APPENDIX J: ASSUMPTIONS AND OUTLOOKS

This appendix provides a summary of the key economic modeling assumptions and basis that Minnesota Power (or the "Company") utilized in the Encompass Power Planning Software ("EnCompass") analysis completed for the 2025-2039 Integrated Resource Plan ("2025 IRP").

In its January 9, 2023 order in Docket No. E-015/RP-21-33, the Minnesota Public Utilities Commission ("Commission") ordered Minnesota Power to consult with stakeholders to develop the modeling inputs and parameters to be used in the Company's next resource plan. As part of the 2025 IRP Engagement Process discussed in Appendix N, subgroups of interested engagement participants named "Technology Assessment Group" or TAG were formed to work with Minnesota Power on developing modeling assumptions. A description of the developed subcommittees process is included in Appendix N. Multiple participants expressed that they did not want to be asked to reach a final consensus on modeling assumptions. While agreed-upon assumptions were not a product of the engagement process, the input and feedback received helped shape key modeling assumptions detailed in this Appendix J.

This appendix, detailing the assumptions and outlooks, is organized in the following format:

A) Base Economic Modeling Assumptions – A review of the base economic assumption used in the analysis for the Plan.

B) Asset Resource Alternatives Evaluated – A description of the new resource alternatives considered in the Plan.

C) Minnesota Power Energy Efficiency Assumptions – A brief description of the energy efficiency scenarios considered in the Plan.

D) Assumptions Utilized for Stressing Variables in the IRP Analysis

E) Long-term Planning and Wholesale Market Interaction – A discussion on utilizing the wholesale market in resource planning.

F) Retirement Methodology for the 2025 IRP Evaluation – A description of the retirement method utilized during the analysis and assumptions for decommissioning of generation facilities.

A. Base Economic Modeling Assumptions

Study Period

The timeline of the 2025 IRP analysis is 2025 through 2039. The power supply costs shown in the Plan are the net present value of cost from 2025 through 2039 and are reported in 2025 dollars, unless noted otherwise. The expansion planning analysis conducted with the EnCompass Model considered 11 years of end effects after 2039 when selecting the lowest cost plan.

Environmental Costs, Pricing, and Wholesale Market

1) The Base forecasts utilized for environmental costs, natural gas prices, market energy prices, and market capacity prices over the study period:[1]

   a) The Reference Case Scenario utilized the Metropolitan Fringe environmental cost values for criteria pollutants from the Environmental and Socioeconomic Costs published on January 3, 2018, under Docket No. E-999/CI-14-643. The mid-point of the environmental costs is utilized in the Reference Case Scenario for the 2025 IRP. Environmental costs

[1] Values are in nominal dollars.

did not impact the resource capacity expansion analysis per direction given by the Commission on December 19, 2023 in Docket No. E-999/CI-07-1199, Docket No. E-999/DI-22-236, Docket No. E-999/CI-14-643. These value ranges are an approximate representation of what is in the EnCompass database.

i) Oxides of nitrogen (“NO_x”) environmental cost range: $7,133/ton in 2025 to $9,756/ton in 2039

ii) Sulfur dioxide (“SO_2”) environmental cost range: $10,989/ton in 2025 to $15,030/ton in 2039

iii) Particulate matter 2.5 (“$PM_{2.5}$”) environmental cost range: $15,625/ton in 2025 to $21,371/ton in 2039

b) The Reference Case Scenario utilized the Metropolitan Fringe environmental costs (referred to as “externality values” in the docket) from the State Externality Docket published on June 16, 2017, under Docket Nos. E999/CI-93-583 and E999/CI-00-1636. The mid-point of the environmental costs is utilized in the Reference Case Scenario for the 2025 IRP. These value ranges are approximate representations of what is in the EnCompass database.

i) Carbon monoxide (“CO”) environmental cost range: $2.04/ton in 2025 to $2.80/ton in 2039

ii) Lead (“Pb”) environmental cost range: $3,511/ton in 2025 to $4,802/ton in 2039

c) The Reference Case Scenario used the environmental cost for carbon from the Commission’s December 19, 2023 Order[2] in Docket Nos. E-999/DI-22-236 and E-999/CI-07-1199. The environmental cost for carbon was included from 2025 through 2050.

i) Carbon environmental cost range: $270/short ton in 2025 to $446/short ton in 2039.

d) Natural gas forecast assumptions utilized in the base forecast.

i) Natural Gas for Minnesota: $3.43/million British thermal units (“MMBtu”) in 2025 to $5.75/MMBtu in 2039

ii) Natural gas supply prices reflect the projected spot market for Minnesota. In addition, a delivery charge was applied on a resource-specific basis. The delivery charges were escalated using the GDPIPD escalation forecast. Delivery charges do not constitute commitments to unit siting but are meant to capture financial impacts of the fuel supply system. The delivery charges applied were as follows:

(1) **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** for the Laskin Energy Center (“LEC”).

[2] *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06 and In the Matter of Establishing an Updated 2022 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06*, Docket Nos. E-999/CI-07-1199 and E-999/DI-22-236, Order Addressing Environmental and Regulatory Costs (Dec. 19, 2023) (hereinafter “December 19, 2023 Order”).

(2) **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** For natural gas, coal-gas refuel, and biomass-gas refuel scenarios of existing units at the Boswell Energy Center ("BEC").

(3) **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** For generic natural gas combined cycle capacity expansion scenarios.

(4) **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** For generic peaking natural gas capacity expansion scenarios.

e) Delivered coal price forecast assumptions utilized in the base forecast represent the attributes of each of Minnesota Power's facilities and include:

i) **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

ii) In the scenario where BEC Unit 4 ("BEC4") is refueled with 40 percent natural gas, the delivered coal-natural gas dual fuel price represents a 60 percent coal and 40 percent natural gas weighting.

f) Delivered biomass price forecast assumptions utilized in the base forecast:

i) **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

g) Wholesale Market Capacity (approximate): the seasonal capacity values shown in Table 1 below were utilized in the EnCompass modeling:

Table 1. Summary of Seasonal Capacity Prices

Capacity Values ($/MW-Month)				
	Summer	**Fall**	**Winter**	**Spring**
2025	**$4,651**	**$5,260**	**$3,050**	**$1,900**
2039	**$9,801**	**$9,801**	**$9,801**	**$9,370**

i) The transition to the Midcontinent Independent System Operator ("MISO") Resource Based Demand Curve ("RBDC") in planning 2025-2026 and will have an impact on the capacity prices across MISO. The third-party forecast used in the IRP was published prior to FERC approving the RBDC. Minnesota Power is monitoring the impacts the RBDC has to capacity prices.

ii) Wholesale market capacity was available up to 100 megawatts ("MW") for the model during all study years.

