Direct Testimony and Schedules
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-23-155

Exhibit ________

POWER SUPPLY STRATEGY AND ALIGNMENT

November 1, 2023

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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, strategic initiatives, project development, Midcontinent Independent System Operator, Inc. ("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 16 years with Minnesota Power in Duluth, Minnesota, and being part of the energy transformation the Company has undergone with its *EnergyForward* strategy.

Q. What is the purpose of your testimony?

A. I provide information on changes to Minnesota Power's power supply and the MISO power market. I discuss the importance of Minnesota Power having the ability to account for both revenues and costs related to capacity revenue transaction and expense. I also provide information on why, from a market participant perspective, it is important for our generating plant chemicals and reagents, as well as nitrogen oxide ("NOx") allowances, to flow through the Company's fuel adjustment clause ("FAC") rider ("FAC Rider").

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

- MP Exhibit ___ (Pierce), Direct Schedule 1 – Capacity Transactions 2020 to 2024; and
- MP Exhibit ___ (Pierce), Direct Schedule 2 – Capacity Transactions Three Years or Less 2020 – 2024.

II. MINNESOTA POWER'S POWER SUPPLY STRATEGY

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 *EnergyForward* 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 the important commitments we have made through Minnesota Power's 2021 Integrated Resource Plan, Docket No. E015/RP-21-33 ("2021 IRP"), approved by the Minnesota Public Utilities Commission ("Commission") in early 2023, and what this means for the Company's power supply strategy and our requests in this Rate Case.

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

A. Under its *EnergyForward* resource strategy, Minnesota Power is delivering 50 percent renewable energy to customers and is the first Minnesota utility to achieve this milestone. The Company is committed to achieving an 80 percent reduction in carbon emissions by 2035 compared to 2005 levels and is working towards the recent carbon-free energy generation standard of delivering 100 percent carbon-free energy by 2040. While delivering increasingly clean energy to customers, *EnergyForward* is also aimed at delivering safe, reliable, and affordable energy to customers across a smarter grid that is increasingly resilient.

Over the past 15 years, the Company has undertaken an intentional effort to increase its deployment of renewable energy. In 2006 and 2007, Minnesota Power began purchasing the entire output of the Oliver County Wind Energy Center 1 and 2 (just under 100 megawatts ("MW")), wind farms built and operated by NextEra Energy in North Dakota. In 2008, Minnesota Power constructed the Taconite Ridge Energy Center, the first commercial wind generating station in northern Minnesota. The Bison Wind Energy Center ("Bison") in North Dakota came next, with four phases of the project completed between 2010 and 2015. Bison, now the largest wind farm in North Dakota with a capacity of just under 500 MW, leverages premier wind resources to deliver carbon-free energy to the Company's customers. In late 2020, Minnesota Power added 250 MW of wind energy through a Power Purchase Agreement ("PPA") with the completion of the Nobles 2 Wind Farm. Combined, these wind projects added more than 850 MW of renewable electricity to the Company's generation portfolio. Most recently, the Commission approved Minnesota Power's 2021 IRP that will have the Company add another 700 MW of new renewable resources to its power supply by 2030. I discuss the Company's future plans and the significant development needed to accomplish this next exciting step in our transformation in my Direct Testimony below.

As the state's largest producer of hydroelectric power with 10 federally licensed facilities, Minnesota Power is well-versed in the power potential of water. In 2011 and 2014, the Company signed 15- and 20-year agreements to purchase 383 MW of carbon-free hydroelectricity from Manitoba Hydro beginning in 2020. To facilitate this purchase, in 2020, Minnesota Power completed construction of and energized the Great Northern Transmission Line ("GNTL"), a 500 kilovolt ("kV") transmission line to carry this Canadian hydropower to the heart of the Company's industrial base on the Iron Range.

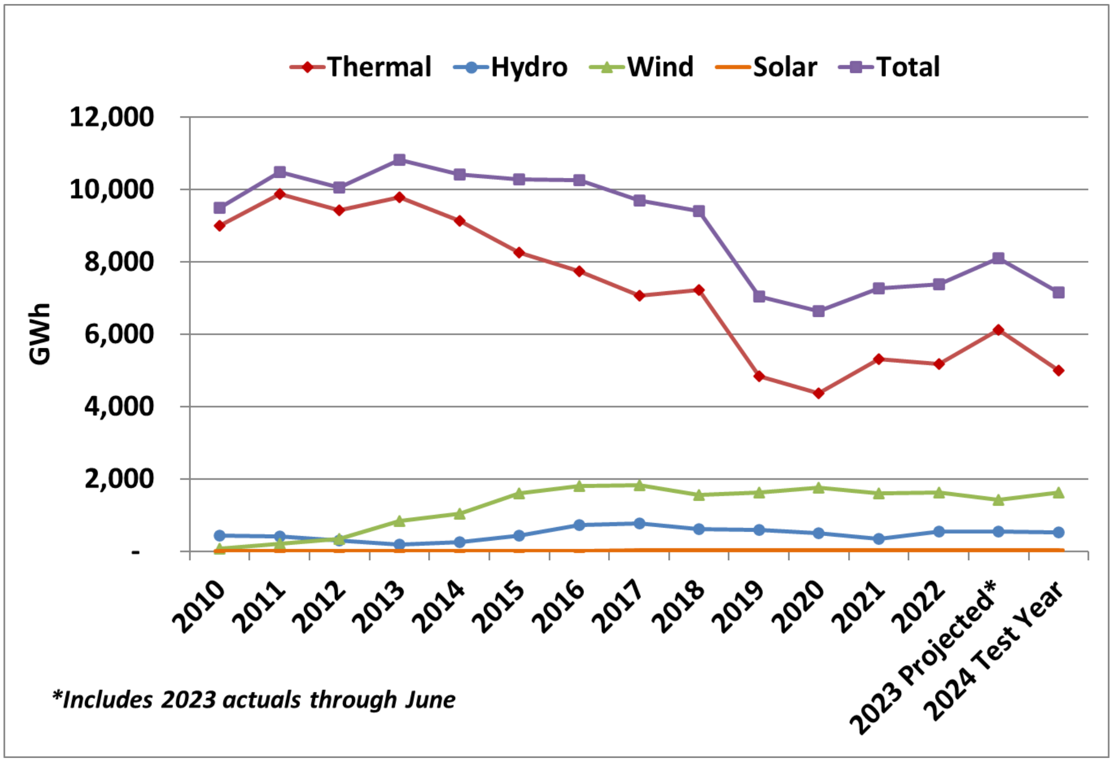
Q. Does this strategy include solar generation?

A. Yes. As an integral part of *EnergyForward*, Minnesota Power is further diversifying its renewable energy options with distributed solar energy generation. For example, the Company worked with the Minnesota National Guard to build a 10 MW solar energy project on the grounds of Camp Ripley near Little Falls, Minnesota ("Camp Ripley Solar Project") in 2016. At the time of installation, the Camp Ripley Solar Project was one of the largest solar energy installations at any National Guard base in the United States and helps meet the Department of Defense's resiliency and energy security goals. Minnesota Power has most recently added approximately 20 MW of additional solar generation in 2022 and 2023 in northern Minnesota, which has aligned with the Minnesota Solar Energy Standard ("SES") requirements, aided in the local economic recovery from the COVID-19 pandemic, invested back in a community impacted by a facility ceasing coal operations, and implemented additional diversity, equity, and inclusion procurement practices. In addition, Minnesota Power's SolarSense and community solar garden programs have added small scale solar resources to meet the SES's 10 percent carve out requirements for systems under 40 kilowatts ("kW").

Q. How has this strategy impacted the overall generation portfolio?

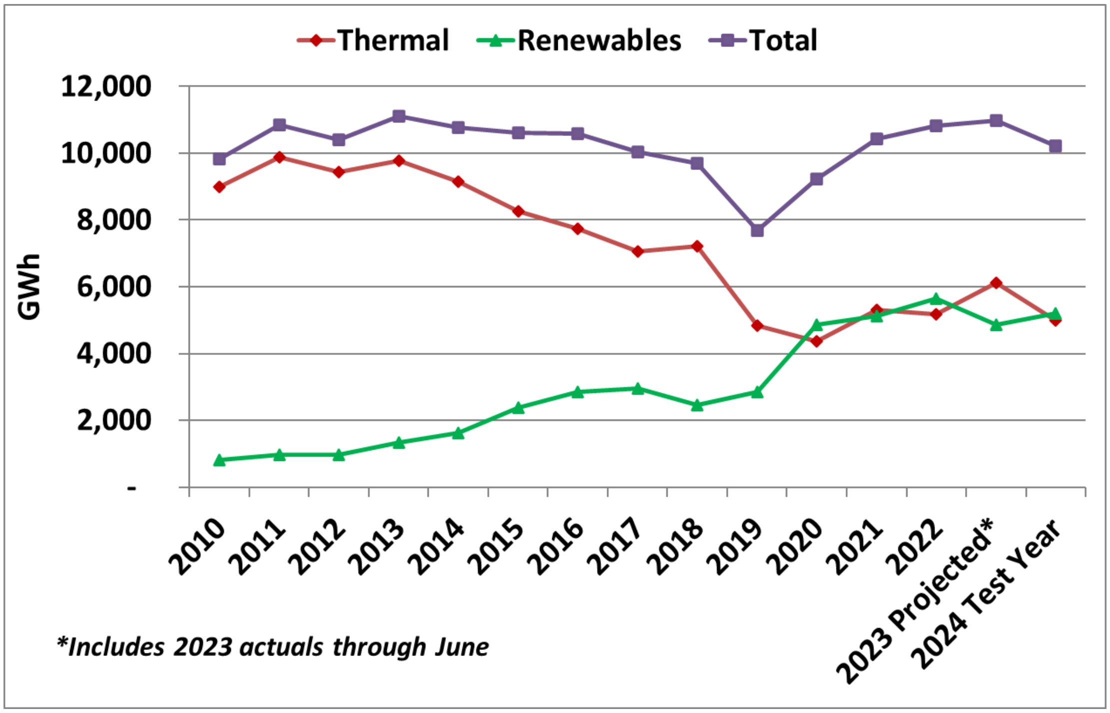
A. As shown in Figure 1, since Minnesota Power initiated its *EnergyForward* strategy in 2010, the Company has removed approximately four million megawatt-hours ("MWh") on average of thermal generation output from its owned power supply portfolio. Over the same period, approximately two million MWh of Company-owned renewable generation was added via the Bison 1, 2, 3, and 4 Wind Facilities. As discussed above, Minnesota Power also procured additional power supply resources through renewable bilateral contracts to further replace the energy removed as coal generation was retired, idled, or remissioned to ensure enough energy and capacity was available for customers to provide a reliable portfolio for the Company's electric supply.

Figure 1. Minnesota Power Owned Generation Output



As shown in Figure 2, which includes both owned and purchased resources, 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 ("RES") a decade early in 2015 and will continue to grow its portfolio of clean energy as it continues to implement its 100 percent carbon-free strategy over the coming years.

Figure 2. Total Power Supply



Q. What does this mean for the Company as it looks to further transition its generation fleet to reduce carbon emissions?

A. The transition to this higher renewable penetration in our portfolio has introduced new operational variability into the power supply. The variability of wind and solar in comparison to the more available thermal generation has created the need for new tools, procedures, and coordination with the broader footprint. Our thermal generation fleet has been experiencing new operational missions including new fuel types and dispatch profiles, which drive variable fuel and reagent requirements, which move with the availability of the renewable energy being deployed in the region.

Further, the need for additional transmission support has also been identified through local and regional planning to maintain the critical reliability required for customers. As Minnesota Power moves beyond 50 percent carbon-free generation in its power supply portfolio of owned assets and PPAs, careful consideration of what reliability attributes will be needed in the resource portfolio additions will be imperative for success. I demonstrate the new variable components later in my testimony.

Q. Please provide updates on the steps the Company has taken to achieve increased renewable generation for its customers.

A. Since Minnesota Power's 2021 Rate Case, Docket No. E015/GR-21-335 ("2021 Rate Case"), its most recent rate case filing, Minnesota Power has secured the output of three regional utility scale solar projects in Northeastern Minnesota. The three projects add approximately 22 MW of solar resources to the Company's system (enough to power 4,000 homes) and were undertaken in response to the Commission's request for utilities to move up the timetables and support pandemic relief through energy project development. These three projects incorporated local labor, local panel manufacturing procurement, tribal engagement, and apprentice programs while economically benefiting the host communities of the Laskin Energy Center ("Laskin") (remissioned coal facility), Sylvan Hydro, and Duluth Solar.

On January 9, 2023, the Commission issued its order unanimously approving the next phase of Minnesota Power's ambitious *EnergyForward* vision of providing 100 percent carbon-free energy.

Minnesota Power's 2021 IRP was approved to set in motion the next important steps in Minnesota Power's journey to procure cost-effective resources to meet its customer and renewable energy needs by 2030. These steps include acquiring at least 300 MW, and up to 400 MW, of wind with at least 200 MW in service by 2026 as practicable and acquiring up to 300 MW of regional/in-service territory or net-zero solar and implementing storage demonstration projects of at least 100 MWh, and up to 500 MWh, by 2026. These additional renewable resources along with Minnesota Power's commitment to cease coal-fired operations at the Company's Boswell Energy Center ("BEC") Unit 3 ("BEC3") by 2030 and BEC Unit 4 ("BEC4") by 2035 will bring Minnesota Power even closer to its carbon-free goal.

