APPENDIX J: ASSUMPTIONS AND OUTLOOKS

The following section provides a summary of the key economic modeling assumptions and basis that Minnesota Power (or "Company") utilized in the Encompass Power Planning Software ("EnCompass") analysis completed for the 2021 Integrated Resource Plan ("2021 IRP").

In its January 24, 2019 order in Docket No. E-015/AI-17-568, 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 2021 IRP Stakeholder Process discussed in Appendix R, a subgroup of interested stakeholders was formed ("Modeling Subcommittee") to work with Minnesota Power on developing modeling assumptions. A description of the Modeling Subcommittee process is included in Appendix R. Multiple stakeholders expressed that they did not want to be asked to reach a final consensus on modeling assumptions. While agreed upon assumptions were not a product of the stakeholder process, the input and feedback received helped shape key modeling assumptions detailed in this Appendix J.

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

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

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

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

D) <u>Assumptions Utilized in the Sensitivity Analysis</u>

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

F) <u>Retirement Methodology for 2021 IRP Evaluation</u> – A description of the retirement method utilized during the analysis within the 2021 IRP and assumptions for decommissioning of generation facilities.

A. Base Economic Modeling Assumptions

Study Period

The timeline of the 2021 IRP analysis is 2021 through 2035. The power supply costs shown in the Plan are the net present value of cost from 2021 through 2035 and are reported in 2021 dollars, unless noted otherwise.

The expansion planning analysis conducted with the EnCompass Model considered 15 years of end effects after 2035 when selecting the lowest cost plan. Note that the EnCompass Model does not have an end effects calculation built within the tool like the Strategist Proview tool that was used in prior resource plan filings. The Company mimicked the end effect calculation available in Strategist by allowing the power supply to economically dispatch for another 15 years after 2035.

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 2021 IRP. Environmental costs were not considered in the expansion plan analysis because the current build for EnCompass does not include the function to consider environmental cost when selecting different resource portfolios. These value ranges are approximate representation of what is in the EnCompass database.

        i. Oxides of nitrogen ("NO_x") environmental cost range: $5,969/ton in 2021 to $7,981/ton in 2035

        ii. Sulfur dioxide ("SO_2") environmental cost range: $9,195/ton in 2021 to $12,295/ton in 2035

        iii. Particulate matter 2.5 ("PM2.5") environmental cost range: $13,075/ton in 2021 to $17,483/ton in 2035

    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 2021 IRP. These value ranges are approximate representations of what is in the EnCompass database.

        i. Carbon monoxide ("CO") environmental cost range: $1.71/ton in 2021 to $2.24/ton in 2035

        ii. Lead ("Pb") environmental cost range: $2,937/ton in 2021 to $3,844/ton in 2035

    c. The Reference Case Scenario utilized the environmental cost for carbon from the Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs published on September 30, 2020, under Docket Nos. E999/CI-07-1199 and E999/DI-19-406. The environmental cost for carbon was included in the Reference Case Scenario from 2021 through 2024 and was used in the swim lane analysis only. Starting in 2025, the middle value for the regulatory cost of carbon was included through the end of the study period and used in the expansion plan analysis and swim lane analysis.

        i. Carbon environmental cost range: $29.03/ton in 2021 to $32.65/ton in 2024

[1] Values are in nominal dollars.

d. The SO_2 allowance price for Cross-State Air Pollution Rule ("CSAPR") Group 2: \$1.78/ton in 2021 to \$0/ton in 2035. The SO_2 allowance prices were used in the Current Customer Cost Perspective scenario.

e. Natural gas forecast assumptions utilized in the base forecast.

   i. Natural Gas for Minnesota: \$3.42/MMBtu in 2021 to \$4.84/MMBtu in 2035

   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 at approximately 2 percent annually, on average, after 2021. The delivery charges applied were as follows:

      1. [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS] for the fuel supply of new generic combustion turbine and combined cycle gas generation alternatives located at Boswell Energy Center ("BEC") site.

      2. [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS] for the fuel supply of new generic combustion turbine and combined cycle gas generation alternatives located at BEC site.

      3. [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS] for the fuel supply of new generic reciprocating internal combustion engine ("RICE").

      4. [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS] for the Nemadji Trail Energy Center ("NTEC") combined cycle facility.

      5. [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS] for the Laskin Energy Center ("LEC").