2) The base case energy market interaction structure for Minnesota Power's analysis assumed that the wholesale market was available throughout the study period. Further discussion regarding the Company's position related to the interaction with, and utilization of the wholesale energy market in long-term planning is discussed further in Part D of this Appendix. The wholesale energy market structure in the modeling represents the day-ahead interaction with the MISO regional market and helps utilities optimize power supply for customers.

A conservative approach was taken when creating the wholesale energy market that would be made available as a power supply resource during the study period. While the regional market is a valuable and useful piece of a utility's power supply, it should not be considered an "endless" resource. To help account for the increased risk and volatility that is present when purchasing incrementally larger amounts of energy from the short-term market, an increasing price adder was included based on the level of energy purchased. As the volume of energy purchased from the market increased, so did the price adder. This is referred to as a "Tiered Energy Market" and includes the following pricing assumptions:

i) 0 to 300 MW at base forecast price

ii) 301 to 450 MW at 125 percent of base market price forecast

iii) 451 to 600 MW at 150 percent of base market price forecast

iv) 601 to 900 MW at tier 1 emergency pricing ($600 / MWh) 901+ MW at tier 2 emergency pricing ($1,000,000 / MWh) representing the cost of unserved energy

In the Capacity Expansion analysis during the resource selection process the energy market was designed to capture the risk of unserved energy occurring during extreme market conditions. A more conservative approach was taken to the energy market design to meet Minnesota Power's system energy needs. This is referred to as the "Limited Energy Market" ("LEM") design for the Capacity Expansion Analysis and includes the following price assumptions:

i) 0 to 100 MW at base forecast price

ii) 101+ at tier 2 emergency pricing of $1,000,000/MWh

Note that anytime an 8,760 hourly dispatch model run ("Product Costing") was performed the "Tiered Energy Market" was used.

3) The estimated decommissioning cost for Minnesota Power's BEC Unit 3 ("BEC3") and BEC4 included in the shutdown scenarios discussed in the 2025 IRP are from a study by Burns & McDonnell called Site Decommissioning Study 2020 that was refreshed mid-2024. Decommissioning costs at each facility are assumed to be recovered and depreciated 10 years past the shutdown date. Remaining plant balances at each facility are assumed to be recovered and depreciated according to their current schedule.

4) Carbon regulation penalty costs

The Reference Case Scenario utilized the carbon dioxide regulation cost from the December 19, 2023 Order. Starting in 2028, the middle value for the regulatory cost of carbon was included through the end of the study period and was net from the environmental cost of carbon where applicable. These costs impacted the resource selection in the capacity expansion plan analysis and used throughout the 2025 IRP analysis.

a) In the Reference Case the Wholesale Market Energy includes an approximate impact of $40.00/ton carbon regulation costs starting in 2028 and increases to $51.25/ton in 2039.

Minnesota Power Resources and Bilateral Power Transactions

Another vital component of a utility's power supply are the contracted purchases and sales conducted within the industry. These transactions optimize the energy surpluses and deficits that occur due to load and supply changes. Also called bilateral transactions, these contracts allow the Company to work with other entities to exchange energy and capacity (see Part 2 of Appendix C for a list of Minnesota Power's current bilateral transactions included in the base case).

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. 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. For this the Company has the following bilateral transaction included in the analysis:

5) An unidentified bilateral energy purchase, referred to as a “bridge purchase” in the analysis write-up, was modeled in EnCompass as an energy only resource to meet increasing customer demand in load sensitivities until alternative generation sources became available in January 1, 2030.

   In the scenarios where the Commission approved carbon regulation value is modeled, the bilateral purchase had a carbon penalty added to the energy price based on the emission rate for a natural gas unit.

Minnesota Power Emission Rate Modeling for Resources and Transactions

6) The emission rates for the thermal generation units included in EnCompass are modeled as tons or pounds per MMBtu of fuel consumed for energy production. The level of effluents emitted per MWh generated will vary depending on the output level of a generation facility. As a generator is dispatched to a lower output level because of economic conditions, the effluents emitted per MWh will increase due to the generator operating at a less efficient level when compared to running at full output. The effluents modeled with emission rates in EnCompass are:

   a) Carbon Monoxide (CO)
   b) Carbon Dioxide (CO_2)
   c) Lead (Pb)
   d) Mercury (Hg)
   e) Nitrogen Oxide (NO_x)
   f) Particulate Matter 2.5 ($PM_{2.5}$)
   g) Sulfur Dioxide (SO_2)

Minnesota Power Load and General Economic Assumptions

For the 2025 IRP, Minnesota Power considered portfolio development under the MISO seasonal resource adequacy construct. Minnesota Power’s planning reserve margin requirement assumptions are driven by the MISO resource adequacy requirements.

7) Customer energy and demand requirements are based on the Expected Scenario in Minnesota Power’s AFR2024 (Docket No. E-999/PR-24-11). The energy and demand forecast are based on the AFR2024 econometric modeling results plus customer adjustments for energy sales to a new customer and transmission losses. The following two base forecasts were modeled in the IRP:

   a) Base Customer Demand outlook
   b) +1100 MW Growth Scenario where industrial demand is increased by +1100 MW by 2035 based on energy demand expectations from customer Minnesota Power serves.

The transmission losses of 6 percent are added to the Annual Energies to capture the power supply requirements for serving Minnesota Power's customers.

8) Initial Capacity accreditation values for generators are based on the MISO seasonal accredited capacity ("SAC") and are based on MISO's Planning Year 2024-2025 accredited values as submitted per the MISO Module E Capacity Tracking ("MECT"). Projections for the SAC values were based on information presented at the January 17, 2024 MISO RASC meeting.[3]

9) Planning reserve margin is based on MISO's seasonal resource adequacy approach. The Planning Reserve Margins are based on Planning Year 2024-2025 Loss of Load Expectation Study Report. The Report shows a 9.0 percent reserve margin in summer, 14.2 percent in the fall, 27.4 percent in the winter, and 26.7 percent in the spring. Future planning years assume the same seasonal planning reserve margin.

10) The utility discount rate is the weighted average cost of capital ("WACC") for Minnesota Power based on current capital structure and allowed return on equity. The utilized discount rate is 6.6534 percent.

11) A general escalation rate of approximately 2.25 percent was utilized, except for capital cost for new and existing generation and transmission that is escalated at a stepped approach starting in 2025 at 4.75 percent and 3.00 percent in 2030 – average of 3.35 percent through the end of the study period.

12) The EnCompass model used in the 2025 IRP analysis includes revenue requirements for Minnesota Power's existing power supply resources, new supply side and demand side resources selected in a plan, and additional transmission upgrades required to a retire an existing generation resource or to add new generation resources to the transmission system. The revenue requirements for additional transmission upgrades are discussed further in Appendix F.