Q. What additional commitments did the Company make in its 2021 IRP?

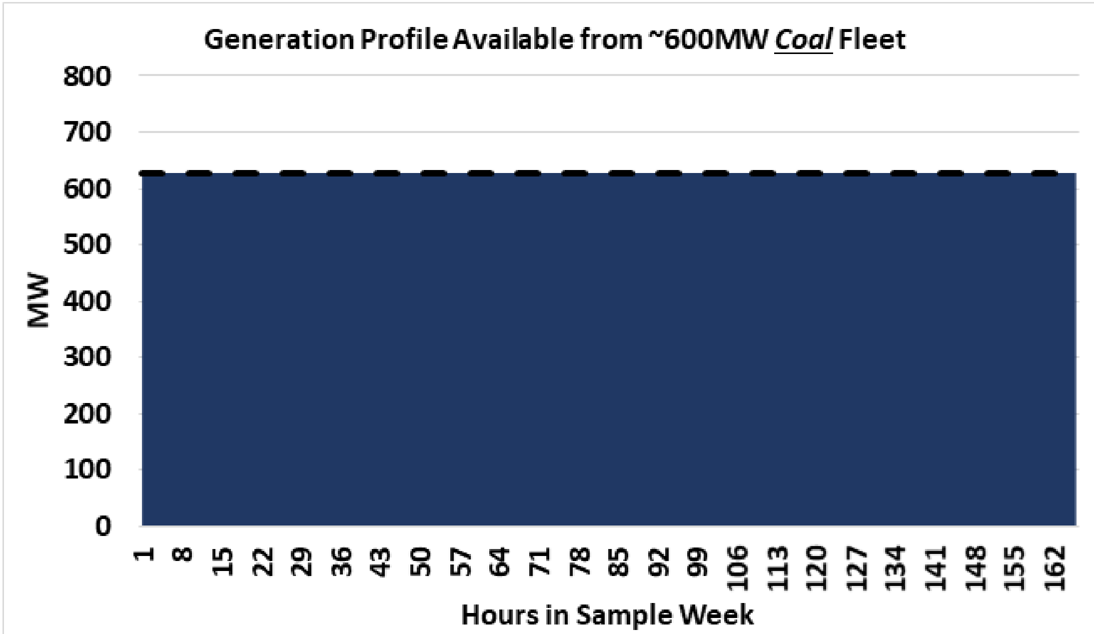
A. As Minnesota Power looks ahead to the next 15 years, the Company finds itself with a strong foundation of clean-energy leadership, having ensured both reliability and affordability while transitioning a system from being almost entirely based on coal generation to one of the highest renewables in the state today. Minnesota Power has taken a broad view and received approval and stakeholder agreement on its 2021 IRP that was supported by environmental advocates, labor, and our host community. Minnesota Power is offering more renewable opportunities for customers in a truly collaborative way that values our workers and communities in this historic energy transition. As we continue to transition, Minnesota Power will be considering all customers in the transformation to ensure there is no one left behind as we move forward.

Building on an extensive process that involved discussion with customers and stakeholders over the past two years, Minnesota Power announced it had reached a joint agreement with stakeholders that included clean energy organizations, labor groups, the City of Cohasset, and Itasca County on November 7, 2022. The City of Cohasset and Itasca County are host communities for BEC, Minnesota Power's last remaining coal-fired power plant. The Commission unanimously approved all the elements of the joint agreement in its order on the 2021 IRP.

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 power supply portfolio that is less dispatchable, as compared to the Company's previous flexible, controllable baseload operations. This is because the new renewable generation additions do not provide energy that is generally available 24 hours a day, seven days a week, and on command like the highly available and dispatchable thermal generation that Minnesota Power previously held. Figure 3 illustrates the availability of a 600 MW coal resource.

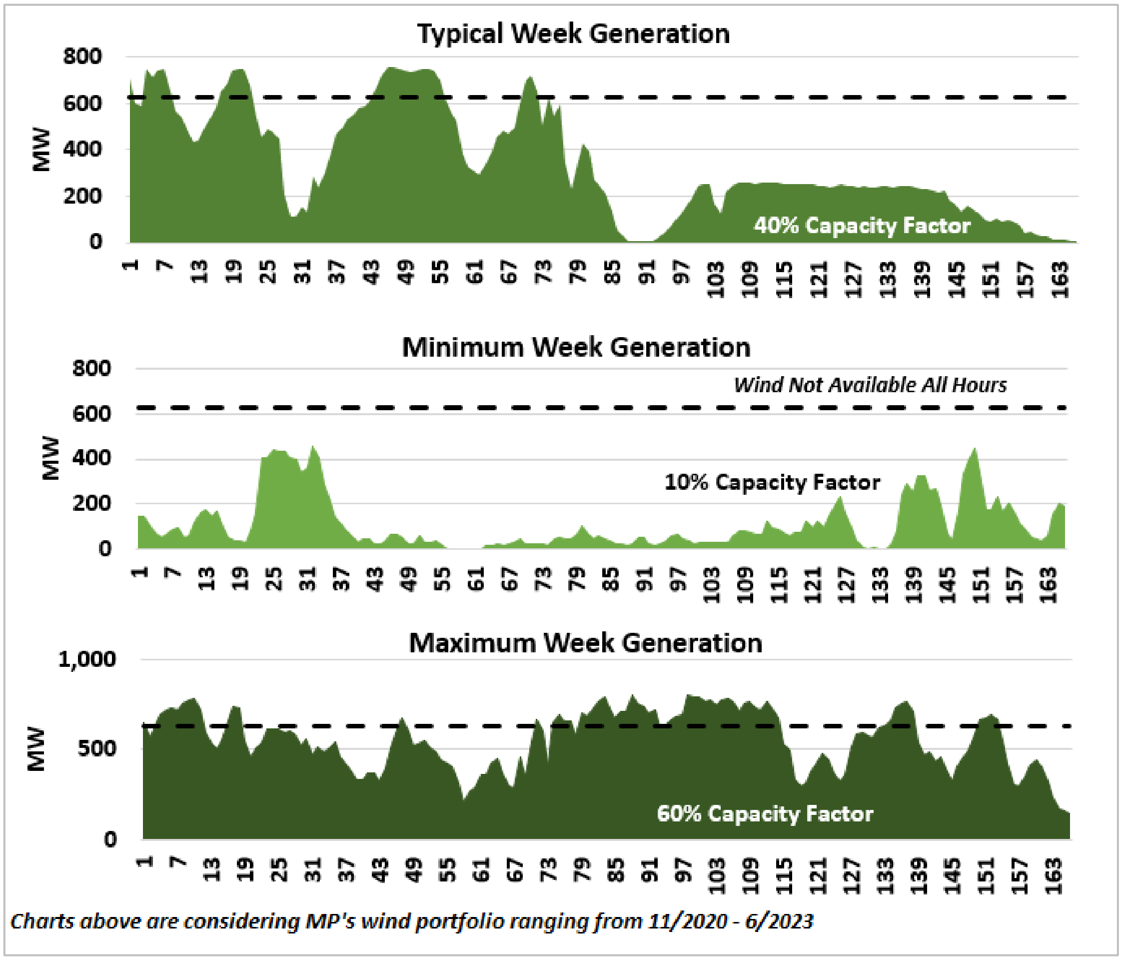
Figure 3. Generation Profile Available



While the generation from a coal resource is highly available, the transformation within Minnesota Power's portfolio and the MISO market continues to transform the power supply landscape making traditional baseload generation move and dispatch in a pattern more like a variable resource. The baseload generators that remain available to the system are being asked to be nimbler and follow the more variable supply and demand needs of the region.

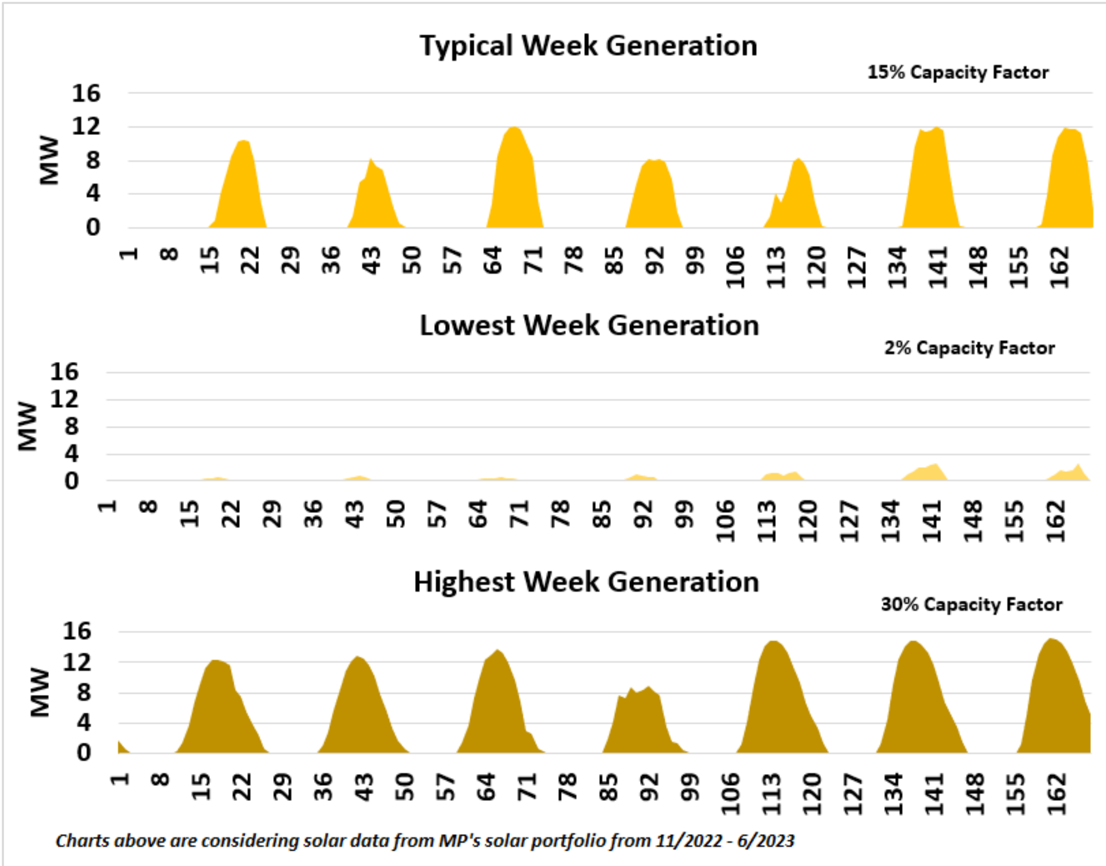
As shown in Figure 4, the hourly wind availability profile is drastically different from the block profile for the coal fleet example that it is being asked to replace. This is due to the variable weather patterns that create wind generation profiles for each renewable facility; while the machines may be mechanically available, if there is not enough wind to turn the turbines, the energy is not available for customers. There are periods when the wind energy exceeds the 600 MW capability of the coal fleet example and several periods when it is lower. Furthermore, the capacity factor or available energy in the 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 for customers.

Figure 4. Hourly Wind Profile for a Week



As Minnesota Power continues to add solar generation to the system in larger volumes per its 2021 IRP, the variable profile of solar will increase the daily variability of the power supply, and the Company must be prepared to manage this evolving dynamic. While solar has a more consistent daily potential, the weather patterns, including cloud and snow cover and storm dynamics, create daily variations in the availability of this renewable resource. Figure 5 demonstrates the solar output from Minnesota Power's power supply from the Camp Ripley Solar Project and Laskin, and despite the daily cycle of the sun, there is still additional variability in the solar output.

Figure 5. Hourly Solar Generation Profile



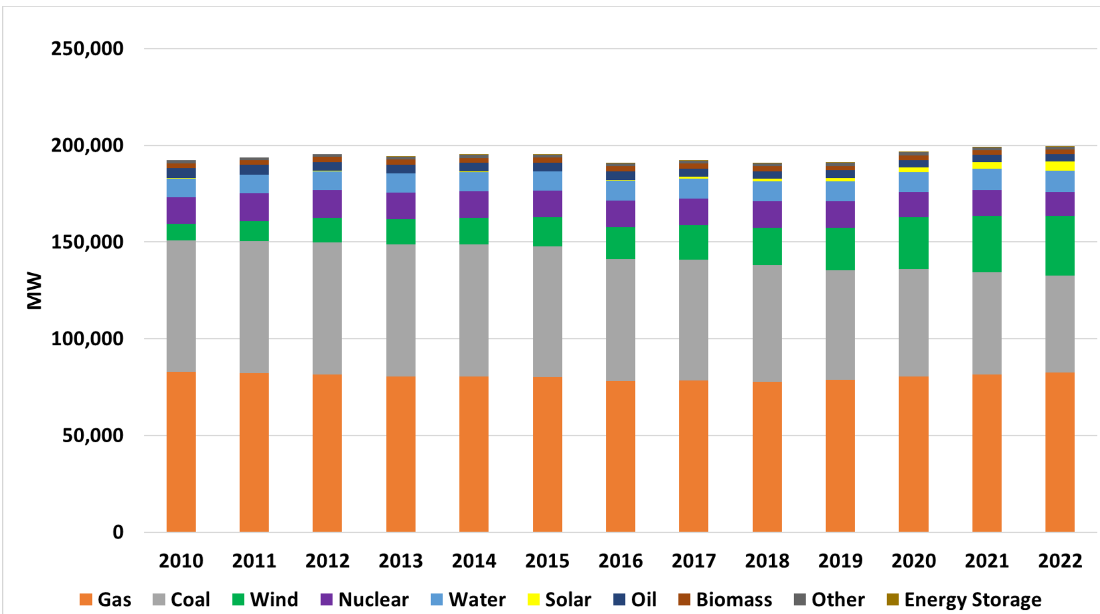
Minnesota Power's transition towards a carbon-free energy supply has significantly increased variability in its daily power supply portfolio. The thermal fleet in Minnesota Power's power supply portfolio has historically contained more fuel availability and certainty than the renewable generation sources that have been utilized to help replace these resources. The clean energy transformation underway on the energy grid will require accommodation for the new attributes that are being added to the power supply.