      6. [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS] For natural gas refuel scenarios of existing units at BEC.

   ii. The firm delivery component of intermediate natural gas resources like the generic combined cycle and NTEC was incorporated into the fixed cost revenue requirement for the asset.

f. Delivered coal price forecast assumptions utilized in the base forecast represent the attributes of each of Minnesota Power's facilities and include: [TRADE SECRET DATA BEGINS

[redacted]

TRADE SECRET DATA ENDS]

g. Delivered biomass price forecast assumptions utilized in the base forecast:

    i. [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]

h. Wholesale Market Capacity (approximate): $1,243/MW-month in 2021 to $7,071/MW-month in 2035. Wholesale market capacity was made available up to a maximum of 100 MW for the model during all study years.

i. Wholesale Market Energy with $15/ton carbon starting in 2025 (approximate): $27/MWh in 2021 to $50/MWh in 2035.

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 Midcontinent Independent System Operator ("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% of base market price forecast
    iii. 451 to 600 MW at 150% of base market price forecast
    iv. Greater than 600 MW at emergency energy price (200% of base market price forecast)

3. The estimated decommissioning cost for Minnesota Power's BEC Units 3 and 4 ("BEC3 & 4") included in the shutdown scenarios discussed in the 2021 IRP are from a study by Burns & McDonnell called Site Decommissioning Study 2020. Decommissioning costs at each facility are assumed to be recovered and depreciated for 10 years past the shutdown date. Remaining plant balances at each facility are assumed to be recovered and depreciated according to their current schedule. This approach is included in Section F of this Appendix.

4. Carbon regulation penalty costs

   As directed in the Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs published on September 30, 2020, under Docket Nos. E999/CI-07-1199 and E999/DI-19-406, Minnesota Power modeled a Reference Case Scenario that included the middle value for the regulatory cost of carbon starting in 2025. The regulatory cost for carbon used in the Reference Case Scenario costs is shown below:

   a. Mid CO_2 regulation value ranging from $15.00/ton starting in 2021 to $18.55/ton in 2035.

<u>Minnesota Power Resources and Bilateral Power Transactions</u>

Another important 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 Plan the Company has the following bilateral transaction alternative made available:

5. An unidentified bilateral purchase, referred to as a "bridge purchase" in the analysis write-up, was modeled in EnCompass as a new resource alternative starting in January 1, 2026.

   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.

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)

There were two approaches taken to modeling emission rates for CO_2 in the EnCompass model.

a. A CO_2 rate was set-up to calculate the cost of a CO_2 regulation penalty; this is referred to as "CO_2" in the EnCompass model. These CO_2 rates were applied to the generation resources that would be subject to a CO_2 regulation penalty in a CO_2 constrained scenario.

b. A CO_2 rate was set-up to calculate the externality cost of CO_2 and to measure the progress on meeting the state greenhouse gas goal (Minn. Stat. § 216H.02); this is referred to as "CO_2-E" in the EnCompass model. This CO_2 rate was assigned to all power supply resources, including bilateral market purchases, generation and energy sales. The accompanying CO_2 with an energy sale is removed from the power supply. The "CO_2-E" rate modeled in EnCompass was pounds per MWh and used in the swim lane analysis only. *Note that the CO_2 emissions from MISO market energy purchases and sales were calculated outside of the EnCompass model.*

Minnesota Power Load and General Economic Assumptions

For the 2021 IRP, Minnesota Power considered portfolio development under both a summer and winter peak seasonal resource adequacy requirement. Minnesota Power's planning reserve margin requirement assumptions are driven by load forecast and MISO resource adequacy requirements.

7. Customer energy and demand requirements are based on the Expected Scenario in Minnesota Power's AFR2020 (Docket No. E-999/PR-20-11). The energy and demand forecast is based on the AFR2020 econometric modeling results plus customer adjustments for energy sales to a new customer and transmission losses.

   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. Capacity accreditation values for generators are the unforced capacity ("UCAP") and are based on MISO's Planning Year 2020-2021 generation performance test results and historical XEFORd[2] per the Module E Resource Adequacy program.

9. Planning reserve margin is based on MISO's required reserve margin of 8.9 percent based on its Planning Year 2020-2021 Loss of Load Expectation Study Report and UCAP generating capability and projected energy demand in the MISO Region.

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 7.0639 percent.

[2] Equivalent Forced Outage Rate Demand ("XEFORd") is a measure of the probability that a generating unit will not be available due to forced outages or forced de-ratings when there is demand on the unit to generate.

11. A general escalation rate of approximately 2.0 percent was utilized, except for capital cost for new and existing generation is escalated at 2.75 percent per year and capital cost for new transmission is escalated at 2.5 percent per year.

12. The EnCompass model used in the 2021 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 is discussed further in Appendix F.

    Revenue requirements are not included for Minnesota Power's base transmission system and distribution system. It's 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 ("2021 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 & 4 has been reduced by approximately 100 MW combined through engineering optimization and capital investments. Minnesota Power is evaluating a project at BECI 3 that would reduce the minimum dispatch level by approximately 100 MW, the project could be implemented prior January of 2022.