    Revenue requirements are not included for Minnesota Power's base transmission system and distribution system. It is important to note that the EnCompass model does not include all the cost attributes required to calculate a customer rate. Refer to Appendix L for the methodology Minnesota Power uses to calculate rate impacts for the Company's preferred plan ("2025 Plan").

Minnesota Power Thermal Unit Minimum/Maximum Dispatch Levels

Minnesota Power has worked diligently to maintain and improve the flexibility of its' thermal units to maximize customer benefits as renewable energy penetration continues to increase. Since 2015, the minimum dispatch level on BEC3 and BEC4 has been reduced by approximately 100 MW combined through engineering optimization and capital investments. In late 2021, Minnesota Power completed a project that further reduced BEC3's minimum dispatch level to 75MW.

The EnCompass model uses the minimum and maximum dispatch levels (shown in Table 2 below) to optimize the power supply mix for customers and minimize costs associated with thermal generation.

[3] https://cdn.misoenergy.org/20240117%20RASC%20Item%2007a%20Accreditation%20Presentation%20(RASC-2020-4%20and%202019-2631379.pdf

Table 2. Summary of Dispatch Levels on Minnesota Power Owned Thermal Units

	Minimum Dispatch Level	Maximum Dispatch Level
Plant		*All Years*
BEC3	75	350
BEC4*	210	580
Laskin Unit 1	15	49
Laskin Unit 2	15	49
Hibbard Units 3 & 4	10	44
Square Butte (Young 2) *	270	430

Denotes a jointly owned unit, Minnesota Power's share of the unit is less than 100%. Dispatch Ranges are shown for the net plant and includes other owner's shares.

B. Asset Resource Alternatives Evaluated

The resource alternatives that were screened as possible new generation alternatives are provided below. The capital costs were based on Minnesota Power's most current planning estimates for such resources. The estimates are high level engineering projections and typically have a +/- 30 percent range of accuracy. For emerging technologies, the accuracy range is significantly more ranging from -50 percent to +100 percent. These resource options were reduced to a smaller list for the 2025 IRP expansion planning evaluation in the EnCompass software through a screening process that is outlined in Appendix K.

1) 55 MW (approximate) natural gas reciprocating engine (6x9 MW)
   a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
2) 110 MW (approximate) natural gas reciprocating engine (6x18 MW)
   a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
3) 48 MW (approximate) natural gas aero-derivative unit
   a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
4) 228 MW (approximate) natural gas 1x1 simple cycle gas turbine
   a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
5) 414 MW (approximate) natural gas 1x1 simple cycle gas turbine
   a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
6) 636 MW (approximate)1x1 combined cycle gas turbine

   a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

7) 541 MW (approximate) 1x1 combined cycle gas turbine with carbon capture
   a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

8) 719 MW (approximate) 1x1 combined cycle gas turbine
   a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

9) 611 MW (approximate) 1x1 combined cycle gas turbine with carbon capture
   a) Estimated base capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

10) 100 MW (approximate) wind farm in Minnesota or North Dakota
   a) Estimated capital build costs without transmission upgrade costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
   b) Transmission interconnection upgrade costs are discussed further in Appendix F.
   c) To capture the potential for future price reductions the capital build costs beyond 2024 are adjusted utilizing a technology curve. The technology curve is the composite of capital cost reduction projected in public sources (NREL 2024 ATB) and/or purchased forecast (IHS Markit).

11) 100 MW (approximate) bifacial thin film photovoltaic ("PV") and single axis tracking solar facility located in Minnesota
   a) Estimated capital build costs without transmission upgrade costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
   b) Transmission interconnection upgrade costs are discussed further in Appendix F.
   c) To capture the potential for future price reductions the capital build costs beyond 2024 are adjusted utilizing a technology curve. The technology curve is the composite of capital cost reduction projected in public sources (NREL 2024 ATB) and/or purchased forecast (IHS Markit).

12) 100 MW / 400 MWh (approximate) lithium-ion battery facility
   a) Estimated base capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
   b) Transmission interconnection upgrade costs are discussed further in Appendix F.
   c) To capture the potential for future price reductions the capital build costs beyond 2024 are adjusted utilizing a technology curve. The technology curve is the composite of capital cost reduction projected in public sources (NREL 2024 ATB) and/or purchased forecast (IHS Markit).

13) 100 MW / 800 MWh (approximate) lithium-ion battery facility
   a) Estimated base capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
   b) Transmission interconnection upgrade costs are discussed further in Appendix F.

c) To capture the potential for future price reductions the capital build costs beyond 2024 are adjusted utilizing a technology curve. The technology curve is the composite of capital cost reduction projected in public sources (NREL 2024 ATB) and/or purchased forecast (IHS Markit).

14) 100 MW / 1200 MWh (approximate) non-lithium battery facility

a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

b) Transmission interconnection upgrade costs are discussed further in Appendix F.

c) To capture the potential for future price reductions the capital build costs beyond 2024 are adjusted utilizing a technology curve. The technology curve is the composite of capital cost reduction projected in public sources (NREL2024) and/or purchased forecast (IHS Markit).

15) 100 MW / 10000 MWh (approximate) non-lithium battery facility

a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

b) Transmission interconnection upgrade costs are discussed further in Appendix F.

c) To capture the potential for future price reductions the capital build costs beyond 2024 are adjusted utilizing a technology curve. The technology curve is the composite of capital cost reduction projected in public sources (NREL2024) and/or purchased forecast (IHS Markit).

16) 200 MW / 2,000 MWh (approximate) pumped storage hydroelectric facility

a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

17) 391 MW (approximate) super critical pulverized coal facility with carbon capture

a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

18) 442 MW (approximate) nuclear small modular reactor

a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

19) 30 MW (approximate) enhanced geothermal in North Dakota

a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

20) 30 MW (approximate) enhanced geothermal in Minnesota

a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

21) 50 MW (approximate) biomass facility

a) Estimated capital build costs in 2024 dollars is **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

22) Residential/Commercial Central Air Conditioning (“CAC”) and electric hot water heater cycling (“HW”) demand response program (investigative values only).

a) The utility cost of implementing the demand response program includes equipment cost of $400 per participant plus a bill incentive of $30 per participant per year (CAC cycling program customers) or $60 per participant per year (HW cycling program customers) in 2025 dollars.

b) The utility cost of implementing the demand response program would also include in 2025 dollars **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS].**

23) Up to 100 MW Incremental Industrial Demand Response

a) A total of 100 MW of Product B is available.

i) Product B: Long-Term Capacity Curtailable with Firm Load Control Periods Product with a $7 per kW-month capacity credit and provides a $30 per MWh Physical Interruption Energy Credit for customers who interrupt operations for economic purposes. This is the "Product B" that MP requested approval for in Docket No. E-015/M-18-735 but was not approved at the time.

b) Note that the base case assumes approximately 50 MW of industrial demand response that is representative of what Minnesota Power has under contract greater than one planning year.