Q. How has the changing Power Supply in MISO changed the dispatchability of the thermal units?

A. MISO dispatches generation based on the offers submitted by market participants and the availability of the resources in the region. Fuel, reagents, environmental allowances, production tax credits, and wear and tear are components of an energy offer for all resources. The available generation combined with the offer components drive how MISO dispatches the generation across the system—typically the lowest cost generation source is dispatched first and then supplemented with higher cost generation to meet the load demand on the system.

As noted in Figure 6,[1] MISO renewable resources have increased by more than 28,000 MW and coal-fired generation resources have decreased by more than 18,000 MW since 2010.

Figure 6. MISO Generation by Fuel Type



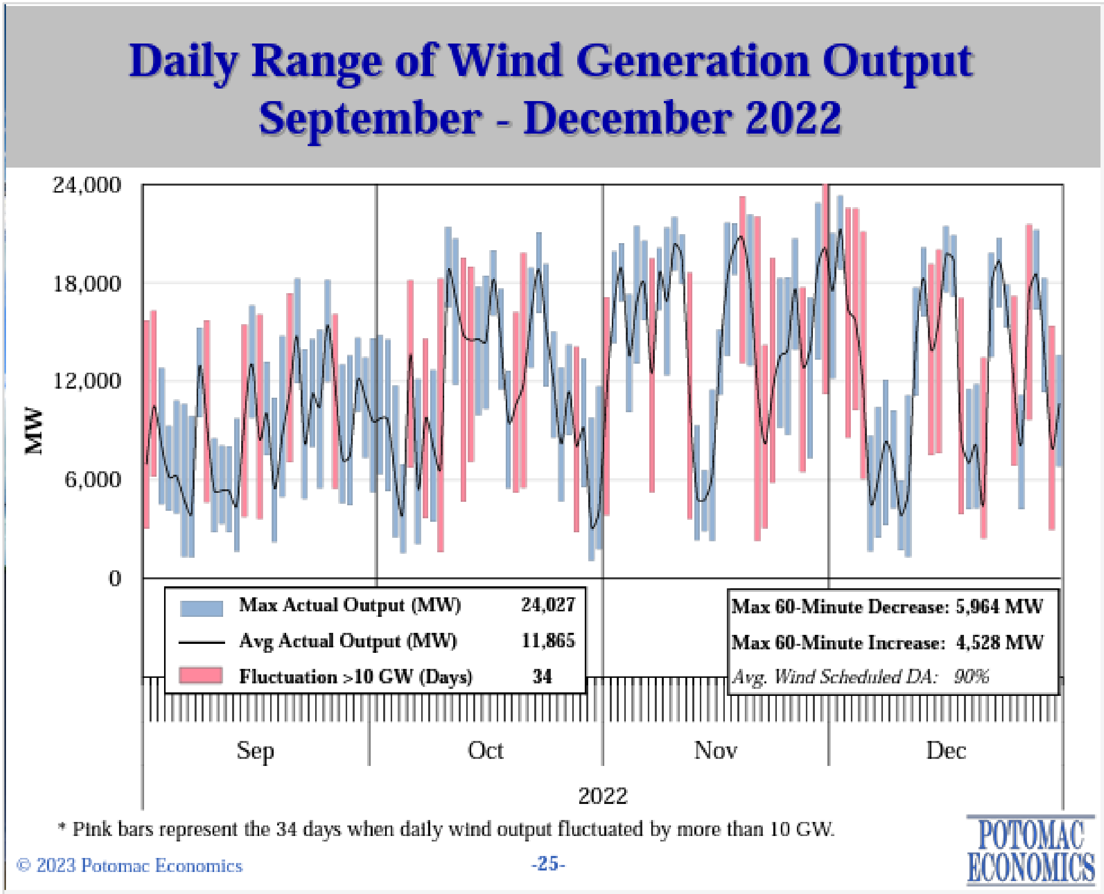
As renewables have increased in the region, there has also been a need for all thermal generation to operate more dynamically to both make room for the wind and solar when it is abundant and react to fill in when the wind and solar are not available. The variable profile of the wind and solar has been an operational change for MISO. While the market has effectively dispatched thermal generation around the growing renewable generation fleet, MISO sees the same wind variability themes that Minnesota Power has as its own system has added wind and solar to its portfolio.

[1] S&P Capital IQ Historical & Future Power Plant Capacity as of 7.28.2023

In the last decade, the wind resource penetration in MISO has increased as coal resources have operated at reduced capacity factors or retired. As noted in the Summary of 2022 MISO State of the Market Report by Potomac Economics, the average hourly wind output grew 23 percent over 2021 and served an average of 23.8 percent of hourly load in the Midwest, which was up from 18.5 percent in 2020.[2] The fluctuation in wind has also grown. Figure 7 illustrates how the wind varied by more than 10 gigawatts ("GW") on 34 days during the period from September to December in 2022.[3] As of May 2023[4], MISO has 30 GW of registered and in-service wind capacity while there is 5.6 GW of registered solar capacity with 2.8 GW of in-service solar capacity. Figure 8 below also highlights how the generation production by fuel mix can vary on a monthly basis.

[2] Summary of 2022 MISO State of the Market Report (page 22).
[3] Summary of 2022 MISO State of the Market Report (page 25): https://cdn.misoenergy.org/20230713%20MSC%20Item%2006%20IMM%20State%20of%20the%20Market%20Recommendations629500.pdf.
[4] MISO Monthly Operations Report May 2023.

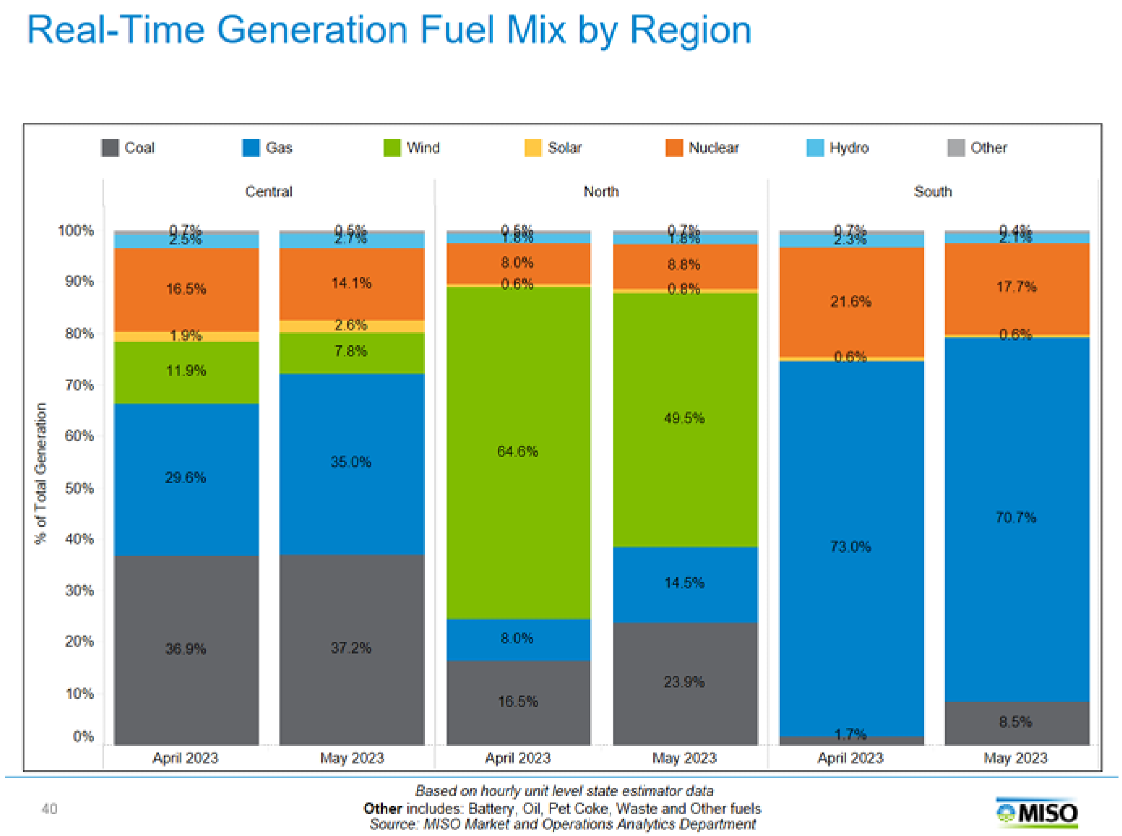
Figure 7. Wind Generation Output 2022



MISO's generation mix over the broad region is also diverse. Minnesota Power is in the "North" region of MISO where there is a larger penetration of wind resources that impact the daily dispatch. Figure 8 highlights the diverse real-time generation mix by region for April and May of 2023 as noted in the MISO Monthly Operations Report dated May 2023.[5]

[5] MISO Monthly Operations Report: https://cdn.misoenergy.org/202305%20Market%20and%20Operations%20Report629380.pdf.

Figure 8. MISO Generation Fuel Mix – 2023



During the months of April and May in 2023, wind generation accounted for half of the energy dispatched for the North Region. The variability of wind in the North, the area in which Minnesota Power operates, is at a higher percentage than other MISO regions where thermal gas and coal are still more prominent (South and Central).

Solar and wind generation resource amounts are expected to continue to grow in the MISO footprint. MISO's interconnection queue consists of more than 1,400 active projects totaling over 240 GW and more than half of these are solar projects.[6] Given the timing of expected fluctuations in solar output, large quantities of solar will also likely lead to significant changes in dispatch, ramping, and other generation attributes needs as the clean energy transformation continues. The wind and solar resource mix changes

[6] Generator Interconnection (updated Aug. 2, 2023): https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf.

in the region have historically had, and will continue to have, a significant impact on thermal generation. Minnesota Power's own thermal fleet has experienced significant changes due to retirement, remission and moving to new operation modes like economic dispatch.

Q. How has the MISO market price volatility impacted the dispatchability of the generation fleet?

A. The MISO price profile has been adapting in response to the changes in the overall generation fleet to a more dynamic portfolio of generation. Driven by several factors, the removal of thermal coal-fired generation in the region along with more variable generation on the system has created additional volatility in the MISO market price that each thermal generation asset must react to daily.

As noted in the MISO Independent Market Monitor's 2022 Status of the Market Report,[7] the MISO all-in price in 2022 rose 77 percent in 2022 to an average of $73 per MWh. The increase was largely caused by rising fuel prices and the effects of the Winter Storm Elliott. Energy prices also increased by 65 percent to an average price of $65 per MWh due to multiple factors including a 36 percent increase in natural gas prices; a reduction in coal conservation measures which began to ease in the fall; the effects of Winter Storm Elliott in December; and a two percent increase in average load. The higher all-in price reflects the contribution of the shortage price in the capacity market in the Midwest from June 2022 to May 2023 when the market cleared at Cost of New Entry ("CONE"). Despite higher gas prices that made coal-fired generation much more profitable to run, the energy output share from coal-fired generation fell in 2021, driven by coal supply chain constraints that reduced coal production. Controlling for the change in gas prices, the implied marginal heat rate measure of prices was relatively unchanged from 2021, increasing slightly due to Winter Storm Elliott in December.

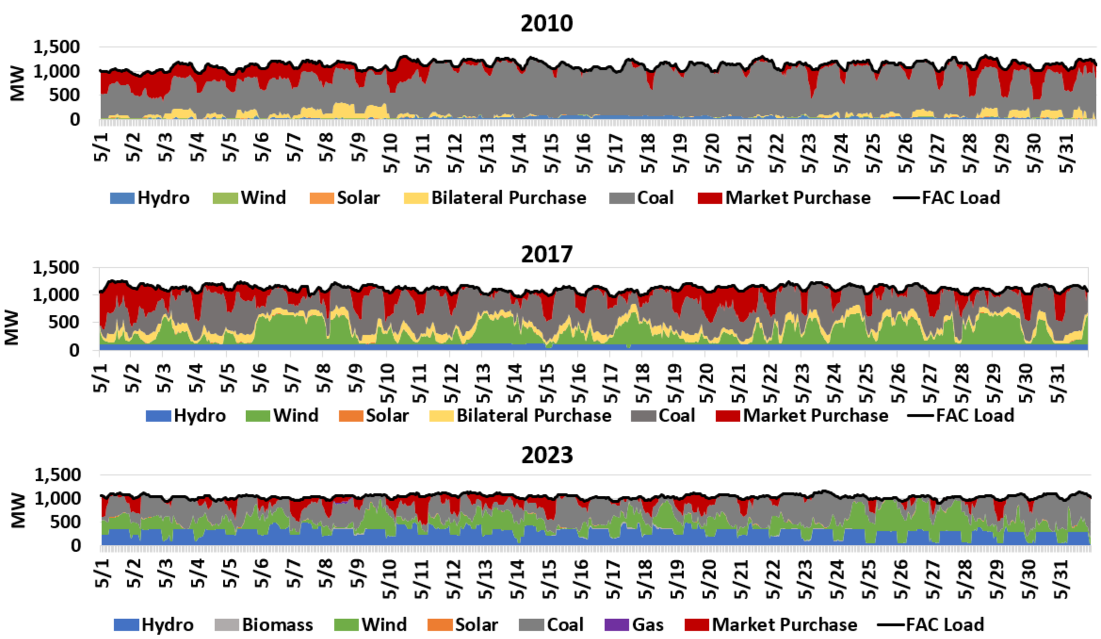
[7] https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf.

