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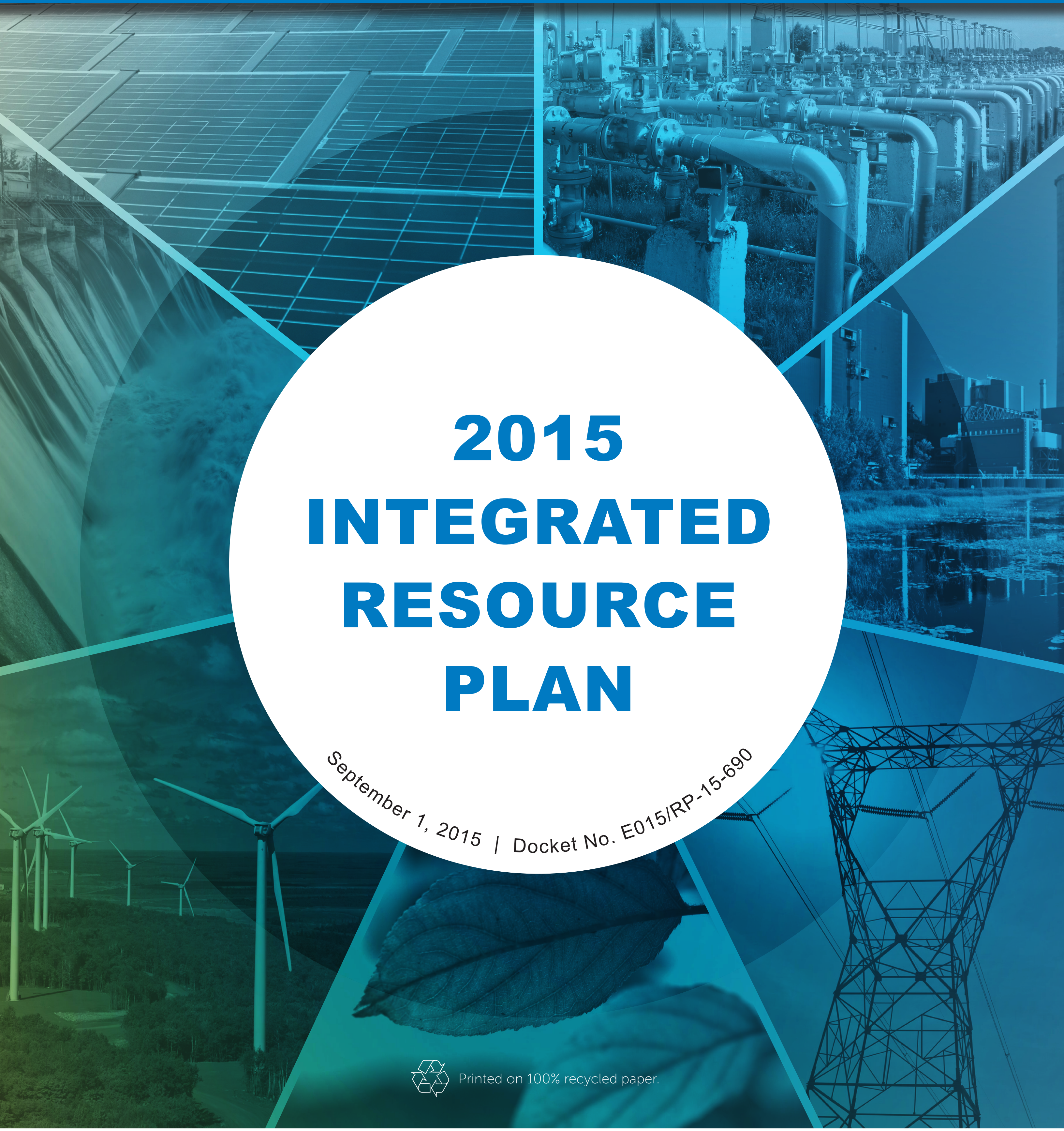

2015 INTEGRATED RESOURCE PLAN

September 1, 2015 | Docket No. E015/RP-15-690

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minnesota power
AN ALLETE COMPANY

EnergyForward

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September 1, 2015

VIA E-FILING
Daniel P. Wolf
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 2015-2029 Resource Plan
Docket No. E015/RP-15-690

Dear Mr. Wolf:

Minnesota Power presents for approval its 2015 Integrated Resource Plan ("2015 Plan" or "Plan") pursuant to the requirements set forth in the Minnesota Public Utilities Commission's ("Commission") Order dated November 12, 2013, in Docket No. E015/RP-13-53. This Plan is being filed under Minn. Stat. § 216B.2422 and Minn. Rules Chapter 7843.

Minnesota Power's 2015 Plan is the next chapter in the Company's *Energy**Forward*** resource strategy. Minnesota Power's *Energy**Forward*** strategy is reshaping the Company's power supply from a predominantly coal-based energy mix to one that is more diverse, while maintaining low cost, reliable electricity to customers. The Plan is designed to supply Minnesota Power customers with a safe, reliable, and affordable power supply while improving environmental performance, reducing emissions, sustaining the Company's high-quality energy conservation program and adding renewables in the near-term and natural gas in the long-term. Minnesota Power's short-term action plan during the five-year period of 2015 through 2019 is comprised of steps that will: a) preserve competitive base load generating resources while reducing emissions, b) increase implementation of least-cost demand-side resources including conservation, c) reduce reliance on coal-fired generation, and d) add renewable energy and transmission infrastructure to the benefit of customers. The Company's long term strategy will focus on further reducing carbon emissions in its portfolio and reshaping its generation mix towards a balance of approximately one-third renewable resources, one-third efficient coal-fired generation and one-third natural gas/other sources. This long-term strategy will position the Company so it can successfully adapt to a range of economic and environmental futures while maintaining service to its customers at a competitive cost.

The 2015 Plan is organized into six sections with supporting appendices as presented in the Table of Contents. The supporting appendices contain in-depth information and, as appropriate, specific responses to the Order dated November 12, 2013, including all agreed-to actions by Minnesota Power.

Certain portions of the Plan 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 attached Affidavit of Service, the Executive Summary has been filed on the official general service list utilized by Minnesota Power as well as the 2013 Integrated Resource Plan service list.

Please contact me at the number or the email address provided if you have any questions.

Yours truly,

Lori Hoyum

Lori Hoyum

LH:sr
Attach.
cc: Service List

STATEMENT REGARDING JUSTIFICATION FOR EXCISING TRADE SECRET INFORMATION

Pursuant to the Commission's revised Procedures for Handling Trade Secret and Privileged Data in furtherance of the intent of Minn. Stat. § 13.37 and Minn. Rule 7829.0500, Minnesota Power has designated portions of its attached 2015 Integrated Resource Plan ("Plan") as Trade Secret.

Minnesota Power is requesting approval of its Plan under Minn. Stat. § 216B.2422 and Minn. Rules Chapter 7843. Minnesota Power has removed certain information from the Plan to prevent disclosure of Minnesota Power's information regarding its methods, techniques, and process for identifying, obtaining, managing, and comparing various resources. This is highly confidential information; Minnesota Power's competitors, as well as its potential suppliers, would gain a commercial advantage over Minnesota Power if this information were publicly available. Minnesota Power follows strict internal procedures to maintain the secrecy of this information in order to capitalize on economic value of the information to Minnesota Power. As a result of public availability, Minnesota Power and its customers would suffer in providing resources to its retail load. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the trade secret designation provided herein.

STATE OF MINNESOTA	)	AFFIDAVIT OF SERVICE VIA
	) ss	E-FILING AND
COUNTY OF ST. LOUIS	)	FIRST CLASS MAIL

Susan Romans, of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 1st day of September, 2015, she e-filed Minnesota Power's 2015 Integrated Resource Plan in Docket No. E015/RP-15-690 on the Minnesota Public Utilities Commission and the Minnesota Department of Commerce via electronic filing. The remaining parties on the attached Minnesota Power's General IRP Service List were served as indicated.

Susan Romans

Susan Romans

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MINNESOTA POWER 2015 RESOURCE PLAN

PETITION FOR APPROVAL

September 1, 2015
Docket No. E015/RP-15-690

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I. ABOUT MINNESOTA POWER

Minnesota Power is transforming the way it energizes communities and businesses through a resource strategy called *Energy**Forward***. The company that was founded as a hydroelectric utility in 1906 and grew to serve its unique customer mix with predominantly coal energy is rebalancing its generation mix by bringing more renewable power to customers while reducing its dependence on fossil fuel. *Energy**Forward*** will bring Minnesota Power to an energy mix of one-third coal, one-third natural gas, and one-third renewables.

A division of ALLETE, Inc., Minnesota Power (or "Company") serves about 144,000 retail electric customers and 16 municipal systems across a 26,000-square-mile service area in central and northeastern Minnesota. ALLETE subsidiary Superior Water, Light and Power provides electricity to 15,000 customers, natural gas to 12,000 customers and water services to 10,000 customers in northwestern Wisconsin.

In 2014, 54 percent of Minnesota Power's kilowatt-hour ("kwh") sales served large power customers, primarily in the taconite mining, iron concentrate, paper, pulp, refining and pipeline industries. Many of these industrial customers operate 24/7, which gives the utility a unique high load factor featuring a power supply with less variation in demand than most utilities.

Minnesota Power has 10 Large Power customer contracts, each serving at least 10 megawatts ("MW") of load: five taconite producing facilities (two are owned by one company), one concentrate reclamation plant, one iron nugget producer and four paper and pulp mills. The processing of taconite, an iron-bearing rock used to make steel, requires large quantities of electric power. Two additional large power customers expected to be operating soon will also be receiving energy from Minnesota Power: PolyMet, a nonferrous mining operation awaiting final permitting, and Essar Steel Minnesota, a major taconite mine and processing plant now under construction. Essar, scheduled to begin producing taconite next year, obtains its electricity from the city of Nashwauk, which is served as a wholesale municipal customer. The Company also powers four wood products manufacturers and provides electric service to two crude oil pipelines and a refinery via contract through affiliate Superior Water, Light and Power Company. In part because of its high concentration of large customers and relatively low proportion of residential customers, 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 1,817 MW on December 30, 2015.

Minnesota Power produces the majority of its electricity from coal-fired generation units, supplemented by a long-term purchase from Square Butte's Milton R. Young 2 ("Young 2") lignite coal generating station in North Dakota. The Company's execution of *Energy**Forward*** is systematically lowering the ratio of coal used to produce energy at Minnesota Power and dramatically lowering emissions from the baseload coal units that remain. In February 2015, the last trainload of coal was unloaded at the Laskin Energy Center ("LEC" or "Laskin"). In the weeks following, the Laskin plant was converted to use cleaner-burning natural gas. In June 2015, Minnesota Power's coal-fired Taconite Harbor Energy Center Unit 3 ("THEC3") ceased generation 48 years after it began operation. The percentage of coal-based generation on the Minnesota Power system has declined from about 95 percent in 2005 to approximately 75 percent today. Additionally, major emission reduction projects at Boswell Energy Center Units 3 and 4, the two largest coal generators remaining on Minnesota Power the system, are contributing to the Company's significantly lower emission profile. A major environmental retrofit was completed at Boswell Energy Center Unit 3 ("BEC3") in 2009. Work is expected to be completed later this year on a mercury emissions reduction project at Boswell Energy Center Unit 4 ("BEC4") that will reduce emission of mercury approximately 90 percent and also reduce levels of particulates and sulfur dioxide.

Over the past decade, the Company has undertaken a systematic effort to increase its deployment of renewable energy. In 2006 and 2007, Minnesota Power began purchasing the entire output of the Oliver 1 and Oliver 2 wind farms built in North Dakota by NextEra Energy. In 2008, Minnesota Power constructed Taconite Ridge, 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 2014. Bison, now the largest wind farm in North Dakota with just under 500 MW, leverages a premier wind resource to deliver carbon-free energy to customers of Minnesota Power. Combined, these wind projects added more than 600 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. Late last year Minnesota Power's Thomson Hydroelectric Station on the St. Louis River was returned to service 28 months after a devastating flood breached a forebay canal and swamped the 107-year-old renewable energy facility, knocking it offline. Repair and refurbishment of other Company hydro facilities, including work at Fond du Lac, Little Falls, Winton, Prairie River and Birch Lake, were commemorated in a series of "Hometown Hydropower" events last summer. In 2011 and 2014, the Company signed 15 and 20-year agreements to buy 383 MW of carbon-free hydroelectricity from Manitoba Hydro beginning in 2020. Minnesota Power is planning the construction of the Great Northern Transmission Line ("GNTL") to carry this Canadian hydropower to the heart of its industrial base on the Iron Range of Minnesota.

As an integral part of *Energy**Forward***, Minnesota Power is further diversifying its renewable energy options to include solar energy generation. The Company is working with the Minnesota National Guard to build a 10 MW solar energy project on the grounds of Camp Ripley near Little Falls, Minn. The Camp Ripley Solar Project will be the largest solar energy installation at any National Guard base in the U.S., covering nearly 80 acres with photovoltaic panels.

Minnesota Power has used imagination and innovation in rebalancing its generation fleet. Young 2, a major source of coal-based generation, is being phased out of the Company's resource mix as this coal generation resource is replaced by wind energy. Minnesota Power in 2009 purchased a 465-mile direct current transmission line ("DC Line") linking Young 2 in North Dakota with Duluth Minn. It was built 30 years earlier to transport "coal by wire" from Young 2 to Minnesota Power. The lignite-fueled energy will eventually be replaced on that DC Line with renewable wind power flowing from the Bison Wind Energy Center, delivering "wind by wire." A creative provision of Minnesota Power's energy purchases from Manitoba Hydro will allow the Company to "store" North Dakota wind energy within the Canadian hydroelectric system.

Minnesota Power is bringing *Energy**Forward***, dedicated to creating a reasonable balance of energy generation that is dependable, affordable and environmentally sound.

II. 2015 RESOURCE PLAN SUMMARY

This Petition presents Minnesota Power's 2015 Integrated Resource Plan ("2015 Plan" or "Plan") for the period 2015 through 2029. The Plan is filed pursuant to Minn. Stat. § 216B.2422, and the Minnesota Public Utilities Commission's ("Commission") November 12, 2013 Order on Minnesota Power's 2013 Integrated Resource Plan ("2013 Plan").[1]

Minnesota Power is pleased to submit its 2015 Plan, the next chapter in the Company's *Energy**Forward*** resource strategy. Minnesota Power's *Energy**Forward*** strategy is reshaping the Company's power supply from a predominantly coal-based energy mix to one that is as reliable and more diverse, while minimizing costs. The Plan is designed to supply Minnesota Power customers with a safe, reliable, and affordable power supply while improving environmental performance, reducing emissions, sustaining the Company's high-quality energy conservation program and adding renewables in the near-term and natural gas in the long-term.

As we look ahead to the next fifteen years, Minnesota Power finds itself in a very different planning position than most of the electric industry, due to its unique customer composition and its forecast of load growth in a period when electric demand has stalled across much of the country. Taconite producers and forest product facilities, including paper mills, served by Minnesota Power have demonstrated their ability to respond to national and global business cycles and industry dynamics through flexibility and product diversification. There are also several large-scale mining projects on the horizon that are highly feasible, and Minnesota Power expects to realize this load growth despite the mediocre macro-economic conditions of the post "Great Recession" world. Continued industry-wide reduction in power demand plus abundant supplies of renewable resources, abundant coal and natural gas supplies are resulting in historic lows in electric power market prices. This is producing an outlook for competitively priced surplus power that could help keep the Company's power supply costs low through select and well-timed bilateral purchases, especially in the near term.

Minnesota Power has taken action to timely address environmental regulations and strongly position its customers for compliance with the Environmental Protection Agency's ("EPA") just finalized Clean Power Plan ("CPP").[2] The Company expects a 90 percent reduction in air emissions and 30 percent reduction in greenhouse gas emissions by 2025, from 2005 levels, with the 2015 Plan short and long-term action plans proposed. The final CPP Rule is being closely examined while state compliance plans are in formation for later this decade. As such, Minnesota Power does not attempt to contemplate a specific compliance outcome in this 2015 Plan. The Company's transformation since 2005 to a less carbon intense power supply through competitive renewable resources, reductions in coal-fired generation, and high performing energy efficiency programs are consistent with state emission reduction policies and aligning with national goals being set. Minnesota Power will continue to highlight the carbon minimizing investments already made on behalf of customers and work closely with the Minnesota Pollution Control Agency ("MPCA") and other stakeholders on the development of CPP compliance plans for Minnesota in the coming months as the state shapes its implementation plan.

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[11] Docket No. E015/M-13-53.
[2] See http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule.

Minnesota Power's 2015 Plan represents a balanced approach to delivering safe, reliable service at the lowest possible cost to customers while protecting and improving the region and state's quality of life through continued environmental stewardship. Additionally, the themes of the 2015 Plan reflect the Company's long-held resource planning principles and strategic goals, while meeting state regulatory and legislative objectives. This Plan:

- Preserves reliable and environmentally compliant electric service to meet customer needs. Through implementation of a diverse and flexible resource mix of renewable energy, coal and natural gas supplies, Minnesota Power will balance its fuel sources and be well positioned to meet the needs of its customers.
- Cost effectively serves increasing customer load requirements while reducing carbon intensity per unit of energy delivered through an optimum mix of effective customer conservation programs, reduced reliance on coal, generating facility efficiency improvements, added renewable energy sources from wind, water, wood and solar and the addition of natural gas in the long term. Minnesota Power will reduce carbon emissions by about 20 percent on its system by 2020 and 30 percent by 2025 while serving about 20 percent more load, meeting the 2015 and 2025 state goals for carbon reduction, and aligning for longer-term greenhouse gas targets compared to 2005 levels.[3]
- Protects affordability through power supply actions that maintain competitive electric service rates for Minnesota Power's customers. The 2015 Plan rate outlook demonstrates cost effectiveness for customers, even as Minnesota Power meets its forecast growth and complies with environmental and energy policies. Minnesota Power has very competitive rates for residential, commercial and industrial customers, especially when compared to regional and national rates.
- Addresses resource planning order requirements as detailed in Minnesota Power's 2013 Plan Order. Specifically, the 2015 Plan addresses:
    - Minnesota Power shall obtain approximately 200 MW, subject to need, of intermediate capacity (and associated energy) in the 2015 – 2017 timeframe. Minnesota Power utilized its bilateral bridge strategy identified in its 2013 Plan to procure 150 MW of power to meet near term requirements. Minnesota Power filed pertinent details of the contracts, such as the duration, price, and amount of capacity and associated energy to be procured as requested in the 2013 Plan Order.
    - *MISO Attachment Y requests and the results.* Minnesota Power submitted the results of its THEC3 Attachment Y study on March 3, 2015, in the 2013 Plan docket. MISO did not identify any need for system support resource

[3] Minn. Stat. § 216H.06, Subd. 1, states, "It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050. The levels shall be reviewed based on the climate change action plan study."

requirements as a result of ceasing coal-fired operations of the generating unit.

- *Energy savings considerations.* Minnesota Power provides an estimation of the amount of embedded energy savings projected in its energy outlooks for non-Conservation Improvement Program ("CIP")-exempt and CIP-exempt sales. Scenarios in 0.1 percent increments for additional energy savings for non-CIP-exempt sales, including a goal of 1.87 percent of Minnesota Power's retail sales,[4] are provided. Additional insights into its CIP–exempt customer energy savings activities are also provided in this Plan.
- *Including the midpoint of the Commission's approved carbon dioxide ("CO_2") cost range in its Base Case assumptions.* Minnesota Power evaluated the impacts of the CO_2 ranges approved by the Commission in its expansion plan and Base Case analysis as well as a wide range of carbon price sensitivities.
- *Effects of retiring or repowering Taconite Harbor Energy Center Units 1 and 2 ("THEC1&2").* Minnesota Power, in response to the 2013 Plan Order, conducted an analysis on its THEC1&2 resources, and is taking specific action in its 2015 Plan. The analysis in the Plan includes a robust transmission evaluation that shows THEC1&2 will cease coal operations by 2020 and be considered for retirement or repowering in that same timeframe.

Minnesota Power's 2015 Plan continues the transition of the Company's fleet toward more diversity and flexibility, and less emissions, with additional major steps that address a changing energy landscape while responding to the 2013 Plan Order. The need for Minnesota Power's industrial customers to be globally competitive, combined with the inherent cyclicality of these natural resource-based industries, along with the knowledge that environmental regulation will continue to be a major factor in energy supply decisions, requires Minnesota Power to plan for its future resource mix in a transformational way. The 2015 Plan helps to ensure that Minnesota Power remains well positioned under most economic and regulatory scenarios to best serve the needs of its customers, large and small.

Key Items Shaping the 2015 Plan

The Commission's November 12, 2013 Order concluded Minnesota Power's 2013 integrated resource plan, and established items for consideration in Minnesota Power's next resource plan (see Appendix N). Since Minnesota Power's 2012 Baseload Diversification Study, the Company has communicated the impacts to its planning from variables such as sensitivities for natural gas pricing, carbon penalties, customer load, and availability of competitive resources options. For the 2015 Plan, Minnesota Power continued its thorough and robust planning evaluations which resulted in the recommendations for future action listed in Sections V and VI. These actions position the Company and its customers well under a wide range of scenarios.

[4] Details on the energy savings evaluation are provided in Appendix B and K and included as part of the expansion planning conducted in Section IV.

Order Point 13 of the 2013 Plan required Minnesota Power to place a regulation tax penalty on carbon emitting resources in the Base Case starting in 2019. A carbon penalty has not been established, nor is it expected to be in place in 2019. The Company highlighted in its evaluation the resource decisions that are impacted by the inclusion of the carbon penalty variable and those that are robust over all sensitivities. The analysis identified that the inclusion of a premature carbon penalty in 2019 is driving unneeded resource additions earlier and increasing customer costs above where they could be with a less intensive action plan, as well as creating a significant deviation in the timing of the Company's *Energy**Forward*** transition. This scenario is an example of what can occur when resource decisions are based on uncertain variables, such as a carbon penalty, which can drive an outcome outside the range of realistic planning and well timed power supply resource decisions.

Order Point 14 of the 2013 Plan required Minnesota Power for its next resource plan to conduct a full analysis of the effects of retiring or repowering THEC1&2, including transmission and distribution effects. Through Minnesota Power's *Energy**Forward*** strategy, the Company is planning for and making progress towards achieving an energy mix of approximately one-third renewable resources such as wind, wood, water and solar, one-third natural gas/other and one-third coal for its long-term position. Evaluation of THEC1&2, and the Company's other small coal-fired generation is an important component of the 2015 resource planning process, and in effectively implementing the *Energy**Forward*** strategy.

The recommendations in Minnesota Power's short and long-term action plans reflect the application of well-established resource planning principles, sound science and economics in evaluating the impact of a future carbon penalty and the repower and/or retirement of the Company's small coal-fired generation. In this formative time where electric costs are rising for Minnesota customers and uncertainty remains about final federal greenhouse gas regulations, additional planning is absolutely necessary. Proposals for customers must balance reliability and affordability, and protect and improve the quality of life in the region and state through continued environmental stewardship.

Integrated Resource Plan Process Streamlining

As the pace of change in the nation's energy landscape quickens, so has that of the Company in developing its 2015 Plan so that it will support timely decisions on key aspects of the Company's energy supply. To that end, Minnesota Power took the following actions and included information in its 2015 Plan that addresses specific interests of regulators and stakeholders, some for the first time, to enable effective and comprehensive stakeholder input and efficient consideration and decision making. These actions include:

- Pre-filed 30 days in advance of the 2015 Plan the Company's load forecast and load and capability calculation in advance of the overall 2015 Plan.
- Pre-filed 30 days in advance of the 2015 Plan the large datasets utilized in the evaluation and analysis, including Strategist software input and output files, along with detailed scripts on Minnesota Power's analysis process.
- Projection of customer rate impacts due to changes in power supplies reflected in the short-term action plan (see Appendix L).

- Projection of customer rate impacts that the Minnesota Renewable Energy Standard ("RES")[5] has had on customers under the Commission ordered[6] uniform reporting system (see Appendix I).
- Education and insight into Minnesota Power's distribution system attributes and planning (see Appendix G).
- Pre-filing and post-filing stakeholder interaction including small and large group meetings; post-filing stakeholder meetings will be held across Minnesota Power's service territory and in St. Paul, Minn.

Creating a More Flexible and Diverse Fleet

As noted, the Company's resource strategy includes a major evolution from a primarily coal-based fleet to a more balanced and flexible set of resources. A more balanced and flexible fleet will provide Minnesota Power the capability to meet customers' needs reliably and cost-effectively while still managing the inherent variability of large industrial customer business cycles. Minnesota Power is aiming for an energy mix of approximately one-third renewable resources such as wind, water, wood and solar, one-third natural gas/other and one-third coal for its long-term position. Diversification of the Company's fleet is already well underway, with much of the progress attributed to the successful implementation of its renewable plans, including wind and wood additions plus Minnesota Power's 250 MW and 133 MW power purchase agreements ("PPA") with Manitoba Hydro. Minnesota Power also is subject to the RES, which requires 25 percent of its retail electric sales to be generated by eligible energy technologies by 2025. Between 2006 and 2015, Minnesota Power executed PPAs and constructed over 600 MW of wind facilities, further diversifying the Company's fleet and meeting the RES with approximately 26 percent of its projected 2025 retail and wholesale electric sales from Minnesota-eligible renewable energy sources.

Wisely Planning for Growth and Inherent Business Cycles

Historically, Minnesota Power has been required to flexibly respond to business cycles which may include large increases in load, or a decrease in load like the one currently being experienced. This need for flexibility will continue and is combined with a forecast for growth in the current planning period. In order to account for system growth while retaining its historical business cycle flexibility, the Company evaluated four forecast scenarios. Three of the scenarios centered around variations of load growth, while the remaining scenario examined load contraction. The evaluation showed Minnesota Power will have the power it needs to serve large load additions under various timing requirements while providing those customers with the cost effective electricity they depend upon. The Company will also have a more flexible fleet to provide contingency capability during business cycles.

Sound Coal Unit Direction

Planning for a smooth evolution away from coal at its small coal facilities is an important part of the *Energy**Forward*** strategy. Optimizing the timing and opportunities at each of its facilities, Minnesota Power is taking its next steps in this transition and has determined that 150

[5] Minn. Stat. § 216B.1691.

[6] Order dated January 6, 2015, in Docket No. E999/CI-11-852.

MW of generation from its small coal-fired facilities is not cost effective to continue on coal. Minnesota Power plans to cease coal-fired operations at THEC1&2 by the end of 2020. As part of this transition, the Company will take advantage of trends in lower cost replacement energy supplies from wholesale markets and idle THEC1&2 in the fall of 2016. With this transition and actions taken since 2013 Plan approval, Minnesota Power will have removed over 560 MW of coal-fired generation from its power supply by 2025.[7]

The decision to idle Taconite Harbor Energy Center ("THEC") rather than close it completely in the near term will give the company more flexibility during a period of time when considerable change is occurring in energy supply and policy. If necessary, and with appropriate notice, the idled units can be restarted and produce electric power to maintain grid reliability.

Boswell Energy Center Units 1 and 2 ("BEC1&2"), part of the larger Boswell Energy Center ("BEC") system, are more efficient and cost effective as a result of direct fuel delivery, and integral shared operations across the larger BEC facility. The 2015 Plan identified that these two generating units (130 MW) will provide valuable generation around the clock for customer needs. A unique emission reduction project that allows the facility's environmental infrastructure to be leveraged to further reduce sulfur dioxide ("SO_2") emissions on BEC1&2 will be implemented. With a reduced emission profile, the BEC small coal-fired generation is proving economic for customers over the short and long-term.

Minnesota Power's newer and larger BEC3 and BEC4 remain core assets that supply large volumes of cost-effective energy to Minnesota Power customers 24 hours a day. The BEC4 Mercury Emission Reduction Project ("BEC4 Project")[8] will be operational in late 2015 and sustain the essential BEC4 resource for customers in an environmentally compliant manner well beyond this Plan horizon.

Competitive Renewable Supply Ahead of RES Target

Through wise planning, regulatory support, successful project execution and capitalizing on economic opportunities, Minnesota Power is a decade ahead of schedule in meeting its requirement to have 25 percent of projected 2025 retail and wholesale electric sales from Minnesota-eligible renewable resources by 2015. Minnesota Power constructed and placed into operation four large and cost-effective wind farms located in North Dakota: the Bison 1, 2, 3 and 4 Wind Projects, and smaller projects, Taconite Ridge Wind Project in Minnesota. Given the high penetration of wind in Minnesota Power's portfolio of over 600 MW, the 2015 Plan is not calling for additional wind resources at this time.[9] Additional customer growth and carbon regulation requirements can drive the power supply evaluation to call for more wind resource; however, until there is additional certainty around both of these areas, additional investment is not warranted for customers. By 2025, the customer power supply is projected to be 35 percent renewable from all renewable sources, consistent with *Energy**Forward***. The Company

[7] Minnesota Power's 2013 Plan identified the retirement of THEC3 (75 MW), refuel of LEC (110 MW) and phase out of 227 MW of coal from the Young 2 generating station in North Dakota partnership with Minnkota Power Cooperative.

[8] Docket No. E015/M-12-920.

[9] Along with Minnesota Power's own renewable generation, the Company has a power purchase arrangement for the Oliver County I and II wind farms in North Dakota for about 100 MW of additional wind power.

continues to evaluate other renewable options including biomass, energy storage, and cost-effective wind projects located in and around Minnesota.

Minnesota Power's 2015 Plan analysis includes scenarios for the least cost expansion plan for meeting 50 and 75 percent of all new energy needs through a combination of conservation and renewable energy resources, in alignment with Minn. Stat. §216B.2422, subd. 2. The results of the 50 and 75 percent expansion plans identify increased cost for customers when compared to the Company's Preferred Plan. The details and results of these expansion plans can be found on page 37 of Appendix K. Minnesota Power will continue to monitor the required scenarios in its resource planning process. Renewable energy investments made to date, on behalf of customers, for meeting the 25 percent RES have been reasonable and resulted in estimated rate impacts that are competitive with alternate power supply resource options, as shown in the results of the Company's RES Rate Impact Analysis (Appendix I).

Solar Energy Strategy Launch

Since the Solar Energy Standard ("SES") was passed in 2013, Minnesota Power has developed a robust, portfolio-based solar strategy consisting of three pillars of focus: 1) customer – maintaining relationships and providing thoughtful incentive and education programs, 2) community – enabling customer access to solar energy options and promoting community development, and 3) utility – implementing efficient resources into the customer power supply. This portfolio-based approach will position the Company for compliance with the SES in 2020. The Company has initiated work on its first utility scale solar project, the 10 MW Camp Ripley Solar Project. While it is estimated that the Company needs approximately 33 MW of solar to meet the SES, early action on the Camp Ripley Solar Project, and a launch of a unique community solar garden will generate solar renewable energy credits ("S-RECs") that provide flexibility to meet SES by 2020 without requiring the development of the entire 33 MW in the next four years.

Expanding Potential for Energy Efficiency and Distributed Generation ("DG")

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. The Company is in the process of developing customer-facing DG programs to deliver value for customers. A backup generation pilot program (10 MW) will be developed for consideration by the Commission in 2016.

The Company will consider enhancements to selected CIP and demand side management ("DSM") programs, while continuing to apply best practices from the conservation industry and developing leading-edge programs. Minnesota Power has maintained a strong record of conservation performance and been a state leader in exceeding the Minnesota 1.5 percent energy savings conservation goal. Along with this strong dedication to conservation, Minnesota Power will continue to work to identify reasonable additions to its DSM programs where it is most beneficial for customers.

Natural Gas Additions and Market Purchases: Well-timed to Optimize Opportunities

Over the past two resource plans, Minnesota Power has been evolving the timing and need to incorporate a natural gas combined cycle (“CC”) resource into its power supply portfolio. With its first 110 MW peaking resource in place at the LEC station since June 2015, the Company’s natural gas portfolio is taking shape and ready for expansion. The significant transformation of small coal generation is reducing the amount of reliable, non-intermittent generation that can serve customers. To replace the energy and capacity that cannot be provided by renewable sources or conservation alone without additional cost increases, a natural gas CC resource provides an efficient, less carbon intensive option to support the reliability of the electric supply including large volumes of low cost dispatchable energy and capacity.

The 2015 Plan evaluation determined that the timing is right to begin development of an additional natural gas resource. Presently, Minnesota Power plans to add 200 – 300 MW of natural gas CC generation by 2024. This timing fits well with the transition of its small coal generation fleet that is expected to no longer be included in the resource portfolio by this same time period. Existing resources, the PPAs with Manitoba Hydro in 2020 and additional solar, along with cost-effective bilateral market purchases, will provide a stable resource mix for the defined period of 2015 through 2024 as a bridge to implementation of a natural gas resource and continued emission reduction.

