Direct Testimony and Schedule
Julie I. Pierce

Before the Minnesota Public Utilities Commission

State of Minnesota

In the Matter of the Application of Minnesota Power
for Authority to Increase Rates for Electric Utility
Service in Minnesota

Docket No. E015/GR-21-335

Exhibit ________

POWER SUPPLY STRATEGY

November 1, 2021

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Julie I. Pierce, and my business address is 30 West Superior Street, Duluth, Minnesota 55802.

Q. By whom are you employed and in what position?

A. I am employed by ALLETE, Inc., doing business as Minnesota Power ("Minnesota Power" or the "Company"). My current position is Vice President of Strategy and Planning.

Q. Please summarize your qualifications and experience.

A. I have over 20 years of experience in the electric industry that includes transmission reliability, energy markets, and utility planning. I am currently responsible for resource planning, project development, Midcontinent Independent System Operator ("MISO") market operations, and Regional Transmission Organization coordination. I graduated from North Dakota State University with a Bachelor of Science in Electrical Engineering. Prior to joining Minnesota Power, I was an engineering manager for MISO. I worked for eight years at MISO, holding various management roles in the organization during that time. I am originally from northern Minnesota and have enjoyed almost 15 years with Minnesota Power in Duluth, Minnesota and being part of the energy transformation the Company has gone through with its *Energy**Forward*** strategy.

Q. What is the purpose of your testimony?

A. I provide further support for the Company's proposed Sales True-up discussed by Company witness Frank L. Frederickson by providing information on changes to Minnesota Power's power supply and changes in the MISO power market. I discuss how these changes have limited Minnesota Power's ability to recover lost customer sales revenues through MISO market sales when our Large Power ("LP") customers either shut down or idle their operations.

I also discuss Minnesota Power's Power Purchase Agreement ("PPA") with Manitoba Hydro for the purchase of 250 MW of capacity and energy to serve Minnesota Power's customers (the "Manitoba Hydro PPA"). In my testimony, I discuss the benefits of this PPA for Minnesota Power's customers and how Minnesota Power intends to recover the costs of this PPA.

Finally, I provide further discussion on the Company's new contracts with municipal utilities that are discussed by Company witness Mr. Frederickson. In my testimony, I discuss how Minnesota Power plans to serve the municipal wholesale customer demand under the new contracts.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibit:

- MP Exhibit ___ (Pierce), Direct Schedule 1 – Asset-Based Loss of Load Wholesale Sales from 2016 to 2020, 2021 projected year, and 2022 test year.

II. MINNESOTA POWER'S CHANGING POWER SUPPLY STRATEGY AND PROPOSED SALE TRUE-UP MECHANISM

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I will discuss how Minnesota Power's power supply portfolio has changed as part of our *Energy**Forward*** strategy and how this transition to more renewable generation resources and reduction in coal generation has impacted the total output and dispatchability of our power supply. I will also discuss how these changes have affected our ability to recover lost sales revenues when our LP customers either shut down or idle their operations.

Q. What is Minnesota Power's current power supply strategy?

A. Minnesota Power has been advancing a transformation of its power supply to a cleaner energy future through its *Energy**Forward*** strategy since 2010. Minnesota Power is now delivering 50 percent renewable energy to customers and was the first Minnesota utility to achieve this milestone. As part of this transition, Minnesota Power has either retired, refueled, or remissioned seven of its nine coal-fired generating units. In our 2021 Integrated Resource Plan ("2021 IRP"),[1] Minnesota Power is continuing to further its *Energy**Forward*** strategy and has committed to achieve an 80 percent reduction in carbon emissions by 2035, compared to 2005 levels, and has a stated goal of delivering 100 percent carbon-free energy by 2050. This transformation has made Minnesota Power a state and regional leader in clean energy, while at the same time providing affordable and reliable electric service for customers.

Q. Please explain further, how Minnesota Power has already transitioned its fleet to reduce carbon emissions.

A. In 2005, Minnesota Power's energy supply had one of the highest carbon intensities in the nation and the Company served its customers from a resource mix comprised of 95 percent coal-fired generation. However, the Company has since reduced its carbon intensity by approximately 50 percent to be at a level of carbon intensity similar to the United States average, moving from a resource mix that was five percent renewable in 2005 to one that reached 50 percent renewable in 2020. Please refer to Direct Testimony of Company witness Jennifer J. Cady for more details on these carbon-reduction achievements as a driver in this rate case.

Q. What steps has the Company taken to achieve this increase in renewable generation and lower carbon emissions?

A. The transformation is the result of both retiring existing thermal generation and adding or purchasing more renewable generation. Since 2010, the Company has retired, idled, or remissioned 600 MW of its coal-based thermal generation portfolio. Specifically, as described by Company witness Todd Z. Simmons, the Laskin Energy Center converted from coal-fired to natural gas-fired generation in June 2015. Taconite Harbor Energy Center ("THEC") Unit 3 ceased coal-fired generation in May 2015. THEC Units 1 and

[1] *In the Matter of Minn. Power's Application for Approval of its 2021-2025 Integrated Res. Plan,* Docket No. E015/RP-21-33, 2021 INTEGRATED RESOURCE PLAN (Feb. 1, 2021).

2 were idled in the fall of 2016, and all coal-fired operations ceased there in 2020. In addition, two of the four coal-fired units of the Boswell Energy Center ("BEC"), Unit 1 and Unit 2 ("BEC1&2)," were retired in December 2018[2]. Minnesota Power also has been reducing its coal based power purchase from Square Butte's Milton R. Young 2 lignite coal generating station ("Young 2")[3].

In the 2021 IRP, the Company is further optimizing Minnesota Power's coal fleet in the market and working with stakeholders as it proposes to move forward with additional actions to transform the coal fleet, which I discuss later in more detail.

These steps in Minnesota Power's coal transition are being done thoughtfully and appropriately to ensure a reliable energy supply for customers and a just transition for northern Minnesota workers and communities.

Q. Describe the renewable generation added to Minnesota Power's system since 2005.

A. Since 2005, the Company has added over 850 MW of wind generation[4], 457 MW of hydro generation[5], and 11 MW of solar generation to its portfolio. Minnesota Power has been keeping pace with Minnesota's Solar Energy Standard to-date in part by adding its Camp Ripley (10 MW) and Community Solar Garden (1.04 MW) solar energy projects. Additionally, Minnesota Power has significantly expanded its SolarSense rebate program for customer-sited solar installations to comply with the small-scale carve-out requirement of the Solar Energy Standard. In May 2021, Minnesota Power received approval from the Minnesota Public Utilities Commission ("Commission") to add approximately 20 MW of additional solar generation to support economic relief and

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[2] BEC1&2 were retired in December 2018 (135 MW).

[3] Reductions to Minnesota Power's Young 2 capacity from 227.5 MW to 80 MW occurred since August 2014 with a phase out of Young 2 by 2026 per agreement with Minnkota Power Cooperative.

[4] The 850 MW of added wind generation includes Minnesota Power owned Bison Energy Center (497 MW), Minnesota Power owned Taconite Ridge Energy Center (25 MW), Oliver I and II wind PPA (99 MW), and Nobles 2 wind PPA (250MW).

[5] Hydro generation includes the 250 MW of capacity and energy and 133 MW energy only purchase from Manitoba Hydro starting in 2020, and 74 MW from Thomson Hydro rebuild project to repair damage from the 2012 flood.

recovery within the Company's service territory in response to the economic impacts of the COVID-19 pandemic. Finally, the Company has obtained Commission approval for two significant renewable PPAs that customers started to receive energy and capacity from in 2020. These include: (1) 250 MW of additional wind generation from the Nobles 2 wind facility in southern Minnesota that commenced commercial operations in December 2020[6] and (2) 250 MW of capacity and energy and 133 MW energy only purchase from Manitoba Hydro that are delivered via our new 500 kilovolt ("kV") Great Northern Transmission Line ("GNTL"). I discuss the Manitoba Hydro PPA further in Section III of my testimony. These additions have significantly transformed Minnesota Power's supply portfolio allowing it to reach the milestone of being half-renewable and has allowed customers to receive carbon free energy from a more diverse set of renewable resources.