By the spring of 2023, natural gas prices had fallen by two-thirds since the spring of 2022, which impacted energy prices, coal resource dispatch, natural gas resource dispatch, congestion, and resource net revenues. The significant drop in natural gas prices due to increased natural gas supply affected resource scheduling and dispatch as Minnesota Power has seen increased ramping from coal fired resources as well as increased dispatch from economic natural gas fired resources.

The volatility between thermal fuel prices and availability coupled with the growing renewable portfolio in the MISO footprint adds considerable variability and uncertainty in both market prices and generation dispatch.

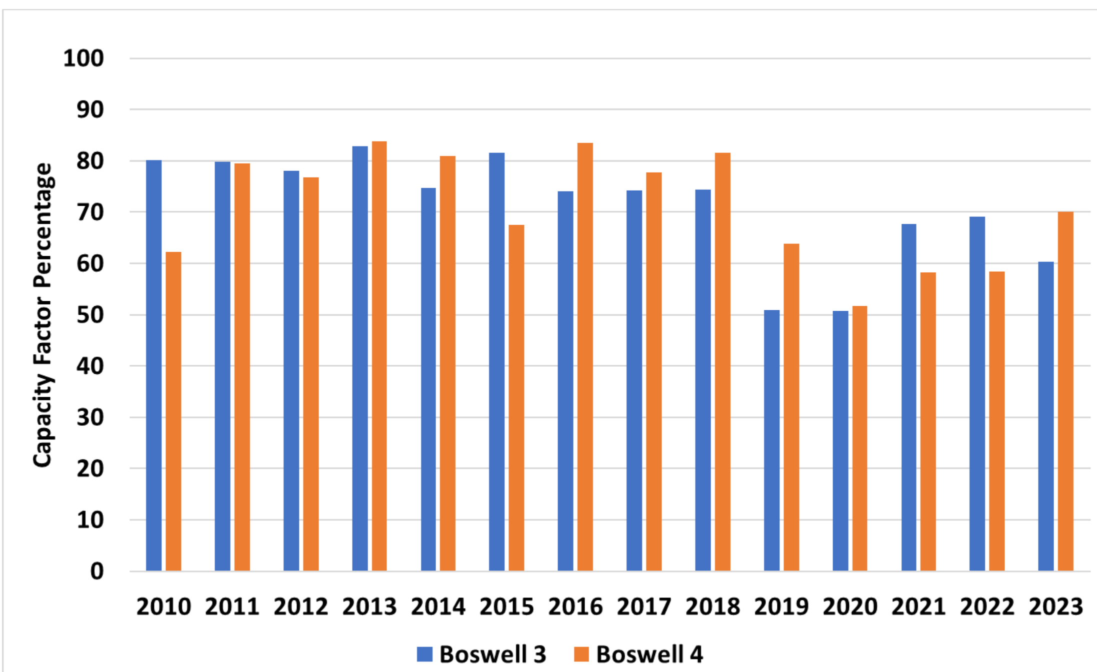
To demonstrate how this variability has impacted Minnesota Power's energy supply portfolio and its thermal generation, Figure 9 includes a power supply comparison between the month of May for three separate years throughout the *EnergyForward* evolution to 50 percent renewable energy—2010, 2017, and 2023.

Figure 9. Minnesota Power Customer Power Supply



The 2010 data identifies how baseload coal supported load in a consistent manner with daily patterns of operation. As Minnesota Power added more renewable energy to its portfolio with its *EnergyForward* strategy by adding significant wind energy capability, the May 2017 power supply demonstrates that there was considerably more variability in the thermal energy serving customers. By May of 2023, Minnesota Power's renewable power supply had reached 50 percent levels on an annual basis as additional hydro and wind generation resources were added to the system. This has further confirmed that the baseload coal-fired generation serving customers has become more variable and is serving a prominent reliability and economic role to be available to serve customers when the renewable energy is not available. As noted in Figure 10, the capacity factor at BEC was 77 percent from 2010–2015 and has decreased to 60 percent in the 2019–2023 time period with its more flexible operations and supporting the core reliability of the more renewable system in the region.

Figure 10. Annual Historical BEC Capacity Factors



More broadly throughout the MISO region, there is an observable change in thermal unit dispatch with the integration of additional renewable resources in the region. A month-to-month comparison of May 2023 and May 2020 for MISO's footprint identified a 36 percent increase in wind generation and 29 percent increase in natural gas utilization for energy dispatch, while thermal coal and nuclear generation resources declined by three percent.[8]

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 remained relatively consistent since 2010, as the Company thoughtfully retired and remissioned its existing coal-fired fleet and achieved a power supply that includes 50 percent renewable energy. Annually, there is minimal change to the level of energy Minnesota Power purchased or self-generated. For example, since 2010, thermal generation decreased by 4 GW, and renewable generation increased by 4.4 GW. However, due to the intermittent characteristics of the renewable energy resources of equivalent nameplate capacity of the retired or re-missioned coal-fired generation, Minnesota Power is seeing increased interaction by 10 percent with the MISO grid to match real-time hourly generation with load as its thermal dispatchable fleet requires additional ramping support to move with the dynamic wind and solar supply changes.

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, are very specific for each utility—they are dependent on each utility's 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 11. The average annual energy price in this figure does not illustrate 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 illustrate that the energy market price outlooks can change significantly within a year, as represented by the dashed line that shows a

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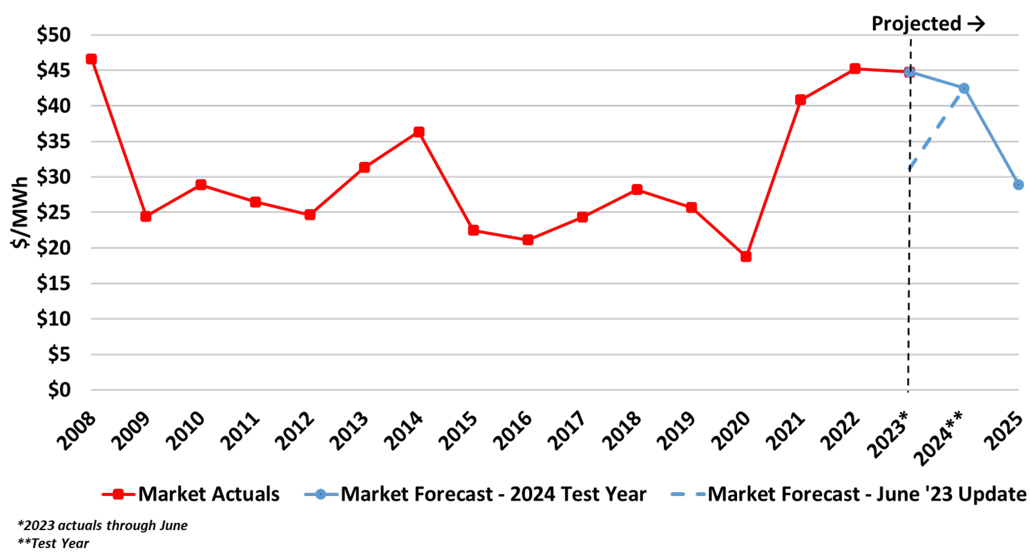
[8] MISO Informational Forum Presentation June 2020: https://cdn.misoenergy.org/202006%20Informational%20Forum%20Presentation455418.pdf.

30 percent decrease in market price outlook for the second half of 2023 from the budgeted value. The market price outlook for 2024 shows an increase of 36 percent from the mid-2023 projections, but also shows an overall decrease from 2023 budgeted levels driven by declining natural gas prices that have an impact on the energy market price. With the exception of 2014, and the energy market increases experienced from 2021 to the present year, the MISO energy price has been relatively stable since 2009; however, market stability is becoming more uncertain with the power supply evolution.[9]

Figure 11. Average Energy Market Price for MP[10]



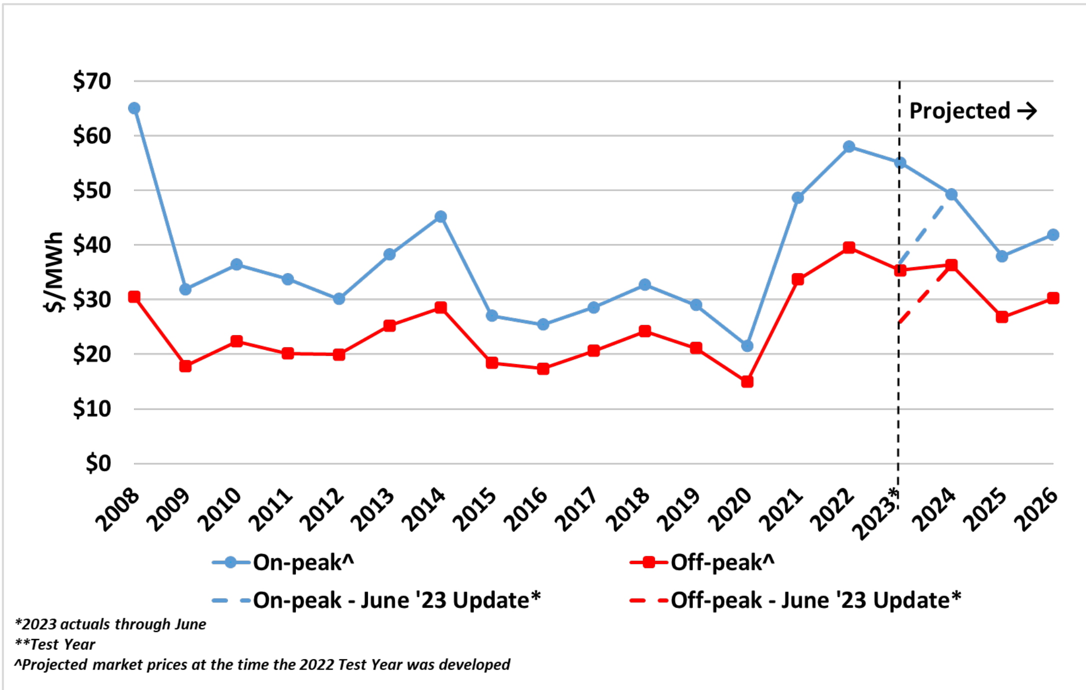
Q. Do MISO prices vary depending on whether power is being bought or sold during on-peak or off-peak periods of each day?

A. Yes. As shown in Figure 12, 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 2022 was approximately 40 percent, which is expected to continue through 2024 based on current outlooks. The recent trend in market price outlooks shown in the dashed lines support

[9] The energy price projection is provided by a third-party forecast from IHS Global Insight.
[10] The Market Forecast used in the "2024 test year" is based on the market price outlook used in the 2024 Budget, which was based on the forward energy market outlook in April 2023. The "June '23 Update" is based on the forward energy market outlook as of June 2023.

the projected price differential between the on-peak and off-peak period, which remains the same at 40 percent. Thus, if Minnesota Power needs additional power or has surplus to sell with the MISO market, the price can vary significantly depending on when the energy is needed or available.

Figure 12. Energy Market Prices On vs. Off-Peak



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

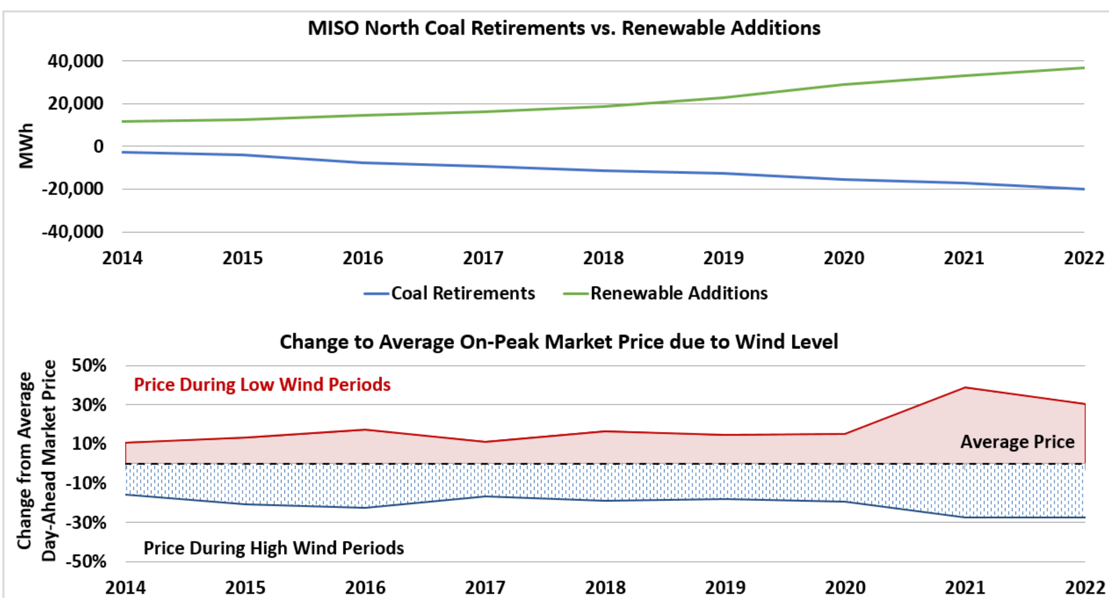
A. Minnesota Power's surplus and deficit profile for MISO purchases and sales has been changing, and with the addition of predominately wind generation, now follows variable wind generation patterns. When the wind energy availability is higher, Minnesota Power typically has a surplus and is selling energy. When wind energy availability is low, there is typically a deficit and Minnesota Power is purchasing energy. Today, the Company's 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 balances, 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 balance with demand 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 are reducing the average market price. Thus, when Minnesota Power makes a sale because its system is surplus when the wind is generating high, the market prices are often lower.

