Xcel Energy Low Carbon Scenario Analysis

Decarbonizing the Generation Portfolio of Xcel Energy's Upper Midwest System

July 2019

Energy+Environmental Economics

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Table of Contents

Acknowledgements & Disclaimer

The authors of this study would like to acknowledge the contributions of the staff of Xcel Energy's Upper Midwest branch, who throughout this effort provided timely input, data, and perspectives. The willing contributions of the Xcel Energy staff were crucial to the development of both methods and results in this study that reflect the unique nature of the electricity system in the region. While the Xcel Energy staff provided crucial inputs and played an important role in scoping the study, the analysis completed here and the conclusions reached thereupon are solely reflective of E3's views and perspectives.

Acronyms

AEO	Annual Energy Outlook
ATB	Annual Technologies Baseline
CAGR	Compound annual growth rate
CCGT	Combined cycle gas turbine
CHP	Combined heat & power
CT	Combustion turbine
DR	Demand response
EE	Energy efficiency
EIA	Energy Information Administration
ELCC	Effective load carrying capability
EV	Electric vehicle
ICE	Internal combustion engine
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated resource plan
LCOE	Levelized cost of energy
LOLE	Loss of load expectation
LOLP	Loss of load probability
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Plan
NREL	National Renewable Energy Laboratory
PPA	Power purchase agreement
PRM	Planning reserve margin
PV	Photovoltaic
RPS	Renewables Portfolio Standard
RTO	Regional transmission organization

Executive Summary

Study Overview

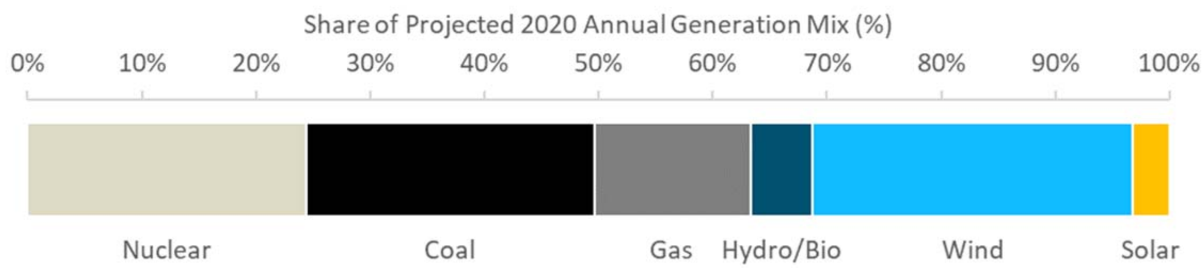
Across the United States, the electricity sector is in a rapid state of transition, driven by multiple factors:

+ An increasing preference for "clean" energy resources and interest in decarbonization of electricity supply at the state, utility, and customer levels;
+ Significant realized cost reductions of renewable resources such as wind and solar, coupled with the emergence of new technologies such as battery storage; and
+ Aging generation infrastructure leading to plant retirements and a corresponding need for investment in new generation resources.

These trends, and the elevated levels of investment in new renewable generation they have prompted throughout the country in the past decade, are likely to continue.

Since 2005, Xcel Energy's Upper Midwest system, which serves customers in Minnesota and four neighboring states, has made significant progress toward decarbonizing its energy supply. The company's conversion of its High Bridge and Riverside coal plants, achievement of energy efficiency consistent with state standards, and investment in a total of over 3,000 MW of wind generation have led to a collective shift towards carbon-free generation resources, which are expected to represent approximately 60% of the Upper Midwest system's generation mix by 2020. The expected annual generation mix for the Upper Midwest system in 2020 is shown in Figure i.

Figure i. Projected annual generation mix in 2020



This shift has enabled significant carbon reductions in the Upper Midwest portfolio, whose 2017 emissions were roughly 30% below a 2005 benchmark level. Xcel also recently established notable forward-looking goals that imply significant continued effort in this area over the long term:

+ Xcel's 2015 Upper Midwest Integrated Resource Plan established plans to retire two coal plants and meet 60% of customer loads with carbon-free resources by 2030; and
+ In December 2018, Xcel announced a company-wide goal to reduce emissions by 80% by 2030 and to be 100% carbon-free by 2050, a first-of-its-kind target among U.S. utilities.

Achieving these ambitious goals will require careful and strategic approaches to planning, procurement, and utility operations. While low-cost wind, solar and energy storage resources will make up the bulk of investments needed to meet Xcel's goals, additional capabilities will be needed to supplement these resources whose availability depends on uncontrollable meteorological phenomena. Balancing load and generation instantaneously and ensuring resource adequacy under all conditions (e.g., during periods of high load and low wind and solar output) requires an evolution in today's operational and planning practices. Designing a low-cost resource portfolio that simultaneously meets future reliability standards and clean energy objectives has become one of the principal long-term planning challenges for utilities today.

This report, commissioned of E3 by Xcel Energy addresses several key questions implied by the company's aggressive carbon targets:

+ What would be the composition of the Upper Midwest system portfolio—and what are its corresponding greenhouse gas emissions—under a "Reference Case" scenario reflecting a business-as-usual, least-cost approach to meeting future energy and capacity needs?
+ What are Xcel's options—and what are the corresponding costs—for achieving steep emission reductions consistent with near- and long-term goals?
+ What are the reliability implications of relying heavily on renewable and storage resources? Could an electric system achieve 100% emissions reductions using only today's commercially available technologies while maintaining reliability?

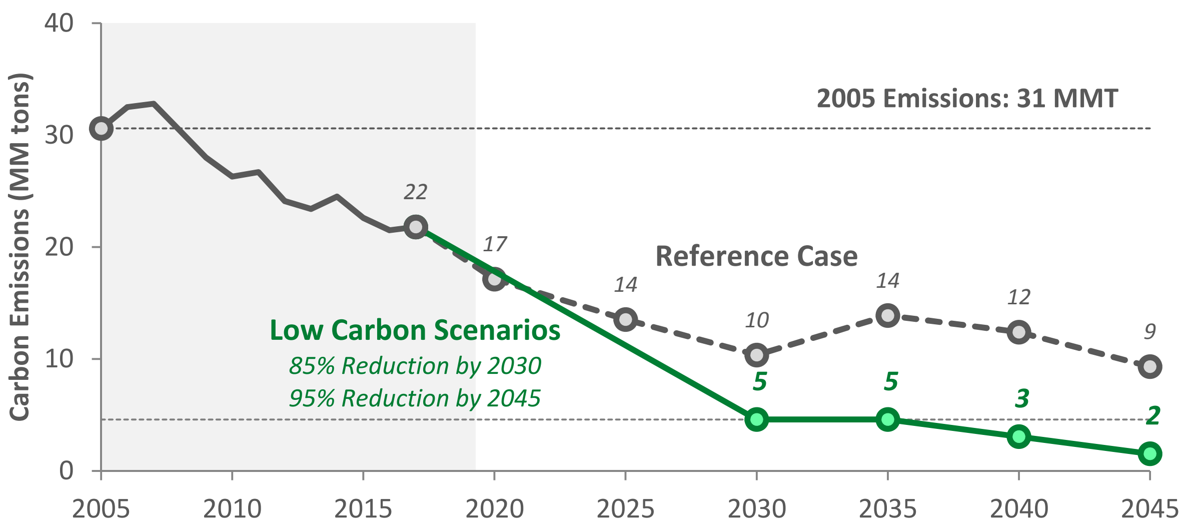
To answer these questions, this study uses scenario analysis to design and characterize a range of different portfolios that each achieve aggressive levels of decarbonization relative to a Reference Case. The portfolios are constructed from different assumptions about potential coal and nuclear plant retirements and future investments in natural gas resources, which in turn determine the quantity and timing of future renewables and storage additions and investments in demand-side resources needed to meet long-term carbon reduction goals.

