minnesota power

AN ALLETE COMPANY

EnergyForward

2021 INTEGRATED RESOURCE PLAN

February 1, 2021

Docket No. E015/RP-21-33

Jennifer J. Peterson
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February 1, 2021

VIA E-FILING
Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's Application for Approval of its 2021-2035 Integrated Resource Plan
Docket No. E015/RP-21-33

Dear Mr. Seuffert:

With this filing, Minnesota Power hereby presents its 2021 Integrated Resource Plan ("IRP") for Minnesota Public Utilities Commission ("Commission") approval.

Minnesota Power is proud to submit this IRP, including the Company's preferred plan – known as the "2021 Plan" – that outlines the next chapter in the Company's *Energy**Forward*** resource strategy. *Energy**Forward*** has reshaped the Company's power supply from an energy mix that was 95 percent coal in 2005 to one that is now delivering 50 percent renewable energy to customers. The 2021 Plan is Minnesota Power's further vision for a sustainable path to a carbon-free energy future by 2050, and outlines bold next steps in the clean energy transition that are centered on a commitment to the climate, customers, and communities. The 2021 Plan is also informed by a first-of-its kind stakeholder engagement process and, if approved, will facilitate a power supply that is 70 percent renewable in 2030, reduce carbon emissions by 80 percent by 2035 and result in a generation mix that is coal-free by 2035 while helping to ensure reliable and affordable power for Minnesota Power customers.

This overall IRP is organized into seven sections with supporting appendices, as presented in the enclosed Table of Contents. The IRP appendices include, among other details, the Company's Baseload Retirement Study (Appendix P) and Securitization Plan (Appendix Q), consistent with the Commission's January 24, 2019 Order in Docket No. E-015/AI-17-568.

Minnesota Power is also pleased to be the first Minnesota utility to initiate an IRP and Baseload Retirement Study using the EnCompass Power Planning model from the outset. Establishing

this sophisticated model has involved many months of advance planning, model development, and coordination with the Company's stakeholders, resulting in the detailed analyses presented in this IRP. With the core plan evaluation submitted with this filing, the Company's analysis will also be supplemented with additional information, no later than April 1, 2021, in Appendix I (Renewable Energy Standard and Solar Energy Standard Cost Impact Report) and part 2 of Appendix K (Additional Analysis).

Certain portions of the IRP contain trade secret information and are marked as such, pursuant to the Commission's Revised Procedures for Handling Trade Secret and Privileged Data, which procedures further the intent of Minn. Stat. § 13.37 and Minn. Rule 7829.0500. As required by the Commission's Revised Procedures, a statement providing the justification for excising the Trade Secret Data is attached to this letter.

As reflected in the Affidavit of Service, the Executive Summary has been e-filed on the attached service list.

Minnesota Power is grateful for the partnership of its customers, communities and interested stakeholders who informed the development of this IRP, particularly in the midst of the COVID-19 global pandemic. Please contact me at the number or the email address provided if you have any questions.

Respectfully,

Jennifer J. Peterson

JJP:th
Attach.
cc: Service List

TRADE SECRET INFORMATION

Minnesota Power has excised material from the public version of the attached report documents as they identify and contain confidential, competitive information regarding the Company's methods, techniques and process for supplying electric service to its customers. The energy usage by specific customers and generation by fuel type has been consistently treated as trade secret in individual filings before the Commission.

Minnesota Power follows strict internal procedures to maintain the privacy of this information. The public disclosure of this information would have severe competitive implications for customers and Minnesota Power.

Minnesota Power is providing this justification for the information excised from the electronically submitted report and attachments in accordance with Minn. Stat. § 13.37. The Company is submitting both public and non-public versions of this filing.

STATE OF MINNESOTA	)	AFFIDAVIT OF SERVICE VIA
	) ss	ELECTRONIC FILING
COUNTY OF ST. LOUIS	)	

Tiana Heger of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 1st day of February, 2021, she served Minnesota Power's 2021 Integrated Resource Plan Compliance Filing in **Docket No. E015/RP-21-33** on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on E-Docket's Official Service List for this Docket were served as requested.

Tiana Heger

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Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	GEN_SL_Minnesota Power_MP's 2021 IRP
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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	GEN_SL_Minnesota Power_MP's 2021 IRP
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MINNESOTA POWER 2021 INTEGRATED RESOURCE PLAN

PETITION FOR APPROVAL

February 1, 2021
Docket No. E015/RP-21-33

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I. ABOUT MINNESOTA POWER

Minnesota Power (or the "Company") is transforming the way it energizes communities and businesses through its *Energy**Forward*** resource strategy. Originally founded in 1906 as a hydroelectric utility, the Company grew over the 20th century to serve its industrial-heavy customer load in northern Minnesota with energy from predominately coal-fired generation. Today, the Company has evolved its generation mix by bringing more renewable power to all customers while reducing dependence on fossil fuels. Under its *Energy**Forward*** strategy, Minnesota Power is now delivering 50 percent renewable energy to customers and is the first Minnesota utility to achieve this milestone. The Company is proud of how far it has come on this clean-energy transformation and recognizes there is more work to do. Minnesota Power has committed to achieve an 80 percent reduction in carbon emissions by 2035 compared to 2005 levels, and outlined a goal of delivering 100 percent carbon-free energy by 2050. While delivering increasingly clean energy to customers, *Energy**Forward*** is also about delivering safe, reliable, and affordable energy to customers across a smarter grid that is more resilient than ever before.

A division of ALLETE, Inc., Minnesota Power serves about 145,000 retail electric customers and 15 municipal systems across a 26,000-square-mile service area in central and northeastern Minnesota. In 2019, 61 percent of Minnesota Power's kilowatt-hour ("kWh") total sales served retail industrial customers in the taconite mining, iron concentrate, paper/pulp, and pipeline industries. Most of these customers operate 24/7, which gives the utility a uniquely high load factor featuring a power supply with less variation in demand than most utilities. This high load factor ensures efficient utilization of Minnesota Power's system, creating value for all of its customers.

Minnesota Power has eight Large Power customer contracts, each serving at least 10 megawatts ("MW") of load. Under these eight contracts, the Company provides electric service to six taconite producing facilities and four paper and pulp mills. In 2020, two of Minnesota Power's Large Power customers, United States Steel's Keetac facility in Keewatin, Minnesota, and Verso Corporation's paper mill in Duluth, Minnesota, were indefinitely idled in response to the sudden and dramatic decline in business conditions resulting from the COVID-19 pandemic. In December 2020, Keetac resumed pellet production[1] but as of the date of this filing, Verso's Duluth mill remains idled.

In part because of its uniquely high concentration of industrial customers and relatively low proportion of residential customers from a kWh sales perspective, Minnesota Power is expected to remain a winter-peaking utility for the foreseeable future. Minnesota Power's electric load reached an all-time peak of 1,818 MW on December 30, 2014.

*Energy**Forward*** has reshaped the Company's power supply from an energy mix that was 95 percent coal in 2005 to one that is now delivering 50 percent renewable energy to customers. The Company has accomplished this dramatic transformation while retaining the lowest electric rates in the state for the average residential customer. Major emission reduction projects at Boswell Energy Center Units 3 ("BEC3") and 4 ("BEC4") were completed in 2015 and resulted in significant reductions of NO_x, SO_2, and mercury emissions – making the BEC, Minnesota Power's only remaining coal generation and source of baseload power, efficient and environmentally-compliant.

[1] Pellet production resumes at Keetac, https://www.wdio.com/mining-news/keetac-mining-pellets-range-us-steel/5948794/?cat=10363.

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, 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 with the completion of the Nobles 2 wind farm project. Combined, these wind projects added more than 850 MW of renewable electricity to the Company's generation portfolio.

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") to carry this Canadian hydropower to the heart of its industrial base on the Iron Range.

As an integral part of *Energy**Forward***, Minnesota Power is further diversifying its renewable energy options with 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, in 2016. The Camp Ripley Solar Project is the largest solar energy installation at any National Guard base in the United States, and helps meet the Department of Defense's resiliency and energy security goals. Minnesota Power is currently working on adding approximately 20 MW of additional solar generation in 2021, which would satisfy its Minnesota Solar Energy Standard ("SES") requirements and aid in the local economic recovery from the COVID-19 pandemic. 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 kW. Finally, as noted in Section II, Minnesota Power's 2021 Plan proposes the addition of 200 MW of new wind resources by 2025 and 200 MW of new solar resources by 2030.

Minnesota Power is continuing its commitment to the climate, customers and communities through its *Energy**Forward*** strategy, which outlines steps to reduce carbon 80 percent by 2035 and provides a vision for a 100 percent carbon-free future.

II. 2021 RESOURCE PLAN SUMMARY

This Petition presents Minnesota Power's 2021 Integrated Resource Plan ("IRP") for the period of 2021 through 2035. This IRP is filed pursuant to Minn. Stat. § 216B.2422, Minn. Rules Ch. 7843, and the Minnesota Public Utilities Commission's ("Commission") September 25, 2020 Order on extending the filing deadline and setting additional requirements for this IRP.[2]

Minnesota Power is pleased to submit its preferred plan – the "2021 Plan" – as the next chapter in the Company's *Energy**Forward*** resource strategy. *Energy**Forward*** has reshaped Minnesota Power's power supply from an energy mix that was 95 percent coal in 2005 to one that is now delivering 50 percent renewable energy to customers. This exciting renewable milestone was achieved in late 2020, all while maintaining Minnesota's lowest electric rates for the average residential customer. This 2021 Plan is key to achieving Minnesota Power's long-term vision for a sustainable carbon-free energy future by 2050 and outlines bold next steps in its clean energy transition that are centered on commitments to the climate, customers, and communities. Minnesota Power is also proud that its 2021 Plan is informed by a first-of-its kind stakeholder engagement process. If approved, the 2021 Plan will reduce carbon emissions by 80 percent by 2035 while ensuring reliable and affordable power for its customers.

As we look ahead to the next 15 years, Minnesota Power finds itself with a strong foundation of clean energy leadership, having ensured both reliability and affordability as it has transitioned to a power supply that is now half renewable. The Company continues to have an energy-intensive customer composition and unique challenges associated with it; therefore, progressing to the next levels of carbon reduction will become more complex and require technological innovation and maximizing existing infrastructure. Both Minnesota Power's historical roots and its future success are tied to the region's unique natural resources-based economy, as it serves some of the nation's largest industrial customers in iron mining and forest product industries. These price sensitive customers are competing in a global economy during unprecedented times, navigating the economic fallout from a global pandemic. At the same time, residential and commercial customers are also struggling with high unemployment and business closures as a result of the COVID-19 pandemic. As Minnesota Power charts the next 15 years of its energy transformation, ensuring competitive electric rates and maintaining reliability for all of its customers and communities are critical considerations.

Minnesota Power's 2021 Plan represents a sound approach to delivering safe, reliable, and affordable energy while ensuring a sustainable future for the climate, its customers and the communities it serves in northern Minnesota. The key themes of the 2021 Plan reflect the Company's long-held resource planning principles while meeting and exceeding current state policy objectives:

- *Climate:* The 2021 Plan offers a bold vision and definitive action to achieve 80 percent carbon reduction by 2035. Our concrete steps include transitioning operations at Boswell Energy Center Unit 3 ("BEC3") to economic dispatch in 2021; the early retirement of Unit 3 by year-end 2029, ceasing coal operations at Minnesota Power's Boswell Energy Center Unit 4 ("BEC4") in 2035, and adding 400 MW of new renewable resources to our energy supply. This 2021 Plan will result in the Company providing a power supply that is coal-free by 2035 and also outlines a future vision for providing 100 percent carbon-free energy to customers by 2050.

[2] Docket No. E015/M-15-690.

- *Customers:* The 2021 Plan preserves regional reliability and energy affordability while also achieving significant carbon reduction through thoughtful planning for the future of the Boswell Energy Center ("BEC"). The 2021 Plan provides the least cost pathway for customers with a reasonable transition timeline. The BEC facility performs among the most efficient thermal coal fired power plants in the country, following investments in state of the art emissions control technology in 2009 and 2015. As Minnesota Power's last remaining source of baseload generation, the BEC is a critical component of reliability for northern Minnesota and the only significant source of generation located between Manitoba Hydro resources to the north and the Twin Cities area to the south. Additionally, the 2021 Plan incorporates future customer-driven activities like energy conservation, distributed generation, demand response, and electrification.
- *Communities:* The 2021 Plan ensures a just transition for BEC's host community, which is the smallest and most geographically isolated coal plant host community in the state of Minnesota, by providing a thoughtful plan for the future of the BEC facility. The proposed timeline creates certainty to enable both employees and the community the necessary time to plan for a future beyond coal operations at the BEC. A socioeconomic evaluation of the impact of the BEC was conducted to ensure the benefits of being a host utility were identified and considered in the 2021 Plan. The 2021 Plan also recognizes the critical infrastructure located in the community and identifies actions that will continue to leverage them for cleaner energy options going forward.

Minnesota Power's IRP meets the requirements of several Commission orders across different dockets, including certain requirements from the following orders:[3]

- On July 18, 2016, the Commission approved Minnesota Power's 2015 IRP with modifications. This IRP will address resource planning requirements as outlined in the July 18, 2016 Order as follows:
    - Minnesota Power shall idle Taconite Harbor Energy Center Units 1 and 2 ("THEC1&2") in 2016, retain the ability to restart them to address reliability or emergency needs on the transmission system, and cease coal-fired operation by the end of 2020. Future refueling and re-mission opportunities will be considered in planning and optimization of the facility for the next resource plan.
    - Minnesota Power's next resource plan shall include a full analysis of all alternatives, including renewables, energy efficiency, distributed generation, and demand response, for providing energy and capacity sufficient to meet its need.
    - Minnesota Power shall investigate the potential for an energy-efficiency competitive bidding process to supplement its existing conservation improvement program ("CIP"), open to both CIP-exempt and non-CIP exempt customers, and shall summarize its investigation and findings in its next resource plan.
- On January 24, 2019, the Commission issued an Order approving a Capacity Dedication Agreement for 50 percent of the capacity of the Nemadji Trail Energy Center ("NTEC"), a proposed 525 MW natural gas combined-cycle power plant in Superior, Wisconsin[4]. In addition to approving the NTEC affiliated interest agreements, the Commission identified the following requirements for Minnesota Power's next resource plan:

[3] A list of IRP requirements and cross reference index can be found in Appendix N.
[4] Docket No. E-015/AI-17-568.

- o A baseload retirement analysis that thoroughly evaluates and includes a plan for the early retirement of Minnesota Power's two remaining coal plants, BEC3 and BEC4, individually and in combination.
- o A securitization plan that could be used to mitigate potential ratepayer impacts associated with any early retirement of one or both of the BEC3 and BEC4 facilities.
- o A proposed bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years.
- o In developing the modeling analysis to be used in its next resource plan, Minnesota Power shall consult with stakeholders, including but not limited to the Department of Commerce and the Clean Energy Organizations, regarding the Company's modeling input and parameters.

Key Items Shaping this IRP and the 2021 Plan

As outlined in the Commission orders above, this IRP is different from previous IRPs for a number of reasons, including: the addition of a Baseload Retirement Study examining the early retirement of Minnesota Power's last remaining coal facility, BEC; a Securitization Plan to investigate whether that financial tool can assist in the early retirement of BEC; and the first IRP in the state of Minnesota to fully utilize the new expansion planning model, EnCompass. Additionally, as further discussed in the following sections, Minnesota Power initiated a first-of-its-kind stakeholder process 18 months prior to filing this IRP that brought diverse groups together to share insights and engaged host community members not normally represented at the Commission.

First, Minnesota Power conducted extensive analysis, evaluating different scenarios for the early retirement of BEC3 and BEC4. Identifying the appropriate timing for any future retirement of a coal-fired, baseload asset is a complex evaluation that includes consideration of the utility's current and future power supply needs, impacts to the reliability of the transmission system, and the time it will take to replace the system reliability and energy provided by the retired units. The early retirement scenarios outlined in this 2021 Plan were informed by the extensive analysis conducted in the Baseload Retirement Study, included as Appendix P. Minnesota Power considered retirement dates as early as 2025 for BEC3 to ensure a wide range of options were explored.

Second, the Company engaged an independent third-party to analyze the feasibility of securitization. The Rocky Mountain Institute ("RMI") is an independent, non-profit organization founded in 1982 to transform global energy use to create a clean, prosperous, and secure low-carbon future. In evaluating whether ratepayer-backed bond securitization ("securitization") is a financing tool that could be beneficial for Minnesota Power's carbon reduction plans, the Company engaged RMI to conduct a feasibility analysis of using securitization to facilitate the early retirement of BEC3 and BEC4. Minnesota Power worked collaboratively with RMI on the production of two phases of a report titled "Using Ratepayer-Backed Bond Securitization for Cost Recovery in Accelerated Asset Retirement: Feasibility Study for Minnesota Power." The phase one report conducted a preliminary feasibility assessment for Minnesota Power, identifying the financial opportunities and challenges associated with securitization, and was submitted to the Commission on October 1, 2020.[5] The phase two report added financial

[5] Docket Nos. E015/RP-15-690, E015/GR-16-664, E015/AI-17-568.

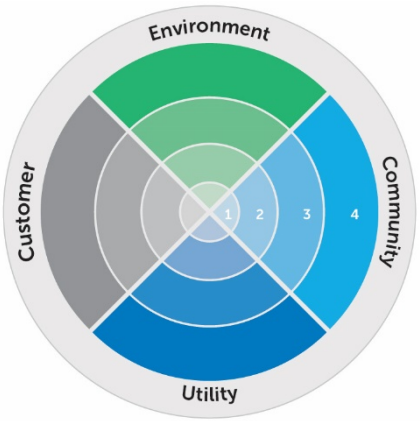
modeling to the feasibility assessment and includes additional case studies. This phase two securitization report is included as Appendix Q.

Finally, a third key item shaping this IRP is the utilization of a new planning software platform. Minnesota Power is the first utility in the State of Minnesota to submit an IRP that fully utilizes the new expansion planning tool, EnCompass. The Company worked diligently through the COVID-19 pandemic in 2020 to onboard the new tool and prepare it for use in the 2021 IRP. Throughout last year, Minnesota Power was in frequent contact with EnCompass support staff to resolve issues as they were identified during the onboarding process. Anchor Power Solutions (the owner of EnCompass) provided new versions of the EnCompass model throughout the IRP study that corrected several issues, and Minnesota Power successfully transitioned to these new versions under an expedited timeline. The Company is pleased to have onboarded and vetted a new model as sophisticated and robust as EnCompass in time to utilize it for this transformational IRP.

A Plan Responsive to Customers, Communities, the Climate and the Region

As noted above, Minnesota Power engaged in a first-of-its-kind stakeholder process for this IRP and Baseload Retirement Study. The 18-month long process brought together a diverse group that included over 70 diverse stakeholders representing various customer groups, environmental organizations, economic development entities, local government, industry, the host community, and others. The IRP stakeholder group met to discuss Minnesota Power's system, regional energy needs, and customer expectations. The stakeholder meetings allowed participants the opportunity to provide their perspective regarding Minnesota Power's future energy mix and the impacts of transitioning the current power system. The Center for Energy and the Environment, the Great Plains Institute, and Lasky Consulting ("Facilitators") were engaged as independent facilitators of the stakeholder process.

This stakeholder process captured the voices of Cohasset, BEC's host community - voices not traditionally heard at the Commission in St. Paul. Minnesota Power recognizes Cohasset's unique position and the incredible economic impact that BEC has on the region. With this in mind, Minnesota Power is presenting a plan that proposes a thoughtful and just transition of the BEC for its employees and its host community. Minnesota Power appreciates the time the stakeholders and facilitators dedicated to this process and their flexibility as the process adapted to the impacts of the COVID-19 pandemic.



While the full stakeholder report is included as Appendix R to this IRP, in order to organize stakeholder feedback in a way that could be used to inform the development of the 2021 Plan, participants were asked to identify and define the issues they cared about most, including what a "best case" and "worst case" future situation might look like for each. These issues were captured in an innovative Issue Map that identified metrics within four broad categories: customers, host communities, the environment, and the grid.[6] Minnesota Power used this forward-looking Issue Map, along with other insights and feedback from the stakeholder process, to develop a plan that was responsive to what stakeholders shared was most important (see additional detail in Section V). The Company recognizes the challenge of climate change, as expressed by stakeholders, and took bold steps in the 2021 Plan to

[6] The issue map and corresponding discussion is captured in the Stakeholder Process Final Report, included as Appendix R.

continue to lead the state in the amount of renewable energy in its portfolio, set industry leading carbon milestones and continue its path towards a sustainable carbon-free energy future.

Additionally, the Company heard clearly from stakeholders that safety, affordability, and reliability are key considerations, especially given northern Minnesota's price-sensitive and globally-competitive industries. The Company systematically identified the key reliability enhancements that would be needed for each retirement scenario to ensure that the system would remain stable. The 2021 Plan is also the least cost IRP alternative that provided a path to coal-free operations.

Finally, in addition to the formal facilitated stakeholder process, Minnesota Power recognized that, particularly during a global pandemic, not all customers are able to participate in a formal stakeholder process to share their insight with the Company. Therefore, the Company engaged all customers directly through a survey to better understand opinions and preferences related to their future energy supply. The survey included questions regarding system reliability, affordability, carbon-free energy renewable goals, and local economic impacts. Nearly 2,300 surveys were completed and returned, and the majority indicated they were foremost concerned with the affordability of electricity, with their next concern being the environmental impacts of electricity. The Company will continue to engage customers through bill messages, social media, and the Minnesota Power website. Minnesota Power values all input from customers and interested stakeholders and, as outlined above, has created an IRP responsive to customers, communities, and the climate.

State-Leading Renewable Energy Additions

Through strategic planning, regulatory support, successful project execution and capitalizing on economic opportunities, Minnesota Power met the state's Renewable Energy Standard of 25 percent renewable energy by 2025 a full decade early, in 2015. Today, Minnesota Power is proud to be the first Minnesota utility to offer a power supply that is 50 percent renewable. In December 2020, the Company achieved this milestone as 250 MW of new wind energy came online in southwestern Minnesota through the Commission approved Nobles 2 power purchase agreement with Tenaska.[7] Earlier in 2020, Minnesota Power completed and energized the 500 kV Great Northern Transmission Line ("GNTL") as a new international connection and began delivering 250 MW of carbon-free hydropower from Manitoba, Canada. This addition from Manitoba Hydro complements Minnesota Power's existing hydro system, which is the largest in the state.

Additionally, as part of the stakeholder engagement process, Minnesota Power heard that it was important to customers and communities that they benefit directly from renewable energy investments and that renewable projects be sited within the region when possible. In an effort to both site renewable energy investments in northern Minnesota and to also contribute to the local economic recovery from the COVID-19 pandemic, the Company has proposed three solar projects totaling 20 MW to be sited at 1) the Laskin Energy Center in Hoyt Lakes, 2) at the Company's Sylvan Hydro Station near Brainerd, and 3) in the city which hosts Minnesota Power's headquarters and largest service center – Duluth, Minnesota. These three solar projects are proposed to be constructed in 2021.[8]

Minnesota Power is proposing to continue its state-leading renewable energy additions in this IRP. The 2021 Plan includes adding an estimated 400 MW of new wind and solar energy, allowing Minnesota Power to increase its renewable energy supply to 70 percent by 2030.

[7] Docket No. E015/M-18-545.
[8] Docket No. E015/M-20-828.

These renewable additions ensure Minnesota Power continues to exceed both the state's Renewable Energy Standard and the Solar Energy Standard ("SES") for many years to come.

Meaningful Carbon Reduction and Creating Certainty for Host Communities

Since 2005, Minnesota Power has reduced carbon emissions by 50 percent and retired, idled or re-missioned 7 of its 9 coal-fired generation units, removing approximately 700 MW of coal-fired generation from its 1600 MW system and making significant carbon reductions. The 2021 Plan identifies Minnesota Power's near term plan to further reduce carbon emissions by adding renewable energy, moving towards economic dispatch on remaining coal units, and proposing a plan to cease coal-fired generation completely by 2035. These actions will increase the Company's renewable portfolio to 70 percent and result in 80 percent reduction in carbon by 2030, all while maintaining cost effective rates for customers. This 2021 Plan exceeds both Minnesota's current state goals, along with the Paris Agreement targets, for greenhouse gas reductions and achieves those reductions with the lowest overall cost compared to other scenarios considered.

Minnesota Power – and the state more broadly – must plan for a lower-carbon future that includes a just transition for workers and communities. The Center for Energy and Environment's 2020 report titled "Minnesota's Power Plant Communities: An Uncertain Future" explored the challenges and opportunities associated with power plant retirements in Minnesota. The report notes that Cohasset, Minnesota – the host community for Minnesota Power's last remaining baseload facility, BEC – is the smallest and most geographically isolated coal plant host community in Minnesota. BEC and its approximately 170 employees are significant drivers of the local economy, with 2018 property tax revenue from the BEC plant accounting for almost 70 percent of Cohasset's city tax base, almost 20 percent of the Grand Rapids School District tax base and 13 percent of Itasca County's tax base.

Planning for a thoughtful transition of Minnesota Power's last remaining coal units is not only critical to ensuring regional reliability and the affordability of energy for customers, but it is also key in creating certainty and allowing adequate time for employees and communities to adjust to a different future. The path to a carbon-free energy future is only sustainable if it includes a just transition for the employees and communities directly affected by energy system change, and Minnesota Power's 2021 Plan provides the time for that thoughtful transition.