Q. What are the key additional power supply actions proposed in the 2021 IRP?

A. Through its 2021 IRP, Minnesota Power outlined a bold vision for a sustainable path to achieve a carbon-free power supply by 2050. The 2021 IRP was informed by a first-of-its-kind stakeholder engagement process and outlines specific steps to facilitate a power supply that is 70 percent renewable in 2030, reduces carbon emissions 80 percent by 2035 from 2005 levels, and results in a generation mix that is coal-free by 2035 — all while helping to ensure reliable and affordable power for Minnesota Power customers and provide a just transition for effected workers and communities. Specific near-term steps to reduce carbon and advance renewable energy include:

- Retiring the currently-idled THEC in 2021;
- Adapting operations at BEC3 to economic dispatch within the MISO market in 2021;
- Implementing the Demand Response Product C for industrial customers in 2022;
- Constructing three solar projects totaling 20 MW in 2022;

[6] *In the Matter of Minn. Power's Request for Approval of a Power Purchase Agreement with Manitoba Hydro Co.*, Docket No. E015/M-11-938, Order (Feb. 1, 2012); *In the Matter of Minn. Power's Petition for Approval of a 250 MW Nobles 2 Wind Power Purchase Agreement*, Docket No. E015/M-18-545, Order Approving Power Purchase Agreement with Revisions, Requiring Reporting, and Requiring Compliance Filing (Jan. 23, 2019).

- Advancing 200 MW of new wind resources by 2025; and
- Maintaining leadership in both electrification and energy conservation efforts.

Longer-term steps outlined in the 2021 IRP include:

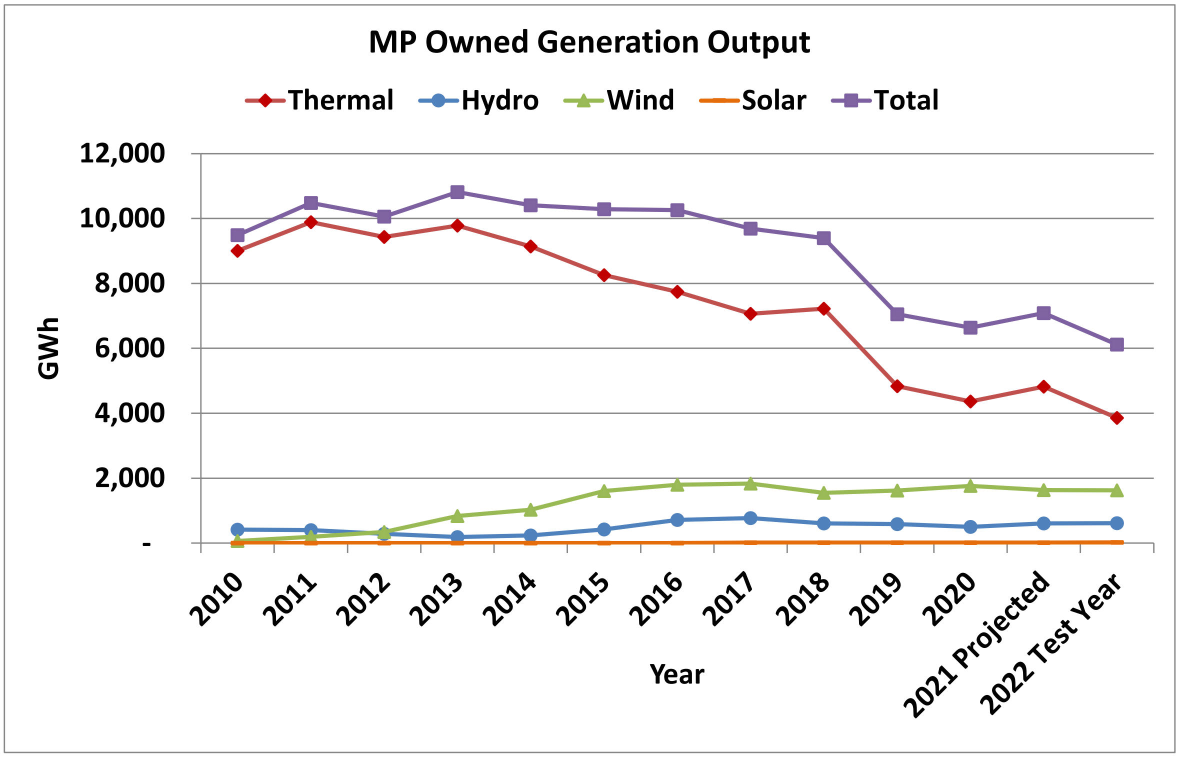
- Retiring BEC3 by December 31, 2029;
- Adding 200 MW of solar that leverage the BEC site or other Minnesota Power facilities by 2030;
- Working collaboratively with customers to pursue up to 50 MW of long-term demand response by 2030; and
- Developing and implementing transmission solutions to facilitate the early retirement of BEC3 and investigating options to refuel or remission BEC4 as coal operations cease by 2035.

In addition to the IRP actions, a project that will be completed in fall 2021 will reduce the BEC3 minimum dispatch level from 175 MW down to 75 MW.

Q. How will Minnesota Power's energy supply transformation impact the generation output from Company-owned generation resources in the 2022 test year?

A. As shown in Figure 1, since Minnesota Power initiated its *Energy**Forward*** strategy in 2010, the Company has removed approximately five million MWh of thermal generation output from its power supply portfolio. At the same time, only approximately two million MWh of Company-owned renewable generation (Bison 1 – 4 and Camp Ripley solar) was added. As discussed later, Minnesota Power needed to procure additional power supply resources through renewable bilateral contracts to replace coal generation that was retired, idled, or remissioned to ensure enough energy and capacity was available for customers to provide a reliable portfolio for its electric supply.

Figure 1. Minnesota Power Owned Generation Output



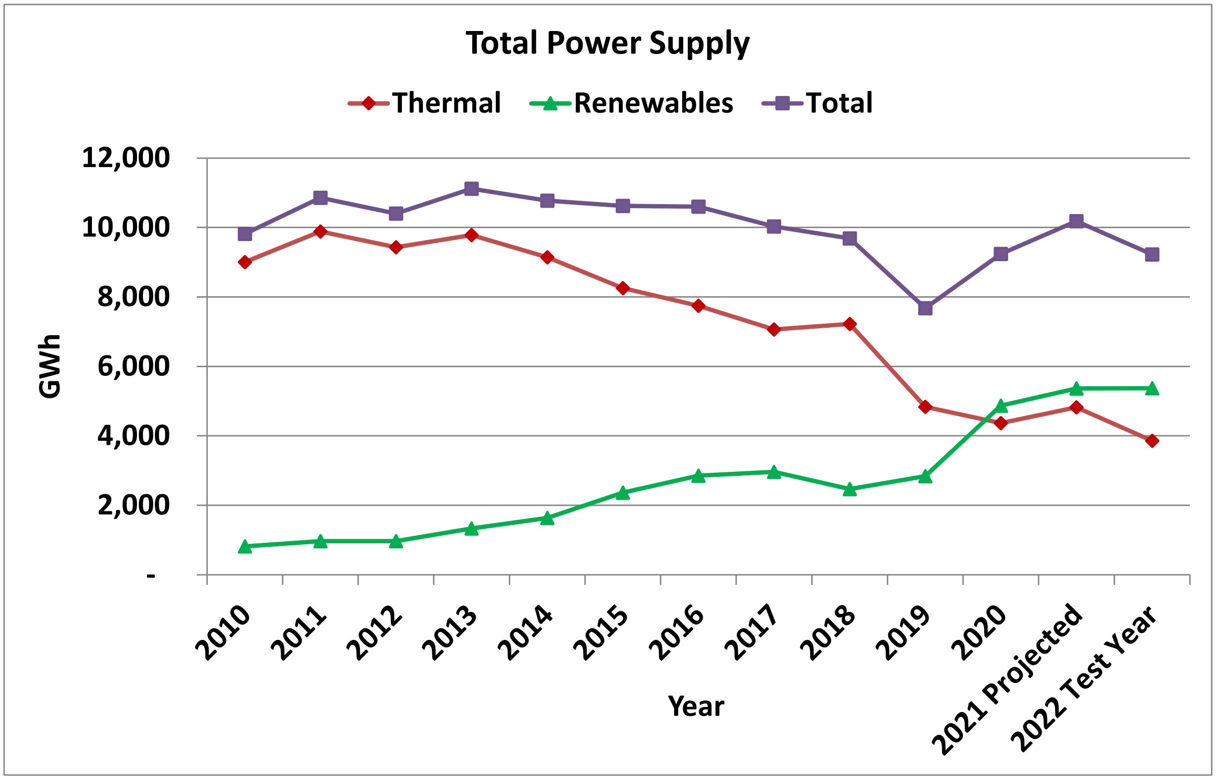
Q. What is the make-up of Minnesota Power's total power supply (both Company-owned and purchased firm resources) in the Company's 2022 test year?