By design, the scope of analysis conducted in this study overlaps considerably with the internal analysis conducted by Xcel Energy in the development of its preferred plan as filed in its Integrated Resource Plan. Wherever possible, this study relies on the same numerical inputs and assumptions as used by Xcel's IRP team, supplemented by publicly available data sources where necessary. This approach was chosen to ensure that the results of Xcel's internal analysis align with the rigorous, industry-standard approaches.

Methods and Assumptions

This study uses scenario analysis to examine the impacts of achieving deep carbon reductions in Xcel's portfolio in accordance with the company's long-term goals. Keeping in mind the breadth of resource options available to meet Xcel's future energy and capacity needs, and consequently the many different pathways to achieve the company's targeted carbon reductions, this analysis designs and evaluates a range of different plausible portfolios. Each scenario examined in this study (with the exception of a counterfactual Reference Case) is designed to achieve carbon reduction milestones of 85% below 2005 levels by 2030 and 95% below 2005 levels by 2045. The trajectory of carbon reductions that each scenario is designed to achieve is shown in Figure ii.

Figure ii. Future Upper Midwest carbon reduction pathway as modeled in this study compared to counterfactual Reference Case



While all scenarios are consistent with the carbon reduction trajectory above, each scenario achieves the desired level of carbon reductions with a unique combination of resource options (i.e., nuclear, fossil, renewable, storage, and demand-side resources). Figure iii shows the range of assumptions used in this study about each of those resources. Overall, this study compares 21 distinct scenarios against a Reference Case that provides a benchmark against which costs and emissions reductions are measured. The purpose of constructing scenarios in this way is to highlight tradeoffs implied by Xcel's key strategic decisions as it transitions toward a low-carbon future:

+ What is the long-term role of nuclear generation in Xcel's portfolio?
+ How would the continued operation of Xcel's coal resources impact its efforts to decarbonize?
+ What role, if any, should new natural gas play in meeting long-term resource adequacy needs?
+ What renewables, storage, and demand-side resources are needed to meet carbon goals?

Figure iii. Range of assumptions about Xcel's resource options captured in scenario analysis

Resource	Scenario Options			
Nuclear	Retire upon license expiry	Relicense Monticello only	Relicense both nuclear plants	Retire Prairie Island by 2030
Coal	Retire all plants at end of useful life	Retire AS King by 2030	Retire all coal by 2030	
Gas	Allow investment in new gas	Limit new gas additions to Sherco CC	Prohibit all new gas investment	
Wind	Add new wind to meet energy, capacity, and clean energy goals			
Solar	Add new solar to meet energy, capacity, and clean energy goals			
Storage	Add new storage to meet capacity & flexibility needs			
DR	Add new DR to meet capacity needs			
Efficiency	Deploy energy efficiency to meet energy, capacity & clean energy needs			

This study utilizes two resource planning models developed to analyze electric systems at high penetrations of renewable generation:

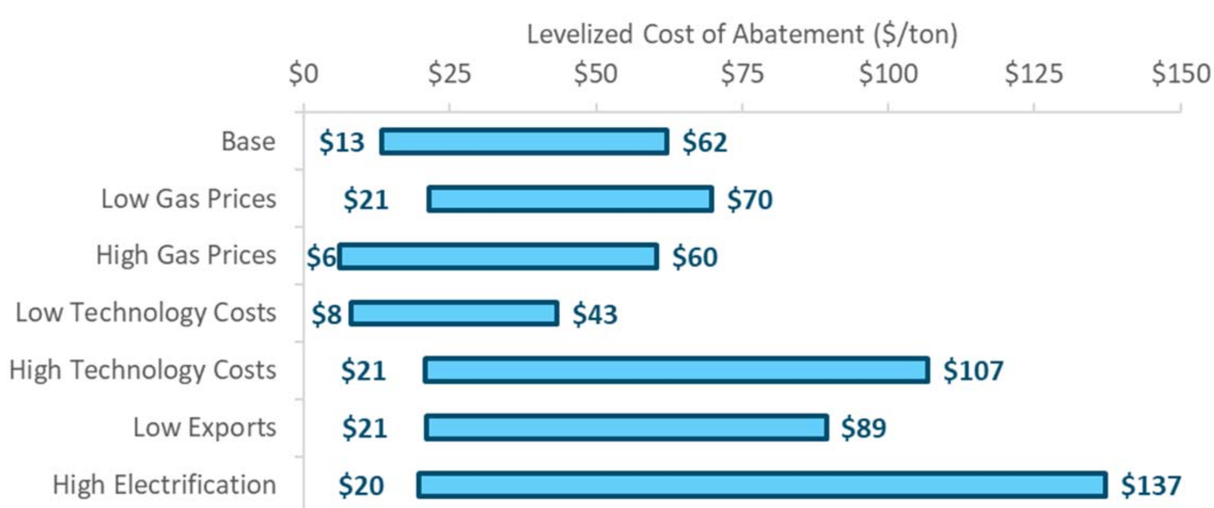
+ **E3's Renewable Energy Capacity (RECAP) model**, a loss-of-load-probability model that provides a detailed and statistically robust perspective on the reliability of electric systems with conventional, renewable, storage, and demand-side resources; and
+ **E3's Renewable Energy Solutions (RESOLVE) model**, a capacity expansion model that uses optimization techniques to identify a least-cost portfolio of resource investments to meet future reliability and clean energy objectives while also simulating electric system operations on an hourly basis.

These tools complement one another and jointly provide a strong foundation for analyzing and understanding the implications of a long-term transition towards low-carbon and carbon-free resource portfolios. In this study, RECAP provides a rigorous, data-driven perspective on the future reliability needs of the Xcel portfolio and the ability of wind, solar, and storage to meet those needs; RESOLVE builds on this analysis to design least-cost portfolios that achieve reliability objectives while meeting clean energy goals, balancing large quantities of variable resources, and minimizing costs.