Bilateral market purchases have a distinct role in meeting customers’ energy needs between now and 2024 and are not a standing supply approach for the long term. Rather, they provide a particular opportunity for very economical, shorter term energy supply given the low price in the current wholesale energy market. Using stably priced, bilateral purchases with strong counterparties from existing assets for some shorter term supply helps mitigate rate impacts on Minnesota Power customers by deferring the addition of capital costs for a natural gas resource between now and 2024. They also allow for flexibility as large new customer loads ultimately materialize, given the wide range of load growth projections illustrated in Minnesota Power’s 2014 Annual Electric Utility Forecast Report (“AFR2014”). Additionally, a more paced timing of adding a natural gas CC resource will aid the development of the best natural gas option for Minnesota Power’s customers.

Minnesota Power will begin a competitive process to secure efficient natural gas resource options for the 2024 time period and bring forward the best alternative for its customers before its next resource plan.

Technological Evolution

Technology evolution in the energy industry is occurring rapidly. Optimization in detecting and extracting shale gas, for example, is impacting gas supply and moderating price volatility outlook. New efficiency in natural gas technology is creating the next generation of reliable energy production with lower emission profiles. Strides are being made in clean coal and new combustion cycles that have promise for future development. Additionally, advances in solar technology have resulted in a reduction in the cost of solar photovoltaic panels, making solar energy a more viable consideration for utility and DG portfolio expansion in the future. 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 creates unnecessary risk for customers and not being flexible to move soon enough can stymie creative and cost effective solutions as well. The most recent example of “right timing” with technology has been the way Minnesota Power advanced its wind development. This effort began first with smaller power purchase agreements and small self-build projects, stepping up to larger commitments as technology matured eventually leading to Minnesota Power’s delivery of a very efficient and cost effective large wind generating portfolio primarily comprised of the North Dakota Bison wind projects. A similar approach is being taken with advancing solar and implementing a diverse strategy that can be built upon as technology and customer options becomes available.

Minnesota Power is steadily following and studying technology developments to determine if and to what extent the significant incorporation of new technologies in its plans to serve customers is appropriate.

Updates Since the Last Approved Minnesota Power Resource Plan

Specific actions taken since the November 2013 approval of Minnesota Power’s 2013 Plan 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:
    - Commissioned the 204.8 MW Bison 4 Wind Project near Center, North Dakota[10] in December 2014.
    - Signed a Memorandum of Understanding with the Minnesota Air National Guard for a new 10 MW solar array, additional conservation and sustainable energy at Camp Ripley located near Little Falls, Minn. in 2014.
- The Thomson Hydroelectric Station (71.3 MW), which was forced offline due to damage caused by heavy flooding in 2012 is restored and being brought back into service. Through a $90.4 million investment the facility will resume full operations by the end of 2015 and provides approximately 280,000 MWh of low-cost renewable energy for customers each year.[11]
- 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:
    - In addition to a 250 MW PPA, a 133 MW PPA with Manitoba Hydro was secured to begin in 2020 which was subsequently approved by the Commission.[12] The PPAs requires a new, international transmission interconnection in partnership with Manitoba Hydro. Minnesota Power has received a Certificate of Need for the Great Northern Transmission Line (“GNTL”)[13] that upon completion of the project will facilitate delivery of the

[10] Docket No. E015/M-09-285.
[11] The Thomson project was approved for rate recovery by the Commission on January 29, 2015 (Docket No. E-015/M-14-577).
[12] Docket No. E015/M-11-938 and Docket No. E015/M-14-960.
[13] Docket No. E015/CN-12-1163.

PPA energy and additional resources for the Upper Midwest. The agreements also provide for a unique wind storage provision that will allow Minnesota Power to effectively store excess wind energy from the Bison wind projects in North Dakota in Manitoba Hydro's hydro facilities. Furthermore, the Midcontinent Independent System Operator ("MISO") has recognized the Manitoba PPA will meet capacity eligibility standards.

  - Minnesota Power values diversity in its renewables portfolio and plans to pursue further action when timing is right for Rapids Energy Center ("REC") and Hibbard Renewable Energy Center ("HREC").
  - Further reductions of Young 2 capacity from the 227.5 MW to 100 MW level occurred upon Minnkota Power Cooperative ("Minnkota") placing in service its new Center to Grand Forks 345 kV transmission line in August 2014. As set forth in Docket No. E015/PA-09-526, the new line will trigger phase-out of Young 2 from Minnesota Power supply resources entirely by 2026.
  - Completed key small coal transitions approved in the 2013 Plan including the refuel of LEC (110 MW) to a natural gas peaking facility and retirement of THEC3 (75 MW) in June 2015.
  - Finalized key short term power purchase extensions in 2014 that secured economic bilateral contracts to bridge Minnesota Power's customer supply requirements to the 2020 time period to allow the small coal transition of LEC and THEC3.
  - Gained Commission approval and began implementation of a major mercury emission reduction project on BEC4 to address Mercury Air Toxics Standard ("MATS,") the Minnesota Mercury Emissions Reduction Act of 2006 ("MERA") and other new and existing state and federal emission control regulations.[14] Minnesota Power plans to complete the BEC4 Project by the end of 2015.

- Minnesota Power remains a state leader in energy conservation and DSM (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, achieving a total savings of 2.5 percent of eligible retail energy sales for 2013, and 2.54 percent of eligible retail energy sales for 2014.[15]
- Minnesota Power advanced its customer solar strategy and outreach. The Company invested in a unique solar energy research partnership with St. Louis County and NRRI (University of Minnesota-Duluth's Natural Resources Research Institute) and installed three solar array technology options on top of the St. Louis County building located in downtown Duluth. Provided a comprehensive Consumer Guide to Solar Power as an

[14] Docket No. E015/M-12-920.
[15] Minnesota Power will file its 2015 CIP Consolidated filing giving its 2015 results on April 1, 2016, and will be providing the Triennial Plan in June 1, 2016.

educational tool to help customers understand how solar works and make an informed decision about whether to install solar.[16] Began a Solar Energy Analysis Pilot to give customers information they need to decide whether solar energy is the right fit for them.

- Minnesota Power has a solid load research foundation and is finalizing an updated load research study. This study is leveraging Minnesota Power's experience with its large customers' years of more sophisticated metering as well as the broader and more recent deployment of advanced metering infrastructure among residential and other customers along with insight gained through ongoing customer surveys.
    - Minnesota Power continues implementation of its residential Time-of-Day ("TOD") Rate with critical peak pricing pilot project. The Commission approved Minnesota Power's proposed Pilot Rider for Residential Time-of-Service in November 2012.[17] The associated web portal that enables customers to view their usage information in monthly, daily, or hourly increments was introduced to two groups of customers in 2012. This pilot builds upon Minnesota Power's existing conservation improvement effort and will offer further insight into customers' appetites for more frequent and in-depth information about their energy usage as well as a rate offering with price signals.
- Several new statutes impacting utilities have been implemented since Minnesota Power filed its 2013 Plan on March 1, 2013. Included in the statutes are new renewable goals, increased net metering limits, an expanded definition of energy conservation improvement, as well as required new studies. Minnesota Power has or is in the process of complying with all newly implemented statutes, and has been an active participant, when applicable and appropriate, of the newly implemented studies. Key statutes and studies for Minnesota Power are:
    - Generate or procure sufficient electricity generated by solar energy to serve its retail electricity customers in Minnesota so that by the end of 2020, at least 1.5 percent of the utility's total retail electric sales to retail customers in Minnesota is generated by solar energy.
    - Increase net metering limits from 40 kW to 1000 kW for investor owned utilities.
    - By July 1, 2014 and each July 1 through 2020, public utilities must file a report with the Commission reporting its progress in achieving the SES.
    - Expands the definition of "energy conservation improvement" to include waste heat recovery that is used for thermal purposed (heating and/or cooling buildings or water); specifies that natural gas or electricity displaced by waste heat recovered and used as thermal energy may count toward a utility's energy savings goal.

[16] For details on these two programs, Visit http://www.mnpower.com/Environment/IsSolarRightForMe/
[17] Docket No. E015/M-12-233.

- Allows utilities to negotiate electric rates with “Energy-Intensive Trade-Exposed” customers.
- Extends multi-year rate plan from three to five years.

Resource Plan Overview: Short and Long-term Action Plans

Minnesota Power considered potential environmental regulation and economic futures along with its sales outlook to develop a resource plan that creates a more flexible and diverse power supply, while balancing cost, reliability and environmental impact for customers. The 2015 Plan continues the transformation of the Company’s resource base by investing in renewable generation, adding natural gas, installing more emissions-control technology at its core baseload generating facilities, and maintaining its strong CIP and DSM programs. Supported by the information and analysis in the Appendices of this Plan, the action plan outlined in the following sections identifies both short and long-term measures that will help Minnesota Power continue to meet customer needs near term and be poised to deliver safe and reliable service at the lowest possible cost to customers for many years.

Short-term Action Plan (2015 through 2019)

Minnesota Power’s short-term action plan during the five-year period of 2015 through 2019 is comprised of steps that will: a) preserve competitive baseload generating resources while reducing emissions, b) continue implementation of least cost demand side resources including conservation, c) reduce reliance on coal-fired generation, d) reduce the carbon intensity of Minnesota Power’s system and e) add renewable energy and transmission infrastructure to the benefit of customers. The specific strategic and necessary actions to achieve these steps include:

1. Reduce emissions associated with converting coal energy to electricity through a series of actions that assure environmental compliance and a sound energy supply for customers. The Company has identified that THEC1&2 (150 MW) can best serve customers through more flexible operation beginning in 2016. THEC1&2 will be idled in 2016 and be utilized for reliability of the bulk electric system as market conditions require. The Company identified a plan to reduce the emission profile of BEC1&2 (130 MW) by leveraging the environmental infrastructure of the BEC facility. Engineering and design planning will continue for 2018 project implementation.
2. Minimize short-term rate impacts for customers while meeting increased demand for electricity, as the northeast Minnesota economy is forecasted to grow in the next several years, by taking advantage of a lower cost power market. Minnesota Power will use economical bilateral market purchases to flexibly help bridge needs in the period between 2016 and 2019. This flexibility is necessary given load projections and the ultimate timing of new large industrial loads on its system as well as any significant downward business cycles that may affect demand from existing large industrial customers.
3. Implement additional solar resources in each of the three pillars of its solar strategy – customer, community and utility to implement 33 MW of solar resources by 2025, complying with the state’s SES. Beginning with a 10 MW utility scale solar array at the

Camp Ripley location in 2016, bringing forth a unique community solar program in fall 2015 to meet customer demand, and continuing to incentivize customer solar programs already in place.

4. Begin competitive procurement process to secure 200 MW – 300 MW of efficient natural gas CC generation supply for implementation by 2024. Actual procurement amount will vary based on continued updates to customer load outlooks and availability of competitive opportunities. Addition of natural gas resources to Minnesota Power's supply portfolio will be subject to Commission review.
5. Consider enhancements to selected CIP and DSM programs, while continuing to apply best practices from the conservation industry and developing leading-edge programs. Minnesota Power has maintained a strong record of conservation performance and been a state leader in meeting the Minnesota 1.5 percent energy savings conservation goal. Along with this strong dedication to conservation, the Company will continue to work to identify additions to its DSM programs where it is most beneficial for customers.
6. Prepare Minnesota Power's transmission system for the long-term addition of new power supply resources. The Company will, subject to Commission route permit approval in early 2016, begin constructing the GNTL to deliver its approved 250 MW and 133 MW purchases from Manitoba Hydro for the term 2020-2035 (a critical element of Minnesota Power's long-term action plan).
7. Minnesota Power will develop customer-facing DG programs that best leverage unique customer and regional attributes to deliver valued and cost effective electric solutions for customers. A backup generation pilot program (10 MW) will be developed for consideration by the Commission in 2016.
8. Continue fleet maintenance programs to sustain the economic viability, availability and reliability of Minnesota Power's generating units. A continuing Company priority throughout this planning period will be to carefully maintain its generation fleet to ensure productivity and efficiency in operation. A rigorous process is in place to sustain existing production across Minnesota Power's wind-water-wood-coal-solar sources of energy conversion while maintaining an excellent environmental record and meeting more stringent environmental standards.
9. Continue active participation in Midwest Renewable Energy Tracking System ("M-RETS") as provided for by the Commission's October 9, 2007 Order.[18] Minnesota Power will leverage the value of renewable energy credits that the M-RETS program certifies to deliver RES and Solar Energy Standard compliance (as applicable) in Minnesota at the lowest possible cost to customers. Minnesota Power will utilize renewable energy credits generated across the years in order to optimally meet the 25 percent RES by 2025 and interim years.

Long-Term Plan (2019 through 2029)

Minnesota Power will focus its long-term plan on a strategy to further reduce carbon emissions in its portfolio and reshape its generation mix towards a balance of approximately

[18] Docket Nos. E999/CI-04-1616 and E999/CI-03-869.

one-third renewable resources, one-third efficient coal-fired generation and one-third natural gas/other sources while preserving reliability and affordability. 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 process 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:

1. Continue implementation of the 250 MW and 133 MW Manitoba Hydro PPAs and GNTL in the 2020 timeframe (383 MW).
2. Optimize the timing of implementing the remaining 22 MW of new solar projects to meet the state Solar Energy Standard.
3. Reduce the Minnesota Power offtake of the Young 2 coal generating station in North Dakota from 100 MW to zero by 2026.
4. Investigate opportunities to further diversify the Company's power supply, including reducing coal-based generation. Minnesota Power will closely assess BEC1&2 economics during this period to determine competitive position of these units.
5. Secure 200 to 300 MW of intermediate natural gas generation resource for Minnesota Power's generation fleet to meet expected capacity and energy needs in the 2023 to 2029 timeframe.
6. Enhance and create additional customer product options through integrated and coordinated distribution, transmission and power supply planning.

Plan Implementation Potential Impact on Costs

In accordance with Minn. Rule 7843.0400, subp, 4, Minnesota Power's 2015 resource planning analysis includes consideration of potential cost impacts resulting from actions taken to be in compliance with Minnesota's RES, and potential expansion plans. The 2015 Plan's Preferred Plan would be expected to increase the average residential rate by about 4.1 percent on a compounded annual basis through 2019. That is equivalent to a total increase of $18.69 per month for an average residential customer above the 2015 estimated Base Rate. The impact to the average Large Power rate would be an increase of about 3.7 percent on a compounded annual basis through 2019. That is equivalent to an increase of 1.2 cents per kWh above the 2015 estimated base rate. Refer to Appendix L for more detail. Power supply costs have inherently been increasing across the industry as new requirements and infrastructure are being incorporated. The analysis detailed in Appendix L indicates that future cost increases through 2019 would trend similar to the cost increases in recent history. However, customers have already seen a nearly 50 percent increase in rates since 2004.

Summary: 2015 Plan Designed to Meet Customer Needs

As Minnesota Power addresses uncertainty in the economic and environmental landscape around energy matters on behalf of its customers, the Company maintains its strong leadership of the transformation required to successfully meet future needs. In order to achieve the goals outlined on pages 14 - 16 of this Section, Minnesota Power respectfully requests Commission approval of its 2015 Plan, as presented in this filing, for the planning period of 2015 through

2029. Minnesota Power is requesting Commission approval of its action plan that includes the following:

- Reduce emissions associated with converting coal energy to electricity through a series of actions that assure environmental compliance and a sound energy supply for customers including idling THEC1&2 in 2016 and utilizing it for reliability of the bulk electric system as market conditions require; and
- Reducing the emission profile of BEC1&2 (130 MW) by leveraging the environmental infrastructure of the BEC facility.
- Minimize short-term rate impacts for customers while meeting increased demand for electricity by taking advantage of a lower cost power market through economical, bilateral market purchases to flexibly help bridge needs in the period between 2016 and 2019.
- Begin competitive procurement process for 200 MW – 300 MW of efficient natural gas CC generation supply for implementation by 2024.

Minnesota Power believes its 2015 Plan will serve its customers in a wise and forward-looking way during the 2015–2029 planning period. Minnesota Power respectfully submits this Plan for the Commission's review and approval.

III. CURRENT OUTLOOK

The electric industry landscape has continued to evolve since Minnesota Power submitted its 2013 Plan. The Company took action to further improve its fleet environmental performance, monitor and assess emerging regulations and increase renewable energy output. As the 2015 Plan is submitted, Minnesota Power is unique among utilities as significant growth is being projected for its large industrial customer segment in the current planning horizon.

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 ("Base Case") for the 2015 Plan. Minnesota Power enters the 2015 Plan timeframe with minimal near-term power supply needs; however, due to projected customer growth, additional long-term power supply will be needed.

Changes since November 2013 Commission Approval of the 2013 Plan

Continued Progress on Renewable and Solar Energy Standards

In 2007, the State of Minnesota enacted legislation requiring Minnesota Power to generate or procure sufficient electricity generated by an eligible renewable energy technology such that at least the following standard percentages of the Company's total Minnesota retail electric sales are generated by these technologies: 12 percent by 2012; 17 percent by 2016; 20 percent by 2020; and 25 percent by 2025. (Minn. Stat. § 216B.1691).

Since May 2011, Minnesota Power has brought extraordinary benefit to its customers with its renewable energy development. Through effective project planning and competitive equipment supply, the Company executed its North Dakota wind initiative. Originally introduced in 2009, the Bison Wind Energy Center was completed in late 2014, with the commissioning of the Bison 4 Wind Project; adding over 200 MW of wind power to the existing 292 MW.

Minnesota Power has already satisfied the state's 25 percent by 2025 requirement and will only propose adding new wind projects if they are economical and bring benefit to customers. Appendix H provides a more detailed presentation of the current renewable energy portfolio that the Company plans to utilize to meet its renewable energy requirement.

In 2013, the State of Minnesota enacted legislation requiring Minnesota Power to generate or procure renewable energy from solar power supplies based on retail sales to non-exempt Minnesota customers of 1.5 percent by 2020. Minnesota Power has announced a three pillar solar strategy that creates opportunity for utility, community and customer solar applications. Appendix H of this Plan provides a more detailed outline of the strategy to implement approximately 33 MW of solar resource by 2025. As its first utility solar project, the Company has partnered with the Minnesota National Guard, and has submitted a petition seeking approval to install a 10 MW solar energy project to be located at Camp Ripley, near Little Falls, Minn. in 2016. Docket No. E015/M-15-773. This customer partnership will make up one-third of the projected solar energy requirement, and is a unique project to launch the Company's solar journey.

Corporate Commitment to Greenhouse Gas Reductions

Minnesota Power continues its commitment to reducing carbon emissions. The significant expansion of Minnesota Power's already substantial renewable energy supply is fundamental to this initiative, as is its commitment to improve energy efficiency, and to consider only carbon-minimizing resources for addition to its generation portfolio. Company actions are leading to a transformation of Minnesota Power's generation fleet.

In early 2015, the Company completed implementation of two key transitions in its small coal generation fleet. LEC was successfully converted from a coal burning unit to burning cleaner natural gas. LEC has a new role in the Company's power supply portfolio as a peaking unit. THEC3 ceased coal operations in June 2015 as part of Minnesota Power's *Energy**Forward*** strategy. This transition of the Company's energy portfolio continues in the 2015 Plan with increasing amounts of energy supplied by renewable resources or natural gas, and decreasing amounts of energy supplied by coal-fired generation.

Distributed Generation

Minnesota Power has just over 200 MW of generation at customer sites and continues to see an increased interest in new technologies such as solar, combined heat and power and traditional backup generation applications. The Company has 15 wind and 132 photovoltaic ("PV") solar systems, for a total of 147 interconnections on the distribution system (see Appendix C, Part 3).

Conservation—Energy Reduction Requirements

In 2007, the State of Minnesota enacted legislation requiring utilities to adopt an annual energy savings goal, equivalent to 1.5 percent of gross annual retail energy sales beginning in 2010. Minnesota Power has a successful track record in exceeding the 1.5 percent benchmark and plans to maintain conservation efforts at this level.[19]

Additional alternatives are considered as part of the 2015 Plan to increase investment in conservation programs. Appendix B addresses Minnesota Power's conservation programs and planning scenarios.

Softening of Energy Market

Since 2009, the nationwide recession and the onset of natural gas supply surpluses have created a significant shift in regional energy markets. Prices have shifted lower to create a new normal for markets, unparalleled in recent history. Minnesota Power has worked to secure extensions of existing key bilateral purchase contracts and entered into new agreements for energy and capacity totaling 200 MW during the 2015-2020 timeframe (see Appendix C, Part 2).

[19] Minnesota Power incorporates the effects of its successful conservation program into its energy forecast. Appendix A outlines this methodology in more detail. Appendix B identifies an estimation for the amount of embedded energy efficiency that is in Minnesota Power's forecast per Order Point 12 of its 2013 Plan approval (Docket No. E015/RP-13-53).

Options for an economical power supply to meet the projected growth in northeastern Minnesota were evaluated in this Plan. The company initiated 100 MW[20] of additional short-term bilateral purchase transactions to capture the benefit of lower market trends for customers, and bridge to the approved power purchases of 250 MW of energy and capacity and 133 MW of energy only from Manitoba Hydro that starts in 2020. In addition to providing a cost effective bridge to Minnesota Power's long-term resource strategy, these transactions also help customers avoid costly generation expense as new large industrial loads transition onto the system.

Demand Response

Minnesota Power has over 100 MW of interruptible demand response capability that it utilizes for peak shaving and emergency operations. The Company has continued offering its interruptible product that permits the curtailment of large industrial load to support Minnesota Power's management of system reliability. Interruptible capability continues to be a robust demand response resource for customers. Minnesota Power also utilizes its dual fuel tariff for demand response operations. Mostly utilized during the winter months, the dual fuel tariff allows interruption of customer electric heating load.

In late 2014, the Company initiated a residential TOD Rate with critical peak pricing pilot program. Under this rate, customers pay more for usage during on-peak hours and critical peak pricing events, and receive a discount for usage during off-peak hours. The goal of this pilot program is to gauge customer interest in new rate offerings that incentivize load shifting, and to further inform decisions about broader program implementation and infrastructure investment. An air conditioning cycling program is being evaluated to determine how this type of program may fit into Minnesota Power's future power supply planning.

Minnesota Power continues to look for opportunities to further partner with its customers for demand response. These key customer relationships have allowed the Company to minimize investment in large generator infrastructure like peaking plants for over a decade to support the Company's resource adequacy program.[21] More information on Minnesota Power's DSM (demand response) programs can be found in Appendix B of this Plan.

Specific Load Additions

Several potential industrial load additions in Minnesota Power's service territory (and its wholesale customers' territory) have been closely monitored since 2013. Essar Steel Minnesota, a significant new customer for the City of Nashwauk, a valued municipal customer, remains in the Company's 15 year outlook. PolyMet, a copper-nickel mine operation located just outside Hoyt Lakes, Minn. is another significant new industrial customer for Minnesota Power, and is included in the 15 year outlook. These additions are reflected in the Base Case of the 2015 Plan. The

[20] These market surplus transactions include the current 50 MW Great River Energy and 50 MW Minnkota Power agreements.

[21] Minnesota Power does not currently utilize its dual fuel program for capacity accreditation purposes. As MISO continues to refine their requirements for demand side resources, Minnesota Power will consider the applicability of the program. The program is estimated to be approximately 20 MW of interruption capability in winter months and less than 10 MW in summer months.

Company is utilizing the Moderate Growth with Deferred Resale scenario from its AFR2014 for the Base Case of its planning evaluation.

The Company will continue to monitor the status of the load potential in northeast Minnesota, and has incorporated a high and low forecast as sensitivities in its evaluation. Appendix A goes into more detail on the other customer load scenarios that are being monitored.

Current Outlook for Large Power and Resale Customers

Recognizing that the majority of Minnesota Power's capacity and energy is used by 10 Large Power customers, it is important to monitor the current outlook of these customers to provide insight into their future electric needs.

The Company recognizes that not all projected growth in its industrial customer class planning scenarios will occur on its proposed schedule. Through its econometric forecasting processes, and by working closely with customers, Minnesota Power identified six scenarios for load growth potential and their impact to electric requirements in its service territory. These scenarios are included in AFR2014, and can be found in Appendix A of this Plan. The Moderate Growth with Deferred Resale scenario is utilized in this Plan; recognizing 194 MW of overall industrial growth for this 15-year time period.

Major industries served by Minnesota Power are summarized below. Substantial load growth potential (i.e. new customers and potential projects) being tracked by the Company are also described.

Mining Customers

Minnesota Power provides electric service to six taconite customers with current production capability of up to 41 million tons of taconite pellets annually (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. Historically, less than five percent of Minnesota taconite production is exported outside of North America.

Table 1: Minnesota Power Taconite Customer Production

Minnesota Power Taconite Customer Production	
Year	**Tons (Millions)**
2014	39
2013	37
2012	39
2011	39
2010	35
2009	17
2008	39
2007	38
2006	39
2005	40

Business cycles and short-term market corrections have and will continue to impact Minnesota's large mining operations. Most recently, several Minnesota iron producers have idled operations: U.S. Steel idled their Keetac Plant in Keewatin in April 2015 and lines 3, 4, and 5 at their Minntac Plant in Mountain Iron in May 2015. Minntac employees returned to work in July and August, while the Keetac plant remains idled. The Mesabi Nugget iron plant near Aurora and Mining Resources iron concentrate plant near Chisholm will be idled for at least two years. These near term impacts are considered in the sensitivity portion of the 2015 Plan analysis.

- Newer types of iron-bearing products have emerged and are being produced on the Iron Range in northeastern Minnesota. Further, the potential for steelmaking on the Iron Range also exists. The combination of new iron ore based projects or expansion indicates growth forecast for mining and mining processing activity.
- Magnetation, Inc. is a high-growth iron ore producer and inventor of hematite beneficiation technology. Magnetation has developed a patented mineral reclamation process (Magnetation Process™) to extract weakly magnetic particles from stockpiles left from the natural ore mining that occurred primarily in the first half of the twentieth century. Magnetation currently operates three facilities in Minnesota Power's service territory: Plant 1 (in Lake Country Power's service territory) is located south of Keewatin, Plant 2 near Taconite, and Plant 4 north of Coleraine near the Canisteo Mine.

  Magnetation is also an equity partner in the Mining Resources Plant 3 facility near Chisholm. The production level of Mining Resources Plant 3 has reached nearly their budgeted full load level. They activated their ball mill circuit in January 2013 and peak demands are now in the 5 to 7 MW range.

Minnesota Power currently provides electric service to the Plant 2 facility as well as to the Jesse Mine train loading facility and Plant 4. Docket No. E015/M-15-699.

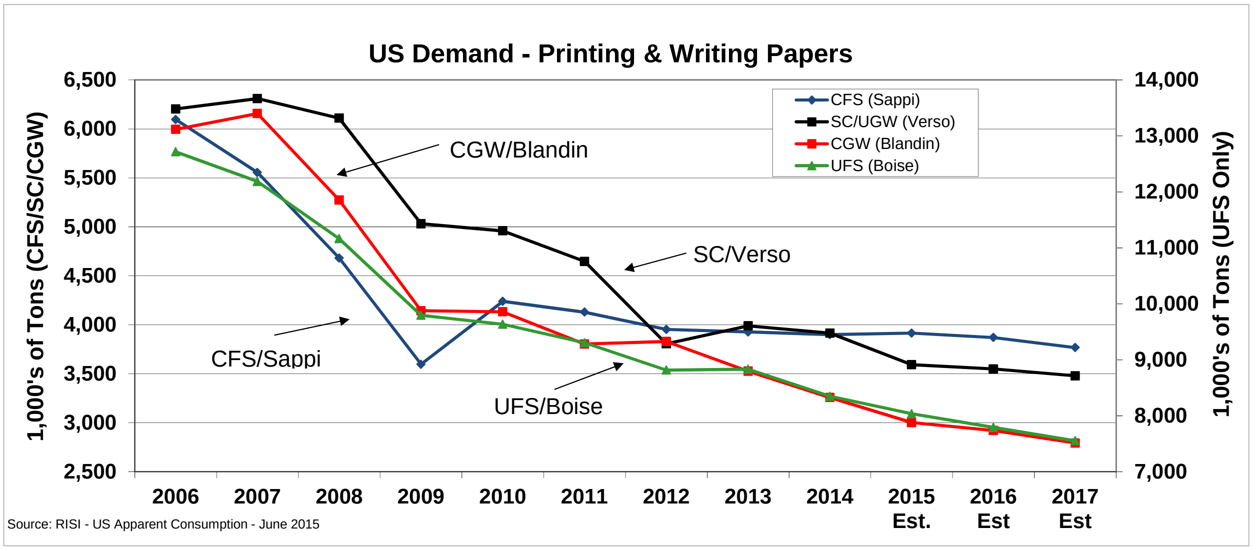
- Essar is developing a fully integrated, onsite, mining through steelmaking project on the Iron Range in northern Minnesota. It is designed to produce up to 2.5 million tons of steel products each year and to employ up to 700 people. Groundbreaking occurred in fall 2008 for the taconite production facility. Construction activities are well underway for the initial 4.1 million ton per year taconite plant, and the permits have been finalized for the expansion to a 6.5 million ton per year taconite production rate. Essar continues to work on the financing for the 6.5 million ton per year operation. Mining operations are slated to start in 2016. Minnesota Power provides wholesale electric service to the City of Nashwauk, who in turn provide retail electric service to the Essar mine, crusher, concentrator, and pellet plant. Minnesota Power also provides retail service to Essar at two points for pit dewatering. The final step to steel making remains under evaluation by Essar.
- PolyMet is a Canadian-based, mine development company with plans to develop an open-pit, copper-nickel mine on the Iron Range. The PolyMet NorthMet Project 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. In June 2015 it was announced PolyMet's Preliminary Final Environmental Impact Statement ("EIS") was completed and is undergoing review. The final EIS is expected to be released in early 2016. Minnesota Power supplies retail service to PolyMet through a long-term electric service agreement. Docket No. E015/M-07-221.

<u>Wood Product Customers</u>

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 paper manufacturing industry has experienced a significant decline in the last decade resulting in mill consolidation and closures throughout North America. Minnesota has directly experienced forest product-related mill closures. Six Minnesota mills have closed since 2006, including three Ainsworth board mills, the Weyerhaeuser truss plant in Deerwood, the Verso paper mill in Sartell, and the Georgia Pacific board plant in Duluth. Minnesota Power provided electric service to the Deerwood and Duluth mills. There have been no mill closures affecting Minnesota Power since the 2013 closure of Georgia Pacific's Duluth, Minn. board plant.

As shown in Figure 1, U.S. printing and writing paper demand is projected to continue to decline, although at a less precipitous rate than during the 2007-2009 period. 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 1: US Paper Demand 2006-2017 (est.)



In spite of the demand trends for U.S. printing and writing paper, the remaining U.S. paper industry continues to operate profitably. In addition to operating at around 19 million tons of productive and competitive capacity, development of new wood-related products is being pursued. The most cost competitive mills with the strongest parent corporations continue to effectively serve their customers.

The four 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, UPM, Verso, and Boise). 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 and profitable capacity utilization rates for these four mills over the forecast period, as these mills successfully control costs, reshape their products and compete for market share.

<u>Pipeline Customers</u>

Minnesota Power has two pipeline customers, Enbridge Energy and Minnesota Pipeline, and both companies rely heavily on Western Canadian crude oil production. Enbridge Energy transports crude oil across North America. Minnesota Pipeline receives oil from Enbridge Energy at Clearbrook, Minn., 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 Pipeline 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 Pipeline systems.

Both Enbridge Energy and Minnesota Pipeline take service under Minnesota Power's Large Light and Power Service Schedule ("LLP Schedule"). Neither Enbridge Energy nor Minnesota Pipeline is now required to provide Minnesota Power with demand nominations under the LLP Schedule; however, these loads have historically been very consistent. Enbridge Energy has added pumping equipment at its Superior, Wis. pumping station, served by Minnesota Power's affiliate and wholesale customer, Superior Water, Light and Power. Enbridge Energy has increased pumping capacity at its Deer River, Minn. substation, with significant projected increases in load through 2018. Other expansion-related projects are in the planning phase at these companies and could potentially increase load across the Minnesota Power service territory within the five to ten-year horizon.

Expected Minnesota Power Load and Capability

Northeastern Minnesota's economy underwent a severe downturn in the recent national recession. Both peak demand and energy use dropped considerably in late 2008, but rebounded in 2010, led by the region's taconite and wood products industries. The non-industrial sectors (residential and commercial) have experienced minimal growth in the years since the recession, which has tempered the outlook for these classes. Overall, growth is still expected throughout the long-term planning horizon, driven by large industrial customer expansion and organic growth in the residential and commercial sectors.

For the 2015 Plan, the load outlook includes a projection for considerable growth over the 15-year period. In particular, Minnesota Power is expecting significant industrial customer expansion. With several growth scenarios incorporated into its latest forecast outlook, the Company has identified the Moderate Growth with Deferred Resale scenario as its consensus outlook for its 2015 Plan. Appendix A of this Plan contains details on Minnesota Power's AFR2014.