A. As shown in Figure 2, Minnesota Power's thermal generation (diamond line) has been decreasing due to retirements, idling, or remissioning since 2013, while the Company has been adding predominantly renewables (triangle line) to augment the power supply. Minnesota Power has tripled its renewable energy since 2014 after meeting the State's Renewable Energy Standard a decade early in 2015. The Company has added two significant renewable power purchases in 2020, the 250 MW and 133 MW Manitoba Hydro and 250 MW Nobles 2 wind farm. However, even with the addition of new renewable generation from the PPAs, Minnesota Power's total power supply output (purchases and Company-owned generation assets) on an annual basis will be slightly lower[7] in 2022 than in 2010. This power supply transformation has provided 50 percent

[7] 2010 equals 9.8 million MWh and 2022 equals 9.2 million MWh.

renewable generation for Minnesota Power customers and has created a new profile of power supply with less thermal dispatchable generation to meet customer needs.

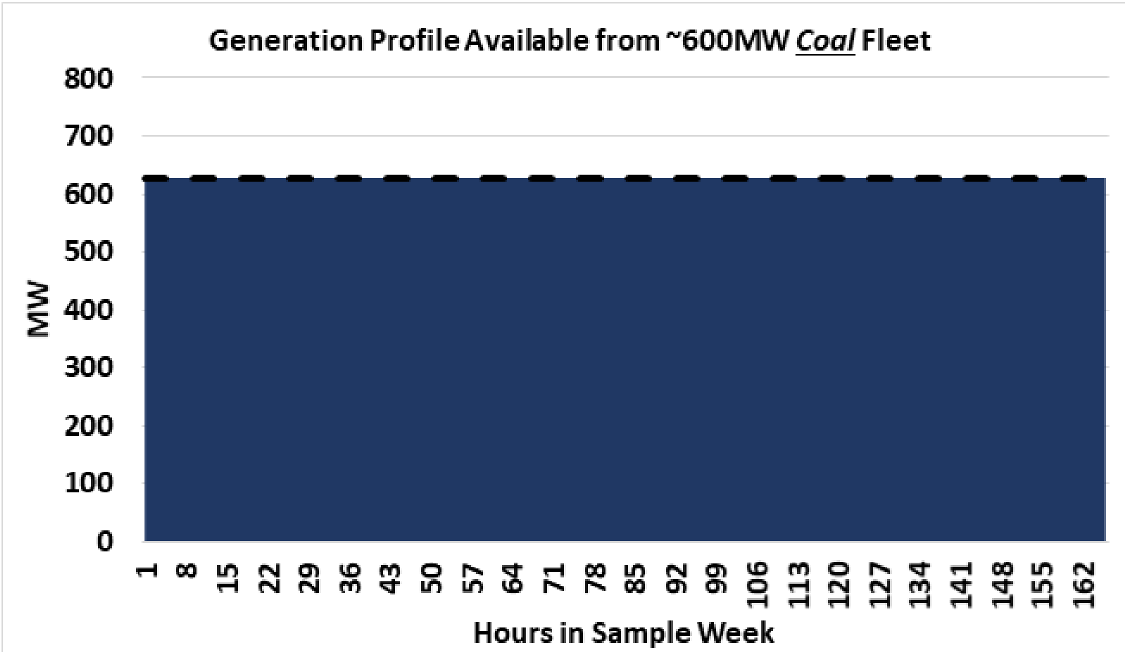
Figure 2. Total Power Supply



Q. How has Minnesota Power's energy transformation impacted the dispatchability of the Company's overall power supply portfolio?

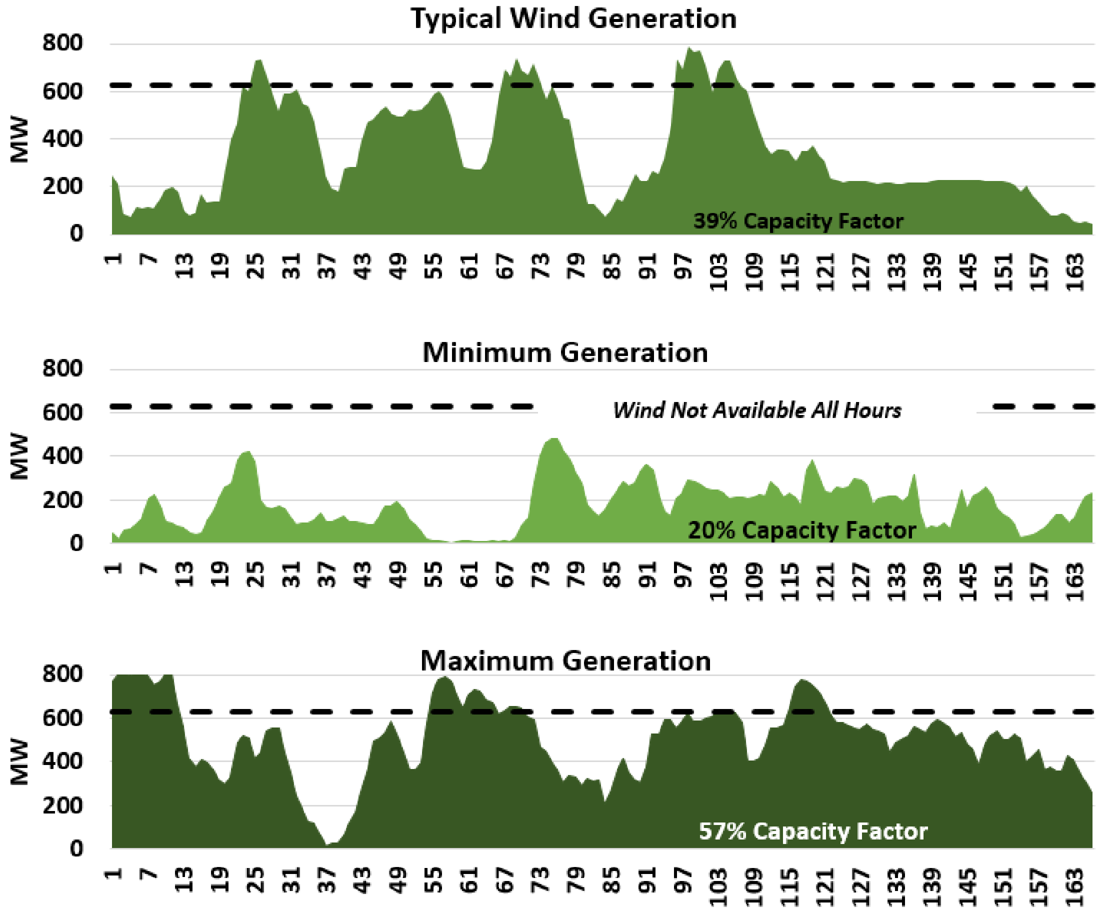
A. While the reduction in thermal-based generation has greatly reduced Minnesota Power's carbon emissions, the addition of renewable generation has created a new, and more intermittent, profile for Minnesota Power's supply portfolio that is less dispatchable, as compared to the Company's previous baseload operations. This is because the new renewable generation additions do not provide energy that is generally available seven days a week, 24 hours a day and on command like the dispatchable thermal generation Minnesota Power previously held as shown in Figure 3.