Key Findings

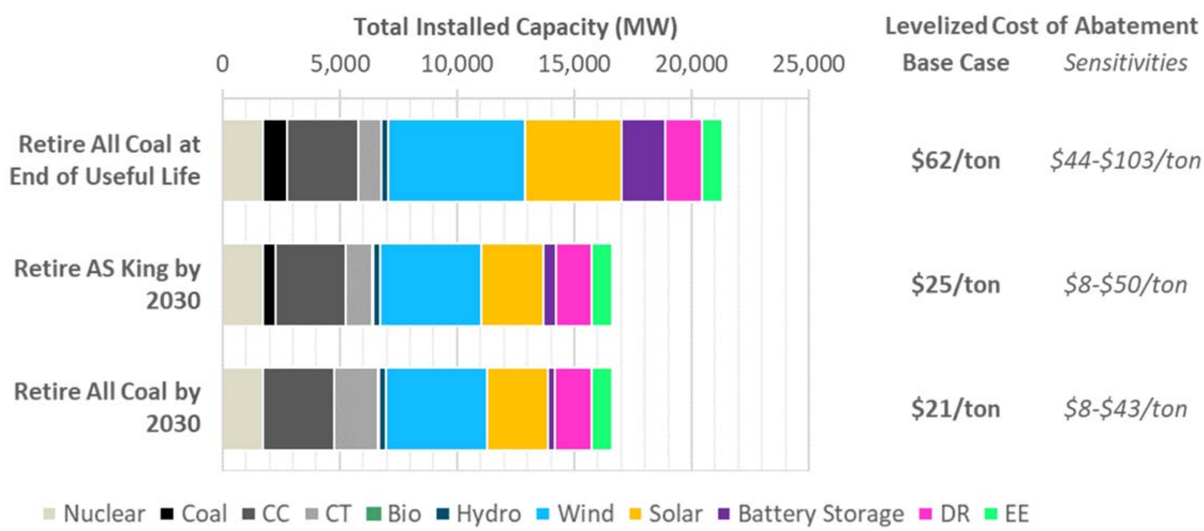
First—and perhaps most significantly—this study suggests that Xcel Energy can achieve substantial reductions in carbon emissions from its Upper Midwest portfolio at relatively low cost. Across the 21 scenarios examined in this study that achieve deep carbon reductions during the study horizon, the lowest-cost scenarios reduce carbon at a levelized cost of $15-20 per ton. The ability to achieve such large emissions reductions at such a relatively low cost results from several converging factors: (1) low natural gas prices, which enable low-cost fuel switching from coal to gas; (2) the relatively low (and falling) costs of new wind and solar resources due to technology improvements over the past decade; (3) a potential to increase deployment of energy efficiency and other demand-side programs to manage load growth; and (4) anticipated reductions in future battery storage costs, which enable integration of high penetrations of renewable generation.

Figure iv. Range of carbon abatement costs across all scenarios and sensitivities.



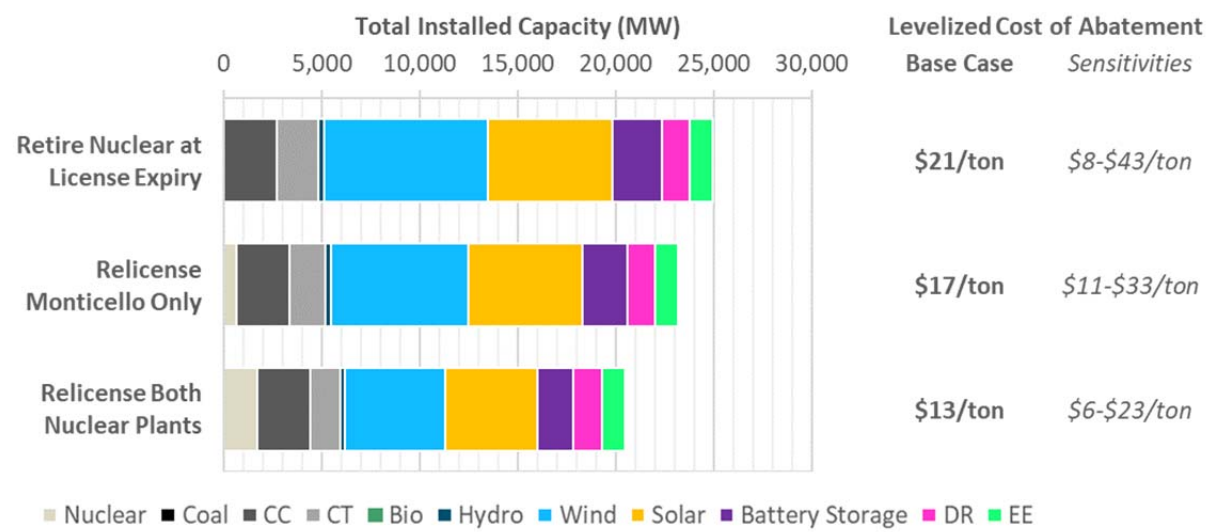
The lowest-cost near-term opportunity to reduce carbon in Xcel's Upper Midwest system is to replace coal generation with a combination of renewables, storage, efficiency, and natural gas generation. The four coal plants owned by Xcel produce approximately 85% of the Upper Midwest system's greenhouse gas emissions in the 2020 Reference Case; while Xcel has already established plans to retire two of these plants prior to 2030, this analysis suggests that accelerating the retirement of its remaining two plants and replacing them with a portfolio of efficiency, renewables, storage, and natural gas generation provides the least-cost pathway to reducing emissions consistent with Xcel's 2030 goals (see Figure v).

Figure v. Xcel resource portfolios that achieve 85% carbon reductions in 2030



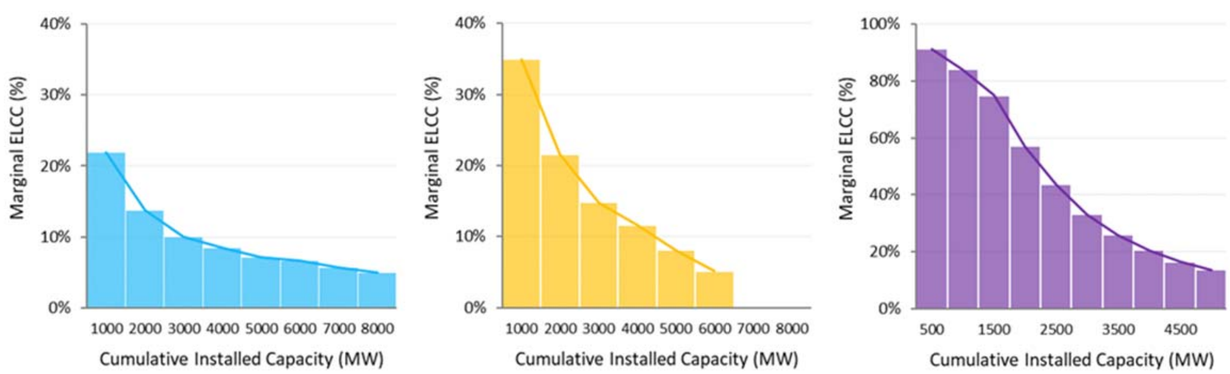
A diverse portfolio of resources—including nuclear—offers the least-cost long-term pathway to deep carbon reductions. Beyond 2030, meeting Xcel's long-term carbon goals will require continued development of new carbon-free energy resources. At the same time, the expiration of existing licenses at both of Xcel's nuclear facilities in the early 2030s raises questions about the role of nuclear in Xcel's long-term generation portfolio. The scenario analysis conducted in this study suggests that under most circumstances, extending the licenses of both Monticello and Prairie Island to allow continued operation provides a least-cost option to meeting long-term carbon goals (Figure vi). This is due not only to the plants' ability to generate carbon-free electricity at relatively low cost but also, and perhaps more significantly, to the fact that nuclear generation (unlike wind, solar, or energy storage) operates as a "firm" resource that can generate at its full nameplate capacity for sustained periods when needed to meet Xcel's reliability needs. This unique combination of characteristics makes Xcel's existing nuclear plants inherently valuable to meeting Xcel's long-term carbon goals.