Minnesota Power is historically a winter peaking utility, and based on monthly trends in load behavior is expected to remain winter peaking for the AFR2014 period of 2014 to 2028. Throughout the forecast time-frame, the seasonal peaks run in parallel. Underlying seasonal peak demand growth is projected to increase at a rate consistent with observed history, about one percent per year. However, load growth in the 2015 to 2017 timeframe will be accelerated as the Company realizes expansions in its industrial customer base. Annual load growth is projected to average three percent per year in the 2015 to 2017 timeframe.

Figure 2 presents both the Company's historic and forecast peak demand by season from the Moderate Growth with Deferred Resale scenario in its AFR2014 submittal, and the foundation for the 2015 Plan evaluation. Figure 2 depicts the significant growth being projected in the forecast period.

Figure 2: Peak Demand by Season

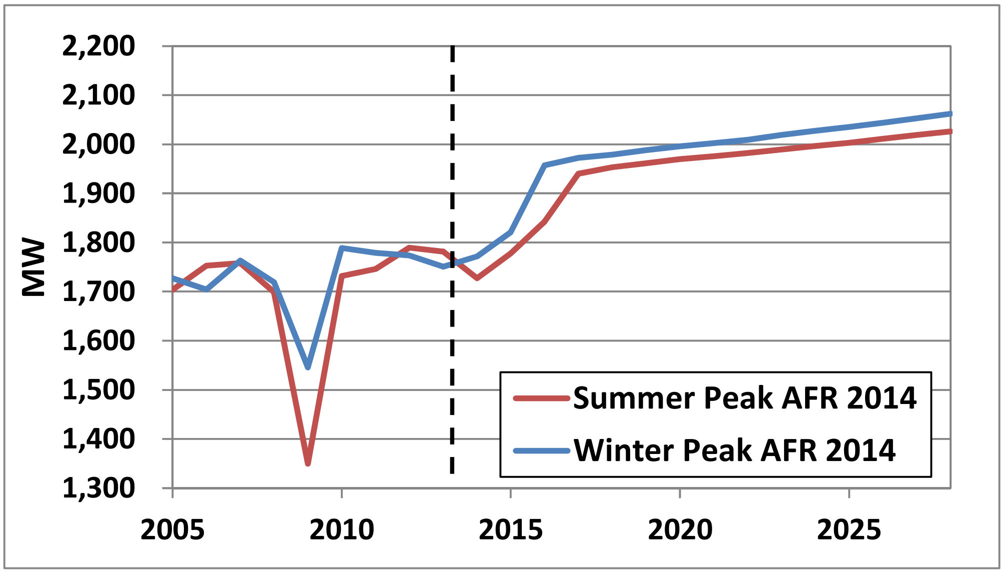
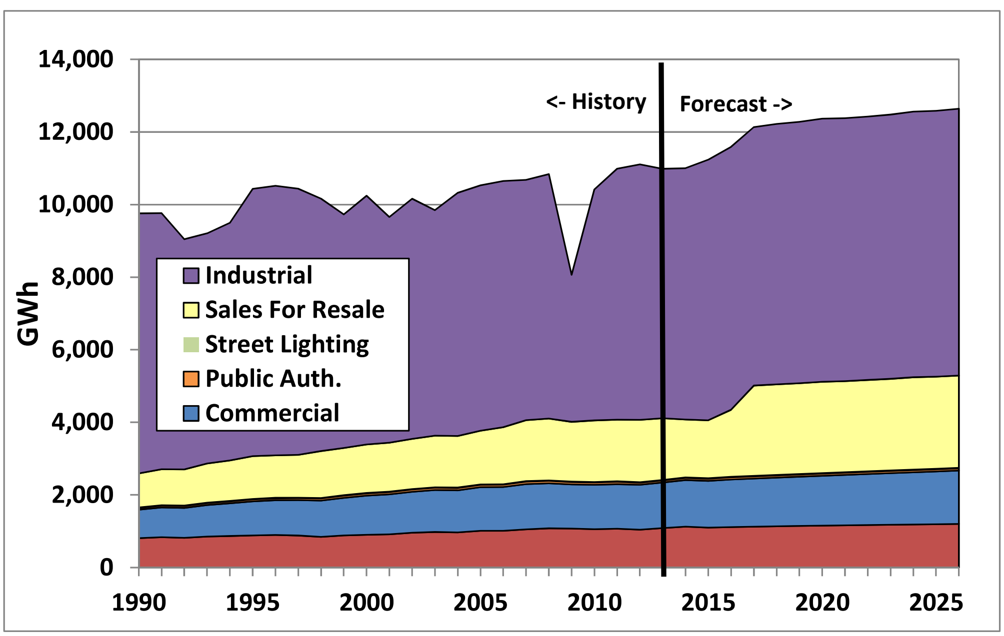


Figure 3 shows historic and forecast energy requirements by customer class, and depicts the large influence the industrial class continues to have on the Company's energy requirements. The large growth in the resale customer class includes the addition of the City of Nashwauk load.

Figure 3: Energy by Customer Class



Considered together, Figure 2 and Figure 3 clearly show the expected future growth and the impact of the 2009 recession. As outlined in the AFR2014, the Company's peak demand and energy use are each expected to grow quickly in the near term with several industrial additions, and are then projected to return to more normal growth levels for the long term.

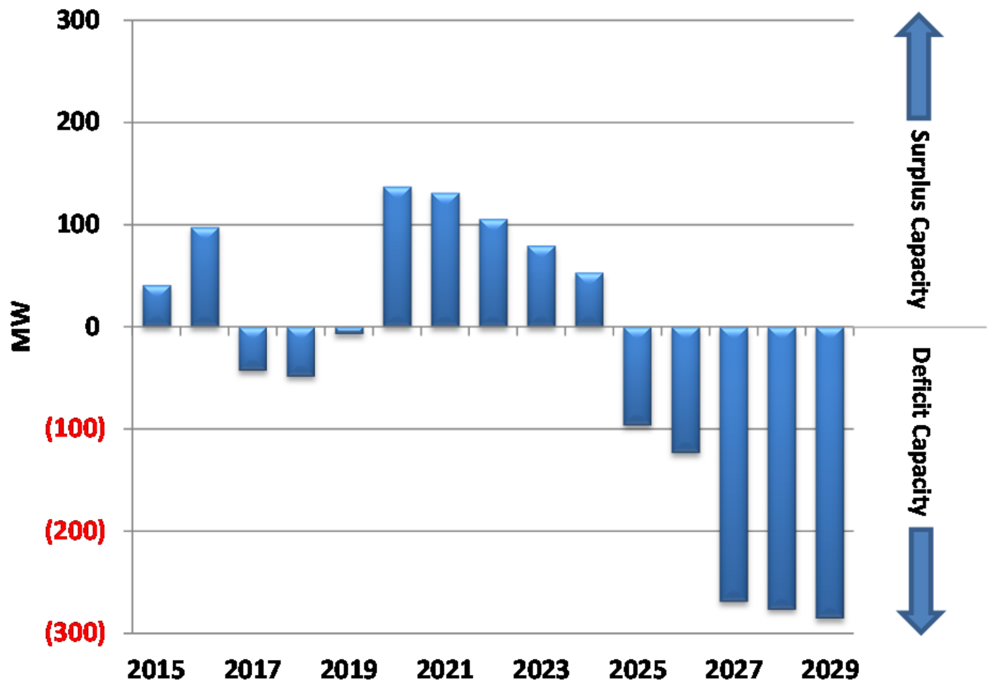
Minnesota Power's system load forecast reflects a projected (summer) peak demand of 1,970 MW by 2026 and 2,070 MW by 2028 with a winter peak between 30 and 40 MW higher. While Minnesota Power's load growth can be unpredictable due to industrial changes, about a one percent underlying demand growth is projected through the forecast period. Energy requirements continue to dominate the Company's supply picture, as the industrial load contributes an average system load factor of approximately 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.

Minnesota Power uses the Planning Year 2015/2016 MISO Module E Load and Capability ("L&C") calculation as one measure to assess resource need. The MISO L&C calculation takes into consideration Minnesota Power's load forecast, expected demand-side resources, Firm and Participation Purchases and Sales, Accredited Unforced Generating Capability ("UCAP") and MISO's required 7.1 percent planning reserves. The result of the L&C calculation is a capacity surplus (or deficit) number for the MISO planning season.[22] Minnesota Power is a winter peaking utility, but as previously noted, bases its resource need on the summer season L&C balance. Most other regional utilities are summer peaking, and have large winter capacity surpluses. Therefore, winter capacity is typically available for purchase and prices are expected to be lower than summer capacity.

To create an understanding of what the potential capacity needs are for the Moderate Growth and Deferred Resale, the load levels of the scenario are combined with an expected set of capacity resources utilizing the L&C guidelines to estimate a remaining surplus or deficit for the planning period. Figure 4 depicts the Base Case summer season capacity needs that are projected as the Company considers its 2015 Plan analysis. For the near term, Minnesota Power expects some minimal capacity surpluses in its Base Case outlook, with capacity need starting to grow in the post-2020 time period.

[22] Minnesota Power utilizes MISO's UCAP (unforced capacity) planning reserve method for its long-term planning. Please see Appendix J for more detail.

Figure 4: Projected Summer Season Capacity Position



Base Case:

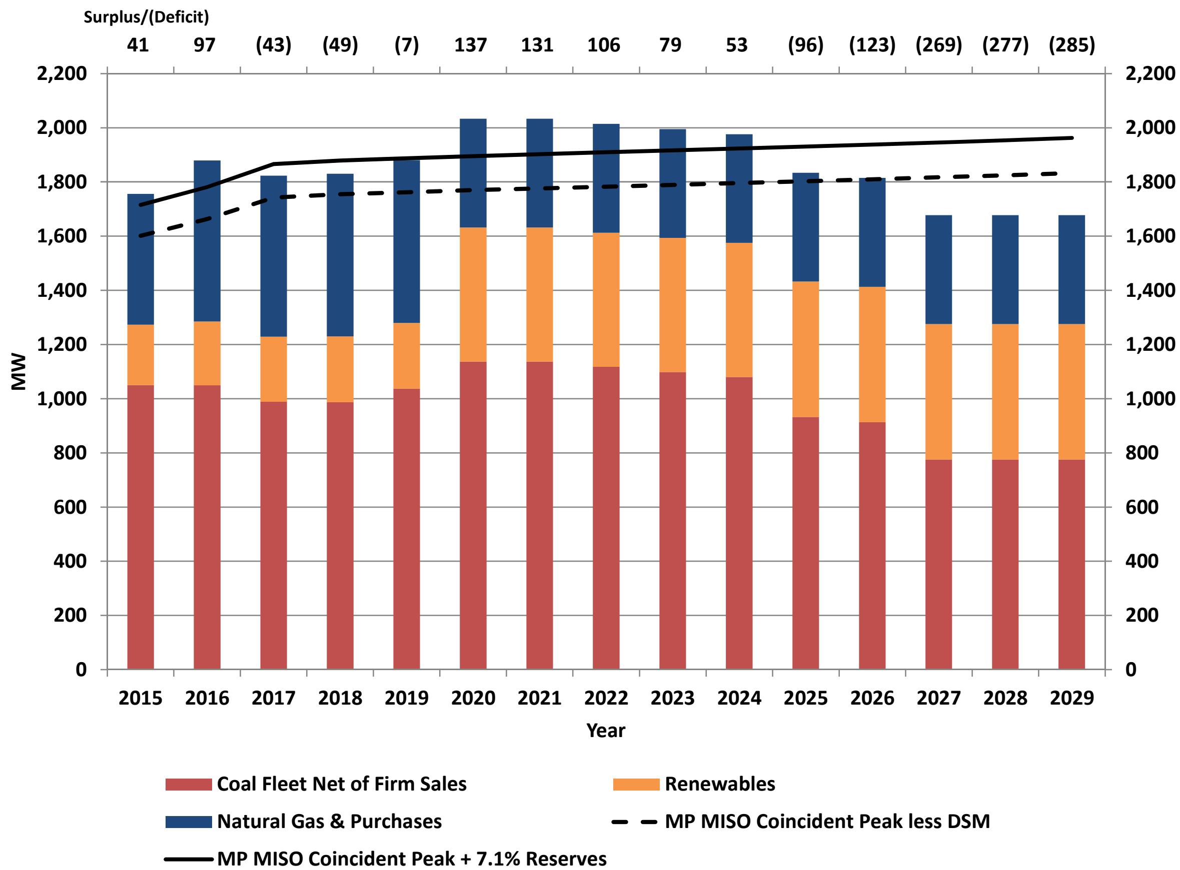
<u>Minnesota Power's Summer and Winter Season Load and Capability (2015–2029)</u>

Figures 5 and 6 present Minnesota Power's Base Case load and capability for summer and winter seasons, respectively, during the forecast period. Key assumptions and events reflected in the Base Case load and capability projections include:

1. No permanent large industrial customer plant closures are projected during the AFR2014 period (see Appendix A). Growth in the industrial customer class brings 194 MW of additional requirements by the end of the planning period.
2. Continuing commitment to conservation initiatives throughout the forecast period will result in achieving at or near historical levels of annual retail energy savings for customers included in Minnesota Power's conservation programs. Load reductions from the Company's conservation efforts are included as reductions in Minnesota Power's projected load (see Appendix A).
3. Through its *Energy**Forward*** strategy a phased reduction of Minnesota Power's 227 MW portion of the Young 2 resource will continue and move from 100 MW to zero in 2026.
4. Operating renewable resource additions required to meet Minnesota's RES including: Thomson hydroelectric station, Taconite Ridge Wind Center, Wing River LLC Community Based Energy Development Project and Bison 1, 2, 3 and 4 wind projects are added to the fleet (see Appendix H).

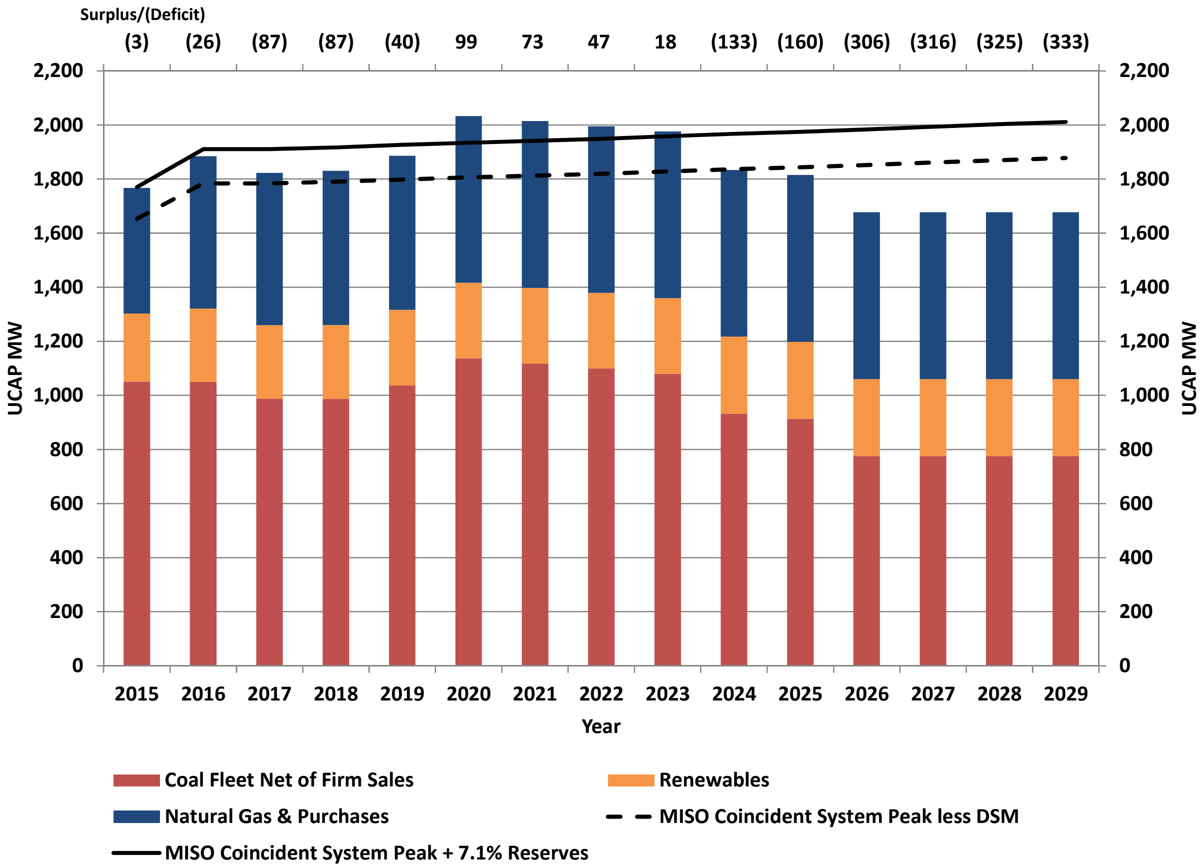
5. Implementation of the 250 MW Manitoba Hydro energy and capacity purchase starting in 2020’ along with the 133 MW Manitoba Hydro energy only purchase starting in 2020.
6. Estimated accredited capacity associated with remaining planned renewable additions are not included in the capability as committed resources. Final timing has yet to be determined for additional resources, such as biomass energy at the REC Center and HREC (see Appendix G).
7. Estimated accredited capacity associated with planned solar additions per Minnesota Power’s solar energy strategy are included to incorporate 33 MW of solar resources by 2025.
8. The Company continues its large industrial customer combined heat and power generation partnerships for DG and behind the meter generation purchases (approximately 280 MW).
9. Existing wholesale power sales and purchase changes (see Appendix C, Part).
    - Baseload power sale of 100 MW (2010-2020)
    - The inclusion of 200 MW of economic market bilateral purchase contracts (2015-2020) as part of the approved bilateral bridge strategy from 2013 Plan
10. Minnesota Power retired its THEC3 (75 MW) in June 2015 and the capacity is no longer included in the portfolio.
11. No retirements of Minnesota Power’s hydroelectric generation resources are included in the Base Case outlook depicted in this section.
12. BEC1&2 and THEC1&2 are removed from capacity outlooks at the end of their accounting life (end of 2024 and 2026, respectively). Within this 2015 Plan is an additional evaluation of the Company’s small thermal coal-fired generation to determine if earlier transition is prudent for these four generating units. The Base Case is the starting point for that evaluation.

Figure 5: Base Case Summer Season Load and Capability



Minnesota Power's winter peak is typically between 30 and 40 MW higher than its summer season peak; therefore, the surplus and deficit outlook is slightly different when shown for the winter season peaks. The general trends remain the same with very little deficit in the near-term and growing long-term needs for capacity starting in the mid-2020s.

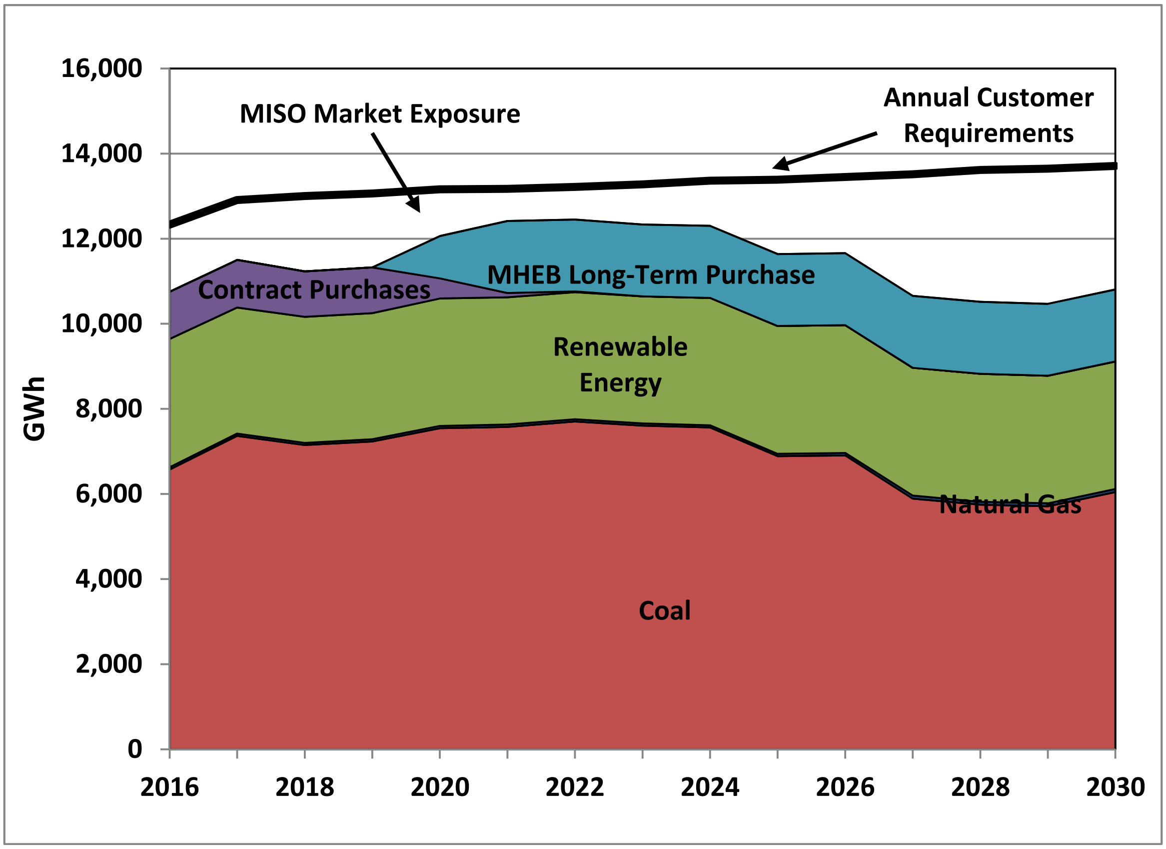
Figure 6: Base Case Winter Load and Capability



Minnesota Power has positioned its generating resources, and made plans for economic purchases to meet the projected needs of its customers in the near term and create a bridge to long-term additions like the GNTL and accompanying Manitoba Hydro power purchases. The 2015 Plan evaluation identifies how the Company will implement a power supply strategy to meet any remaining needs after consideration of small thermal coal-fired generation decision making and projected customer growth.

The Base Case energy position is shown in Figure 7, and identifies that in the near term, the Company has minimal energy needs and will use the regional wholesale market to optimize its energy supply in keeping with its least-cost, customer focused strategy.

Figure 7: Base Case Energy Position



The regional market allows the Company to maximize its generation and transactions. In particular, the market provides timely and cost-effective flexibility to help support the integration of additional renewable energy into Minnesota Power's system. The maturity and flexibility within the regional energy market allows the Company to buy and sell electricity to manage supply and demand for the topmost portion of its load at the lowest possible cost.

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 from the AFR2014: the Upside, Downside, and Current Contract. These outlooks, shown in Figures 8 and 9, 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 Upside outlook contemplates significant growth in the mining industry, capturing nearly 125 MW of additional growth potential in a high economic boom in the industrial sector. The Downside and Current Contract forecasts evaluate a slowdown in the key industries Minnesota Power serves, along with a continued sluggish U.S. economy that could deliver nearly 320 MW of demand destruction in northeast Minnesota. Appendix A contains additional detail on each scenario.

Figure 8: High and Low Demand Outlook Sensitivities

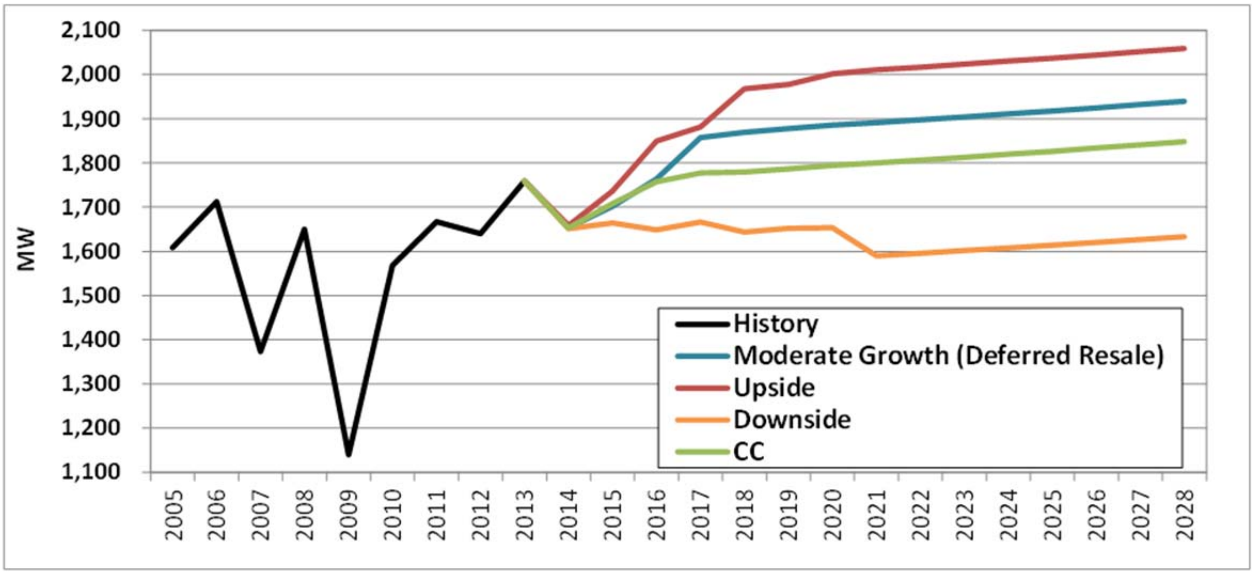
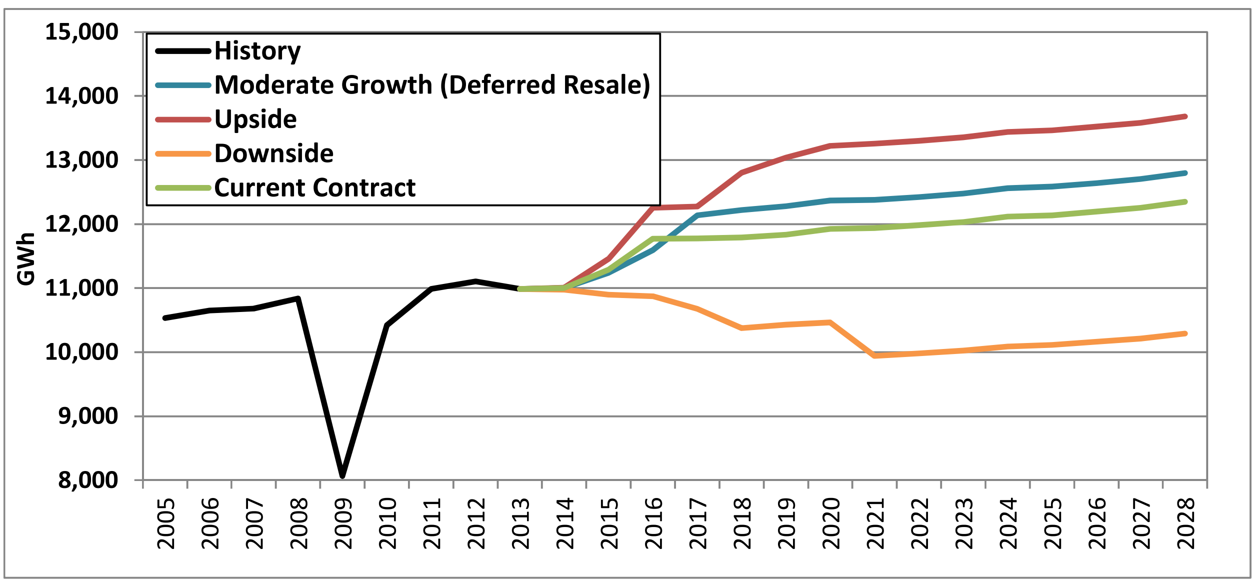


Figure 9: High and Low Energy Outlook Sensitivities

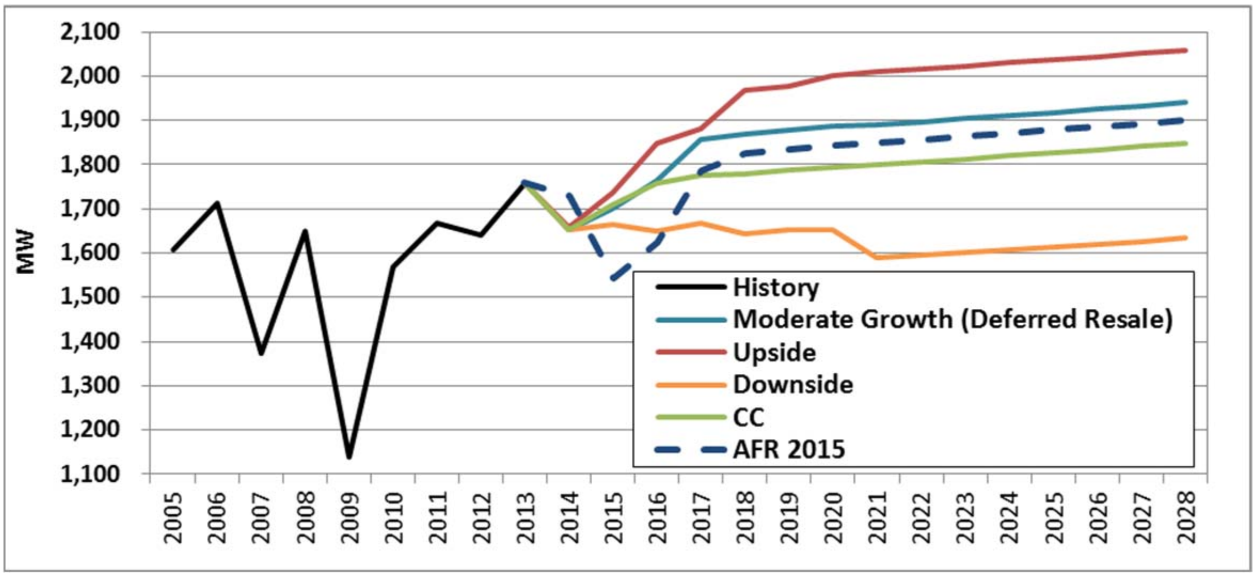


Minnesota Power continually monitors the potential for industrial growth in northeastern Minnesota, and recognizes the key role the mining and paper industries play in customer make-up, and system needs and costs. The viability of these customers is the engine that helps drive the economy in northeastern 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.

Annual Electric Utility Forecast Report ("AFR2015") Outlook Demand and Energy

At the time of the 2015 Plan evaluation, the Company's latest customer load outlook was the AFR2014. Minnesota Power submitted its AFR2015 on July 1, 2015. The AFR2015 outlook is within the range of load sensitivities being considered in the 2015 Plan. AFR2015 encompasses the expansion plan discussion in Appendix K of this Plan. The short and long-term action plans being brought forward in the 2015 Plan (Section V and VI) are consistent with resource decisions under an AFR2015 expansion plan evaluation.

Figure 10: High and Low Demand Outlook Sensitivities with AFR2015



IV. 2015 PLAN DEVELOPMENT

Minnesota Power's 2015 Plan is a balanced approach to delivering safe, reliable service at a reasonable cost to customers, while protecting and improving the region and state's quality of life through continued environmental stewardship. Since its 2013 Plan, Minnesota Power has refined and updated its outlook on major factors driving power supply decisions. The Company has identified options that further transform its power supply to align with its *Energy**Forward*** strategy. Minnesota Power's 2015 Plan continues on the path toward reducing emissions, protecting reliability and ensuring competitive, cost-effective rates for customers, while complying with state and federal environmental regulations and goals.

Evaluation Framework

When approaching resource evaluations, Minnesota Power utilizes key planning principles to ensure the outcome is robust, and in the best interest of all its customers. These principles help guide the analysis process and shape the resulting Preferred Plan, which embodies the Company's *Energy**Foward*** vision. The guiding principles are:

1. Diversity – A power supply mix that cost-effectively manages risks in environmental regulation, fuel cost and generation technology.
2. Flexible – A power supply adaptable to industry changes and fleet transitions.
3. Less Carbon-intense Power Supply – Effectively reduce the carbon concentration of the power supply while managing customer costs.
4. Efficiency – A reliable power supply that serves customer needs with the appropriate level of capital investment.

There are a series of key, long-term planning questions in this fifteen-year planning period. The 2015 Plan takes into consideration the questions listed below, and identifies the Preferred Plan as the least cost and most reasonable for this planning period.

- When is the most prudent timing to transition small coal generation facilities?

  Minnesota Power recognized environmental rule uncertainties at the time of its 2015 Plan analysis and submittal. The proposed EPA CPP was under review, but not final at the time of this analysis. A final CPP Rule could have provided additional insight into the timing of transition for small coal units; however, a thoughtful planning process between the EPA, MPCA and other Minnesota state agencies will begin now that the CPP is final.[23] Without the final rule, the planning analysis conducted considered the economic impacts of coal-fired generation and alternatives available for refuel, remission and retirement for customer power supply.