The EnCompass model uses the minimum and maximum dispatch levels (shown in Table 1 below) to optimize the power supply mix for customers and minimize costs associated with thermal generation – this includes the potential project to lower BEC3 minimum dispatch level.

Table 1: Summary of Dispatch Levels on Minnesota Power Owned Thermal Units

<table>
<tr><th></th><th colspan="2">Minimum Dispatch Level</th><th>Maximum Dispatch Level</th></tr>
<tr><td>Plant</td><td>Pre - 2022</td><td>Jan. 2022+</td><td>All Years</td></tr>
<tr><td>BEC3</td><td>175</td><td>75</td><td>350</td></tr>
<tr><td>BEC4*</td><td colspan="2">210</td><td>580</td></tr>
<tr><td>Laskin Unit 1</td><td colspan="2">15</td><td>49</td></tr>
<tr><td>Laskin Unit 2</td><td colspan="2">15</td><td>49</td></tr>
<tr><td>Hibbard Units 3 & 4</td><td colspan="2">10</td><td>44</td></tr>
<tr><td>Square Butte (Young 2)*</td><td colspan="2">270</td><td>430</td></tr>
</table>

**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. These resource options were reduced to a smaller list for the 2021 IRP expansion planning evaluation in the EnCompass software through a screening process that is outlined in Appendix K.

1. 591 MW (approximate) natural gas 1x1 combined cycle facility
   a. Estimated capital build costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
2. 280 MW (approximate) natural gas combustion turbine unit
   a. Estimated capital build costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
3. 114 MW (approximate) natural gas aero-derivative unit
   a. Estimated capital build costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
4. 48 MW (approximate) natural gas aero-derivative unit
   a. Estimated capital build costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
5. 110 MW (approximate) natural gas reciprocating engines (6 x 18MW engines)
   a. Estimated capital build costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
6. 391 MW (approximate) super critical pulverized coal generation asset with 80% CO_2 capture equipment

   Estimated capital build costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
7. 165 MW (approximate) nuclear small modular reactor ("SMR") facility
   a. Estimated capital build costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
8. 50 MW (approximate) biomass-fired unit
   a. Estimated capital build costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
9. 100 MW (approximate) wind farm located in North Dakota
   a. Estimated base capital build costs without transmission interconnection upgrade costs in 2021 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 2021 are adjusted utilizing a technology curve. The technology curve is the composite of capital cost reduction projected in public sources (NREL 2020 ATB) and purchased forecast (IHS Markit).

10. 100 MW (approximate) wind farm located in southern Minnesota
    a. Estimated capital build costs without transmission upgrade costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
    b. Transmission interconnection upgrade costs are discussed further in Appendix F to be filed on February 1st, 2021.
    c. Wind built prior to 2025 assumed to include a 60 percent PTC.
    d. Wind built in 2025 and afterwards does not include the PTC.
    e. To capture the potential for future price reductions the capital build costs beyond 2021 are adjusted utilizing a technology curve. The technology curve is the composite of capital cost reduction projected in public sources (NREL 2020 ATB) and purchased forecast (IHS Markit).

11. 100 MW (approximate) bifacial thin film photovoltaic ("PV") and single axis tracking solar facility located in Minnesota
    a. For generic solar and "Net Zero" solar, the estimated base capital build costs without transmission upgrade costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
    b. For clarity, up to 300 MW of "Net Zero" solar is available to be selected and assumes transmission interconnection upgrade costs are zero.
    c. Transmission interconnection upgrade costs are discussed further in Appendix F.
    d. Solar facilities built prior to 2024 were assumed to include a 26 percent investment tax credit ("ITC").
    e. Solar facilities built in 2024 and afterwards were assumed to include a 10 percent ITC.
    f. To capture the potential for future price reductions the capital build costs beyond 2021 are adjusted utilizing a technology curve. The technology curve is the composite of capital cost reduction projected in public sources (NREL 2020 ATB) and purchased forecast (IHS Markit).

12. 100 MW / 400 MWh (approximate) lithium ion battery facility
    a. Estimated base capital build costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
    b. To capture the potential for future price reductions the capital build costs beyond 2021 are adjusted utilizing a technology curve. The technology curve is the

composite of capital cost reduction projected in public sources (NREL 2020 ATB & EIA 2019 Annual Energy Outlook) and purchased forecast (IHS Markit).

13. 100 MW / 800 MWh (approximate) lithium ion battery facility
    a. Estimated base capital build costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
    b. To capture the potential for future price reductions the capital build costs beyond 2021 are adjusted utilizing a technology curve. The technology curve is the composite of capital cost reduction projected in public sources (NREL 2020 ATB & EIA 2019 Annual Energy Outlook) and purchased forecast (IHS Markit).