Leveraging Customer-Sited Resources in the Grid of the Future: Leading on Energy Efficiency, Distributed Generation, and Electrification Efforts

As Minnesota Power continues its state-leading path in adding renewable energy and reducing carbon, customer-driven resources like energy efficiency, demand response, distributed generation, and electrification will play an important role in decarbonization. Minnesota Power, together with its customers, community stakeholders, and trade allies, has achieved success through its energy conservation programs and has surpassed Minnesota's energy savings goal each year since it was implemented in 2010. On average, nearly 70 million kWh of energy savings were achieved each year over that decade, equivalent to powering 9,000 homes for a year, removing 11,000 cars from the road for a year, or saving 54,000 tons of carbon each year. The Company intends to continue building upon its successful track record of supporting energy efficiency and has committed in its most recent CIP Triennial Filing to an energy savings goal of 2.5 percent each year through 2023, well above the state's 1.5 percent energy savings goal.[9] In fact, as noted in Appendix B, Minnesota Power has incorporated

[9] Docket No. E015/CIP-20-476.

findings from the Center for Energy and the Environment's 2020-2029 Minnesota State Demand Side Potential Study into its energy savings goals in the current Triennial.

Partnerships with the Company's customers for efficiently meeting their energy needs is at the core of Minnesota Power's business. Through decades of optimizing the infrastructure in the region, Minnesota Power has created a strong reputation and trust with its customers as the Company helps educate and implement new programs and energy options. Minnesota Power has offered a rebate program for customers to install their own distributed solar systems since 2004, nearly a decade before Minnesota passed the 2013 SES. The Company has since expanded that program, and was the first in Minnesota to offer a dedicated Low-Income Solar grant program. Meeting customer desires and leveraging the system benefits of distributed energy resources are an important focus for Minnesota Power, as outlined in both this IRP and its 2019 Integrated Distribution Plan.

Minnesota Power's customer demand response programs are advanced and continue to evolve. The Company has been optimizing, with its customers, one of the largest demand response programs in the state for over two decades. Leveraging the flexibility of its unique customers to assist in managing the electric needs of the region has been the result of a strong partnership that will continue to be vital as it move towards an efficient decarbonization of the system. The need for long-term demand response opportunities is emerging as Minnesota Power bridges and manages volatility in available resources and paves the pathway with new innovative technologies. The continued energy system transformation will require all tools to be available and provide value to the grid. Minnesota Power will continue to work with its customers to implement a long-term demand response product to maximize this resource for our region.

In addition to conservation and renewable energy programs for customers, Minnesota Power is committed to facilitating electrification and offers a number of electric vehicle ("EV") programs to customers. The Company has offered a Residential Off-Peak EV Service Tariff since 2015.[10] Specifically for commercial customers, Minnesota Power's EV Commercial Charging Rate Pilot was approved by the Commission on December 12, 2019.[11] On July 31, 2020, the Company also filed a petition for approval of a portfolio of EV programs designed to address persistent barriers to residential EV adoption in northern Minnesota, including a Residential EV Charging Rewards Pilot Program, a Residential EV Charging Rebate Program, and a dedicated Education and Outreach budget for EV programs. The Company has other efforts under development, to include a Mine Truck Electrification Pilot Program and the deployment of additional EV charging infrastructure in northern Minnesota. More information about Minnesota Power's electrification efforts can be found in its annual Transportation Electrification Plan filing, submitted to the Commission on July 6, 2020.[12]

Finally, Minnesota Power is preparing both the technical infrastructure and electric rate structure to facilitate a future clean energy system that leverages a more dynamic grid, capturing the benefits of conservation, distributed energy resources, electrification, and more. In December 2020, the Company submitted to the Commission an innovative proposal, developed with extensive stakeholder engagement, to transition its electric rate design from the current Inverted Block Rate structure to a Time of Day rate for all residential customers – which is the first such proposal in Minnesota.[13] Minnesota Power has invested in widespread deployment of

[10] Docket No. E015/M-15-120.
[11] Docket No. E015/M-20-638.
[12] Docket No. E999/CI-17-879.
[13] Docket No. E015/M-20.850.

Advanced Metering Infrastructure and is in the final stages of implementing a Meter Data Management System ("MDM"). These infrastructure investments, coupled with an innovative rate design proposal, are preparing for a future that incentivizes and optimizes the grid for clean energy options like conservation, distributed energy resources, and electrification.

Technological Evolution and Planning for a Just, Carbon-Free Energy Future

Minnesota Power's 2021 Plan outlines a commitment to reduce carbon 80 percent by 2035 from 2005 levels and a goal to achieve a sustainable carbon-free energy power supply by 2050. The Company is steadily following and studying technology developments to determine the best path forward in meeting its 2050 carbon-free goal. While this IRP identifies specific steps the Company will take to reduce carbon emissions by 2035, new technology is needed to meet carbon goals beyond that date. Technology evolution in the energy industry is occurring rapidly, and the Company is optimistic that due to technological advances in lower carbon resources, renewable energy, energy storage, and demand side resources, more cost effective options will be available in future years to help it meet its 2050 goal. Minnesota Power's customers are best served by a resource strategy that is flexible and nimble to be able to help develop and capitalize on these technology developments at the right time. Advancing too soon can create unnecessary risk for customers.

While this 2021 Plan represents meaningful action on carbon reduction, the Company is also investigating carbon neutrality efforts and the ability to make key advancements in that field in the near term. Minnesota Power is particularly interested in carbon neutrality efforts that leverage the natural resources in northern Minnesota and that invest in the unique region it serves. As an example of this effort, in January 2021, Minnesota Power partnered with the University of Minnesota's Natural Resources Research Institute on a grant application to the United States Forest Service to investigate the production of biochar at Minnesota Power facilities, evaluate carbon credit opportunities, and deploy a biochar soil amendment at a Minnesota Power or customer site. Biochar is carbonized biomass that is obtained from sustainable sources (like northern Minnesota timber) and sequestered in soils to sustainably enhance their agricultural and environmental value.[14] As the paper industries that have supported northern Minnesota's economy for over a century are in decline, finding new and sustainable markets for wood resources is critical to the regional economy and forest management. Minnesota Power looks forward to investigating this, and other, carbon neutrality efforts on its path to a carbon-free energy future.

Lastly, for Minnesota Power, sustainability means more than just reaching the landmark environmental goal of providing a carbon-free power supply. For example, creating a more diverse and equitable workplace, increasing diversity within the Company's supply chain, and being responsive to community needs are important components of Minnesota Power's sustainable path towards a cleaner energy future. Sustainability also extends to supporting the Company's customers and unique region. As such, for a carbon-free energy future to be truly sustainable it needs to ensure a just transition for workers and communities directly affected by energy system changes. Minnesota Power is committed to charting a future energy path that considers the quality of life in our region and addresses climate change while also promoting economic growth and strong communities.

[14] https://biochar.international/the-biochar-opportunity/what-is-biochar/

Thoughtfully Planning to Maintain Affordability for a Unique Region

Minnesota Power is proud to currently offer the lowest electric rates in the state of Minnesota for the average residential customer, and in 2018 offered the 13th lowest retail rates in the nation.[15] However, the Company recognizes that its customers of all sizes require electric rates that continue to be affordable in the future. Minnesota Power serves a variety of customers that are price sensitive, from its residential customers that are considered low-income, to some of the nation's largest industrial customers that are operating in competitive global markets. The 2021 Plan provides the least cost IRP alternative for the 15-year outlook and maintains affordability and reasonable cost increases while achieving significant carbon reduction with state-leading conservation efforts, industrial demand response programs and renewable energy integration.

As the Labors' International Union of North America ("LiUNA") noted in December 2020, northern Minnesota is a region particularly impacted by the economic crisis following the COVID-19 pandemic. The statewide unemployment rate in the fall of 2020 was nearly double what it was in March of the same year, increasing from 2.9 percent to 4.4 percent. But that increase does not capture the full impact of the economic crisis as the Minnesota Department of Employment and Economic Development assessed a reduction in unemployment rates were due to individuals dropping out of the labor force, rather than moving into employment.[16] Minnesota Power's unique large industrial customer class has also experienced significant challenges associated with the economic implications of the pandemic. In 2020, two of Minnesota Power's key large industrial customers idled operations due to the economic recession – Keewatin Taconite and Verso Corporation's Duluth mill. For context, in 2019, those two customers used approximately the same amount of energy as Minnesota Power's entire residential class.[17] While Keewatin Taconite has since resumed operations, significant economic challenges remain for many of Minnesota Power's customers – reinforcing the need for affordable energy now and in the future.

Minnesota Power is familiar with adjusting power supply strategies to respond to fluctuations in demand typically caused by recessionary impacts or business cycle changes for industrial customers. As stated earlier, Minnesota Power has seen a decrease in demand due to the idling of industrial customers and the lasting effects from the COVID-19 pandemic recession. This decline will be partially offset with PolyMet expected to start operations in 2025, then relatively flat demand post 2025. The flexibility built into the 2021 Plan is important as Minnesota Power's customers continue operations post pandemic. In order to account for uncertainty in customer demand, the Company evaluated how the 2021 Plan responded when customer demand was stressed through a sensitivity analysis. To capture the potential variability in demand, a range of load sensitivities that considered the return of an idled industrial customers (+100 MW), or the loss of additional industrial load (-75 MW). The 2021 Plan demonstrates that Minnesota Power has a robust and flexible strategy that is positioned to serve demand under various outlooks while providing those customers with the cost effective and reliable electric service they depend upon.

[15] Numbers according to the Edison Electric Institute. In 2018, Minnesota Power's retail rates were ranked 13th lowest among 168 investor-owned utilities.
[16] Docket No. E015/M-20-828. LiUNA Comments Filed on December 11, 2020.
[17] Docket No. E015/M-20-492, Minnesota Power's Supplemental Report filed on August 31, 2020, and Docket No. E015/M-20-814.

Ensuring Reliability for the Region

As the Midcontinent Independent System Operator ("MISO") noted in its December 2020 Reliability Imperative report[18], current reliability challenges will become more significant as additional renewable energy is added to the system and traditional baseload generation is taken off line. Extreme weather events also highlight the importance of ensuring reliability during system transformation. During the Polar Vortex of January 2019, the coldest temperature recorded in the lower 48 states was set in the northern Minnesota community of Cotton, with a temperature of -56 degrees Fahrenheit.[19] MISO and the local utilities are responsible for working together to ensure there are adequate tools available, like dispatchable capacity and demand response, to manage reliability on an ongoing basis. These reliability challenges are further evidenced by the fact that MISO has declared an increasing number of emergencies since the summer of 2016, which is changing MISO's overall risk profile.

Additionally, in October 2020, MISO published a summary of its Renewable Integration Impact Assessment ("RIIA"), which is North America's most comprehensive renewable integration study initiative to date.[20] While RIIA determined that there are technically feasible solutions to accommodate a system that meets half of its annual demand from renewable resources, significant system-wide complications arise when renewable penetration passes just thirty percent. RIIA attributes these system challenges to the variability of renewable resources, changes in resource availability, and the overall lack of transmission capacity. As Minnesota Power currently offers a resource mix that is half renewable, the 2021 Plan presents an ambitious commitment to increase that amount to 70 percent by 2030, maintaining reliability in the midst of a dramatically changing system is critical.

Over and over again, when Minnesota Power customers are surveyed they indicate reliability as one of their top concerns. As discussed in Minnesota Power's 2019 Rate Case, a customer survey was conducted for Minnesota Power that contacted 800 residential customers, a sample that accurately reflected the actual residential customer base in key demographic areas. When asked about the importance of different words that could be used to describe their electric utility, residential customers ranked reliable and safe the highest, followed by affordable.[21]

BEC is Minnesota Power's only remaining source of baseload generation and the only significant source of generation to support reliability in the region between the Twin Cities and Manitoba. The BEC facility has electric infrastructure that maintains critical energy services for the region.

As Minnesota Power has transitioned 7 of 9 coal fired units and added over 1100 MW of new renewable energy, it has made over $500 million of investments to maintain transmission reliability since 2009. These grid investments covered replacing aging infrastructure, enhancing security, preparing for outages caused by extreme weather events, integrating more renewable sources and maintaining reliability as coal-fired generation came offline.

Additional reliability transmission enhancements will be needed to transform to the higher levels of carbon reduction and move away from baseload coal fired generation. The 2021 Plan outlines steps for Minnesota Power to be coal-free by 2035 and the needed grid transformation

[18] https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative%20FINAL504018.pdf
[19] https://www.weather.gov/dlh/January2019Cold
[20] https://cdn.misoenergy.org/RIIA%20One%20Pager484752.pdf
[21] Docket No. E015/GR-19-442, Case Overview Direct Testimony of Frank L. Frederickson at 66-67. The Commission subsequently approved withdrawal of this rate case on December 11, 2020.

to prepare for an early BEC3 retirement. Planning for a future without baseload generation will take time, study and implementation to ensure grid reliability is not negatively affected. The transmission evaluation for the BEC retirement alternatives in Appendix F identifies the significant investment needed to move away from baseload generation at that site. Minnesota Power will be working to optimize the existing infrastructure at the facility to minimize the impact of the transformation.

Resource Updates Since the Last Approved Minnesota Power Resource Plan

Specific actions taken since the July 2016 approval of Minnesota Power's 2015 Plan in Docket No. E015/RP-15-690 include:

- Minnesota Power has acted to implement and procure the most appropriate sources to add to its renewable energy supply (see Appendix H). The Company has:
    - Energized the 500 kV GNTL in June 2020, enabling the delivery of 250 MW of hydropower from Manitoba, Canada to Minnesota Power's system;
    - Added 250 MW of wind energy through a Power Purchase Agreement ("PPA") with Tenaska's Nobles 2 project. The Nobles 2 wind generation facility in southwestern Minnesota achieved commercial operations in late 2020;
    - Developed its first utility scale solar project with a 10 MW project at Camp Ripley, near Little Falls, Minnesota. The 10 MW Camp Ripley Solar Project was completed in November 2016 and represents one third of the solar needed to meet the Company's requirements under the state's SES mandate;
    - Expanded customer-sited solar programs and added a 1.04 MW Community Solar Garden Program in 2018. Minnesota Power is on track to meet the requirements of the small-scale carve-out within the SES.
- In addition to the wind and solar energy noted above, Minnesota Power has made, or is making, the following modifications to its supply side resources:
    - Retired 130 MW of coal fired generation at Boswell Energy Center Units 1 and 2 ("BEC1&2") in 2018;
    - Continued to idle operations at the Taconite Harbor Energy Center ("THEC") from 2016 to 2020;
    - Gained Commission approval of agreements dedicating 50 percent of the capacity of the NTEC in January 2019. NTEC is a proposed 525 MW natural gas combined-cycle power plant that would be located in Superior, Wisconsin. NTEC has received a Certificate of Public Convenience and Necessity from the Public Service Commission of Wisconsin for both the proposed generating facility and the required 345 kV high voltage transmission line. The Minnesota Supreme Court is still considering the applicability of a Minnesota EIS process while it progresses through additional Wisconsin permitting processes.
- Minnesota Power remains a state leader in energy conservation and demand side management (see Appendix B). Under its CIP performance, Minnesota Power has met or exceeded the state's 1.5 percent energy savings goal by refining its conservation program strategy and expanding upon a proven program platform. In fact, Minnesota Power exceeded the energy savings goal year after year for the last decade and has committed to continued, ambitious energy savings goals over the next several years.

Resource Plan Overview: Short- and Long-term Action Plans

Minnesota Power's robust resource planning analysis considered a number of options in developing the 2021 Plan and identifying the path to 80 percent carbon reductions and coal-free operations for Minnesota Power by 2035. The proposed short and long-term action plans identified below include the steps needed to achieve that ambitious carbon commitment, while also maintaining reliability of the regional grid, ensuring continued affordability for customers and providing for a just and thoughtful transition for BEC's host community. Supported by the information and analysis in the Appendices of this IRP, the actions outlined in the following sections identify both short- and long-term steps that will help Minnesota Power continue to meet customer needs near term (over the next five years) and be poised to deliver safe and reliable service to customers for many years to come.

Short-term Action Plan (2021 through 2025)

Minnesota Power's short-term action plan during the five-year period of 2021 through 2025 is comprised of steps that will immediately reduce carbon emissions in the near term and continue the addition of carbon-free energy renewables, conservation and other demand side resources to the Company's resource portfolio. The specific strategic and necessary actions to achieve these steps include:

- Retire the currently idled THEC facility in September 2021. Originally a 225 MW coal generating station built to support iron mining on Minnesota's north shore and acquired by Minnesota Power in 2001, THEC1 was retired in 2015, and the remaining two units were idled in 2016. Given the potential rate impacts, Minnesota Power is not proposing modifying the existing accounting life of THEC, which is through 2026 and reflects the emission reduction investments at these facilities;
- Construct three solar projects totaling approximately 20 MW in the Company's service territory in 2021 to both meet Minnesota Power's requirements under the Solar Energy Standard and assist in the local economic recovery from the COVID-19 pandemic;
- Adapt operations at BEC3 to move to economic dispatch within the MISO market in 2021. This change in operations will result in immediate carbon reduction while supporting reliability in the region and continuing to provide economic benefits for the local host community;
- Continue to investigate and prepare BEC4 to transition to future economic dispatch, in coordination with MISO and BEC4 joint owner WPPI Energy;
- Maintain leadership in conservation programs and electrification efforts. Minnesota Power has surpassed the state's conservation goals for the last decade and has identified ambitious energy savings goals in its 2021-2023 CIP Triennial Plan. The Company is also implementing infrastructure investments, rate design changes and EV programs to position for a future grid that accommodates further electrification;
- Implement the Product C Demand Response program for industrial customers in 2022. In early January 2021, Minnesota Power submitted a petition requesting Commission approval of eight multi-year Product C agreements with industrial customers that will collectively enable between 100 and 202 MW of demand response product[22] to be sold each year from 2022 to 2028; and

[22] Docket No. E015/M-21-28.

- Add 200 MW of new wind resources to Minnesota Power's power supply portfolio by 2025.

Long-Term Plan (2026 through 2035)

Minnesota Power will focus its long-term plan on a strategy to further reduce carbon emissions in its portfolio and reshape its generation mix away from coal fired generation. This long-term strategy will continue resource diversification and position Minnesota Power to be able to successfully adapt to a range of economic and environmental futures while maintaining service to its customers at a competitive cost. Each component of this long-term plan has been proven through the planning analysis to be flexible and robust to keep progress toward the Company's strategic resource goals on track in a variety of future scenarios. Planned components include:

- Retire BEC3 by December 31, 2029;
- Add 200 MW of solar that leverages the Boswell site or other Minnesota Power facilities by 2030, leveraging existing interconnections and reinvesting in utility host communities;
- Work collaboratively with customers to pursue up to 50 MW of long-term demand response by 2030 to address future resource adequacy changes;
- Develop and implement transmission solutions to address reliability issues related to the early retirement of BEC3; and
- Investigate options to refuel or remission BEC4 and associated reliability transmission as coal operations cease by 2035.

A Bold, Least Cost Plan With Minimal Near Term Customer Rate Impact

The 2021 Plan evaluation identified that the Company's short- and long-term action plans were the least cost options of the scenarios considered for the study period through 2035. In accordance with Minn. R. 7843.0400, subp, 4, Minnesota Power's 2021 resource planning analysis considers the likely effect of plan implementation on electric rates. As further detailed in Appendix L, the 2021 Plan incremental power supply costs in 2024 would be expected to increase the average Residential customer's rate by about 1.31 percent compared to 2021 base rates. That is equivalent to an increase of $1.12 per month compared to 2021 base rates. The impact to the average Large Power customer rate would be an increase of about 0.57 percent compared to 2021 base rates, equivalent to an increase of $24,674 per month.

Minnesota Power believes its 2021 Plan will continue to serve its customers in a thoughtful and forward-looking way during the 2021-2035 planning period, and proudly presents a plan that reflects our commitment to our customers, communities, and the climate. Minnesota Power respectfully submits this 2021 Plan for the Commission's review and approval.

III. CURRENT OUTLOOK

Since filing the 2015 Plan, the electric industry continues to take steps that accelerate the reduction in carbon emissions and the addition of renewable energy resources. Minnesota Power is a leader in both the state and the region by already reducing carbon emissions by 50 percent since 2005, and surpassing 50 percent renewable energy production in 2020. The proposed 2021 Plan continues this trajectory and the Company's commitment to a sustainable power supply, while at the same time recognizing the Company's unique nature among utilities with its large industrial customer concentration and a winter peaking system.

This section identifies the major items contributing to Minnesota Power's outlook for customer demand for electricity and the supply resources that will be utilized as the foundation for the "Base Case" in this IRP. The Company enters this IRP time frame with existing generation sufficient to meet its power supply need, and thus has minimal new power supply needs over the study period that need to be addressed. However, with Minnesota Power's commitment to reduce carbon within the power supply, additional carbon-free energy will be needed to displace existing carbon based energy resources.

Current Outlook

Minnesota Power's Summer Load and Capability (2021-2035)

The Load and Capability ("L&C") combines peak customer demand levels in the most recent Annual Electric Utility Forecast Report ("AFR2020"), with the capacity resources in Minnesota Power's portfolio to understand potential capacity outlook for the next 15-year planning period. For more information on the Base Case and the Company's approach to developing a customer demand forecast refer to Minnesota Power's AFR2020 filing in Docket No. E-999/PR-20-11 or Appendix A of the IRP.

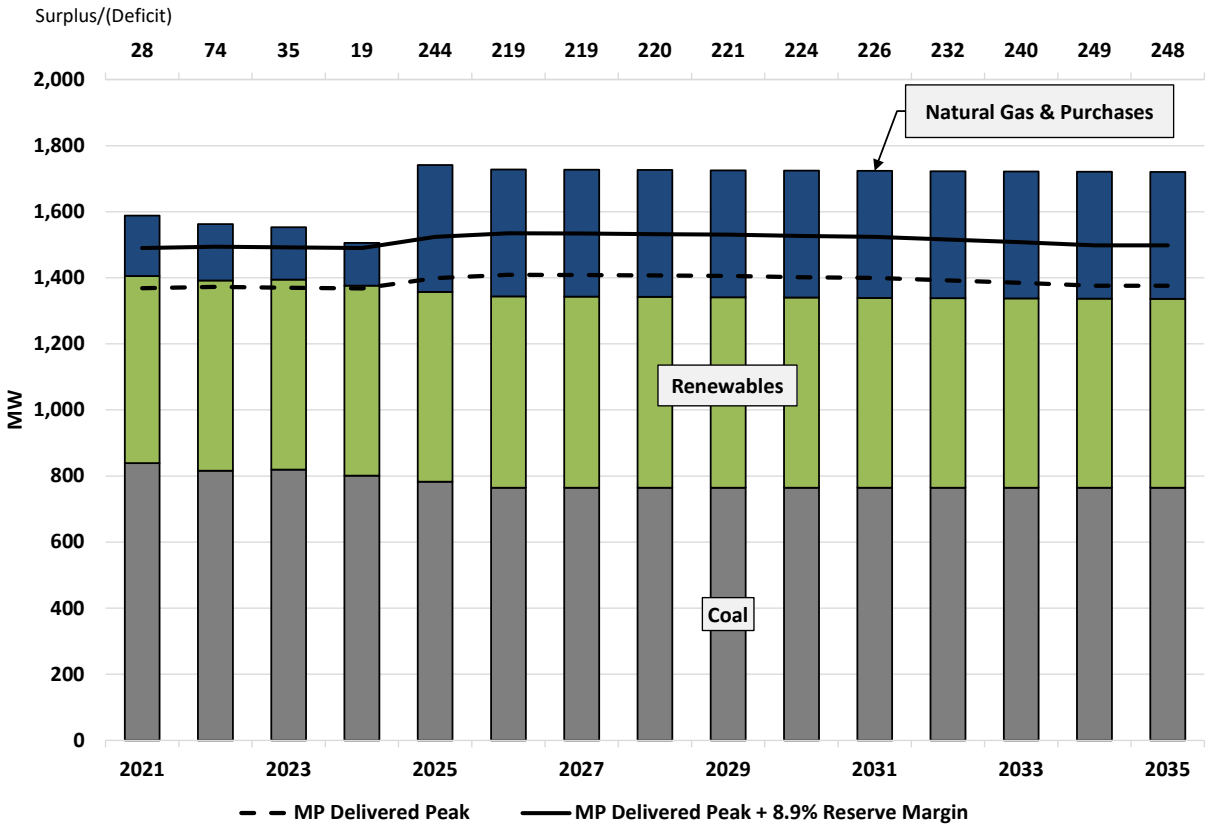
Minnesota Power creates the L&C with the Planning Year 2020-2021 MISO Module E L&C calculations as a starting point. The L&C calculation takes into consideration Minnesota Power's customer load forecast for peak demand coincident with MISO's peak, expected demand-side resources, bilateral purchases and sales, Accredited Unforced Generating Capability ("UCAP"), changes to the Effective Load Carrying Capability of wind and solar as those resources increase on the system, and MISO's required 8.9 percent planning reserve margin. New generation resources approved by the Commission or anticipated new resources are included, such as the Nemadji Trail Energy Center ("NTEC") in 2025 and the 20 MW of solar projects needed to comply with the SES in 2022. The result of the L&C calculation is a capacity surplus or deficit for each MISO Planning Year in the 15-year outlook.