The outlook for low natural gas prices and efficiency improvements in gas generation also influences the timing of small coal generation facility transition. New resources that can provide

[23] The EPA issued the final CPP on August 3, 2015; 28 days prior to September 1, 2015, the date Minnesota Power's resource plan was due per Order Point 9 of the 2013 Plan Order.

reliable and cost effective power supply take considerable time to plan and procure.[24] Thoughtful forward planning identifies customer need for new generation and allows a competitive procurement process to be implemented.

These factors, combined with the benefit small coal assets have provided to customers and could continue to provide in the near term, need careful consideration. The Company has incorporated into its *Energy**Forward*** strategy a long term vision that will cease coal-fired operations at its small coal facilities over time. This strategy carefully weighed customer, local community and employee impacts as well as environmental regulatory considerations. The 2015 Plan valuated these important variables when determining the appropriate time to take the recommended actions.

- How will the Company position and augment its power supply to meet near and long-term load growth potential (270 MW) and small coal transition that is emerging in its service territory?

  Minnesota Power's service needs are tied closely to its largest customer class, and the last several decades have included periods of growth and downturn. Despite the current economic correction mining customers are taking, the Company is projecting continued growth (see Section III). Although forecasts identify that electric growth is flattening regionally and nationally, resource planning requires a consideration of higher and lower outlooks to reflect the potential for changing large industrial customer profiles on Minnesota Power's system. The 2015 Plan takes into consideration projected customer power supply needs, along with three sensitivities of various load growth potential. The Preferred Plan is identified as the least cost and most reasonable; for more detailed analysis see Appendix K.

- How will the Company comply with the SES in 2020 and beyond?

  Minnesota Power has developed a robust, portfolio-based solar strategy consisting of three pillars of focus: the customer, community and utility to meet and integrate solar power supply. This strategy was submitted on June 1, 2015 as part of the Company's SES Report[25] and is discussed further in Appendix H. The Company will add approximately 33 MW of solar powered generation to its portfolio to comply with the 2020 SES requirements. The 2015 Plan includes Minnesota Power's strategy to comply with the SES in the Base Case and Preferred Plan.

- How is Minnesota Power's Preferred Plan positioned to meet the CPP and other environmental regulations as described in Appendix E of this Plan?

  Minnesota Power's 2015 Plan identifies power supply actions that reduce its overall criteria emission profile by 90 percent and CO_2 emissions by 30 percent by 2025 (from 2005 levels). The *Energy**Forward*** strategy is transitioning the Company's energy portfolio from previous levels to a mix of one-third coal, one-third natural gas, and one-third renewables. This strategy will position Minnesota Power's customers for the

[24] A new natural gas resource can take four to six years to plan, build and begin operations. See Appendix J for additional planning assumptions for new power supply resources.
[25] Docket No. E999/M-15-462.

reliable, affordable and environmentally conscious energy supply balance that society and the industry are working toward.

While the Company cannot predict the outcome of all final EPA and state of Minnesota rulemakings, it can take prudent steps at a reasonable pace that balance customer needs with regulatory requirements. The 2015 Plan identifies short and long-term action plans that reduce coal-fired generation and increase renewables, natural gas and investment in energy efficiency.

- How will Minnesota Power keep cost to customers reasonable as the region and its own power supply system are transformed?

  Power supply costs have been increasing across the industry as the infrastructure transitions away from CO_2 intensive generation towards more renewable, natural gas and DG. The pace of customer cost increases and the timing of the transition away from coal are being carefully considered as the Company transforms its power supply. Preventing unreasonable cost burdens for customers is fundamental while transitioning the energy supply to include more renewable, natural gas and DG.

The 2015 Plan projects a cost effective rate outlook for customers, even as Minnesota Power meets its forecast growth and complies with environmental and energy policies. Minnesota Power has very competitive rates for residential, commercial and industrial customers, especially when compared to regional and national rates (see pages 78-79 for a detailed rate comparison).

Beginning with the 2010 Integrated Resource Plan, the Company identified that power supply diversification and environmental pressure on its coal-fired generating facilities would be key themes in the next decade. The February 2012 Baseload Diversification Study framed-up the high level cost ranges for Minnesota Power's coal-fired generating facilities to meet a wide range of potential outcomes for air, water and waste regulations being contemplated at the federal and state level. As more information and certainty with the final EPA MATS Rule became known, the Company was able to continue the process of designing and evaluating detailed alternatives for its coal-fired generation facilities.[26] Using engineering and site specific detail, Minnesota Power determined specific quantifiable and actionable options for each alternative available during plan development. The 2013 Plan finalized the Company's Preferred Plan for MATS compliance by identifying each facility impacted by MATS, and communicating the best compliance path for serving customer power supply. To comply, Minnesota Power took action in 2014 and 2015 to refuel LEC to natural gas and cease coal-fired operations at THEC3.

The 2015 Plan continues the evaluation of the Company's small coal fleet. Although the small coal fleet is currently compliant with the MATS regulation, there continues to be cost pressure to cease coal operations from new environmental regulations, such as the CPP. The outlook for continuing low natural gas prices, as well as the advancements in natural gas generation technology, and rising delivered coal costs are also factors. The 2015 Plan addresses the economics for continuing to use the small coal-fired generation fleet, and the method Minnesota Power employed to determine the best path forward for serving its customer power supply needs in this period of uncertainty.

[26] See Appendix E for additional information on Minnesota Power's latest outlook on environmental regulations.

In addition, the 2015 Plan continues to consider enhancements to Minnesota Power's long standing DSM. The partnerships forged with customers have served northeast Minnesota well as energy infrastructure has been added at customer sites. There are 280 MW of customer sited generation with combined heat and power, solar, and demand response programs that allow customer load to be interrupted to protect the reliability of the power system. There is approximately 125 MW of interruptible capability[27] (see Section III of this Plan for more details). Additionally, energy savings from the Power of One® conservation program has reduced the need to generate electricity by 607 GWh since its inception in the mid-1990s.

The forward expansion plan evaluates new DSM programs that expand on the existing programs. For the 2015 Plan, the Company considered two new load control program concepts for residential and commercial air conditioners, and residential hot water heaters. These load control programs have the potential to reduce Minnesota Power's peak demand by approximately 15 MW. Several alternatives that expand the Company's programs and assist residential and commercial customers in conserving energy are also evaluated. More information on the new conservation scenarios is included in Appendix B and K. The new DSM programs are included in the analysis as resource options available to reduce customer requirements. The DSM programs are compared to the cost of other supply side resources (i.e. natural gas CC, solar and wind generation) to determine the best combination of options for Minnesota Power customers.

To prepare for the 2015 Plan and evaluation of the Company's power supply requirements several items were updated and refined from the 2013 Plan. These items include:

1. Generation additions and transitions outlined the most recent activities (see Appendix C). Minnesota Power incorporated its Bison 4 wind farm (204.8 MW) and its LEC refuel to natural gas (110 MW) along with the retirement of THEC3 (75 MW) and further reductions from Young 2 (125 MW to 100 MW).
2. Environmental regulation outlooks (see Appendix E) – Minnesota Power evaluated the status and certainty around the environmental regulations it monitors on an ongoing basis to determine which rules would be part of its Base Case evaluation, and which would be considered in an EPA sensitivity.
3. Per Order Point 13 from the 2013 Plan Minnesota Power included the midpoint of the Commission's approved CO_2 range in its Base Case assumptions. A case where no CO_2 regulation penalty is included in the Base Case assumptions was also used in the analysis. As the final carbon regulation mechanism has not been determined for the electric industry or state, and the timing of a regulation penalty may exceed the 2019 timeframe, Minnesota Power included both outcomes as it selected its Preferred Plan for recommendation. Impacts of key assumptions on power supply decisions are carefully considered in order to ensure actions that increase costs for customers are recommended only when the timing is appropriate.
4. Remission alternatives were refined to be specific to each Minnesota Power facility to gain necessary insight to cost estimates for decision making.

[27] Minnesota Power's Environmental Cost Disclosure brochure from 2014.

5. Generation revenue requirements were updated with the latest information for ongoing capital and operating expenses at each facility.
6. Minnesota Power's capacity resources were updated to include the latest in near-term bilateral contract and accredited capacity values. MISO's UCAP value for accredited capacity is used in the 2015 Plan, as well as Minnesota Power's coincident peak demand forecast and the associated Planning Reserve Margin.
7. Industry Outlooks (see Appendix D) - Minnesota Power assembled the latest industry data for DSM programs, generation technology, natural gas, coal, and other key power supply drivers and trends to ensure an up-to-date set of assumption data was available.
8. Minnesota Power's energy demand outlook was updated with AFR2014, its July 1, 2014 submittal to the Department of Commerce – Division of Energy Resources ("Department").[28]
9. The existing thermal generation fleet analysis assumes that each unit is shutdown or retired at the end of its useful accounting life. This is a change from the 2013 Plan where the thermal generation was assumed to continue operation throughout the planning period. This change was made to reflect the Commission-approved accounting end of life used to recover revenue requirements from customers.
10. Minnesota Power's solar strategy of adding 33 MW of solar generation to comply with the SES is included in the Base Case assumptions.

Together, the items above were considered in the 2015 Plan evaluation to a level appropriate for establishing a power supply strategy and determining Minnesota Power's short and long-term action plans (see Section V and VI).

Handling Uncertainty

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 for the best interests of customers on an ongoing basis.

Minnesota Power strived to create a Preferred Plan that contains robust power supply decisions to position its customers for the industry transformation ahead, while shielding them from unnecessary reliability and cost risk. The Company's planning process evaluates and compares various outcomes with a series of sensitivity impacts. This is done prior to adding an action to its short or long-term action plans. The key area of uncertainty for the 2015 Plan is the outcome of the greenhouse gas regulation (e.g. CCP).

[28] As Minnesota Power needed to begin its resource planning analysis in early 2015, the AFR2014 was the latest load outlook available for use. The AFR2015 filing was made to the Department on July 1, 2015, and was incorporated into the analysis as a sensitivity to ensure the short and long- term action plans were not impacted by the update in projection (See Appendix K).

CO_2 Regulation

Minnesota has a history of forward-looking power supply policy that positions the State well for a future of less carbon-intensive resources. The Green House Gas Emissions Reduction Goal (Minn. Stat. § 216H.02) identifies significant target reductions of 15 percent for 2015, 30 percent for 2025 and 80 percent for 2050. Minnesota Power provides a short and long-term action plan that meets these goals; more information is available in Appendix E of this Plan. The EPA final CPP Rule was released August 3, 2015, and Minnesota Power is currently assessing the CPP as it relates to the State of Minnesota and its potential impacts on the Company.

Each power supply action step was considered under a range of potential carbon futures for the 2015 Plan. By evaluating several outcomes, the Company clearly identified for customers what resource options are based on carbon regulation assumptions versus ongoing power supply needs. The approach to evaluating carbon regulation impacts for the 2015 Plan include:

- Utilizing a $21.50/ton regulation penalty per Order Point 13 of the 2013 Plan as a Base Case assumption.
- Comparing the short and long-term action plans with other plausible carbon alternatives, including a delayed carbon regulation penalty to 2025 and a zero carbon regulation penalty.
- Evaluating the resource selections and the resulting annual customer costs.
- Determining how Minnesota Power would be positioned to implement resource alternatives for customers in the future should a carbon regulation penalty or target be implemented.

Given the uncertainty of a CO_2 regulation penalty, and the uncertainty of timing for implementation, Minnesota Power included a case where no CO_2 regulation penalty is included in the Base Case assumptions. A case where the midpoint of the Commission's approved CO_2 range is also included in the Base Case assumptions. Having two Base Cases, one that includes and one that excludes a CO_2 regulation penalty, allows the company to understand how a carbon penalty can change the timing and technology type of new resource additions, and when to begin transition of existing resources. Analysis for past resource plans, as well as the current one, indicate that the timing and value of a CO_2 regulation penalty can influence resource decisions both on technology and timing, and these factors were taken into consideration when developing the Preferred Plan.

It was difficult to assign a value to CO_2 for analysis purposes in the absence of the final published CPP. Fortunately, the Company had already implemented its strategy to reduce CO_2 emissions in its power supply as part of its overall *Energy**Forward*** strategy, which positions the company well to comply with future CO_2 regulations.

Analysis Process

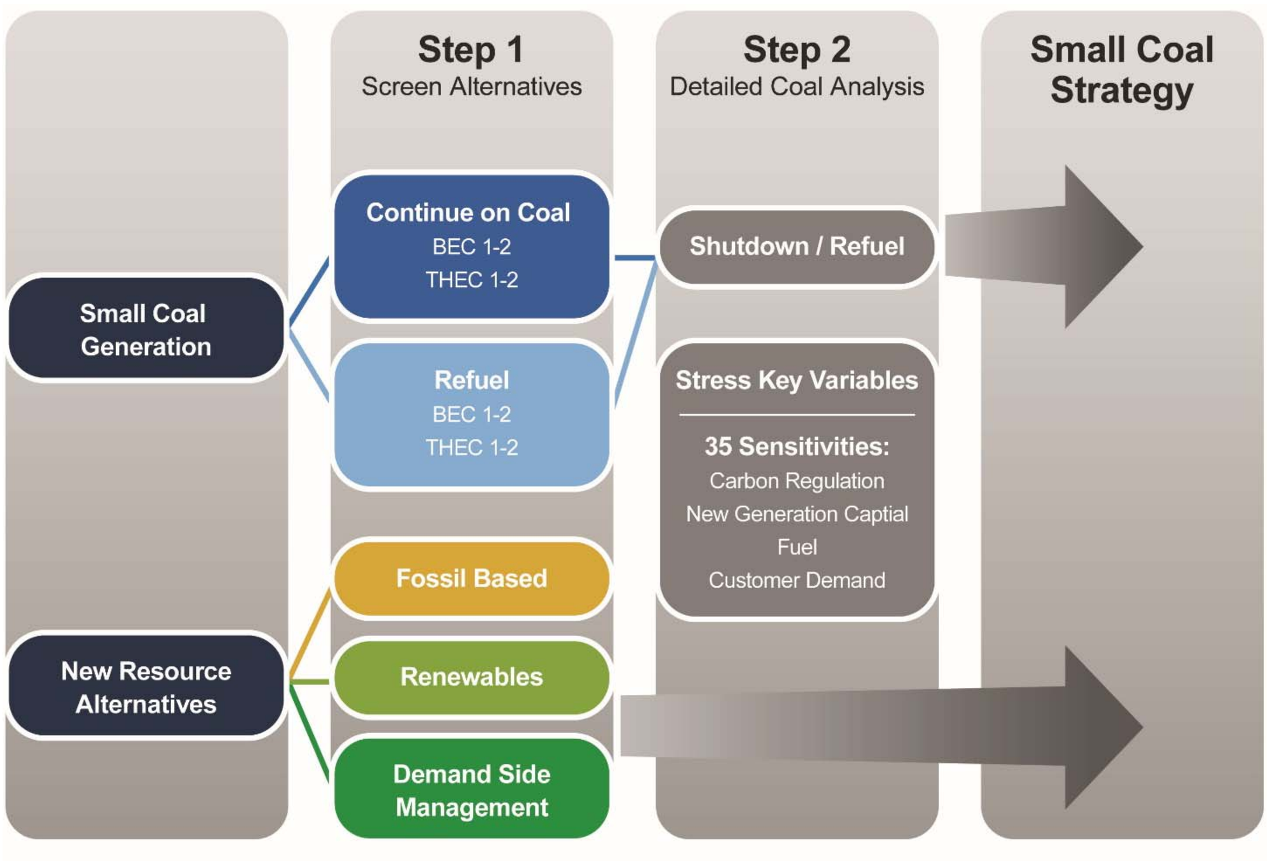
A four-step planning evaluation was used to arrive at the operational strategy for each generating facility, and to find the best resource alternatives to augment the Company's power supply for long term customer requirements. The Preferred Plan was created by first determining the operational status of the remaining small coal-fired generation facilities as identified in the preferred Small Coal Strategy, and then augmenting this with the expansion plan that best served customer needs over the planning period. The four sequential steps of the 2015 Plan include:

1. *"Screen Remission Options for Small Coal & Alternatives"* – Determine if a remission alternative is most cost-effective for each remaining small coal-fired generation facility. Screen which new resource alternatives and DSM programs are most cost-effective at augmenting the power supply.
2. *"Detailed Coal Analysis"* – Determine if a small coal-fired generation facility should be closed/shutdown prior to the accounting end of life rather than move forward with the cost effective option(s) from Step 1.
    a. This step includes a series of over 35 sensitivities that stress key power supply cost drivers such as delivered fuel, CO_2 penalties, capital and additional customer load outlooks (see Appendix J).
3. These first two steps define Minnesota Power's Small Coal Strategy.
4. *"Detailed Resource Analysis"* – Identify a resource expansion plan that will augment the preferred Small Coal Strategy identified in Steps 1 and 2 to best meet customer requirements over the study period.
5. *"Swim Lane Comparative Analysis"* – Compare and stress Minnesota Power's Preferred Plan against three other viable power supply portfolio alternatives in a swim lane[29] analysis.
    a. The three other swim lane alternatives include these action plans:
        I. Continue small coal operations through the mid-2020s
        II. Refuel BEC1&2 with natural gas
        III. Take early action on shutting down remaining small coal-fired generation
    b. The comparison of the three swim lane alternatives includes a series of over 50 sensitivities that stress the key power supply cost drivers such as delivered fuel, CO_2 penalties, capital and additional customer load outlooks to identify how robust each lane is under the numerous variable changes (see Appendix K).

For steps 1 and 2 of this evaluation, Minnesota Power identified site specific alternatives for each of its remaining small coal-fired generation facilities. Many considerations and variables enter into the decision whether to continue operating on coal through the mid-2020s, remission, or retire the facility. Insights are shown in Figure 11 and under the "Coal-Fired Generation Considerations." 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.

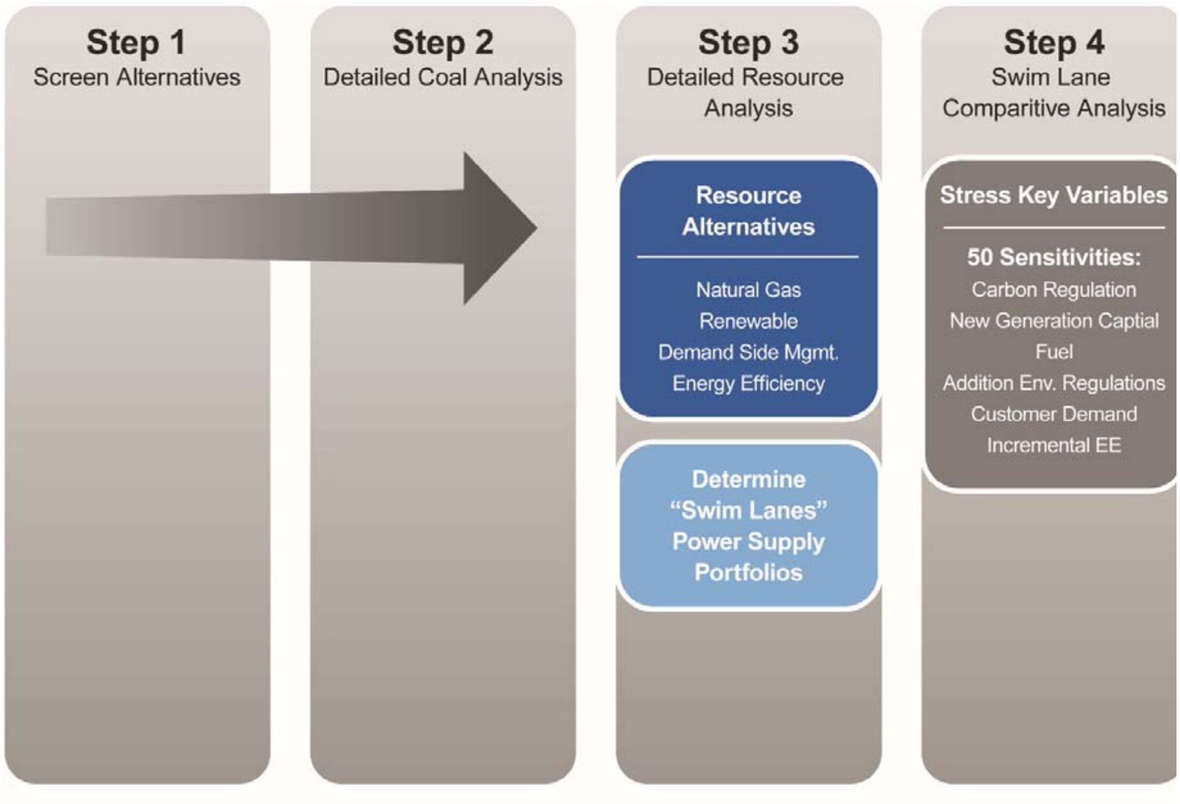
[29] A swim lane is a mechanism to evaluate alternatives by considering them in a side-by-side "lane." For the 2015 Plan, each lane contains an alternative path for Minnesota Power's supply options.

Figure 11: Plan Development Process - Steps 1 and 2



The 'Expansion Planning for New Generation Resources' section beginning on page 57, describes results from Step 3 that determined which resources and DSM programs should augment the supply portfolio for the planning period. The detailed results from Step 3 are included in Appendix K of this Plan. The comparison of the three swim lane alternatives, Step 4, is discussed in the 'Analysis and Insights' section beginning on page 80, and will demonstrate how the Preferred Plan will bring cost and environmental benefits to customers' electric supply. Steps 3 and 4 are shown in Figure 12.

Figure 12: Plan Development Process - Steps 3 and 4



Coal-Fired Generation Considerations (Step 2)

The 2013 Plan considered the impacts of the newly formed MATS Rule and identified the need for significant emission reduction. As a result, THEC3 was retired in June 2015, and both units at LEC were refueled with natural gas in the first half of 2015. This path was identified to be the most cost-effective for customers and the surrounding region, and coupled with prior actions reduced Minnesota Power's power supply mix from 95 percent coal in 2005 to 53 percent coal by 2016.

The remaining small coal-fired generation in the Company's power supply for the 2015 Plan are THEC1&2 near Schroeder, Minn. (150 MW) and BEC1&2 in Cohasset, Minn. (130 MW). For each of the remaining small coal-fired facilities the Company identified and considered detailed alternatives for remission or retirement. More detailed information is available in Appendix C. There is also a brief overview of the remission opportunities for THEC1&2 and BEC1&2 below.

Boswell Energy Center

BEC is Minnesota Power's largest coal-fired generation facility, with around 200 full-time employees and a capacity of just over 1,000 MW. BEC is among the largest employers in Itasca County. BEC1&2 combine for approximately 130 MW of the total BEC capacity, and provide integral shared infrastructure that supports operation of all four generating units at the facility.

BEC3 at 355 MW, and BEC4 at 585 MW, are the largest units. BEC3 and BEC4,[30] produce over 5.8 million MWh annually for customers. The two smaller units provide vital restoration capability during startup operations and black-start plans, as well as facility-wide support. Operating at baseload levels, BEC provided nearly half of the energy that Minnesota Power generated to meet customer requirements in 2014.

Substantial investments have been made at the BEC facility for environmental and efficiency related improvements over the past several years. BEC4, the Company's largest baseload generating resource, is undergoing an extensive emission reduction project to address mercury, PM, SO_2 and other air pollutants, while also reducing plant wastewater, is scheduled to be completed by the end of 2015.[31] In 2009, BEC3 completed a significant multi-pollutant environmental retrofit for controlling SO_2, NO_x, PM and mercury. Upon completion of the BEC4 Project, the BEC facility will be environmentally compliant with the MATS Rule, and the MERA.[32]

Investments have also been made in emission reduction technologies at BEC1&2 within the last decade. BEC1&2 operate with emission control equipment including low NO_x burners and fabric filters to control PM. The fabric filter bags also contribute to consistent mercury co-benefit removal. In 2008 and 2009, BEC1&2, respectively, were retrofitted with Mobotec Rotating Opposed Fired Air and ROTAMix emission control systems to further reduce the NO_x emissions from these units. BEC1&2 are in compliance with the MATS requirements, but have additional SO_2 reductions to further improve ambient air quality standards and meet by 2019 per Minnesota Power's Consent Decree with the EPA.[33] The new limits require that BEC1&2 use a scrubber system to reduce SO_2 to continue to operate on coal past 2019. This is referred to in the plan analysis as the "BEC 1-2 Coal" scenario. The project results in a 95 percent reduction in SO_2 at BEC1&2. Other alternatives for environmental compliance with the new SO_2 limits include refueling the two units with natural gas, or ceasing operation by 2019. Both "BEC 1-2 Coal" scenario and refuel on natural gas scenario assumes that BEC1&2 will cease operation at the end of its current useful accounting life in 2024.

The BEC 1-2 Coal scenario includes a unique and low cost solution to reduce SO_2 emissions at BEC1&2. The environmental control systems on BEC3 can be used to reduce SO_2 emissions from BEC1&2. This can be achieved by rerouting the effluents from BEC1&2 through BEC3's state of the art wet scrubber, where it will remove acid gases (SO_2, hydrochloric acid ("HCL") and other elements) as well as reduce PM before exiting the stack. This re-routing option will optimize the BEC facility for efficiency, and lower emissions. BEC1&2 already share a common stack with BEC3. This project would move the entry point of BEC1&2 effluents up stream to take advantage of the existing wet scrubber. Minnesota Power identified through an engineering evaluation that the cost of the project would be approximately $30 million to reroute the effluents, with no expected increase in variable cost. This project is not expected to have any impact on BEC3 operations, and would maintain BEC1&2's current capacity rating of approximately 130 MW. This project leverages the BEC3 scrubber investment to reduce

[30] BEC4 is jointly owned by Minnesota Power and WPPI Energy. The Company has an 80 percent ownership share of BEC4.
[31] Docket No. E015/M-12-920.
[32] Minnesota Power filed Mercury Emission Reduction Reports with the Commission in 2011 and 2012 (see Docket No. E015/M-11-712 and Docket No. E015/M-12-734).
[33] See Appendix E of this Plan for further detail of the EPA Consent Decree.

emissions at BEC1&2, which is a low cost way to achieve BACT (Best Available Control Technology) level acid gas emissions. Continuing BEC1&2 provides a reasonable cost power supply resource for customers in comparison to alternatives, and allows the Company to bridge to its next significant resource addition. At the time of this analysis, that resource is identified as an efficient natural gas-fired generation unit that would be built in the mid-2020 timeframe, congruent with the BEC1&2 end of useful accounting life in 2024, at which point the future state of BEC1&2 will be decided.

The retirement scenario for BEC1&2 has facility-wide impacts due to the operational integration of the overall facility. As mentioned above, the BEC units are not stand-alone, making it difficult for them to be separated; they share unit critical electrical, water and heating infrastructure, ancillary services and fuel handling with the rest of the facility. Specifically, BEC1&2 provide support to BEC3 and BEC4 during black-start procedures, ongoing operations,[34] and during critical system restoration activities for Minnesota Power. If BEC1&2 are retired, a new system restoration plan will need to be developed by the Company for the region. Site-wide operational costs would need to continue if BEC1&2 are retired, including an average $0.6 million in capital cost annually and $2.6 million in operation and maintenance ("O&M") cost annually. These costs include common equipment, such as station heating, and services that will need to continue for power production to occur at BEC if BEC1&2 were shut down. A closure of BEC1&2 would increase the operational costs for the remaining units at the facility. Minnesota Power included these costs for a BEC1&2 shutdown scenario that was evaluated to ensure BEC3 and BEC4 would have the operational support needed.

Also integral to the shutdown scenario are the transmission reliability considerations. Removing the 130 MW of generation from the region will adjust power flow and delivery on the bulk electric system. The Company performed a transmission engineering analysis that identified a BEC1&2 shutdown scenario would create operational conditions in which Minnesota Power would be unable to reliably serve the Grand Rapids area, resulting in a local blackout. See Appendix F of this Plan for more detail. Several transmission projects with an approximate cost of [TRADE SECRET DATA EXCISED] were identified that would mitigate the Grand Rapids area transmission reliability. Minnesota Power included these costs in all of the BEC1&2 shutdown scenarios evaluated (2019 and 2024). The transmission cost estimates are also included in 2019 for the natural gas refuel scenario, as BEC1&2 would be operating as a peaking resource with an estimated 10 to 20 percent capacity factor. As peaking units, BEC1&2 would not be able to instantaneously provide transmission system support, unlike today when the units operate as baseload generating resources.[35]

A refuel of the BEC1&2 boilers to natural gas was another alternative considered prior to conducting the shutdown evaluation. The refuel conversion would entail inserting natural gas burners into the current boilers and allowing them to fire completely on natural gas as a fuel source. This option would maintain full capacity benefit for customers, and allow the units to serve as a peaking energy resource to protect customers from high regional market prices. To

[34] BEC1&2 provide compressed air, service water and intake cooling water to the larger BEC facility. The electrical and communication infrastructure of BEC1&2 is also closely intertied with BEC3.
[35] If a shutdown of BEC1&2 became imminent, Minnesota Power would enter into the MISO Attachment Y process to secure final confirmation of transmission reliability requirements from its regional transmission operator.

help manage the start-up time requirements for BEC1&2 once refueled to natural gas, steam needs to be routed from BEC3 to the BEC1&2 turbines to keep them warm and ready for start-up due to their outdoor location.[36]

The refuel option also allows BEC1&2 to continue to operate as part of the larger BEC facility infrastructure, and meet system restoration requirements. BEC has natural gas supply infrastructure in place, including appropriately sized pipe that could accommodate the operation of BEC1&2 on natural gas. Minimal common infrastructure would need to be added to implement a refuel at this facility. The estimated capital cost of a natural gas refuel for BEC1&2 is $16 million (see Appendix C). Moving BEC1&2 to natural gas would bring Minnesota Power's portfolio to over 250 MW, or more than 10 percent of the Company's installed generation. Emission profiles would be lower than coal-fired operation, specifically for CO_2, but customers would be exposed to more price volatility which would affect costs.

Figure 13 compares BEC1&2 under a coal-fired and natural gas-fired resource scenario, over a range of run times.[37] If BEC1&2 are converted to natural gas and continue to run at the same high capacity factor level (shaded area in Figure 13), the cost is higher than if they are kept as coal-fired generators.[38] Figure 13 also identifies that the natural gas refuel option could benefit customers if BEC1&2 were running less than 35 percent of the time. Current run rates for BEC1&2 are in the high 70 percent range. Under a carbon regulation penalty (see Figure 14), which includes the Commission's approved $21.50/ton CO_2 regulation penalty, BEC1&2 would need to fall below a 60 percent run rate for the refuel option to provide benefit. This is a good example of how the timing, structure and value of the CO_2 regulation penalty can impact a decision on an asset, and why it's important to consider how a penalty is used to make critical resource decisions for customers. It is important to note that the CPP does not include price on carbon, rather an emission rate or mass limit determined state by state.

[36] The steam needed for a BEC1&2 start-up on natural gas is taken into account by reducing the output at BEC3 by 14 MW when considering the refuel alternative.
[37] Based on operations data over the past eight years.
[38] A capacity factor represents how much of the year a generator resource runs in comparison to its nameplate capacity. Minnesota Power's coal-fired fleet runs at higher capacity factors to serve the high energy needs of its customers and provide low cost energy all hours. Peaking natural gas resources typically run at low capacity factors (less than 20 percent on average).