14. 100 MW / 1200 MWh (approximate) flow battery facility
    a. Estimated capital build costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
    b. To capture the potential for future price reductions the capital costs were held flat in nominal dollars. A public or purchased forecast for a flow battery technology curve was not available.

15. 200 MW / 1,600 MWh (approximate) adiabatic compressed air energy storage facility
    a. Estimated capital build costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]

16. 200 MW / 2,000 MWh (approximate) pumped storage hydroelectric facility
    a. Estimated capital build costs in 2021 dollars is [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]

17. 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 $200 per participant plus a bill incentive of $25 per participant per year (CAC cycling program customers) or $60 per participant per year (HW cycling program customers) in 2021 dollars.
    b. The utility cost of implementing the demand response program would also include in 2021 dollars [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]. The initial program cost and annual O&M were allocated 50/50 between the CAC and HW programs.

18. Up to 200 MW Incremental Industrial Demand Response
    a. Two DR alternatives are available. A total of 200 MW of Product B or Product D is available. For clarity, these two demand response products are mutually exclusive.

   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 ultimately not approved at the time.
   ii. Product D: *Long-Term Emergency Only Product* with a $5/kW-month capacity credit.

b. If the Commission approves Product C Agreements currently pending in Docket No. E-015/M-21-28, it will impact the availability of a potential Product B and Product D.

c. Note that the base case assumes approximately 40 MW of industrial demand response that is representative of what Minnesota Power has under contract greater than one planning year.

C. Minnesota Power Energy Efficiency Assumptions

Minnesota Power has evaluated past Conservation Improvement Program ("CIP") 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 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. Two scenarios of additional energy and capacity savings above the base were developed for modeling in EnCompass: High Scenario or Very High Scenario, resulting in aggregate capacity savings by 2025 of approximately 3.4 MW and 6.8 MW, respectively. The Base and Very High scenario were developed from the "Program" and "Max Achievable" scenarios identified in the Minnesota Potential Study published December 4, 2018. The High Scenario is the mid-point between the base and Very High Scenario. Minnesota Power worked with the Center for Energy and Environment staff in developing the energy efficiency programs modeled in EnCompass. 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 2, below. Each scenario shows the additional costs and additional first year GWh/GW savings as compared to the base plan which is included in the base energy forecast for the 2021 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 2024, the year following the Company's most recently submitted triennial (Docket No. E015/CIP-20-476).

Table 2: Summary of Alternative CIP Scenarios – Year 2024 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 (MN Energy Efficiency Potential Study "Program")	$15.8	$0.0	0	0
High Scenario	$24.0	$8.2	18.9	.00168
Very High Scenario (MN Energy Efficiency Potential Study "Max Achievable")	$40.2	$24.5	37.7	.0033

D. Assumptions Utilized in the Sensitivity Analysis

The following variables were stressed low and high in the single variable sensitivity analysis.

1. Wholesale market energy with $15/ton carbon starting in 2025
    a. A lower sensitivity representing a decrease of 50 percent from Reference Case Scenario: **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
    b. A low sensitivity representing a decrease of 25 percent from Reference Case Scenario: **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
    c. A high sensitivity representing an increase of 25 percent from Reference Case Scenario: **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
    d. A higher sensitivity representing an increase of 50 percent from Reference Case Scenario: **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
2. Wholesale market energy with $5/ton carbon starting in 2025
    a. The Low Environmental/Regulatory Costs Scenario: **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**
    b. A lower sensitivity representing a decrease of 50 percent from Low Environmental/Regulatory Costs Scenario: **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

c. A low sensitivity representing a decrease of 25 percent from Low Environmental/Regulatory Costs Scenario: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
d. A high sensitivity representing an increase of 25 percent from Low Environmental/Regulatory Costs Scenario: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
e. A higher sensitivity representing an increase of 50 percent from Low Environmental/Regulatory Costs Scenario: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]

3. Wholesale market energy with $25/ton carbon starting in 2025
   a. The High Environmental/Regulatory Costs Scenario: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
   b. A lower sensitivity representing a decrease of 50 percent from High Environmental/Regulatory Costs Scenario: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
   c. A low sensitivity representing a decrease of 25 percent from High Environmental/Regulatory Costs Scenario: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
   d. A high sensitivity representing an increase of 25 percent from High Environmental/Regulatory Costs Scenario: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
   e. A higher sensitivity representing an increase of 50 percent from High Environmental/Regulatory Costs Scenario: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
4. Wholesale market energy with no carbon regulation penalty
   a. Current Customer Cost Perspective Scenario: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
   b. A lower sensitivity representing a decrease of 50 percent from Current Customer Cost Perspective Scenario: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
   c. A low sensitivity representing a decrease of 25 percent from Current Customer Cost Perspective Scenario: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
   d. A high sensitivity representing an increase of 25 percent Current Customer Cost Perspective Scenario: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]
   e. A higher sensitivity representing an increase of 50 percent from Current Customer Cost Perspective Scenario: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]