Figure 3. Generation Profile Available



As Figure 4 demonstrates, the hourly wind profile availability is drastically different from the block profile for the coal fleet that it replaced. There are periods when the wind energy exceeds the 600 MW capability of the coal fleet and several periods when it is lower. Furthermore, the capacity factor or available energy from Minnesota Power's wind portfolio can vary from week to week, creating uncertainty on the level of renewable energy available during each week. The result is a generation output profile that is much more variable than in the past.

Figure 4. Hourly Wind Profile for a Week



Q. How does the variability impact the Company's overall power supply?

A. As generation availability changes due to the Company's power supply transition and more intermittent generation being added, additional factors like wind and sun availability increase the uncertainty of the total generation energy production available hourly, daily, or annually. The Company's hourly surplus and deficit profile currently varies significantly during high-wind and low-wind conditions each day just due to the North Dakota and Minnesota wind in the portfolio. Figure 4 above includes a typical week, low week, and high week of wind variability at our North Dakota and Minnesota wind generation facilities that demonstrates this variation. Based on actual observations at Minnesota Power's wind facilities over a one-week period, wind generation capacity factors can vary from 20 percent to 57 percent.

Q. How is Minnesota Power's current generation matched to its load?

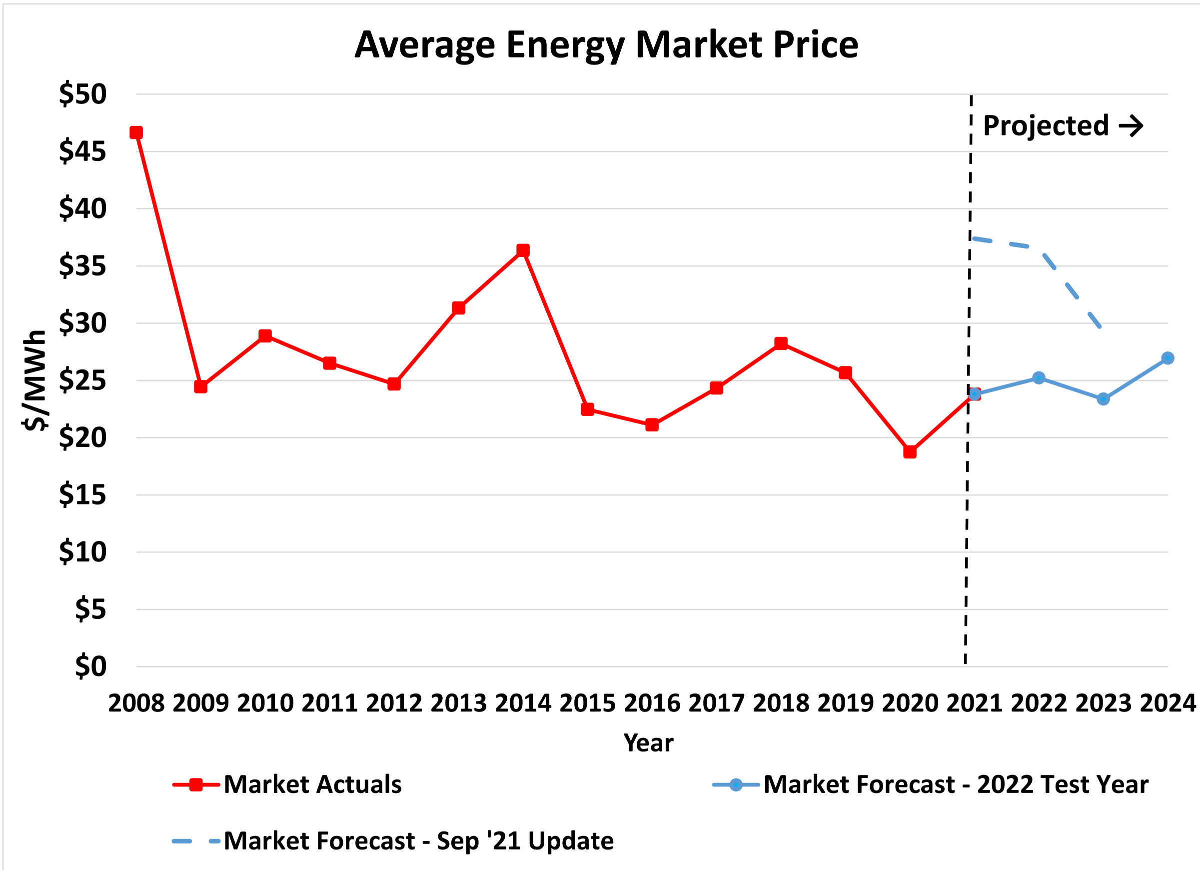
A. As shown in Figure 2 above, Minnesota Power's total power supply has held relatively flat since 2010 as the Company thoughtfully retired and remissioned its existing coal fleet and achieved a power supply that includes 50 percent renewable energy. Annually, there is minimum change to the level of energy Minnesota Power purchased or self-generated. However, due to the intermittent characteristics of the renewable replacement energy of coal generation, Minnesota Power is seeing increased interaction with the MISO grid to match hourly generation with load.

Q. What is the average price a utility can expect to sell and purchase energy in the MISO market?

A. The MISO market dynamics, such as average market prices and variability of the market price, is very specific for each utility — it is dependent on their geographical and electric grid location within the larger MISO footprint and the characteristics of the surrounding load and generation. The average annual energy market price and current projections through 2024 for Minnesota Power are provided in Figure 5 below. The average annual energy price does not show the variability that a utility can see on an hourly basis or in the bilateral markets, both of which can vary greatly. However, it does show that the energy market price outlooks can change significantly within a year, as represented in the dashed line that shows the increase in market price outlook from early in 2021 to September 2021. The market price outlook for 2022 has increased 45 percent since earlier in 2021. With the exception of 2014 and the current energy market increases in 2021, the MISO energy price has been relatively stable since 2009; however, market stability is likely becoming more uncertain.[8]

[8] The energy price projection is provided by a third-party forecast from IHS Global Insight.

Figure 5. Average Energy Market Price[9]



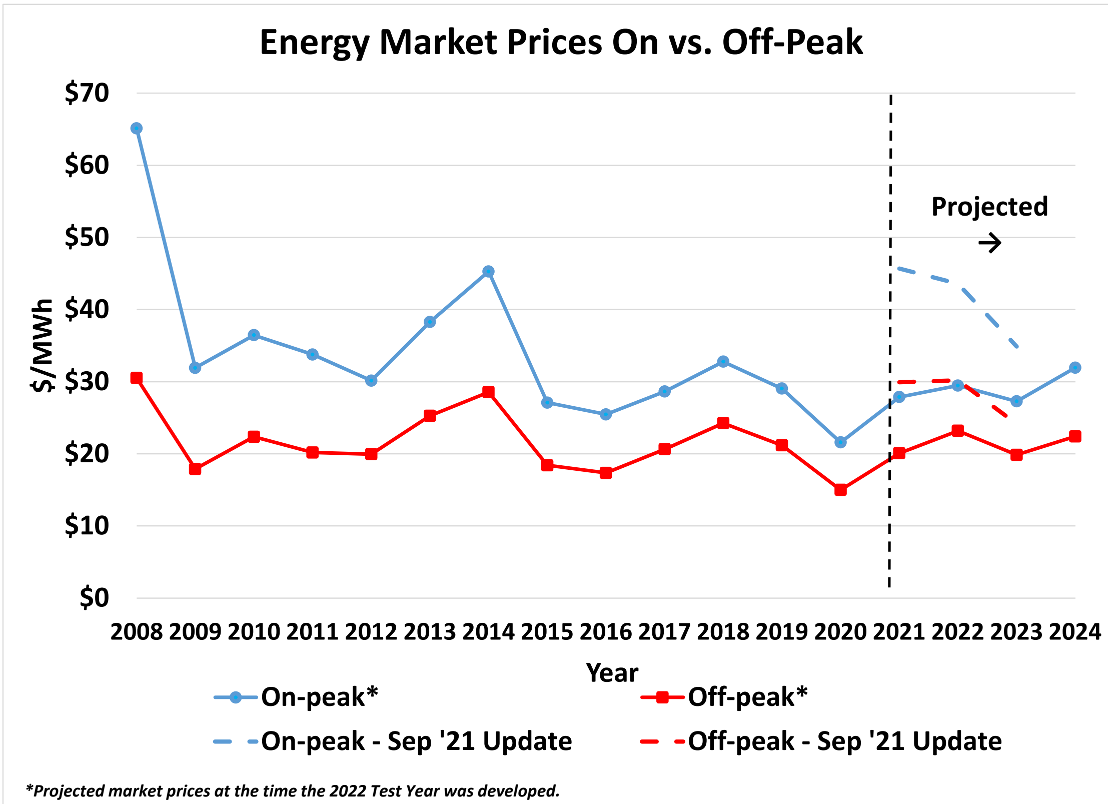
Q. Do MISO prices vary depending on whether power is being bought or sold during on-peak or off-peak periods of each day?