Figure vi. Xcel resource portfolios that achieve 95% carbon reductions in 2045



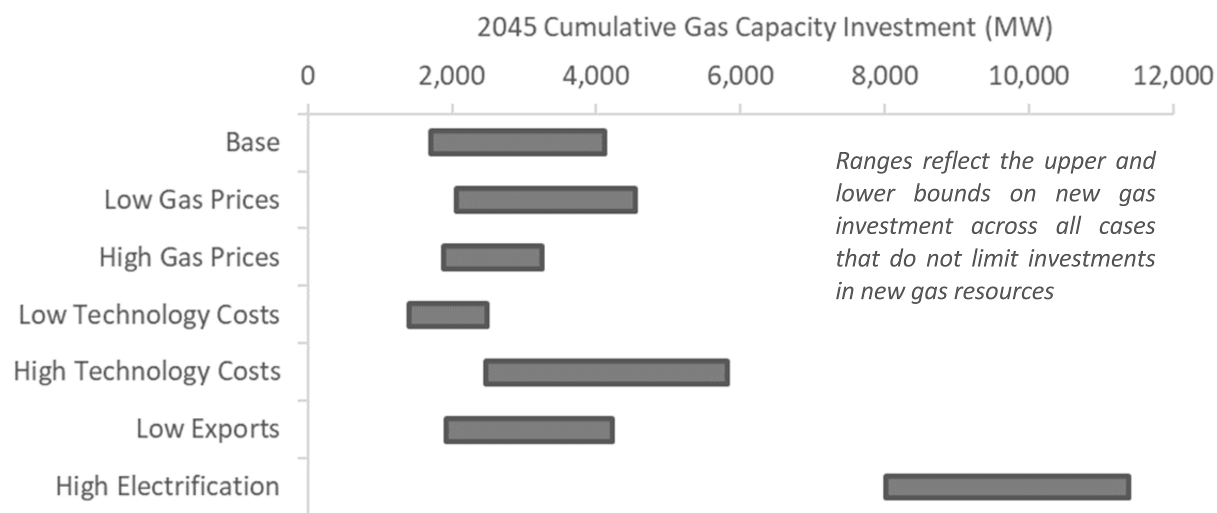
While new resources like wind, solar, and storage will play a central role in supplying carbon-free energy to Xcel's customers, these resources alone cannot meet Xcel's resource adequacy needs at reasonable costs. The reliability analysis conducted in this study highlights the limitations of renewable and storage resources to meet resource adequacy needs: due to variability and limits on duration, these resources offer less capacity value than firm resources that can produce at full capacity when needed. Further, because their marginal capacity value declines with increasing penetration, wind, solar, and storage offer a relatively poor substitute for traditional firm capacity resources in meeting reliability needs at scale (see Figure vii). Taken to an extreme, this study shows that a system designed to rely solely on renewables and storage to meet reliability needs would require prohibitively large investments. These findings underscore the need for an evolving approach to resource adequacy—by both Xcel and MISO—as renewables and storage reach greater levels of penetration. Such an approach is critical to ensure that sufficient resources are available even when variable renewables and storage alone cannot produce sufficient levels of generation to meet load.

Figure vii. Marginal capacity values of wind, solar, and storage resources in Xcel's 2030 portfolio



Natural gas plants will be critically important to ensure a reliable system but will operate at low capacity factors. Because of the inherent limitations of renewables and storage resources to satisfy resource adequacy needs alone, some form of firm, dispatchable capacity will be needed to complement large anticipated investments in efficiency, renewables, and storage that needed to decarbonize Xcel's energy supply. While Xcel's existing nuclear plants are highly valuable because of their firm attributes, they alone are not sufficient to satisfy the need for firm capacity; natural gas resources will continue to play a crucial role in meeting system reliability. Figure viii shows the range of new investments in natural gas resources across all the cases and sensitivities that allowed gas investment as part of the least-cost plan. Under Base Case assumptions, the level of new gas investments needed by 2045 spans a range from 2,000 to 4,000 MW (depending on whether existing nuclear plants are relicensed); among most other sensitivities, a similar range is observed. One sensitivity stands out for its outsized effect: in the High Electrification sensitivity, due to large new loads that increase winter peak significantly, the level of investment in new gas resources in least-cost portfolios is dramatically higher—8,000 to 11,000 MW. Collectively, these observations point to a more general finding: investment in new natural gas resources to meet capacity needs enables a low-cost pathway to decarbonize electricity and to facilitate levels of electrification needed to meet economy-wide carbon reduction goals.

Figure viii. Range of investments in new natural gas capacity resources by 2045 as part of a least-cost plan to achieve deep carbon reductions



Finally, while this study identifies a number of promising pathways towards Xcel's long-term carbon goals, the cost of achieving carbon reductions remains highly uncertain and subject to impacts of factors beyond the company's control. Even in the scenario that this study identifies as a least-cost plan—one that combined nuclear relicensing, accelerated coal retirements, and investments in renewables, storage, efficiency, and gas to meet long-term goals—the potential costs calculated at the study's endpoint in 2045 spans a broad range from 150% above to 125% below the costs under Base Case assumptions. The largest potential sources of risk identified in this study result from uncertainty on the future cost of new renewable and storage resources and the uncertainty of how the changing generation mix in the broader MISO system will impact Xcel's opportunities to manage costs through market transactions. The exposure of Xcel's portfolio to such uncertainty and the associated risks underscores the importance of constant vigilance and responsiveness to rapidly changing market conditions.

1 Introduction

1.1 Study Motivation

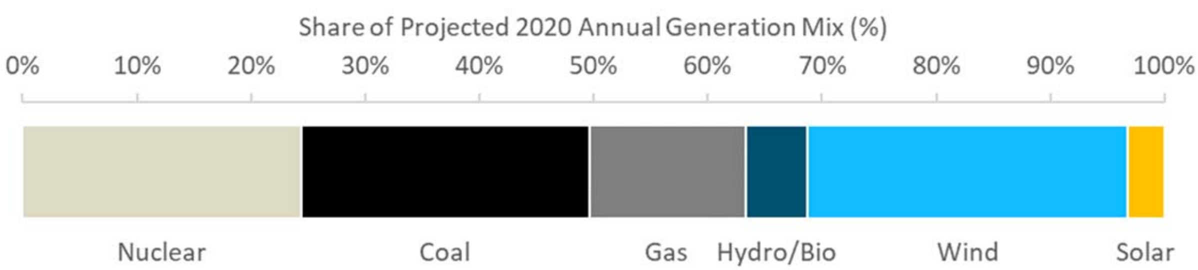
Across the United States, the electricity sector is in a rapid state of transition, driven by multiple factors:

+ An increasing preference for "clean" energy resources and interest in decarbonization of electricity supply at the state, utility, and customer levels;
+ Significant realized cost reductions of renewable resources such as wind and solar, coupled with the emergence of new technologies such as battery storage; and
+ Aging generation infrastructure leading to plant retirements and a corresponding need for investment in new generation resources.