5. Natural gas price forecast for Minnesota

   a. A lower sensitivity representing a decrease of 50 percent from base: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]

   b. A low sensitivity representing a decrease of 25 percent from base: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]

   c. A high sensitivity representing an increase of 25 percent from base: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]

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

   e. The highest sensitivity representing an increase of 100 percent from base: [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET DATA ENDS]

6. Environmental Cost and Regulatory costs

A Reference Case Scenario was evaluated that included the mid carbon regulatory cost for CO_2 starting in 2025, along with the mid carbon environmental cost prior to 2025, and environmental cost for other effluents for the entire study period. Note that all environmental costs were included in the swim lane analysis only. To comply with the Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Cost published on September 30, 2020, under Docket Nos E999/CI-07-1199 and E999/DI-19-406, the following environmental and regulation cost scenarios were included in the 2021 IRP analysis:

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

Note the four scenarios listed above, along with the Reference Case Scenario and Current Customer Cost Perspective, were evaluated under a Summer Resource Adequacy and Winter Resource Adequacy look – these are referred to as Futures in the analysis. Minnesota Power's approach to developing the Futures will be discussed further in Section IV of 2021 IRP.

The evaluation of several carbon regulation levels provides insight into what the customer impact of potential carbon regulation prices will be. The carbon regulation costs used in the Low Environmental/Regulatory Costs and High Environmental/Regulatory Costs scenario are shown below. The carbon regulatory cost ranges are from the Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Cost published on September 30, 2020, under Docket Nos E999/CI-07-1199 and E999/DI-19-406.

a. The low value for the carbon regulatory cost ranges from $5.00/ton starting in 2025 to $6.18/ton in 2035.

b. The high value for the carbon regulatory cost ranges from $25.00/ton starting in 2025 to $30.91/ton in 2035.

The environmental 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.[3]

a. The low value for the SO_2 Environmental cost ranges from $5,067/ton starting in 2021 to $6,774/ton in 2035.

b. The high value for the SO_2 Environmental cost ranges from $12,621/ton starting in 2021 to $16,876/ton in 2035.

c. The low value for the NO_x Environmental cost ranges from $2,751/ton starting in 2021 to $3,679/ton in 2035.

d. The high value for the NO_x Environmental cost ranges from $8,181/ton starting in 2021 to $10,939/ton in 2035.

e. The low value for the $PM_{2.5}$ Environmental cost ranges from $7,193/ton starting in 2021 to $9,618/ton in 2035.

f. The high value for the $PM_{2.5}$ Environmental cost ranges from $17,931/ton starting in 2021 to $23,975/ton in 2035.

g. The low value for the Pb Environmental cost ranges from $2,661/ton starting in 2021 to $3,483/ton in 2035.

h. The high value for the Pb Environmental cost ranges from $3,213/ton starting in 2021 to $4,206/ton in 2035.

i. The low value for the CO Environmental cost ranges from $1.23/ton starting in 2021 to $1.62/ton in 2035.

j. The high value for the CO Environmental cost ranges from $2.18/ton starting in 2021 to $2.86/ton in 2035.

k. The low value for the CO_2 Environmental cost ranges from $10.21/ton starting in 2021 to $17.89/ton in 2035.

l. The high value for the CO_2 Environmental cost ranges from $47.86/ton starting in 2021 to $82.60/ton in 2035.

[3] SO_2, NO_x, and $PM_{2.5}$ are the environmental cost values for criteria pollutants from the Environmental and Socioeconomic Costs published on January 3, 2018, under Docket Nos E-999/CI-14-643. CO and Pb are the 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 carbon environmental cost ranges are from the Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Cost published on September 30, 2020, under Docket Nos E999/CI-07-1199 and E999/DI-19-406.

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

7. Coal fuel prices
    a. The low sensitivity reduced coal prices by approximately 10 percent from base.
    b. The high sensitivity increased coal prices by approximately 20 percent from base.
8. 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.
9. Capital costs excluding solar, wind, and batteries
    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.
10. Wind capital costs
    a. Low technology cost curve – reduced base capital by 8.4 percent in 2025.
    b. High technology cost curve – increase base capital by 5.9 percent in 2025.
11. Solar capital costs
    a. Low technology cost curve – reduced base capital by 5.6 percent in 2025.
    b. High technology cost curve – increase base capital by 17.4 percent in 2025.
12. Li-ion Battery costs
    a. Low technology cost curve – reduced base capital by 7.8 percent in 2025.
    b. High technology cost curve – increased base capital by 23.2 percent in 2025.
13. Wind and Solar Capacity Accreditation
    a. Low sensitivity with ELCC decreased by 2.5 percentage points.
    b. High sensitivity with ELCC increased by 2.5 percentage points.
14. Planning Reserve Margin (“PRM”) requirement
    a. Low sensitivity - The PRM established by MISO in their Planning Year 2020-2021 Loss of Load Expectation Study Report was decreased by 2 percent from base.
    b. High sensitivity - The PRM established by MISO in their Planning Year 2020-2021 Loss of Load Expectation Study Report was increased by 2 percent from base.
15. MISO Coincidence Factor