Minnesota Power is a winter peaking utility, and monitors the capacity position for both the winter and summer periods to ensure year round reliability for its customers. The Company's winter peak demand coincident with MISO is typically between 15 and 45 MW higher than its summer peak. MISO's existing resource adequacy construct requires utilities to demonstrate they have sufficient capacity resources for the summer period. MISO is actively exploring with stakeholders through its Resource Availability and Need ("RAN") initiative new resource capacity constructs that could require each utility to demonstrate resource adequacy for multiple periods. For the purposes of the IRP analysis, as the new tariff is still in exploration, the L&C for the summer period is provided.

Figure 1 shows the L&C for the summer period. This is the starting capacity position in the IRP and EnCompass evaluation. For the near term, Minnesota Power is expecting the capacity position to be neutral as excess capacity caused by the idling of Verso and Keetac is being

assigned to Large Power Demand Response ("DR") Product C, as described in Docket No. E-015/M-18-735. Note that Minnesota Power's own customers maintain a critical portfolio of generation resources and Demand Side Management ("DSM") resources that contribute to meeting the capacity need – this is referred to as "DSM/Customer Gen" in the L&C Figure. Since the AFR2020 was filed, Keetac has announced a resumption of operations. Please refer to the AFR on the Company's long-term expectations for taconite production.

Figure 1: Base Case Summer Season Capacity Position Outlook

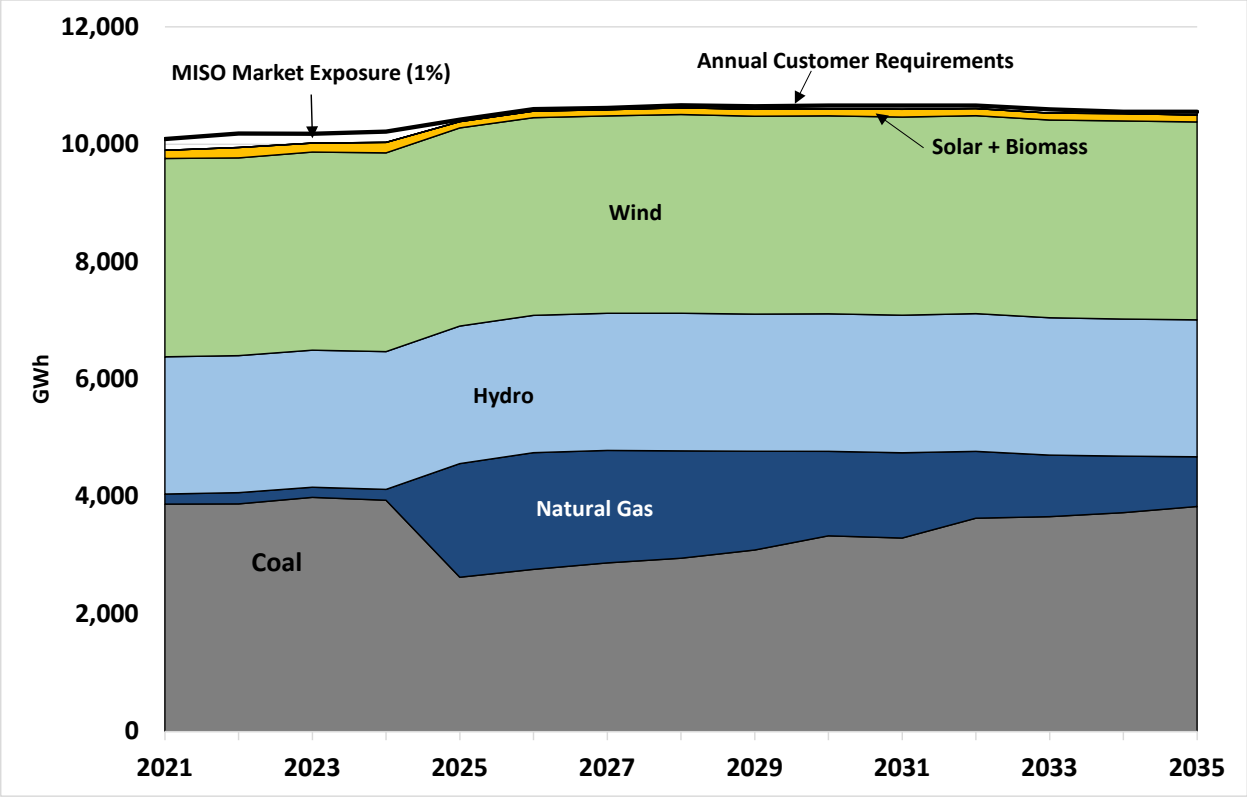


Later in the planning period, Minnesota Power has surplus capacity starting in 2025. This is a change from prior L&C looks in the 2015 IRP and *Energy**Forward*** Resource Package petition. The surplus capacity is due to an unexpected decline in industrial demand brought on by the COVID-19 pandemic along with increased energy efficiency resulting in lower residential and commercial demand. As the Company does have fluctuation in its yearly customer operations, Minnesota Power is including a sensitivity analysis that includes high and low customer demand outlooks to show the impact to the L&C and the resource selection. The high scenarios reflect a demand forecast that considers the return of recently idled industrial customer load

Since the 2015 Plan, Minnesota Power has added more than 500 MW of additional renewables and has retired about 275 MW of additional coal generation, resulting in a 50 percent reduction in carbon and achieving 50 percent renewables well ahead of the State's current Renewable Energy Standard ("RES") of 25 percent renewable by 2025.

The Base Case energy position is shown in Figure 2, and it identifies that the Company has minimal energy needs to be addressed over the study period given the current outlook for demand and generation available to serve customers.

Figure 2: Base Case Energy Position Outlook



Minnesota Power's Large Industrial Customer Base

Minnesota Power's customer mix is uniquely weighted with resource-based industry and trends in sales are largely driven by demand for iron ore, steel, paper, and oil transportation. About 61 percent of the Company's retail and required resale energy sales serve industrial customers. Demand for iron and steel is highly cyclical, and the impacts of the general economic downturn (2009), the industry-specific downturn (2015-2016), and the recent COVID-19 pandemic induced recession have resulted in dramatic reductions in Minnesota Power's overall retail sales. The Company's paper customers continue to be challenged by the prolonged decline of printing and writing paper consumption, and this has resulted in idling of paper machines or entire mills over the last two decades. Oil and natural gas pipeline customers served by the Company tend to have more consistent operations, though require significantly smaller amounts of energy than the Company's mining or paper customers. The dynamics of these industries compel Minnesota Power to work closely with customers to develop forecast assumptions that are consistent with the current macroeconomic outlook.

Major industries served by Minnesota Power are summarized below.

Mining Customers

Minnesota Power provides electric service to six taconite mining facilities with current annual production capability of up to 41 million tons of taconite pellets (see Table 1). Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities, and are part of the integrated steel industry. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, pipe and tube products for the gas and oil industry, and in the construction industry.

Table 1: Minnesota Power Taconite Customer Production

Minnesota Power Taconite Customer Production	
Year	Tons (Millions)
2005	40
2006	39
2007	38
2008	39
2009	17
2010	35
2011	39
2012	39
2013	37
2014	39
2015	31
2016	29
2017	38
2018	39
2019	37
2020	30
Average	35

Business cycles and short-term market corrections have and will continue to impact Minnesota's large mining operations. Most recently, several Minnesota taconite mines temporarily idled operations due to the COVID-19 pandemic induced recession. All facilities have resumed production as of this Plan's filing. The Company's load forecast assumes continued operation at five of its six mining customers through the end of the forecast timeframe. This equates to a 35 million ton level of production, and is consistent with the long-term (2005-2020) historical average.

The Company's base case load forecast assumes operations begin at the PolyMet NorthMet Project. PolyMet is a Canadian-based, mine development company with plans to develop an open-pit, copper-nickel mine on the Iron Range that will annually produce 72 million pounds of copper, 15.4 million pounds of nickel, 720,000 pounds of cobalt, and 106,000 troy ounces of precious metals.

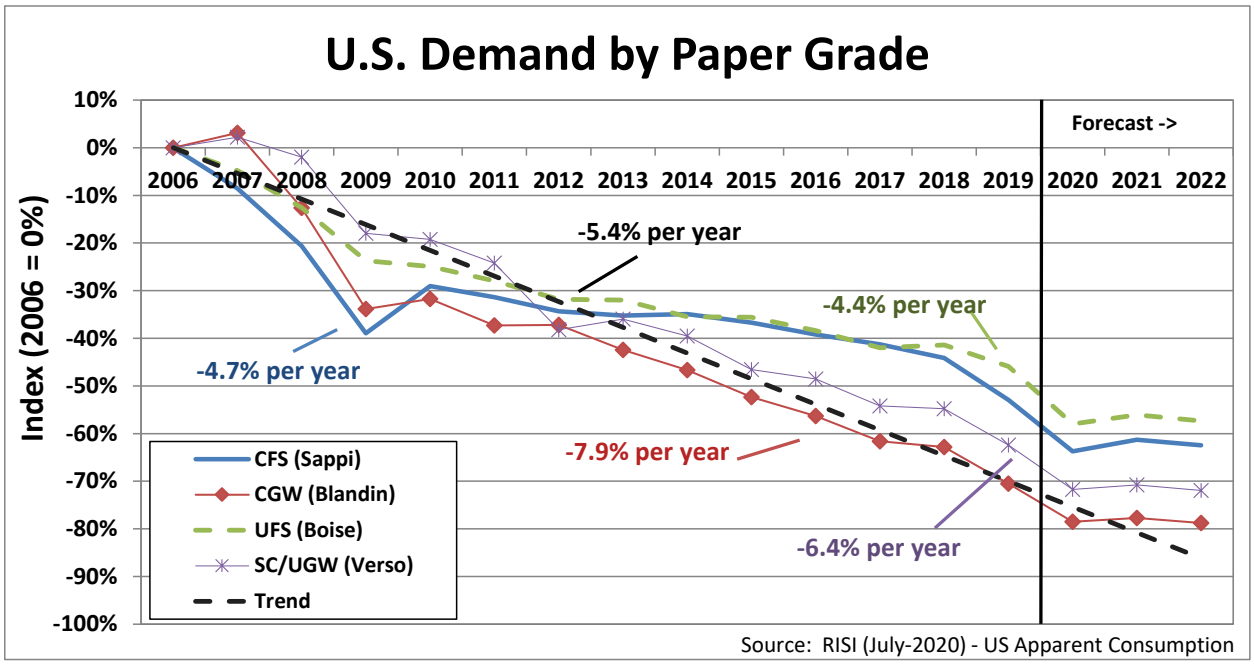
Wood Product Customers

Minnesota Power serves four paper and pulp customers who produce market pulp and various grades of printing and writing paper used in office papers, magazines, catalogs, and print advertising/direct mail. The North American printing and writing paper manufacturing

industry has experienced a significant decline in the last decade resulting in mill consolidation and closures. The COVID-19 pandemic has exacerbated the precipitous drop in graphic paper demand due to reduced magazine and catalog mailings and with many employers either mandating or allowing employees to work from home. Minnesota Power's customers' operations have reflected the industry's decline; in the last decade, Boise Paper (owned by Packaging Corporation of America) idled its #2 and #4 paper machines, Blandin Paper Company (owned by UPM-Kymmene) idled its #5 paper machine, and Verso Corporation's Duluth mill was indefinitely idled.

As shown in Figure 3, U.S. printing and writing paper demand was projected to continue to decline prior to the COVID-19 pandemic recession, which reduced consumption of printing and writing papers by over 20 percent. This decline in demand for printing and writing paper is driven by electronic media substitution and the associated migration of advertising budgets away from catalogs, newspaper inserts, brochures, and direct mail.

Figure 3: US Paper Demand 2006-2022 (est.)



The three currently operating paper mills served by the Company, representing approximately 1.5 million tons of paper production and about 360 thousand tons of dissolving pulp, are owned by well-established, major paper industry leaders (Sappi, Blandin Paper Company, and Boise Paper). As reflected in this Plan, Minnesota Power's assessment is that these corporations view their Minnesota assets as strategic to their respective business strategies. Each of the Minnesota mills is well positioned and cost-competitive in their respective paper markets with excellent customer relationships. The Company projects steady capacity utilization rates for these three mills over the forecast period, as these mills successfully control costs, reshape their products, and compete for market share. The Company's forecast assumes the Verso Duluth mill remains idled indefinitely, and that Sappi and Boise Paper continue to operate at current levels.

Pipeline Customers

Minnesota Power has two pipeline customers, Enbridge Energy and Minnesota Pipe Line Company, and both companies rely heavily on Western Canadian crude oil production. Enbridge Energy transports crude oil across North America. Minnesota Pipe Line Company receives oil from Enbridge Energy at Clearbrook, Minnesota, and delivers it to refining centers in the Twin Cities metropolitan area. A significant oil discovery in northern Alberta in the early 1990s has led to increased throughputs on both the Enbridge Energy and Minnesota Pipe Line Company systems. At the same time, shale oil production in North Dakota has also been increasing. Oil sands and North Dakota shale oil production are forecast to continue to increase over present day levels over the next few years. This will prompt the need for increased transport capacity on the Enbridge Energy and Minnesota Pipe Line Company systems.

Both Enbridge Energy and Minnesota Pipe Line Company take service under Minnesota Power's Large Light and Power Service Schedule ("LLP Schedule"). Neither Enbridge Energy nor Minnesota Pipe Line Company is currently required to provide Minnesota Power with demand nominations under the LLP Schedule. Pipeline maintenance and replacement activities at these companies is not expected to result in a net load increase across the Minnesota Power and Superior Water, Light and Power service territories.

Minnesota Power Load and Capability Forecast

Minnesota Power identified four scenarios for load growth potential and their impact to electric requirements in its service territory. Two of these scenarios, including the IRP's base case outlook are included in AFR2020, and can be found in Appendix A of this Plan. The Company also evaluated sensitivities that included accelerated rates of EV and Distributed Solar Generation ("DG solar") adoption in its resource planning analysis.

The AFR2020 Expected Scenario is utilized as the Base Case outlook in this IRP. This scenario assumes the permanent idling of one taconite mining facility and one paper mill with fairly steady contraction in all other customers' usage over the 15-year period. The AFR2020 Expected Scenario features an annual energy sales decline of about -0.4 percent per year (on average) from 2019 through 2034. Summer and Winter peak demands are projected to decline at average annual rates of -0.5 percent and -0.3 percent, respectively. The AFR2020 load forecast reflects 103 megawatts (MW) of system load loss by 2030.[23]

Minnesota Power is historically a winter peaking utility, and based on monthly trends in load behavior is expected to remain winter peaking for the AFR2020 period of 2020 to 2034. Throughout the forecast time-frame, the seasonal peaks run in parallel with some slight divergence in the later years of the forecast due to increasing saturation of DG solar and EVs.

Figure 4 presents both the Company's historic and forecast peak demand by season from the Expected Scenario in its AFR2020 submittal, and the foundation for the analysis in this IRP. Figure 2 depicts the significant near-term impacts of the COVID-19 pandemic recession (2020), a partial recovery by industrial customers (2021), the PolyMet NorthMet mine's start-up (2025), and the long-term underlying decline in loads due to conservation.

[23] Relative to the 2019 Annual Peak.

Figure 4: Peak Demand by Season

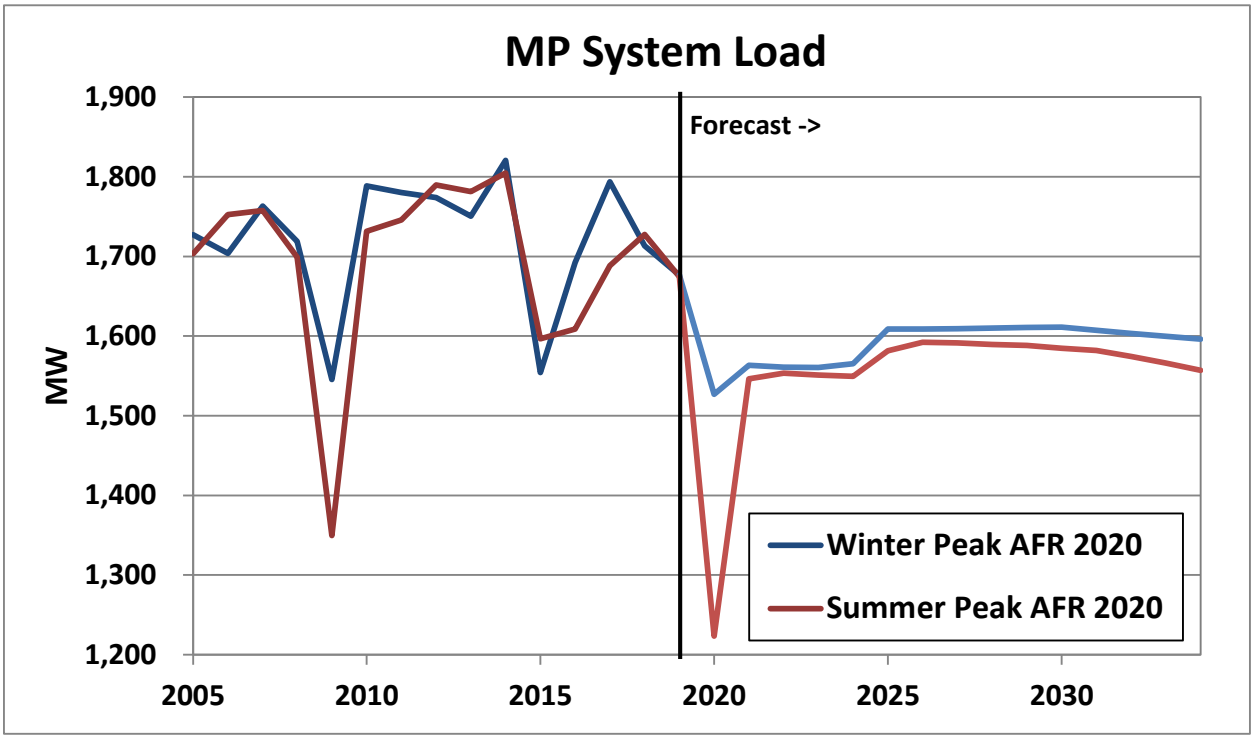
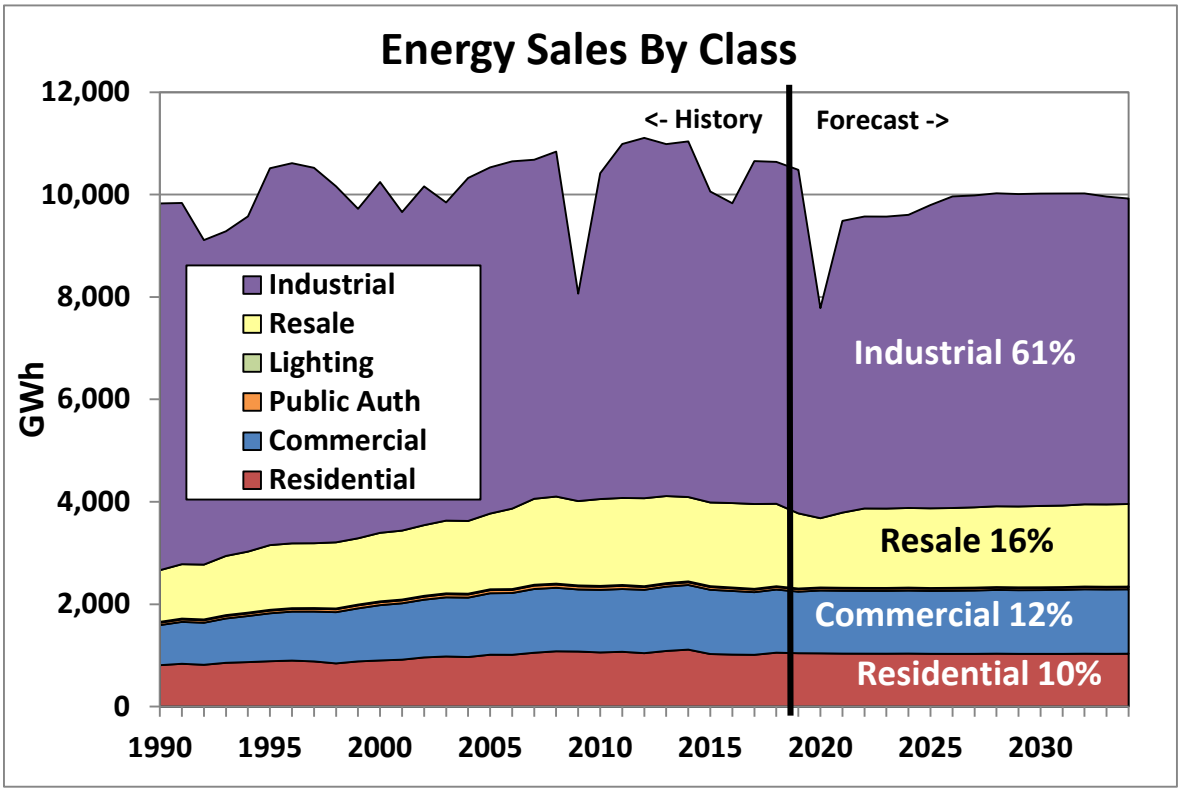


Figure 5 shows historic and forecast energy requirements by customer class, and depicts the large influence the industrial class continues to have on the Company's energy requirements.

Figure 5: Energy by Customer Class



Minnesota Power's system load forecast reflects projected (summer) peak demands of about 1,580 MW for the post-2025 timeframe with winter peaks between 30 and 40 MW higher.

Energy requirements continue to dominate the Company's supply picture, as the industrial load contributes an average system load factor of nearly 80 percent—still one of the highest in the nation. This system load factor drives the need for efficient energy intensive resources to serve customer requirements.

High and Low Sensitivities for Demand and Energy

To capture the plausible ranges of uncertainty in Minnesota Power's customer outlooks three additional sensitivities were chosen for further examination: the High, Low, and Mine Restart. These outlooks, shown in Figures 6 and 7, were used to determine contingencies for Minnesota Power's short- and long-term action plans, and to recognize the range of uncertainty that exists within the Company's unique customer base.

The High outlook contemplates the full operation of all taconite mining customers and the restart of the Verso Duluth paper mill, capturing about 100 MW of additional load over the Base Case. The Mine Restart outlook also reflects full operation by taconite mining customers, but the Verso mill remains idled indefinitely. The Low outlook is a constant 5 percent (approx. 75 MW) lower than the Base Case to simulate the loss of additional industrial load. Appendix A contains additional detail on the Base/Expected and High Scenarios.

Figure 6: High and Low Demand Outlook Sensitivities for MISO Coincident Peak (CP)

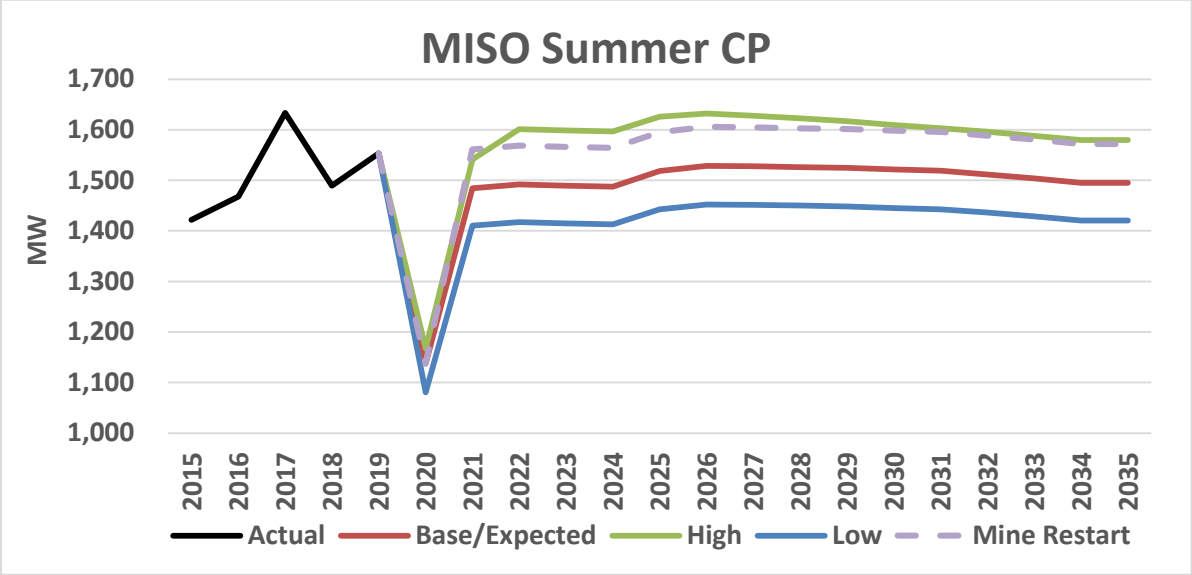
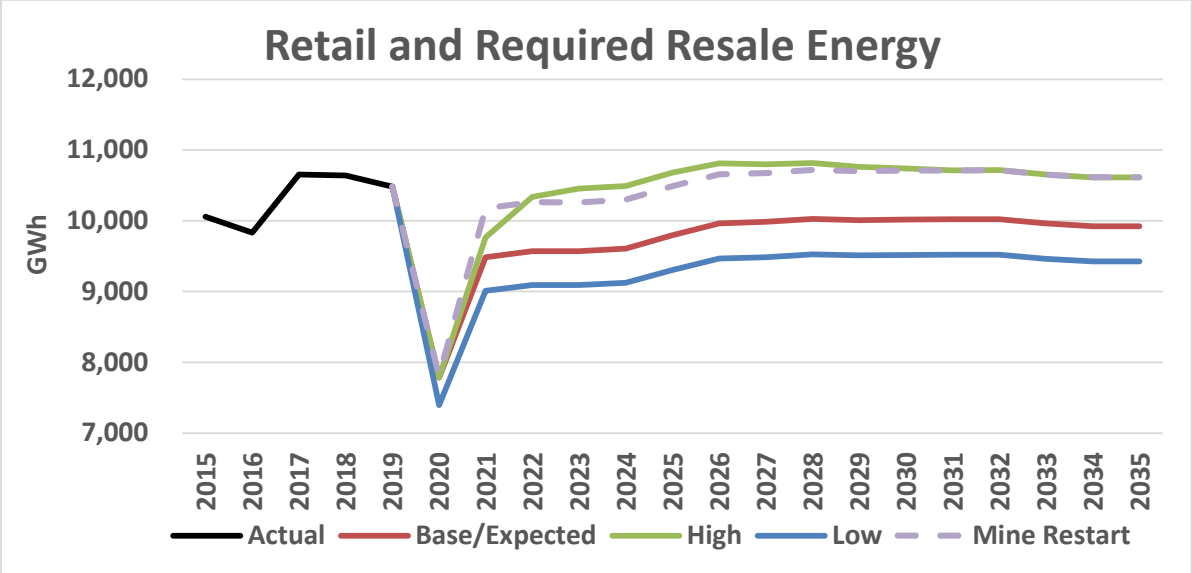


Figure 7: High and Low Energy Outlook Sensitivities



Minnesota Power continually monitors the potential for industrial growth in northeastern Minnesota, and recognizes the key role the mining and paper industries play in customer make-up, and system needs and costs. The viability of these customers is the engine that helps drive the economy in northeastern Minnesota. Making prudent and reasonable power supply plans for meeting future electric needs of industry, and all other customers, is critical in helping to keep economic balance in place to best serve all customers.