Figure 13: BEC1&2 Levelized Product Cost at Varying Capacity Factors with No CO_2 Regulation Penalty

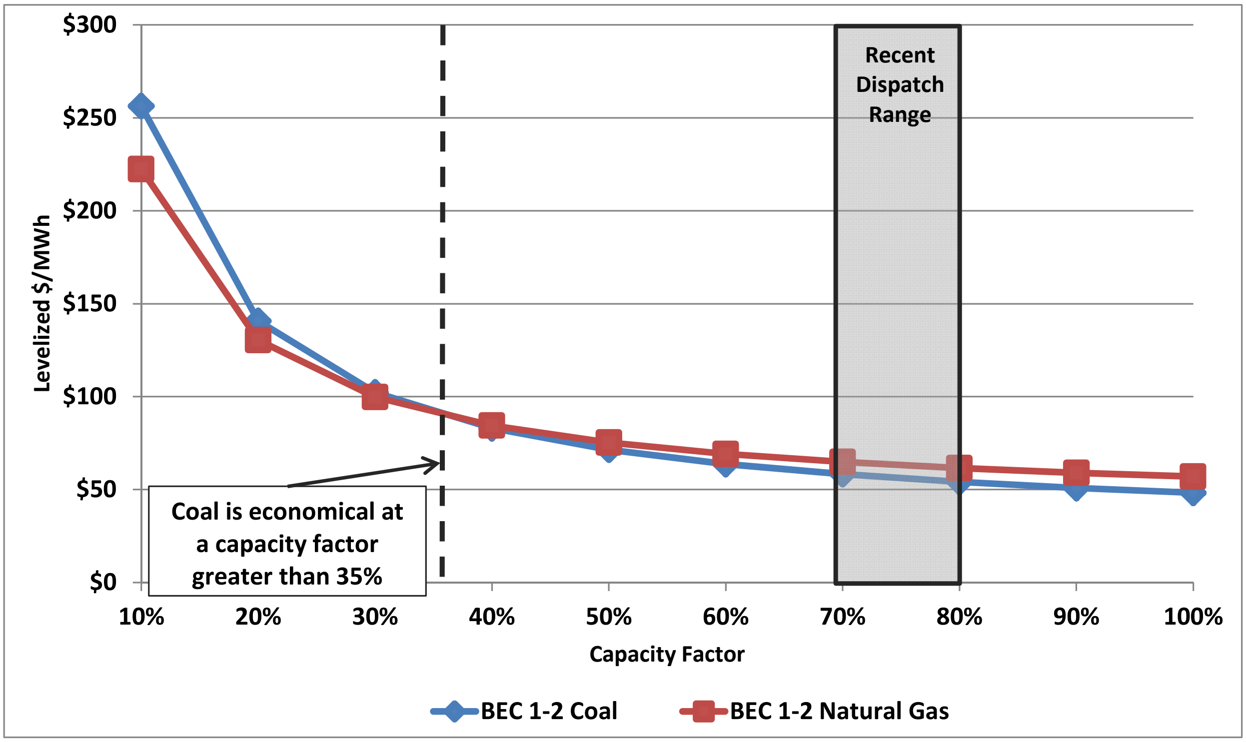
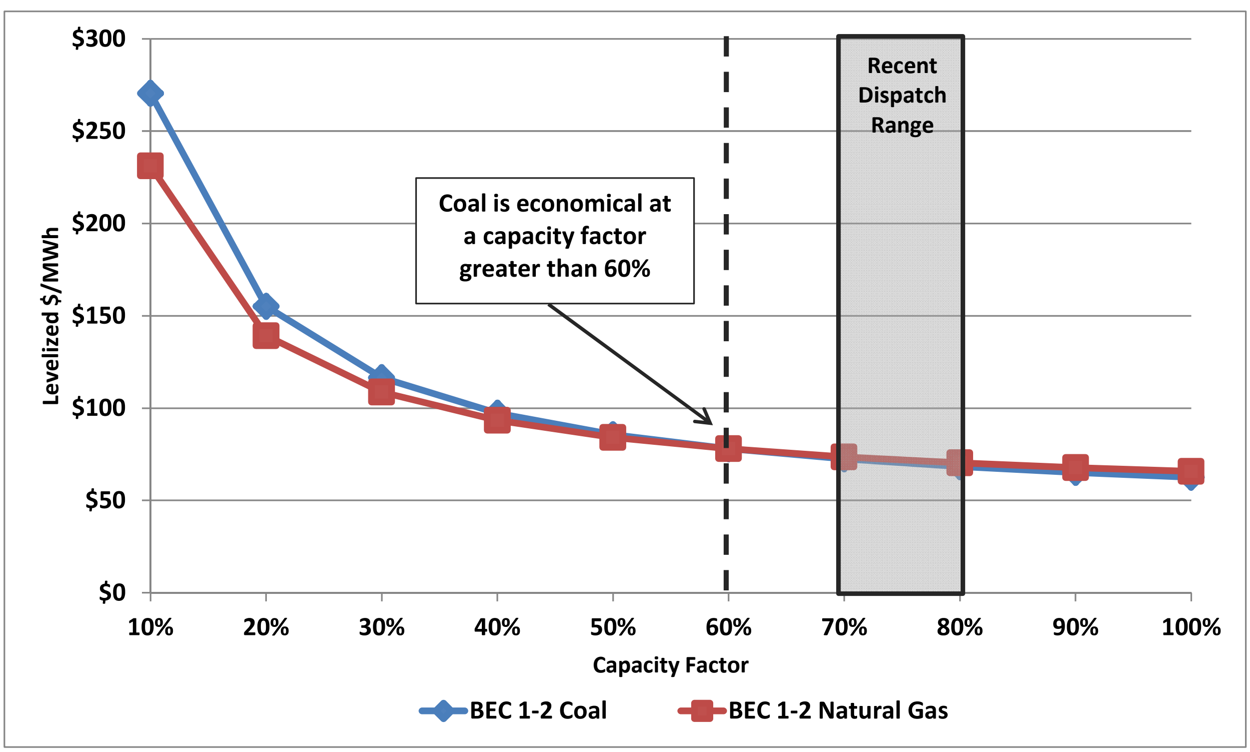


Figure 14: BEC1&2 Levelized Product Cost at Varying Capacity Factors with $21.50/ton CO_2 Regulation Penalty



Figures 13 and 14 are screening level in nature, and add further insight into the two alternatives. It is a limited comparison of the two options for BEC1&2, and does not consider the remaining power supply resource decisions that must be made. When the natural gas refuel and existing operations options are evaluated through a full production cost analysis in the Strategist software, such as in Step 2 or “Detail Coal Analysis,” the results are more indicative of the best option for customers.

Step 2, or the “Detailed Coal Analysis,” indicated that customers would not benefit from a retirement of BEC1&2. This analysis showed that it would be unnecessarily costly to shutdown these two units prior to their end of useful accounting life in 2024. The evaluation included the optimization of the BEC1&2 Shutdown by 2019, continue on coal, or refuel with natural gas options with the rest of the system alongside new generation resource alternatives. When the option to shutdown BEC1&2 by 2019 was given to the system wide optimization evaluation in the Strategist Proview software, it identified that BEC1&2 remain a viable power supply resource through the end of 2024, and provide a power supply benefit of approximately $12 million.

The operational outcome of BEC1&2 did vary depending on which level of a CO_2 regulation penalty is applied (see Table 2). The lower values of CO_2 regulation penalty (zero and $9/ton) identified that continuing on coal was the best option for customers. The higher levels of CO_2 regulation penalty ($21.50/ton and $34/ton) identified the refuel with natural gas option was the lowest cost option for customers. As Step 4 and the associated swim lane analysis will demonstrate, when the $21.50/ton CO_2 regulation penalty is delayed from 2019 to 2025 (to reflect a more reasonable start date for a carbon penalty mechanism) the option to continue to operate on coal is also the lowest cost option.

Table 2: BEC1&2 Results from Step 2 Analysis "Detailed Coal Analysis”

	Base (no CO_2 penalty)	**CO_2 Penalty $9/ton**	**CO_2 Penalty $21.50/ton**	**CO_2 Penalty $34/ton**	**CO_2 $21.50/ton Starting in 2025**
BEC 1&2 Continue Coal Operations	X	X			X
BEC 1&2 Refuel w/ Natural gas by 2019			X	X	
BEC1&2 Shutdown by 2019					

While not included as a direct cost to the BEC1&2 shutdown alternative, the Company evaluated the socioeconomic impact on the local communities in compliance with Minnesota resource planning rule (Minn. Rules 7843.0400, Subp. 3(A)). Minnesota Power established a valuation of the socioeconomic impact of a closure of BEC1&2 (see Appendix M). The findings emphasized that Minnesota Power’s generating facilities provide significant benefit to the communities and surrounding region through tax payments, employment and vendor utilization.

If the Company were to close BEC1&2, the loss of 35 jobs and the associated support roles throughout the local area would create a one percentage point increase in unemployment almost immediately for the area. This is a significant change, in that Itasca County is experiencing historically high unemployment rates, nearly two times the State average. Overall, the loss of revenue and wages would contribute to $29 million in loss each year for the region after the closure. As demonstrated during the Baseload Diversification Study process and associated stakeholder outreach for the 2013 Plan, Minnesota Power has been a trusted community partner for decades and continues to carefully consider these impacts of its electric service.

Minnesota Power identified through the BEC1&2 detail evaluation that at this time, with current environmental regulations and no certainty on CPP in the near-term; there are no driving factors to close these two resources prior to the end of 2024. BEC1&2 will best serve customers through their continued operation on coal as part of a larger facility with plans to lower their emission profile by the end of 2018. Minnesota Power will continue to monitor industry, environmental and system conditions that impact BEC1&2 and all of its resources. Through its ongoing resource planning process, the Company will communicate with stakeholders as power supply action plans evolve for BEC1&2.

Taconite Harbor Energy Center

As part of the outcome of the 2013 Plan, further evaluation of THEC1&2 was required for the 2015 Plan. The Commission and Minnesota Power were in agreement that the Company would include in this evaluation a detailed examination of alternatives at THEC:

> "In its next resource plan filing, Minnesota Power shall include a full analysis of the effects of retiring or repowering the Taconite 1 and 2 plants, including transmission and distribution effects."[39]

This section will describe the continuation of Minnesota Power's evaluation of the economical re-missioning options available at THEC, and the effects of retiring the remaining two units. The evaluation supports the associated short and long-term action plan recommendation included in the Preferred Plan. The Company's Preferred Plan includes ceasing coal operations at THEC1&2 by 2020, and beginning the transition by entering into a near-term economic idle by the end of 2016.

THEC is located near Schroeder, Minn., on the North Shore of Lake Superior, and has a generation capability of 225 MW. There are three units located at THEC; although THEC3 was retired from operation in June 2015. This retirement resulted from the Company's Commission approved 2013 Plan, and reduced THEC's generation capability to approximately 150 MW. The three 75 MW units were originally purchased by Minnesota Power from bankrupt LTV Steel Mining Co. in 2001. Investment was made to bring the units up to utility industry standard, and the units were restarted in 2002.[40] There are approximately 40 full-time employees at THEC. The three generating units are housed in a single building with shared electrical and heating infrastructure, and a single control room for unit operations. The facility does not have direct

[39] Order Point 14 of the Commission's Order dated November 12, 2013, in Docket No. E015/RP-13-53.
[40] In the 2004 Integrated Resource Plan, the Commission allowed THEC to be part of Minnesota Power's retail rate base. Docket No. E-015/RP-04-865.

access to natural gas as a fuel source, and the closest pipeline access is approximately 30 miles to the south in Silver Bay, Minn. The facility is located at an active shipping port on Lake Superior, and receives coal shipments for its operations.

As part of Minnesota Power's AREA Plan,[41] THEC1&2 were fitted with Mobotec multi-emission control technology designed to deliver a 62 percent reduction in NO_x emissions, a 65 percent reduction in SO_2 emissions, and up to a 90 percent reduction in mercury emissions. Conversion of the hot-side electrostatic precipitator ("ESP") to a cold-side ESP for improved particulate removal also took place in this time period. The mercury and acid gas removal systems were modified on THEC1&2 in early 2015, and they are in compliance with the MATS requirements.

Minnesota Power considered various remission options at THEC1&2, including refueling with compressed natural gas or torrefied wood, continuing to operate on coal through 2026, or economically idle the facility in the near term. High level engineering estimates were used to determine the feasibility and cost of the refueling options, and were compared to current operations on coal or an idling of the units. In all scenarios, it is assumed that THEC1&2 would shut down by the end of 2026, which correlates to the current end of their useful accounting life.

A refuel of the THEC1&2 boilers to natural gas is a viable remission option for the facility, although it will be unique when compared to typical natural gas refueling projects. With no natural gas supply at the facility, this alternative would require compressed natural gas to be delivered via truck or vessel to the facility. The tanks of compressed natural gas would need to be directly hooked up to the THEC1&2 fuel systems. The fuel cost for this scenario takes into consideration the estimated cost to compress and deliver natural gas to the facility. This refuel alternative also requires inserting natural gas burners into the current boilers, and allowing them to fire completely on natural gas as a fuel source. This option would maintain full capacity benefit of the facility (150 MW) for customers and serve as a peaking energy resource to protect customers from high regional market prices. The estimated capital cost of a compressed natural gas refuel for THEC1&2 is [TRADE SECRET DATA EXCISED] (see Appendix C).

The other refuel option considered at THEC1&2 is using torrefied wood as the primary fuel source. Torrefied wood is a biomass material that goes through a process that roasts the wood to remove moisture creating an energy dense material that can be used similar to coal. The benefit of torrefied wood is it is easy to handle and could be used at THEC1&2 with no expected modifications to the facility. The current fuel handling system used to move coal from the stock piles to the boiler can also be used for handling torrefied wood. There is also an environmental benefit for customers, as this refueling option is part of a biomass portfolio, and could be leveraged as part of carbon-minimizing strategies to meet greenhouse gas targets in the future. This outcome would be heavily dependent on the treatment of biomass fuel in carbon regulation, and associated state implementation plans. The increase in cost for this refuel option is fuel related, where THEC1&2's current delivered fuel price for coal is [TRADE SECRET DATA EXCISED] compared to the projected cost for torrefied wood of [TRADE SECRET DATA EXCISED]

[41] Arrowhead Regional Emissions Abatement Plan. Docket No. E-015/M-05-1678.

the cost of delivered coal. There have been test pilots that prove torrefied wood is technologically feasible as a fuel source, although the supply chain has not yet achieved commercial scale quantities. Minnesota Power continues to actively research and monitor advancements in torrefied wood that could make refueling an economical option for customers (see Appendix D).

The first step in the THEC1&2 evaluation is to compare the re-missioning alternatives of compressed natural gas and torrefied wood to continuing on coal before considering a shutdown alternative for the facility. THEC has been maintaining a 60 to 75 percent capacity factor for the past eight years, providing baseload energy and capacity for Minnesota Power's customers. When the generation costs are compared one-to-one, continuing to operate on coal is clearly the lowest cost option for customers, with and without a carbon regulation penalty (Figures 15 and 16).

Figure 15: THEC1&2 Levelized Product Cost at Varying Capacity Factors with No CO_2 Regulation Penalty

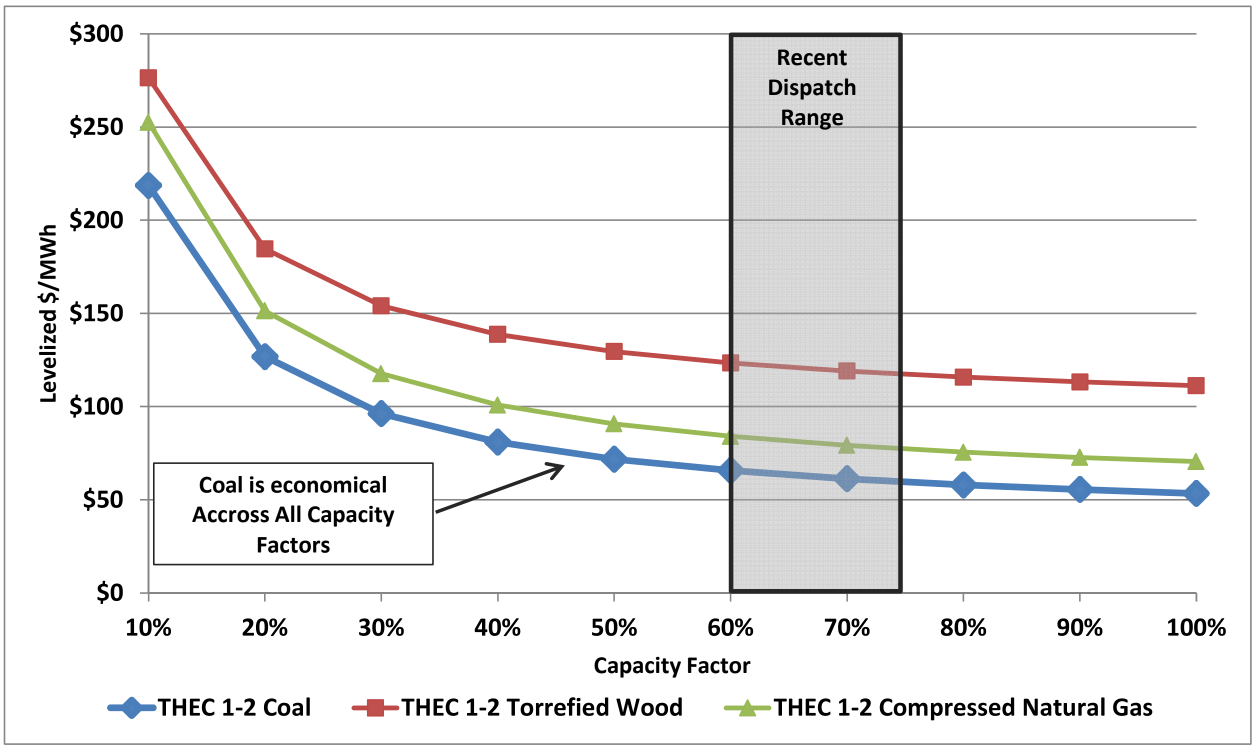
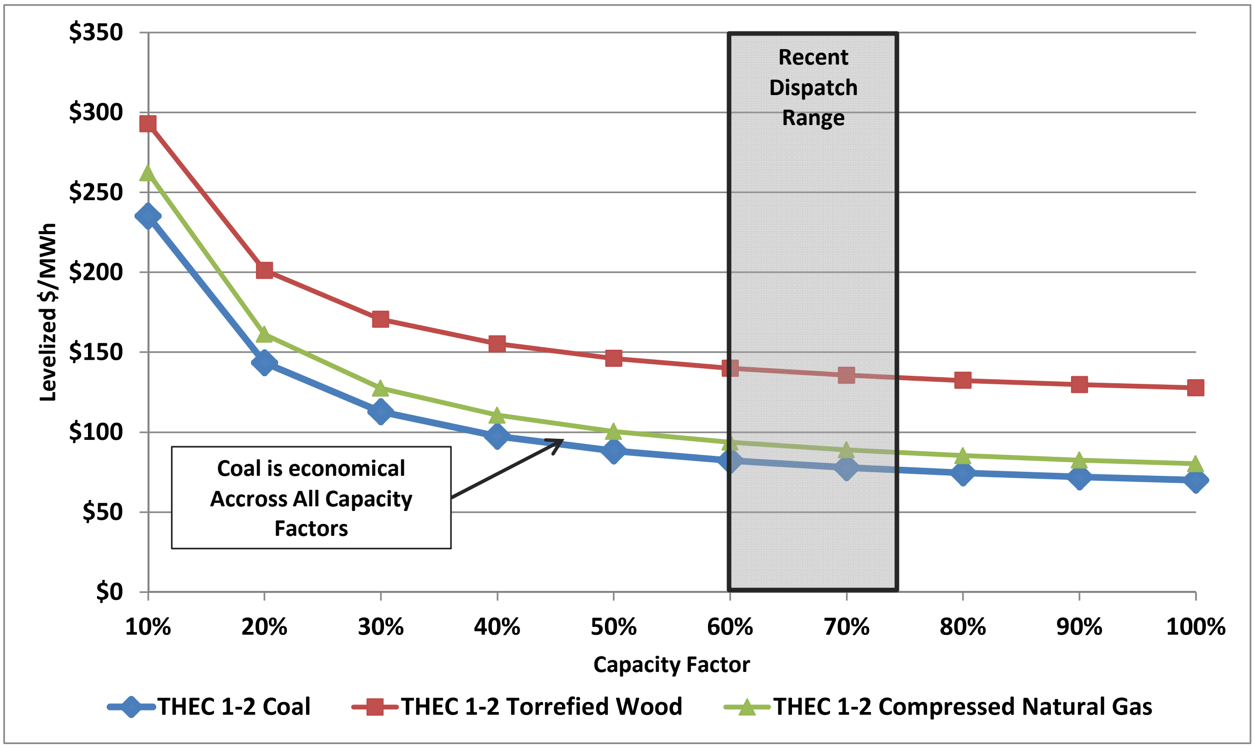


Figure 16: THEC1&2 Levelized Product Cost at Varying Capacity Factors with $21.50/ton CO_2 Regulation Penalty



Figures 15 and 16 are also screening level in nature to gain further understanding of the alternatives. It is a limited comparison of the options for THEC1&2 and does not consider the remaining power supply resources that must be made. However, when an option is lower cost across all capacity factors this screening level analysis can be used to remove more expensive alternatives prior to the Step 2 "Detailed Coal Analysis" analysis. With continuing to operate THEC1&2 on coal clearly being the lowest cost option across the CO_2 regulation penalty scenario and capacity factors, the other two refueling alternatives were not carried forward into Step 2. These two refueling options will need additional work on their competitiveness profile to become viable options for the THEC facility.

As the Company moved into the Step 2 "Detailed Coal Analysis" analysis for THEC1&2, the shutdown timing alternatives and economic idling options were defined. One early shutdown scenario was considered for 2019, along with an idling/limited operations scenario that would start in 2017.[42] The concept of the idle alternative was to allow the evaluation to consider an energy only alternative for the facility as the unit transitions to a shutdown status, providing customers the flexibility of a known and available power supply resource that could be called on for reliability purposes.

[42] The idle alternative was modeled in Strategist with the capacity of THEC1&2 being removed in 2017 and energy only operation in 2017 and 2018 where the facility generated energy during the summer and winter peak months and idled during the spring and fall months. The cost for O&M and capital necessary for an energy only operation at THEC1&2 was included in the idle scenario.

Through the shutdown alternative comparison, Minnesota Power conducted a transmission and distribution evaluation to determine the impacts of having THEC1&2 removed from the bulk electric system near Schroeder, Minn. The results of this study are available in Appendix F. The results indicated a THEC1&2 shutdown scenario would create transmission reliability concerns in the area, and upgrades are required to ensure the electric service to Minnesota Power customers is maintained. There were two sets of transmission projects identified to fix the reliability concerns: set one would be required at the time of shutdown with Minnesota Power's current system configuration, and set two is related to new load growth being projected in the region.[43] The estimated costs for the transmission projects are [TRADE SECRET DATA EXCISED].

To ensure a robust analysis of the shutdown and idle alternatives for this facility in Step 2, the option to shut down or idle THEC1&2 was included in a system wide optimization evaluation. The results indicated that customers would benefit from an idle operation of THEC1&2 in the near term. When the option to idle THEC1&2 by 2017 was given to the system wide optimization, it identified that the idle scenario was the lowest cost option across the base assumptions, including all CO_2 regulation penalty sensitivities. This is shown in Table 3. For the longer-term, ceasing coal-fired operation at THEC1&2 by 2020 was identified as optimal timing to transition to a new mission for the facility. Ceasing all coal operations by 2020 provides a smooth transition within the overall Company power supply as the Manitoba Hydro purchases of 383 MW create a long capacity position and aligns with the potential for carbon reduction targets.

Table 3: THEC1&2 Results from Step 2 Analysis "Detailed Coal Analysis"

	Base	CO_2 Penalty in 2019 $21.50/ton	CO_2 Penalty in 2019 $9/ton	CO_2 Penalty in 2019 $34/ton	CO_2 $21.50/ton Starting in 2025
THEC1&2 Continue Coal Operations					
THEC1&2 Idle by 2017	X	X	X	X	X
THEC1&2 Shutdown by 2019					

The flexibility of having THEC1&2 energy and capacity available in the near term will provide optionality for Minnesota Power's customer portfolio in 2017 through 2019, as the region continues to transform its power supply and regional reserve margins decline. The idle scenario allows the flexibility to leverage the low regional energy market pricing, resulting in projected power supply cost savings for customers ranging from $29 to $43 million. Cost savings

[43] Appendix F outlines the transmission mitigation identified for the region. Minnesota Power will be entering into the MISO Attachment Y2 process to gain additional confirmation about reliability impacts of a potential shutdown of the facility by 2020. However, additional remission and refuel evaluation will be done during Minnesota Power's next resource plan to confirm final facility transition plans.

projections are shown in Table 4. Being able to call back THEC1&2 maintains the capability to respond to regional reliability requirements.

Table 4: Power Supply Cost Comparison Between Idle in 2017 and Shutdown in 2019

Strategist Power Supply Cost 2015-2034 NPV ($ Millions)	**Base**	**CO_2 Penalty in 2019 $21.50/ton**
THEC 1&2 Idle by 2017	$ 7,506	$ 8,488
THEC 1&2 Shutdown by 2019	$ 7,534	$ 8,532
Delta ("Idle" minus "Shutdown")	$ (29)	$ (43)

While not included as a direct cost to the THEC1&2 shutdown alternative, the Company evaluated the socioeconomic impact on local communities in compliance with Minnesota resource planning rule (Minn. Rules 7843.0400, Subp. 3(A). Minnesota Power established a valuation of the socioeconomic impact of a closure of THEC1&2, and is included in Appendix M. The valuation study emphasized that Minnesota Power's generating facilities provide significant benefit to the communities and surrounding region through tax payments, employment and vendor utilization. If the Company were to close the THEC facility, the loss of nearly 40 jobs and the associated support roles throughout the local region would create a three percentage point increase in unemployment almost immediately for the area. The resulting loss of revenue and wages would contribute to $36 million in loss each year for the area after the closure.

To protect affordability and flexibility for customers and reduce emissions further in the region, Minnesota Power will proactively idle coal operation at the THEC as part of its short-term action plan. The idle will begin by the end of 2016, and the units will be available to regional markets on a seasonal basis for reliability to generate electricity.[44] The THEC1&2 idle is expected to reduce overall emissions in the region, and specifically carbon emissions, by approximately 1,000,000 tons per year (if the units are idled for an entire year starting in 2017). Any additional capacity and energy replacement for THEC1&2 will be handled through the Company's near and medium-term market mechanisms.

For the long term, Minnesota Power recommends that coal-fired operations cease by 2020 for THEC1&2. The Company will become more surplus in capacity with the start of its Manitoba Hydro 250 MW purchase that will accommodate this transition timing. It also aligns with the timing of potential CO_2 reduction targets in the 2020 period. Future refueling and remission opportunities for THEC1&2 will be considered in planning and optimization of the facility for Minnesota Power's next resource plan. The facility maintains a strong presence in the region with an operating deep water port, rail line, and power generation infrastructure. The Company will be working closely with regional leaders to identify the best alternatives for the facility. As demonstrated during the Baseload Diversification Study process and associated stakeholder outreach, Minnesota Power has been a trusted community partner for more than a decade and continues to consider the impacts of its electric service in a thoughtful way.

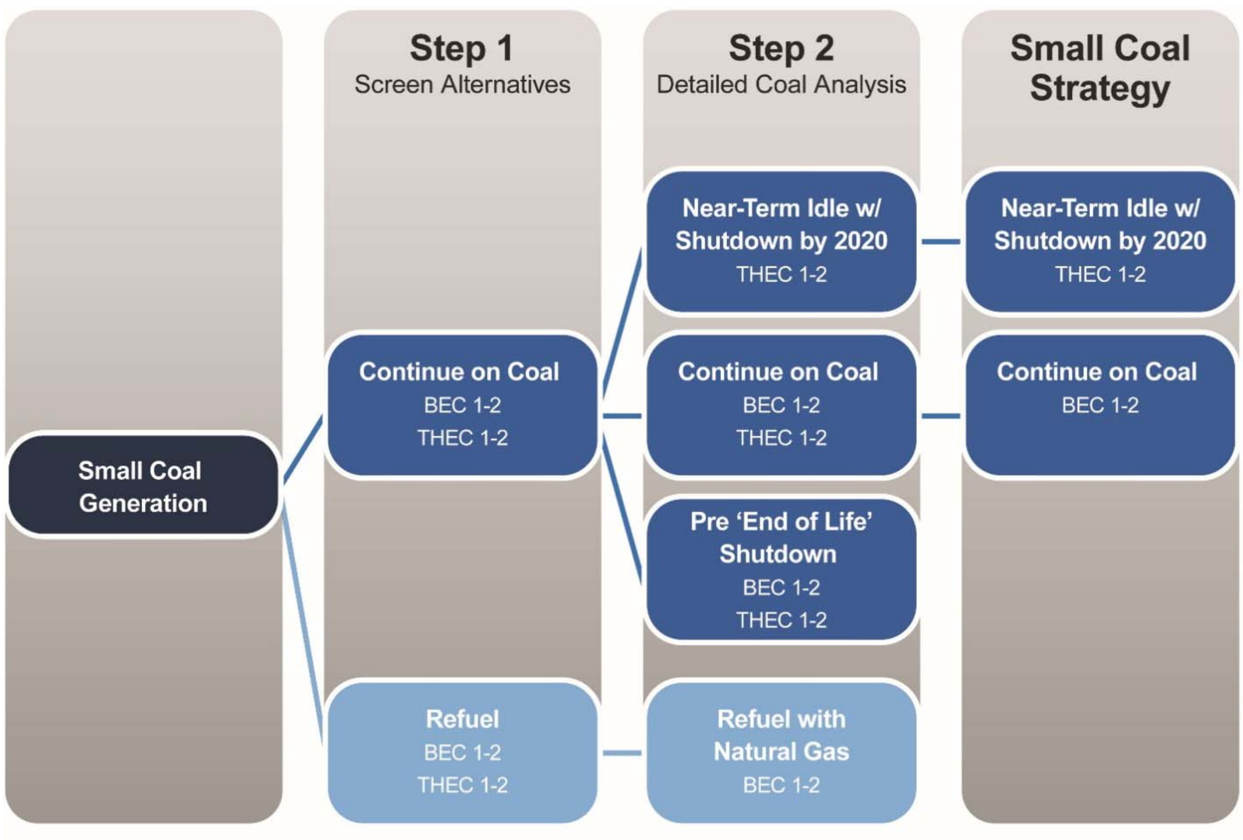
[44] Facility staffing will be reduced and call back and start up procedures will be in place to accommodate the need for plant operations.

Conclusions for Small Coal

Minnesota Power has evaluated specific strategies for its remaining small coal-fired fleet since its 2013 Plan. Under its most up-to-date outlooks and with engineering estimates taken into consideration, the Company is confident that its preferred Small Coal Strategy is the best path forward for customers at this time. Utilizing least cost alternatives, protecting affordability and moving toward the goals set in its *Energy**Forward*** strategy, Minnesota Power will idle THEC1&2 in 2016, and cease coal-fired operation by 2020. The Company will continue operation of its BEC coal-fired generation facility, while overall emissions will be reduced by idling THEC1&2. This is illustrated in Figure 17.

Minnesota Power recognizes that future environmental regulations could drive change in the resource decisions identified in the Preferred Plan. Since 2005, the Company has been transitioning away from 410 MW of coal-fired generation and the Preferred Plan is recommending an additional 150 MW of coal-fired generation be transitioned by 2020. This will result in 560 MW of coal-fired generation being removed from the power supply, which will well-position the Company for future CO_2 regulation and to achieve its *Energy**Forward*** vision. The Preferred Plan is Minnesota Power's next step to reducing coal-fired generation in the power supply while providing a cost-effective transition to a lower-carbon future.

Figure 17: Minnesota Power's Preferred Plan for Small-Coal Fleet

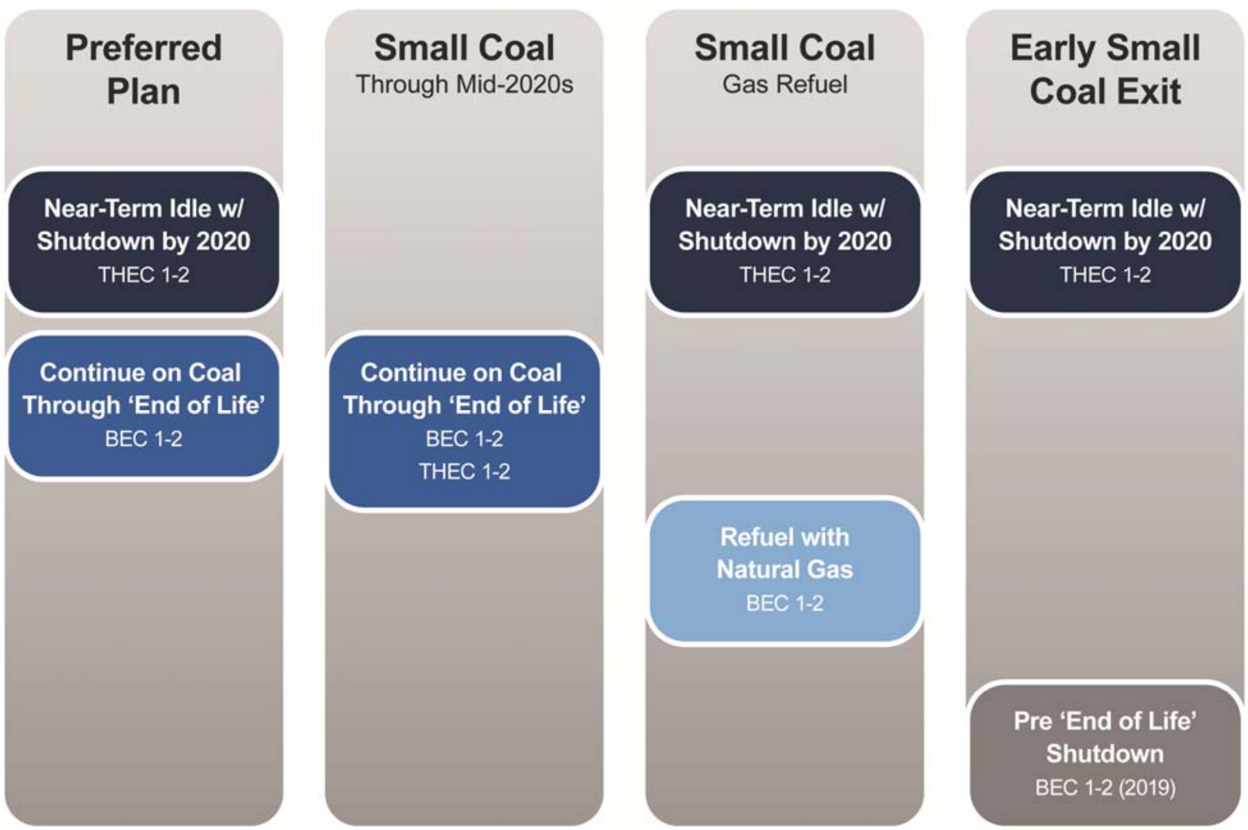


Alternative Swim Lanes for Small Coal Generation

The small coal evaluation above identifies a range of plausible futures for the Company's small coal fleet as these units transition to their end of useful accounting life. To recognize and more fully explore the outcomes of other transition plans, Minnesota Power incorporated into its expansion planning an evaluation of the other prevailing outcomes for its remaining small coal fleet. Stakeholders will be able to consider the impact of the Small Coal Strategy, and also three alternative paths or "swim lanes" for Minnesota Power's coal-fired facilities, as part of complete power supply portfolios that meet future customer requirements. The three swim lanes (illustrated in Figure 18) that were included into the remaining steps of the evaluation are:

1. "Small Coal Through Mid-2020s" --Continue to operate remaining small coal facilities through their end of life.
2. "Small Coal Gas Refuel" - Refuel BEC1&2 with natural gas and cease coal operations at THEC1&2 by 2020.
3. "Early Small Coal Exit" - Shutdown Minnesota Power's BEC1&2 and THEC1&2 by 2020.