These trends, and the elevated levels of investment in new renewable generation they have prompted throughout the country in the past decade, are likely to continue.

Since 2005, Xcel Energy's Upper Midwest system, which serves customers in Minnesota and four neighboring states, has made significant progress toward decarbonizing its energy supply. The Company's conversion of its High Bridge and Riverside coal plants, achievement of energy efficiency consistent with state standards, and investment in a total of over 3,000 MW of wind generation have led to a collective shift towards carbon-free generation resources, which are expected to represent approximately 60% of the Upper Midwest system's generation mix by 2020. The expected annual generation mix for the Upper Midwest system in 2020 is shown in Figure 1-1.

Figure 1-1. Projected annual generation mix in 2020

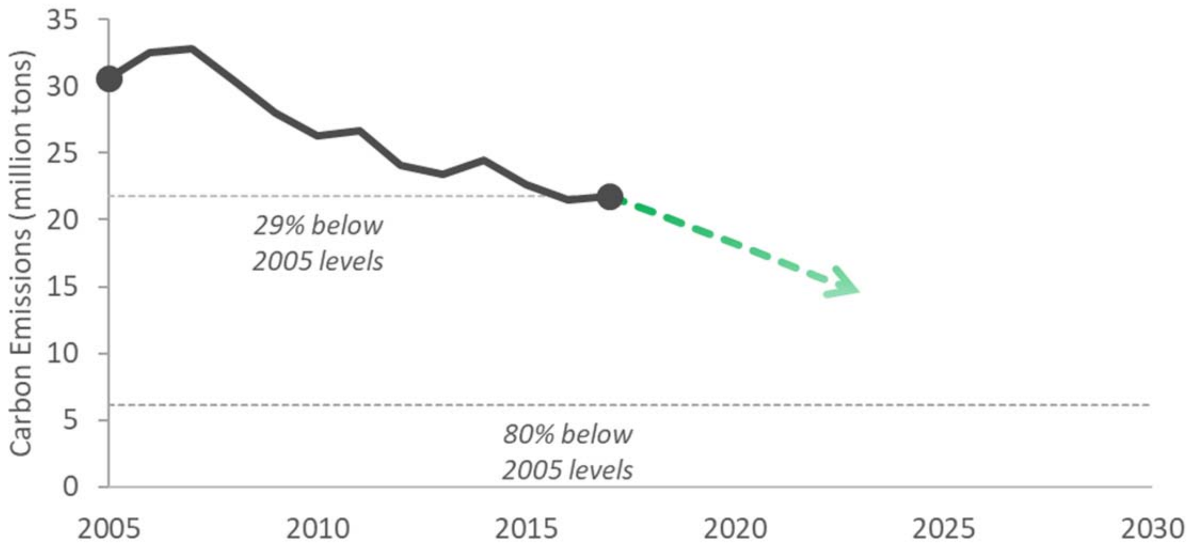


This shift has enabled significant carbon reductions in the Upper Midwest portfolio, whose 2017 emissions were roughly 30% below a 2005 benchmark level. Xcel also recently established notable forward-looking goals that imply significant continued effort in this area over the long term:

+ Xcel's 2015 Upper Midwest Integrated Resource Plan established plans to retire two coal plants and meet 60% of customer loads with carbon-free resources by 2030; and
+ In December 2018, Xcel announced a company-wide goal to reduce emissions by 80% by 2030 and to be 100% carbon-free by 2050, a first-of-its-kind target among U.S. utilities.

Thus, while the greenhouse gas emissions attributed to the Upper Midwest portfolio as of 2017 were roughly 30% below 2005 levels, significant additional reductions will be needed to meet the Company's long-term goals (see Figure 1-2).

Figure 1-2. Historical carbon emissions attributed to Xcel's Upper Midwest portfolio and a pathway towards long-term goals



Achieving these ambitious goals will require careful and strategic approaches to planning, procurement, and utility operations. While low-cost wind, solar and energy storage resources will make up the bulk of investments needed to meet Xcel's goals, additional capabilities will be needed to supplement these resources whose availability depends on uncontrollable meteorological phenomena. Balancing load and generation instantaneously and ensuring resource adequacy under all conditions (e.g., during periods of high load and low wind and solar output) requires an evolution in today's operational and planning practices. Designing a low-cost resource portfolio that simultaneously meets future reliability standards and clean energy objectives has become one of the principal long-term planning challenges for utilities today.

Within its current integrated resource planning cycle, whose analytical horizon stretches through 2034, Xcel's Upper Midwest system faces several significant questions that will establish a path to meeting long-term emissions goals. Among the key questions are: (1) how to manage retirement of aging coal generators; (2) whether to seek extensions for nuclear plants whose current licenses expire shortly after 2030; (3) what level of investment in renewables, storage, and efficiency will be needed to meet greenhouse gas reduction targets; and (4) the extent to which investment in new gas resources will be needed for reliability purposes.

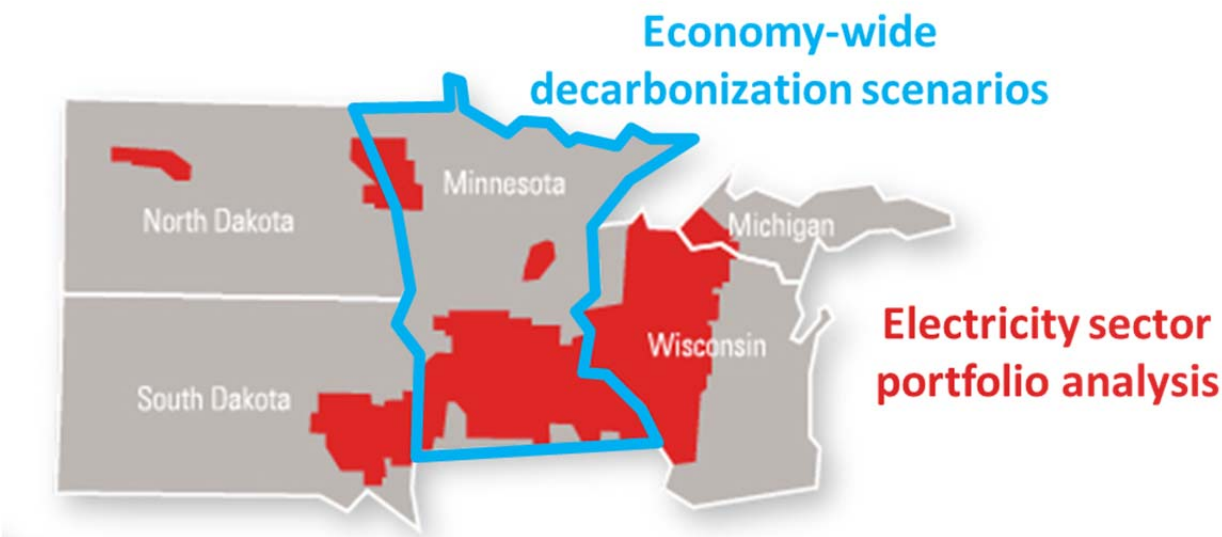
Both to inform its own strategic decision-making and to inform and engage stakeholders, Xcel commissioned two studies to provide an independent, unbiased, third-party perspective on these and related issues:

(1) An economy-wide analysis of deep decarbonization pathways for the State of Minnesota that establishes a vision for how the state could reduce carbon emissions 80% below 2005 levels by 2050; and

(2) An electricity portfolio optimization analysis that identifies a range of strategies Xcel could implement to meet near-term goals and align with long-term goals.