Changes Since June 2016 Commission Approval of the 2015 Plan

Continued Progress on Carbon Reductions and Renewable Additions

The Company is proud to say that it met the RES a decade ahead of schedule and is continuing to lead the state in renewable integration. Following the commercial activation of the Nobles 2 wind facility, the Company reached 50 percent renewable energy in December 2020. This success is the result of the Company's continuing commitment to delivering safe, reliable, and affordable energy across a smarter grid that is able to adjust to the transitioning baseload fleet, respond to renewable energy production, and provide greater resiliency through increased situational awareness and capability. As fossil fuel facilities are phased out of the generation fleet, the Company is investing in solar and wind generation to provide its service area with carbon-free energy power. Furthermore, the Company is recertifying its carbon-free hydropower facilities and exploring options for the expansion of biomass generation.

The Company has aggressively pursued solar generation and accompanying service options since 2015, including completing its first utility-scale solar project at Camp Ripley and constructing a now fully-subscribed community solar garden program. In addition, Minnesota Power has proposed several solar installations at existing Company facilities (Laskin Energy Park and Sylvan Hydro Station) as well as a solar array located on 9 acres of land owned by the City of Duluth.[24] The Company seeks to construct 20 new megawatts of solar in 2021.[25] The Company also continues to evaluate opportunities that enhance the geographic diversity of its wind resources. Over the past several years, there have been significant improvements in wind turbine technology (larger rotors and improved controls) and wind resource assessment (better siting and turbine layout). Minnesota Power has capitalized on these developments through a series of Company-owned wind resources and Power Purchase Agreements ("PPAs"), including the 250 MW PPA with Tenaska described above. The Company executed a unique solution for its customers to provide transmission access to North Dakota wind resources through the purchase of the existing DC Line that runs between the Square Butte substation near Center, North Dakota and the Company's Arrowhead substation near Duluth, Minnesota.

While Minnesota Power's current renewable generation is double the 2025 RES, further renewable integration is a continuous effort and a high priority. As previously described in Section II, the Company engaged diverse stakeholders, customers and host communities to hear their perspective regarding Minnesota Power's future energy mix and the impacts of transition the current power system. The insights and feedback gathered from the interested parties help inform the evaluation of BEC3 and BEC4, the Company's sole remaining coal generation plants, as well as the inclusion of additional renewable energy resources. As the Company's load changes continue to develop, the Company will continue to prioritize and finalize renewable projects in order to maintain the RES requirement for 2025 and beyond.

Integrated Distribution Plan

On November 1, 2019, the Company submitted it's first-ever Integrated Distribution Plan ("IDP"), a new biennial report containing a 5-year historical summary as well as a 5-year investment plan and 10-year future outlook for the distribution system. The Company's 2019 IDP (Docket No. E015/M-19-684) built its distribution strategy upon the priorities of technology, innovation, and continuous learning with the customer experience being the intense focus of

[24] In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery from the COVID-19 Pandemic, Docket Number E, G999/CI-20-492.
[25] In the Matter of a Petition of Minnesota Power for the Approval of the Acquisition of Solar Power to Support Economic Relief and Recovery, Docket Number E015/M-20-828.

those priorities. Minnesota Power is planning for the future of an advanced grid while enhancing the customer experience. The Company's 10-year long-term plan focuses on continued investment in infrastructure with accelerated investments in the near-term in systems and data to optimize the 21st century power grid. Investments in data and applications will provide a greatly enhanced customer experience while providing key operational benefits for reliability and safety. The Company's IDP is covered in more detail in Appendix G.

Transmission Planning

The Company has implemented many of the transmission projects necessary to support transmission system reliability in the local areas impacted by fleet transition decisions at LEC, THEC, and BEC1&2, and is continuing to work on implementing additional projects. Further study and system operating experience since the 2015 IRP has also led to the identification and implementation of additional projects not previously considered at the time. Local transmission system impacts from small coal unit closures and the projects implemented to address those impacts are discussed extensively in Appendix F, Part 6. With some limited exceptions, the Company has been able to successfully maintain a reliable system with less reliance on its fleet of small coal-fired generation.

In addition to implementing fleet transition-related improvements, the Company successfully completed construction of the GNTL to facilitate its hydro power purchases with Manitoba Hydro, continued to evaluate the optimal future for its existing high voltage direct current ("HVDC") assets in light of current and future regional transmission system needs, continued to address aging infrastructure on its system through transmission capital investments, and participated in the development of the CapX2050 Transmission Vision Report, March 2020.[26]

The Nemadji Trail Energy Center

On July 28, 2017, Minnesota Power filed a petition for approval of an "*Energy**Forward*** Resource Package" in Docket No. E015/AI-17-568, requesting approval of three new generation resources to meet the needs identified in the 2015 IRP: a 250 MW wind PPA, a 10 MW solar PPA, and agreements for 48 percent of the capacity of NTEC, a proposed 525 MW natural gas combined-cycle power plant in Superior, Wisconsin. In its January 24, 2019 Order, the Commission approved the NTEC agreements as reasonable and consistent with the public interest.

The NTEC project is currently progressing through the Wisconsin permitting process to obtain the necessary approvals to begin construction of the facility in Superior, Wisconsin. NTEC has received a Certificate of Public Convenience and Necessity from the Public Service Commission of Wisconsin for both the proposed generating facility and the required 345 kV high voltage transmission line.[27] NTEC has also received a Prevention of Significant Deterioration Permit for a new major source of emissions from the Wisconsin Department of Natural Resources ("WDNR").[28] The NTEC project partners are currently working with both the WDNR and the U.S. Army Corps of Engineers to obtain a Section 404 Wetland permit and its Section 401 Certification. Finally, the NTEC project partners will continue to work with the WDNR to procure a Construction Stormwater Permit in the first part of 2021.

In addition to progressing through permitting processes, NTEC is also currently the subject of legal proceedings at the Minnesota Supreme Court.[29] When the Commission approved NTEC

[26] The report is available at the CapX2020 website, http://www.capx2020.com/.
[27] Docket Nos. 9698-CE-100 and 9698-CE-101.
[28] EI Facility No. 816127840 and Construction Permit No. 18-MMC-168.
[29] Case No. A19-0688.

it was presented with two issues: whether to grant a petition for an environmental assessment worksheet under the Minnesota Environmental Policy Act ("MEPA"), Minn. Stat. §§ 116D.01–.11 (2018); and whether to approve the affiliated-interest agreements. The Commission concluded that MEPA does not apply to the decision to approve the affiliated-interest agreements. The Commission also concluded that it lacks jurisdiction to order an environmental assessment worksheet for a power plant located in Wisconsin. The Minnesota Court of Appeals concluded that the Commission erred by approving the affiliated-interest agreements "without substantively addressing the criteria" that govern whether an environmental assessment worksheet is necessary. The court of appeals reversed and remanded for the Commission to determine whether the Wisconsin power plant "may have the potential for significant environmental effects and, if so, to prepare an [environmental assessment worksheet] before reassessing whether to approve the affiliated-interest agreements."

On appeal to the Minnesota Supreme Court, the issues presented are: (1) whether MEPA applies to the decision of the Commission to approve the affiliated-interest agreements; and (2) whether the dormant Commerce Clause of the United States Constitution allows application of MEPA to the siting and permitting of the Wisconsin power plant. This case is pending a decision from the Minnesota Supreme Court, which is expected in 2021.

Demand Response

The Commission proposed DR Product C in August 2019. On January 4, 2021, Minnesota Power filed a petition for the approval of a new DR product, Product C Agreements, in Docket No. E015/M-21-28. Product C is a Market Surplus Service Capacity Product that allows Minnesota Power to work with participating customers to identify options for any excess capacity that does not fit into other DR products or current needs of the Company for Resource Adequacy. Interested Large Power customers must be willing to make a longer-term commitment to sell capacity to a third party through Minnesota Power.

Product C subscriptions are being modeled in the IRP as DR not available to Minnesota Power for MISO Resource Adequacy requirements.

Distributed Generation

Minnesota Power has a long history of encouraging its customers to participate in their energy choices. Over the past two decades, Minnesota Power has grown customer programs and internal expertise as customers have explored connecting new technologies to the distribution system.

Solar photovoltaics are the current dominant choice for customer self-generation. Since 2004, Minnesota Power has provided customers with rebates and consultation through the SolarSense program. In addition, Minnesota Power has actively worked to improve the interconnection process and experience for customers.

Minnesota Power has a mix of small wind generators and solar PV systems from under 2 kW to 1,000 kW connected to the distribution system. The majority of systems have been installed with the help of the SolarSense program offerings. The program was greatly expanded in 2017 to meet the small scale carve out of the SES of 2013. The program is currently approved to run through 2024.[30] SolarSense includes a rebate program, a low income grant program, and a solar energy consultation service.

The cumulative number of installations reported in 2020 include 15 wind generators and 478 solar installations totaling 9.34 MW of distributed generation on our system. Over the

[30] Docket Nos. E015/M-16-485, E015/M-20-607.

coming years, Minnesota Power anticipates the continued growth of small scale distributed energy resources, and the Company will continue to support customers with services ensuring the safe and reliable integration of these resources.

Conservation

Minnesota Power continued its history of strong conservation program performance throughout the 2017-2019 CIP plan achieving energy savings in 2017, 2018, and 2019 of 2.6 percent, 2.6 percent, and 2.5 percent respectively. On March 20, 2019, the Minnesota Department of Commerce ("Department") outlined a plan to extend the 2017-2019 CIP Triennial Plans through 2020 citing ongoing stakeholder work to review the fuel switching prohibition, status of federal lighting standards, and several legislative proposals.[31] Minnesota Power submitted its proposed 2020 plan on July 1, 2019, including a request to significantly increase the energy-savings goal for the Energy Partners Low Income program to accommodate increased interest.

On July 1, 2020, Minnesota Power filed its 2021-2023 CIP Triennial Plan filing proposing a savings goal of 2.5 percent of retail sales, well above the 1.5 percent energy-savings goal for CIP.[32] In developing targets for the 2021-2023 triennial, the Company leveraged the Minnesota State DSM Potential Study funded by the Department and led by the Center for Energy and Environment ("CEE"). Minnesota Power worked closely with CEE to update assumptions in the study to accurately capture the Company's service territory, customer base, system and historical experience with CIP. Minnesota Power is confident that the 2021-2023 plan includes a combination of traditional programs and innovative delivery strategies to provide a balanced and meaningful customer experience and position the Company for continued success in meeting or exceed its energy-savings goals.

Sales and Demand Forecast

The Company's load forecast methodology has been updated to incorporate assumptions for conservation, EV adoption, and DG solar. Specific modeling assumptions, modeling methodology, and results are documented in the Company's AFR2020 filing in Docket No. E-999/PR-20-11, also Appendix A to the IRP. Minnesota Power's large industrial customer assumptions have also shifted notably since the 2015 IRP's approval. Recent industrial customer activity and forecast assumptions are above under the header "Minnesota Power's Large Industrial Customer Base."

[31] Docket No. E015/CIP-16-117.
[32] Docket No. E015/CIP-20-476.

IV. 2021 MODELING APPROACH

The IRP analysis used the new EnCompass resource modelling software, which replaced the Strategist model used by Minnesota Power in prior Resource Plans. EnCompass is a more granular tool and can model Minnesota Power's system on an hourly basis, whereas Strategist could not. The EnCompass model was selected through a robust "request for information" process where the Company vetted ten potential planning models. Minnesota Power intends to use EnCompass in future Resource Plans. Minnesota Power believes EnCompass's more granular modeling capabilities will more accurately forecast customer energy and capacity needs, and can be relied upon to provide additional insights and approximate reliability needs.

Minnesota Power is following a similar approach used in prior Resource Plans where the Company evaluated early small coal retirements along with replacement energy and capacity needs. In this IRP, this includes performing a traditional Capacity Expansion Analysis that selects resources to replace BEC3 and BEC4 energy and capacity in several early retirement scenarios across Minnesota's designated carbon regulation cost and environmental cost futures. Also included is a Swim Lane analysis that compares Minnesota Power's 2021 Plan against other viable power supply portfolios alternatives, which were also compared across the Minnesota's designated carbon regulation cost and environmental cost futures and sensitivities that stress key assumptions.

In its January 24, 2019 order in Docket No. E-015/AI-17-568, the Commission ordered Minnesota Power to consult with stakeholders to develop the modeling inputs and parameters to be used in the Company's next resource plan. As part of the formal IRP stakeholder engagement process, the Facilitators convened a subgroup of interested stakeholders ("Modeling Subcommittee") to work with Minnesota Power staff on developing modeling assumptions. A description of the specific Modeling Subcommittee process to date can be found in the Stakeholder Engagement Report included in Appendix R. Multiple stakeholders expressed that they did not want to be asked to reach a final consensus on modeling assumptions. While agreed upon assumptions were not a product of the stakeholder process, the input and feedback received helped shape some of the key modeling inputs Minnesota Power used in the EnCompass analysis. For example, the technology curve that project declining costs for batteries, solar, and wind, were discussed and vetted with stakeholders at the IRP Modeling Subcommittee meetings. The Company appreciates the feedback received and enjoyed the conversations with stakeholders. The assumptions resulting from working with internal subject matter experts and stakeholders are provided in Appendix J.

This section introduces the analysis processes used to develop the 2021 Plan, the BEC3 and BEC4 retirement scenarios that were the outcome from the Baseload Retirement Study, and new resource alternatives that were available for the model to select.

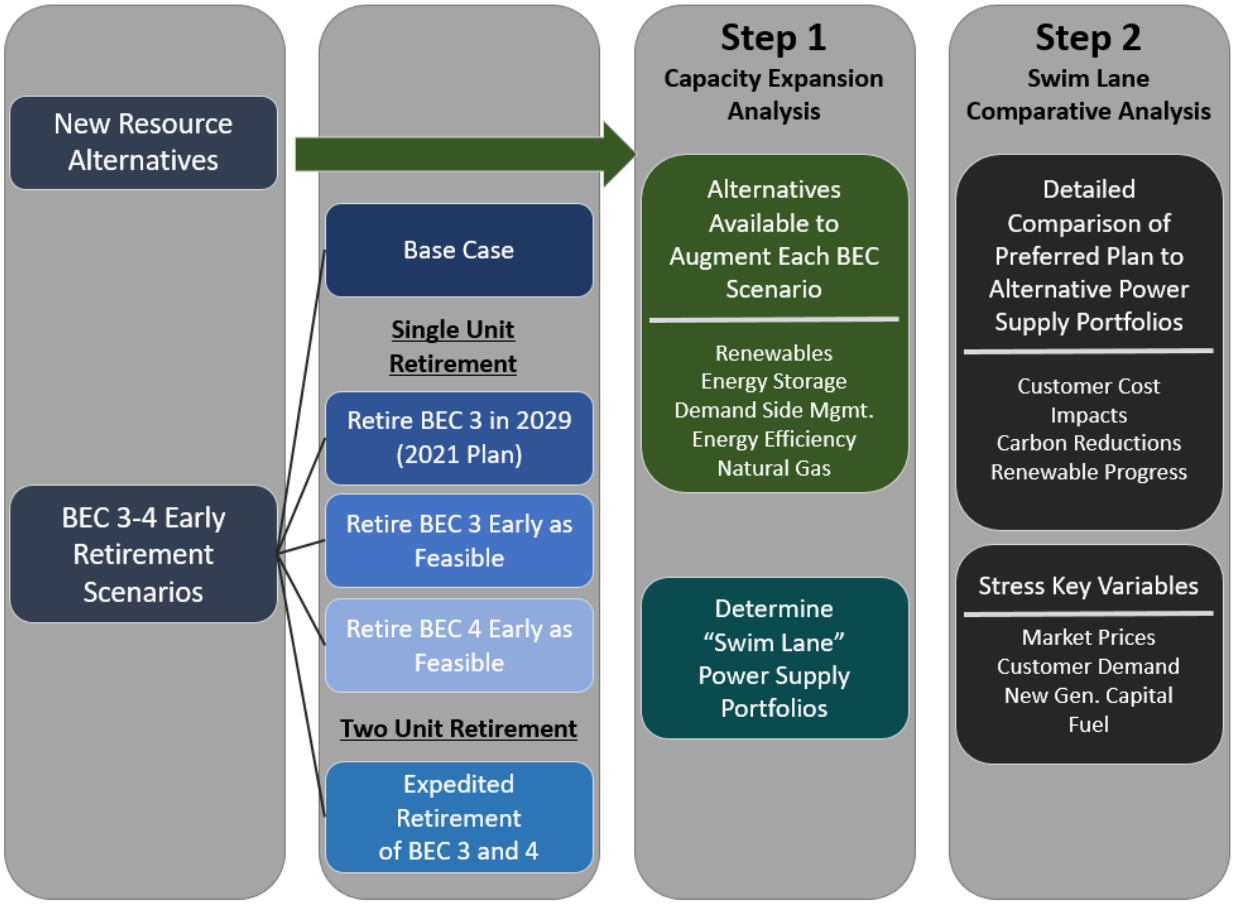
Analysis Process

A two-step planning evaluation was used to conduct an extensive analysis, evaluating the different scenarios for the early retirement of BEC3 and BEC4, and to select the least cost resource alternatives to augment the Company's power supply for long-term customer requirements. Identifying the appropriate timing for early retirement of coal-fired, baseload generation is a complex evaluation that includes consideration of Minnesota Power's current and future power supply needs, cost to replace the energy and capacity, impacts to the environment, and impacts to the reliability of the transmission system. The two sequential steps of the IRP include:

1. “Capacity Expansion Analysis” – Identify which resource alternatives should be added to the power supply. This includes resource alternatives that replace BEC3 and BEC4 capacity and energy in the early retirement scenarios.
2. “Swim Lane Comparative Analysis” – Detailed comparison of Minnesota Power’s 2021 Plan against other viable power supply portfolio alternatives in a swim lane analysis. This is the core analysis used to determine if early retirement of BEC3 and BEC4 is the least cost plan.

For the two-step evaluation, Minnesota Power identified site-specific alternatives for BEC3 and BEC4. There are several considerations and variables that enter into the decision to continue operating or retire a facility. For example, time to engineer, procure, and construct new transmission needed to mitigate transmission issues caused by a retirement can take several years and needs to be factored into choosing the dates considered for early retirement. The Baseload Retirement Study (Appendix P) identified that the need for significant transmission was one of the key factor in determining the earliest feasible retirement date, along with community impacts caused by retirement. The EnCompass analysis factors in the appropriate cost for studying early retirement, including transmission upgrades, decommissioning costs, environmental costs, and changes to operation and maintenance (“O&M”) and capital cost at each unit. The dates considered for BEC3 and BEC4 early retirement are discussed further in the Appendix P. Shown in Figure 8 is the two-step evaluation process used in the IRP analysis.

Figure 8: Plan Development Process



See Appendix K for more details on the analysis used to screen resource alternatives and demand-side resources to select the most cost-effective options for customer needs.

BEC Early Retirement Scenarios and Alternatives Evaluated

The Capacity Expansion Analysis evaluated several early retirement scenarios for BEC3 and/or BEC4. Factored into the earliest timing for a BEC retirement was the magnitude of the impact to the bulk electric system and the timing to implement solutions to address these impacts, which could include new transmission or new local generation. (Refer to Minnesota Power's Appendix P Baseload Retirement Study on how the Company identified early retirement scenarios for BEC3 and BEC4.) Shown below are the early retirement scenarios included in the EnCompass IRP analysis.

BEC Early Retirement Scenarios ("RS0#" is scenario name used in EnCompass modeling)[33]

1. 2021 Plan: BEC3 retires in 2029
2. "Expedited" Retirement of BEC3 and BEC4: BEC3 retires in 2025 and BEC4 retires in 2030
3. Retire BEC3 as Early as is Feasible: BEC3 retires in 2025
4. Retire BEC4 as Early as is Feasible: BEC4 retires in 2030

A "Base Case" scenario was also included in the analysis where no early retirement action is taken on BEC3 and BEC4.

Given the potential for significant remaining customer energy and capacity requirements when evaluating retirements such as BEC, several generation alternatives and supply-side resources were modeled to replace the energy and capacity retired and meet long-term customer demand for electricity. These resource alternatives can also be selected to reduce overall system carbon emissions if it is economical to do so. For Step 1 Capacity Expansion Analysis, the Company allowed EnCompass to select from the following supply and demand side resource options:[34]

Demand Side Alternatives

1. Up to 200 MW Long-Term Industrial Demand Response
    a. EnCompass can select either Product B or Product D
2. Air Conditioning Load Control and Hot Water Load Control
3. High and Higher Energy Efficiency Scenarios

Supply Side Alternatives

1. 100 MW Wind Farm in Minnesota
2. 100 MW Wind Farm in North Dakota
3. 100 MW Solar Farm Located at Existing Generation Site in Minnesota (i.e., "Net Zero Interconnect")
4. 100 MW Solar Farm Located in Minnesota

[33] Retirement occurs at the end of the year. For example, a 2025 retirement occurs on 12/31/2025.
[34] Appendix K: Detailed Resource Planning Analysis includes a complete list of resource alternatives considered in the analysis. This list was screened to remove higher cost alternatives due to limitations on the number of resource alternatives that can be evaluated in EnCompass.

5. 590 MW Natural Gas-Fired and Hydrogen Ready 1x1 Combined-Cycle (“CC”)
6. 280 MW Natural Gas-Fired and Hydrogen Ready Combustion Turbine (“CT”)
7. 110 MW Natural Gas-Fired Reciprocating Internal Combustion Engines (“RICE”)
8. 115 MW Natural Gas-Fired Aeroderivative LMS100 (“Aero”)
9. 100 MW Li-Ion Battery with 4 hours of Storage
10. 100 MW Li-Ion Battery with 8 hours of Storage
11. 100 MW Flow Battery with 12 Hours of Storage
12. 150 MW Bilateral Bridge Transaction

Note that more than one of each resource alternative mentioned above can be chosen during the Capacity Expansion Analysis. Also, the capacity listed is the installed capacity value for each resource. For information on capital costs, please refer to the Appendix J: Assumptions and Outlooks.

Futures Considered in the IRP Analysis

The Capacity Expansion Analysis and the Swim Lane Comparative Analysis was conducted for the four Commission-ordered environmental cost scenarios and the Reference Case Scenario with mid-carbon regulatory costs starting in 2025.[35] Minnesota Power included a no carbon regulation cost and no environmental cost scenario to clearly identify customer cost impacts, given carbon regulation cost and other environmental cost are currently not included in rates. Reflected in Table 2 are the futures included in the IRP Analysis, in total, there were five environmental futures that evaluated over 37 sensitivities.[36] The insights gathered from the IRP analysis assisted in the Company's development of the 2021 Plan.

Table 2: Six Futures Considered in 2021 IRP Analysis

		Carbon Dioxide (CO_2)				Other Criteria Pollutants
		Prior to 2025		2025 and Thereafter		
Futures	**EnCompass Case Name**	**Environmental Cost**	**Regulation Cost**	**Environmental Cost**	**Regulation Cost (2025)**	**Environmental Costs**
Low Environmental Cost	CLE1S	Low	-	Low	-	Low
High Environmental Cost	CHE1S	High	-	High	-	High
Low Environmental Cost and Low Carbon Regulation Cost	CLER1S	Low	-	-	$5/Ton	Low
High Environmental Cost and High Carbon Regulation Cost	CHER1S	High	-	-	$25/Ton	High
Reference Case	CREF1S	Mid	-	-	$15/Ton	Mid
No Environmental Cost and No Carbon Regulation Cost [37]	CCUST1S	-	-	-	-	-

[35] Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs, Docket Nos. E999/CI-07-1199 and E999/DI-19-406 (Sep. 30, 2020).
[36] For the initial IRP filing not all the environmental futures that are required for resource planning analysis are included in the sensitivity analysis. The Company is planning to file a supplemental analysis that includes the remaining environmental futures. The following environmental futures will be included in a supplemental filing: Low Environmental Cost, High Environmental Cost, and Low Carbon Regulation Cost and Low Environmental Cost.
[37] The No Carbon Regulation Cost and No Environmental Cost future was included in the Step 1 Capacity Expansion Analysis and used to determine energy supply mix, energy need, carbon reduction, and projecting annual customer cost impacts. This future was not included in the Step 2 Swim Lane Analysis.