Figure 18: Coal Strategy for Preferred Plan and Three Alternative Swim Lanes



The Analysis and Insight section will compare and contrast the swim lanes for Minnesota Power's small coal-fired fleet. First, expansion plans for additional resources that will augment the small coal strategy must be incorporated in order to create a complete set of power supply portfolios. The new resource selections that augment the Preferred Plan are discussed in the next two sections.[45]

Expansion Planning for New Generation Resources (Step 3)

Minnesota Stat. § 216B.2422 subd. 2 state," 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." As detailed on pages 37 - 40 of Appendix K, Minnesota Power based its new energy requirements on the generation set-up for the Base Case in Strategist, which is also the "Small Coal Through Mid-2020s" swim lane, prior to any new resources being added to the power supply. The evaluation was conducted with and without a CO_2 regulation penalty. The results showed that wind was the preferred renewable resource when 50 and 75 percent of new energy requirements must be met by a renewable resource (see Figure 27 on page 38 of Appendix K). Additionally, the results indicated that as more wind generation is added to the power supply the preferred natural gas resource can switch from an efficient CC to a more inefficient combustion turbine. Meeting the new energy requirements under the 50 and 75 percent renewable scenarios is more costly than the swim lanes identified in Section IV. Power supply costs are higher by approximately $10 million to $161 million.

Minnesota Power is committed to meeting a significant share of its new energy requirements with cost-effective, carbon-minimizing resources such as renewable generation and energy conservation. This is demonstrated through Minnesota Power's PPA with Manitoba Hydro for 250 MW of energy and capacity and an additional 133 MW of energy only beginning in 2020. Approximately 25 percent of the 1,000 MW of renewable generation and expanded energy conservation identified in the Company's Preferred Plan will be met by the hydro power from Manitoba Hydro which meets the definition of a renewable source under the resource plan statute.

Minnesota Power is considering many technologies to help serve its growing customer power requirements. DSM, energy efficiency, solar, wind, energy storage, biomass, traditional natural gas, and clean coal thermal generation are the major categories the Company is monitoring as emerging and improving technologies. Appendix K of this Plan identifies how Minnesota Power screens available alternatives for its resource planning evaluation. Through its 2015 Plan evaluation and resource screening, the Company identified that natural gas technologies (both small and large options) along with expanded DSM and energy efficiency will best position the Company to meet its growing power supply needs. These choices will continue to move Minnesota Power's portfolio towards its *Energy**Forward*** vision based on its guiding principles.

The range of technologies included in the expansion planning process does not indicate that Minnesota Power has a position on any particular emerging technology. In many cases, the Company supports further advancement of other developing technologies through regional

[45] The expansion plans that augment the alternative swim lanes are shown in Appendix K.

studies and academic research, some of which are described in Appendix D. Minnesota Power also pursues partnerships on DG projects, as described in Appendix B of this Plan. Resource options continually evolve, and for its 2015 Plan the Company utilized the lowest cost resources from each of the dispatchable, intermittent renewable and demand side options to help determine the best resources for its power supply needs.

For Step 3 - “Determine Expansion Plan”, the Strategist Proview software was used to determine expansion plan portfolios for all four swim lanes. Strategist allows a utility to offer many resource types into a production cost evaluation, and optimize the technologies that best fit to meet projected customer needs over a defined study period. The Company allowed Strategist to select from the following supply and demand side resource options:[46]

- 200 MW share of a natural gas-fired 2x1 CC
- 221 MW natural gas-fired combustion turbine
- 55 MW natural gas-fired reciprocating internal combustion engine
- 102 MW wind farm located in North Dakota.
- 50 MW solar farm located in central Minnesota
- 50 MW to 150 MW of bilateral bridge transactions
- DG and energy conservation programs:
    - Air conditioning load control and hot water load control
    - Up to 25 MW of customer-sited backup generation
    - Three levels of increased investment in energy efficiency[47]

The expansion plan optimization was conducted for both a $21.50 per ton carbon regulation penalty and no carbon penalty outlook. The CO_2 regulation penalty included additional costs on existing and new generating sources starting in 2019 of $21.50 per ton. As described above, Minnesota Power included both of these CO_2 penalty levels to clearly identify what expansion plan resource decisions are due to greenhouse gas regulation penalty, versus customer load requirements. The insights gathered from the expansion plan evaluation assisted in the Company’s selection of its recommended short and long-term action plans as part of its 2015 Preferred Plan.

Expansion plans were then created for 35 different sensitivities, including the required CO_2 regulation penalty ranges, delivered fuel costs and other key variables. This was done to understand how new resource selections differ due to changing factors. For a complete list of sensitivities, see Appendix J of this Plan. The insight gained by running multiple expansion plans over multiple sensitivities for the Preferred Plan is discussed later in this section.[48]

Each of the other three alternative swim lanes were evaluated in the same manner with a resulting expansion plan created for each. Appendix K provides the resulting plans for each

[46] Note that more than one of each resource option can be chosen during the optimization process. Also, the capacity listed is the installed capacity value for each resource.
[47] Appendix B provides additional details on the three energy efficiency scenarios utilized.
[48] The expansion plans that augment the alternative swim lanes are shown in Appendix K.

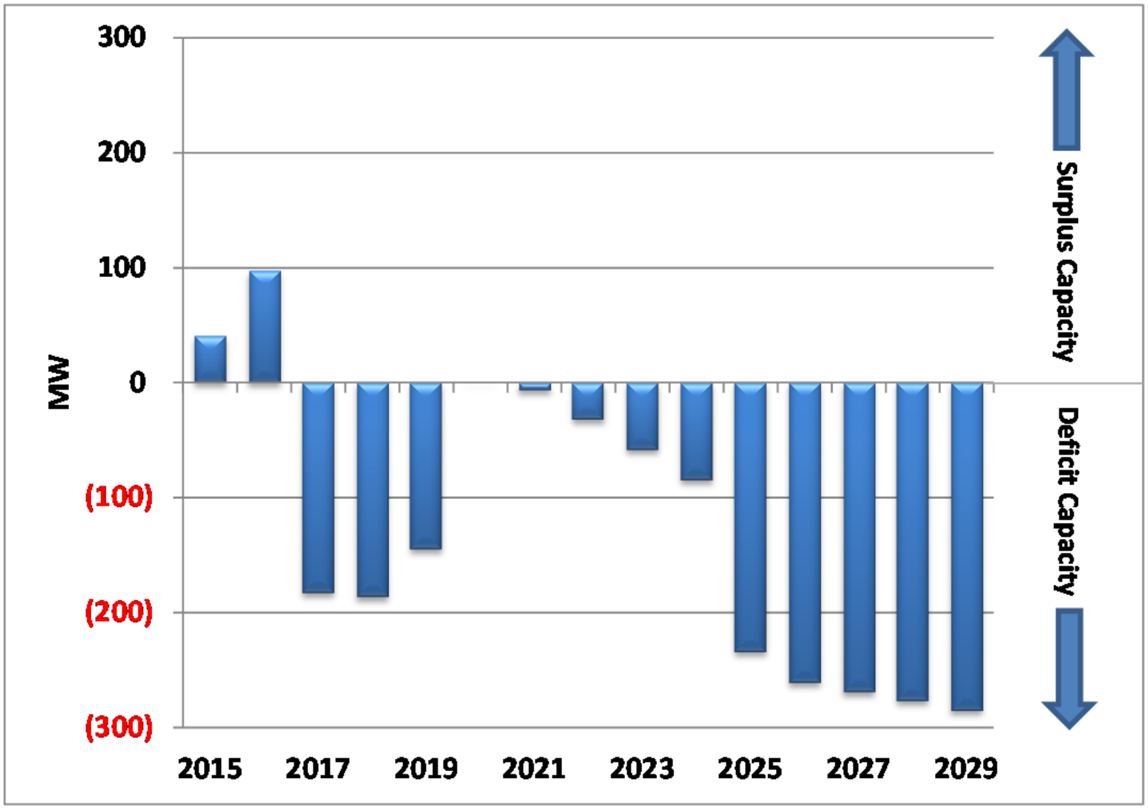
power supply portfolio. The portfolios were then compared and contrasted with the Company's Preferred Plan. Described below is the creation of the Preferred Plan followed by the "Analysis and Insights" section. A comparison with the other three small coal alternative swim lane portfolios is included to further justify Minnesota Power's short and long-term action plans.

Developing the Preferred Plan

Minnesota Power's Preferred Plan for its coal-fired generation results in approximately 140 MW less capacity available for meeting resource adequacy requirements. The resulting capacity position (surplus/deficit) provided in Figure 19 includes the near-term idle of THEC1&2, and eventual ceasing of coal-fired operation by 2020.[49] This new capacity position provided the starting point for the expansion planning (Step 3) portion of the evaluation.

[49] The full nameplate capability of THEC1&2 is approximately 150 MW; however, the UCAP for THEC1&2 is approximately 140 MW.

Figure 19: Updated Summer Season Capacity Position with Preferred Coal Strategy (No New Resource Additions)



Minnesota Power identified it would need approximately 200 MW of capacity from 2017-2019 due to the idling of THEC1&2. In 2020, the Manitoba Hydro 250 MW transaction begins bringing the power supply back to a neutral position before the next significant capacity need. The need for 200 MW to 300 MW begins in 2025 due to end of life of BEC1&2, and remains through the study period to 2029.

Table 5 provides the lowest cost power supply expansion plans for the Preferred Plan under both carbon regulation penalty levels, and the Winter Season Peak Demand sensitivity. This sensitivity was included to identify what resource expansion options would be different if the Company planned based on its own winter peak demand instead of the MISO summer peak demand. For the 2015 Plan, evaluation of the winter season peak did not provide any new resource selections compared to the summer coincident peak demand. This finding confirmed that Minnesota Power's recommended resource actions were robust under both seasonal peak considerations.

While additional detail is provided on each resource addition listed below, Minnesota Power's Preferred Plan is comprised of minimal resource additions in the first five years (2015 to 2019), relying on bilateral bridge transactions to meet customer needs until the Manitoba Hydro 250 MW and 133 MW purchases begin. After 2019, the addition of a clean and efficient natural gas resource (200-400 MW) is showing customer benefit across almost all sensitivities. Expansion of DSM, DG and energy efficiency options were also a prominent trend and are explained in more detail below.

Table 5: Expansion Plan Results for New Resource Additions with Preferred Plan (coal generation)

	Preferred Plan	Preferred Plan *if $21.50/ton CO_2 regulation penalty implemented*	Preferred Plan *w/ Winter Peak Demand*	Preferred Plan *w/ Winter Peak Demand + $21.50/ton CO_2 Regulation Penalty*
Short-Term (2015-2019) Actions				
Small Coal Shutdown/Refuel:				
THEC1&2 Idle by 2017	X	X	X	X
THEC1&2 Shutdown by 2019				
BEC1&2 Shutdown by 2019				
BEC1&2 Gas Refuel by 2019				
Resource Additions:				
Combustion Turbine				
2x1 Combine Cycle (partial share)				
Reciprocating Engine				
Solar				
Wind		X		X
Bilateral Bridge Transactions	X	X	X	X
DSM Additions:				
Back-up Generation Program	X			
AC Load Control				
HW Load Control				
Energy Efficiency	X	X	X	X
Long-Term (2020-2029) Actions				
Resource Additions:				
Combustion Turbine				
2x1 Combine Cycle (partial share)	X	X	X	X
Reciprocating Engine				
Solar				
Wind				
Bilateral Bridge Transaction				
DSM Additions:				
Backup Generation Program				
CAC Load Control				
HW Load Control				
Energy Efficiency				
Strategist Power Supply Cost 2015-2034 NPV:	**$7.54 B**	**$8.58 B**	**$7.56 B**	**$8.59 B**

The expansion plan for the Preferred Plan also highlights the extreme difference in power supply costs that a future carbon regulation penalty could bring to customers. Over $1 billion dollars is added to customers' power supply costs when the utility is required to pay a carbon regulation penalty on all CO_2 emitted. This significantly increases the cost of electricity for customers, and CPP framework does not place a value on CO_2.

For example, the expansion plan for a $21.50/ton CO_2 regulation penalty selects 205 MW of additional wind generation resource. In the same scenario with no CO_2 regulation penalty, there is no additional wind resource added. Wind is an energy only resource with minimal capacity credit. This expansion plan selection is solely a carbon penalty related resource addition, and would not be a necessary cost to customers without a CO_2 regulation penalty. The additional wind build would increase capital spend by [TRADE SECRET DATA EXCISED] for the power supply in 2019.

Due to a lack of clarity on pending carbon regulation at the time of the analysis, the Company did not force selection of wind additions in the near term. Minnesota Power's Preferred Plan still provides a power supply with 35 percent renewable energy by 2025, and is identified as the most economical path forward for customers. Additional detail is provided in the "Analysis and Insights" section below.

Natural Gas

Analysis performed for Minnesota Power's Baseload Diversification Study, 2013 Plan, and now the 2015 Plan consistently show that natural gas CC generation has a place in the long term power supply. The benefits for long-term power supply diversification are clear. The 2020 and beyond time period identified up to 400 MW of natural gas additions to augment a growing customer base and renewable power supply.

Natural gas fits well with intermittent generation like wind and solar. Natural gas is a flexible, fast-acting resource that can be present to deliver energy when wind and solar are not available. As Minnesota Power has already incorporated significant wind resources into its portfolio (over 600 MW in total) and is growing its solar portfolio, the addition of this more flexible technology is sensible and timely.

The expansion planning identified that an efficient and low cost natural gas resource, such as owning a portion of a 2x1 CC generating unit, should be considered over a combustion turbine. Hundreds of expansion plans developed over multiple sensitivities concluded that a share of 2x1 CC was included in the post-2020 period over 90 percent of the time. Minnesota Power's high load factor and energy intensive customers gain value from generating resources that can produce efficient, low cost energy. A new natural gas addition also positions Minnesota Power for future carbon targets and competitive markets.

The Strategist Proview results for the expansion plan analysis in Step 3 identify a 400 MW share of a 2x1 CC is needed. This quantity occurred because the resource was offered as 200 MW blocks and two blocks were required to meet the customer demand beyond the fifteen year planning period. After further review, it was identified Minnesota Power only needed 300 MW of capacity to meet needs through 2029. To better align the new resource additions with the projected capacity need for the 2015 Plan, the 2x1 CC included in the Preferred Plan was reduced from 400 MW to 300 MW.

The prevalence of the CC technology over the range of expansion plans solidified the resource selection for Minnesota Power's long-term plan. In order to prepare for the implementation of a resource of this magnitude, specifically when considering a partial participation scenario for the 2024 time period, the Company must begin resource investigation activity.[50] For its short-term action plan, the Company plans to begin a competitive procurement process for 200 MW – 300 MW of efficient natural gas CC generation. Implementation for this CC unit would take place by 2024. Actual procurement amount will vary based on continued updates to customer load outlooks and availability of competitive opportunities. The addition of a natural gas resource to Minnesota Power's energy supply portfolio will be subject to further Commission approval.

Wind Generation

Minnesota Power currently has over 600 MW of high capacity factor wind generation in its power supply. Absent any carbon regulation penalty, the analysis shows the lowest cost plan for customers does not include new wind generation at current cost (approximately [TRADE SECRET DATA EXCISED]). The analysis identified two primary factors that influence the economics of adding wind to the Company's power supply; inclusion and timing of a CO_2 regulation penalty, and project cost. As demonstrated in the expansion planning analysis, wind was shown economical for customers at the mid CO_2 regulation penalty level or greater. Regardless of CO_2 regulation penalty levels, wind was shown cost effective for customer post-2020 when wind costs are between [TRADE SECRET DATA EXCISED].

Minnesota Power is not recommending the addition of new wind for its 2015 Plan. Until there is more certainty on the timing and structure of a carbon regulation, or future wind costs in the post-2020 time period, the Company will remain flexible when considering additional wind. Adding wind could be economical for customers under certain power supply conditions. However, with an already 600 MW wind portfolio, a capital investment would be an unnecessary increase for customers at this time. The Company's *Energy**Forward*** strategy is positioning the power supply for a less carbon-intense future, and the Company does not need to take additional action at this time.

Bilateral Bridge Transactions

An important component of a utility's power supply is contracted purchases and sales, conducted to optimize the power surpluses and deficits that occur due to load and supply changes. These agreements are called bilateral transactions, and they allow Minnesota Power to work with other entities to procure energy and capacity from existing resources. See Appendix C, Part 2 for a list of the Company's current bilateral transactions, which were included in the Base Case.

[50] The expected implementation time frame for a large efficient CC is five to seven years.

A bilateral transaction is functionally different than the day-ahead regional energy and capacity markets represented by the MISO tariff construct. Bilateral transactions are typically forward, medium to longer-term contracts with defined pricing terms. Day-ahead markets operate in the 24-hour to 48-hour time frame with spot market prices (see Appendix J). Minnesota Power monitors the bilateral power markets to identify opportunities to contract with other entities when it is in the best interest of its customers. In the Preferred Plan, a short-term bilateral bridge purchase will allow the Company to flexibly idle THEC1&2 in the near-term and delay further investment in new generation resources until 2024, when a natural gas CC resource is recommended. The bilateral bridge transactions provide significant savings to customers when compared to a wholly-owned resource. These purchases also provide near-term stability in power supply costs for customers.

Bilateral purchases have a distinct role in meeting energy needs, and are not a standing approach to supplying customers over the long-term. Rather, they are distinct opportunities for very economical shorter-term (typically three to five year) additions to the power supply. The bilateral bridge strategy of using stably priced bilateral purchases with strong counterparties helps mitigate electricity requirements and supply allows for certain flexibility as large new customer loads are introduced on Minnesota Power's system.

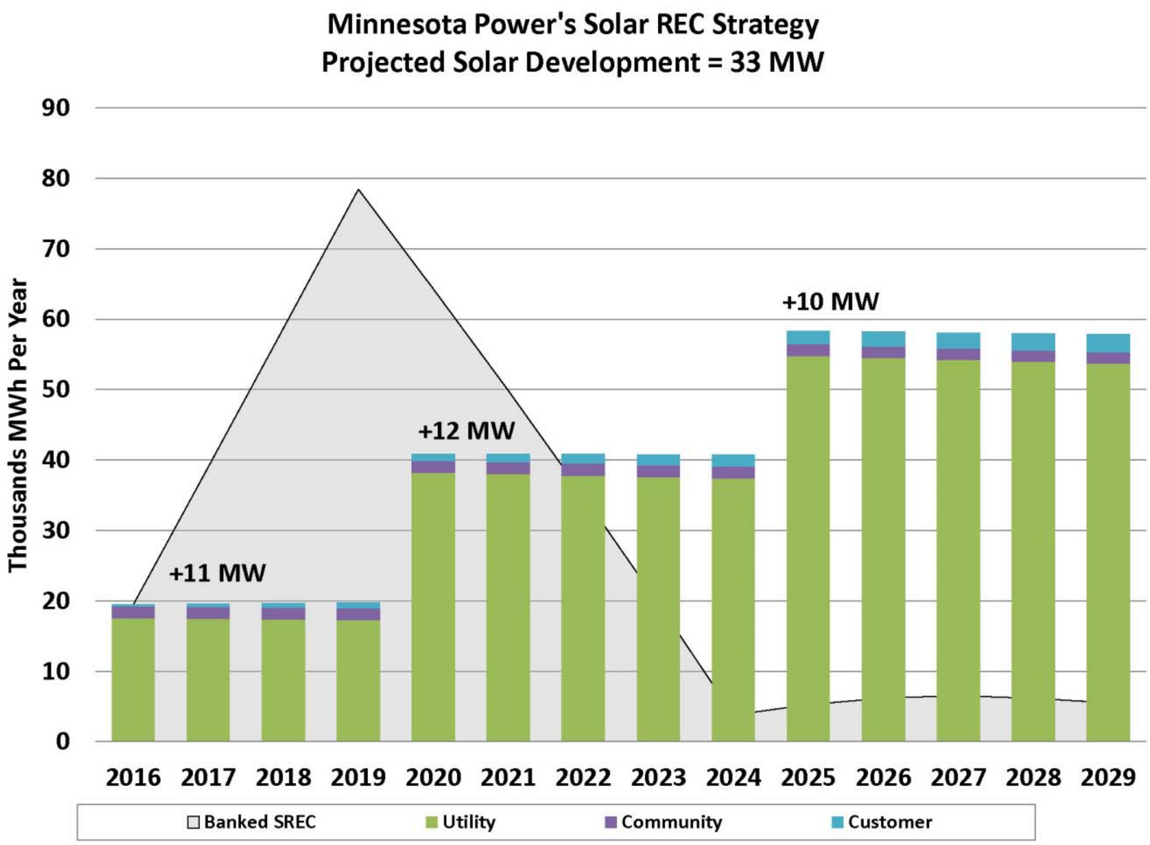
As with the 2013 Plan, the Company is recommending that additional bilateral bridge transactions be utilized to optimize its flexible operation of THEC1&2 in the 2017 to 2020 timeframe. As these units are transitioned away from coal-fired generation and the Company finalizes its plans for a natural gas resource in the 2024 timeframe, these purchases will be required.

Solar Generation

Minnesota Power has outlined a broad solar strategy to meet the estimated SES requirement in 2020. See Appendix H of this Plan for more details.[51] Utilizing its customer, community and utility focus, the Company will leverage multiple sizes and types of solar energy to meet the projected requirements. In 2016, Minnesota Power will implement a 10 MW solar array located at Camp Ripley near Little Falls, Minn.[52] The Company will also bring forward a unique community solar pilot program to augment its successful customer incentive programs already in place. In total, Minnesota Power is estimating 33 MW of solar resource additions, as part of its strategy to meet and sustain the 2020 requirement.[53]

[51] Docket No. E999/M-15-462.
[52] Docket No. E015/M-15-773.
[53] The solar strategy of incorporating 33 MW of new solar resource for the SES requirement is included in the Base Case for the 2015 Plan.

Figure 20: Minnesota Power's Solar Resources to Fulfill Solar Energy Standard



Adding new solar generation beyond Minnesota Power's current strategy was not prevalent in the expansion planning evaluation, and is shown as a less cost-effective resource alternative for customers. The solar generation characteristics do not align well with the energy needs of the Company's customers. Minnesota Power has a high load factor due to the high concentration of industrial load on the system and energy supply is required around the clock. The Company has a winter peak that normally occurs during the evening when the sun is less available. This limits the peak following benefit of solar to only the summer months when Minnesota peak demand is more aligned with neighboring utilities.

Minnesota Power recognizes that solar technology is continuing to become more efficient, and costs are declining. At the right cost level, solar could begin to show a benefit to customers in the expansion planning process. To understand at which cost level solar is selected in the expansion plans for customers (above the 33 MW of solar included in the Base Case) a sensitivity was included that varied the cost of solar in $5/MWh increments from $75/MWh to

$90/MWh.[54] Solar that was priced in the [TRADE SECRET DATA EXCISED] range started to show economic benefit for customers in the mid-2020s. Most expansion plans in this solar cost range identified an additional 50 MW of solar. Adding solar in the short-term action plan period (2015-2019) showed no benefit to customers at the cost ranges studied. Given that at certain cost ranges solar starts to show a benefit for customers during the study period, Minnesota Power will continue to evaluate new solar technology trends in future resource plans to identify when it will augment the power supply with additional solar.

Demand-side Management

Minnesota Power currently has a significant amount of DSM capability (over 100 MW) on its system. Existing programs include partnerships with large industrial customers, and dual fuel rate programs with residential and commercial customers. These existing programs are a valuable component of Minnesota Power's least cost supply strategy, and help to ensure the reliability of the regional power system.

The Company is investigating additional demand response opportunities in the 2015 Plan through the evaluation of two peak-shaving programs for central air conditioning ("CAC") customers and electric hot water ("HW") customers. Minnesota Power's load forecast process identified an increasing trend in air conditioning saturation for its customers. Typically a winter peaking utility, the Company previously focused its residential and commercial demand response programs on the electric heating characteristics of its load. However, with the emerging air conditioning trend, a CAC interruption program could provide benefit to the power supply. The HW demand on Minnesota Power's system has also been increasing over the past years and was explored further in the analysis for this Plan. Through a preliminary design process identified in Part 3 of Appendix B, Minnesota Power created a CAC cycling and HW cycling program for consideration in its expansion planning:

- Based on the CAC peak-shaving program design and the current projection of CAC saturation on Minnesota Power's system, there is an estimated 7 MW available for this type of program by 2020. The net present value of the sample CAC cycling program's costs is estimated to be $1,460/kW, as described in Appendix B.
- Based on the HW peak-shaving program design and the current projection of HW saturation on Minnesota Power's system, there is an estimated 7 MW available for this type of program by 2020. The net present value of the sample HW cycling program's costs is estimated to be $1,929/kW, as described in Appendix B.

The CAC peak-shaving program shows promise as a new DSM option when compared to the HW peak shaving program. At this time the CAC program was not selected for customers in the expansion planning analysis for the 2015 Plan; therefore no peak-shaving programs were included in the Preferred Plan. However, as energy markets begin to rise again and program costs become more efficient, this type of program can be beneficial and will be monitored for implementation in future plans.

[54] The range in solar cost used for these sensitivities is lower in cost than the current planning estimate used (see Appendix J).

The initial design and investigation of CAC and HW cycling programs is a good example of how Minnesota Power is working to identify beneficial DSM options for its customers. Along with a strong dedication to conservation, the Company has a significant amount of DSM capabilities developed through longstanding commitment and relationships with its customer base. Minnesota Power will continue to work to identify reasonable additions to its DSM programs that benefit customers and provide power supply efficiencies.

Distributed Generation Programs

Minnesota Power has approximately 280 MW of distributed generation interconnected to its system (Appendix C, Part 3). The technologies include wind, solar, and combined heat and power. The Company has identified a new distributed generation opportunity that utilizes customer sited backup generation to provide up to 25 MW of nameplate capacity and emergency energy for the power supply. This new program concept gives the customer the option to add backup generation technology on site for a monthly demand fee to provide sustainable energy during distribution outages. Because the new backup generation will provide capacity and emergency energy to the larger power supply (when the distribution system is intact), part of the program cost will be funded by Minnesota Power customers. The customer receives the benefit of having a generator located on site to serve their energy needs when and if the utility is unable to serve them. The capital cost the customer would pay is comparable to adding a small peaking unit to the power supply (see Appendix J). The backup generation program was modeled in two phases, 8 MW by 2017 and an additional 17 MW by 2019. Each phase was modeled as a separate resource option to identify an optimal size for a pilot program. The backup generation program showed benefit to customers and therefore, approximately 8 MW from the first phase of the program are included in the Preferred Plan.[55]

Energy Efficiency

Minnesota Power is a state leader when it comes to meeting the 1.5 percent savings goal implemented in 2010 as part of the Next Generation Energy Act of 2007. Since 2010, the Company achieved first year savings that ranged between 60,000 MWh to 78,000 MWh, with an average first year cost of $0.09 per kWh. The Company remains dedicated to continuous program improvement and views ongoing energy efficiency initiatives through its utility sponsored CIP as a strong component of its broader *Energy**Forward*** strategy. Minnesota Power has evaluated past CIP program performance, related success factors, and potential future opportunities to determine scenarios that would help meet the Company's resource planning goals, while continuing to comply with the State's CIP specific requirements related to the 1.5 percent energy-savings policy goal.

The Company's approach to developing scenarios for increased levels of planned energy efficiency included analysis and research, which provided insight into historical performance, future opportunities, and the changing energy efficiency environment in which the Company operates. As identified in Appendix B of this Plan, three scenarios of incremental energy and

[55] Given the uncertainty of the demand for customer-sited backup generation only the first phase of the program (8 MW) was included. If customer interest is greater, Minnesota Power can adjust its capacity requirements in future resource plan filings.

capacity savings to the existing plan were developed: 11 GWh, 15 GWh or 30 GWh per year, resulting in aggregate capacity savings by 2025 of approximately 20 MW, 25 MW and 50 MW, respectively. The levelized first year savings of the three incremental energy efficiency programs are shown in Table 6.

Table 6: Incremental Energy Efficiency Programs First Year Cost Levelized Over Life of Programs

($/MWh)	11 GWh	15 GWh	30 GWh
Levelized First Year Cost Over Life of Program	$32	$36	$45

Strategist compared the incremental energy and capacity saving programs to other supply side resources such as new natural gas-fired CC to determine the lowest cost option for meeting future customer needs. The incremental energy efficiency programs showed benefit for customers, and were selected at various levels in the majority of expansion plans evaluated. To capture this trend and the expected benefits of energy efficiency, an incremental increase in program spending from current program levels is included in the Preferred Plan.

Although the other scenarios contemplating even higher levels of incremental savings were also prevalent in the expansion plans, they were not included in the Preferred Plan. This was done due to a high degree of risk associated with assuming historical performance of energy efficiency programs are sustainable, and that significant new savings can be found each year to accumulate high levels of aggregate capacity in the long term expansion plan. Relying on significant levels of energy and capacity savings to defer large long term resource decisions could put maintaining reliability and affordability for customers at risk. In the event that the energy efficiency programs do not perform as projected, additional power supply would be required, and large resource additions take years to implement.

Minnesota Power continues to support energy efficiency to promote customer energy savings. However, the Company will proceed cautiously as it incorporates the concept of new programs as a replacement for supply-side resources. As part of its short-term action plan, Minnesota Power included additional support of energy efficiency programs for customers to augment its already high-performing programs in place.

The expansion planning analysis provided key insights to the Company as it developed its Preferred Plan, and committed to its short and long-term action plans. The following actions provide a responsive set of resource and demand-side options to meet stakeholder requirements, and work to maintain Company values of finding a balanced, reliable and affordable power supply portfolio.

<u>Short-term Action Plan:</u>

- Idle operations at THEC1&2 in October 2016 and maintain availability for seasonal reliability needs.
- Cease 150 MW coal operations at THEC1&2 by the end of 2020 and evaluate viability to refuel, repurpose or retire the THEC facility in the next resource plan.

- Continue engineering and design planning for additional SO_2 reduction at BEC1&2 for 2018 project implementation.
- Consider additional investment in enhancing energy efficiency conservation programs.
- Implement a backup generation pilot program for approval and customer implementation.
- Begin the competitive procurement process of efficient 200-300 MW natural gas CC generation supply for implementation by 2024.
- Implement additional solar resources in each of the three pillars of its solar energy strategy – utility, community and customer. Add 10 MW utility scale solar at the Camp Ripley, and implement a unique community solar program by end of 2016.