Figure 13 illustrates the impact wind variability has on actual MISO market price since 2014. For example, in 2022, on-peak market prices were 30 percent higher than the average in low wind periods and 27 percent lower than average in the high wind periods; and we have seen as high as 39 percent difference during low wind periods in 2021.

Figure 13. 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 above highlights this trend by comparing the increasing renewable build-out in MISO North[11] 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. While more recently higher natural gas prices and congestion on the grid are driving costs in a higher direction, it demonstrates the new variability the region is feeling with higher intermittent energy supply. 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 market prices affect Minnesota Power's ability to recover lost revenue caused by the unexpected loss of load from Large Power ("LP") customer group.

III. PROPOSED RATE STABILIZATION MECHANISM

Q. When Minnesota Power loses a Large Power 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. While Minnesota Power has not made any sales due to loss of load since 2021, when sales are made, the revenues are used to help offset the lost revenue from the loss of load Minnesota Power

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

experienced, and as noted in the previous section, market volatility plays a significant role in the ability to recover lost revenue.

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 Direct Testimony of Company witness Mr. Joshua D. Taran.

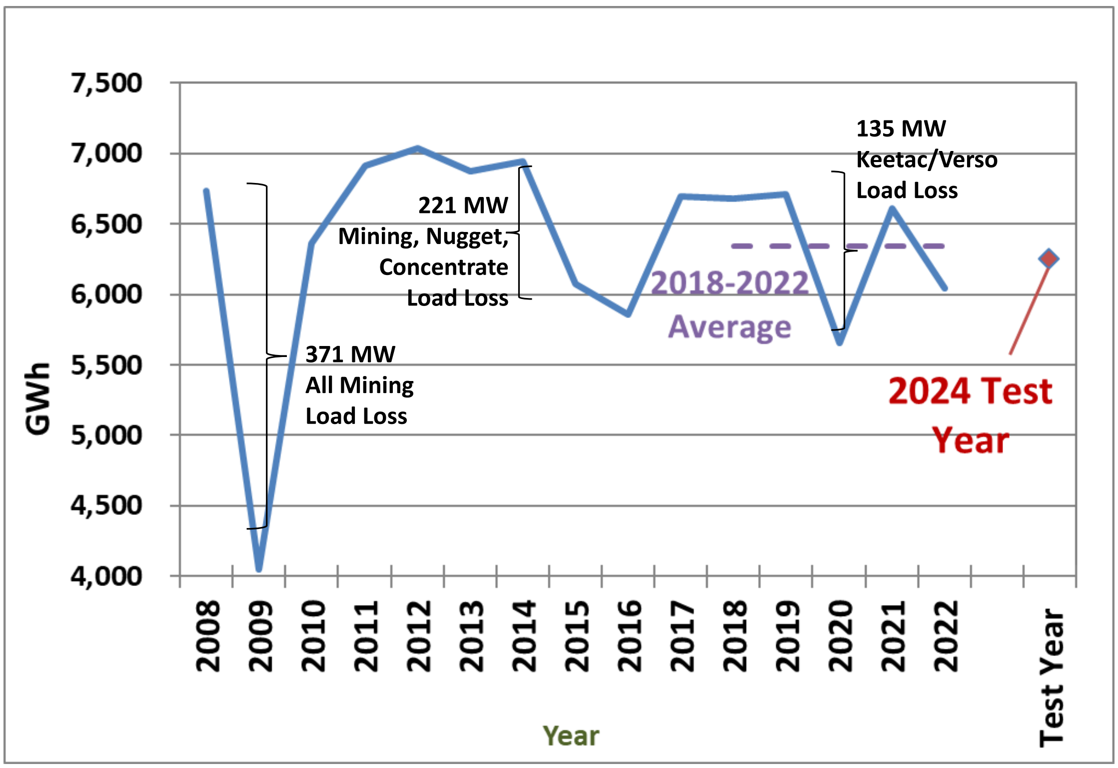
Q. Does the Company typically recover all its LP revenue losses when an LP customer reduces its load?

A. No. In the current markets, 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 and continues to be more uncertain with the changing grid and supply. At the same time, the costs to provide electric service to our customers have been increasing. If the markets were strong enough to completely offset all the lost revenue, then the impact to Minnesota Power would be zero.

This energy price 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 of lost revenues in 2018 and one percent of lost revenue in 2020 of the lost LP revenues through margins on bilateral sales. The details around these contracts and how they function are included in the Direct Testimony of Company witness Mr. Frank L. Frederickson. 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.

As noted in the Direct Testimony of Company witness Mr. Frederickson, both historic and current customer operations have shown that our large customers can experience significant year to year downturns and load reductions due to the highly cyclical and increasing subjectivity to the steel industry's technological evolution. This puts Minnesota Power in a position where it can and does experience a significant loss of customers and is not able to recover its cost of service. Figure 14 provides a visual depiction of how retail load for LP customers has fluctuated from 2008 to 2022, plus the expectation for the 2024 test year.

Figure 14. Energy Sales to the Industrial Customer Class



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 customer loss of load are priced using the average cost of fuel. The "source" of these transactions may include rate based generating unit energy, bilateral purchases, and energy market purchases. Therefore, the wholesale transaction margins that are created because 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 rate stabilization mechanism?

A. No. Even if MISO energy prices increase in the future, history has demonstrated that market prices will fluctuate over time based on market dynamics like renewable availability, fuel cost, economic conditions, 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 rate stabilization mechanism as discussed by Company witness Mr. Frederickson is designed to smooth the impact of LP customer volatility and reduce the impact of setting the test-year industrial production levels either too high or too low. The rate stabilization mechanism will align risks and benefits from LP volatility and incorporate a balanced methodology to incorporate revenues recovered in the MISO energy market. Therefore, if market prices increase to a level that covers lost revenue, the rate stabilization mechanism with the proposed tracker would simply not be triggered[12] for that time-period.

It is also important to note that the rate stabilization 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 year, these additional revenues beyond the baseline would be added to the proposed

[12] As described by Company witness Mr. Frederickson, the tracker would carry over year to year and would increase and decrease as actual LP revenues vary from the baseline. Once the tracker balance reached a threshold, proposed to be triggered by an amount of five percent or more of LP base revenues, the balance would be either credited or billed to customers as a rider on bills.

tracker. Therefore, the rate stabilization mechanism is an important tool for the Company and customers regardless of future wholesale MISO energy prices.

Q. In summary, why is a rate stabilization mechanism needed?

A. The rate stabilization 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 revenues on MISO sales due to loss of customer load. The MISO energy markets have materially changed with increasing renewable energy and variable natural gas prices, resulting in uncertain 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 rate stabilization mechanism is consistent with previously approved sales forecast true-ups[13] and balances the risk of more volatile market prices resulting from the de-carbonizing of the power supply and changes in company revenue caused by fluctuations in LP customers' operations.

As discussed by Company witness Mr. Frederickson, due to Minnesota Power's unique customer mix and customer concentration, the rate stabilization mechanism will help the Company reduce the need for future rate cases that are triggered solely by fluctuations in LP operations. As discussed by Company witness Mr. Taran, ALLETE's credit rating agencies and credit ratings would favor the rate stabilization mechanism, as it shares rewards and risks of LP volatility with all customers and the Company. The rate stabilization 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.

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[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-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 9 (June 12, 2017); *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).

IV. ENVIRONMENTAL COSTS AND MARKET PARTICIPATION

A. <u>NOx Allowances</u>

Q. Are there other recent regulations that the Company needs to include in its overall strategy when it considers its market participation?

A. Yes. The U.S. Environmental Protection Agency ("EPA") announced the final Good Neighbor Plan ("GNP"), also known as the Good Neighbor Rule ("GNR"), a rule that was designed to reduce smog-forming NOx pollution from power plants in 23 states (now including Minnesota), which is designed to improve air quality for millions of people living in downwind communities. The GNR was finalized soon after (March 15, 2023), then published in the Federal Register on June 5, 2023, making the change effective starting August 4, 2023, a partial ozone season for 2023. The GNP targets the ozone season from May 1 through September 31 of each year and impacts Minnesota Power's thermal fleet, which currently includes BEC Units 3 and 4, Laskin Units 1 and 2, and Hibbard Renewable Energy Center ("HREC") Units 3 and 4.

Minnesota Power and other parties disagree with the EPA's disapproval of the Minnesota State Implementation Plan ("SIP"). The Company is participating in a Minnesota coalition with other Minnesota utilities and industry ("the parties") litigating the EPA's Minnesota SIP partial approval/disapproval as well as the final Federal Implementation Plan ("FIP") rule. On April 14, 2023, the parties co-filed challenges to the EPA's final Minnesota SIP disapproval, submitting a petition for reconsideration and stay to the EPA and a petition for judicial review to the United States Court of Appeals for the Eighth Circuit. The parties are challenging and requesting reconsideration of certain technical components of the EPA's review and subsequent partial disapproval of the state of Minnesota's SIP, including the rulemaking process, air modeling practices, and other emissions inventory aspects. On May 31, 2023, the parties filed a "Motion to Stay the SIP Disapproval" with the Eighth Circuit Court, which granted the stay on July 5, 2023, precluding the ability for the GNP to take effect in the State of Minnesota while a stay remains in effect. Subsequently, on August 4, 2023, the parties also filed challenges against the FIP rule itself, in the form of a Petition for Administrative Reconsideration and Stay to the EPA, as well as a Petition for Judicial Review to the Eighth Circuit Court.

The Company does not currently anticipate that the State of Minnesota will be subject to compliance obligations for the shortened Good Neighbor Plan 2023 ozone season, which would have gone into effect on August 4, 2023, without the stay issued on July 5, 2023. Future compliance obligations and timing will be dependent on the eventual resolution of the Eighth Circuit stay in the SIP disapproval case, as well as the ultimate disposition of the August 4, 2023, FIP challenge filings. The Company is anticipating the probability that there will be impacts from the implementation of the GNR to the 2024 test year. Further, there is a need to address a mechanism in this rate review for the inclusion of the impacts of this substantial rulemaking.

Q. How do changes to the GNR impact the 2024 test year?

A. The GNR is a new federal air quality regulation which establishes additional NOx air emissions requirements for the ozone season (May–September) during the 2023–2030 timeframe. Under this plan, Minnesota Power must have enough allowances by the compliance deadline of June 1 of the subsequent year following the subject period (for example, by June 1, 2025, for the 2024 ozone season). This number of allowances is made up of "free" or granted allowances dependent on historical emissions and generation levels as well as additional allowances that need to be procured in the open market. The GNR aims to reduce NOx from large stationary emitters including power plants and certain industrial sources.

The 2024 test year must include anticipated expenses associated with the ozone season or identify another mechanism to handle the rule impacts on an annual basis that could become active for Minnesota Power customers. At this time, the Company has identified the potential for approximately $10.8 million to be part of the 2024 test year, with a range of potential outcomes as described further below in my testimony.

As an illustrative example of this variability, Table 1 identifies the variation in actual NOx tons produced as compared to the 2023 ozone season allocated NOx allowances for the 2020 through 2022 timeframe for the Laskin and HREC units; HREC and Laskin units are both economically offered into the MISO market, and the number of allocated allowances may or may not be enough to cover the allowance need in a given ozone season. Looking back at the actual NOx allowances/tons produced, Minnesota Power would have needed to take action by either procuring NOx allowances or adjusting the generation output to meet the GNR requirements. The variability in NOx allowances on an annual basis highlights that the costs or credits are not consistent year over year but follow the output of the generation and should be part of the FAC Rider versus keeping this variable attribute of operations in base rates.

Table 1. Comparison of Allocated vs. Actual NOx By Generator

	Laskin Energy Center			Hibbard Renewable Energy Center		
Year	**2020**	**2021**	**2022**	**2020**	**2021**	**2022**
Allocated Allowances	22	22	22	53	53	53
Actual NOx Tons	10	63	36	127	139	246
Surplus/(Deficit)	12	(41)	(14)	(74)	(86)	(193)

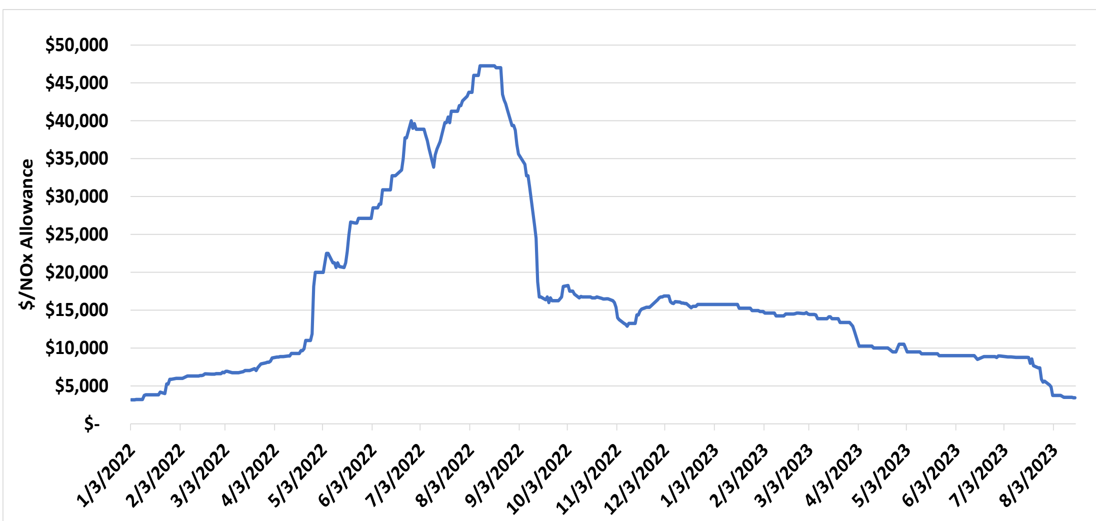
Q. What is the breakdown of the NOx allowance allocation in the 2024 test year?