V. 2021 PLAN DEVELOPMENT

Minnesota Power's 2021 Plan outlines additional actions to further reduce carbon emissions, sets key milestones in its transition away from coal fired generation, and augments its portfolio with additional clean energy. Since the submissions of the 2015 Plan and the 2017 Energy***Forward*** Resource Package, Minnesota Power has refined and updated its key assumptions and utilized its Baseload Retirement Study to identify early retirement scenarios for its remaining coal generation. Through its broad stakeholder process, the Company gathered insights into the issues most important to the participants and incorporated the feedback received during the IRP Modeling Subcommittee meetings. The 2021 Plan is the next phase of Minnesota Power's Energy***Forward*** strategy and was created using core resource planning principles that address reliability, customer costs, technology evolution, and host community impact.

This Section covers the following topics:

- Key Planning Principles and Handling Uncertainty
- Step 1: Capacity Expansion Analysis
- Step 2: Analysis and Insights
- Minnesota Power's 2021 Plan Characteristics

Key Planning Principles and Handling Uncertainty

Key Principles

There are a series of key principles that Minnesota Power took into consideration to help guide the analysis process and to ensure the resulting strategy is robust, sustainable, and in the best interest of customers. These principles helped shape the resulting 2021 Plan, which embodies the Company's *Energy**Forward*** strategy and also incorporates the key insights stakeholders identified through the IRP Stakeholder process:

1. **Advance Sustainability** – Minnesota Power is committed to the climate and a sustainable future for both its customer and communities. The planning evaluation considered plans that continue the carbon reduction journey began in prior IRPs, and aligns with Minnesota Power's long-term vision to provide 100 percent carbon-free energy. Minnesota Power is a clean energy leader, already delivering 50 percent renewable energy to its customers, which provides a strong foundation from which to start. A successful plan also needs to be sufficiently robust and flexible to adapt to changing customer demand, leave room for advancements and innovation in existing and new carbon-free technologies, leverage existing infrastructure to minimize cost impacts, and be informed by our customers and host communities.
2. **Ensure reliability** – Our customers receive reliable energy service today and expect it will continue as Minnesota Power transitions toward providing increasingly cleaner energy. Minnesota Power has the responsibility to plan and bring forward a resource strategy and accompanying grid improvements that provide adequate energy resources that can be available during extreme conditions, such as a polar vortex or heat wave, under varying levels of renewable production and system conditions. The

Plan will demonstrate how the Company plans to meet expected resource adequacy requirements over the next fifteen years.

3. **Manage Costs for Customers** – An IRP is designed to deliver the least cost strategy for meeting system requirement needs over the study period. Minnesota Power has developed the Plan based on sound IRP analysis that best manages customer costs from multiple perspectives and outcomes. Large changes in customer costs over a short period of time can create a significant burden for customers, as they have to adapt their operations, budgets, and plans. An IRP should identify a plan that aligns the lowest cost power supply over the long term and with reasonable costs and cost increases for customers.
4. **Allow Time for a Just Transition for Host Communities** - A resource plan needs to consider the socioeconomic impacts of difference scenarios and should evaluate a just transition for the employees and communities directly affected by facility changes. Allowing time for a thoughtful transition that minimizes impacts to local tax base, jobs, industry, and community health will help maintain a more stable environment for innovation, visioning and planning, and reduce impacts. Through its journey to decarbonize its fleet, Minnesota Power has transitioned seven of its nine coal fired facilities in the region. Each move required careful planning and preparation to ensure impacts were evaluated and communicated to regulators, employees, and affected communities.
5. **Allow Time for Technology to Develop and Advance –** A carbon-free future will require advancements in technology to provide adequate energy resources and ensure safe, reliable, and affordable electric service as we address the final increments of carbon reduction. Efficiencies and costs must continue to improve for technologies in place today and new technologies must also emerge in the exploration of carbon-free fuels (i.e., hydrogen and biofuels) for critically important dispatchable resources. A robust IRP will take into consideration developing technology and the role it must play in a future energy system, even though the technology may not be cost effective today. A diverse energy supply with multiple technologies will create a stronger electric system for the future. With technologies continuing to advance quickly, maximizing existing infrastructure and allowing time for innovation will best position the power supply for a carbon-free future.

Handling Uncertainty with a Flexible Plan

Utilities plan in an uncertain business environment, and must recognize that not all assumptions will become reality. Resource planning in Minnesota is dynamic and allows additional information to be gathered and applied to adjust resource strategies on an ongoing basis, in the best interests of customers.

Minnesota Power endeavored to create a 2021 Plan that contains robust power supply options to position its customers towards a sustainable carbon-free future, while mitigating unnecessary reliability and cost risk. The Company's planning process evaluates and compares resource strategy outcomes with a series of sensitivities. There are three key areas of

uncertainty the Company identified for the 2021 Plan: (1) MISO resource adequacy and availability of transmission, (2) customer demand outlooks, and (3) technology advancements.

MISO Resource Adequacy and Availability of Transmission:

Minnesota has an established history of robust resource planning processes that ensure reliable energy service, while at the same time positioning for a future of less carbon-intensive resources. During the study period for this Plan, the energy transformation is creating uncertainty and Minnesota Power must take a flexible approach to planning its power supply that allows for pivots in strategy. As baseload generation retires in the region, the system is becoming more reliant on wind and solar resources that are only available when the wind is blowing or the sun is shining. Minnesota Power therefore identified two key areas of uncertainty at MISO during the study period: 1) MISO resource adequacy construct changes, and 2) the capability of the transmission system to handle new renewable additions and retirement of additional baseload generation.

To ensure reliability during the clean energy transition, MISO is working with stakeholders on changes to the MISO resource adequacy construct that could impact how Minnesota Power plans for the capacity and energy needs of the system in future IRPs. The core tenants of the resource adequacy construct in place today were formed when MISO's energy mix contained mostly dispatchable coal and gas generation. As the power supply transitioned and accommodated the addition of more renewable energy, MISO's resource adequacy construct had to adapt, like enhancing requirements for demand response and better capturing the accredited capacity value for renewables. MISO, along with Minnesota Power, recognizes that the resource adequacy construct needs to continue to adapt for even higher levels of renewable energy penetration, and to ensure there can be energy coverage for all system conditions to ensure reliability. In the immediate future, the changes are focused on three broad categories: 1) multi-season resource adequacy construct, 2) accreditation enhancements for solar and energy storage, and 3) regional resource assessments of changing reliability risk profile. Minnesota Power continues to monitor the ongoing resource adequacy work at MISO and will adapt future actions and analyses methods as needed.

An important component of a successful transition to a carbon-free energy future is having a robust transmission system that can integrate increasing renewable energy, while facilitating the retirement of baseload generation and ensuring energy can be delivered to where it is needed on a 7x24 basis. While it is uncertain exactly how much more renewable energy can be added to the system before significant new transmission is needed, the MISO RIIA study identified increasing system-wide complications arise when renewable penetration passes 30 percent. A real time indication of this system-wide complication is seen in the MISO interconnection queue, where the addition of large volumes of new renewable energy is already requiring significant upgrades to the transmission system.

As baseload generation in MISO continues to transition, there are significant transmission projects that could be needed to facilitate additional coal retirements to the extent they are not replaced with generation that has similar grid attributes at the same site. This is especially true

for BEC Unit 3 and Unit 4, where a MISO Attachment Y2 study[38] identified these units as critical to the existing system and that additional transmission upgrades will be needed prior to retirement. Please refer to Appendix F for more detail on the MISO Attachment Y2 study results, along with insights from Minnesota Power's own independent transmission planning studies. Minnesota Power's robust IRP analysis took into consideration potential transmission needs when evaluating adding additional renewable energy and the scenarios that resulted in the retirement of BEC Unit 3 and Unit 4, along with running key sensitivities that varied the cost of interconnecting new renewables.

Minnesota Power, along with Minnesota regulators and policymakers and MISO, must address this challenge to maintain system reliability during the rapid decarbonization and transition of the power supply. Identifying the problems and finding solutions to ensure reliability during this transition will take time, and maximizing critical infrastructure is key to an efficient transition. To the extent possible, the resource planning analysis must try to anticipate change in the future resource availability as a central part of a plan. For example, the IRP analysis anticipates the capacity credit for solar will decline over the study period as more solar is added and sensitivities are used that stress resource adequacy requirements. A plan must also adapt to the changing energy landscape as the rules and requirements for a reliable system adapt to a carbon-free future.

Customer Demand Outlook:

There is inherent uncertainty in any customer demand outlook used in the IRP analysis. An IRP strategy should be robust across multiple outcomes to best navigate this uncertainty. With Minnesota Power's uniquely large industrial customer mix, there will be swings in industrial customer demand depending on the health of the economies they serve or the customers' respective industries (see Figure 5 in Section III to see how industrial demand has varied since 1990). The more recent trend Minnesota Power has experienced is a declining load environment caused by idling of industrial customers (i.e., Blandin paper machine No. 5 and Verso Duluth Mill) and lasting effects from the economic recession caused by the COVID-19 pandemic. While this decline is not offset by changes in Minnesota Power's smaller residential and commercial classes, it is somewhat offset by the planned load addition of PolyMet in 2025. To capture the variety of possible future demand scenarios, the IRP analysis included a range of load sensitivities from the return of an idled industrial customer (+100 MW) to the loss of additional industrial load (-75 MW).

Advancements in Technology:

The advancement in carbon-free technologies will be a key driver of how quickly and cost effectively Minnesota Power can move towards its goal to be 100 percent carbon-free by 2050. Minnesota Power recognizes that currently, the technology does not exist to cost-effectively achieve a carbon-free system, but believes the industry will continue to make advancements in the coming years. Over the 15-year study period, there is uncertainty as to how quickly costs will decline for some technologies, such as solar, along with how quickly technologies like energy storage (i.e., batteries, compressed air, and pump hydro), carbon capture, and carbon-

[38] The Attachment Y-2 study is a non-binding study performed by MISO, that provides guidance of transmission reliability issues caused by the retirement of a generator unit.

free fuels (i.e., hydrogen, and biofuels) will advance so that they can be implemented as part of a cost effective, reliable energy solution for customers. These technologies, in addition to a suite of demand response and energy efficiency efforts, could be important complements to the Company's growing renewable portfolio. Minnesota Power's own analysis took into consideration the declining capital costs for renewables and energy storage, along with stressing the rate of cost decline as part of the sensitivity analysis (Appendix J provides additional insights into the sensitivities considered). A flexible plan should allow time for these innovative technologies to advance further so they can be incorporated into future actions.

It is difficult to develop a plan that can hedge against all uncertainties over a 15-year study period. The Company's Energy***Forward*** strategy has already reduced carbon emissions by leveraging existing infrastructure and maintaining a dispatchable generation portfolio to meet energy needs. The 2021 Plan, as described below, will take further carbon action while providing flexibility as the Company continues to monitor and take measured actions to manage uncertainties in the coming years.

Step 1: Capacity Expansion Analysis

Minnesota Power arrived at its 2021 Plan using a two-step planning evaluation process that is described in further detail in Section IV. This section discusses the analytical results from Step 1 - the Capacity Expansion Analysis. The objective of step 1 is to identify the least cost supply side and demand side alternatives to replace the energy and capacity needed in the BEC Unit 3 and 4 retirement scenarios, developed in the Baseload Retirement Study in Appendix P. In total, the four BEC retirement scenarios below were included in the Capacity Expansion Analysis, along with a Base Case scenario:[39]

1. 2021 Plan: BEC Unit 3 retires in 2029;
2. "Expedited" Retirement of BEC Units 3 and 4: BEC Unit 3 retires in 2025 and BEC Unit 4 retires in 2030;
3. Retire BEC Unit 3 as Early as is Feasible: BEC Unit 3 retires in 2025;
4. Retire BEC Unit 4 as Early as is Feasible: BEC Unit 4 retires in 2030; and
5. Base Case: no early retirement action is taken in this IRP for BEC Units 3 and 4.

To understand why certain resources are selected in Step 1, it is important to know the overall capacity and energy need for each retirement scenario. In its base outlook as discussed in Section 3, Minnesota Power does not currently have a material capacity or energy need after the recent addition of the MHEB 250 MW PPA and Nobles 2 250 MW wind PPA in 2020, 20 MW solar being added by 2022, and Minnesota Power's 250 MW share of NTEC in 2025. However, when the retirement scenarios are layered onto the Company's base outlook and significant baseload generation is removed from the power supply, an energy and capacity need is created that must be addressed by the Capacity Expansion Analysis. Figure 9 shows the change in capacity need when BEC is retired in each of the scenarios.

[39] For all retirement scenarios, reference to a year indicates retirement on December 31 of that year.

The greatest capacity need is over 500 MW in the "Expedited Retirement of BEC" scenario, where both BEC Units 3 and 4 are retired early. It would take a significant amount of renewable energy generation to replace over 500 MW of capacity. For example, it would take an additional 2,200 MW of solar or 3,000 MW of wind to replace the Boswell capacity, which does not factor in the energy that also needs to be replaced. In contrast, when BEC Unit 3 is retired at the end of 2029 in the 2021 Plan, there is a modest capacity need of approximately 100 MW. Minnesota Power anticipates this capacity need could increase 30 to 40 MWs for the winter peak period. The capacity outlook is set forth below in Figure 9:

Figure 9: Capacity Outlook for BEC Units 3 & 4 Retirement Scenarios

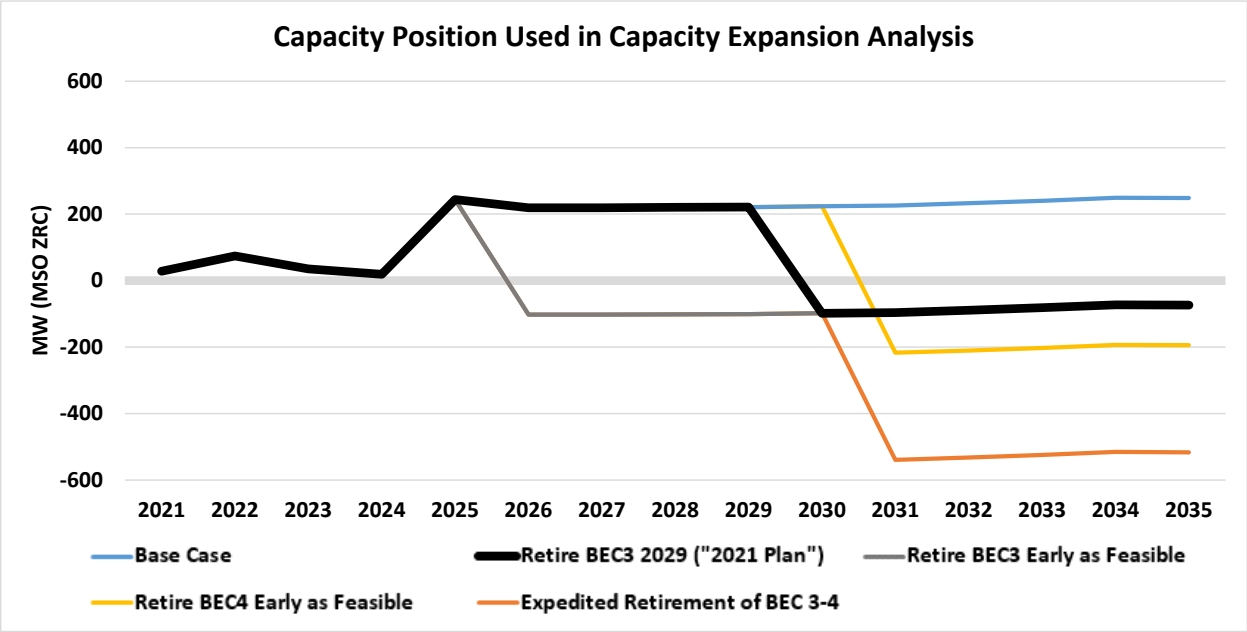
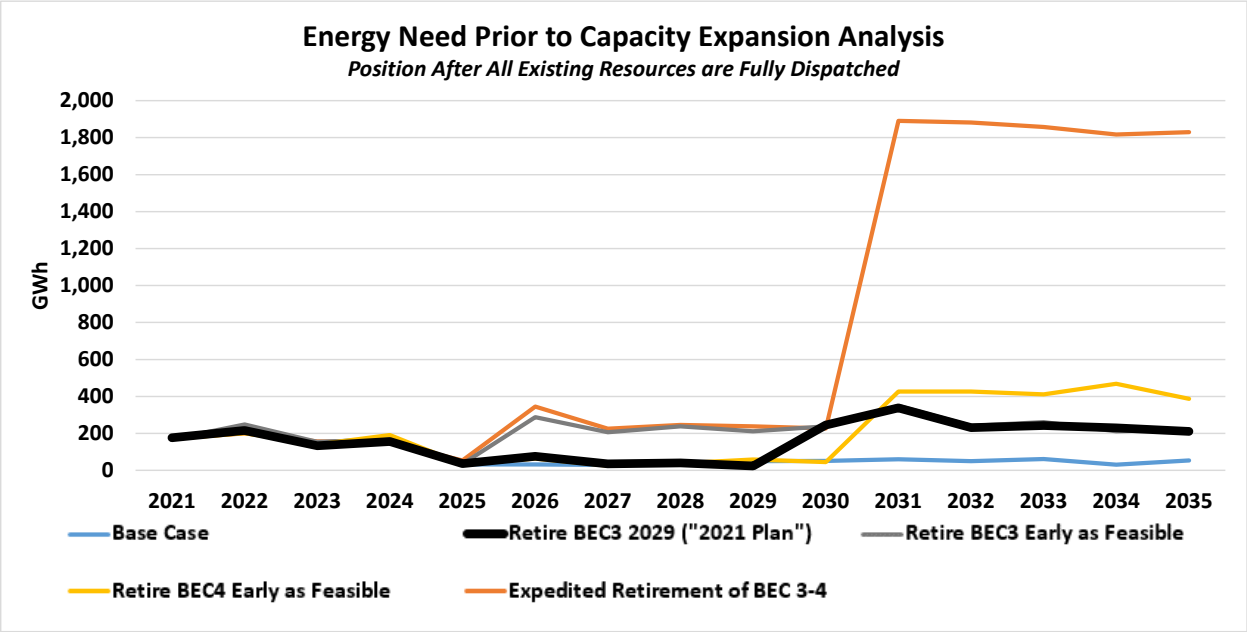


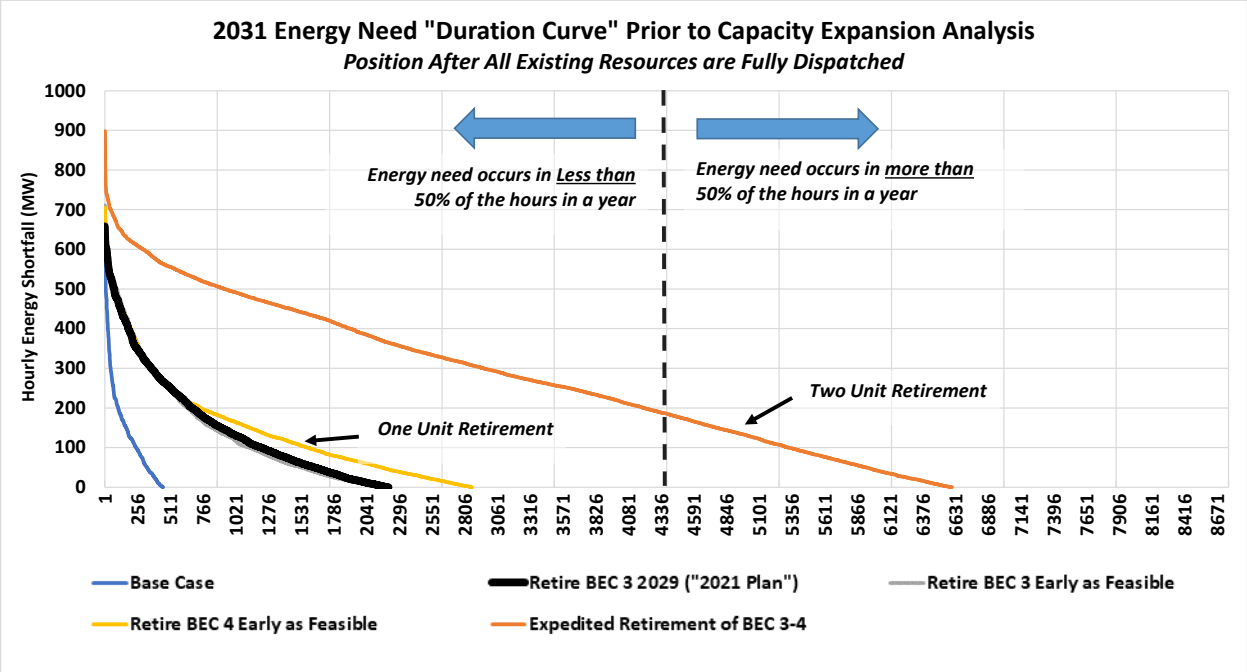
Figure 10 illustrates the change in energy needs in the different BEC Units 3 and 4 retirement scenarios. The open energy position post retirement ranges from 2 percent (~250,000 MWhs annually) in the BEC Unit 3 retirement scenario (2021 Plan), and up to 19 percent (~1,855,000 MWh annually) in the expedited, two-unit retirement plan. The energy need is modest in the single unit retirement scenarios, but increase significantly when both Boswell units are retired.

Figure 10: Energy Need Outlook for BEC Units 3 and 4 Retirement Scenarios



An important aspect to understanding the characteristics of an energy need after a generator retirement is the magnitude (MW level needed in an hour) and the frequency (number of hours in a year energy is needed). A simple method to demonstrate this is to look at the duration curve of the energy need in a single year. The year 2031 was selected because it's the first year following the latest retirement date in any of the BEC retirement scenarios. It shows both the depth and frequency of that energy need in one look. Figure 11 shows the duration curve of the energy need in 2031 for the BEC Units 3 and 4 retirement scenarios. The greatest energy need is when both BEC Units 3 and 4 are retired under the expedited scenario, with an average energy need of approximately 300 MW over 75 percent of the hours in a year – but this need ranges from 1 MW to 900 MW, highlighting the variability of Minnesota Power's need throughout the year absent of any baseload generation and Minnesota Power's high penetration of renewables. The energy need in the BEC one-unit retirement scenarios is significantly less and has a more "peaking" profile with an average energy need of around 150 MW over 25 percent of the hours in a year.

Figure 11: Energy Need Duration Curve in 2031 for BEC Units 3 and 4 Retirement Scenarios



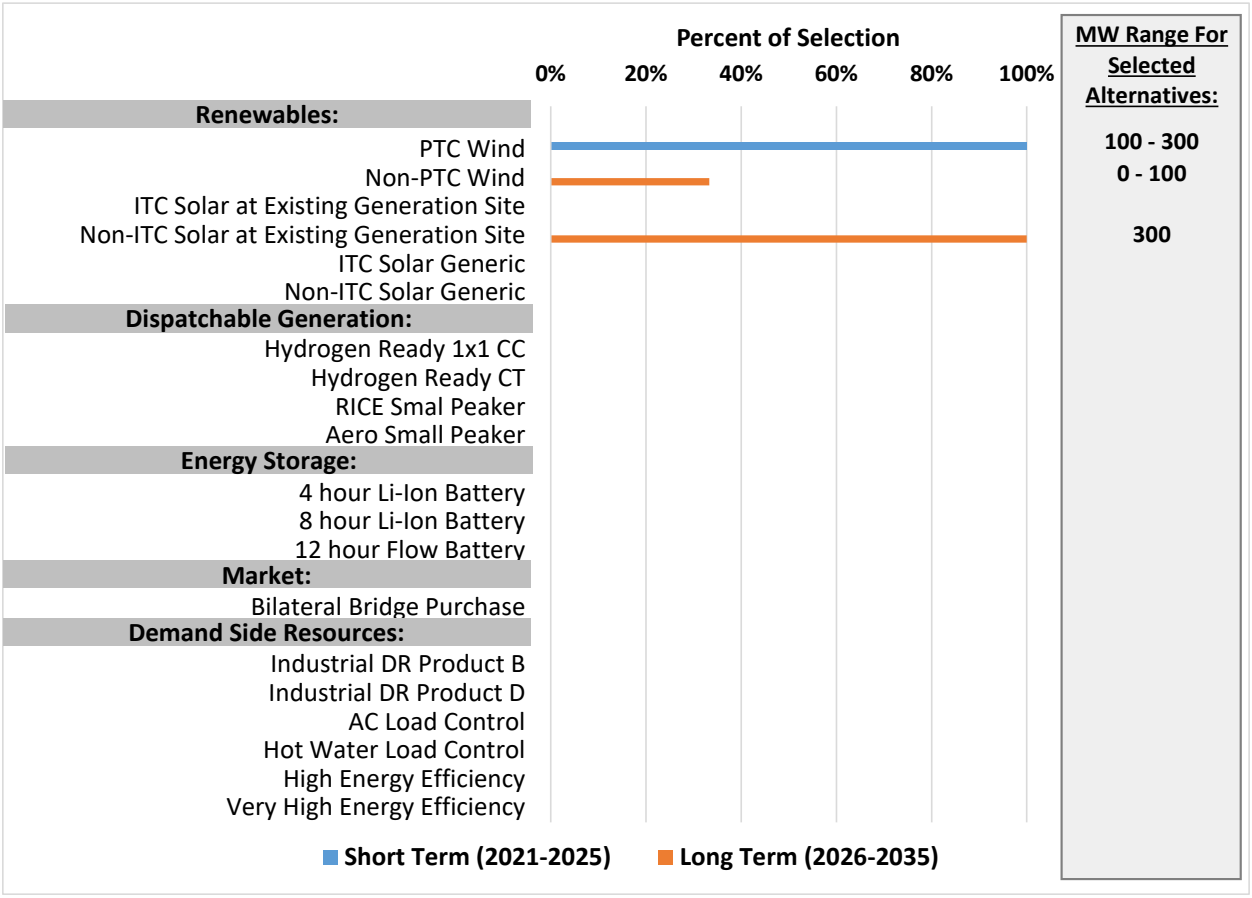
The following sections will discuss which resources were selected by the EnCompass model in the Capacity Expansion analysis. Note that the remaining discussion on modeling in this section is based on the 2021 Plan in which BEC Unit 3 retires by December 31, 2029. The Capacity Expansion Analysis Results for the other BEC retirement scenarios evaluated and the Business as Usual scenario are shown in Appendix K. The "Swim Lane Analysis" in Step 2 (i.e., alternative power supply portfolios comparison) will provide further insights on how Minnesota Power arrived at a BEC Unit 3 retirement by December 2029 as being the least cost plan.