While the geographic scopes of these studies differ (see Figure 1-3.), they complement one another by creating general blueprints for decarbonizing electricity and the broader economy; in doing so, they highlight the central role of the electric utility in meeting long-term climate objectives. Together, these two studies supplement Xcel's own IRP analysis by providing an alternative and independent perspective that address the challenges facing Xcel's Upper Midwest system.

Figure 1-3. Overlapping geographic scopes of E3's two studies



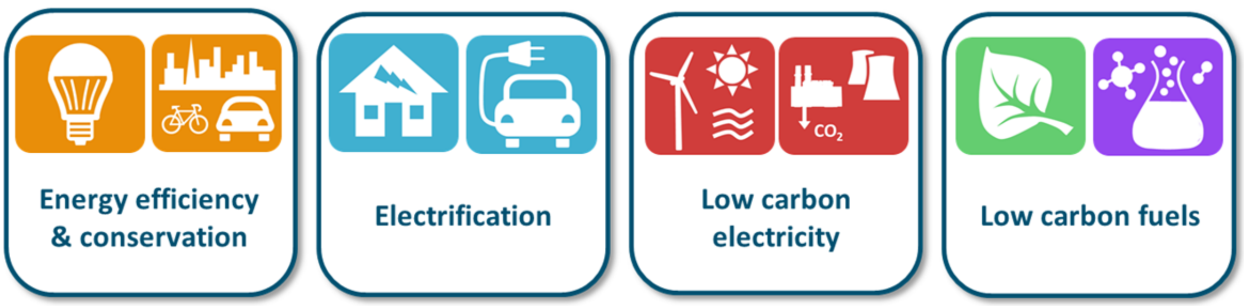
1.2 Lessons from Pathways Analysis

E3's "Minnesota Decarbonization Analysis," an economy-wide study of decarbonization for the state, contributes to a growing body of literature that explores the landscape of what is needed to reach deep levels of decarbonization, typically 80% reductions below a baseline level by 2050. These studies, conducted by E3 and others, have generally converged on a consensus view that four foundational "pillars" are necessary to achieve such significant reductions across the economy:

+ Deployment of ambitious levels of **energy efficiency & conservation** beyond levels of historical achievement;
+ **Electrification of end uses** traditionally fueled by fossil fuels, including vehicles, space and water heating, and industrial processes;

+ Production of **low-carbon electricity** to supply clean energy to both existing and newly electrified loads; and
+ Use of **low-carbon fuels**—for instance, biofuels, synthetic gas, and/or hydrogen—to supply energy to end uses that continue to rely on liquid and/or gaseous fuels.

Figure 1-4. Four pillars of deep decarbonization



These pillars highlight the central role of the electric sector in decarbonization: significantly reducing economy-wide greenhouse gas emissions requires the electric sector to decarbonize generation while supplying clean energy to new loads as more fossil-fueled end uses convert to electricity.

A number of the key findings from E3's decarbonization study for the state of Minnesota expand upon the necessity and role of these four pillars and further underscore the importance of decarbonizing electricity supply while minimizing costs to the extent possible:

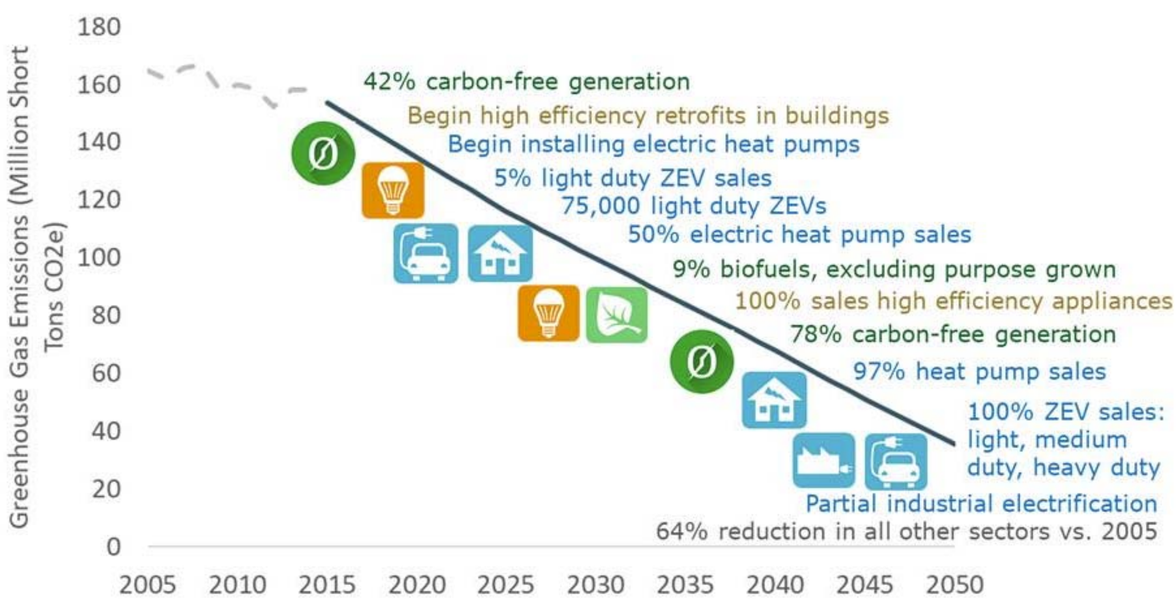
+ **Electrification and zero-carbon electricity are necessary (but not sufficient) to reach statewide goals.** The analysis demonstrates how increased reliance on low-carbon electricity enables emission reductions by avoiding direct combustion of fossil fuels in households, businesses, and vehicles across a number of scenarios.
+ **Buildings and transportation have significant potential to drive load growth, especially after 2025.** The analysis also highlights the significant potential for adoption of new electric appliances and vehicles, and the potential impact on total electricity requirements for Minnesota utilities. Transportation and building electrification drive electric load growth,

especially after 2030, particularly in a future with constraints on bioenergy. Electrification of space heating has a particularly large impact on both total load (MWh) and peak demand (MW).

+ **Reasonable electric rates and low costs for new electric devices are essential for electrification.** The levels of electrification modeled in buildings and transportation are dependent on consumer adoption, which will benefit from reductions in capital costs and reasonable electric rates, even as the electric grid continues to decarbonize.

The economy-wide emissions trajectory towards deep decarbonization, along with the key transformations that enable these reductions, are shown in Figure 1-5.