A. As identified in the Direct Testimony of Company witness Mr. Todd Z. Simmons and, in particular, in Table 5 of his Direct Testimony, the GNR has identified that Minnesota Power will receive, through the GNR allocation process, a certain number of allowances for each generating station impacted by the rule. This includes the two units at BEC as well as both HREC units and both Laskin units. Allowances are utilized to account for the NOx emissions each year. Accounting for the allowances received and the expectation of allowances needed based on the 2024 test year operational plan, Minnesota Power will either need to procure additional allowances, curtail generation to reduce the need for additional allowances, or sell applicable unused allowances if the rule stay is overturned or resolved.

The anticipated generation operations for the 2024 test year have the impacted units operating at levels that still require Minnesota Power to acquire allowances. However, while the modeling shows the need to procure additional NOx allowances, the overall need for allowances will depend on the MISO market prices and the overall operation of the units. For example, if the MISO market prices are lower than expected, there may not be a need for additional NOx allowances as the units may not run as much as anticipated.

The historical NOx allowance pricing can be very volatile, as noted in Figure 15. During the 2022 and 2023 ozone seasons, allowance pricing was as high as approximately $47 thousand and as low as approximately $3.3 thousand per allowance. This type of volatility adds to the uncertainty of generation output and allowances needed in a given ozone season each year.

Figure 15. Historical NOx Allowance Pricing



As Figure 15 demonstrates, the $10.8 million estimate for the 2024 test year is very uncertain and can vary year to year with the operations and allowance marketplace. This variability results in the need for a cost recovery mechanism that is appropriate for market-based outcomes and directly attributed to fuel utilization.

Q. Did Minnesota Power previously seek to include NOx allowances in the FAC Rider?

A. Yes. As discussed by Company witness Mr. Simmons, Minnesota Power requested to add NOx allowance credit/cost recovery to the sulfur dioxide ("SO_2") credit/cost recovery in the FAC Rider in Minnesota Power's 2009 Rate Case, Docket No. E015/GR-09-1151 ("2009 Rate Case"). The SO_2 credit/cost recovery of allowances was authorized to flow through the FAC Rider in Minnesota Power's 2008 Rate Case, Docket No. E015/GR-08-415 ("2008 Rate Case"). While there were no current regulations regarding NOx allowances, Minnesota Power recognized that regulations would be coming and requested equal treatment of both NOx and SO_2 allowance treatment. With Minnesota added to the GNR, Minnesota Power believes there is cause to request the addition of NOx allowance revenue or cost recovery through the FAC Rider at this time.

Q. Why does Minnesota Power wish to add NOx allowances to the FAC Rider recovery at this time?

A. As discussed earlier in my testimony, the level of generation from Minnesota Power's thermal fleet is no longer consistent and is becoming more variable with increased integration of renewable energy sources into the portfolio, more flexible operations (*i.e.*, economic dispatch), and changes to the broader region. Since the level of allowances will directly correlate with Minnesota Power's generation operations (and likely vary significantly from year to year), it will be important to consider these costs as a part of generation dispatch along with fuel, purchased power, and other costs that currently flow through the FAC Rider. The energy landscape has changed over the past several years and it has become more important to consider variable costs of thermal generation when making economic dispatch decisions.

Like other ongoing expenses, emission allowance costs are directly related to unit operations. The emission allowances and costs vary with generation production levels (the same as fuel costs) and must be managed accordingly. Allowance purchase cost or sale revenue will depend on unit operating levels, fuel quality, and regulatory requirements, and will be subject to allowance market conditions, which may include times of price increases and volatility. The NOx allowance activity is now highly correlated with the operations and fuel, is a variable cost, and more closely aligns with the other fuel-related costs.

While Minnesota Power has not had the need to purchase or sell NOx allowances in recent years, the new inclusion in the GNR requires Minnesota Power to have a mechanism to account for the revenues and expenses of the program going forward. During the 2009 Rate Case, the Commission did not make any decision on how NOx allowance purchases or sales should be handled if or when they were to occur.

With the GNR now including Minnesota, the purchase and or sale of allowances will be forecasted and budgeted on an annual basis but may not be the same year over year.

Q. What is the Company requesting with respect to NOx allowances in the 2024 test year?

A. Minnesota Power believes that the best way to track and recover revenue and expenses of NOx allowances is through the Company's FAC Rider. Minnesota Power is therefore requesting to account for NOx allowances through the FAC Rider. This treatment would be in alignment with the treatment of SO_2 allowances as granted in the 2008 Rate Case. If approved, the Company is requesting that all NOx allowances be moved to the FAC Rider effective with the implementation of final rates in this case.

Q. How are NOx allowances currently recovered?

A. NOx allowance revenue and expense for environmental compliance are currently recovered through base rates at a level set during the last rate case as part of operations and maintenance. To date, NOx allowances have not been included in base rates, as there have been no revenues or expenses incurred.

Minnesota Power is requesting to add NOx allowance revenue or cost recovery in the FAC Rider similar to the treatment of SO_2 allowances. To date, Minnesota Power has not had to purchase SO_2 allowances, and therefore, the costs have not been allocated to customers. However, if credit or cost from NOx allowances are incurred and allowed to be recovered through the FAC Rider, the Company proposes that the credit or cost be applied to all sales on a per MWh basis similar to MISO costs.

Q. What is the 2024 test year impact of this proposal?

A. Minnesota Power has included NOx allowance costs in the 2024 test year but will not request recovery in the interim rate request. As discussed in the Direct Testimony of Company witness Mr. Simmons, Table 5, Minnesota Power projects the 2024 test year cost for NOx allowances to be $10,763,360.

Because of the uncertainty with ongoing litigation affecting the implementation timing of the GNR, the Company decided to remove NOx allowance costs from its interim rate request. This is a voluntary adjustment to ensure that customers do not pay for allowance costs that may be delayed into and beyond the 2024 test year. Minnesota Power has included NOx allowances in the final rate request as provided in the 2024 test year since the litigation is expected to be a temporary delay of GNR implementation. The Company is requesting that these allowances be moved to the FAC Rider effective with final rates, as the FAC Rider is a more appropriate mechanism to recover costs which are directly tied to the level of generation of Minnesota Power's fossil fuel plants. The NOx allowances are therefore included in the revenue requirement calculation in the Class Cost of Service Study ("CCOSS") for final general rates and are reflected in a revised FAC Rider forecast rather than in final base rates. This is the same way other FAC Rider items are treated in the CCOSS, with both FAC Rider revenues and expenses included in the CCOSS, and the overall impact treated as a rate design issue, which is effectuated on Volume 3, Direct Schedules E-1 and E-2.

If the 2024 test year costs are moved to the FAC Rider with final rates, it is estimated that the impact to the 2024 test year FAC Rider cost would be approximately $10.8 million. Subsequent years will be managed through the FAC Rider forecast process.

Q. Why is it reasonable to include NOx revenues and expenses in the FAC Rider?

A. Revenues and expenses of NOx allowances should be treated similarly to the sale and purchase of SO_2 allowances, which are accounted for and tracked through the FAC Rider to ensure timely refunds to customers and collection of costs by the Company. NOx produced at a generating station is directly related to the fuel burned at the station. As noted by Company witness Mr. Simmons, Minnesota Power has projected and budgeted for NOx allowances in the 2024 test year; however, that level is specific to 2024 and may not be representative of future years. Because the purchase or sales of NOx allowances are based on the generation output in each ozone season, it would be more appropriate to allow any purchases or sales to be accounted to Minnesota Power's customers through the FAC Rider.

The FAC Rider is a transparent process that occurs on an annual basis. With multiple regulatory oversight steps with opportunity for stakeholders to review and provide comments, the forecast and true-up mechanisms incorporated into the FAC Rider process creates a strong environment for managing the variability of the NOx requirements and their direct correlation to fuel, markets, and generation output.

B. <u>Reagents</u>

Q. What is the Company requesting with respect to reagents for its generation facilities in the 2024 test year?

A. Minnesota Power proposes including reagents and chemicals for environmental compliance in the FAC Rider.

Q. How are the costs of the reagents currently handled by the Company?

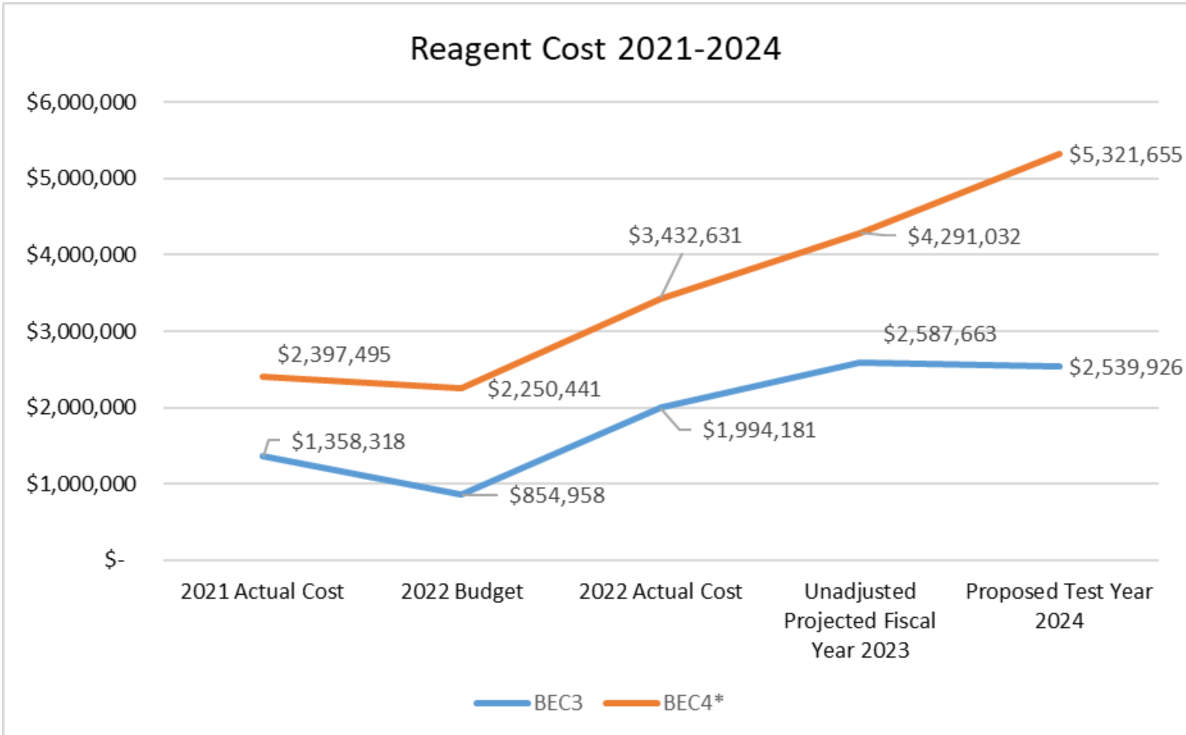
A. Reagents and chemicals for environmental compliance are currently recovered through base rates at a level set during the last rate case as part of Operating and Maintenance ("O&M") expense. The test year forecast for reagents and chemicals is discussed by Company witness Mr. Simmons in his Direct Testimony.

As discussed earlier in my testimony, the level of generation from Minnesota Power's thermal fleet is no longer consistent and is becoming more variable with its increased integration of renewable energy sources into its portfolio and the broader region. The reagents needed to operate are directly attributed to the generation output on an annual basis. Minnesota Power is requesting to add reagents cost recovery in the FAC Rider, which aligns with the treatment of other costs that are operational in nature. If reagent costs are allowed to be recovered through the FAC Rider, the Company proposes the costs would be applied to all sales on a per MWh basis similar to MISO costs.

Q. What is the 2024 test year impact of this proposal for reagents?

A. Minnesota Power estimates total reagent costs for the 2024 test year to be $5,321,655 for BEC4 (includes WPPI Energy portion) and $2,539,926 for BEC3, as noted below in Figure 16 and as discussed by Company witness Mr. Simmons in his Direct Testimony. Reagent costs are significantly lower for BEC3 in the 2024 test year as the result of a planned extended outage. Due to the extended outage, the reagent use for BEC3 may not reflect the reagent use in future years and is an example of why reagent costs should be recovered through the FAC Rider, as this mechanism will better align reagent costs with the expected use on an annual basis. In the 2024 test year, both BEC3 and BEC4 had commodity escalation of 20 percent and 25 percent on carbon and limestone, respectively, from the previous year, providing another example of how costs can change year over year.

Figure 16. 2021-2024 Reagent Cost



*BEC 4 includes WPPI Energy share of unit

Q. What Minnesota statute allows for possible Commission approval of recovery of reagent costs through the FAC Rider?

A. Minn. Stat. § 216B.16, subdivision 7(4) gives the Commission the ability to allow for the recovery of prudent costs incurred for sorbents, reagents, or chemicals used to control emissions, provided that these costs are not recovered elsewhere in rates.

Q. Has Minnesota Power previously asked to recover the costs of reagents and chemicals for environmental compliance through the rate case or other filings?

A. Yes. As discussed by Company witness Mr. Simmons, Minnesota Power has requested to recover the costs of reagents and chemicals for environmental compliance through the Minnesota Power's 2016 Rate Case, Docket No. E015/GR-16-664 ("2016 Rate Case"), as well as through the Fuel and Purchased Energy Rider, Docket No. E015/M-22-547.