A summary of the EnCompass Capacity Expansion Analysis results with BEC Unit 3 retired in 2029 is shown in Figure 12.[40] The figure also demonstrates the robustness of the IRP analysis with the diverse supply and demand side technologies Minnesota Power considered in the EnCompass analysis. Additional resource alternatives were evaluated in the screening process and are also discussed in Appendix K. Note that the resource selections shown below are based on the following futures: the Reference Case, High Carbon Regulation Cost and High Environmental Costs, and No Carbon Regulation Costs and No Environmental Costs.[41]

[40] Minnesota Power focused on the "BEC 3 Retired in 2029" scenario because it was identified as a least cost retirement action in the 2021 Plan.

[41] The Reference Case and High Carbon Regulation Cost and High Environmental Cost are required to be evaluated as part of the IRP process per the Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs, Docket Nos. E999/CI-07-1199 and E999/DI-19-406 (Sep. 30, 2020). Minnesota Power chose to include a "no carbon regulation cost and no environmental cost" scenario to provide an additional perspective that captures a market without a carbon tax.

Figure 12: Capacity Expansion Analysis Results for BEC Unit 3 Retired in 2029 ("2021 Plan")



The Capacity Expansion Analysis clearly indicates that wind and solar are the least cost resources to replace BEC Unit 3 in the three futures that were evaluated, and were selected in modeling. In general, wind is being selected earlier in the study period to take advantage of the available federal Production Tax Credit ("PTC") and lower cost resource due to the availability of this subsidy. Solar is selected closer to the BEC Unit 3 retirement date of 2029 and leverages infrastructure at an existing energy site, such as Boswell, to reduce or avoid additional grid interconnection costs. No other resource technologies or demand side resources were directly selected by Encompass in these three futures. The following sections provide additional insights into how Minnesota Power used the Capacity Expansion Analysis to determine the new resources utilized in the 2021 Plan.

Wind

Minnesota Power currently has over 850 MW of wind generation in its power supply. In 2019, the Commission approved the 250 MW Nobles 2 wind PPA that achieved commercial operations in December 2020. This latest wind addition increased Minnesota Power's wind portfolio by 1 million MWh, resulting in nearly 3.2 million MWh of total wind generation in its energy mix.

The Capacity Expansion Analysis included resource alternatives with two cost profiles for wind additions. First, wind available in the EnCompass model prior to 2025 includes the benefits from a 60 percent Federal PTC. Second, wind available in 2025 and forward included no PTC benefits. Note that the wind capital projections applied a technology curve that assumed that improvements in technology result in declining capital costs in real dollars.[42]

The Capacity Expansion Analysis selected 100 to 300 MW of PTC-qualified wind prior to 2025, regardless of whether carbon regulation costs were included. This demonstrates that wind is part of a least cost option for replacing BEC Unit 3 energy in the portfolio. Later in the study period and after the PTC expires, additional wind was minimally selected after 2025 and only in the "High Carbon Regulation Cost and High Environmental Costs" future.

Minnesota Power is recommending the addition of 200 MW of new wind prior to 2025. Minnesota Power recognized that the EnCompass model was selecting 300 MW in the near term, but 200 MW is a better fit for customers and the overall power supply for the following reasons:

1. Additional wind, above 200 MW, in the near term will result in excess energy in the portfolio with NTEC coming online and BEC Unit 3 continuing to operate through end of 2029. To better manage any excess energy, 200 MW is a more appropriate fit before 2030 to manage excess energy.
2. Manages near term rate increases caused by the addition of wind. The EnCompass modeling is demonstrating a small near term power supply cost increase ($1/MWh to $2/MWh) caused by the addition of this wind. Adding wind greater than 200 MW would put additional stress on customer rates and not support a reasonable cost progression.

Solar

Minnesota Power outlined in the 2015 IRP a broad solar strategy to meet the estimated SES requirement in 2020 and beyond. The Commission approved this strategy of adding approximately 33 MW of solar resource additions by 2025. Today, Minnesota Power's solar portfolio consists of a 10 MW solar array located at Camp Ripley, a 1.04 MW Solar Garden program, along with approximately 7 MW of distributed solar. Minnesota Power is currently requesting Commission approval to pursue 20 MW of utility-scale solar projects in Northern Minnesota to meet its remaining requirements under the SES.[43] If approved, these solar projects will support economic development and recovery within the Company's service territory following the COVID-19 pandemic. The proposed 20 MW of utility-scale solar projects are included in the Base Case with an expected start date by the end of 2021.

Multiple cost profiles for new utility scale solar were contemplated in the IRP analysis. Included in the analysis were the benefits of the 26 percent Investment Tax Credit ("ITC") in the near term, and locating solar at an existing utility owned site, such as Boswell, to avoid additional MISO network interconnection cost. For clarity, the IRP analysis included the following cost profiles for new solar additions and the years they were made available:

[42] Refer to Appendix J for additional detail on the sources used to develop the technology curves.
[43] Docket No. E015/M-20-828.

- Solar with 26 percent ITC + Located at Existing Site (Available Prior to 2024 Only);
- Solar with 26 percent ITC + Generic Site (Available Prior to 2024 Only);
- Solar with 10 percent ITC + Located at Existing Site (Available in 2024 and Forward); and
- Solar with 10 percent ITC + Generic Site (Available in 2024 and Forward).

Note the solar capital projections applied a technology curve that assumed improvements in technology that result in declining capital costs in real dollars.

In Step 1, the Capacity Expansion Analysis, selected 300 MW of solar across all futures evaluated. Typically across the futures, the solar additions occurred in the Long-Term planning period (2026-2035) near the time of the BEC Unit 3 retirement in 2029, and only solar located at an existing site was selected to maintain the transmission cost savings. The analysis indicates that procuring large utility scale solar today to take advantage of the 26 percent ITC is not showing value for customers. However, longer-term, around the time of BEC Unit 3 retirement in 2029, approximately 200 MW of solar was typically economic to provide carbon-free energy to support the baseload transition. Another 100 MW of solar was selected in the last year of the study period. Minnesota Power recommends the later solar addition can be vetted further in future IRPs to validate the need for these resources at that time. Therefore, Minnesota Power recommends pursuing 200 MW of solar interconnected at the Boswell site or another existing Minnesota Power facility by 2030.

Industrial Demand Response

Minnesota Power currently has approximately 250 MW of interruptible demand response capability on its system, which it utilizes for limited peak market price shaving and emergency operations. Existing demand response programs include partnerships with large industrial customers and duel fuel rate programs with residential and commercial customers. These existing programs are a valuable component of Minnesota Power's power supply mix, and help to ensure reliability for the region.

Included in the IRP analysis as alternatives are new demand response programs for both industrial customers and residential/commercial products. Specifically, there are two new industrial demand response programs available to be selected by EnCompass:

1. The first program, referred to as Product B, includes long-term capacity with firm load control products. This product would offer a $7 per kW-month capacity credit and provides a $30 per MWh energy credit for curtailed energy. Minnesota Power requested acquiring Product B from industrial customers in the Industrial Demand Response Product petition.[44] Ultimately, the Commission did not approve Product B, but commissioners expressed interest in seeing it included as an option in future IRPs.
2. The second program, referred to as Product D, includes long-term emergency capacity. The product would offer a $5 per kW-month capacity credit.

[44] Docket No. E015/M-18-735.

This industrial demand response resource is fully available in the mid to late 2020s, when the proposed Product C demand response program subscription is currently set to end. The Product C program is discussed further in Minnesota Power's Petition requesting approval of Industrial Demand Response Product C.[45]

The Company also continues to investigate additional demand response opportunities for residential and commercial customers through the evaluation of two peak-shaving programs for central air condition ("CAC") customers and electric hot water ("HW") customers. As a winter peaking utility, the Company previously focused its residential and commercial demand response programs on the electric heating characteristics of its load. However, both of these types of demand response programs could benefit customers, and both programs were available for the Encompass model to select in the IRP.

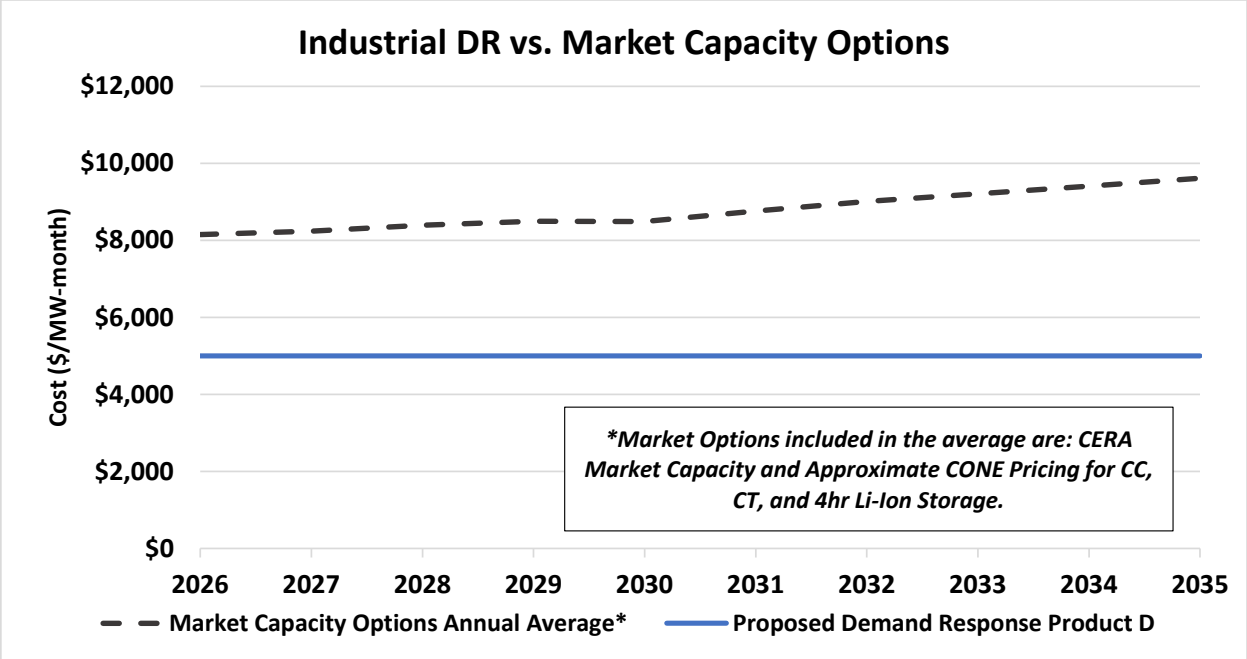
Due to a minimal capacity need over the study period, even with BEC Unit 3 retiring in 2029, the industrial and residential/commercial demand response programs were not selected by EnCompass for capacity replacement.[46] However, Minnesota Power is committed to utilizing and continuing to work with industrial customers to leverage demand response resources in lieu of building new infrastructure. By partnering with customers on these large scale demand response opportunities the Company can implement reasonable additions to its demand response programs that benefit customers with long-term resource options that can help manage resource adequacy uncertainty.

For example, Product D, as evaluated in the IRP analysis, is competitive compared to the forecast for market capacity that is being selected by the Capacity Expansion Analysis or other capacity alternatives not selected by EnCompass – see Figure 13 below. During this 15 year study period, Minnesota Power anticipates the MISO resource adequacy construct will change. There are active initiatives at MISO that are exploring a multi-season resource adequacy construct (i.e., adding both winter and summer season requirements), resource accreditation enhancements that reduce accredited levels of intermittent resources, and regional resource assessments that show a changing reliability risk profile. Any of these enhancements could have an impact on the Company's overall capacity need in the future. As such, Minnesota Power plans to explore these impacts further going forward. A cost effective and resource efficient approach to managing this uncertainty is to work with industrial customers to pursue up to 50 MW of long-term industrial demand response by 2030.

[45] Docket No. E015/M-21-28.

[46] The Encompass modeling suggest that the size of the 100 MW block of industrial demand response factored into why EnCompass did not select it. With the demand credit for Product D being lower cost than the market outlook for capacity it would be expected the model to select it. Given EnCompass can select a "perfect fit" for market capacity, it was lower cost to select the market purchase. This is why Minnesota Power identified it would use customer demand response before purchasing capacity from the market for a long-term need.

Figure 13: Proposed Industrial Demand Response Product D Compared to Market Capacity Options



Natural Gas

Today, Minnesota Power has a minimal level of natural gas generation in its power supply, but that will increase with the addition of NTEC in 2025. The 100 MW Laskin Energy Center, a coal unit refueled with natural gas in 2015, is the sole peaking gas unit on Minnesota Power's system today. The Company's 50 percent capacity share of NTEC, providing efficient and low carbon emitting combined-cycle generation, will increase our natural gas generation portfolio to nearly 400 MW (Laskin Energy Center in addition to NTEC).

New, modern, and efficient gas generation can serve an important role on the system as a bridge energy resource to a carbon-free future in 2050. A typical characteristic of gas generation is flexibility, the ability to quickly generate energy when needed by the system. It can fit well with variable generation like wind and solar, especially with a utility like Minnesota Power with a high load factor. Furthermore, over the long term the natural gas generation industry has begun to build a sustainable future as vendors finalize plans and develop flexible options for carbon-free operations through hydrogen as a fuel source or with carbon capture technologies. The IRP evaluated several different natural gas technologies ranging from small peakers (RICE and Aeroderivatives), large peakers (Framed CT), and large and efficient combined-cycle units. Gas generation was also evaluated as a resource that could be located at Boswell to utilize existing infrastructure and avoid costly transmission upgrades when BEC Unit 4 is retired. With Minnesota Power's minimal need for additional capacity after the retirement of BEC Unit 3, the EnCompass model did not select any additional gas generation in the next 15 years. The relatively low capacity needs were met through the addition of wind and solar resources as Minnesota Power has sufficient dispatchable generation already in its supply.

In the scenarios in which BEC Unit 4 was retired, natural gas generation was selected, which is an expected outcome given that natural gas has the attributes to avoid costly transmission upgrades and efficiently replaces the significant volume of dispatchable capacity and energy removed in those scenarios. In the Swim Lane analysis discussed later, new gas generation, along with renewable generation, was included as replacement generation in the scenarios with early retirement of BEC 4. Additional detail on this Capacity Expansion Analysis scenario is included in Appendix K.

Energy Storage

Energy storage is a dispatchable technology that is developing as a future innovative technology. Energy storage options continue to mature and technology costs decline, specifically for technologies with longer-term storage capabilities can support the significant time periods when other renewable resources are not available. The IRP evaluated several technologies, including lithium-ion ("li-ion") batteries, flow batteries, adiabatic compressed air storage, and pumped hydro. Not all energy storage technologies were included in the EnCompass analysis as alternatives; the adiabatic compressed air storage and pumped hydro were screened out in the busbar analysis discussed further in the detailed analysis of Appendix K, to ensure Encompass could run efficiently. However, Minnesota Power recognizes that any of these technologies can evolve in the near future with technological changes that would change their cost outlooks. The Company will continue to monitor storage technology alternatives and the role they can play as a dispatchable resource in its power supply as it continues its transition away from coal fired generation.

Included in the EnCompass modeling were li-ion batteries and flow batteries with hours of storage ranging from 4 hours up to 12 hours to capture both short and longer duration storage applications. Minnesota Power applied a technology curve that assumed improvements in technology advancements in batteries (specifically li-ion and flow) results in declining capital costs in real dollars.

Due to a minimal capacity and modest energy need over the study period, even with BEC Unit 3 retired in 2029, no energy storage resources were selected by EnCompass.

Transmission

Strengthening and expanding the local and regional transmission system is a critical aspect of the transformation to a more sustainable and increasingly cleaner energy future. The current grid was designed around a system with centralized baseload generation and will need enhancement and investment to accommodate a future with higher penetrations of clean energy. To date, Minnesota Power has already seen the need for additional transmission to transition its small baseload resources as BEC Units 1 and 2 were retired and Taconite Harbor Energy Center was idled (refer to Appendix F for a discussion on this additional transmission). Further, the 500 kV GNTL project that went into service in 2020 facilitates the delivery of nearly 1.5 million MWh of carbon free hydro energy into Minnesota Power's service territory, accessing large volumes of renewable energy sources. Minnesota Power recognizes that utilizing new transmission to support transitioning the fleet to a carbon-free power supply is necessary and will grow in complexity as additional baseload resources are removed.

Through its Baseload Retirement Study, Minnesota Power identified several reliability transmission projects that would be needed to enable the transmission system to handle a retirement of BEC Unit 3 and/or 4.[47] These grid evaluations were designed to identify what additional transmission would be needed to support reliable electric service in the region if no generating resources were located at the Boswell facility. In lieu of transmission solutions, the generation alternative that could be placed at the existing facility with similar operating characteristics as Boswell units are considered to be gas generation – specifically, larger peakers or combined-cycle technology. For the Capacity Expansion Analysis, the EnCompass model had the option to either select a transmission solution or replacement generation at the Boswell facility to allow an early retirement in each of the scenarios.

Minnesota Power identified that taking action to strengthen the grid to accommodate a BEC Unit 3 retirement in 2029 would support a cost-effective transition of coal fired generation. The higher cost transmission that was needed to retire BEC Unit 4 was not found to be cost effective as it required significant high voltage transmission projects to be built. Therefore, the scenarios with BEC Unit 4 retired selected a generation replacement versus moving forward with the transmission build out.

Other Resources Considered

Additional energy efficiency above Minnesota Power's state leading programs and a generic bilateral market purchase were also evaluated in the Capacity Expansion Analysis, but were not selected by the EnCompass model. While not being prominent in the 2021 Plan, both of these will be critical tools to manage customer costs as the Company develops its long term path towards its goal to be 100 percent carbon-free by 2050.

Minnesota Power will continue its strong leadership in energy efficiency programs with a 2.5 percent annual requirement to investigate additional program opportunities through future Conservation Improvement Program Triennial filings, well above the state goal of 1.5 percent annual savings. The Company anticipates that as power supply transition continues, energy efficiency will have a prominent role to help customers control rising energy costs and adapt behavior for new Time of Use and Dynamic pricing models. Please refer to Appendix B for more detail on the additional energy efficiency programs evaluated in the Encompass IRP analysis. The analysis indicates additional energy efficiency was not selected because lower cost wind with the PTC was available to meet the energy and capacity need during the same period energy efficiency was available to be selected. Refer to the Busbar analysis in Appendix K on how the cost of additional energy efficiency compared to the cost of wind.

An important component of a utility's power supply is contracted purchases and sales, conducted to optimize the energy surpluses and deficits that occur due to load and supply changes in the shorter-term. These agreements are called bilateral transactions, and they allow Minnesota Power to work with other entities to procure energy and capacity from existing resources. Often, bilateral purchases are a cost-effective tool to meet a power need that exists over shorter periods of time, when compared to adding a new generation resource. See Appendix C, Part 2 for a list of the Company's current bilateral transactions, which were included in the base case. A bilateral alternative was evaluated in the Capacity Expansion

[47] Appendix F and Baseload Retirement (Appendix P) study elaborate on the transmission solutions needed.

Analysis, which modeled an intermediate energy and capacity purchase that provided energy during the peak periods of the day. This bilateral transaction was not selected to meet long-term capacity and energy needs. However, the Company continues to use bilateral transactions to manage it short-term energy position, for example to replace energy during planned outages or during periods of lower renewable production.

Key Insights from Capacity Expansion Analysis

The Capacity Expansion Analysis provided key insights to the Company as it developed its 2021 Plan and crafted its recommended resource mix. Based on the results of the analysis shown in Figure 12 and discussed in Appendix K, the following insights were observed in the Capacity Expansion Analysis.

BEC Unit 3 Retired in 2029

- 100 MW to 300 MW of Wind that qualifies for the PTC was selected consistently across the futures.
- 200 MW to 300 MW of solar located at BEC or another utility site was selected near the time of BEC 3 retirement in 2029.
- Implementing new transmission solutions to address reliability issues related to retirement of BEC 3 was selected instead of building new gas generation at the site.

Other BEC Units 3 and 4 Retirement Scenarios:

- 100 MW to 300 MW of Wind that qualifies for the PTC was selected consistently across the futures.
- Typically, 100 MW to 300 MW of solar located at BEC or another utility site was selected near the time of a BEC retirement.
- In the BEC 4 retirement scenario specifically, gas generation was selected to avoid building the required significant high voltage transmission projects needed to maintain grid reliability.

Other Observations

- There is value for customers, and protection against future capacity volatility, to pursue additional long term Industrial Demand Response by 2030 to address future resource adequacy changes and volatility.

These insights were used to inform replacement capacity and energy portfolios for the 2021 Plan and the other BEC Units 3 and 4 retirement scenarios evaluated in the next section.

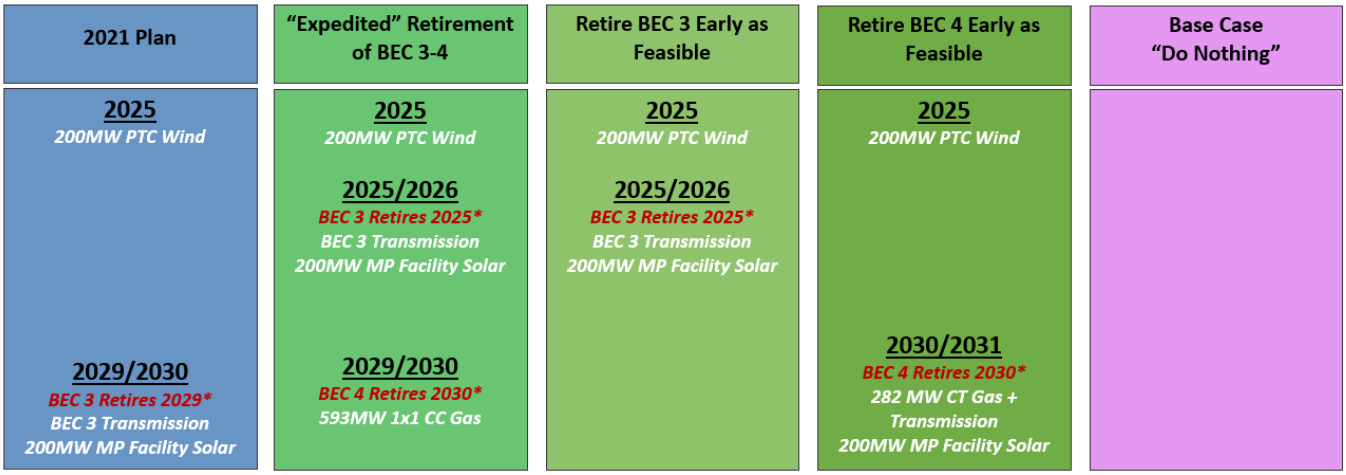
Step 2: Analysis and Insights – Comparison of 2021 Plan to "Swim Lane" Alternatives and Sensitivity Analysis

In the second step of the evaluation process, Minnesota Power compared the 2021 Plan plus three alternative power supply portfolios ("Swim Lanes") that varied the timing of BEC Unit 3 or 4 retirement, along with a Base Case where no additions were made to the power supply. This portion of the analysis was designed to verify whether any of the other early retirement scenarios performed better than the 2021 Plan.

The scenarios were developed through the Baseload Retirement Study (Appendix P) and based on reasonable timeframes for considering an early retirement within the next 15year study period. The transmission grid enhancements needed, available energy and capacity replacement options, and socioeconomic impacts were key factors in determining the timeframes for each scenario.

