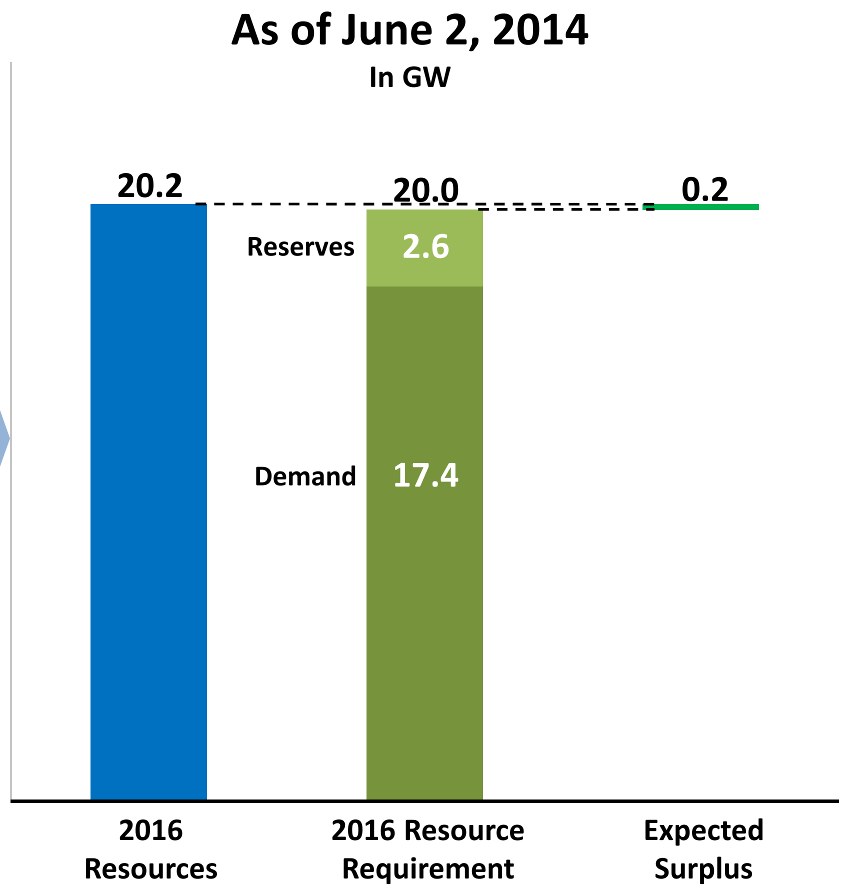
LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, NSP, OTP SMP
2	ALTE, MGE, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA, SME