Q. Why is the Company requesting this change again?

A. Reagent costs, much like NOx allowances, are variable costs and are directly related to the production of the generating units. Reagent usage at a generating station is directly related to the fuel burned at the station. Because the reagent use and expense are directly tied to the generation output, it would be unreasonable to build a specific amount of expected expenses into base rates; it would, however, be appropriate to allow expenses to align with the generation expenses through the FAC Rider. Allowing reagent expense cost recovery through the FAC Rider provides additional transparency and regulatory review of the costs associated with reagents on an annual basis. These costs would be more closely aligned with the actual use, while costs in a rate case may be overstated or understated in any given year.

As discussed earlier in my testimony, the level of generation from Minnesota Power's thermal fleet is no longer consistent and is becoming more variable with its increased integration of renewable energy sources into the portfolio, more flexible operations (*i.e.*, economic dispatch), and the broader region. BEC3, Laskin Units 1 and 2, and HREC Units 3 and 4 are all offered into the MISO market on an economic basis and dispatched by MISO when needed to support the overall system or used for local reliability when needed. The reagents needed to operate are directly attributed to the generation output on an annual basis and will vary based on when each unit is called upon for dispatch by the MISO market.

The FAC Rider is a transparent process that occurs on an annual basis. With multiple regulatory oversight steps, including opportunities for stakeholder review and comments, the forecast and true-up mechanisms incorporated into the FAC Rider process creates a strong environment for managing the variability of the reagent usage requirements and the direct correlation to fuel, markets, and generation output.

Q. How has the Commission previously responded to the Company's request to move reagents to the FAC Rider?

A. In the 2016 Rate Case, Department of Commerce ("Department") witness Lerma La Plante was concerned that Minnesota Power would not be incentivized to minimize costs if the cost of reagents were included in the FAC Rider. Additionally, the Department pointed to other rate cases where the Commission denied recovery of chemical and reagent costs for Otter Tail Power Company (Docket No. E017/GR-15-1033) and Xcel Energy (Docket No. E002/GR-12-961). The Commission denied Minnesota Power's request in the 2016 Rate Case to include reagents in the FAC Rider, as it was also concerned that including these costs in the FAC Rider would remove a major incentive for the Company to limit reagent costs between rate cases.

Q. What has changed since the Commission's decision in the 2016 Rate Case that addresses the Commission's prior concerns and has led Minnesota Power to renew its request to include reagent costs in the FAC Rider?

A. Overall operation of the Company's generating fleet and interaction with the market has continued to transition since the 2016 Rate Case, including an increase in cycling and variable dispatch. Further, Otter Tail Power Company requested, and the Commission approved, recovery of reagent costs through its energy adjustment rider in its 2020 rate case (Docket No. E017/GR-20-719). In that proceeding, the Commission noted that the Legislature "clearly contemplated the possibility of reagent cost recovery" through a rider and that "[i]f reagent costs do begin to rise disproportionately, the Commission will have the opportunity to investigate further and modify recovery in future" rider proceedings.[14] Minnesota Power is requesting the same treatment in this case.

Finally, with the FAC reform and changes to FAC Rider forecasting, significant events, and the true-up process, there are multiple ways for oversight in the FAC Rider regulatory process. The increased transparency and review process provides ample

[14] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 29 (Feb. 1, 2022).

opportunity to question, validate, and approve annual reagent expenses through the FAC Rider with appropriate regulatory oversight of those annual costs.

Q. Please explain why the current market conditions are different and provide additional support to move reagent costs and NOx allowance revenue and expense to the FAC Rider while still protecting customers from excessive costs?

A. As described above, the MISO market and the changing power supply to more renewable generation resources and more flexible operations at BEC have impacted thermal generation, which is now subjected to increased cycling and variable dispatch more than ever. Leaving both revenue and expenses in base rates could lead to a mismatch in cost signals when making dispatch decisions, which could result in an "artificially" low cost of baseload generation in the market, increased rate case filings, greater revenues or expenses in between rate cases, and cash flow issues. The ability to flow both revenue and expenses through the FAC Rider aligns costs to the cost causers in a timelier fashion. Thermal generation is now variable, and the costs/credits are now variable as well, just like fuel. Therefore, the costs/credits are better suited to flow through the FAC Rider. Additionally, Minnesota Power remains incentivized to negotiate its reagent costs with suppliers, even if the reagent cost is in the FAC Rider. This is because the Company will need to remain diligent to keep overall operating costs of these units economical for their selection in the market. Company witness Mr. Simmons discusses these considerations in more detail in his Direct Testimony.

V. SYMMETRICAL TREATMENT OF CAPACITY REVENUE AND EXPENSE

Q. Please explain the process Minnesota Power uses for capacity transactions?

A. Capacity transactions are made when Minnesota Power has determined, through an evaluation process, the expected surplus or shortfall for capacity and makes purchases or sales to meet the requirements for the retail customer's resource adequacy short-term needs. As a rule, the amount of capacity available to sell at wholesale will be reduced as the energy requirements for any retail revenue class increases. Likewise, if the capacity requirements for any retail revenue class are reduced, there will be an increase in the amount of capacity that is available to sell at wholesale. Additionally, when there is a capacity shortfall, Minnesota Power can procure capacity through the MISO capacity market, through a third-party wholesale transaction, or through an agreement with a retail customer. As part of the planning process, Minnesota Power establishes the level of capacity transactions the Company can expect given the retail demand requirements forecasted and the system capacity resources available to meet that forecast.

Q. What is capacity revenue and expense?

A. Capacity revenue is received when Minnesota Power has excess capacity available and is able to sell that excess capacity through a bilateral sale to a counterparty or through the MISO Planning Resource Auction ("PRA"). Capacity expense is created when Minnesota Power does not have enough capacity available and must procure the needed level of capacity for Minnesota Power customers through a bilateral purchase from a counterparty, customer, or through the MISO PRA. Minnesota Power typically purchases capacity for our customers through the bilateral markets or demand response programs but not typically through the MISO PRA due to the price uncertainty inherent in MISO PRA. The Direct Testimonies of Company witnesses Ms. Leah N. Peterson and Mr. Fredrickson provide additional information regarding capacity that comes from our customers through our demand response programs.

Q. Please describe the MISO capacity requirements and process.

A. As a member of MISO, Minnesota Power must demonstrate resource adequacy on an annual basis to ensure sufficient resources are available to reliably serve load on a forward-looking basis. Minnesota Power proves resource adequacy through the MISO PRA process. MISO recently changed the capacity requirements from an annual construct to a seasonal construct and with the accredited capacity value having more emphasis on generation performance during tight operating hours. The change in the PRA process to a seasonal construct has required considerable change in planning and increased variability and risk in the PRA planning process. On a seasonal basis, Minnesota Power has the potential to have excess capacity in some seasons and have a shortfall of capacity in other seasons.

Q. Please explain Minnesota Power's Resolution to the 2019 Rate Case, Docket No. E015/M-20-429) ("2019 Rate Case Resolution") and its impact on capacity revenue and expense.

A. In the 2019 Rate Case Resolution, the Commission approved the ability to move all asset-based wholesale sales credits to the FAC Rider and resolve Minnesota Power's 2019 Rate Case, Docket No. E015/GR-19-442 ("2019 Rate Case"). The resolution effectively moved both energy and capacity sales credits to the FAC Rider. However, the capacity expense remained a Company expense and recovered through base rates as approved in the 2021 Rate Case.

Q. What is the Company proposing for treatment of the revenue and expense in the 2024 test year?

A. To align the capacity revenue and expense to the impacted MISO Planning Year, Minnesota Power is requesting the ability to create a Rider for Capacity Revenue and Expense Adjustment for contracts and PRA results for a period that is equal to or less than three years. Capacity purchases that are longer term (greater than three years) would remain in base rates as established by the general rate case process. Minnesota Power also asks for symmetrical treatment for approved demand response programs that are short-term in nature to flow through this proposed rider.

The Company's proposed new Rider for Capacity Revenue and Expense Adjustment would fall under the Fuel and Purchased Energy Rider (Minnesota Statutes Section 216B.16, subdivision 7), and would have a defined regulatory process for filings, forecasts, true-ups, transparency, and regulatory oversight.

Creating a Rider for Capacity Revenue and Expense Adjustment will allow Minnesota Power to balance the capacity needs between seasons and planning years more effectively. For the first seasonal capacity accreditation year, Minnesota Power experienced both a capacity surplus as well as a capacity shortfall, as noted in Table 2 below. MP Exhibit ___ (Pierce), Direct Schedule 2 illustrates for 2020 through 2024 how the combined capacity revenue and expense would flow through the proposed Rider for Capacity Revenue and Expense Adjustment.

Table 2. Projected Capacity Position for Planning Year 2023/2024

[TRADE SECRET DATA BEGINS

	Summer 2023	Fall 2023	Winter 2023/2024	Spring 2024	Net 2023/2024
Position	[redacted]				
Capacity Price ($/KW-Month)					
Revenue/(Expense)					

TRADE SECRET DATA ENDS]

The proposed Rider for Capacity Revenue and Expense Adjustment, while also addressing the new dynamic of near-term capacity planning, could also support the evolution of additional demand response programs and services by creating a mechanism to share both the costs and the benefits of customer subscribed demand response in the same cost recovery mechanism.

Q. How is Minnesota Power currently treating capacity revenue and expenses?

A. In 2020, as part of the 2019 Rate Case Resolution, Minnesota Power filed a petition to move asset-based wholesale sales credits to the FAC Rider and resolve the 2019 Rate Case. The 2019 Rate Case Resolution moved both energy margins and capacity revenues for asset-based wholesale credits to the FAC Rider. The result of this action separated the treatment of capacity revenue and expense.

Under the current process, capacity revenue is applied to customers through the FAC Rider, and capacity expense is applied through base rates at a level set during the last rate case.

Q. Why does Minnesota Power feel the current treatment for capacity revenue and expense is not in the best interest of its customers?

A. The change to the MISO seasonal capacity construct has created uncertainty due to the potential for excess capacity in one season and the potential for a shortfall of capacity in another season. The new capacity construct also creates an uncertainty on the value of capacity from season to season, creating a disparity between the potential expense and revenue. The MISO Seasonal Capacity Construct, volatility of capacity accreditation, along with variable expense and revenue have added short-term uncertainty/risk to the Company for timely cost recovery of capacity related expense. The capacity revenue and expense variability under the new seasonal construct are identified in MP Exhibit ___ (Pierce), Direct Schedule 1 for 2020 through 2024. Schedule 1 identifies all capacity revenue and expense (both long and short term) and illustrates the variability between revenue and expense, as well as the variability with the new seasonal construct.

As part of the Reliability Imperative initiative, MISO continues to propose changes to improve the capacity construct due to the changing power supply mix and its impact on the grid, which creates considerable uncertainty in both expense and revenue in the future. Aligning capacity revenue and expense recovery will provide less volatility and more certainty to customers and the Company going forward and create symmetrical treatment for capacity revenue and expense.

Q. What else has changed with the new MISO Seasonal Capacity Construct?

A. The MISO Seasonal Capacity Accreditation value for thermal and dispatchable generation (*i.e.*, hydro facility with ponding capability) is now more dependent upon the performance of the generation facility during a select few tight operating hours on the grid over a rolling three years. Previously, the accredited capacity value for thermal generation was solely based on generation performance during all hours over a rolling three years. Since the accredited capacity value under the new construct is based on fewer hours, an untimely forced outage during a tight operating period on the grid will have a greater impact on the accredited capacity value than before. This results in more volatility in the accredited capacity value between seasons and planning years. Depending on generation performance and associated accredited capacity value assumed in the test year, base rates could understate or overstate the capacity purchase cost.

Also, if a generation facility must perform planned maintenance that is greater than 31 days in length during a season, the facility may not be able to be accredited for a portion or all of a particular season. The inability to accredit a larger generator due to planned maintenance would create a significant short position and require a capacity purchase for an individual season or seasons. If the long outage was not performed in a test year, the capacity expense would not be effectively reflected in the test year and base rate calculation. Conversely, if a large outage was in a test year and part of the base rate calculation, the capacity expense could be overstated for future years or until the next general rate case was filed and resolved.

Q. Do you have any examples to further illustrate your concern described above?

A. Yes. Participation in the PRA is required for all MISO Market Participants with more than 50 MW of excess capacity for an upcoming planning year. It has been Minnesota Power's long-standing practice to use the MISO PRA process to ensure resource adequacy and offer our excess capacity into the market for the prompt planning year.

For the MISO Planning Year 2022/2023, which was the last annual auction construct, Minnesota Power had sufficient resources to meet its obligations on an annual basis. The surplus for Local Resource Zone 1 was **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** MW of Zonal Resource Credits ("ZRC"). Minnesota Power also has sufficient resources to meet its contractual obligations for the load it serves in Local Resource Zone 2, with an expected **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** MW of excess ZRCs. The excess capacity cleared at $7,198/MW-Month, providing Minnesota Power customers with immediate benefits as the revenues flowed through the FAC Rider.

For the new MISO PRA Seasonal Construct Planning Year 2023/2024, Minnesota Power had a surplus of capacity for the Fall and Winter seasons and a shortfall of capacity for the Summer and Spring seasons, as noted in Table 2 above. Minnesota Power utilized the bilateral capacity market to sell capacity in the Fall and Winter and purchase capacity in the Summer and Spring seasons to ensure resource adequacy prior to entering the MISO PRA.

For the MISO Planning Year 2023/2024, the average seasonal clearing price for capacity was significantly lower than the prior year – $282/MW-Month versus $7,198/MW-Month in the prior planning year. The key drivers for the lower clearing price were a decrease in demand and an increase in capacity resources available from new builds and higher accredited capacity values for existing generation.