Figure 1-5. Emissions and infrastructure transformations in the "High Electrification" scenario from E3's economy-wide pathways analysis



1.3 Study Overview

As a complement to the economy-wide pathways study, this study focuses on how to decarbonize electricity supply in the Upper Midwest. In doing so, it addresses several key questions implied by Xcel's aggressive targets:

- What is the composition of the Upper Midwest system portfolio—and what are its corresponding greenhouse gas emissions—under a "Reference Case" scenario reflecting a business-as-usual, least-cost approach to meeting future energy and capacity needs?
- What are Xcel's options—and what are the corresponding costs—for achieving steep emission reductions consistent with near- and long-term goals, and how do these compare to the Reference Case?
- What are the reliability implications of relying heavily on renewable and storage resources? Could an electric system achieve 100% emissions reductions using only today's commercially available technologies while maintaining reliability?

To answer these questions, this study uses scenario analysis to design and characterize a range of different portfolios that each achieve aggressive levels of decarbonization relative to a Reference Case. The portfolios are constructed from different assumptions about potential coal and nuclear plant retirements and future investments in natural gas resources, which in turn determine the quantity and timing of future renewables and storage additions and investments in demand-side resources needed to meet long-term carbon reduction goals. The analysis spans the years 2020 through 2045, extending beyond the traditional IRP planning horizon in an effort to provide additional information on the implications of Xcel's long-term goals; however, the analysis stops short of attempting to "solve" for how Xcel Energy might meet its 2050 goals in recognition of the likely but unpredictable role that future technological innovation will play in allowing Xcel to achieve the final increments of decarbonization. Figure 1-6 shows the building blocks this study used to construct alternative scenarios and develop portfolios.

Figure 1-6. Building blocks for scenario development.

Resource	Scenario Options			
Nuclear	Retire upon license expiry	Relicense Monticello only	Relicense both nuclear plants	Retire Prairie Island by 2030
Coal	Retire all plants at end of useful life	Retire AS King by 2030	Retire all coal by 2030	
Gas	Allow investment in new gas	Limit new gas additions to Sherco CC	Prohibit all new gas investment	
Wind	Add new wind to meet energy, capacity, and clean energy goals			
Solar	Add new solar to meet energy, capacity, and clean energy goals			
Storage	Add new storage to meet capacity & flexibility needs			
DR	Add new DR to meet capacity needs			
Efficiency	Deploy energy efficiency to meet energy, capacity & clean energy needs			

The study relies primarily on two complementary models developed by E3, both designed to investigate the implications of heavy reliance on renewables and storage:

+ **E3's Renewable Energy Capacity (RECAP) model**, a loss-of-load-probability model that provides a detailed and statistically robust perspective on the reliability of electric systems with conventional, renewable, storage, and demand-side resources; and
+ **E3's Renewable Energy Solutions (RESOLVE) model**, a capacity expansion model that uses optimization techniques to identify a least-cost portfolio of resource investments to meet future reliability and clean energy objectives.

These tools complement one another and jointly provide a strong foundation for analyzing and understanding the implications of a long-term transition towards low-carbon and carbon-free resource portfolios. In this study, RECAP provides a rigorous, data-driven perspective on the future reliability needs of the Xcel portfolio and the ability of wind, solar, and storage to meet those needs; RESOLVE builds on this analysis to design least-cost portfolios that achieve reliability objectives while meeting clean energy goals, balancing large quantities of variable resources, and minimizing costs.

1.4 Relationship to Xcel's Analysis

By design, the scope of analysis conducted in this study overlaps considerably with the internal analysis conducted by Xcel Energy in the development of its preferred plan as filed in its Integrated Resource Plan. Wherever possible, this study relies on the same numerical inputs and assumptions as used by Xcel's IRP team, supplemented by publicly available data sources where necessary. This approach was chosen to ensure that the results of Xcel's internal analysis align with the rigorous, industry-standard approaches.

The methods employed in this study, which E3 has used across a wide range of North American jurisdictions, are generally consistent with those used in the Strategist model used by Xcel Energy's IRP team. However, E3's RESOLVE model and Strategist do deviate from one another in several key methodological areas; the key differences between the two are discussed further in Section 2.1.2.

The inputs and assumptions used in this study provided by Xcel Energy are consistent with public data sources that E3 has used in other studies. To that effect, the key findings of this study are E3's conclusions, and do not directly represent conclusions or future commitments of Xcel Energy. This study makes no recommendations for formal preferred plan for the company, but does offer a supplemental perspective for the Commission and stakeholders to consult in evaluating Xcel's proposed preferred plan.

1.5 Report Contents

The remainder of this report is organized as follows:

- **Section 2** describes the scenarios and modeling approach used in the study;
- **Section 3** describes the key modeling inputs and assumptions that shape the analysis;
- **Section 4** presents the results of the reliability analysis;
- **Section 5** presents the results of the portfolio analysis; and
- **Section 6** discusses the key conclusions reached from this study.

Additional details on the study's methods, data inputs, and results can be found in the technical appendices:

- **Appendix A** describes the methodology of RECAP;
- **Appendix B** describes the methodology of RESOLVE;
- **Appendix C** provides additional detail on the development of study inputs; and
- **Appendix D** provides additional detail model results across the scenarios and sensitivities.

2 Modeling Methodology

2.1 Modeling Approach

This study relies upon two resource planning models developed by E3 and tailored towards analysis of electric systems at high penetrations of renewable generation to develop and analyze a range of scenarios to explore potential options for carbon reductions in the Upper Midwest system portfolio:

+ **E3's Renewable Energy Capacity (RECAP) model**, a loss-of-load-probability model that provides a detailed and statistically robust perspective on electric systems that rely on a combination of conventional, renewable, storage, and demand-side resources; and
+ **E3's Renewable Energy Solutions (RESOLVE) model**, a capacity expansion model that uses optimization techniques to identify a least-cost portfolio of resource investments to meet future reliability and clean energy objectives.

These two tools complement one another in their application, together providing a strong foundation with which to analyze and understand implications of long-term transitions towards low carbon and carbon-free portfolios. As illustrated in Figure 2-1, these models are used together: the study first uses RECAP to characterize potential contributions of different technologies towards system resource adequacy needs; this, in turn, serves as an input to RESOLVE, to ensure that the least-cost portfolio outcome meets reliability goals.

Figure 2-1. Two-phase approach used in this study

2.1.1 RELIABILITY ANALYSIS

2.1.1.1 Scope of Analysis

One of today's principal concerns among utilities and system operators alike is the preservation of resource adequacy in electric systems that are rapidly transitioning towards greater reliance on variable (e.g. wind and solar) and use-limited resources (e.g. storage, demand response) and away from traditional sources of firm, dispatchable capacity (e.g. nuclear, coal, and gas). Many jurisdictions—including the Midcontinent Independent System Operator (MISO), of which Xcel's Upper Midwest system is a member—have transitioned towards the use of "effective load carrying capability" (ELCC)—a rigorous measure of capacity value derived through loss-of-load-probability analysis—to measure the contributions of wind and solar towards resource adequacy needs, and there is growing consensus within the industry that such techniques will eventually be needed for storage at higher levels of deployment as well. This study's first phase begins with a detailed examination of the potential contributions of such resources towards Xcel Energy's future resource adequacy needs.