2016 Resource Adequacy Forecast Zone Summary

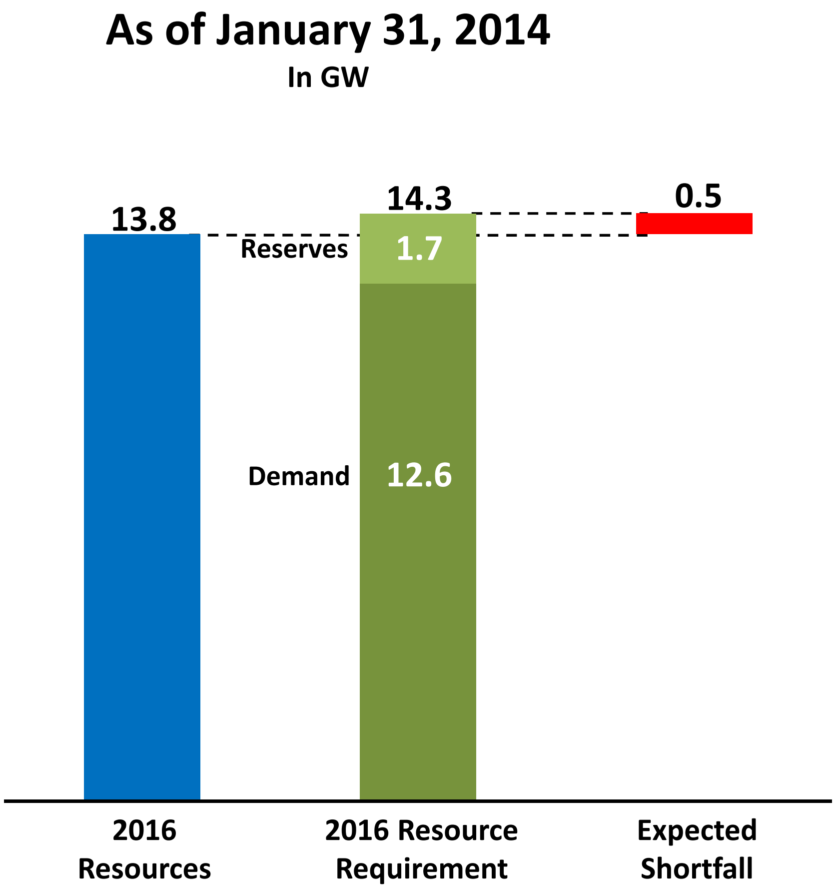


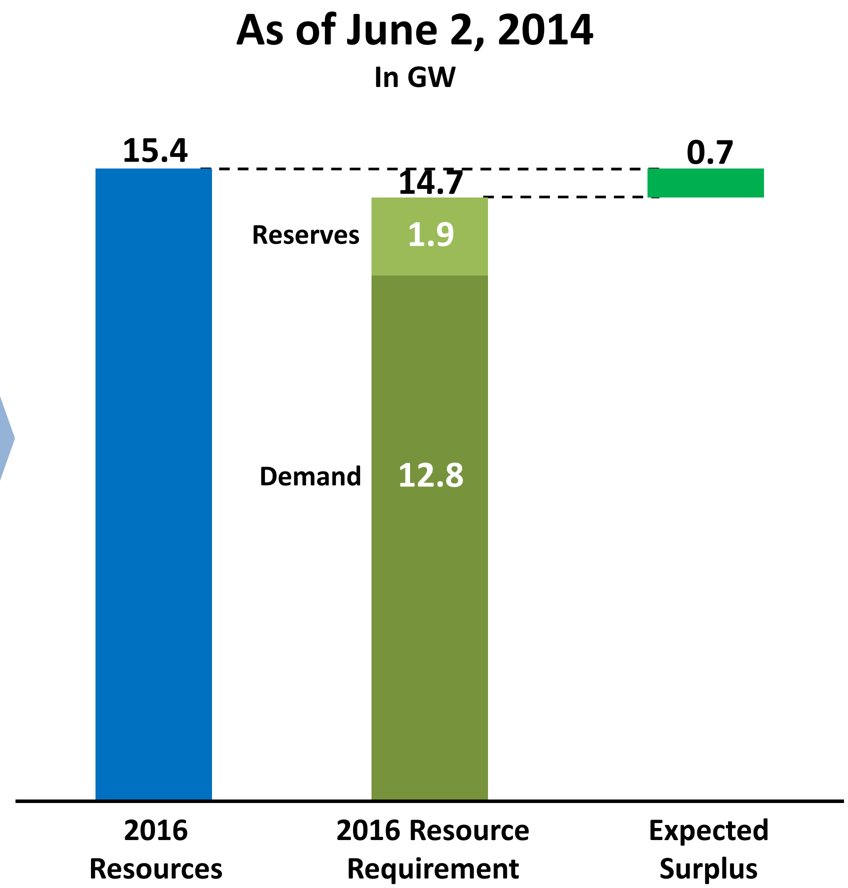