The three Swim Lane alternatives were developed and compared to the 2021 Plan portfolio with BEC Unit 3 retired in 2029 – See Figure 14 for a summary of the resource decisions included in each Swim Lane. The new resources additions in each Swim Lane were informed by the EnCompass modeling results from Step 1: Capacity Expansion Analysis described above. Based on the insights from Step 1, the expansion plan for each Swim Lane contains similar core renewable resource additions to Minnesota Power's 2021 Plan, demonstrating a "no regrets" decision to adding 400 MW of renewables by 2030.

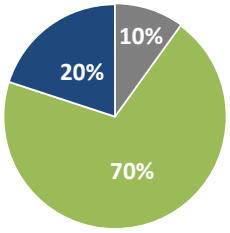
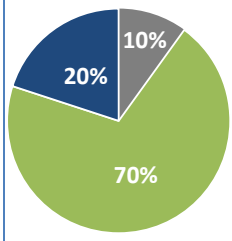
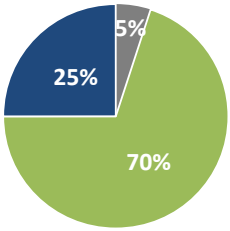
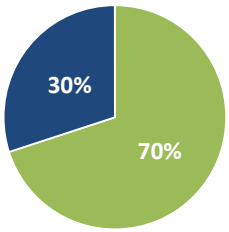
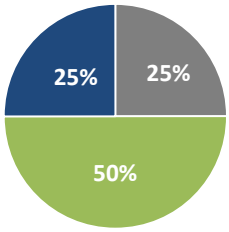
Figure 14: Alternative Power Supply Portfolios ("Swim Lanes") Evaluated in Step 2



*Retired at end of the year

Minnesota Power wanted to verify whether these alternative retirement times and expansion plans performed better compared to the 2021 Plan, and to further assess the benefits of its 2021 Plan for stakeholders. Table 3 provides an overview of each of the Swim Lanes and the highlights from the EnCompass evaluation in Step 2. The plans vary slightly in terms of the generation mix for coal and natural gas, although the resulting renewable mix is the same. All Swim Lane alternatives achieve 80 percent carbon reduction between 2031 and 2035, well ahead of Minnesota's statewide GHG goal of 80 percent carbon reduction by 2050, and the 2021 Plan is the lowest cost plan to achieve these reductions.

Table 3: Overview of 2021 Plan and Swim Lane Alternatives

	Single Unit Retirement			Two Unit Retirement	
Portfolio Name	**2021 Plan** Retire BEC3 in 2029	**Retire BEC3 Early as Feasible**	**Retire BEC4 Early as Feasible**	**Expedited Retirement of BEC 3 and 4**	**Base Case "Do Nothing"**
2031 Approximate Energy Mix: Coal, Renewables, Natural Gas and Purchases					
2021 Plan Costs (NPV, 2021-2035): *(Least cost portfolio highlighted in green)*					
Reference Case Mid-Carbon Regulation +Mid Environmental Cost	**$7,891 M**	**$7,903 M**	**$7,918 M**	**$7,944 M**	**$8,010 M**
High Carbon Regulation + High Environmental Cost	**$8,276 M**	**$8,302 M**	**$8,281 M**	**$8,366 M**	**$8,379 M**
Installed Capacity by 2031 (MW):					
Renewable	**1722**	**1722**	**1722**	**1722**	**1302**
Coal	**468**	**468**	**350**	**0**	**818**
Natural Gas	**389**	**389**	**982**	**671**	**389**
Carbon Reduction from 2005 Levels:[48]					
2026	**75%**	**80%**	**76%**	**80%**	**69%**
2031 to 2035	**80%**	**80%**	**82%**	**88%**	**66%**
Estimated Customer Cost Impact when Compared to Base Case ($/MWh): *(Least cost impact highlighted in green)*					
2026	**+ $1**	**+ $6**	**+ $1**	**+ $6**	**-**
2031	**+ $4**	**+ $3**	**+ $8**	**+ $11**	**-**

[48] Minn. Stat. § 216H.02 GHG Statewide Reduction Goal is 30% by 2025 and 80% by 2050.

To help describe the insights from the Swim Lane Analysis, and how the 2021 Plan is not only the least cost, but the most reasonable plan for this IRP, Minnesota Power will utilize the feedback and insights from its stakeholders. Minnesota Power engaged in a first-of-its-kind stakeholder process for this IRP and Baseload Retirement Study nearly 18 months prior to submitting the Plan. This stakeholder process gathered insights and feedback from a diverse group of over 70 participants regarding Minnesota Power's future energy mix and the impacts of transitioning the power system even further. A product from this year long process was an innovative Issue Map that captured key metrics based on issues that were important to stakeholders.

The metrics were summarized into four broad categories or perspectives:

1. Customers
2. Environment
3. Host Community
4. Utility (System and Reliability)

Minnesota Power used this forward-looking Issue Map, along with other insights and feedback from stakeholders, to develop a 2021 Plan that was responsive to what stakeholders shared was most important. The following section evaluates the 2021 Plan and alternative Swim Lanes based on the metrics identified in the Issue Map.

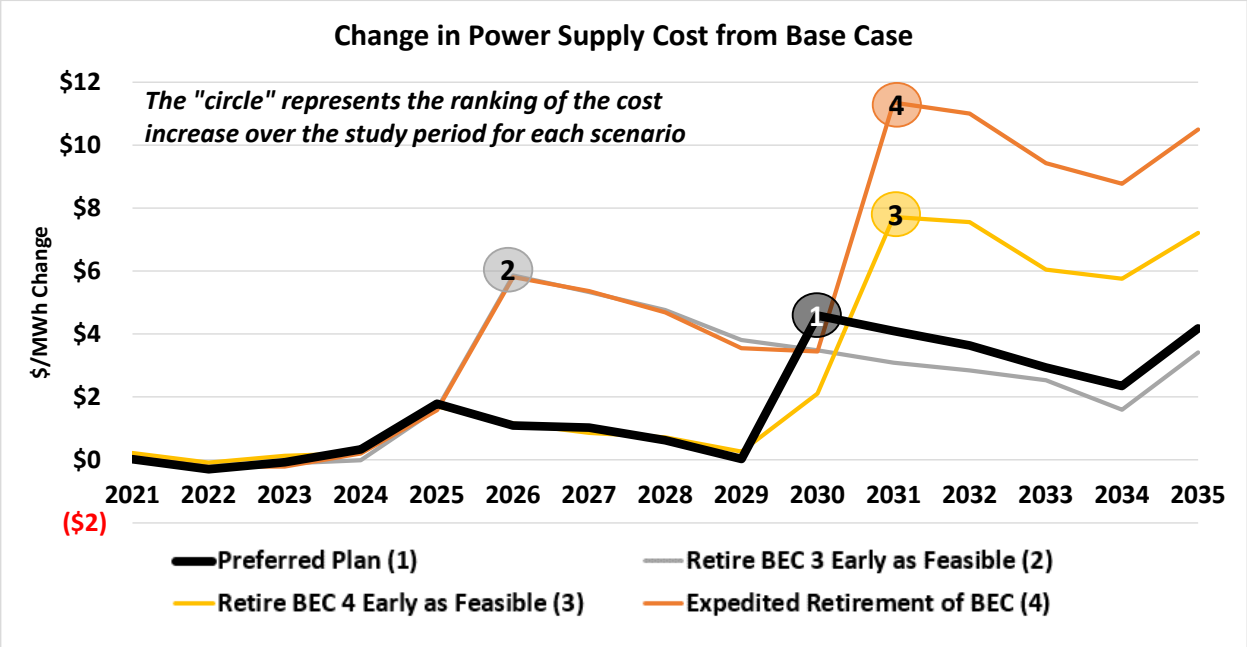
1. Customer

Stakeholders identified the key issues for customers are affordability, reliability, and optionality. Today, Minnesota Power offers a strong suite of energy-oriented options for customers, ranging from demand response programs, rebates through energy efficiency and distributed solar programs, and options to increase their renewable energy. Furthermore, the Company maintains a cost effective energy mix that is sufficient to provide reliable electric service, while being 50 percent renewable. The 2021 Plan continues the transition to a more sustainable energy future with Minnesota Power's renewable portfolio growing to 70 percent and achieving an 80 percent carbon reduction by 2035 with the lowest cost increase profile of all the retirement scenarios considered.

The least cost plan is often arrived at by comparing the net present value of power supply cost for 15 or more years, but potential large cost increases that could occur within the planning period are frequently missed in this type of analysis. Stakeholders communicated that having competitive and affordable electric rates was an important issue, and a key aspect of affordability is avoiding large increases in power supply costs. It was important to Minnesota Power to bring forward a 2021 Plan that delivered a thoughtful transition plan for BEC Units 3 and 4 that avoided large increases in power supply cost for customers. The 2021 Plan was not only the overall least cost plan in the IRP evaluation timeframe (2021-2035), but it also had the most gradual cost increase over time. Figure 15 below shows the change in power supply cost of the retirement scenarios from the Base Case. This figure can be useful in informing where customer rates could go directionally, if the actions in that plan or Swim Lane are taken. It's important to note, however, that actual rates are decided by the Commission through a rate case proceeding, and those outcomes will be reflected on the customer bill. Furthermore,

Minnesota Power is actively engaged in proposing opportunities to mitigate customer rates, and those efforts are not directly captured in a resource planning analysis.

Figure 15: 2021 Plan Power Supply Cost Compared to "Swim Lane" Alternatives



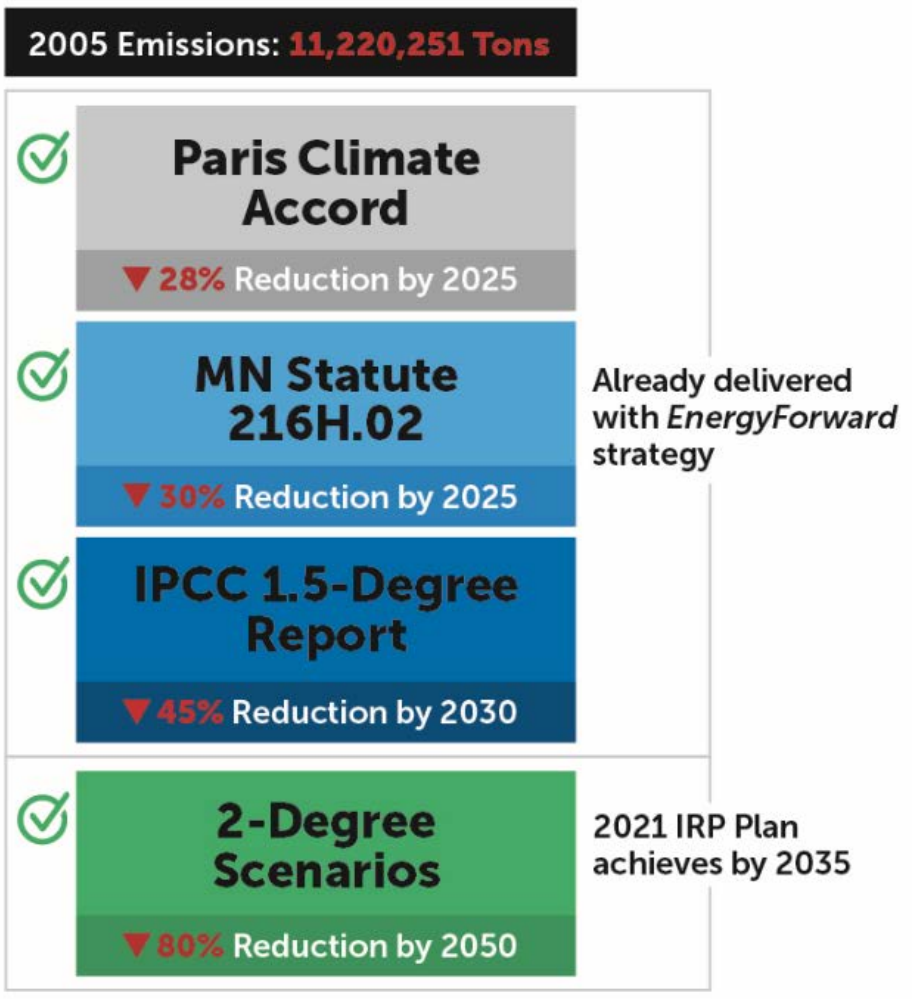
Directionally, the BEC retirement scenarios other than the 2021 Plan resulted in a higher power supply cost increases for customers, with the expedited retirement of BEC Units 3 and 4 scenario having an increase that is more than double the 2021 Plan. The larger increase in 2031 in the “Expedited Retirement of BEC” and “Retire BEC 4 Early as Feasible” is mostly driven by the large capital investment in new gas generation required to avoid building the significant high voltage transmission projects otherwise necessary for retirement of BEC Unit 4.

2. Environment

Stakeholders identified key environmental issues as Minnesota Power’s impact to air, water, health, and contribution to climate change. Building a sustainable energy future is a core mission for Minnesota Power to protect the integrated region where our employees live, work, and play. To date, Minnesota Power has taken significant action and leads the State of Minnesota in achieving a 50 percent carbon reduction from 2005 levels in 2021. The Company has taken action throughout its history to consider implications to the climate, its customers, and communities as it has addressed generation operations and additions. Previously-implemented pollution control investments in its fossil fleet were industry leading at the time, meeting or exceeding state thresholds and ensuring Minnesota Power’s operations were best in class for baseload generation facilities (refer to Appendix E for more on investment made in pollution controls). The leadership in environmental emission reductions and adding increasingly cleaner generation resources has created a strong track record and foundation for Minnesota Power’s vision to reach a sustainable 100 percent carbon-free future by 2050.

The 2021 Plan identifies Minnesota Power's near term plan to further reduce carbon emissions by adding renewable energy, moving towards economic dispatch on remaining coal units, and proposing a plan to cease coal-fired generation completely by 2035. These actions increase the renewable portfolio to 70 percent and achieve 80 percent carbon reduction by 2030, while ensuring cost-effective rates for customers. Figure 16 below demonstrates that Minnesota Power's 2021 Plan, along with the alternative Swim Lanes, exceed both Minnesota's current goals and the Paris Climate Accord targets for GHG reductions. And although all Swim Lanes exceed Minnesota's statewide GHG goals, the 2021 Plan achieves it with the lowest overall cost and the most reasonable cost increase progression and impact on communities. Minnesota Power's 2021 Plan considers the climate, customers, and communities as it sets a meaningful path forward to a carbon-free future submittal.

Figure 16: Minnesota Power's Progress on Reducing Carbon Emissions



3. Host Community

Minnesota Power's Boswell Energy Center currently contributes a significant amount of property tax revenue to the City of Cohasset, Itasca County, the Grand Rapids Independent

School District 318, the Taconite Assistance Area, and the region. The Boswell Energy Center and its approximately 170 employees are significant drivers of the local economy, with 2018 revenue from the Boswell plant accounting for almost 70 percent of the City of Cohasset's tax base, almost 20 percent of the Grand Rapids School District tax base, and 13 percent of Itasca County's tax base. The retirement of either Boswell unit would result in the loss of tax revenues and jobs in the region (Refer to Appendix M for a discussion on socio economic impacts to the region). The IRP Stakeholder group identified an overarching key issue to consider is a just transition that minimizes the impacts to tax base, jobs, local industry, and community health.

It is important to Minnesota Power that the 2021 Plan ensures a just transition for Boswell Energy Center's employees and host community, which is the smallest and most geographically isolated in the state of Minnesota. Providing a thoughtful transition plan for the Boswell facility creates certainty and a timeline to enable both employees and the community to plan for a future beyond coal operations at Boswell Energy Center. Compared to the other plans evaluated in the Step 2 Swim Lane Analysis, the 2021 Plan that is least cost for customers overall, provides a more meaningful "runway" for workers and the host community to plan for the 2030 transition. The BEC retirement scenarios with accelerated retirement (i.e., Retire BEC 3 Early as Feasible) do not provide sufficient time for the affected employees and host communities to plan for this significant change, which in turns threatens the very health of the community for its citizens. If the action Minnesota Power takes on Boswell's transition away from coal fired generation is too drastic, such as a premature full closure, the losses from tax revenue and jobs would likely be unsurmountable for the host community.

Minnesota Power's transition of its last remaining coal units is not only critical to ensuring regional reliability and the affordability of energy for customers, but it is also key in creating certainty and allowing time for employees and communities to adjust to a different future. The path to a carbon-free future is only sustainable if it includes a just transition for the employees and communities directly affected, and Minnesota Power's 2021 Plan provides the time for that thoughtful transition.

4. Utility (System and Regional Reliability)

Minnesota Power is responsible for delivering safe, affordable, and reliable electric service to each of its customers on a continuous and daily basis. The Company has had the privilege to earn the trust of its customers over the last 115 years of delivering on this responsibility. The resource-based economy in Northeastern Minnesota is highly interrelated and serving their energy needs requires a thoughtful approach. Minnesota Power has planned for sufficient resources and reliable grid capability to deliver reliable energy service to its customers into the future as part of the proposed 2021 Plan. A stable power supply mix will also be beneficial as the Company manages uncertainty with the MISO resource adequacy construct.

Furthermore, the 2021 Plan timeline allows for technology to develop and advance, ensuring technologies are selected for customers that will provide reliable, sustainable energy for many years. Rushing into an earlier retirement decision for Boswell would likely result in the need to replace Boswell with dispatchable technologies that are available today, losing the ability to leverage existing infrastructure for carbon free technologies in the future. Additional time will allow innovation in technologies like energy storage and cleaner dispatchable fuels to advance; creating opportunity for more robust energy additions that positions the State and Minnesota

Power for a more sustainable carbon free future. Minnesota Power has consistently exceeded state clean energy goals without risking safety, reliability, and affordability – and this Plan will continue to deliver on that leadership.

In summary, Minnesota Power's stakeholder outreach for this IRP was a first of its kind conversation and collaboration on the energy future of northern Minnesota. Through the development of these key areas and shared insights, Minnesota Power was able to propose a balanced, meaningful 2021 Plan for consideration. Taking into account the direction of each stakeholder component on the Issue Map, Minnesota Power has created a long term, sustainable carbon-free vision for its energy supply and a commitment to near term actions to reduce carbon while allowing time for a reasonable transition for employees, the grid and the host community.

Sensitivity Analysis

Each Swim Lane alternative and the 2021 Plan was put through a series of 37 sensitivities that stressed the main drivers for resource decisions. These drivers include fuel costs, technology cost, market prices, and customer demand. These Swim Lanes were put through the Reference Case (Refer to Appendix K for the Swim Lane Analysis results for the remaining four Environmental Cost Futures and No Carbon Regulation Cost and No Externality Value look). The sensitivities helped determine whether the 2021 Plan and its resource actions would be the best option for customers. Table 4 below illustrates how the scenarios performed over a range of sensitivities. The results of this analysis clearly indicate that the 2021 Plan for customers is least cost across the majority of the sensitivities. Another observation was the scenarios with a 2029 BEC Unit 3 retirement were the majority of the least cost plans, concluding that this is the optimal timing for one BEC unit to retire. The sensitivities and consideration of the Swim Lane alternatives help solidify that the 2021 Plan is the most sustainable plan that ensures reliability, manages costs for customers, provides for a just transition for host communities, and allows time for technology to develop and advance.

Table 4: Step 2 Sensitivity Analysis - 2021 NPV of Cost for Reference Case Scenario ($millions)

	Single Unit Retirement			Two Unit Retirement	
EnCompass Sensitivities	**2021 Plan *Retire BEC3 in 2029***	**Retire BEC3 Early as Feasible**	**Retire BEC4 Early as Feasible**	**Expedited Retirement of BEC 3 and 4**	**Base Case "Do Nothing"**
Base Case	**$7,891**	$7,903	$7,918	$7,944	$8,010
1 Coal +20%	**$7,750**	$7,783	$7,762	$7,837	$7,846
2 Coal -10%	**$7,963**	$7,969	$7,991	$7,993	$8,093
3 Biomass +15%	**$7,888**	$7,908	$7,909	$7,932	$8,001
4 Biomass -15%	**$7,897**	$7,917	$7,917	$7,950	$8,006
5 Lower Gas -50%	$7,780	$7,809	**$7,758**	$7,814	$7,871
6 Low Gas -25%	$7,874	$7,887	**$7,862**	$7,914	$7,976
7 High Gas +25%	**$8,033**	$8,045	$8,075	$8,087	$8,163
8 Higher Gas +50%	**$8,133**	$8,139	$8,165	$8,166	$8,304
9 Highest Gas +100%	$8,359	**$8,338**	$8,391	$8,368	$8,545
10 Energy Market -50%	$6,619	$6,674	$6,673	$6,820	**$6,562**
11 Energy Market -25%	**$7,346**	$7,383	$7,377	$7,499	$7,358
12 Energy Market +25%	$8,339	$8,344	$8,357	**$8,316**	$8,537
13 Energy Market +50%	$8,578	$8,565	$8,565	**$8,493**	$8,790
14 Capital Costs -30%	$7,891	$7,903	$7,889	**$7,881**	$8,018
15 Capital Costs +30%	**$7,887**	$7,907	$7,935	$8,007	$8,011
16 No Market Sales	**$7,734**	$7,768	$7,761	$7,822	$7,818
17 No Sales and Purchases	$9,315	$9,524	**$9,162**	$9,307	$9,369
18 Market Access -50%	$8,298	$8,365	**$8,258**	$8,312	$8,401
19 Low Interconnect Costs	**$7,876**	$7,890	$7,898	$7,927	$8,014
20 ITC & PTC Extension	**$7,892**	$7,896	$7,907	$7,937	$8,005
21 Wind Cost Curve Low	**$7,895**	$7,907	$7,915	$7,949	$8,012
22 Wind Cost Curve High	**$7,892**	$7,911	$7,924	$7,946	$8,011
23 Solar Cost Curve Low	**$7,883**	$7,900	$7,905	$7,932	$8,008
24 Solar Cost Curve High	**$7,911**	$7,920	$7,938	$7,961	$8,013
25 Storage Cost Curve Low	**$7,892**	$7,911	$7,916	$7,946	$8,014
26 Storage Cost Curve High	**$7,891**	$7,910	$7,916	$7,944	$8,010
27 AFR 2020 Low Scenario	**$7,573**	$7,598	$7,607	$7,657	$7,668
28 AFR 2020 Load w Keetac	$8,385	$8,399	**$8,377**	$8,385	$8,511
29 AFR 2020 High Scenario	$8,424	$8,443	**$8,406**	$8,424	$8,551
30 Residential TOU	**$7,884**	$7,894	$7,908	$7,935	$8,012
31 Higher DG & EV Growth	**$7,896**	$7,900	$7,913	$7,946	$8,011
32 Renewable ELCC -2.5%	**$7,896**	$7,919	$7,916	$7,945	$8,013
33 Renewable ELCC +2.5%	**$7,888**	$7,905	$7,915	$7,947	$8,011
34 PRM -2%	**$7,892**	$7,909	$7,913	$7,935	$8,010
35 PRM +2%	**$7,899**	$7,917	$7,918	$7,946	$8,013
36 MISO CF -2%	**$7,886**	$7,902	$7,915	$7,942	$8,004
37 MISO CF +2%	**$7,906**	$7,927	$7,912	$7,946	$8,019
Sum of Least Cost Runs	**27**	**1**	**6**	**3**	**1**

Insights on Minnesota Power's Thermal Fleet from IRP Analysis

Minnesota Power's thermal fleet serves the dispatchable needs of the system, providing reliable energy service for customers by acting as a back stop when renewables are unavailable. The following section provides a discussion of insights gained from the analysis on the Boswell Energy Center, in addition to a discussion on why Minnesota Power is proposing to move forward with the retirement of Taconite Harbor Energy Center units 1 and 2 in 2021.

BEC Unit 3

BEC Unit 3 is an economic capacity and energy resource for customers, is well controlled for pollution, and will be transitioning operations to economic dispatch in 2021. Minnesota Power has worked diligently to maintain and improve the flexibility of all of its thermal units, including BEC Unit 3, to maximize customer benefits as renewable energy penetration continues to increase. Since 2015, through operational optimization and capital investments, the minimum dispatch level on BEC Units 3 and 4 have been reduced by approximately 100 MW combined. Minnesota Power is also implementing a project at BEC Unit 3 that will reduce the minimum dispatch level from 175 MW down to 75 MW. This project will be implemented prior to January of 2022 and is reflected in the IRP analysis. These actions to improve the flexibility of the fleet should have direct impacts on the environment, by reducing carbon emissions and allowing for additional renewable energy to flow onto the system.

Minnesota Power did screen other fuel options at BEC Unit 3 as an option for retirement. This included refueling the boiler with natural gas that is available at the site. Refueling would require a capital investment to install the natural gas capability, along with a reduction in O&M due to fewer staff needed to operate a natural gas fired steam unit. The large peaking asset would have long lead time startup operations, and with a minimal capacity need was screened from the alternatives. Instead, Minnesota Power will invest in strengthening the transmission system around the Boswell Energy Center ahead of Unit 3 retirement, and position the Company for other carbon-free alternatives at the site.

The Swim Lane analysis also demonstrates that the 2021 Plan that defers BEC Unit 3 retirement to December 2029 is the lowest cost scenario for customers. Moving the BEC Unit 3 retirement earlier, to December 2025, had a higher cost increase than the 2021 Plan and would put additional cost burden on customers in the near term. The 2029 timeline as described above also allows for a just transition for the community and employees, allows time for the transmission enhancements to maintain reliability to be implemented, and provides time for additional innovation in technology. For these reasons, Minnesota Power proposes the most prudent action for BEC Unit 3 is to retire in December 2029. Given the potential rate impacts, Minnesota Power is not proposing modifying the existing accounting life of BEC Unit 3 and common facilities (currently through 2035).