A. Yes. As shown in Figure 6, the on-peak and off-peak time periods have different pricing profiles, creating a significant price difference throughout each day. The price differential between the on-peak and off-peak time periods from 2015 to 2020 was approximately 40 percent, which is expected to continue through 2024 based on current outlooks. However, the recent trend in market prices outlooks shown in the dashed lines shows the price differential between the on-peak and off-peak time period increasing to 50 percent. Thus, if Minnesota Power needs additional power or has surplus to sell with

[9] The Market Forecast used in the "2022 test year" is based on the market price outlook used in the 2022 Forecast at Completion filed May 3, 2021, which was based on the forward energy market outlook in February 2021. The "Sep '21 Update" is based on the forward energy market outlook as of September 2021.

the MISO market, the price can vary significantly depending on when the energy is needed or available.

Figure 6. Energy Market Prices On vs. Off-Peak



Q. How has Minnesota Power's changing power supply impacted its MISO purchases and sales?

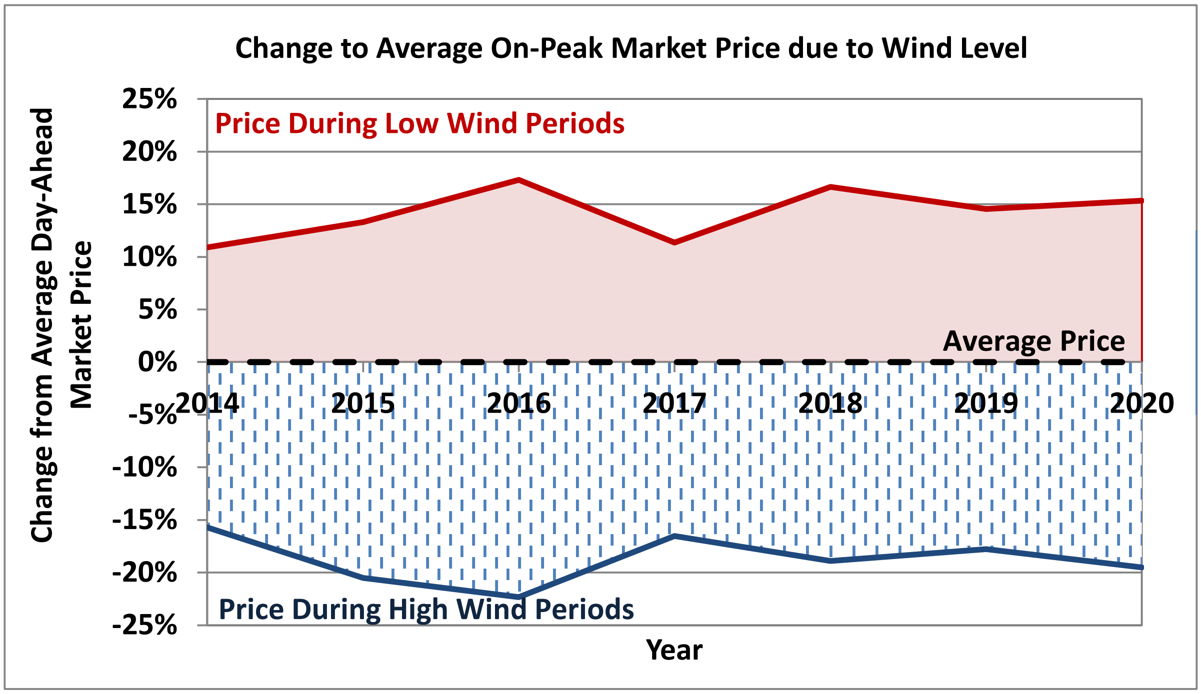
A. Minnesota Power's surplus and deficit profile for MISO purchases and sales has been changing, and with the addition of predominately wind generation, now follows variable wind generation patterns. When the wind energy availability is higher, Minnesota Power typically has a surplus and is selling energy. When wind energy availability is low, there is typically a deficit and Minnesota Power is purchasing energy. Today, the Company's surplus and deficit profile will vary by up to 850 MW in high wind to low wind conditions on a daily basis. Minnesota Power uses a third-party wind forecast and internal tools to anticipate renewable profiles, determine impacts to MISO purchases and sales balance, and optimize our power supply accordingly in MISO. With Minnesota Power's large wind portfolio, the Company's MISO purchases and sales generally follow the wind profile in its portfolio and can vary from day to day.

Q. How does the availability of wind generation impact MISO market prices?

A. The amount of wind generation in the MISO footprint is significant enough that wind availability impacts the regional energy supply, demand balance, and resulting energy market prices. The market prices during high and low wind periods can vary greatly. Market prices are often lower when the Company's and regional wind generation is at its highest level, and market prices are higher when wind generation is at its lowest level. Overall, the lower prices during periods of high wind energy availability is reducing the average market price, including when the Company is generating excess wind energy. Thus, when Minnesota Power makes a sale, the market prices are often lower.

Figure 7 below demonstrates the impact wind variability had on actual MISO market price since 2014. For example, in 2020, on-peak market prices were 15 percent higher than the average in low wind periods and 20 percent lower than average in the high wind periods.

Figure 7. Change to Average On-Peak Market Price due to Wind Level



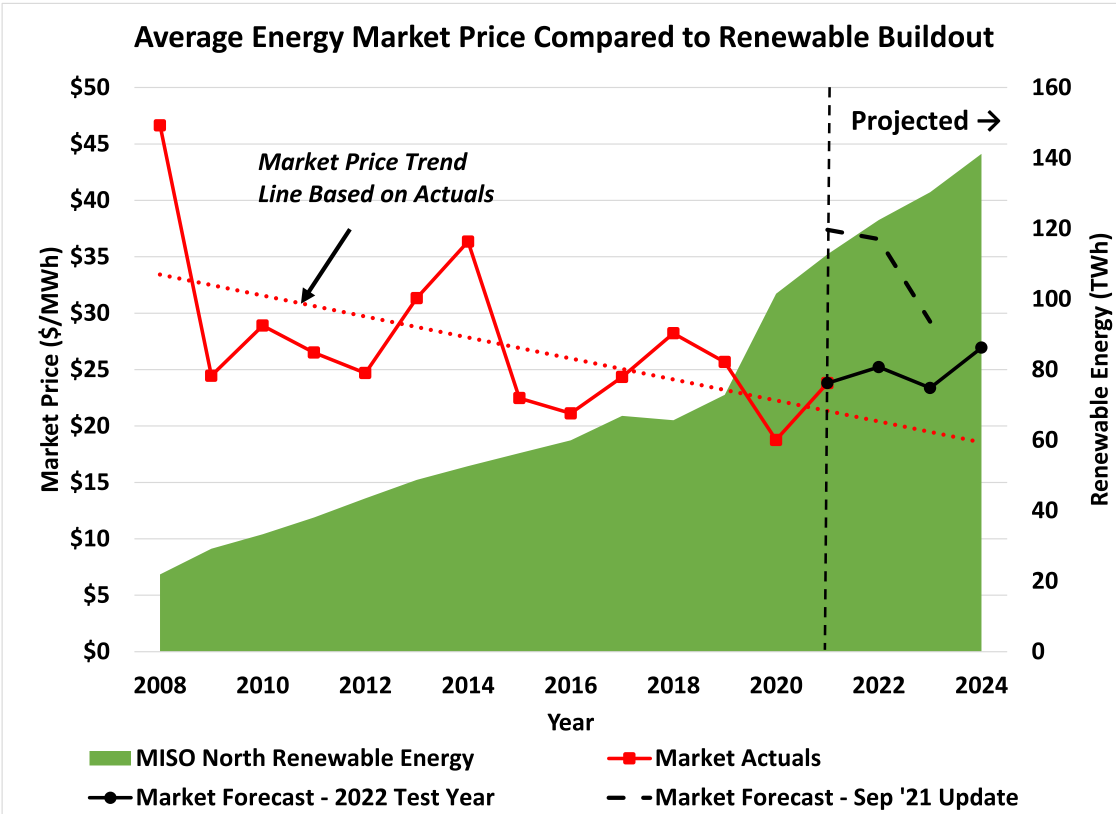
Q. Does Minnesota Power's transition to a 50 percent renewable generation portfolio and the overall industry trend toward higher renewables impact MISO energy sale prices?