24) Production Tax Credit ("PTC") and Investment Tax Credit ("ITC") assumptions are included in the evaluations. All tax credits were assumed to be sold to a third-party and incurred a 7 percent transfer discount. Minnesota Power assumed that prevailing wage and apprenticeship requirements were met and excluded the bonuses for energy impacted community and domestic content.

a) The 100 percent PTC for wind is assumed through the end of the study period.

b) The 100 percent PTC for solar is assumed through the end of the study period.

c) The 100 percent PTC for new biomass is assumed through the end of the study period.

d) The 30 percent ITC for meeting labor requirements was assumed for battery storage through the end of the study period.

e) The 30 percent ITC for meeting labor requirements was assumed for pumped hydro through the end of the study period.

f) The 30 percent ITC for meeting labor requirements was assumed for small modular reactors through the end of the study period.

g) The 30 percent ITC for meeting labor requirements was assumed for geothermal through the end of the study period.

h) The 100 percent 45Q carbon capture credit was assumed for new coal and combined cycle that included carbon capture environmental controls.

C. Minnesota Power Energy Efficiency Assumptions

Minnesota Power has evaluated past Energy Conservation and Optimization ("ECO") performance, related success factors, and potential future opportunities to determine scenarios that would help meet the Company's resource planning goals, while continuing to exceed the

State's ECO specific requirements related to the 1.75 percent of sales 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. Two scenarios of additional energy and capacity savings above the base were developed for modeling in EnCompass: High Scenario and Very High Scenario, resulting in aggregate capacity savings. By the first year, 2027, these scenarios result in capacity savings of approximately 3.4 MW for the High Scenario and 6.3 MW for the Very High Scenario. The High and Very High scenario reflect 3.5 percent of sales and 4 percent of sales, respectively. Minnesota Power's scenarios for the 2021 IRP were developed using the 2020-2029 Minnesota State Demand Side Management Potential Study ("Potential Study") funded by the Department of Commerce and led by the Center for Energy and Environment. Subsequently, the 2021 IRP informed the Company's goals for the 2024-2026 ECO plan, which was used as the baseline Energy Efficiency ("EE") assumption built into the 2025 IRP customer demand forecast. More details on the development and resulting savings are discussed in Appendix B.

A high-level summary of the modeled scenarios is shown in Table 3. Each scenario shows the extra costs and first year gigawatt hour ("GWh")/gigawatt ("GW") savings compared to the base plan included in the base energy forecast for the 2025 IRP analysis. The remaining columns represent the costs and energy savings for the options. Note the energy and demand savings and associated costs shown here are first-year savings for 2027, the year following the Company's most recently submitted Triennial (Docket No. E-015/CIP-23-93).

Table 3. Summary of Alternative ECO Scenarios – Year 2027 is shown

	Annual Program Costs (million $)		*Annual Savings at the Generator	
Scenario	*Total*	*Cost Above Base*	*Energy Above Base (GWh)*	*Summer Peak Reduction Above Base (GW)*
Base	$12.56	-	-	-
High Scenario	$25.06	$12.50	15.6	.0015
Very High Scenario	$45.12	$32.56	28.6	.0028

D. Assumptions Utilized for Stressing Variables in the IRP Analysis

The following variables were stressed low and high.

25) Wholesale market energy price sensitivities:

a) Wholesale market energy with $40/ton carbon starting in 2028

i) A low sensitivity representing a decrease of 50 percent from Reference Case Scenario: **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

   ii) A high sensitivity representing an increase of 50 percent from Reference Case Scenario: **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

b) Wholesale market energy with \$5/ton carbon starting in 2028

   i) The Low Environmental/Regulatory Costs Scenario: **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

c) Wholesale market energy with \$75/ton carbon starting in 2028

   i) The High Environmental/Regulatory Costs Scenario: **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

d) Wholesale market energy with no carbon regulation penalty

   i) Current Customer Cost Perspective Scenario: **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

26) Natural gas price forecast for Minnesota

   a) A low sensitivity representing a decrease of 50 percent from base: **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

   b) A higher sensitivity representing an increase of 50 percent from base: **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

27) Environmental Cost and Regulatory costs

28) A Reference Case Scenario was evaluated that included the mid carbon regulatory cost for CO_2 starting in 2028, along with the mid carbon environmental starting in 2025, and environmental cost for other effluents for the entire study period. As directed in the December 19, 2023 Order, the following environmental and regulation cost scenarios were also included in the 2025 IRP analysis.

   - Low Environmental/Regulatory Costs
   - High Environmental/Regulatory Costs
   - Low Environmental Costs
   - High Environmental Costs

   Note the two scenarios “Low Environmental/Regulatory Costs” and “High Environmental/ Regulatory Costs,” along with the Reference Case Scenario and Current Customer Cost Perspective, were evaluated under a Seasonal Resource Adequacy look. Minnesota Power’s approach to developing the Futures will be discussed further in Section IV of 2025 IRP.

   The evaluation of several carbon regulation levels provides insight into what the customer impact of potential carbon regulation prices will be.

   a) The low value for carbon regulatory cost ranges from \$5.00/ton starting in 2028 to \$6.41/ton in 2039.

   b) The high value for carbon regulatory cost ranges from \$75.00/ton starting in 2028 to \$96.09/ton in 2039.

29) The cost assumptions used in the environmental and regulation costs scenarios shown above for SO_2, NO_x, $PM_{2.5}$, CO, Pb, and CO_2 are shown below. Where applicable, the range for the Metropolitan Fringe was used. Note scenarios subject to environmental and regulation costs for CO_2 emissions, the final environmental costs were reduced by regulation costs.

a) SO_2 Environmental Cost

i) The low value for the SO_2 Environmental cost ranges from $6,055/ton starting in 2025 to $8,281/ton in 2039.

ii) The high value for the SO_2 Environmental cost ranges from $15,082/ton starting in 2025 to $20,629/ton in 2039.

b) NO_x Environmental Cost

i) The low value for the NO_x Environmental cost ranges from $3,288/ton starting in 2025 to $4,497/ton in 2039.

ii) The high value for the NO_x Environmental cost ranges from $9,777/ton starting in 2025 to $13,373/ton in 2035.

c) $PM_{2.5}$ Environmental Cost

i) The low value for the $PM_{2.5}$ Environmental cost ranges from $8,596/ton starting in 2025 to $11,757/ton in 2039.