a. A low sensitivity to the MISO coincidence factor of 2 percent below base, which resulted in a MISO coincident peak demand higher than base.

b. A high sensitivity to the MISO coincidence factor of 2 percent above base, which resulted in a MISO coincident peak demand lower than base.

16. Customer sales forecast

    a. The low sensitivity is based on a 5 percent reduction in customer demand from the Expected Scenario in the AFR2020.

    b. The high sensitivity is based on the High Scenario in the AFR2020.

    c. 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.

    d. The Higher DG Solar + EV Growth Scenario increase DG solar penetration rates from the base case and increases the EV growth rate from the base case.

17. Energy Market Interaction

    a. The Reduced Market Access by 50% sensitivity reduced area interchange limits by 50 percent from base.

    b. The No Market Sales sensitivity removed the capability to sell economic or surplus energy into the market.

    c. 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.

18. Renewable Uncertainty

    a. Interconnection costs for wind was reduced by approximately 30 percent and interconnection costs for solar was reduced by approximately 65 percent. The approach to developing interconnection costs is discussed further in Appendix F.

    b. The 60 percent PTC for wind is extended through 2035. The 26 percent ITC is extended through 2035.

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.

It should be noted that the term “market” consists of two segments, capacity and energy. Minnesota Power recognizes that exposure to either a capacity or energy market for a majority of power supply requirements is not in the best interest of customers. However, its utilization in moderation in long-term planning can, and does, bring benefits and efficiencies to its customers.

From a long-term planning perspective, the Company limits utilization of market capacity to no more than 100 MW through the planning period. The inclusion of a small amount of market capacity brings benefit to the customer by bridging short-term capacity needs. These purchases can come at a lower cost than building a new resource, 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 market capacity, production cost models like EnCompass would be forced to suggest that a utility build a new resource. A facility of up to hundreds of megawatts in size, depending on technology, would be recommended when a single megawatt purchase could satisfy the need. This is not prudent resource planning for capacity and can lead to an expedited overbuild of generation if the results of expansion planning models without market capacity were implemented as prescribed.

The availability of a small amount of market capacity must be present in the long-term. The foundation of resource planning, the regional reserve margin requirements, ensure that participating utilities are moving towards integrating new resources as demand rises on the power system. When demand is stagnant or falling, as the industry has seen recently, there can be generation surpluses on the system. Or as utilities build new resources that are in excess of their direct needs, due to the size of a particular generation technology, there can be temporary surpluses. The Company has utilized the bilateral market for decades to buy and sell capacity from existing generation sources on both a long and short-term basis. These transactions have benefited customers by keeping power supply additions paced with system load growth, and by allowing Minnesota Power to sell excess generation during load decline. 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 new 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.

Similarly, the presence of an energy market in resource planning allows for the optimization of power supply needs on a more granular level. Regional markets like MISO allow day-to-day energy needs to be pooled together such that each utility is continuously working for the larger energy needs of the region. 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.

Energy market purchases are in the best interest of customers to plan and assist 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. Not having the regional market available during long-term expansion planning to help with the intermittency of renewable generation would promote overbuilding of a single utility's system and not account for existing regional support. Excluding the presence of the market would not only result in increased customer cost, but also minimize the value proposition of regional markets like MISO.

Minnesota Power has a long-term planning strategy of avoiding expansion plans that rely on more than [TRADE SECRET DATA BEGINS [redacted] TRADE SECRET END] percent of energy supplied for load requirements to be solely supplied from the wholesale market. The Company will procure resources, either generation assets or bilateral power purchase transactions sourced from these assets to ensure its customers are not exposed to significant wholesale market fluctuations. 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 are updated on a biannual basis. 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, 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 2021 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 2021 IRP Evaluation

This Appendix provides additional detail on Minnesota Power's existing thermal fleet and the methodology utilized in the 2021 IRP to evaluate the customer impact of the retirement of the BEC3 & 4 generation assets. Specifically, this section discusses the following items:

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

Generating Asset Retirement Background

The 2021 IRP evaluates the viability of Minnesota Power's continuing to operate its remaining two baseload generating assets, BEC3 & 4, into the future. The evaluation of coal-fired power plant retirement is driven mainly 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 and efficient natural gas-fired combined cycle units. Couple these variables with the increasing pressure from low-cost natural gas supplies, and declining cost of renewables and storage, and the result is that many utilities have begun retiring baseload coal generation and continue to evaluate alternatives available for each of their remaining coal-fired generating assets.