A. Yes. There are several factors affecting market prices, such as abnormal weather events and natural gas prices. Historical data also supports that some of the recent decline in energy prices can be explained by increasing renewable generation within MISO. Figure 8 highlights this trend by comparing the increasing renewable build-out in MISO North[10] to the declining market prices. Minnesota Power also has cause to assume that lower natural gas prices have driven some of the decline in energy prices over this same period. The MISO market price will affect the amount of sales revenue that Minnesota Power can expect to receive when it sells energy. Next, I discuss how the lower MISO

[10] MISO North includes the following states: Montana, North Dakota, South Dakota, Minnesota, Iowa, and Wisconsin.

market prices affect Minnesota Power's ability to recover lost revenue caused by the unexpected loss of load from LP customers.

Figure 8. Average Energy Market Price Compared to Renewable Buildout



Q. When Minnesota Power loses an LP customer, what steps are taken to recover that lost sales revenue through MISO market sales?

A. Minnesota Power's customer mix is comprised largely of industrial customers, and the business cycles that can occur in each of the industries we serve can create large fluctuations in system load on an annual basis. When an LP customer comes off the system or reduces load significantly, the Company attempts to offset that loss of load by selling the same amount of energy into the MISO market. The sales that Minnesota Power has made due to loss of load are identified in MP Exhibit ___ (Pierce), Direct Schedule 1 for 2016 through 2021. These revenues were used to help offset the lost revenue from the loss of load Minnesota Power experienced.

Q. Why is LP revenue mitigation important to the Company?

A. Base rates are set with an agreed upon sales forecast, with expected demand and energy revenue based on this load. Of course, if load declines significantly or a large customer shuts down, it will have a significant negative impact on the Company's revenue. Minnesota Power's unique risk profile as it relates to customer concentration is discussed in the testimony of Company witnesses Patrick L. Cutshall and Ann E. Bulkley.

Q. Does the Company typically recover all of its LP revenue losses when an LP customer reduces its load?

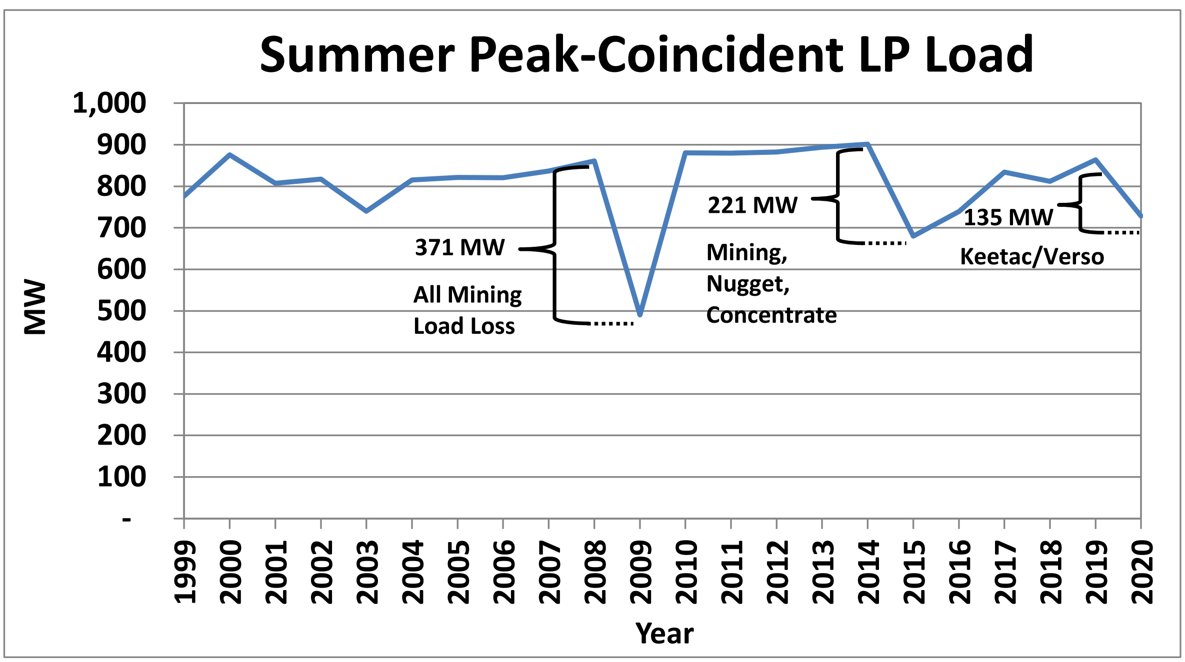
A. No. In the current low-priced market, the revenue lost due to customer load reduction cannot be fully recovered in the wholesale energy market. It is difficult to recover the revenue lost due to an LP customer downturn, as the MISO market prices have typically been low during times when Minnesota Power has a customer loss. While at the same time, the costs for providing electric service to our customers have been increasing. If the markets were strong enough to completely offset all of the lost revenue, then the impact to Minnesota Power would be zero.

As an example of this phenomenon, in 2016 and 2020, several large industrial customers were idled, resulting in an unexpected reduction of up to approximately 200 MW of LP customer load. Minnesota Power made bilateral market sales in an attempt to recover the lost revenue from these two LP customer downturns. In 2016 and 2020, these sales were made in a lower energy priced market and during that two-year time period, the cost to serve the sales increased, further reducing the sale margin available. As a result, the Company was only able to recoup a fraction of the revenues lost because of the LP customer downturns.

This lower energy priced market dynamic results in uncertainty for Minnesota Power's capability to recover lost revenues through margins on bilateral sales. As such, the Company was able to recover only 30 percent in 2018 and one percent in 2020 of the lost LP revenues through margins on bilateral sales. This example demonstrates the fluctuation in Company revenue that can occur when there is a loss of customer load. The inability to recover 100 percent of the lost LP revenues creates a difficult cost recovery equation for Minnesota Power in meeting its ongoing fixed-cost requirements. Please refer to MP Exhibit ___ (Pierce), Direct Schedule 1 for the annual margin Minnesota power was able to recover through bilateral sales from LP loss of load.

Both history and current customer operations have shown that our large customers can experience significant downturns and load reductions with short notification times[11] that put Minnesota Power in a position where it is not able to recover its cost of service. Figure 9 below demonstrates how retail load for LP customers has fluctuated from 1999 to 2020.

Figure 9. Summer Peak-Coincident LP Load



[11] As referenced in the LP Customer Outlook Direct Testimony of Mr. Frederickson and the Direct Testimony of Company witness Benjamin S. Levine, in early 2020 there was a significant reduction in steel production caused by domestic automotive production shutdowns during the COVID-19 pandemic that were announced with short notice.

Q. Do wholesale sale transactions entered into as a result of the customer loss of load impact asset-based wholesale sale margins?

A. No. Asset-based wholesale sale margins are wholesale transactions sourced from Minnesota Power's generating unit energy — that is, energy from generation facilities included in rate base and paid for by customers. Transactions that are made as a result of a customer loss of load are priced using the average cost of fuel. The "source" of these transactions includes both rate based generating unit energy, bilateral purchases, and energy market purchases. Therefore, the wholesale transaction margins that are created as a result of a customer loss of load do not represent a purely asset-based source but rather margin from a combination of an asset-based and purchased energy.