ii) The high value for the $PM_{2.5}$ Environmental cost ranges from $21,428/ton starting in 2025 to $29,308/ton in 2039.

d) Pb Environmental Cost

i) The low value for the Pb Environmental cost ranges from $3,289/ton starting in 2025 to $4,497/ton in 2039.

ii) The high value for the Pb Environmental cost ranges from $3,842/ton starting in 2025 to $5,255/ton in 2039.

e) CO Environmental Cost

i) The low value for the CO Environmental cost ranges from $1.48/ton starting in 2025 to $2.02/ton in 2039.

ii) The high value for the CO Environmental cost ranges from $2.61/ton starting in 2025 to $3.57/ton in 2039.

f) CO_2 Environmental Cost

i) The low value for the CO_2 Environmental cost ranges from $143.20/ton starting in 2025 to $245.10/ton in 2039.

ii) The high value for the CO_2 Environmental cost ranges from $396.45/ton starting in 2025 to $544.00/ton in 2039.

30) A sensitivity was included that removed all externality values and carbon regulatory costs. This is referred to as the Current Customer Cost Perspective scenario.

31) Biomass fuel prices

a) The low sensitivity reduced biomass prices by approximately 15 percent from base.

b) The high sensitivity increased biomass prices by approximately 15 percent from base.

32) Capital costs for New Technology

a) The low sensitivity reduced base project costs by 30 percent from base.

b) The high sensitivity increased project costs by 30 percent from base.

33) MISO Resource Adequacy Uncertainty

a) Planning Reserve Margin (“PRM”) requirement

i) Low sensitivity – The Seasonal PRM established by MISO in their Planning Year 2024-2025 Loss of Load Expectation Study Report decreased by 2 percent from base.

ii) High sensitivity - The Seasonal PRM established by MISO in their Planning Year 2024-2025 Loss of Load Expectation Study Report was increased by 2 percent from base.

b) Direct Loss of Load

i) The seasonal class average for the Direct Loss of Load (“DLOL”) or Installed Capacity (“ICAP”) ratios are applied to new resource ICAP values to determine the DLOL accredited MW values. There are DLOL/ICAP ratios provided for 2027 and 2032, and the years between milestones are interpolated.

ii) The reserve margin is based on a ratio between Minnesota Power’s traditional coincident peak demand and a MP specific DLOL Planning Reserve Margin Requirement load value provided by MISO. The resulting ratio is applied to the coincident peak demand forecast. MISO has not filed with FERC how the demand will be calculated and allocated to each utility for DLOL. Based on information shared at MISO stakeholder meetings and Minnesota Power specific DLOL data provided by MISO, Minnesota Power thinks this is a reasonable approach until better information is available.

34) Customer sales forecast

a) The IRP evaluation included three load forecasts sensitivities:

i) -200 MW industrial demand reduction

ii) +500 MW industrial demand increase based on the AFR 2024 Planning Scenario

iii) +1500 MW industrial demand increased and 1.5x load growth in residential and commercial classes above the Base Case.

b) The Time of Use sensitivity moves all residential customers to a hypothetical Time of Use rate program. The sensitivity is modeled as reducing load during the peak hours and increasing load during all other hours to keep the energy sales forecast neutral.

c) The Higher distributed generation (“DG”) Solar + electric vehicles (“EV”) Growth Scenario increases DG solar penetration rates from the base case and increases the EV growth rate from the base case.

35) Energy Market Interaction

a) The No Market Sales and Purchases sensitivity removed the tiered energy market, allowing only purchases of emergency energy. Also removed the capability to sell economic or surplus energy into the market.

36) Renewable Uncertainty

a) A 7 percent energy factor reduction was applied to wind generating resources.

37) Interconnection costs for wind, solar and battery storage were estimated and included in the modeling. The approach to developing interconnection costs is discussed further in Appendix F. Assumptions are listed below.

a) Wind Low-End GIA Cost **[TRADE SECRET DATA BEGINS [redacted] TRADE SECRET ENDS]**

b) Solar Low-End GIA Cost **[TRADE SECRET DATA BEGINS [redacted] TRADE SECRET ENDS]**

c) Battery Low-End GIA Cost **[TRADE SECRET DATA BEGINS [redacted] TRADE SECRET ENDS]**

38) PTC and ITC availability sensitivity

a) The benefit from the PTC or ITC was removed in the 2025 Plan Characteristics Analysis.

E. Long-term Planning and Wholesale Market Interaction

This discussion is included to demonstrate why it is reasonable for the Company to assume a specific level or range of market purchases throughout the planning period within a resource plan.

Capacity Market

It should be noted that the term “market” consists of two segments, capacity and energy. Minnesota Power recognizes excessive exposure to a capacity or energy market for any power supply requirements can increase cost risk and might not be in customers' best interest. Modeling limited capacity purchases allows a robust evaluation of long-term resources rather than over reliance on market that results in non-viable plans that don’t fully capture impacts of purchase power on the capacity position or cost risks.

The Company limits utilization of capacity purchases to no more than 100 MW through the entire planning period. This approach provides a strategic bridge for short-term capacity needs. These purchases are expected to be priced at a lower cost than new resources and bridge the Company’s need until the capacity need grows to a large enough magnitude to justify a resource build. In the absence of bridge purchases, the capacity expansion model would show the need for a new resource, typically larger than the immediate need, which could distort the overall planning approach of determining the preferred resource plan.

The pattern of allowing a short-term bridge capacity purchase is maintained in the entire range of the study. The expected availability of short-term bridge capacity is based on the concept of regional reserve margin requirements, where all parties are planning a system for having adequate resources plus the planning reserve margin. The Company has utilized the bilateral capacity market for decades to buy and sell capacity on both a long and short-term basis. The presence of a market capacity transaction in expansion planning outlooks identifies that a utility can optimize the timing of its next resource or wait until innovative technologies mature and become lower costs by reaching out to the industry marketplace and looking for a transaction to help bridge their customers to the next resource.

Energy Market

The MISO energy market provides a seamless interface for balancing resources and load in real time and day ahead timeframes and the 20 years of the Locational Marginal Price history has been extremely helpful in designing resource plans.

Regional markets like MISO allow daily energy needs to be pooled together so that each utility is continuously providing for the region's larger energy needs. It is prudent planning practice to include some wholesale market interaction in base planning assumptions, as utilities transition into new generating resources and power purchase transactions for customers. When considering the integration of intermittent generation into the supply portfolio, as many utilities have embarked on with the onset of the Minnesota Renewable Energy Standard and low cost of solar and wind resources, it is appropriate to have a wholesale market available. However, the responsibility to ensure there are adequate resources to serve load is with the utilities on behalf of their customers.