2016 Resource Adequacy Forecast
Zone 1





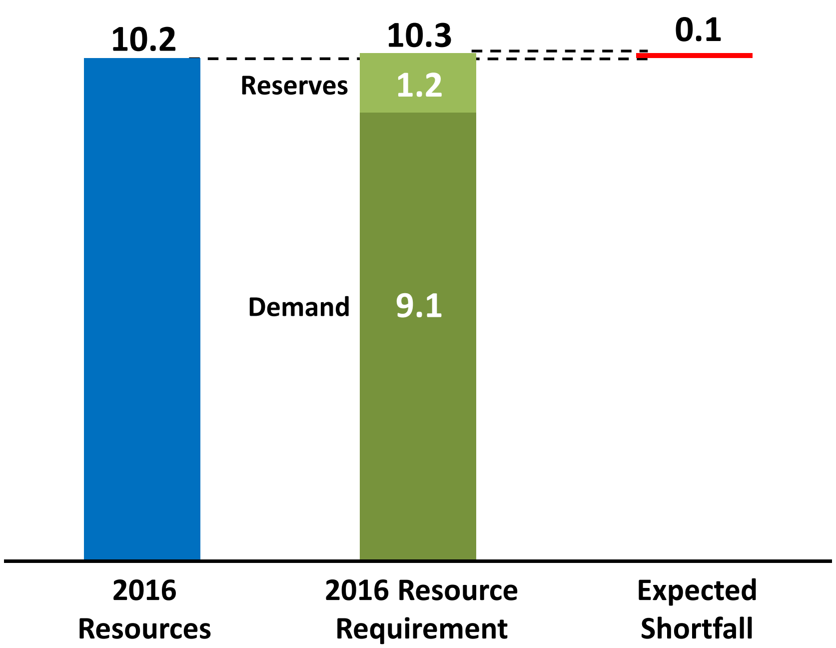
2016 Resource Adequacy Forecast Zone 2



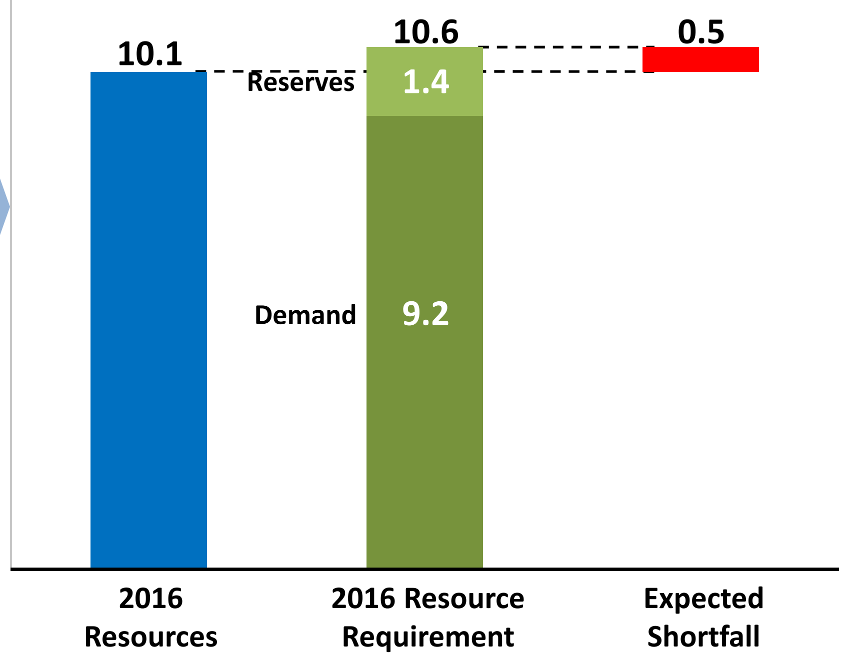