Long-term Action Plan:

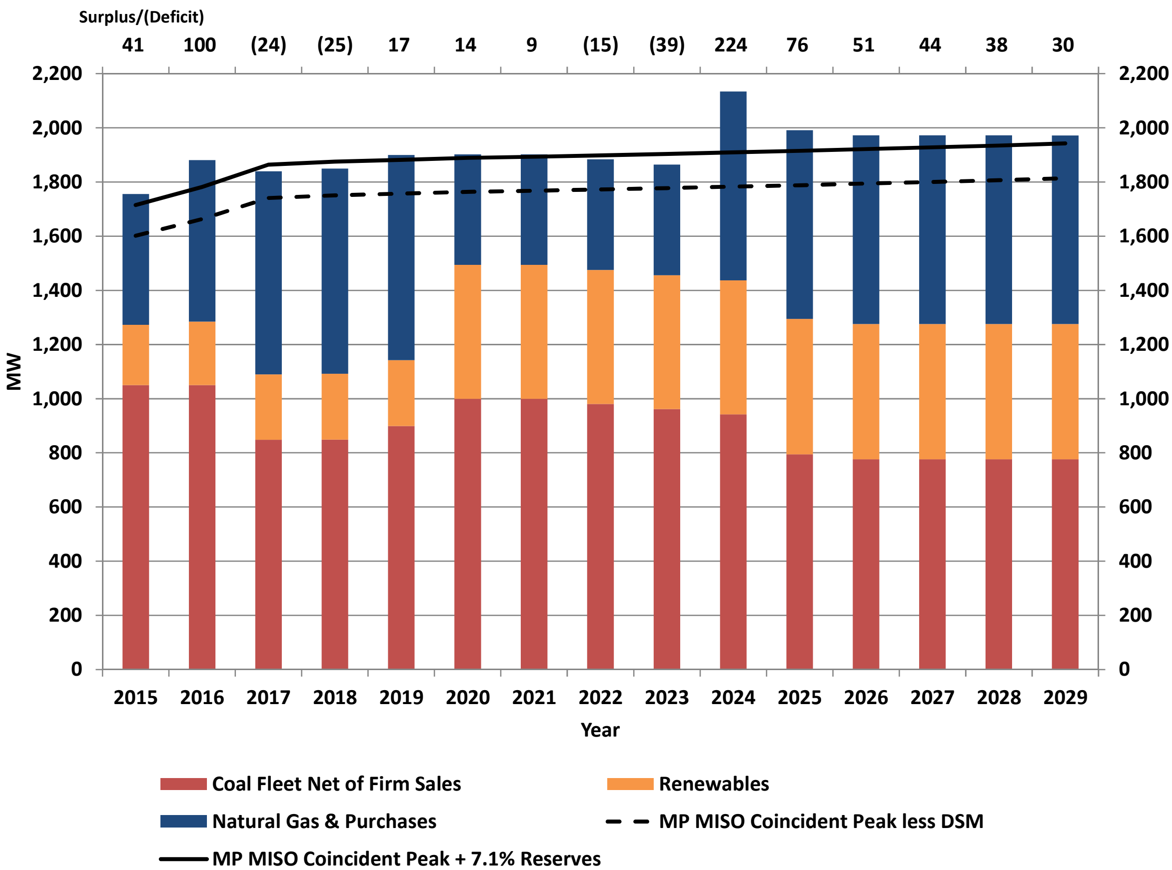
- Continue implementation of the 250 MW and 133 MW Manitoba Hydro PPA and GNTL in the 2020 timeframe (383 MW).
- Optimize the timing of implementing the remaining 22 MW of new solar projects to meet the SES, as well as monitor solar energy trends to identify when it is economical to augment the power supply with additional solar.
- Reduce the Minnesota Power off-take of the Young 2 resource from 100 MW to zero by 2026.
- Minnesota Power will continue to closely assess BEC1&2 economics during this period to determine the units' competitive position by 2025.
- Secure and implement 200-300 MW natural gas CC by 2024.
- Continue to enhance and create additional customer product options through integrated and coordinated distribution, transmission and power supply planning.

Characteristics of Minnesota Power's Preferred Plan

The Preferred Plan continues the transition of Minnesota Power's fleet to be more diverse, flexible and lower emitting. To accomplish this, the Company is taking major steps that address a changing energy industry environment. The Preferred Plan implements both capacity and demand-side resource changes that will provide a more balanced supply portfolio, with reasonable cost increases for customers reaching 45 percent coal-fired generation by 2025, down from 95 percent in 2005. The 2015 Plan will move Minnesota Power toward its *Energy**Forward*** vision, and a power supply that is made up of a third renewable, a third coal-fired, and a third natural gas and purchases over the long term. The Preferred Plan protects affordability, preserves reliability, and sustains environmental stewardship.

Figures 21 and 22 demonstrate the resulting capacity and energy position of the Preferred Plan. The 2015 Plan reduces coal-fired generation by an additional 150 MW on top of the 410 MW committed through Minnesota Power's 2013 Plan. Incorporating all the action items above brings the Company's capacity position into compliance with future resource adequacy requirements.[56] The capacity and energy outlook serves customer requirements with minimal market reliance while abiding by the Company planning principles.

Figure 21: Preferred Plan Summer Season Capacity Outlook



[56] Minnesota Power recognizes the current outlook identifies a significant surplus in 2024 as the new natural gas generation is incorporated. Final timing and amount will be solidified as part of the competitive bidding process.

Figure 22: Preferred Plan Energy Position Outlook[57]

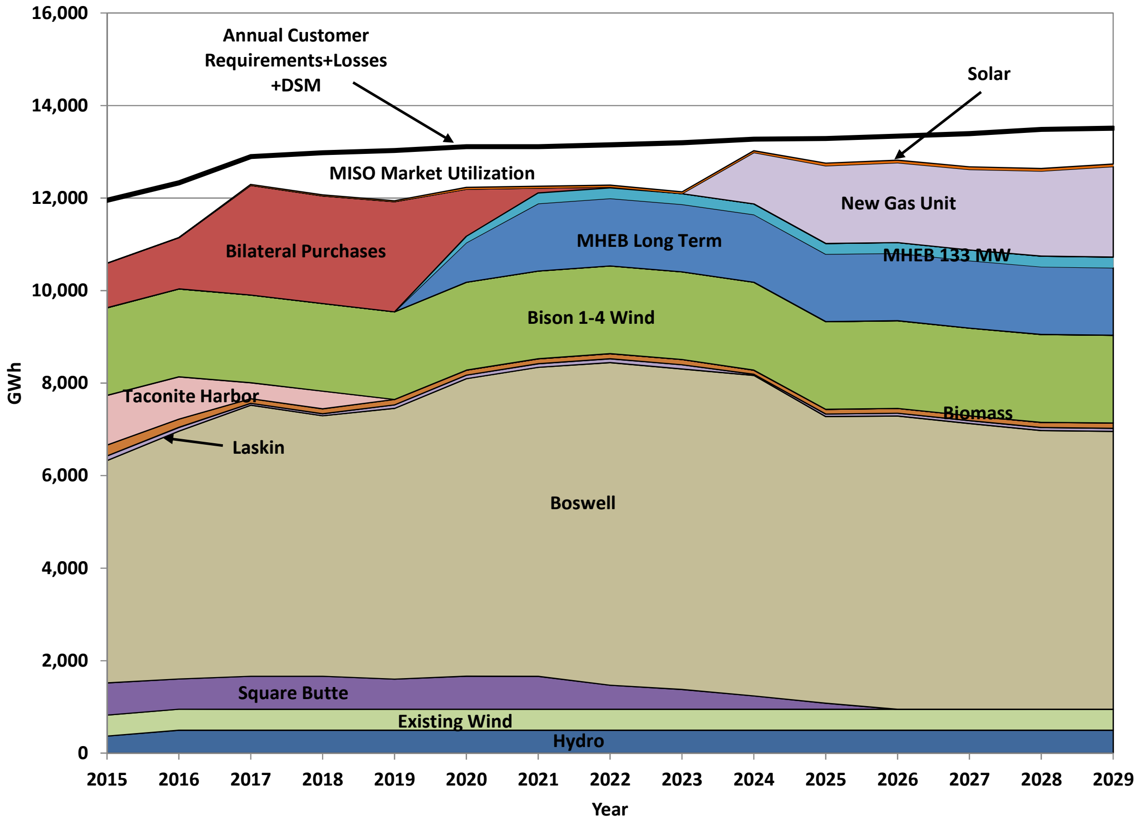
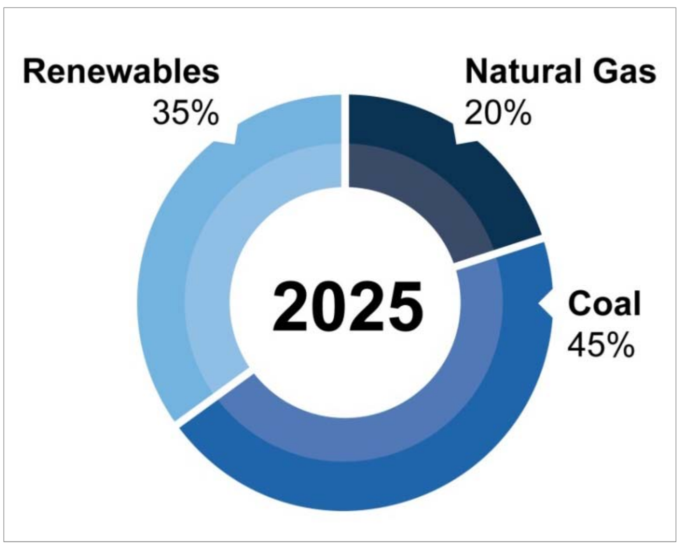


Figure 23: Preferred Plan Power Supply Mix in 2025



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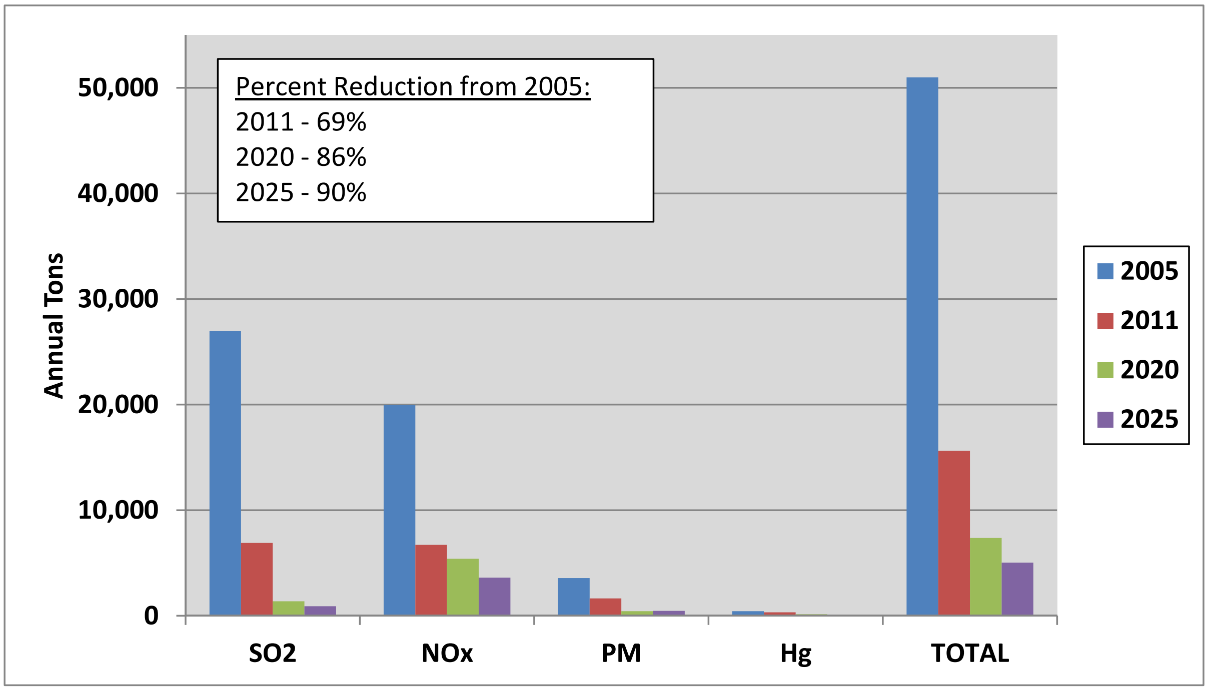
57 This energy position represents the full capability of energy sources in Minnesota Power's Preferred Plan. Actual dispatch will vary in real time operations.

The Preferred Plan brings Minnesota Power additional diversity to its power supply mix, reducing coal below 50 percent and augmenting both the renewable and natural gas components.[58] The new power supply mix brings the Company one step closer its vision for one-third coal, one-third renewables and one-third natural gas (Figure 23). Representing a dramatic and responsive shift from a 95 percent coal-fired portfolio as of late 2005.

Environmental benefits are inherent in this transformation and help position the power supply for future regulations. Minnesota Power will achieve immense environmental reductions by 2025 with the implementation of the Preferred Plan – since 2005 and incorporating the *Energy**Forward*** vision there will be a reduction of 90 percent in overall emissions (Figure 24) and a reduction of over 88 percent for key air effluents like SO_2 and mercury (see Figure 25 and 26).

Figure 24: Emission Reductions Achieved and Projected with Preferred Plan



[58] The power supply mix is established by quantifying the energy production from Minnesota Power's portfolio in 2025, assuming no carbon tax penalty is present.

Figure 25: Mercury Reductions Achieved and Projected with Preferred Plan

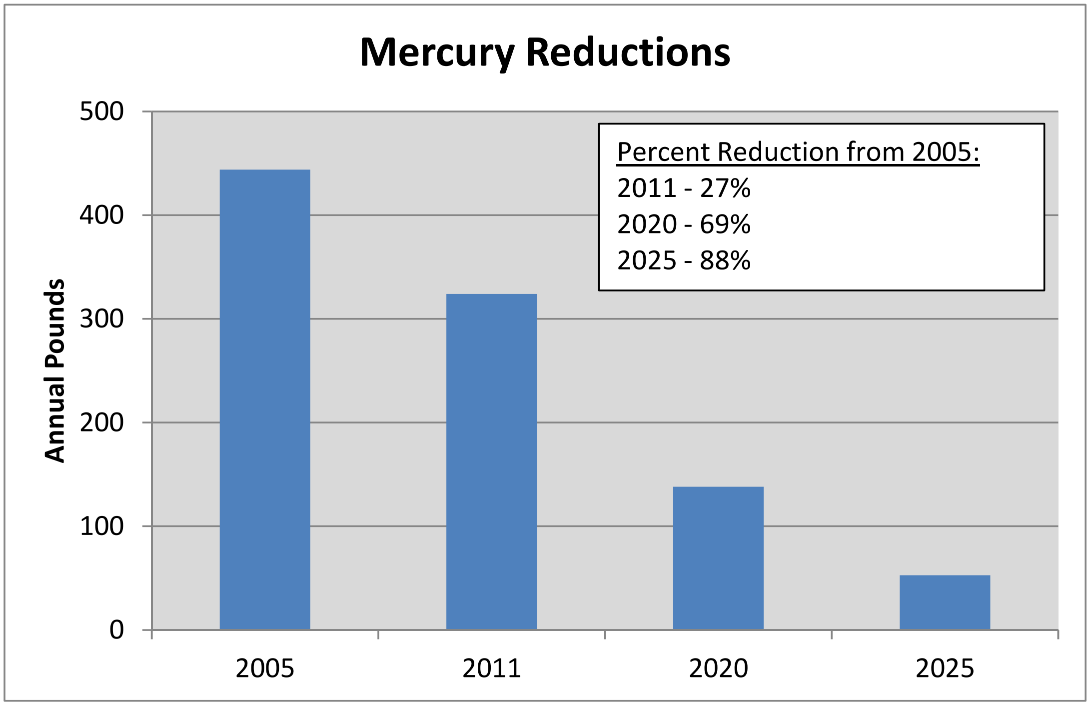
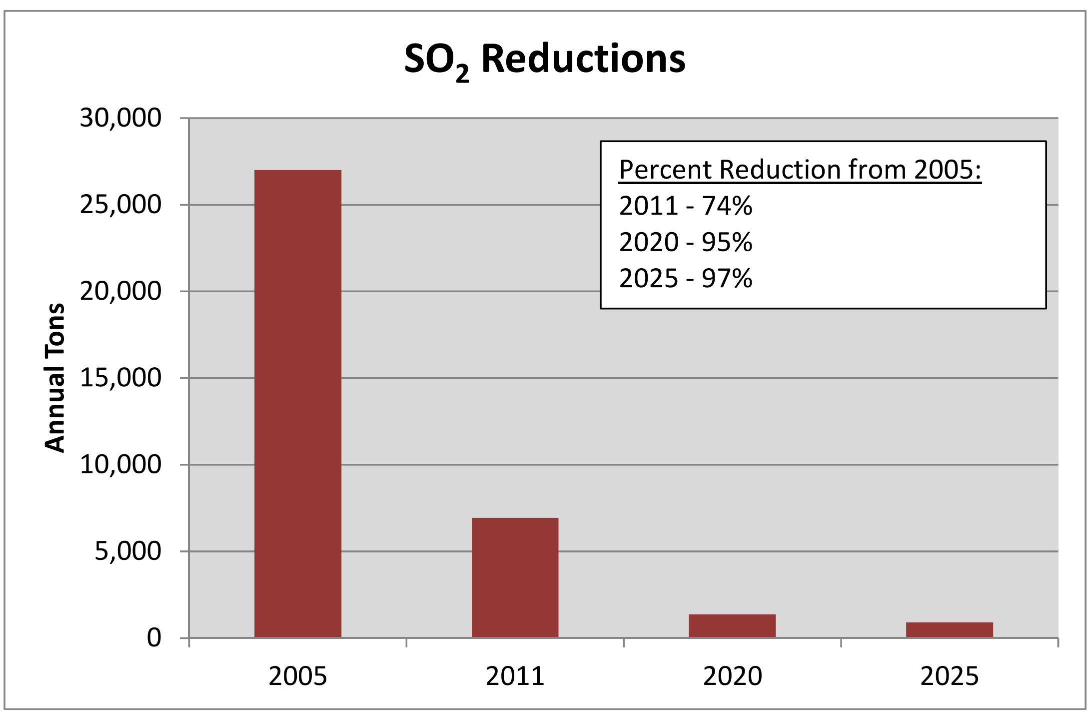


Figure 26: SO_2 Reductions Achieved and Projected with Preferred Plan



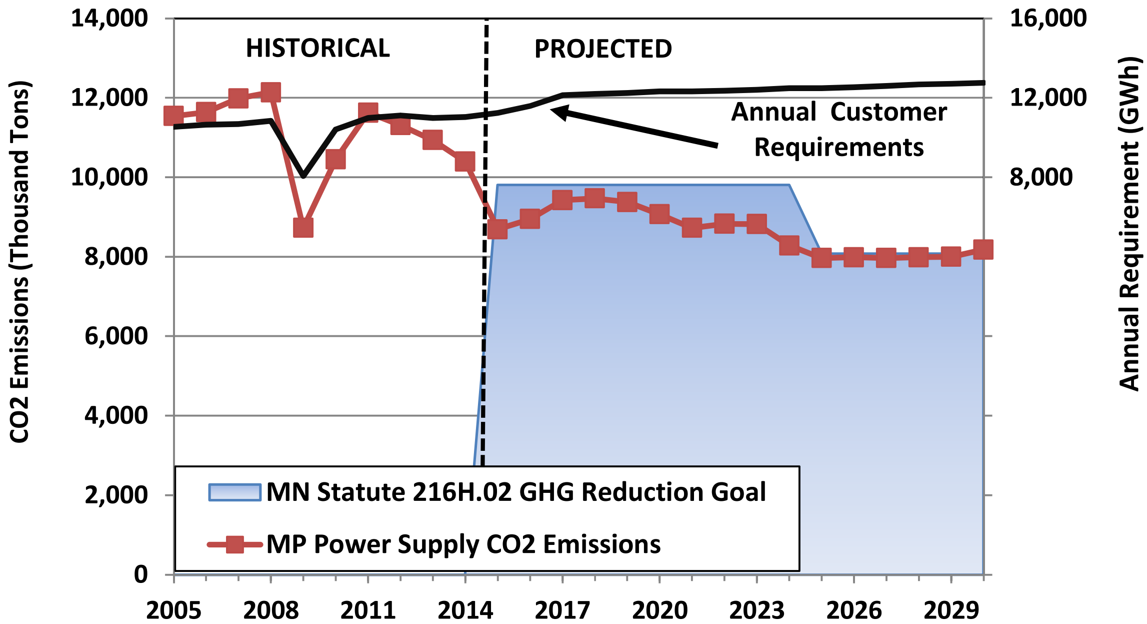
Since 2005, the Company has committed to add only carbon-minimizing resources to its generation fleet. As load continues to grow, Minnesota Power has kept to this strategy and is continually reducing the carbon intensity of its power supply. With the Preferred Plan, nearly 2,000 MW of generation reshaping will take place for the Company's supply portfolio by 2026:

- Adding Renewable Energy
  - Wind (over 600 MW)
  - Solar (33 W)
  - Manitoba Hydro (383 MW)
  - Rebuild of Thomson Hydro Station(70 MW)
- Reducing Coal-fired Generation
  - Phase out of power purchase from Young 2 (227 MW)
  - Refueling LEC (110 MW) with natural gas
  - Ceasing coal operations at THEC facility by 2020 (225 MW).
- Adding Natural Gas
  - Combined Cycle by 2024 (300 MW)

These actions represent a significant transformation to less carbon intense resources for a utility with a current peak demand of about 1,800 MW. Minnesota Power is well positioned to demonstrate its carbon reduction impact. Specifically, the Company is projecting full compliance with the Minnesota state goals for greenhouse gas reduction, and will exceed the 2015 goal of a 15 percent reduction from 2005 levels and the 2025 goal of a 30 percent reduction from 2005 levels (Figure 27). While executing these reductions, Minnesota Power is planning for its largest growth in industrial customers since the late 1970s.

Minnesota Power remains committed to its planning principle of finding less carbon intense resources. The Company will undoubtedly need to evaluate additional resource actions in the post-2020 time period, as environmental regulations continue to evolve and clarity on the CPP is obtained. However, Minnesota Power's cumulative resource actions, including those in the Preferred Plan, will already reduce greenhouse gases by 30 percent by 2025; well positioning its customers to meet future greenhouse gas regulations.

Figure 27: Greenhouse Emission Reductions Achieved with Preferred Plan



Customer Cost Impact of Preferred Plan

Minnesota Power was asked in Order Point 5.f. of the Commission's May 6, 2011, 2010 Plan Order[59] to include a "cost impact analysis by customer class" in its 2013 resource plan. The Company is providing an update to the cost impact analysis in Appendix L of this Plan. The intent of the analysis is to help stakeholders identify how the proposed power supply actions could potentially impact their electricity costs into the future.[60] Minnesota Power worked diligently to identify the most efficient way of translating the forward-looking cost projections into an estimate for each customer class. Appendix L describes the methodology used to develop the calculations and includes projected customer cost detail for the Preferred Plan and swim lane alternatives.

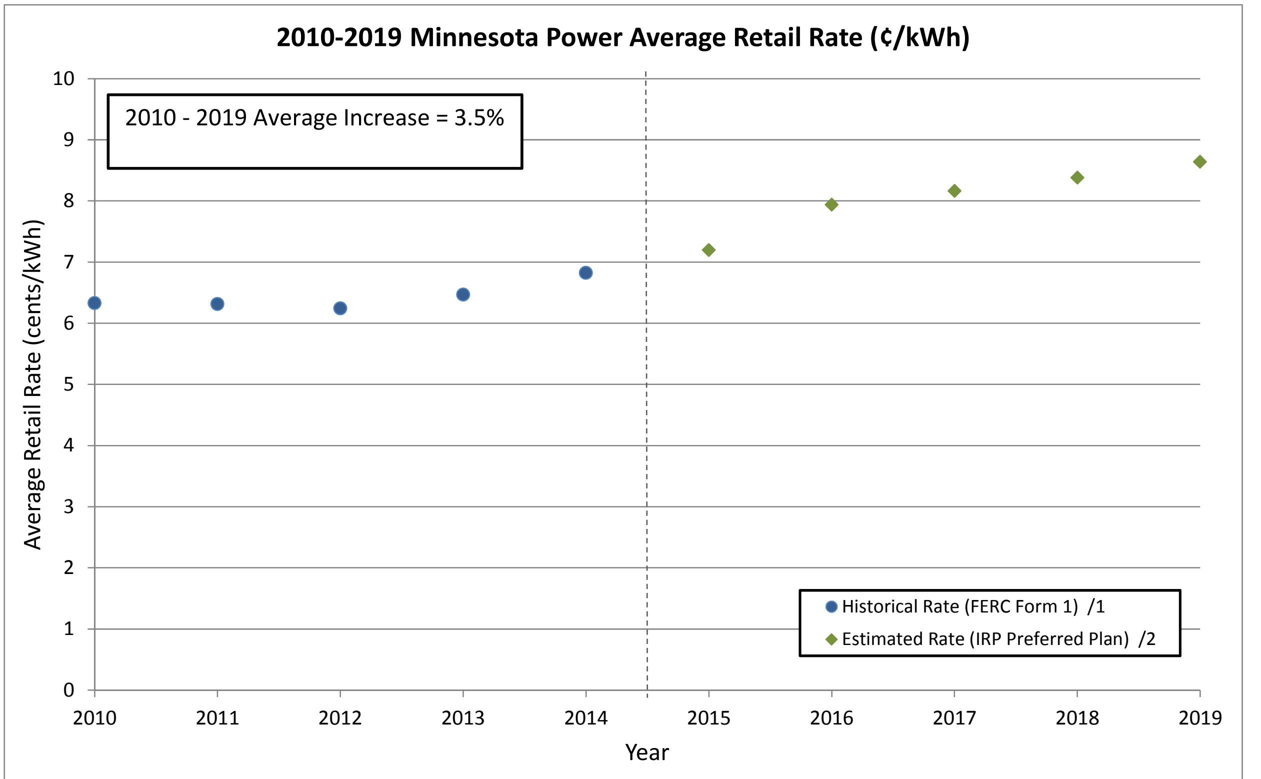
For purposes of this analysis, the terms "cost impact" and "rate impact" are assumed to have the same meaning. However, the estimated rate impacts may not correspond with actual rates that the Commission sets for various rate classes in the future. In addition, numerous simplifying assumptions have been made in both the calculation methodology and the input variables, and these assumptions naturally cause imprecision in the estimates. Long-term resource planning is inherently uncertain, rather directional, and therefore causes additional uncertainty in these resulting rate impacts projections.

[59] Docket E-015/RP-09-1088.

[60] Minnesota Power utilized a five-year forward look for the rate impact estimation, as further projection would carry a significant level of uncertainty and be less meaningful for customers.

Power supply costs have inherently been increasing across the industry as new requirements and infrastructure are being incorporated. Minnesota Power has been diligent in its effort to protect affordability for its customers and has maintained some of the lowest electricity rates in the nation.[61] The Preferred Plan was evaluated to determine the potential future impact on average retail rates. The results indicate that future cost increases through 2019 would trend similar to the cost increases in recent history. However, customers have seen a nearly 50 percent increase in rates since 2004. Implementation of the Preferred Plan is not indicating a dramatic shift in rates, as can be the case during significant power system transformations. The need to minimize cost increases cannot be understated, especially for the Company's largest energy intensive and trade-exposed customers. Figure 28 plots the recent average retail rates and identifies that an average 3.5 percent annual increase would be plausible if perfect ratemaking were to take place in the next five-year timeframe.

Figure 28: Average Retail Rate Recent History and Outlook with Preferred Plan



1/ The historical rates are based on revenue and energy sold reported in FERC Form No. 1, Page 304. Beginning in 2010, Transmission and Renewable Resources Rider revenue collected from customers was no longer reported on Page 304. As a result, cash collected from customers under these riders was added to the Page 304 revenue to determine the average retail rates for 2010 - 2012.
2/ Estimated rates for 2015 -2019 were estimated by adding incremental IRP Power Supply costs to existing base rates and cost recovery rider revenue requirements. Refer to Appendix L for details.

[61] Minnesota Power has most recently been noted as having the second lowest electricity rates out of 169 utilities by the Edison Electric Institute and second lowest in the region consisting of Iowa, Kansas, Minnesota, Missouri, North Dakota, South Dakota and Wisconsin.

To gain granularity and meet the intent of the Commission request and stakeholder interest, the rate impacts were estimated by customer class for the 2015-2018 time period (see Appendix L). As new resources are added as part of the Preferred Plan there are year-to-year fluctuations in costs. The resulting 2019 increases (compounded from 2015 levels) are identified in Figure 26 along with an estimate of the average customer impact per month in each class. For context, Figures 29-32 shows a comparison of Minnesota Power's electric rates to regional and national averages. Minnesota Power has very competitive rates for residential, commercial and industrial customers (Figures 30-32) when compared to regional and national rates.