Q. Would an increase in wholesale MISO energy prices negate Minnesota Power's need for a Sales True-up mechanism?

A. No. Even if MISO energy prices increase in the future, history has demonstrated that market energy prices will fluctuate over time based on market dynamics like renewable availability, fuel cost, and abnormal weather events. Given that the prior ten years of market energy prices have consistently been below a level where lost revenue could be recovered, there is no indication that an increase in energy prices would be sufficient and sustainable enough to recover future lost LP revenues.

The Sales True-Up mechanism as discussed by Company witness Mr. Frederickson is designed to incorporate any offsetting revenues recovered in the MISO energy market. Therefore, if market prices increase to a level that covers lost revenue, the Sales True-up Mechanism would simply not be triggered[12] for that time period.

It is also important to note that the Sales True-up Mechanism is intended to capture positive differences in LP sales compared to a baseline, as well as negative differences. For example, if a new LP customer comes online or expands operations after the test

[12] As described by Company witness Mr. Frederickson, the trigger to activate the Sales True-up Mechanism is a $10 million or greater variance in adjusted base LP sales (LP sales variance plus any offsetting sales due to loss of load) compared to a baseline that will be set in the current rate proceeding.

year with enough additional load to trigger the Sales True-up Mechanism, these additional revenues beyond the baseline would be credited to customers. Therefore, the Sales True-up Mechanism is an important tool for the Company and customers regardless of future wholesale MISO energy prices.

Q. In summary, why is a Sales True-up Mechanism needed?

A. The Sales True-up Mechanism is needed because Minnesota Power is unable to recover a reasonable amount of the LP base rate revenue and earn a reasonable return from margins on MISO sales due to loss of customer load. The MISO energy markets have materially changed with increasing renewable energy and low natural gas prices, resulting in lower energy prices in the region. Minnesota Power does not anticipate energy prices to increase to a sustained level that would be needed to replace the lost LP base rate revenue. The Sales True-up Mechanism is consistent with previously approved sales forecast true-ups[13] and balances the risk of more volatile market prices as a result of de-carbonizing the power supply and changes in company revenue caused by fluctuations in LP customers' operations.

As discussed in the Direct Testimony by Company witness Mr. Frederickson, due to Minnesota Power's unique customer mix and customer concentration, the Sales True-up Mechanism will help the Company reduce the need for future rate cases that are triggered solely by fluctuations in LP operations. As discussed in the testimony of Mr. Cutshall, ALLETE's credit rating agencies and credit ratings would favor the mechanism, as it shares rewards and risks of LP volatility with all customers and the Company. The Sale True-up Mechanism is a simple and balanced method to align risks and benefits of LP volatility that occur between rate cases to all customers and the Company.

[13] *In the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS at 148-149 (Dec. 26, 2014). *In the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 9 (June 12, 2017).

III. MANITOBA HYDRO POWER PURCHASE AGREEMENT

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I discuss the key benefits of Minnesota Power's Power Purchase Agreement with Manitoba Hydro for the purchase of 250 MW of capacity and energy to serve Minnesota Power's customers (the "Manitoba Hydro PPA"). The Manitoba Hydro PPA was approved by the Commission on February 1, 2012,[14] and Minnesota Power is now seeking recovery of the previously approved demand costs of the Manitoba Hydro PPA in this rate case.

Q. What are the key aspects of the Manitoba Hydro PPA?

A. The Manitoba Hydro PPA was executed on May 19, 2011 and is a 15-year agreement for Minnesota Power to purchase a premium renewable resource that is 250 MW of hydroelectric energy and capacity seven days a week and 16 hours a day from Manitoba Hydro. The term of the Manitoba Hydro PPA is from June 1, 2020 through May 31, 2035. This contract delivers nearly 1.5 million MWh of carbon free energy to customers via the GNTL. The Manitoba Hydro PPA and GNTL is a key pillar of Minnesota Power's *Energy**Forward*** strategy to reduce carbon emissions and add renewable energy sources that supports Minnesota Power's existing wind and solar portfolio. It is one of the foundational renewable projects that help achieve 50 percent renewable energy in 2021.

Q. What is the power source for the Manitoba Hydro PPA?

A. The Manitoba Hydro PPA provides reliable power sourced from Manitoba Hydro's entire hydro system, including the Keeyask Generating Station. The Keeyask Generating Station is a 695 MW hydroelectric facility on the lower Nelson River in northern Manitoba that was constructed by the Keeyask Hydropower Limited Partnership — a limited partnership between Manitoba Hydro and four Manitoba First Nations. The Keeyask Generating Station began producing renewable energy in March

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[14] *In the Matter of Minn. Power's Request for Approval of a Power Purchase Agreement with Manitoba Hydro Co.*, Docket No. E-015/M-11-938, Order (Feb. 1, 2012).

2021. Once complete, Keeyask will generate an average of 4.4 million MWh of renewable energy annually.

Q. Were any other facilities required to be constructed to enable this capacity and energy to be delivered to Minnesota Power?

A. Yes. The delivery of the energy under the Manitoba Hydro PPA required the construction of two new 500 kV transmission lines. The first is the GNTL, a 500 kV high-voltage transmission line from the Canadian border to Grand Rapids, Minnesota, which completed construction ahead of schedule in February 2020. The second is the Minnesota-Manitoba Transmission Project ("MMTP"). Manitoba Hydro constructed this new transmission line from Winnipeg, Manitoba in Canada to the United States border to connect with the GNTL. This line went in service on June 1, 2020. Together, these two 500 kV lines establish the reliable international transmission path needed to reliably transport renewable energy to Minnesota Power customers over the long term.

Q. What are the benefits of the Manitoba Hydro PPA for Minnesota Power's customers?

A. The Manitoba Hydro PPA allows Minnesota Power to provide customers with a renewable energy source that has a unique combination of baseload supply characteristics, price certainty, and resource optimization flexibility that is not available in comparable alternatives for meeting customer requirements. The addition of the Manitoba Hydro resource in 2020 supports Minnesota Power's economic and sustainable supply strategy and significantly reduces Minnesota Power's carbon emissions, enhances fuel diversity, and furthers the Company's progress in incorporating more carbon-free resources into its power supply. The key benefits of the Manitoba PPA identified in the Commission-approved 2011 Manitoba Hydro petition included:

- The 250 MW of capacity and associated energy with its base load characteristics is projected to be a cost effective resource that meets Minnesota Power customer requirements;

- The pricing terms gives Minnesota Power the best cost certainty on energy supply versus available alternatives, especially considering uncertainties in the natural gas prices and carbon markets;
- This power supply aligns with the Company's previously approved Integrated Resource Plan recommending diversification away from Minnesota Power's preponderance of coal-based resources and reshaping its power supply portfolio to increase flexibility;
- This purchase significantly reduces Minnesota Power's percentage of energy supply that produces carbon and other emissions, thus reducing carbon and other emission penalty cost exposure; and
- The PPA provides valuable resource flexibility in conjunction with the Energy Exchange Agreement, leveraging the use of wind and hydro energy within Minnesota Power's supply to benefit customers.

Q. As part of its approval of the Manitoba Hydro PPA, did the Commission affirm these customer benefits of the Manitoba Hydro PPA?

A. Yes. In approving the Manitoba Hydro PPA, the Commission relied on an analysis conducted by the Minnesota Department of Commerce ("Department") to determine whether the Manitoba Hydro PPA was in the public interest.[15] After examining the terms of the Manitoba Hydro PPA, the Department concluded "that proposed PPA would provide the most appropriate resources for MP to meet its resource needs over the period 2020 through 2035" and that "the cost (price) of the proposed PPA is reasonable."[16]

[15] *In the Matter of Minn. Power's Request for Approval of a Power Purchase Agreement with Manitoba Hydro Co.*, Docket No. E-015/M-11-938, Order (Feb. 1, 2012).

[16] *In the Matter of Minn. Power's Request for Approval of a Power Purchase Agreement with Manitoba Hydro Co.*, Docket No. E-015/M-11-938, Dep't Comments at 25 (Nov. 18, 2011).