Table 2 above highlights Minnesota Power's position per season and the variability experienced for both surplus/shortfall and revenue/expense. The new seasonal construct's variability and volatility in both position and price are apparent, especially given that Minnesota Power's generation portfolio was nearly identical between Planning Year 2022/2023 and Planning Year 2023/2024; there were no retirements or resource additions that occurred. The Customer and Company impact is dramatic between the two types of MISO capacity constructs, highlighting why it is important to align both the revenue and expense in the same cost allocation bucket.

Q. What are the benefits to Minnesota Power's customers if this proposal is approved by the Commission?

A. The Minnesota Power customers would benefit from the symmetrical treatment of both capacity sale revenue and purchase expense. The proposed Rider for Capacity Revenue and Expense Adjustment will enable both revenue and expenses that are incurred in the annual MISO PRA process to align, and the established regulatory process will provide needed oversight. Through the regulatory process (FAC forecasting, significant events, and true-up filings), the Commission and stakeholders will have transparency and oversight into the capacity purchases and sales needed to remain resource adequate in each season and have the oversight to determine prudency in the contracting process.

Q. How would the Rider for Capacity Revenue and Expense Adjustment rate be calculated?

A. Minnesota Power is proposing that the capacity revenue and expense for capacity sales and purchases that are made either from Minnesota Power customers, bilaterally, or through the PRA and are three years in length or less be applied to all firm sales on a per MWh basis. Minnesota Power is proposing to follow the MISO Planning Year with this rider mechanism, which is currently June through May, with a planned start of the June 1 planning year.

VI. CONCLUSION

Q. Does this complete your Direct Testimony?

A. Yes.

Capacity Revenue and Expense
2020 Actual

Line No.		ZONAL RESOURCE CREDITS	CAPACITY EXPENSE	JURISDICTION CAPACITY EXPENSE	CAPACITY REVENUE	JURISDICTION CAPACITY REVENUE	NET EXPENSE/REVENUE	JURISDICTION NET EXPENSE/REVENUE
		[TRADE SECRET DATA BEGINS						
1	**Three Years or Less**							
2	Great River Energy - 1	[redacted]						
3	Great River Energy - 2	[redacted]						
4	Great River Energy - 3	[redacted]						
5	Manitoba	[redacted]						
6	Virginia Public Utilities	[redacted]						
7	NextEra	[redacted]						
8	NextEra	[redacted]						
9	Planning Resource Auction 19/20	[redacted]						
10	Planning Resource Auction 20/21	[redacted]						
11	**Greater than Three Years**	[redacted]						
12	Rockgen	[redacted]						
13	Manitoba	[redacted]						
14	Minnkota Power Cooperative	[redacted]						
15	Manitoba	[redacted]						
16	Manitoba Credit	[redacted]						
17	Oconto	[redacted]						
18	Basin	[redacted]						
19								TRADE SECRET DATA ENDS]
20	**Total Capacity Expense / Revenue**		$ (6,626,615)	$ (5,757,534)	$ 6,358,281	$ 5,524,392	$ (268,334)	$ (233,142)

Note: **MN Jurisdictional (Most Recent Fiscal Year 2020 Cost of Service Study - 2021 Rate Case)**
Production Demand **0.86885**
Source: Docket No. E015/GR-21-335 Volume 4, COS-3, Part 8b, Allocator CC-PROD - Demand Only

Capacity Revenue and Expense
2021 Actual

Line No.		ZONAL RESOURCE CREDITS	CAPACITY EXPENSE	JURISDICTION CAPACITY EXPENSE	CAPACITY REVENUE	JURISDICTION CAPACITY REVENUE	NET EXPENSE/REVENUE	JURISDICTION NET EXPENSE/REVENUE
		[TRADE SECRET DATA BEGINS						
1	**Three Years or Less**							
2	Dairlyand	[redacted]						
3	WPPI							
4	NextEra							
5	Planning Resource Auction 20/21							
6	Planning Resource Auction 21/22							
7	**Greater than Three Years**							
8	Rockgen							
9	Manitoba							
10	Manitoba Credit							
11	Oconto							
12								TRADE SECRET DATA ENDS]
13	**Total Capacity Expense / Revenue**		**$ (670,480)**	**$ (582,547)**	**$ 4,555,735**	**$ 3,958,250**	**$ 3,885,255**	**$ 3,375,703**

Note: **MN Jurisdictional (Most Recent Fiscal Year 2020 Cost of Service Study - 2021 Rate Case)**
Production Demand **0.86885**
Source: Docket No. E015/GR-21-335 Volume 4, COS-3, Part 8b, Allocator CC-PROD - Demand Only

Capacity Revenue and Expense
2022 Actual

Line No.		ZONAL RESOURCE CREDITS	CAPACITY EXPENSE	JURISDICTION CAPACITY EXPENSE	CAPACITY REVENUE	JURISDICTION CAPACITY REVENUE	NET EXPENSE/REVENUE	JURISDICTION NET EXPENSE/REVENUE
		[TRADE SECRET DATA BEGINS						
1	**Three Years or Less**							
2	Dairlyand	[redacted]						
3	WPPI							
4	Great River Energy (Bos4)							
5	Planning Resource Auction 21/22							
6	Planning Resource Auction 22/23							
7	**Greater than Three Years**							
8	Rockgen							
9	Manitoba							
10	Oconto							
11	Hibbing Public Utilities							
12								TRADE SECRET DATA ENDS]
13	**Total Capacity Expense / Revenue**		**$ (23,676,730)**	**$ (20,861,330)**	**$ 13,456,470**	**$ 11,856,361**	**$ (10,220,260)**	**$ (9,004,969)**

Note: **MN Jurisdictional (2021 Cost of Service Study)**
Production Demand **0.88109**
Source: Volume 4, COS-3, Part 8b, Allocator CC-PROD - Demand Only

Capacity Expense and Revenue
2023 Projected Year

Line No.		ZONAL RESOURCE CREDITS	CAPACITY EXPENSE	JURISDICTION CAPACITY EXPENSE	CAPACITY REVENUE	JURISDICTION CAPACITY REVENUE	NET EXPENSE/REVENUE	JURISDICTION NET EXPENSE/REVENUE
		[TRADE SECRET DATA BEGINS						
1	**Three Years or Less**							
2	Bilateral Capacity Purchase	[redacted]						
3	Great River Energy (Bos4)							
4	Planning Resource Auction 22/23							
5	**Greater than Three Years**							
6	Rockgen							
7	Manitoba							
8	Oconto							
9	Hibbing Public Utilities							
10								TRADE SECRET DATA ENDS]
11	**Total Capacity Expense / Revenue**		**$ (24,702,980)**	**$ (21,814,461)**	**$ 9,313,605**	**$ 8,224,565**	**$ (15,389,375)**	**$ (13,589,896)**

Note: **MN Jurisdictional (Projected Fiscal Year 2023 Cost of Service Study)**
Production Demand **0.88307**
Source: Volume 4, COS-3, Part 8b, Allocator CC-PROD - Demand Only

Capacity Expense and Revenue
2024 Test Year

Line No.		ZONAL RESOURCE CREDITS	CAPACITY EXPENSE	JURISDICTION CAPACITY EXPENSE	CAPACITY REVENUE	JURISDICTION CAPACITY REVENUE	NET EXPENSE/REVENUE	JURISDICTION NET EXPENSE/REVENUE
		[TRADE SECRET DATA BEGINS						
1	**Three Years or Less**							
2	Great River Energy (Bos4)	[redacted]						
3	WPPI Winter							
4	WPPI Spring							
5	Bilateral Capacity Purchase							
6	Planning Resource Auction 23/24							
7	Planning Resource Auction 24/25							
8	**Greater than Three Years**							
9	Rockgen							
10	Manitoba							
11	Oconto							
12	Hibbing Public Utilities							
13					TRADE SECRET DATA ENDS]			
14	**Total Capacity Expense / Revenue**		**$ (24,739,840)**	**$ (21,932,363)**	**$ 6,686,907**	**$ 5,928,077**	**$ (18,052,933)**	**$ (16,004,286)**

Note: **MN Jurisdictional (Proposed Test Year Cost of Service Study)**
Production Demand **0.88652**
Source: Volume 3, Direct Schedule E-3, Part 8b, Allocator CC-PROD - Demand Only

Capacity Revenue and Expense
Three Years or Less
2020 Actual

Line No.		ZONAL RESOURCE CREDITS	CAPACITY EXPENSE	JURISDICTION CAPACITY EXPENSE	CAPACITY REVENUE	JURISDICTION CAPACITY REVENUE	NET EXPENSE/REVENUE	JURISDICTION NET EXPENSE/REVENUE
		[TRADE SECRET DATA BEGINS						
1	**Three Years or Less**							
2	Great River Energy - 1	[redacted]						
3	Great River Energy - 2							
4	Great River Energy - 3							
5	Manitoba							
6	Virginia Public Utilities							
7	NextEra							
8	NextEra							
9	Planning Resource Auction 19/20							
10	Planning Resource Auction 20/21							
11								TRADE SECRET DATA ENDS]
12	**Total Capacity Expense / Revenue**		**$ (4,233,500)**	**$ (3,678,276)**	**$ 336,184**	**$ 292,093**	**$ (3,897,316)**	**$ (3,386,183)**

Note: **MN Jurisdictional (Most Recent Fiscal Year 2020 Cost of Service Study - 2021 Rate Case)**
Production Demand **0.86885**
Source: Docket No. E015/GR-21-335 Volume 4, COS-3, Part 8b, Allocator CC-PROD - Demand Only

Capacity Revenue and Expense
Three Years or Less
2021 Actual

Line No.		ZONAL RESOURCE CREDITS	CAPACITY EXPENSE	JURISDICTION CAPACITY EXPENSE	CAPACITY REVENUE	JURISDICTION CAPACITY REVENUE	NET EXPENSE/REVENUE	JURISDICTION NET EXPENSE/REVENUE
		[TRADE SECRET DATA BEGINS						
1	**Three Years or Less**							
2	Dairlyand	[redacted]						
3	WPPI							
4	NextEra							
5	Planning Resource Auction 20/21							
6	Planning Resource Auction 21/22							
7								TRADE SECRET DATA ENDS]
8	**Total Capacity Expense / Revenue**		$ -	$ -	$ 1,188,511	$ 1,032,638	$ 1,188,511	$ 1,032,638

Note: **MN Jurisdictional (Most Recent Fiscal Year 2020 Cost of Service Study - 2021 Rate Case)**
Production Demand **0.86885**
Source: Docket No. E015/GR-21-335 Volume 4, COS-3, Part 8b, Allocator CC-PROD - Demand Only

Capacity Revenue and Expense
Three Years or Less
2022 Actual

Line No.		ZONAL RESOURCE CREDITS	CAPACITY EXPENSE	JURISDICTION CAPACITY EXPENSE	CAPACITY REVENUE	JURISDICTION CAPACITY REVENUE	NET EXPENSE/REVENUE	JURISDICTION NET EXPENSE/REVENUE
		[TRADE SECRET DATA BEGINS						
1	**Three Years or Less**							
2	Dairlyand	[redacted]						
3	WPPI							
4	Great River Energy (Bos4)							
5	Planning Resource Auction 21/22							
6	Planning Resource Auction 22/23							
7								TRADE SECRET DATA ENDS]
8	**Total Capacity Expense / Revenue**		$ -	$ -	$ 9,575,548	$ 8,436,920	$ 9,575,548	$ 8,436,920

Note: **MN Jurisdictional (2021 Cost of Service Study)**
Production Demand **0.88109**
Source: Volume 4, COS-3, Part 8b, Allocator CC-PROD - Demand Only

Capacity Expense and Revenue
Three Years or Less
2023 Projected Year

Line No.		ZONAL RESOURCE CREDITS	CAPACITY EXPENSE	JURISDICTION CAPACITY EXPENSE	CAPACITY REVENUE	JURISDICTION CAPACITY REVENUE	NET EXPENSE/REVENUE	JURISDICTION NET EXPENSE/REVENUE
		[TRADE SECRET DATA BEGINS						
1	**Three Years or Less**							
2	Bilateral Capacity Purchase	[redacted]						
3	Great River Energy (Bos4)							
4	Planning Resource Auction 22/23							
5								TRADE SECRET DATA ENDS]
6	**Total Capacity Expense / Revenue**		$ (875,000)	$ (772,686)	$ 5,097,848	$ 4,501,757	$ 4,222,848	$ 3,729,071

Note: **MN Jurisdictional (Projected Fiscal Year 2023 Cost of Service Study)**
Production Demand **0.88307**
Source: Volume 4, COS-3, Part 8b, Allocator CC-PROD - Demand Only

Capacity Expense and Revenue
Three Years or Less
2024 Test Year

Line No.		ZONAL RESOURCE CREDITS	CAPACITY EXPENSE	JURISDICTION CAPACITY EXPENSE	CAPACITY REVENUE	JURISDICTION CAPACITY REVENUE	NET EXPENSE/REVENUE	JURISDICTION NET EXPENSE/REVENUE
		[TRADE SECRET DATA BEGINS						
1	**Three Years or Less**							
2	Great River Energy (Bos4)	[redacted]						
3	WPPI Winter							
4	WPPI Spring							
5	Bilateral Capacity Purchase							
6	Planning Resource Auction 23/24							
7	Planning Resource Auction 24/25							
8								TRADE SECRET DATA ENDS]
9	**Total Capacity Expense / Revenue**		$ (796,860)	$ (706,432)	$ 2,596,852	$ 2,302,161	$ 1,799,992	$ 1,595,729

Note: **MN Jurisdictional (Proposed Test Year Cost of Service Study)**
Production Demand **0.88652**
Source: Volume 3, Direct Schedule E-3, Part 8b, Allocator CC-PROD - Demand Only