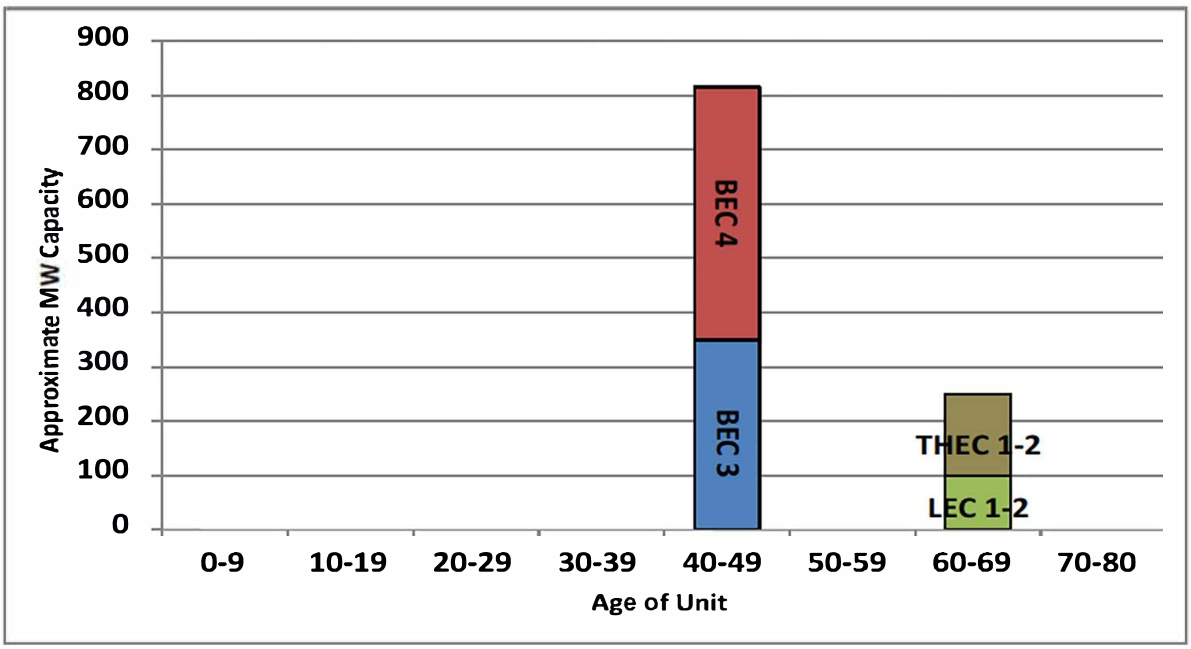
In this highly uncertain landscape of future environmental regulations, the alternatives for existing coal-fired generating assets are limited. The realm of current considerations by U.S. utilities for the future of these generating assets largely includes:

- Continued operation with additional retrofit and environmental controls;
- Idling operations or mothballing – i.e., suspending operations for a certain period of time and allow for reassessing operations at a later date; 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 being addressed in its 2021 IRP are part of the aging fleet within the United States, albeit 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 greater than 40 years old, these assets have been maintained and operated prudently. BEC3 & 4 do have a remaining plant balance of approximately $725 million, and a significant portion is tied to the investment in environmental controls that occurred between 2009 and 2016. BEC3 & 4 are viable power supply resources for Minnesota Power and customers are benefitting from the cleaner energy being produced. More detail on each of the BEC generating units can be found in Appendix C.

Figure 1: Minnesota Power's Age of Fleet



Asset Retirement Methodology

Identifying the appropriate timing for any future retirement of a coal-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 & 4 are the only remaining baseload generators in Minnesota Power's system, and notably, in all of northern Minnesota. The retirement of the last remaining baseload generation in a region will have widespread and significant impacts to the regional system that will need to be addressed prior to retirement. These effects of generation asset retirement on future and long-term fleet outlook were given careful consideration for the 2021 IRP.

When evaluating a potential asset retirement, it is critical to consider the following 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 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 2021 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 remain 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 require continued cost recovery through rates. Depending on the magnitude, the remaining asset value can impact a decision of when to retire an asset. In the asset retirement scenarios, the remaining value of any facility was treated as a cost, which was assumed to be recovered over the currently-approved accounting life of the asset, regardless of when the retirement takes place.