Figure 29: Estimated Rate Impact Outlook by Customer Class

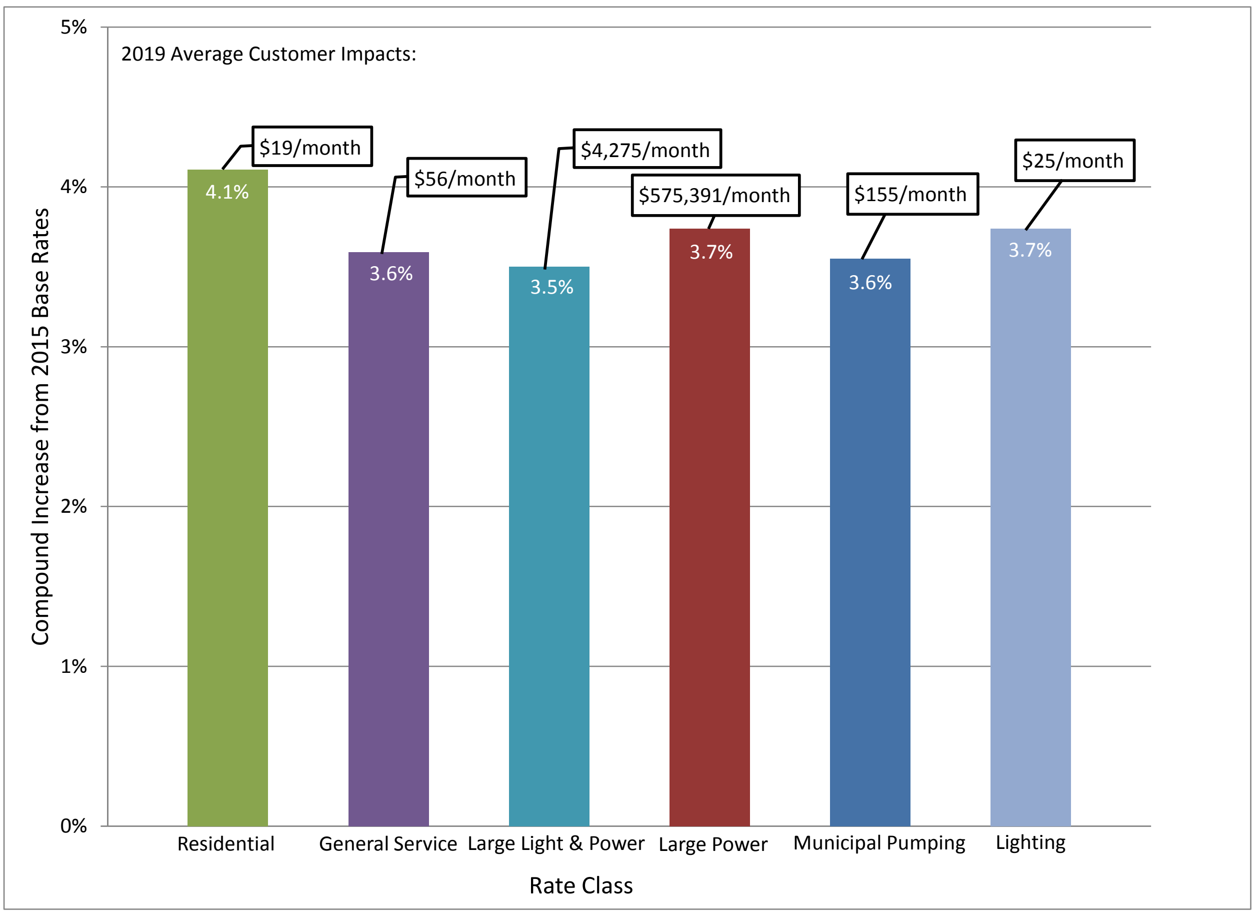


Figure 30: Regional and National Comparison of Residential Electric Rates in 2014

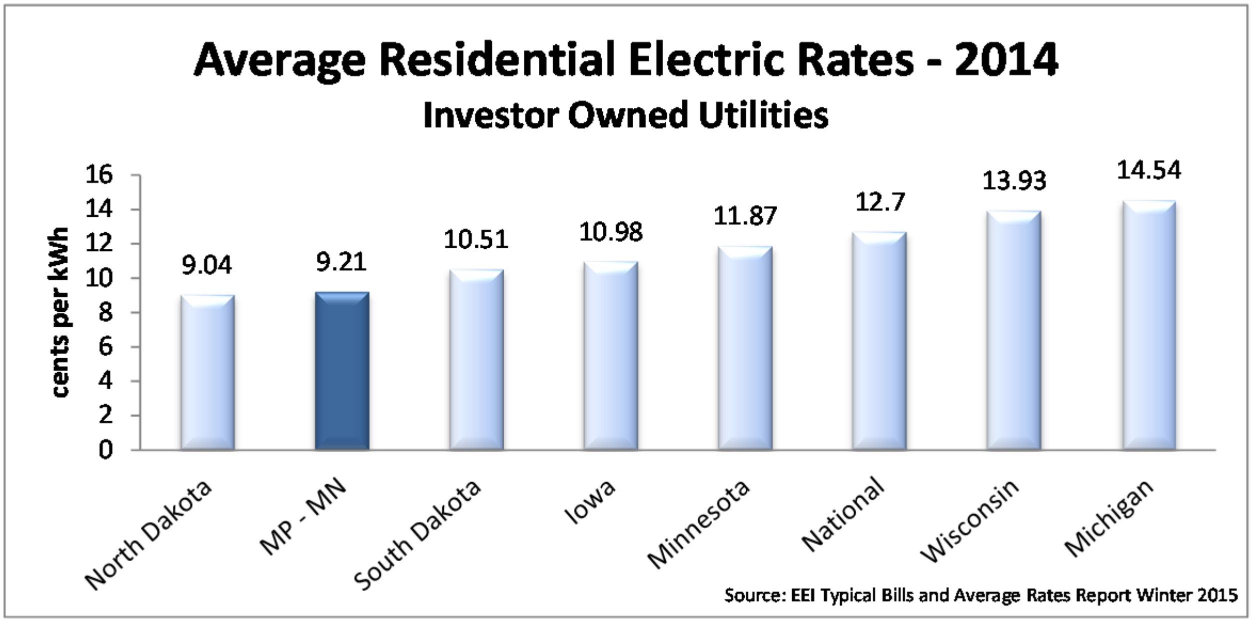


Figure 31: Regional and National Comparison of Commercial Electric Rates in 2014

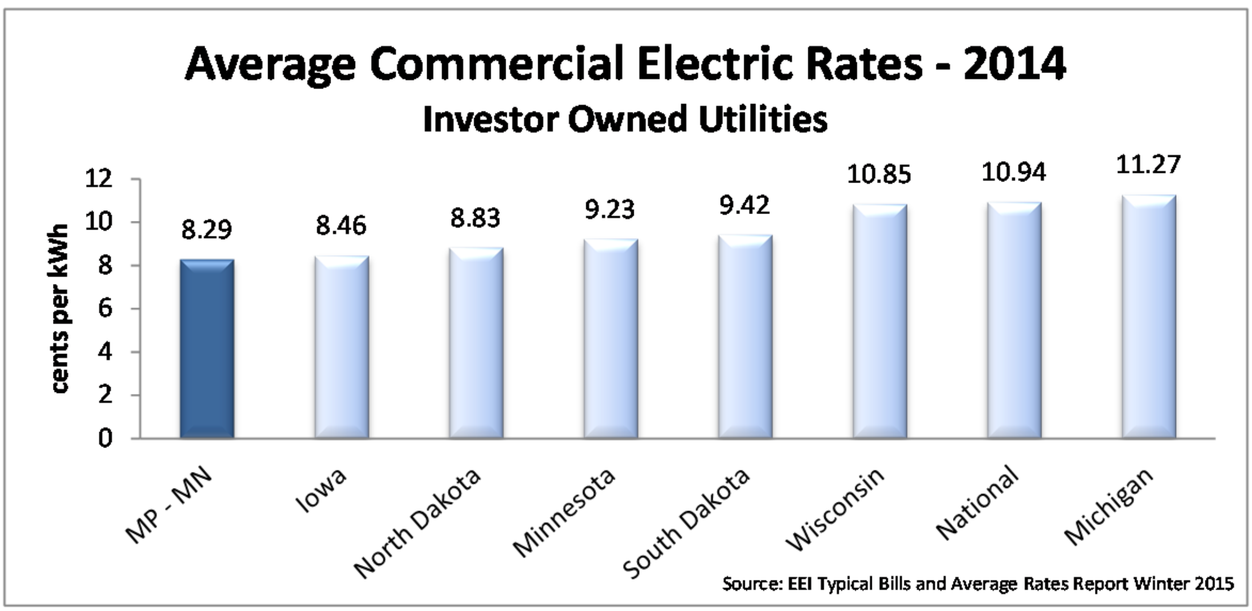
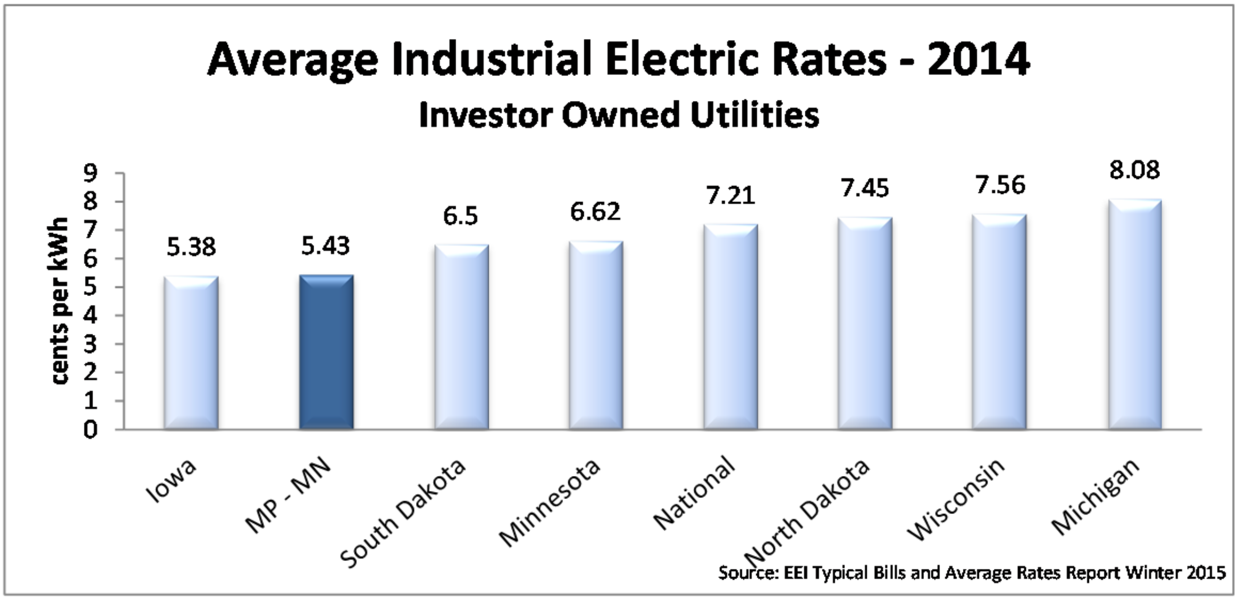


Figure 32: Regional and National Comparison of Industrial Electric Rates in 2014



Figures 30 through 32 provide comparisons of the Company's electric rates to other investor owned utilities in the upper Midwest as well as nationally. These rate comparisons use data from the most recent Edison Electric Institute ("EEI") Typical Bills and Average Rates publication.

The EEI publication uses customer classes defined by the Federal Energy Regulatory Commission ("FERC") – Residential, Commercial and Industrial. The Company uses six classes, so the average EEI rates are not directly comparable with the Company's rates presented in the 2015 Plan.

As utilities make significant capital investments, rates are likely to increase. Similarly, rates may not change if the company is not making significant investments. Because each utility is different, the timing of capital investments can vary greatly. Because of these differences, the rate comparisons are not fully comparable. However, the information provided by the comparisons can be helpful in showing the general level of competitiveness among regionally comparable utilities.

Minnesota Power continues to incorporate the power supply actions needed to reshape and transform its electric supply at reasonable customer costs. These actions are driven in part by Minnesota's RES and SES, conservation improvement plans and the Next Generation Energy Act of 2007. The actions taken to meet these standards are creating meaningful change on the power system and creating emission reductions that are outperforming even national goals (see Appendix H). At the same time, under this environment, Minnesota Power continues to carefully and prudently evaluate its system and protect affordability for customers.

The current Commission requirement to consider a carbon regulation penalty in 2019 for resource planning evaluation creates a cost increase projection for Minnesota customers. Until a carbon regulation penalty is determined at the national or state level, impeding resource plans with an assumed carbon price penalty and the resulting premature actions could increase costs to Minnesota electric consumers without delivering commensurate environmental benefits.

Analysis and Insights – Comparison of Preferred Plan to "Swim Lane" Alternatives and Sensitivity Analysis

Minnesota Power considered its Preferred Plan plus three swim lane alternative paths for its small coal-fired generation fleet that vary the timing of when small coal generation is removed from the power supply and refueling opportunities are utilized as shown in Figure 18 on page 56.

The most prominent comparison of the swim lanes is between the Preferred Plan and the Small Coal Gas Refuel, where the inclusion of the CO_2 regulation penalty changes the lowest cost plan from the Preferred Plan to the Small Coal Gas Refuel swim lane. Minnesota Power recognizes that including the penalty would drive a different resource selection than what is included in the Preferred Plan, but for the following reasons Minnesota Power supports its Preferred Plan as being in the best interest of customers:

- Reduces CO_2 to state greenhouse gas goal levels
- Transition off 560 MW of small and purchased coal by 2025
- Minimizes power supply costs under a scenario where a CO_2 regulation penalty is delayed until 2025
- Avoids unnecessary wind build until costs are either economical for customers, or an implementation of a CO_2 regulation penalty
- Operate BEC1&2 on coal to bridge to new CC in 2024
- Minimizes market exposure when MISO planning reserve margins are declining
- Purchase bridge energy and capacity between 2015 and 2019

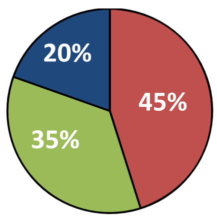
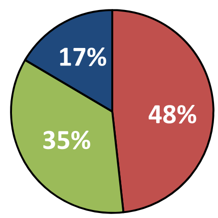
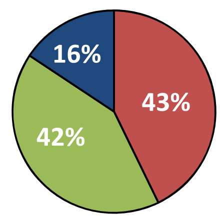
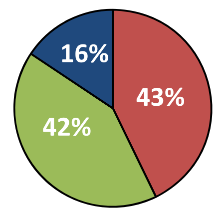
Minnesota Power wanted to verify whether or not these alternative swim lane paths were in the best interests of customers compared to the Preferred Plan, and to further assess the benefits of its Preferred Plan for stakeholders. The three swim lane alternatives were first put through Minnesota Power's expansion planning process for direct comparison to the Preferred Plan. In this process, the least cost power supply additions were identified for each option (see Appendix K). The expansion plan for each swim lane contains similar core resource additions to Minnesota Power's Preferred Plan, demonstrating the resilient nature of the Preferred Plan for meeting customer requirements. These resource additions include:

- The next thermal generation resource alternative added is a 300 MW share of a 2x1 CC facility, reflecting the benefit of additional efficient natural gas generation. The timing of the CC addition varies slightly with it being added in the 2021 to 2025 period in all swim lanes.
- With exception of the Small Coal through Mid-2020s, all swim lanes utilize some amount of short-term bilateral bridge purchase, reflecting the benefit that economical short-term purchases can provide to improving the timing of new generation additions.

- Wind addition is made in Small Coal Refuel and Early Small Coal Exit swim lanes, reflecting the benefit additional wind could have if a moderate CO_2 regulation penalty is realized in the energy market.

Table 7 provides an overview of each of the swim lanes and gives the highlights of the initial Strategist evaluation for the options. The plans vary slightly in terms of generation mix and estimated emission reductions; however, the Preferred Plan is the lowest cost under the base assumptions and in a scenario where the \$21.50/ton CO_2 regulation penalty is delayed until 2025 - further supporting the actions taken in the Preferred Plan.

Table 7: Overview of Preferred Plan and Swim Lane Alternatives

Portfolio Name	Preferred Plan	Small Coal Through Mid-2020's	Small Coal Gas Refuel	Early Small Coal Exit
2025 Energy Portfolio Coal Renewables Natural Gas and Purchases				
2015 NPV of Plan Costs	**\$7.54 B**	**\$7.57 B**	**\$7.59 B**	**\$7.62 B**
2015 NPV of Plan Costs w/ CO_2 Regulation Tax in 2019	**\$8.59 B**	**\$8.66 B**	**\$8.54 B**	**\$8.56 B**
2015 NPV of Plan Costs w/ CO_2 Regulation Tax in 2025	**\$7.99 B**	**\$8.02 B**	**\$8.00 B**	**\$8.03 B**
Renewable: Installed Capacity & Contracts 2025 (MW)	**1,088**	**1,088**	**1,293**	**1,293**
Coal: Installed Capacity 2025 (MW)	**853**	**1,005**	**853**	**853**
Natural Gas: Installed Capacity 2025 (MW)	**410**	**410**	**410**	**410**
CO_2: State GHG Goal – Percent Reduction from **2005-2025**	**31%**	**29%**	**36%**	**36%**
Mercury: Percent Reduction from 2005-2025	**88%**	**86%**	**88%**	**88%**
Other Emissions: Percent Reduction from 2005-2025	**90%**	**86%**	**90%**	**90%**

Each swim lane alternative and the Preferred Plan was then put through a series of 50 sensitivities that stressed the main drivers for resource decisions. These drivers include fuel, capital, additional EPA regulation, carbon sensitivities, and additional energy efficiency programs. The series of swim lanes were put through both scenarios with and without the Commission approved mid CO_2 regulation penalty, resulting in 100 unique sensitivities. The sensitivities help determine whether the Preferred Plan and its resource actions would be the best option for customers.

The Preferred Plan provided low cost power supply in nearly 50 percent of the sensitivities considered and assumes an affordable and balanced series of actions across this wide range of sensitivities. The Preferred Plan represents the next step in Minnesota Power's *Energy**Forward*** strategy, resulting in a diverse generation portfolio fuel mix that allows flexibility for the Company to take advantage of changing fuel cost and future carbon regulation trends. Only a decrease in new generation capital cost from the expected forecast or a carbon regulation penalty would favor a BEC1&2 refuel with natural gas. It is important to consider that if a CO_2 regulation penalty of $21.50/ton is delayed to 2025 the Preferred Plan is the lowest cost option for customers. This highlights the risk of making near term resource decisions based only on the results that minimize power supply cost around a planning level CO_2 regulation cost that is not finalized – possibly burdening customers with unnecessary cost.[62] Minnesota Power does find the CO_2 regulation penalty useful in understanding how a penalty mechanism can change resource planning decisions and inform decision making. However, decisions should not be made on a CO_2 regulation penalty alone until such a penalty and implementation timing is clearer. Minnesota Power will have the flexibility through its ongoing resource planning process in future planning cycles to consider alternate actions if carbon regulation outcomes unfold that are not met by Minnesota Power's already aggressive carbon reduction plan through its *Energy**Forward*** strategy and Preferred Plan actions recommended in this submittal.

Minnesota Power's Preferred Plan positions the power supply well for a potential carbon regulation with the assertion that BEC1&2 will cease coal-fired operation at the end of their accounting life at the end of 2024 and THEC1&2 by 2020. In fact, the Preferred Plan is consistent with EPA's CPP goal of 30 percent CO_2 reduction from 2005 levels by 2030. Furthermore, 300 MW of efficient natural gas resource with lower carbon energy along with the 383 MW of carbon-free energy from Manitoba Hydro in 2020 replaces power required from the small coal transition and serve a growing customer load demand. The Preferred Plan is in the best interest of customers and effectively hedges the customers against a future CO_2 regulation penalty if one was to be implemented.

[62] The CPP does not include a price on CO_2, rather a compliance target for the regulatory approach.

Table 8: Step 4 Sensitivity Analysis: 2015 NPV of Alternative Cost with Sensitivities ($millions)

Strategist Sensitivity Number	Sensitivities	Preferred Plan	Small Coal Through Mid-2020s	Small Coal Gas Refuel	Early Small Coal Exit
0	Base	$7,541	$7,572	$7,587	$7,620
1	CO_2 Penalty in 2019 $9/ton	$7,906	$7,949	$7,919	$7,950
2	CO_2 Penalty in 2019 $34/ton	$9,256	$9,349	$9,138	$9,161
3	Social Cost of Carbon (3% Discount Rate)	$13,504	$13,609	$13,209	$12,800
5	Low Coal Forecast (-30%)	$7,013	$7,004	$7,093	$7,127
6	High Coal Forecast (+30%)	$8,040	$8,110	$8,051	$8,079
7	Low Biomass (-10%)	$7,537	$7,568	$7,583	$7,616
8	High Biomass (+10%)	$7,546	$7,577	$7,592	$7,624
9	Lower Natural Gas (-50%)	$7,343	$7,388	$7,399	$7,382
10	Low Natural Gas (-25%)	$7,443	$7,480	$7,498	$7,511
11	High Natural Gas (+25%)	$7,631	$7,659	$7,670	$7,718
12	Higher Natural Gas (+50%)	$7,716	$7,742	$7,752	$7,815
13	Highest Natural Gas (+100%)	$7,876	$7,899	$7,909	$8,001
14	Low Externality Values	$7,340	$7,365	$7,398	$7,426
15	High Externality Values	$7,741	$7,779	$7,776	$7,814
16	No Externality Value	$7,258	$7,278	$7,320	$7,346
17	Lower Wholesale Market (-50%)	$7,217	$7,245	$7,276	$7,348
18	Low Wholesale Market (-25%)	$7,419	$7,450	$7,472	$7,526
19	High Wholesale Market (+25%)	$7,665	$7,696	$7,708	$7,716
20	Higher Wholesale Market (+50%)	$7,795	$7,827	$7,833	$7,814
21	No Wholesale Market	$9,500	$9,496	$9,458	$8,999
22	Low New Generation Capital Cost (-30%)	$7,474	$7,511	$7,438	$7,452
23	High New Generation Capital Cost (+30%)	$7,608	$7,634	$7,737	$7,787
24	Wind Capital $35/MWh	$7,541	$7,572	$7,498	$7,531
25	Wind Capital $45/MWh	$7,541	$7,572	$7,552	$7,584
26	Wind Capital $55/MWh	$7,541	$7,572	$7,605	$7,637
27	Wind Capital $65/MWh	$7,541	$7,572	$7,658	$7,691
28	Wind Capital $75/MWh	$7,541	$7,572	$7,712	$7,744
29	Solar Capital $75/MWh	$7,541	$7,572	$7,587	$7,620
30	Solar Capital $80/MWh	$7,541	$7,572	$7,587	$7,620
31	Solar Capital $85/MWh	$7,541	$7,572	$7,587	$7,620
32	Solar Capital $90/MWh	$7,541	$7,572	$7,587	$7,620
35	Wind Capacity Accreditation (-20%)	$7,547	$7,577	$7,594	$7,623
36	AFR 2014 Potential Downside	$6,761	$6,804	$6,832	$6,915
37	AFR 2014 Potential Upside	$7,957	$7,957	$8,002	$7,992
38	AFR 2014 Current Contract Scenario	$7,384	$7,417	$7,431	$7,477
40	EPA Sensitivity More Stringent	$7,702	$7,742	$7,748	$7,779
41	PRM Sensitivity (+2%)	$7,556	$7,583	$7,604	$7,629
42	MISO Coincident Factor (-2%)	$7,566	$7,590	$7,615	$7,637
43	MISO Coincident Factor (+2%)	$7,533	$7,566	$7,578	$7,614
45	Winter MISO Coincident Peak Demand	$7,545	$7,575	$7,592	$7,622
46	Incremental EE +3GW	$7,545	$7,575	$7,591	$7,621
47	Incremental EE +6GW	$7,542	$7,573	$7,588	$7,619
48	Incremental EE +9GW	$7,541	$7,572	$7,587	$7,619
49	Incremental EE +12GW	$7,541	$7,573	$7,587	$7,620
50	Incremental EE +15GW	$7,543	$7,574	$7,589	$7,622
51	Incremental EE +18GW	$7,544	$7,577	$7,591	$7,625
52	Incremental EE +21GW	$7,547	$7,580	$7,594	$7,629
53	Incremental EE +24GW	$7,551	$7,584	$7,597	$7,633
54	Incremental EE +27GW	$7,555	$7,589	$7,602	$7,638
55	Incremental EE +30GW	$7,560	$7,595	$7,607	$7,644
56	CO_2 Penalty in 2025 $21.50/ton	$7,986	$8,023	$7,999	$8,033
Least Cost Count		46	1	3	2

Table 9: Step 4 Sensitivity Analysis with $21.50/ton CO_2 Regulation Penalty as Base Assumption: 2015 NPV of Alternative Cost with Sensitivities ($millions)

Strategist Sensitivity Number	Sensitivities	Preferred Plan	Small Coal Through Mid-2020s	Small Coal Gas Refuel	Early Small Coal Exit
0	Base	$8,592	$8,661	$8,537	$8,564
5	Low Coal Forecast (-30%)	$8,120	$8,149	$8,100	$8,137
6	High Coal Forecast (+30%)	$9,041	$9,147	$8,953	$8,970
7	Low Biomass (-10%)	$8,587	$8,656	$8,532	$8,559
8	High Biomass (+10%)	$8,596	$8,665	$8,541	$8,568
9	Lower Natural Gas (-50%)	$8,371	$8,456	$8,320	$8,286
10	Low Natural Gas (-25%)	$8,482	$8,558	$8,430	$8,427
11	High Natural Gas (+25%)	$8,705	$8,768	$8,645	$8,697
12	Higher Natural Gas (+50%)	$8,795	$8,854	$8,726	$8,794
13	Highest Natural Gas (+100%)	$8,942	$8,999	$8,869	$8,963
14	Low Externality Values	$8,548	$8,618	$8,491	$8,519
15	High Externality Values	$8,924	$9,004	$8,843	$8,876
16	No Externality Value	$8,470	$8,536	$8,418	$8,446
17	Lower Wholesale Market (-50%)	$8,095	$8,157	$8,064	$8,152
18	Low Wholesale Market (-25%)	$8,390	$8,455	$8,346	$8,405
19	High Wholesale Market (+25%)	$8,784	$8,854	$8,718	$8,710
20	Higher Wholesale Market (+50%)	$8,945	$9,015	$8,872	$8,829
21	No Wholesale Market	$10,565	$10,609	$10,419	$9,965
22	Low New Generation Capital Cost (-30%)	$8,525	$8,599	$8,387	$8,397
23	High New Generation Capital Cost (+30%)	$8,659	$8,722	$8,687	$8,731
24	Wind Capital $35/MWh	$8,592	$8,661	$8,448	$8,475
25	Wind Capital $45/MWh	$8,592	$8,661	$8,501	$8,528
26	Wind Capital $55/MWh	$8,592	$8,661	$8,555	$8,581
27	Wind Capital $65/MWh	$8,592	$8,661	$8,608	$8,635
28	Wind Capital $75/MWh	$8,592	$8,661	$8,661	$8,688
29	Solar Capital $75/MWh	$8,592	$8,661	$8,537	$8,564
30	Solar Capital $80/MWh	$8,592	$8,661	$8,537	$8,564
31	Solar Capital $85/MWh	$8,592	$8,661	$8,537	$8,564
32	Solar Capital $90/MWh	$8,592	$8,661	$8,537	$8,564
35	Wind Capacity Accreditation (-20%)	$8,598	$8,665	$8,544	$8,567
36	AFR 2014 Potential Downside	$7,584	$7,656	$7,565	$7,655
37	AFR 2014 Potential Upside	$9,087	$9,130	$9,031	$9,013
38	AFR 2014 Current Contract Scenario	$8,393	$8,461	$8,339	$8,381
40	EPA Sensitivity More Stringent	$8,753	$8,831	$8,698	$8,723
41	PRM Sensitivity (+2%)	$8,607	$8,671	$8,554	$8,573
42	MISO Coincident Factor (-2%)	$8,617	$8,679	$8,565	$8,582
43	MISO Coincident Factor (+2%)	$8,584	$8,655	$8,528	$8,559
45	Winter MISO Coincident Peak Demand	$8,596	$8,664	$8,542	$8,567
46	Incremental EE +3GW	$8,602	$8,670	$8,547	$8,572
47	Incremental EE +6GW	$8,597	$8,665	$8,542	$8,567
48	Incremental EE +9GW	$8,593	$8,662	$8,538	$8,565
49	Incremental EE +12GW	$8,591	$8,660	$8,536	$8,563
50	Incremental EE +15GW	$8,590	$8,659	$8,536	$8,563
51	Incremental EE +18GW	$8,590	$8,659	$8,535	$8,564
52	Incremental EE +21GW	$8,591	$8,660	$8,536	$8,565
53	Incremental EE +24GW	$8,591	$8,661	$8,537	$8,567
54	Incremental EE +27GW	$8,593	$8,663	$8,539	$8,570
55	Incremental EE +30GW	$8,596	$8,667	$8,542	$8,574
Least Cost Count		**3**	**0**	**41**	**4**

The Small Coal Through Mid-2020s swim lane, which assumes to continue coal-fired operation through the end of the useful life (mid-2020s) at both THEC1&2 and BEC1&2, is not identified as the lowest cost option under any of the 100 sensitivities, other than a lower than expected coal price outlook with no CO_2 regulation cost. This supports Minnesota Power's Preferred Plan in which THEC1&2 idle in the near term, and lost energy is replaced with bilateral purchases until the Manitoba Hydro 383 MW PPA purchases start in 2020.

The potential for additional EPA regulations was considered as a sensitivity to include costs for the coal ash residual and effluent limit guidelines currently being contemplated (see Appendix E of this Plan). This sensitivity added costs to each generation facility under the current expectation for the rules. As Table 9 identifies, the Preferred Plan continues to be the lowest cost alternative for customers when compared to the other swim lane options.

The sensitivities and consideration of the swim lane alternatives help solidify that the Preferred Plan will meet its goal to balance improving environmental performance, preserving reliability and protecting affordability for customers.

V. SHORT-TERM ACTION PLAN

Minnesota Power's resource plan creates a more flexible and diverse power supply, while balancing cost, reliability and environmental impact for customers. The 2015 Plan continues the transformation of the Company's resource base by taking another step in transitioning its small coal fleet, incorporating solar generation, adding natural gas to its fuels portfolio, installing more emissions-control technology at its core, coal-fired, baseload generating facilities, and increasing its strong energy conservation and DSM programs. 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.

Plans to Meet Short-term Need (2015-2019)

Minnesota Power's short-term action plan during the five-year period of 2015 through 2019 is comprised of steps that will: a) preserve competitive base load generating resources while reducing emissions, b) increase implementation of least cost demand side resources including conservation, c) reduce reliance on coal-fired generation, and d) add renewable energy and transmission infrastructure to the benefit of customers. The specific strategic and necessary actions to achieve these steps include:

1. Reduce emissions associated with converting coal energy to electricity through a series of actions that assure environmental compliance and a sound energy supply for customers. The Company has identified that THEC1&2 (150 MW) can best serve customers through more flexible operation beginning in 2016. THEC1&2 will be idled in 2016 and be utilized for reliability of the bulk electric system as market conditions require. The Company identified a plan to reduce the emission profile of BEC1&2 (130 MW), by leveraging the environmental infrastructure of the BEC facility. Engineering and design planning will begin for 2018 project implementation.
2. Minimize short-term rate impacts for customers while meeting increased demand for electricity, as the northeast Minnesota economy is forecasted to grow in the next several years, by taking advantage of a lower cost power market. Minnesota Power will use economical, bilateral market purchases to flexibly help bridge needs in the period between 2016 and 2019. This flexibility is necessary given load projections and the ultimate timing of new large industrial loads on its system as well as any significant downward business cycles that may affect demand from existing large industrial customers.
3. Implement additional solar resources in each of the three pillars of its solar strategy – customer, community and utility – to implement 33 MW of solar resources by 2025, complying with the State of Minnesota's SES. Beginning with a 10 MW utility scale solar array at the Camp Ripley location in 2016, bringing forth a unique community solar program in fall 2015 and continuing to incentivize customer solar programs already in place.
4. Begin competitive procurement process for 200 MW – 300 MW of efficient natural gas CC generation supply for implementation by 2024. Actual procurement amount will

vary based on continued updates to customer load outlooks and availability of competitive opportunities. Addition of natural gas resources to Minnesota Power's supply portfolio will be subject to Commission review.

5. Consider enhancements to selected CIP and DSM programs, while continuing to apply best practices from the conservation industry and developing leading-edge programs. Minnesota Power has maintained a strong record of conservation performance and been a state leader in meeting the Minnesota 1.5 percent energy savings conservation goal. Along with this strong dedication to conservation, Minnesota Power will continue to work to identify reasonable additions to its DSM programs where it is most beneficial for customers.
6. Prepare Minnesota Power's transmission system for the long-term addition of new power supply resources. The Company will, subject to Commission route permit approval in early 2016, begin constructing the GNTL to deliver its approved power purchases of 250 MW of energy and capacity and 133 MW of energy only from Manitoba Hydro for the term 2020-2035 (a critical element of Minnesota Power's long-term action plan).
7. Complete final review and begin utilization of its 2013 Load Research study Advanced Metering Infrastructure Project to better quantify customer energy use, providing a robust basis for future customer conservation projects and sound rate design.
8. Minnesota Power will develop customer-facing DG programs that best leverages unique customer and regional attributes to deliver valued and cost effective electric solutions for customers. A backup generation pilot program (10 MW) will be developed for approval by the Commission in 2016.
9. Continue fleet maintenance programs to sustain the economic viability, availability and reliability of Minnesota Power's generating units. A continuing Company priority throughout this planning period will be to carefully maintain its generation fleet to ensure productivity and efficiency in operation. A rigorous process is in place to sustain existing production across Minnesota Power's wind-water-wood-coal-solar sources of energy conversion while maintaining an excellent environmental record and meeting more stringent environmental standards.
10. Continue active participation in M-RETS as provided for by the Commission's October 9, 2007 Order,[63] as well as establishing a program and protocols for tradeable, renewable energy credits.[64] Minnesota Power will leverage the value of renewable energy credits that the M-RETS program certifies to deliver RES and SES compliance (as applicable) in Minnesota at the lowest possible cost to customers. Minnesota Power will utilize renewable energy credits generated across the years in order to optimally meet the 25 percent RES by 2025 and interim years.

[63] Docket No. E999/CI-04-1616.
[64] Docket Nos. E999/CI-04-1616 and E999/CI-03-869.

Four Key Contingencies

The planning process and analysis discussed in this Plan allowed Minnesota Power to consider several sensitivities that address the uncertainty that is present with the state of the economy and environmental compliance policy. Each sensitivity evaluated gave the Company the insight needed to be prepared for the potential paths each of these can take in the near term. Four key contingencies and their anticipated implications that Minnesota Power will continue to monitor are:

1. Extensive customer load additions or expansions do not materialize in the short term. Minnesota Power would have minimal excess capacity after its supply-side action plan and would consider making commitments for long-term power sales to mitigate the effect of the unrealized customer load. This is made easier with the Company's plan to utilize the bilateral power market rather than a large new resource investment in the near term to optimize the power supply costs while integrating the new customer load.
2. Carbon regulation policy implementation is expedited on a national level for existing generating resources. Minnesota Power would accelerate its long-term actions to reduce carbon and consider the addition of new carbon-minimizing generation resources and/or secure additional bilateral purchases until a resource could be placed into service.
3. Continue optimization of Minnesota Power's renewable energy supply. With over 600 MW of competitive wind projects already present in its portfolio, Minnesota Power is already a decade ahead of its RES target and is closely monitoring the need for additional intermittent renewable energy. Minnesota Power will solicit a request for proposal for a minimum of 100 MW and up to 200 MW of competitive wind to be installed if a carbon regulation drives additional transition of coal-fired generation prior to 2020.
4. Economic recession or industry contraction. If a recession re-emerges or key industries are forced under additional economic pressure impacting Minnesota Power's largest customers, the Company will have excess capacity and will consider making commitments for power sales to mitigate the effect of the reduced customer load.

Minnesota Power will continue to closely monitor the economic and environmental regulation outlooks and evaluate its short-term action plan as the landscape unfolds to ensure that customers and stakeholders are served in a reliable and forward-looking way during the planning period.

VI. LONG-TERM ACTION PLAN

Plans to Meet Long-term Need (2019-2029)

Minnesota Power will focus its long-term action plan on a strategy to further reduce carbon emissions in its portfolio, and diversify its generation mix towards a balance of approximately one-third renewable resources, one-third natural gas/other and one-third efficient coal-fired generation. This long-term strategy will position the Company 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 the long-term action plan was proven through the planning process analysis to be flexible, robust, and to support the Company's strategic resource goals in a variety of future scenarios. Planned components include:

1. Continue implementation of the 250 MW and 133 MW Manitoba Hydro PPA, and GNTL in the 2020 timeframe (383 MW).
2. Optimize the timing of the remaining 22 MW of new solar projects to meet the state SES, as well as monitor solar energy trends to identify when it is economical to augment the power supply with additional solar.
3. Reduce the Minnesota Power offtake of Young 2 from 100 MW to zero by 2026.
4. Investigate opportunities to further diversify the Company's power supply, including reducing coal-based generation. Minnesota Power will closely assess BEC1&2 economics during this period to determine competitive position of these units by 2025.
5. Secure and implement 200 to 300 MW of efficient natural gas CC generation resource for Minnesota Power's generation fleet to meet expected capacity and energy needs by 2024.
6. Enhance and create additional customer product options through integrated and coordinated distribution, transmission and power supply planning.