Energy market purchases are in the best interest of customers to plan and integrate with the variability of intermittent resources. Wind, hydro, and solar all rely on the availability of other generation to “fill in the gaps” when the resource is not available and move the excess renewable energy when resource supply is greater than load. Not having the regional market available during long-term expansion planning to help with the intermittent nature of renewable generation would promote overbuilding of a single utility’s system and not account for reasonable levels of market energy. Excluding the presence of the market would not only result in increased customer costs but also minimize the value proposition of regional markets like MISO.

With the progression of resource transformation from a fleet of dispatchable baseload resources to higher levels of intermittent resources and natural gas dispatchable resources, the dynamics of the market interface in resource planning has become much more complicated. Historic pricing shapes are typically scaled to forecasted values and have the hourly shape that would send the “price” signal to the capacity expansion planning that a high dependency on the market is least cost We know from best practices and risk management principles that the market has much higher levels of price uncertainty, especially given the current trends. In order to reflect the expectation of the market supply in the realm of meeting other planning objectives and knowing the complexity of the other resource availability, resource planning is modeling a more limited and expensive market. Once the resource planning capacity expansion has provided results to select a resource portfolio, the production model is set up with a more operational view of the MISO market, with tiered pricing that is indicative of showing both a market for excess resource production and the ability to have a net purchase for periods of resource outages. This approach is reflective of each utility taking their responsibility to create a reliable portfolio for customers and bringing those resources to the regional marketplace for optimization.

Market energy purchases are limited through both a capacity limit and a tiered cost structure, which increases as energy purchases increase (as described in item A.2). Both regional capacity and energy prices are projected through the independent scenario forecasts that Minnesota Power subscribes to and updated biannually. The uncertainty of market prices and level of capacity interaction is tested through sensitivity analyses. These sensitivities illustrate potential operational and cost risks for customers of a given portfolio and help identify if a different resource strategy is needed. Items D.1-4 and 17 above identify the ranges utilized. The wholesale market is included in the 2025 IRP and the regional reserve margin and bilateral support of the region will continue to be part of the Company’s power supply in the future.

F. Retirement Methodology for 2025 IRP Evaluation

This Appendix provides additional details on Minnesota Power’s existing thermal fleet and the methodology utilized in the 2025 IRP to evaluate the customer impact of the retirement of the BEC3 and BEC4 and the Hibbard Renewable Energy Center (“HREC”) generation assets. Specifically, this section discusses the following items:

- Generation Asset Retirement background; and
- Generation Asset Retirement methodology.

Generating Asset Retirement Background

This IRP evaluates the viability of Minnesota Power's continued operation of its remaining two baseload generation assets post ceasing coal operations, BEC3 and BEC4, into the future. The IRP also included a Dispatchable Generation Retirement study for HREC. The evaluation of power plant retirement is driven by two factors: 1) the increasing environmental regulation and State policies that move towards a more carbon free power supply, and 2) lower cost replacement options such as wind generation, energy storage, and cleaner, efficient natural gas-fired combined cycle units. Couple these variables with tax incentives for carbon free technologies, and declining cost curve outlook for renewables and energy storage, and the result is that many utilities have begun retiring older generation and continue to evaluate alternatives available for each of their remaining coal-fired and biomass generating assets. Although, as higher levels of retirement occur in MISO, there is more scrutiny of how that generation is replaced. As dispatchable generation is being replaced with more intermittent resources, there are operational characteristics being lost that are needed for a reliable system. This was part of the reason Minnesota Power added the reliability criteria evaluation to the IRP analysis – ensure that the needed operating characteristics provided by coal generation are being replaced at the appropriate level for reliability.

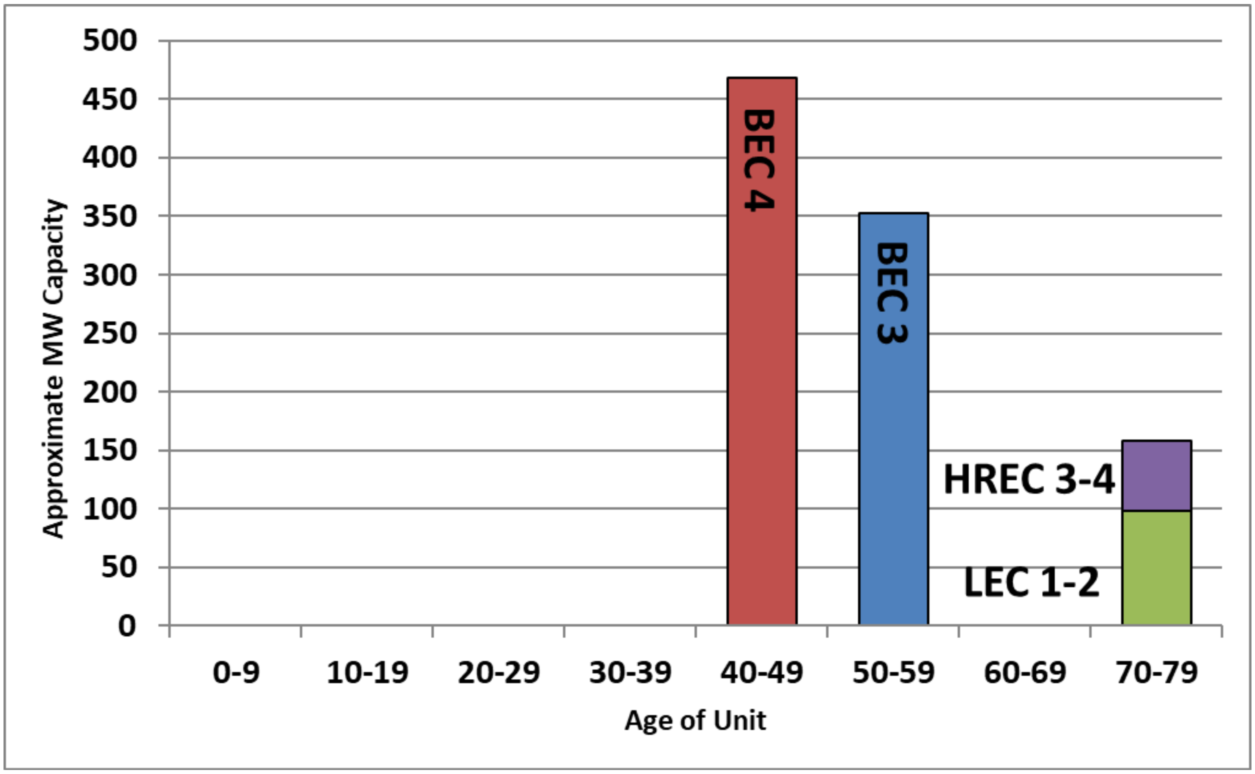
In this highly uncertain landscape of future environmental regulations, the alternatives for existing coal-fired generating assets are limited. The realm of current considerations by U.S. utilities for the future of these generating assets includes:

- Continued operation with additional retrofit and environmental controls – i.e., carbon capture.
- Idling operations or mothballing – i.e., suspending operations for a certain period and allow for reassessing operations later; and
- Permanent shutdown/retirement including dismantling.