2016 Resource Adequacy Forecast
Zone 3

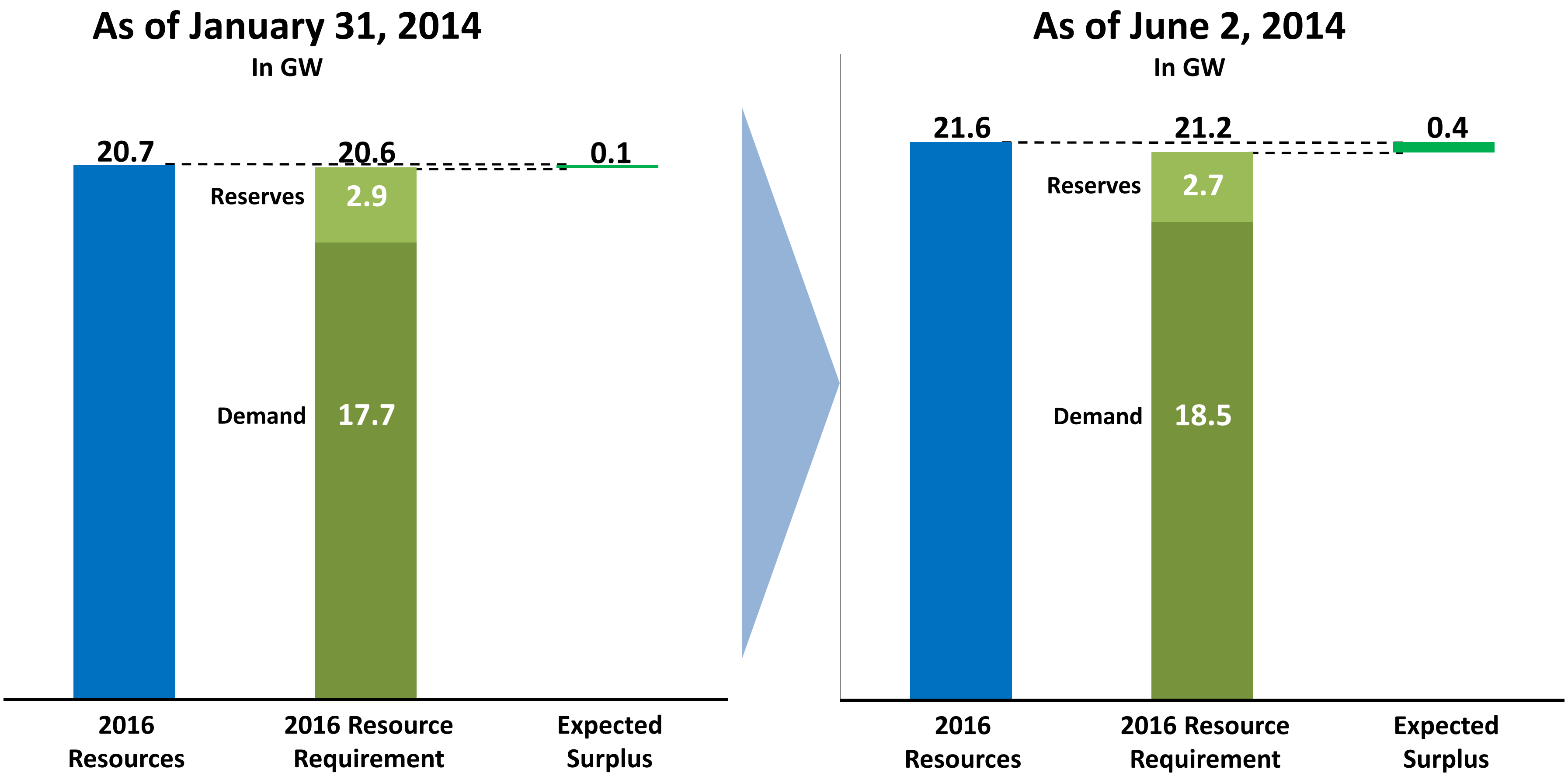
As of January 31, 2014
In GW