BEC Unit 4

If the 2021 Plan is approved by the Commission, BEC Unit 4 will be the last baseload operating unit in Northern Minnesota. The Company is committed to ceasing coal-fired operations at Minnesota Power's BEC Unit 4 in 2035. Like BEC Unit 3, BEC Unit 4 is an economic capacity and energy resource for customers and is well controlled for pollution. The Company has also begun investigating what actions are needed to transition to economic

dispatch in a similar manner as is being proposed for BEC Unit 3. BEC Unit 4 is jointly owned with WPPI and any changes in operations will be coordinated with this co-owner, including moving to economic dispatch, remission, or retirement. Careful consideration must be taken to ensure WPPI and its customer base are not negatively impacted by any changes at BEC Unit 4, and Minnesota Power will continue to work closely with its partner on alternatives.

BEC Unit 4 is a critical electric infrastructure asset for maintaining regional reliability in the region, which is supported by the findings in MISO Attachment Y2 study discussed in both Appendix F and the Baseload Retirement Study (Appendix P). It is in the interest of customers to continue to leverage the existing infrastructure at BEC Unit 4 to avoid costly high voltage transmission projects. The Swim Lane analysis supports investigation into options for continuing operating BEC Unit 4 post-coal, with the most significant cost increases occurring when BEC Unit 4 is retired. Minnesota Power will begin its investigation into other future non-coal fuel options at BEC Unit 4, including biomass and other lower carbon alternatives for its next integrated resource plan.

Taconite Harbor Energy Center

Since the 2015 IRP, Minnesota Power has completed the transmission projects ordered by the Commission to facilitate the idling of Taconite Harbor Energy Center Units 1 and 2 in 2016. In recent years, the Company has continued to make THEC Units 1 and 2 available to MISO for maintaining resource adequacy. Since idling the units in 2016, neither MISO nor Minnesota Power has needed to restart these units to address reliability or emergency needs on the transmission system.

The Company has investigated several refueling or remission options for the site. Options considered included refueling the boilers with biomass, natural gas, or propane, or utilizing existing land and interconnect for new solar or energy storage. These options were deemed to not be a good fit for the site and the existing infrastructure for a variety of reasons, including: the lack of existing gas pipeline infrastructure, the wood basket for biomass is limited due to the plant's location on Lake Superior, a challenging topography for solar, and high costs to implement energy storage efficiently.

With no resource replacement economically viable and minimal need from MISO demonstrated to utilize the units for regional reliability on an ongoing basis, Minnesota Power is recommending Taconite Harbor Energy Center Units 1 and 2 be retired no later than September 2021, which is also aligned with the expected expiration of current environmental permits. Given the potential rate impacts, Minnesota Power is not proposing modifying the existing accounting life of Taconite Harbor which is through 2026 and reflected the emission reduction investments at these facilities.

Minnesota Power's 2021 Plan Characteristics

The 2021 Plan proposed by the Company continues the transition of Minnesota Power's fleet through the Energy***Forward*** strategy by being reducing carbon, strengthening the electric grid and optimizing existing assets for customers. To accomplish this, the Company is taking prudent steps to address climate change today by optimizing the existing coal fleet in the market and transitioning BEC Unit 3 to economic dispatch in 2021, coordinating with WPPI on a path

forward to move BEC Unit 4 to economic dispatch shortly after, and maximizing the use of renewable energy and grid capabilities. Minnesota Power is delivering a power supply that is half renewable today and advancing clean energy even further with the proposed addition of 400 MW of renewable energy by 2030. As part of the preparation for BEC Unit 3's retirement, Minnesota Power is proposing to invest in the infrastructure needed to enable retirement and manage the delivery of increasing amounts of renewable energy. The 2021 Plan will move Minnesota Power towards a power supply that is 70 percent carbon-free generation in 2030 and starts to identify a path towards 100 percent carbon-free energy by 2050 while protecting affordability and preserving the reliability of the power supply.

It is important to note that Minn. Stat. § 216B.2422 subd. 2(c) requires, "As a part of its resource filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable resource." Since the 2021 Plan recommends meeting its capacity needs through 100 percent new renewable resources and maintaining existing conservation programs, this Plan meets these requirements such that no further analysis of the requirement is needed.

Figure 17 below demonstrates the summer capacity position resulting from the 2021 Plan. Due to the removal of 350 MW of BEC Unit 3 in 2029, there is an identified need for additional capacity resources. Incorporating the proposed 400 MW of additional renewables, combined with continued investment in conservation and distributed solar programs, brings the Company's capacity position into compliance with future resource adequacy requirements. As discussed earlier, pursuing 50 MW of industrial demand response to address future resource adequacy changes and volatility will also benefit customers. This additional 50 MW of demand response is not reflected in the capacity look below. Therefore, if the Commission supports pursuing long-term demand response for customers, then Minnesota Power would expect a slight increase in available long-term capacity.

Figure 17: 2021 Plan Capacity Outlook

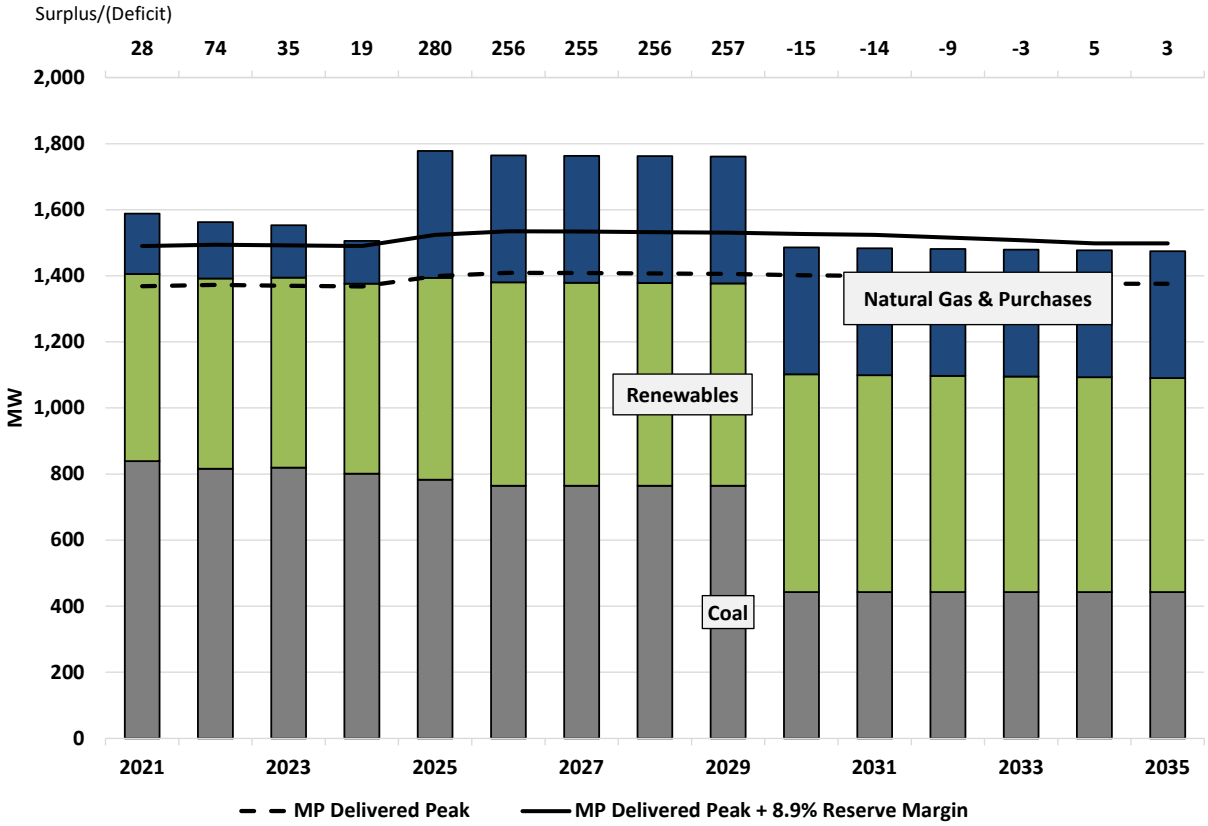


Figure 18 further provides a long-term look at Minnesota Power's expected energy position. The 2021 Plan provides sufficient energy resources to serve customer requirements, while enhancing flexible operations at BEC Units 3 and 4 through economic dispatch and thereby allowing more opportunities to purchase lower cost energy from the market when available. Longer-term, the additional 400 MW of renewables replace BEC Unit 3 energy that is removed through retirement of this unit in 2029.

Figure 18: 2021 Plan Energy Position Outlook

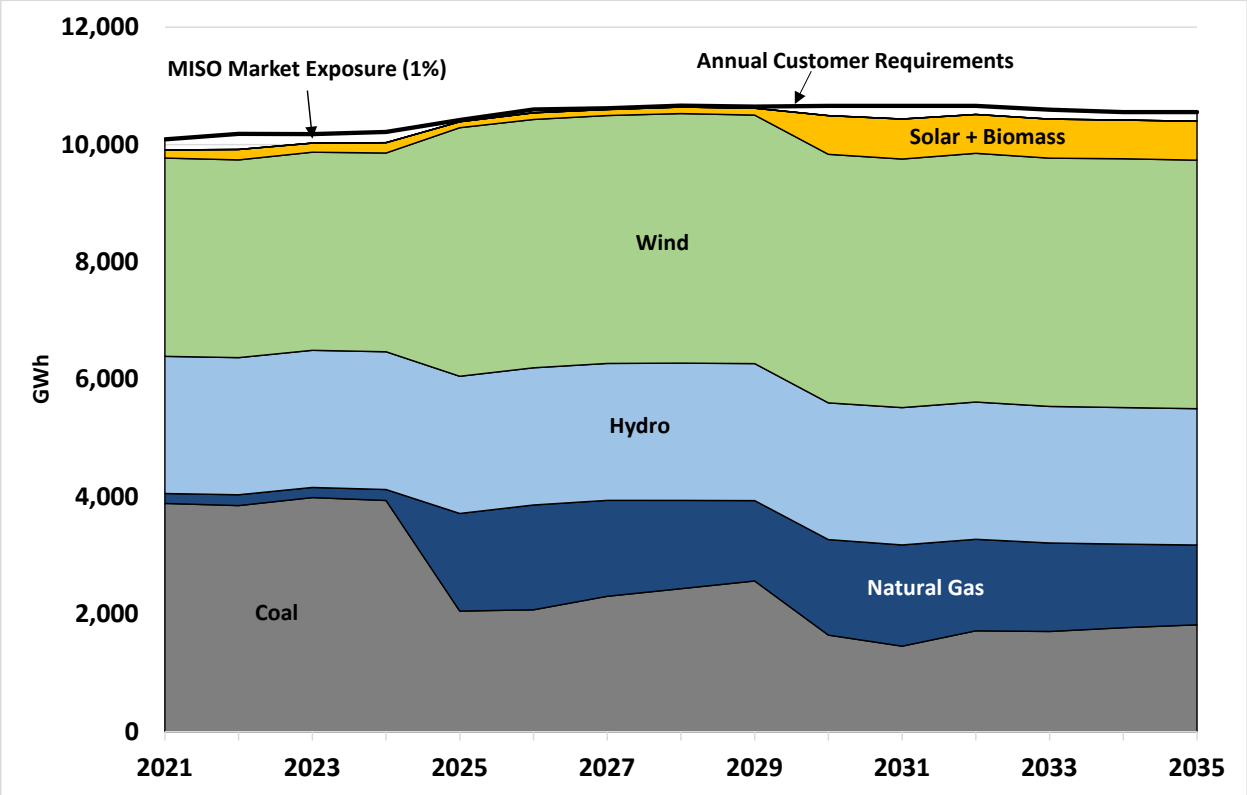
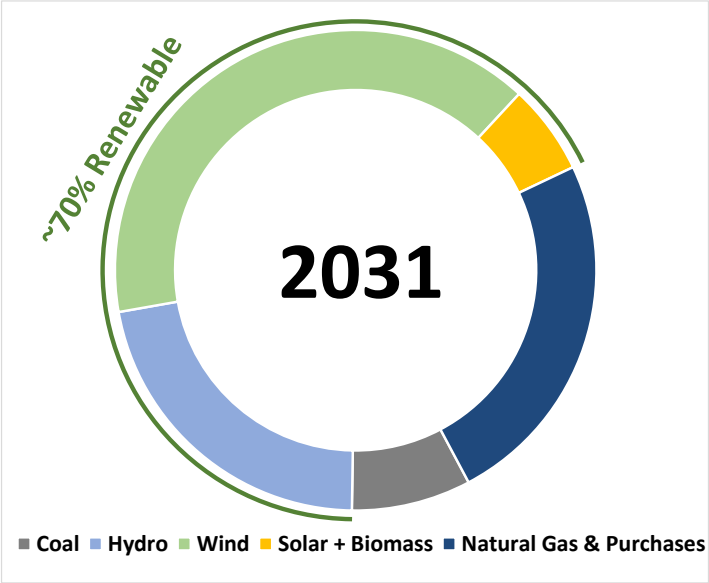


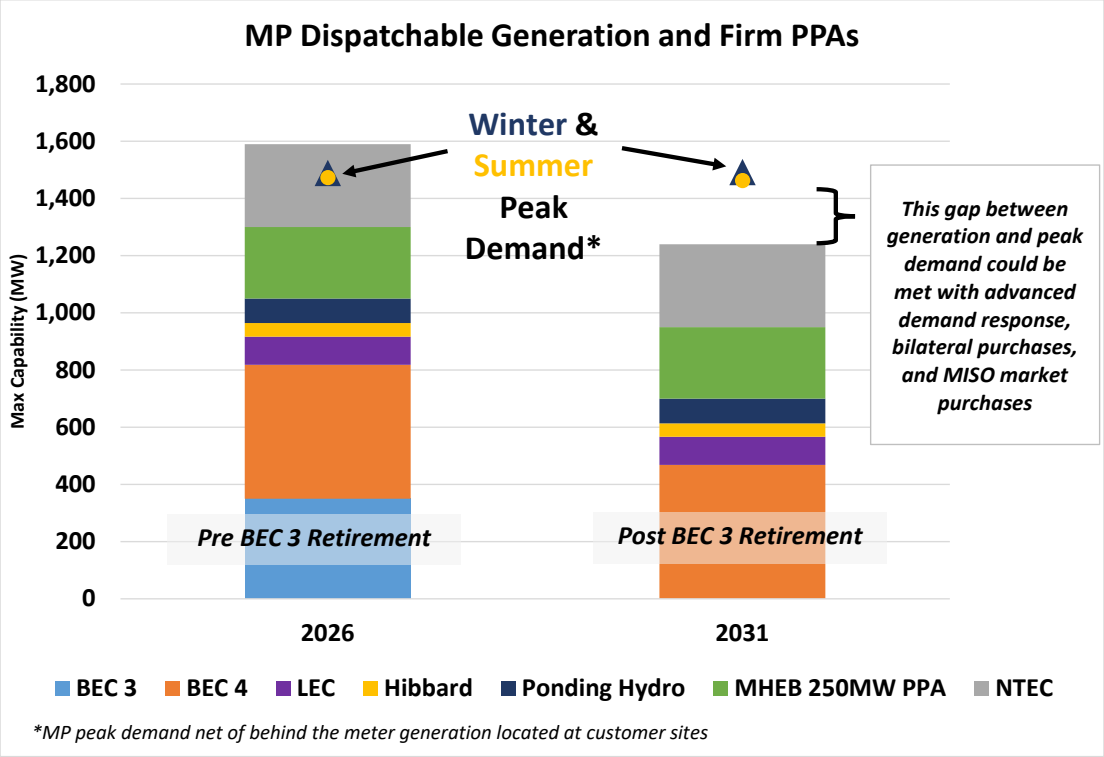
Figure 19 below demonstrates that the 2021 Plan brings additional carbon-free energy and market access into Minnesota Power's power supply mix, increasing renewable generation to approximately 70 percent and allowing more access to market purchases through flexible operations at Boswell Energy Center. The proposed power supply mix brings the Company closer to achieving its vision for 100 percent carbon-free energy by 2050.

Figure 19: 2021 Plan Power Supply Mix in 2031



Minnesota Power continually monitors the capability of its system to meet peak demand, absent of any renewable generation from its 1300 MW fleet of wind and solar. This is a scenario of high renewable penetration is one in which the system would likely be stressed and when customers are most reliant on energy for heating needs, as Minnesota Power's winter peak often occurs when temperatures are well below zero for several days. As shown in Figure 20, Minnesota Power has sufficient dispatchable generation and firm energy procured through PPAs (i.e., MHEB 250 MW PPA) to meet customer demand during a winter peak with little to no renewables production from the wind and solar fleet. Minnesota Power recognizes that after the BEC Unit 3 retirement, there is an approximate 200 MW shortfall between winter peak demand and the capabilities of its dispatchable generation and firm PPAs. The Company anticipates it can rely more on the industrial demand response portfolio, along with firm energy purchases, to manage these periods. The 2021 Plan does show Minnesota Power is resource adequate during the study period, and should have sufficient resources to meet its system peak. With greater reliance on intermittent energy from wind and solar resources to maintain resource adequacy, and the rapid exit from coal-fired generation, Minnesota Power expects changes will likely be needed to the current resource adequacy construct. Minnesota Power continues to monitor how MISO resource adequacy requirements will change in the coming years and the impact it will have on capacity needs. With the BEC Unit 3 retirement proposed for 2029, Minnesota Power will have time to adapt to changes to the MISO resource adequacy construct, if needed.

Figure 10: Minnesota Power's Dispatchable Fleet and Firm PPAs Available to Meet Peak



The actions proposed in the 2021 Plan will have socioeconomic impacts to northeastern Minnesota that will result in changes to jobs and gross domestic product ("GDP"). Minnesota Power performed a socioeconomic impact study using the industry accepted model built by Regional Economic Model, Inc. Not all actions in the 2021 Plan will have direct economic impacts on the region, and for this study only the resource actions that are expected to have direct impacts were included:

1. Construction of three solar projects totaling 20 MW of local scale solar in 2021;
2. Construction of 200 MW of utility scale solar at the Boswell site or another Minnesota Power facility by 2030;
3. Retirement of BEC Unit 3 by December 31, 2029; and
4. Construction of transmission solutions to address reliability issues related to the early retirement of BEC Unit 3.

The actions to prepare for BEC Unit 3 retirement, the solar and transmission additions, are expected to have an immediate positive impact with an increase to total regional employment of 173 jobs per year and increase in annual GDP by $16.7 million. After BEC Unit 3 is retired in 2029, those immediate positive impacts are entirely offset by long lasting negative impacts to the region. Post retirement, regional employment is expected to decrease by 107 jobs and annual regional GPD is reduced by $23.2 million. This highlights the challenge for communities and the broader region (i.e., northeastern Minnesota) to offset the economic impacts caused by coal unit retirements with only additional actions taken by the utilities (i.e., new solar and transmission). Please refer to Appendix M for more detail on the results, other economic impacts to the region, and assumptions used in Minnesota Power's socioeconomic study.

Key Contingencies

The planning process and resource plan analysis discussed in this IRP allowed Minnesota Power to consider several contingencies that address the uncertainty that is present with the business environment and potential climate compliance policy. Each gave the Company the insight needed to be prepared for the potential paths each of these can take in the near term. The key contingencies and their anticipated implications that Minnesota Power will continue to monitor are:

1. Uncertainty in Customer Demand due to Business Climate: If a recession re-emerges or customers are forced under additional economic pressure impacting Minnesota Power's demand, the Company will have excess capacity and will consider making commitments for power sales to mitigate the effect of the reduced customer load.
2. Carbon Regulation Policy Implementation is expedited on a National Level for Existing Generating Resources: Minnesota Power would re-evaluate its long-term actions to reduce carbon and consider the addition of new carbon-minimizing generation resources, new technology, and/or secure additional bilateral purchases until a resource could be placed into service.
3. Technology Advancements: Advancements in carbon-free energy technologies occur quicker and costs decline at a faster rate than expected. Minnesota Power would re-evaluate its long-term actions to reduce carbon quicker and consider the addition more carbon minimizing technologies.
4. MISO Resource Adequacy and Availability of Transmission: MISO is preparing to transition its resource adequacy tariff to have changes to its capacity accreditation construct. Minnesota Power will continue to monitor the cost of interconnecting new resources as Minnesota Power seeks to implement its short and long-term action plan additional renewables to the system.

Minnesota Power will also continue to closely monitor the business environment and potential climate compliance policy outlooks and evaluate its short-term action plan as the landscape unfolds to ensure that customers, communities and stakeholders are served in a reliable and forward-looking way during the planning period.

Conclusion

The 2021 Plan analysis identified that the Company's Short- and Long-Term Action plans were the least cost options of the scenarios considered for the study period through 2035. The Swim Lane evaluation confirmed that a BEC Unit 3 retirement at the end of 2029 is reasonable and the cost burden for customers to retire BEC Unit 4 early is too high. The additional 400 MW of renewables that was supported through the Capacity Expansion Analysis plus continued leadership in conservation programs, demand response, and renewable implementation puts Minnesota Power on a sustainable path to 80% carbon reduction by 2030. Lastly, implementing transmission solutions to address reliability issues related to retiring BEC Unit 3 and ceasing coal operations and investigating options to remission BEC Unit 4 will put Minnesota Power on a path towards 100 percent carbon free by 2050. The 2021 Plan, in its entirety, is a bold and least cost plan that reflects Minnesota Power's commitment to our customers, communities, and the climate.

VI. SHORT-TERM ACTION PLAN

Minnesota Power's resource plan communicates the Company's vision for a sustainable carbon-free energy future and outlines the bold next steps in its clean energy transition that are centered on a commitment to the climate, customers, and communities. The 2021 Plan continues the transformation of the Company's resources by outlining a vision to deliver 100 percent carbon-free energy by 2050 and a commitment to reduce carbon emissions by 80 percent by 2035 in a sustainable way. The resulting action plan outlined in the following sections identifies both short- and long-term measures that will help Minnesota Power continue to meet stakeholder needs in the near term and be poised to deliver safe and reliable service at the most reasonable cost to customers for many years.

Steps to Meet Short-term Action Plan (2021 through 2025)

Minnesota Power's short-term action plan during the five-year period of 2021 through 2025 is comprised of steps that will immediately reduce carbon emissions in the near term and continue the addition of carbon-free renewables, conservation, and other demand side resources to the Company's resource portfolio. The specific strategic and necessary actions to achieve the short-term action plan goals include:

1. Retire the currently idled THEC facility in September 2021. Originally a 225 MW coal generating station built to support iron mining on Minnesota's north shore and acquired by Minnesota Power in 2001, THEC1 was retired in 2015, and the remaining two units were idled in 2016. Given the potential rate impacts, Minnesota Power is not proposing modifying the existing accounting life of THEC, which is through 2026 and reflects the emission reduction investments at these facilities.
2. Construct three solar projects totaling approximately 20 MW in the Company's service territory in 2021 to both meet Minnesota Power's requirements under the SES mandate and assist in the local economic recovery from the COVID-19 pandemic.
3. Adapt operations at BEC3 to move to economic dispatch within the MISO market in 2021. This change in operations will result in immediate carbon reduction while supporting reliability in the region and continuing to provide economic benefits for the local host community.
4. Continue to investigate and prepare BEC4 to transition to future economic dispatch, in coordination with MISO and BEC joint owner WPPI Energy.
5. Maintain leadership in conservation programs and electrification efforts. Minnesota Power has surpassed the state's conservation goals for the last decade and has identified ambitious energy savings goals in its 2021-2023 CIP Triennial Plan. The Company is also implementing infrastructure investments, rate design changes, and EV programs to position for a future grid that accommodates further electrification.
6. Implement the Product C Demand Response program for industrial customers in 2022. In early January 2021, Minnesota Power submitted a petition requesting Commission approval of eight multi-year Product C agreements with industrial customers that will collectively enable between 100 and 202 MW of demand response product to be sold each year from 2022 to 2028.[49]

[49] Docket no. E015/M-21-28.

7. Add 200 MW of new wind resources to Minnesota Power's power supply portfolio by 2025.

VI. LONG-TERM ACTION PLAN

Plans to Meet Long-term Need (2026-2035)

Minnesota Power will focus its long-term plan on a strategy to further reduce carbon emissions in its portfolio and continue reshaping its generation mix in a way that considers the climate, customers and communities holistically. This long-term strategy will continue diversifying resources and position Minnesota Power to be able to successfully adapt to a range of economic and environmental futures while maintaining safe, reliable, and affordable service to its customers. Each component of this long-term plan has been proven through the planning process analysis to be flexible and keep progress toward the Company's strategic resource goals on track in a variety of future scenarios. Planned components of the long-term plan include:

1. Retire BEC3 by December 31, 2029;
2. Add 200 MW of solar that leverages the Boswell site or other Minnesota Power facilities by 2030, leveraging existing interconnections and reinvesting in utility host communities;
3. Work collaboratively with customers to pursue up to 50 MW of long-term demand response by 2030 to address future resource adequacy changes;
4. Develop and implement transmission solutions to address reliability issues related to the early retirement of BEC3; and
5. Investigate options for refuel or remission BEC4 and associated reliability transmission as coal operations cease by 2035.