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 the amount of expected salvage that would be received from scrap copper and steel. For the 2021 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 2020 Site Decommissioning Study completed by Burns & McDonnell.

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, and 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 2021 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 that is required to ensure that 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 likely 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 could approach $1 billion. Given the potential magnitude and time required to implement a new transmission project, Minnesota Power takes careful consideration evaluating transmission needs. Appendix F outlines in more detail Minnesota Power's approach to developing transmission costs associated with the retirement of BEC3 and/or 4.

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 regulation costs. Utilities are required to include these costs when evaluating resource options in a resource plan and certificate of need proceeding. In the 2021 IRP analysis, these costs are added onto any generation or energy purchase within the power supply that emits these pollutants. Also taken into consideration are the costs of pollutants from energy that is 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 2021 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 a very important consideration when developing a resource plan – balancing the value of avoided emissions with the resulting customer rate impact.

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

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 direct economic impacts associated with each individual retirement or addition in the Resource Plan 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 2021 IRP.

Pre-notification Requirements

The process for removing a generating unit from the interconnected power system is complex. Each shutdown has the potential to have far reaching impacts on the physical side of the power system, as well as 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. EPA, Minnesota Department of Natural Resources, and the Midwest Reliability Organization.

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. 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.

Minnesota Power's Methodology for Asset Retirement

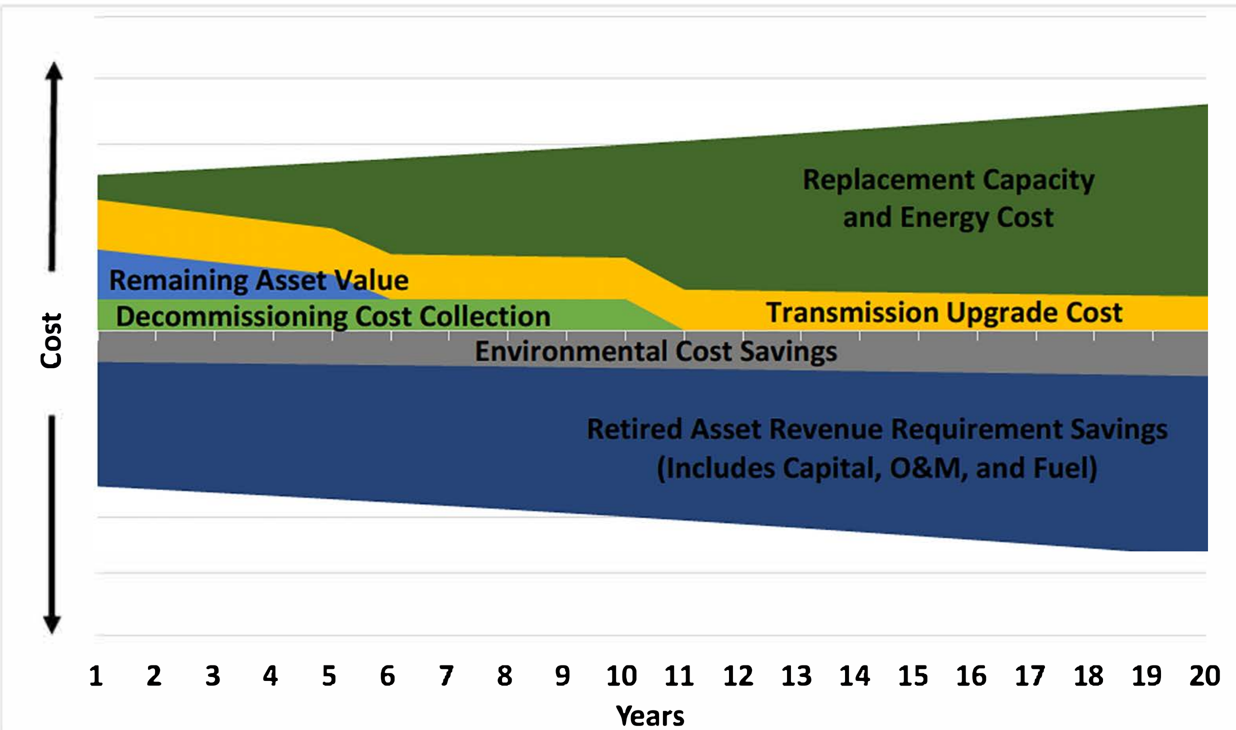
Minnesota Power assumed in its base case that BEC3 & 4 continued to operate at an investment level required for continued long-term operations through the end of each asset's currently approved accounting life. For BEC3 & 4, a matrix of remaining asset values were calculated that identified what the decommissioning and transmission upgrade costs that would be incurred if the unit was 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

[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.

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 come up with 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 2021 IRP and carefully monitor the drivers that determine the viability of an asset retirement.