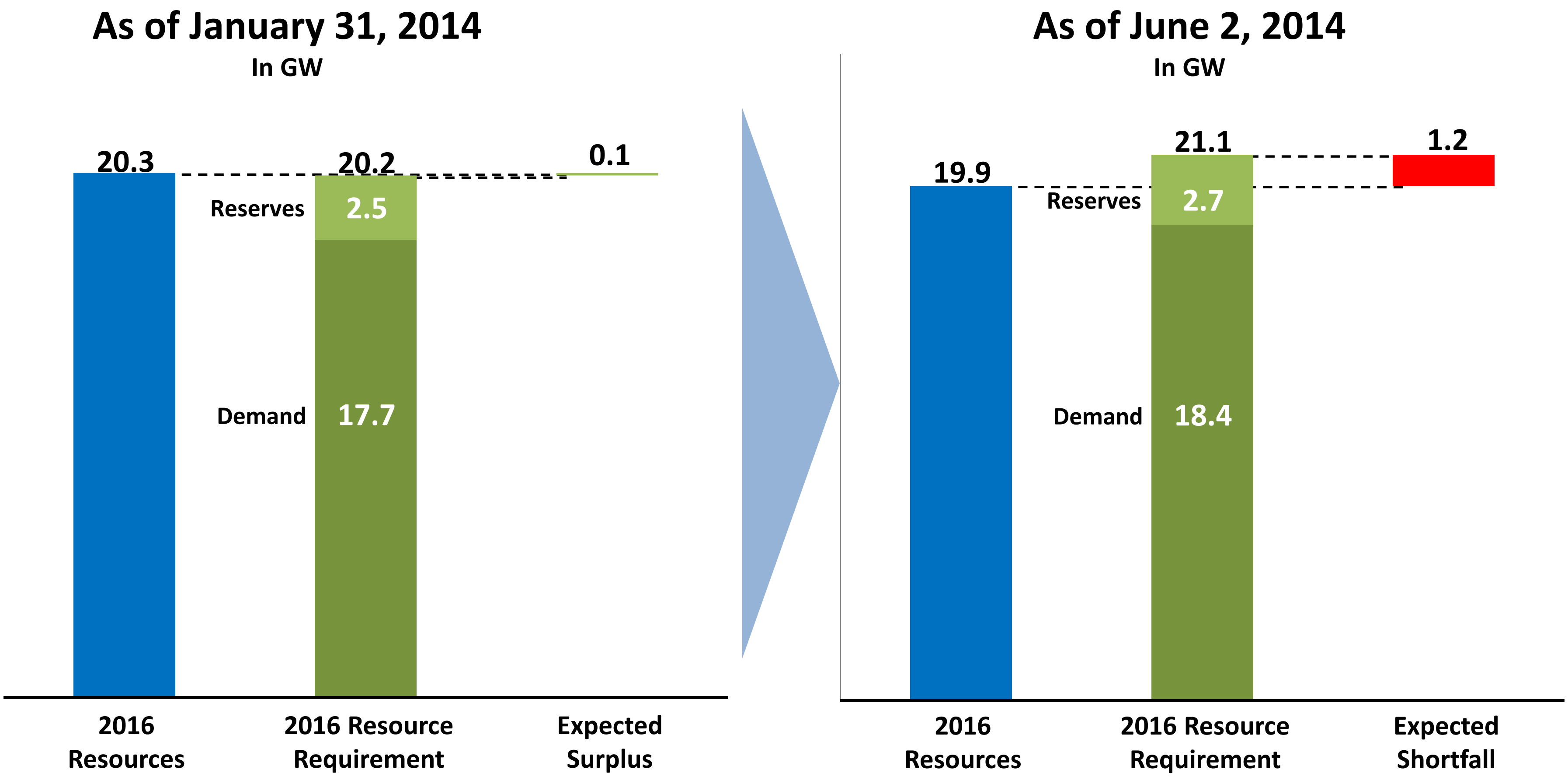
As of June 2, 2014
In GW



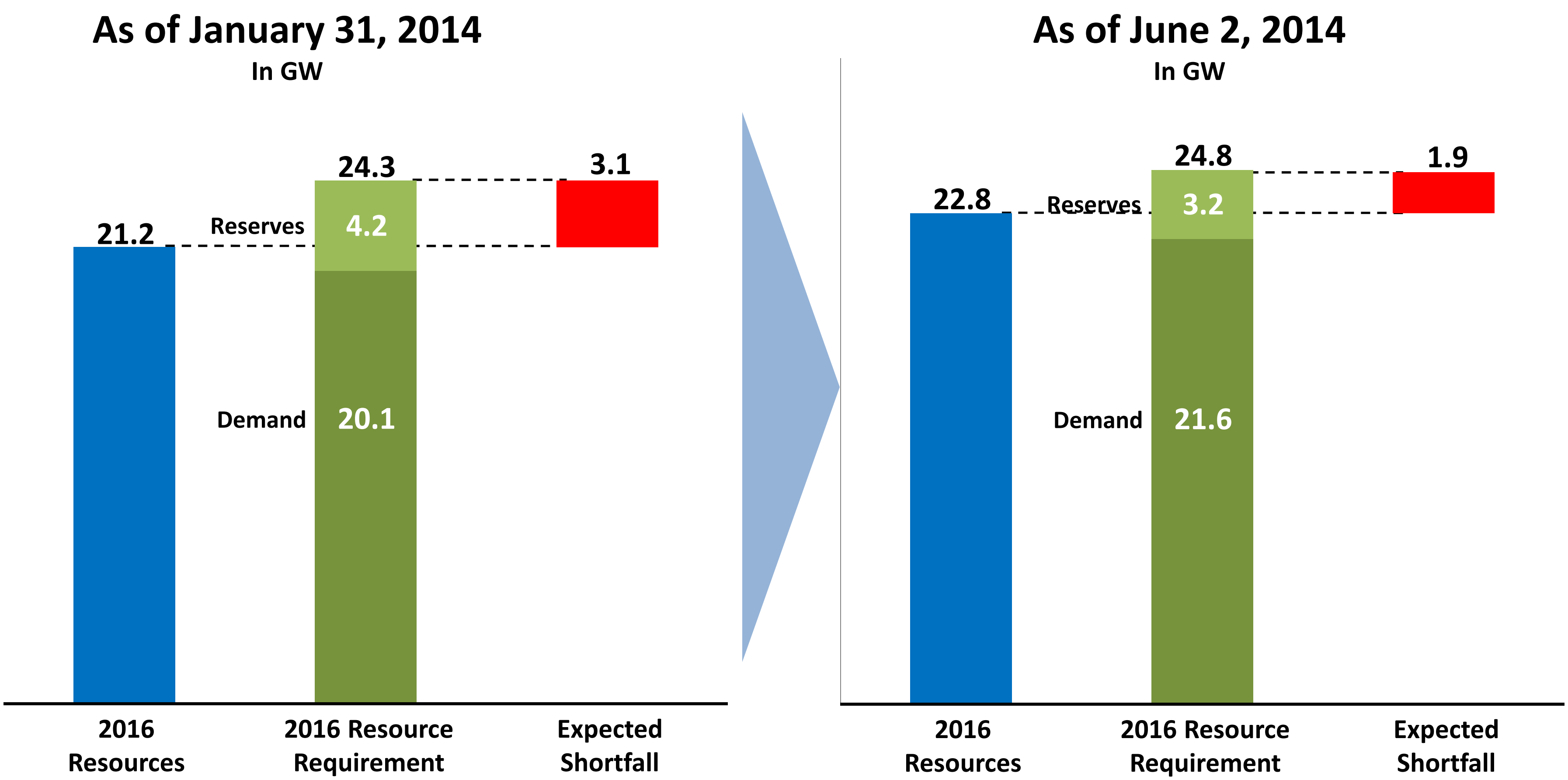
2016 Resource Adequacy Forecast
Zones 4 and 5