Q. How does Minnesota Power propose to recover the capacity costs for the Manitoba Hydro PPA in this rate case?

A. Consistent with the term of the Manitoba Hydro PPA, Minnesota Power proposes to recover the capacity payment cost of this PPA beginning on January 1, 2022 and continue for the next 13.5 years (i.e., May 31, 2035). Note that the energy cost associated with the PPA is recovered through the Company's Fuel and Purchased Energy Adjustment Clause.

Q: Why did Minnesota Power not request recovery of the capacity payments when the Manitoba Hydro PPA started in 2020?

A. Minnesota Power and Manitoba Hydro negotiated a delay as to when the capacity payments for the 250 MW PPA would begin. The 250 MW PPA began on June 1, 2020 when GNTL went in-service and energy from the PPA began flowing on the line. However, because Manitoba Hydro had permitting delays on MMTP, the parties negotiated contingencies in the event MMTP was not in-service at the same time as GNTL. As part of those contingencies, the parties agreed to delay the capacity payments under the 250 MW PPA until January 1, 2022. The 19-month delay in the capacity payments to Manitoba Hydro was a cost savings for customers, which was meaningful rate mitigation for customers at a much needed time in the midst of the COVID-19 pandemic. Minnesota Power did receive the 250 MW of capacity from the PPA and accredited it with MISO during this 19-month period. With the delay in capacity payments ending, Minnesota Power is requesting full recovery for Minnesota Power since capacity payments are generally not recoverable through the Company's Fuel and Purchased Energy Adjustment Clause.

IV. NEW CONTRACTS WITH MUNICIPAL UTILITIES

Q. Do the new contracts with 13 municipal wholesale customers discussed by Company witness Mr. Frederickson require Minnesota Power to add additional generation resources?

A. No. Minnesota Power currently serves the full requirements of the 13 Minnesota municipal wholesale customers and the new contracts have new contract terms, but it does not change the volume of energy Minnesota Power will sell to these municipal wholesale customers. Minnesota Power continuing to serve the municipal wholesale customer under a new contract will not require adding additional resources to serve those requirements and should help our other customers' rates over the contract period by providing revenue from ongoing MWh sales. Please refer to Direct Testimony of Company witness Mr. Frederickson for more details on the new contracts signed with municipal customers.

Q. How will Minnesota Power serve the municipal wholesale customer demand under the new contracts?

A Minnesota Power will serve the municipal wholesale customer requirements as part of the Company's management of its overall supply portfolio. This includes leveraging system resources and market purchases to serve municipal wholesale customer demand.

V. CONCLUSION

Q. Does this complete your testimony?

A. Yes.

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NON-PUBLIC DATA EXCISED

Asset-Based Loss of Load Wholesale Sales
2016 Actual

LINE No.		Executed due to Loss of Load	MWH	FUEL COST	SALES PRICE	NET ENERGY MARGIN
			TRADE SECRET DATA BEGINS			
1	MISO Market Sales	yes	[redacted]			
2	Alliant	yes				
3	Shell	yes				
4	MISO Costs	yes				
						TRADE SECRET DATA ENDS
	Total Wholesale Energy Sales		814,305	$ 14,370,894.15	$ 27,042,540.58	$ 12,671,646.43

Total Loss of Load Margin $ 12,671,646.43

	Loss of Load Margin Divide by Customer Group	Margin by Customer Group
TRADE SECRET DATA BEGINS		
Industrial Customers	[redacted]	
Municipal/Other Retail Customers		
		TRADE SECRET DATA ENDS

PUBLIC DOCUMENT
NON-PUBLIC DATA EXCISED

Asset-Based Loss of Load Wholesale Sales
2017 Actual*

LINE No.	Executed due to Loss of Load	MWH	FUEL COST	SALES PRICE	NET ENERGY MARGIN
		TRADE SECRET DATA BEGINS			
1	MISO Market Sales	[redacted]			
2	MISO Costs				
					TRADE SECRET DATA ENDS
	Total Wholesale Energy Sales	-	$ -	$ -	$ -

Rate Case test year. No loss of load sales included.

Total Loss of Load Margin $ -

PUBLIC DOCUMENT
NON-PUBLIC DATA EXCISED

Asset-Based Loss of Load Wholesale Sales
2018 Actual

LINE No.		Executed due to Loss of Load	MWH	FUEL COST	SALES PRICE	NET ENERGY MARGIN
			TRADE SECRET DATA BEGINS			
1	MISO Market Sales	yes	[redacted]			
2	NextEra	yes				
3	Shell	yes				
4	MISO Costs	yes				
						TRADE SECRET DATA ENDS
	Total Wholesale Energy Sales		180,160	$ 4,077,008.58	$ 5,601,657.89	$ 1,524,649.31

Total Loss of Load Margin $ 1,524,649.31

	Loss of Load Margin Divide by Customer Group	Loss of Load Margin Margin by Customer Group
TRADE SECRET DATA BEGINS		
Industrial Customers	[redacted]	
Municipal/Other Retail Customers		
		TRADE SECRET DATA ENDS

Asset-Based Loss of Load Wholesale Sales
2019 Actual

LINE No.		Executed due to Loss of Load	MWH		FUEL COST	SALES PRICE	NET ENERGY MARGIN
			TRADE SECRET DATA BEGINS				
1	NextEra	yes	[redacted]				
2	Shell	yes					
3	MISO Costs	yes					
							TRADE SECRET DATA ENDS
	Total Wholesale Energy Sales		230,762	-	$ 5,213,168.56	$ 7,504,412.00	$ 2,291,243.44

Total Loss of Load Margin $ 2,291,243.44

Loss of Load Margin	Divide by Customer Group	Margin by Customer Group
TRADE SECRET DATA BEGINS		
Industrial Customers	[redacted]	
Municipal/Other Retail Customers		
		TRADE SECRET DATA ENDS

Asset-Based Loss of Load Wholesale Sales
2020 Actual

LINE No.		Executed due to Loss of Load	MWH	FUEL COST	SALES PRICE	NET ENERGY MARGIN
			TRADE SECRET DATA BEGINS			
1	NextEra	yes	[redacted]			
2	Macquarie	yes				
3	Shell	yes				
4	MISO Costs	yes				
						TRADE SECRET DATA ENDS
	Total Wholesale Energy Sales		518,056	$ 13,059,320.05	$ 13,575,112.80	$ 515,792.75

Total Loss of Load Margin $ 515,792.75

Loss of Load Margin

	Divide by Customer Group	Margin by Customer Group
TRADE SECRET DATA BEGINS		
Industrial Customers	[redacted]	
Municipal/Other Retail Customers		
		TRADE SECRET DATA ENDS

PUBLIC DOCUMENT
NON-PUBLIC DATA EXCISED

Asset-Based Loss of Load Wholesale Sales
2021 Projected Year

LINE No.		Executed due to Loss of Load	MWH	FUEL COST	SALES PRICE	NET ENERGY MARGIN
			TRADE SECRET DATA BEGINS			
1	NextEra	yes	[redacted]			
2	Macquaire	yes				
3	Shell	yes				
4	MISO Costs	yes				
	Total Wholesale Energy Sales		1,394,904	$ 35,081,625.63	$ 37,814,053.00	$ 2,732,427.37

Total Loss of Load Margin $ 2,732,427.37

	Loss of Load Margin	
	Divide by Customer Group	Margin by Customer Group
	TRADE SECRET DATA BEGINS	
Industrial Customers	[redacted]	
Municipal/Other Retail Customers		
	TRADE SECRET DATA ENDS	

PUBLIC DOCUMENT
NON-PUBLIC DATA EXCISED

Asset-Based Loss of Load Wholesale Sales
2022 Test Year*

LINE No.	Executed due to Loss of Load	MWH	FUEL COST	SALES PRICE	NET ENERGY MARGIN
		TRADE SECRET DATA BEGINS			
1	MISO Market Sales	[redacted]			
2	MISO Costs				
					TRADE SECRET DATA ENDS
	Total Wholesale Energy Sales	-	$ -	$ -	$ -

**Rate Case test year. No loss of load sales included.*

Total Loss of Load Margin $ -

	Loss of Load Margin	
	Divide by Customer Group	Margin by Customer Group
	TRADE SECRET DATA BEGINS	
Industrial Customers	[redacted]	
Municipal/Other Retail Customers		
	TRADE SECRET DATA ENDS	