A unit retirement for existing Minnesota Power thermal facilities could occur based on a number of factors: 1) reaching the end of the useful accounting life or engineering life; 2) increased environmental regulations, which make the unit uneconomical to upgrade or operate; 3) failure of a major component which makes the unit uneconomical to repair; 4) state policies that lead to a more carbon free power supply mix serving customers; or 5) a shift in strategy or generation requirements, which change the need for the unit as a power supply resource.

A unit's age and size are both significant factors when evaluating the economic viability of the generating asset. The Company recognizes that thermal generating assets at BEC and HREC being addressed in its 2025 IRP are part of the aging fleet within the United States, albeit BEC has the only two remaining baseload generation assets in northern Minnesota and in the Company's power supply. Although with the two units' ages both being between 45 and 52 years old, these assets have been maintained and operated prudently today. BEC3 and BEC4 do have a remaining plant balance of approximately $638 million today, and sizable portion is tied to the investment in environmental controls that occurred between 2009 and 2016. HREC provides valuable renewable energy that can be dispatched when other renewable resources are not available, although it is the oldest thermal unit in Minnesota Power's portfolio. HREC current remaining plan balance is approximately $22 million. BEC3 and BEC4and HREC are viable power supply resources for Minnesota Power and customers are benefitting from the dispatchable energy being produced. More detail on each of the BEC and HREC generating units can be found in Appendix C.

Figure 1. Minnesota Power's Age of Thermal Fleet



Asset Retirement Methodology

Identifying the appropriate timing for any future retirement of a coal or biomass-fired asset is a complex evaluation that includes consideration of the utility’s current and future power supply needs, impacts to the reliability of the transmission system, and time it will take to restore the system reliability and energy provided by the retired units, which could take up to over 8-10+ years. BEC3 and BEC4 are the only remaining baseload generators in Minnesota Power’s system, and notably, in all northern Minnesota. The retirement of the last remaining baseload generation in a region will have widespread and significant impacts to the regional system that must be addressed before retirement. These effects of generation asset retirement on future and long-term fleet outlook and socioeconomic impact were given careful consideration for the 2025 IRP.

When evaluating a potential asset retirement, it is critical to consider the following cost areas: 1) the remaining value of the asset being retired, 2) the cost of physical decommissioning and restoration of the site, 3) the replacement cost of additional generating supply, 4) the cost of transmission upgrades requirement to maintain reliability, and 5) the avoided environmental costs or carbon regulation costs. The effect of these factors on customer power supply costs and the time it will take to build replacement generation or new transmission must be considered in any retirement decisions. The retirement of a generating facility has an economic effect on the surrounding communities, which is also an important consideration. Areas of consideration are detailed below, along with the methodology utilized for asset retirement assessment in the 2025 IRP.

1) Remaining Asset Value

The remaining value of a generating asset represents the remaining financial obligation of investments made in the unit that have not yet been recovered. Minnesota Power has carefully and prudently ensured that each of its facilities remains ready and available to meet customer needs over the past several decades. This was achieved through appropriate capital investments as well as regular operations and maintenance expenditures, which are further described in Appendix C. Due to this continued capital investment, upon retirement there will be a remaining asset value that will be included in base rates for any asset that is retired prior to its current approved book life using accelerated depreciation. Depending on the magnitude, the remaining asset value can impact a decision of when to retire an asset.

2) Decommissioning Cost

When an asset is retired there is a cost associated with the decommissioning of the facility and site, as well as bringing the property back to a useable or saleable condition. The costs typically include all environmental conditions associated with lead paint, asbestos, or hazardous materials on site, and deductions for expected salvage that would be received from scrap copper and steel. For the 2025 IRP, the expenses associated with the decommissioning of a generating asset were included as part of the expense of retirement and were assumed to be recovered over a 10-year period. The decommissioning costs used in this analysis are based on the BEC and HREC decommissioning refresh from the 2020 Decommissioning Study completed by Burns & McDonnell in 2024.

3) Replacement Power Cost

The timing of a generating asset retirement determines the replacement power needed. Any retirement action removes both energy and capacity from the customer power supply; this reduction is taken into the larger planning process to identify the least cost mechanism to meet expected customer requirements. Resource alternatives used to replace lost energy and capacity range from a new dispatchable generating plant, intermittent renewable generation, a regional wholesale market purchase, or demand-side resources (such as energy efficiency and load control). Each resource alternative is compared in terms of how it fits (i.e., energy profile and time it takes to build) with the rest of the existing power supply to meet customer load requirements. Section IV of the 2025 IRP outlines the Company's planning process in more detail, including the process for defining an expansion plan to meet customer requirements.

4) Transmission Upgrade Costs

When an asset is retired, it is important to include the cost of new transmission required to ensure reliable electric service can be maintained for customers. Minnesota Power's experience to date is that a change in operating status of a baseload generation asset (i.e., retirement) will result in new transmission being required to be built. Depending on the scope and scale of the transmission project, it could be expected to take over 8-10+ years to develop, permit, and construct a project, and the cost of the new addition could approach $1 billion. Given the potential magnitude and time required to implement a new transmission project, Minnesota Power considers evaluating transmission needs. Appendix F outlines in more detail Minnesota Power's approach to developing transmission costs associated with the retirement of BEC4 and HREC.

5) Avoided Environmental or Regulatory Costs

Minnesota Statutes[4] direct the Commission to establish a value for environmental cost of several pollutants (NO_x, SO_2, Hg, Pb, $PM_{2.5,}$ and CO_2) and CO_2 future regulation costs. Utilities must include these costs when evaluating resource options in a resource plan and certificate of need proceeding. In the 2025 IRP analysis, these costs are added onto any generation or energy purchase within the power supply that emits these pollutants. Also considered are the costs of pollutants from energy replacing retired generation. The cost of emissions removed when a generator is retired and the costs of emissions from replacement energy is netted, and this can be referred to as "Environmental Costs Impact." (Note that the "Environmental Costs Impact" can include environmental cost and CO_2 regulation costs.)

Environmental costs will influence the resource selection in the IRP analysis, but the savings in environmental costs are not directly reflected in customer rates. For example, the least cost plan when considering the value of avoided environmental costs could also result in the highest rates for customers, because there is no financial compensation for avoiding emissions. This is an especially important consideration when developing a resource plan – balancing the value of avoided emissions with the resulting customer rate impact.