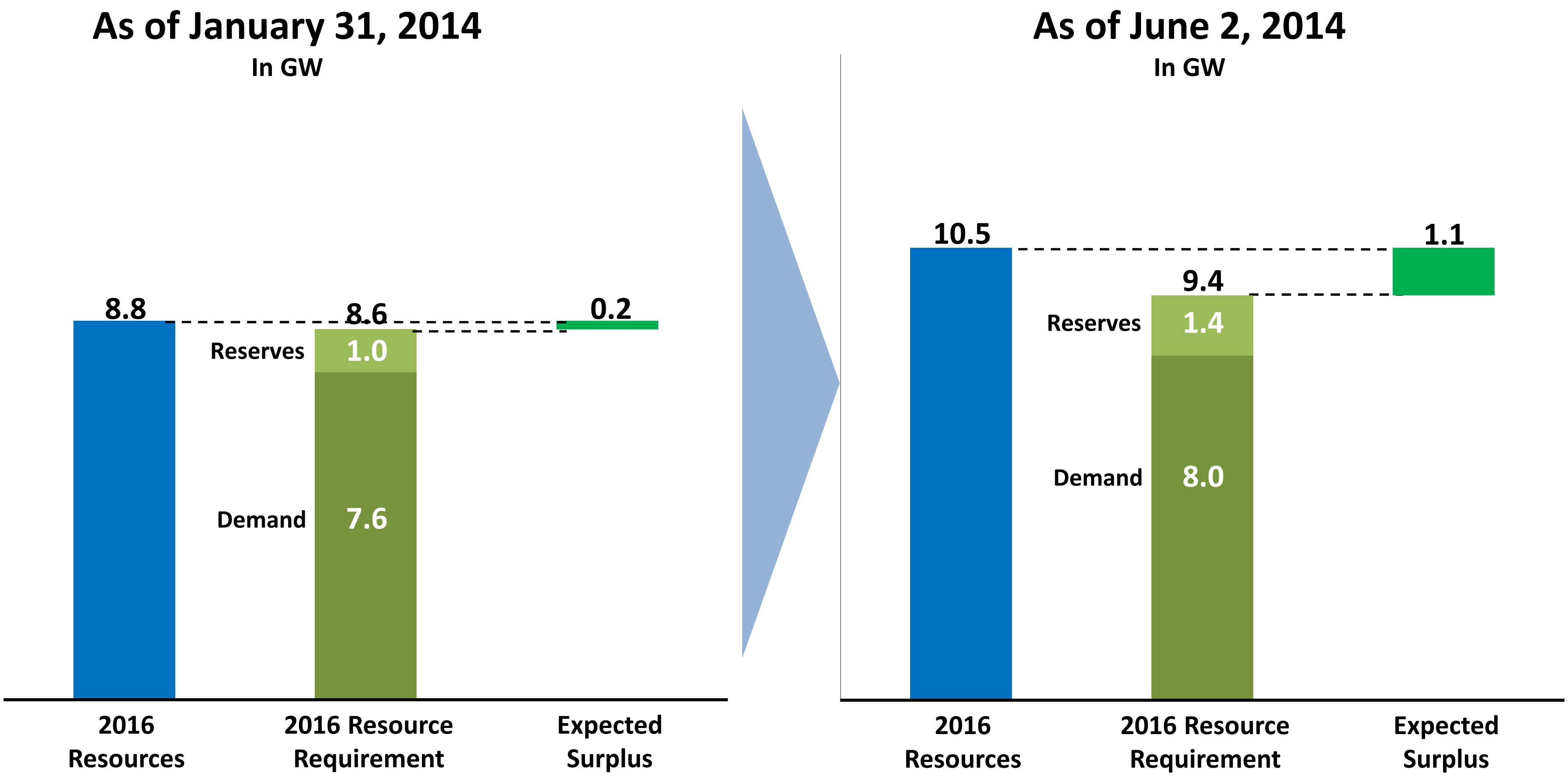
2016 Resource Adequacy Forecast
Zone 6



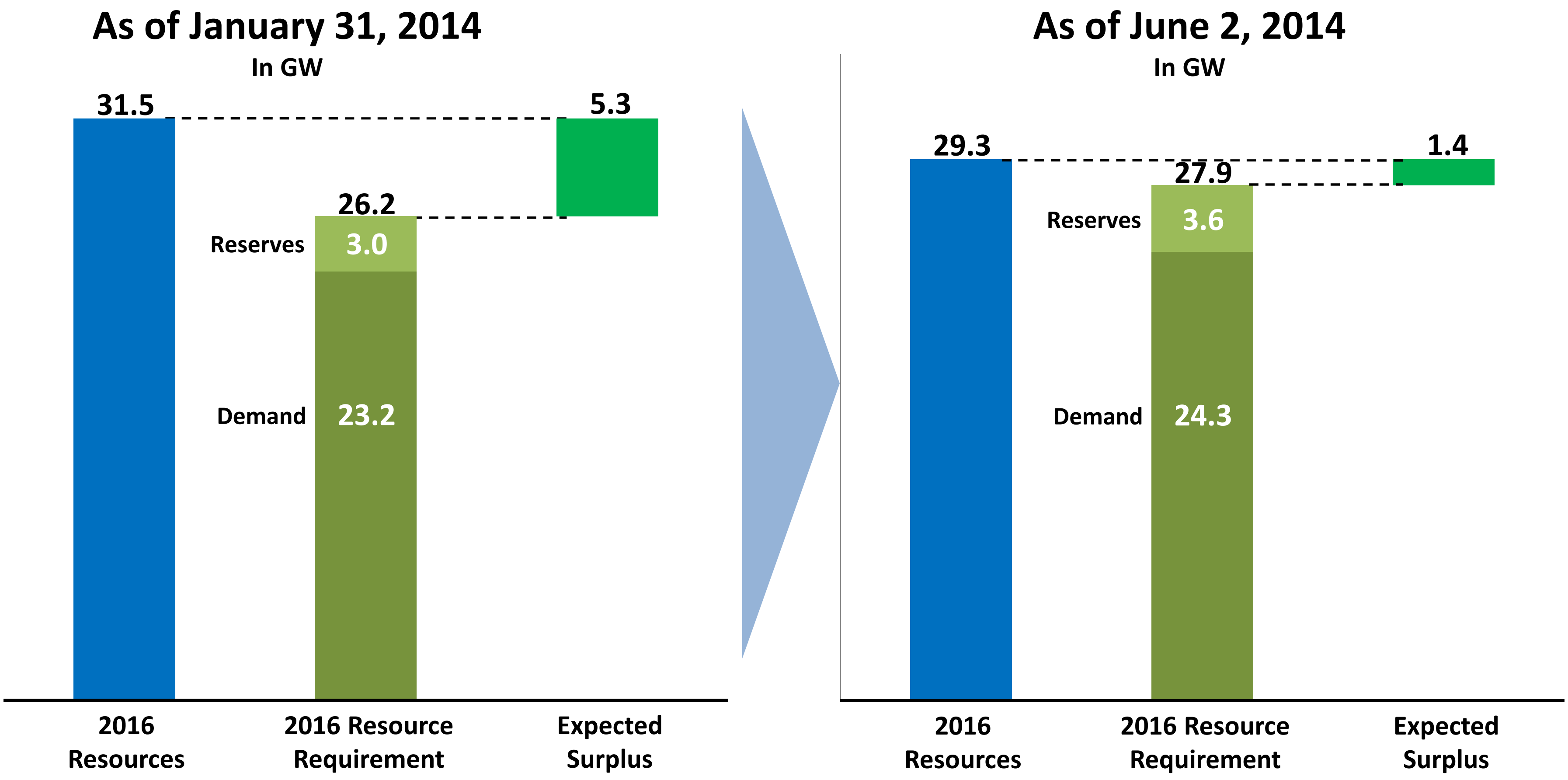
2016 Resource Adequacy Forecast
Zone 7



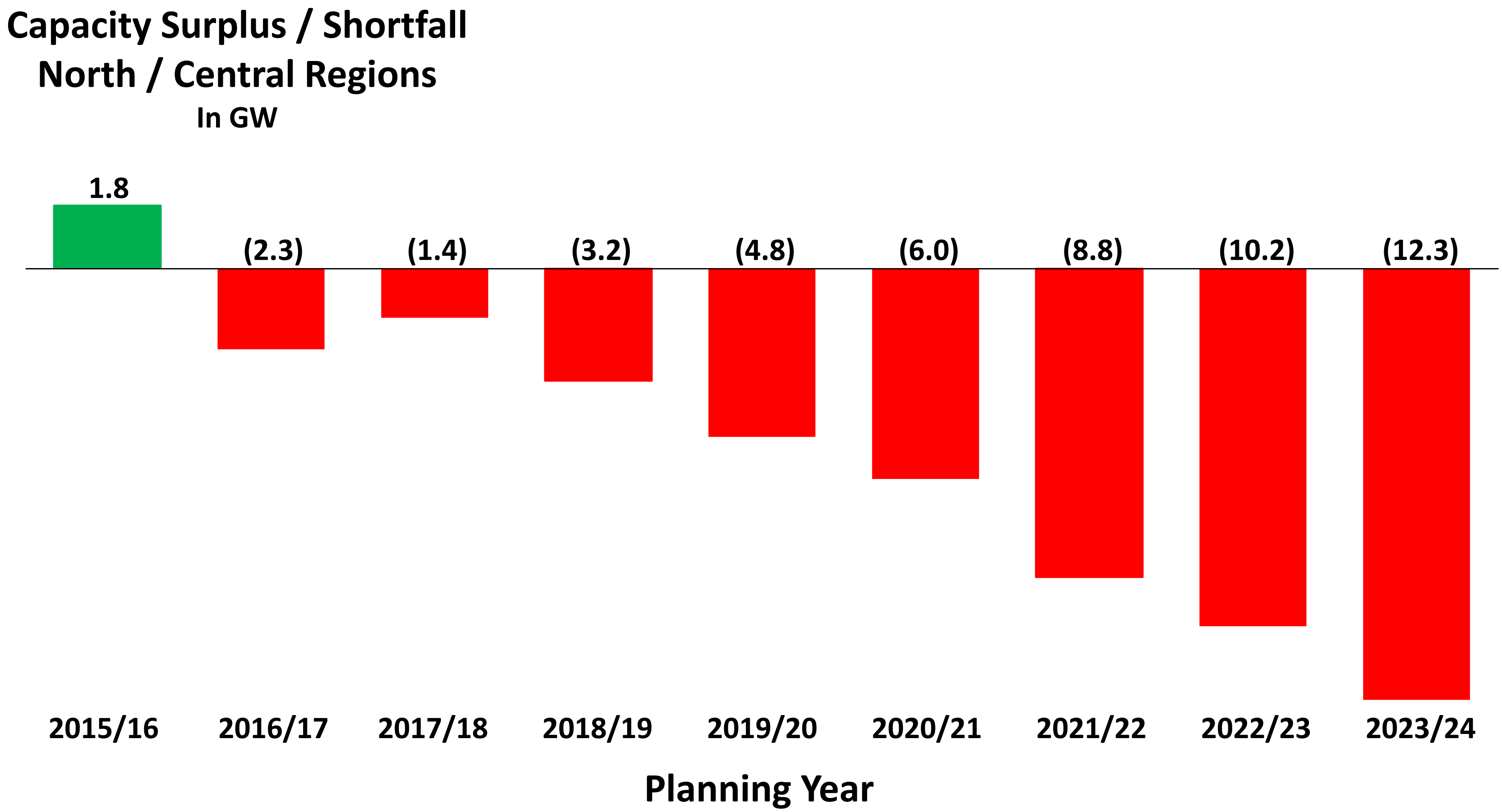
2016 Resource Adequacy Forecast
Zone 8



2016 Resource Adequacy Forecast
Zone 9



The region is preliminarily forecasting little new generation to serve continuing load growth



This slide shows **a preliminary forecast** of a 10-year period, as is required for the NERC Long Term Reliability Assessment. MISO fully expects that **these figures will change significantly as future capacity plans are solidified** in the future by load serving entities and state commissions.

MISO

Work initiated by MISO to ensure all possible resources were available for use in 2016 is progressing

- Evaluation of unused / trapped generation capacity
  - Study indicated that 1,363 MW across 119 units might be accessible
  - Studies and cost estimates should be complete by September
- Load Modifying Resources have been catalogued and processes / procedures to provide for more efficient use are being refined with Load Serving Entities
- South to Central / North transfer limits have been held at 1,000 MW during SPP settlement negotiations