Community Impact

The most difficult aspect of considering a future generating asset retirement is the associated effect on surrounding communities. Some direct economic impacts to the community would include job losses at the facility itself, reduced income for the facility's suppliers and service providers, and loss of tax revenues for local government. Further, there are secondary economic impacts including: reduced retail purchases and associated tax revenues from former facility employees, possible outmigration from the area and reduced property values. An additional, less quantifiable effect would be the loss of volunteer work, sponsorship, and general community involvement from the facility or facility employees and families.

The Company examined the socioeconomic impacts associated with each individual retirement or addition in the IRP and then estimates the secondary effects using a regional economic impact model. Minnesota Power uses a custom Regional Economic Model, Inc. ("REMI") software REMI model build specifically for the Company's 13-County "Planning Area" or "Region."[5] This study's detailed findings, modeling assumptions, and methodology are detailed in Appendix M of the 2025 IRP.

Pre-notification Requirements

The process for removing a generating unit from the interconnected power system is complex. Each shutdown can have far-reaching impacts on the physical side of the power system and financial repercussions to customers' electric service. Coordination of such retirements requires the involvement of many agencies and entities and significant advanced notice for each. Some of the parties who will need to be engaged include MISO, the Commission, North American Reliability Corporation, Minnesota Pollution Control Agency, U.S. Environmental Protection Agency ("EPA"), Minnesota Department of Natural Resources, and the Midwest Reliability Organization.

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[4] Minn. Stat. §§ 216B.2422, subd. 3 and 216H.06.

[5] Minnesota Power's 13-County Planning Area is defined as: Carlton, Cass, Crow Wing, Hubbard, Itasca, Koochiching, Lake, Morrison, Pine, Saint Louis, Todd, and Wadena counties in Minnesota, and Douglas County in Wisconsin.

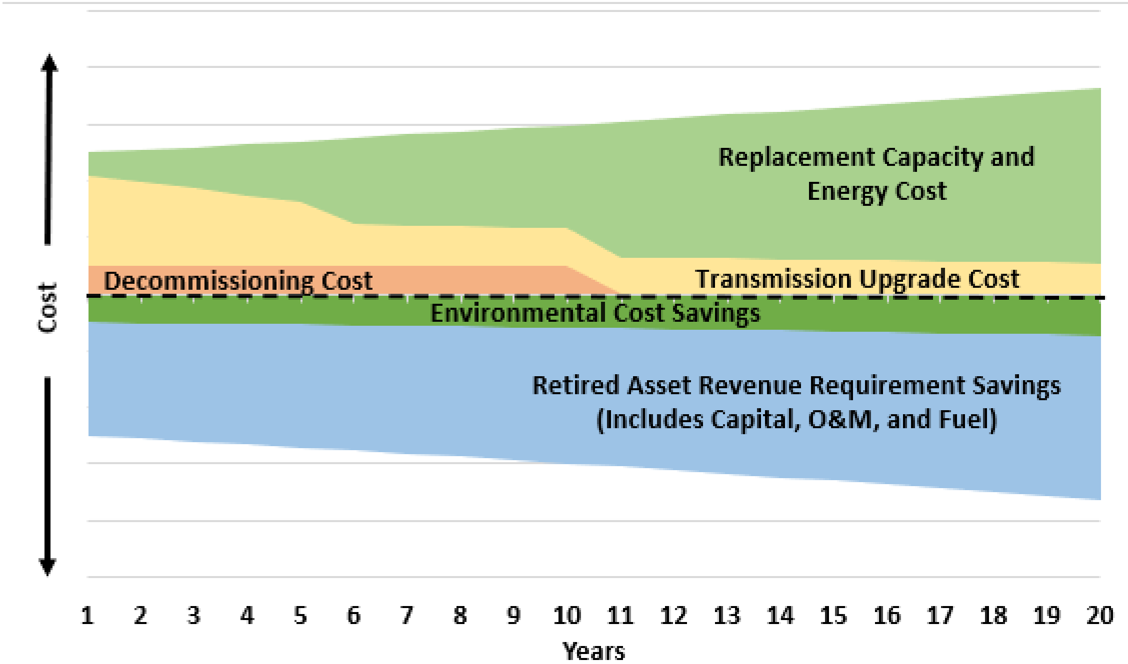
The timeline required for coordination can change on a case-by-case basis and can be delayed based on increases in volumes of shutdown requests to each entity. When first evaluating retirements, up to a 10-year timeframe can be expected as reasonable for the last two large generators located in northern Minnesota to be shut down while allowing for necessary coordination with the associated processes of each agency and entity. The is the second IRP where Minnesota Power evaluated retirement at BEC, and the company has started to take action on preparing the system for post coal operations, which could reduce the timeframe between making the decision and retirement – although, other factors such as bring replacement generation online could again extend the timeframe for retirement.

Minnesota Power's Methodology for Asset Retirement

Minnesota Power assumed in its base case that HREC continued to operate at an investment level required for continued long-term operations. The base case assumed that BEC3 and BEC4 ceased coal operations at the cease coal commitment date approved in the 2021 IRP. With the BEC3 cease coal date of by 2030 and the current approved accounting book like through 2035, the depreciation was accelerated to align with the cease coal date of 2030 in the analysis. The BEC4 cease coal date of by 2035 is close to the current approved book life of December 2035, only minor modifications were needed to be made in the base case for BEC4. For BEC3 AND BEC4 and HREC, a matrix of remaining asset values was calculated that identified what the decommissioning and transmission upgrade costs that would be incurred if the unit were retired in a particular year.

EnCompass was utilized to evaluate if asset retirement would be economically plausible or if it showed a benefit for customers. The EnCompass analysis took into consideration all aspects of the retirement including 1) remaining asset value and decommissioning cost, 2) replacement capacity and energy cost, 3) transmission upgrade costs required to restore system reliability, 4) retired asset revenue requirement savings for customers (i.e. fuel, O&M, and avoided capital costs), and 5) and the environmental cost and carbon regulation cost impacts. The graphic below demonstrates a hypothetical retirement in which all four components work together to produce the ultimate value equation for the customer by netting both the costs and benefits. Note the graphical representation is not to scale and is for demonstration purposes only; each shutdown scenario would look different.

Figure 2. Sample Retirement Diagram



The EnCompass simulations are not robust enough to dictate the ultimate retirement planning decision for a generating asset; they can, however, be a useful planning tool. Minnesota Power will take the outcome of the retirement analysis conducted within the 2025 IRP and carefully monitor the drivers to determine the viability of an asset retirement.