As a member of MISO, Xcel Energy is obligated to meet an annual planning reserve margin (PRM) requirement by either self-supplying capacity or purchasing it directly through the MISO market. The accounting conventions through which capacity from resources is accredited towards this requirement are administered by MISO; the contribution of each type of generation resource depends on its performance characteristics and availability to produce power during the most constrained periods of the year:

- Traditional dispatchable resources are accredited at their full firm capacity;[1]
- Wind and solar resources are assigned capacity value based on ELCC studies conducted by MISO (currently, 16% and 50%, respectively, but subject to periodic updates with changes to the system); and
- Energy storage with four hours of duration is assigned full capacity value.

Projecting how capacity accreditation for variable and use-limited resources will change in MISO over the twenty-five year horizon of this analysis—which would require forecasting changes in its load and resource mix and a corresponding loss-of-load-probability analysis across the full RTO footprint—is beyond the scope of this type of study.

Rather than undertaking such an exercise, this study relies on a simplifying convention for variable and use-limited resources that considers only the capacity value that those resources provide to Xcel's Upper Midwest system. This is accomplished by developing a model of the Upper Midwest loads and resource portfolio in RECAP and using the model to derive curves of the "effective load carrying capability" (ELCC) as a function of penetration for wind, solar, storage, and demand response. Through the development of these ELCC curves that reflect the capacity value of variable and use-limited resources, RECAP is used to derive inputs for a resource adequacy requirement to be used in the optimization process. The conventions used in this study are shown in Table 2-1, where they are contrasted against the actual obligations Xcel Energy faces as a MISO member.

[1] Traditional dispatchable resources are accredited based on their UCAP or unforced capacity value.

Table 2-1. Conventions used for resource adequacy accounting in this study compared to Xcel's obligation as a MISO member

Assumption	Xcel's MISO Obligation	RESOLVE Portfolio Analysis
Planning reserve margin requirement	3% above Xcel non-coincident peak demand	
Thermal/dispatchable plants	Plant-specific firm capacity rating	
Wind & solar ELCC	MISO accredited ELCC (currently 50% for solar and 16% for wind)	RECAP ELCC curves for Xcel Energy system
Energy storage ELCC	Full capacity accreditation for storage with >4 hour duration	RECAP ELCC curve for Xcel Energy system

Notably, this study preserves Xcel's PRM requirement of 3% above its noncoincident peak, which inherently captures a large portion of the reliability benefits that Xcel Energy realizes through its MISO membership: a lower planning reserve margin requirement due to the diversity benefit of participation in a capacity sharing pool. The important distinction between this study's approach and Xcel's obligation is the use of Xcel-specific ELCC curves for variable and use-limited resources, which ensures that each portfolio of resources is sufficient to meet Xcel's own resource adequacy needs while still relying on the diversity benefit afforded to it through MISO membership.

The reliability analysis conducted in the first phase serves a secondary purpose as well: it provides an opportunity to examine what infrastructure investments would be needed to achieve a reliable portfolio that relies solely on carbon-free, non-combustion resources (primarily nuclear, wind, solar, and storage). In addition to deriving ELCC curves for a variety of resources, this study uses RECAP to design two portfolios that rely exclusively on carbon-free resources to serve load by 2045: one that includes Xcel's existing nuclear plants and another that relies only on wind, solar, and storage to meet reliability needs. These two portfolios are compared against today's system to illustrate the magnitude of investment needed to reach a fully carbon-free portfolio without any fossil combustion.

2.1.1.2 Methodology

The reliability analysis conducted in the first phase of this analysis is completed using RECAP, a loss-of-load-probability model developed by E3 and specifically tailored to answer questions on resource adequacy in systems heavily reliant on variable and use-limited resources. Its rigor lies in its simulation of the capability of a portfolio of generating resources to meet loads across a wide range of potential conditions, using a Monte Carlo approach to simulate thousands of potential years of plausible conditions on the system. RECAP incorporates features such as:

+ Use of decades of historical weather data to develop synthetic hourly load shapes reflective of long-term patterns of load variability;
+ Stochastic internal logic to produce chronological strips of load and corresponding renewable profiles that preserve correlations observed in a limited set of weather-matched chronological data;
+ Stochastic simulation of forced outages based on expectations for mean time to failure and mean time to repair for dispatchable generators; and
+ Time-sequential dispatch logic that allows the model to track state of charge and/or other constraints on use-limited resources (e.g. energy storage, demand response) that may limit their availability.

Through this robust simulation of load and generator availability, RECAP can be used to analyze whether an electric system's generation portfolio meets a specified reliability standard (most commonly, a standard of no more than "one day in ten years" of lost load). In evaluating resource adequacy, RECAP also produces a number of metrics directly useful to utilities in planning and procurement, including (1) a target planning reserve margin; (2) a variety of statistics for a given electricity system to characterize the size, frequency, and duration of reliability events; and (3) ELCC values for different types of resources on the system. Additional detail on the methodology of the RECAP model is presented in Appendix A.

This study relies on RECAP's simulation capabilities primarily to produce ELCC curves that serve as a key input into RESOLVE. The portfolio analysis relies on a PRM requirement to design a portfolio that meets reliability needs, and so RECAP is used to determine the extent to which variable and use-limited resources can contribute to meeting that requirement. RECAP is used to derive ELCC "curves" that capture how the capacity value of each resource changes as a function of penetration that in turn serve as inputs to a portfolio optimization process that uses this information to determine the appropriate level upon which to rely upon these resources to meet resource adequacy needs.

2.1.2 PORTFOLIO ANALYSIS

2.1.2.1 Scope of Analysis

The purpose of the second phase of this analysis is to design and evaluate a range of portfolios that simultaneously meet Xcel's reliability standards and ambitions for greenhouse gas reductions while also mitigating costs to its ratepayers. Designing portfolios to meet multiple objectives is a complex multidimensional problem that, in the context of increasing reliance on variable and use-limited resources, presents a new challenge to resource planners. In developing future resource plans, utilities must consider a broader range of available resource options (e.g. thermal generators, renewables, storage, demand-side resources), each with unique characteristics in their potential impacts on the system and interactive effects with other resources. Developing a least-cost plan to meet multiple objectives requires consideration of a range of different questions:

+ What are the fixed costs associated with a specific portfolio of new resources due to investments and operations and maintenance?
+ To what extent will a portfolio of resources meet resource adequacy needs, considering both the declining ELCC of different resource types and the interactive effects between technologies?
+ How will a portfolio affect the operations of the electric system across the year, and thereby the cost and associated greenhouse gas intensity to meet utility load?

+ How could retirement of existing plants either facilitate or inhibit the achievement of utility goals?

This second phase uses optimization modeling techniques to answer these questions through the development of a range of portfolios to meet Xcel's reliability standards while achieving substantial levels of carbon reduction.

2.1.2.2 Methodology

In this phase, this study uses E3's RESOLVE model to optimize future generation portfolios. RESOLVE is a capacity expansion model that uses linear programming to identify optimal long-term generation and transmission investments in an electric system, subject to reliability, technical, and policy constraints. Designed specifically to address the capacity expansion questions for systems seeking to integrate large quantities of variable resources, RESOLVE layers capacity expansion logic on top of a reduced-form production cost model to determine the least-cost investment plan, accounting for both the up-front capital costs of new resources and the variable costs to operate the grid reliably over time. In an environment in which most new investments in the electric system have fixed costs significantly larger than their variable operating costs, this type of model provides a strong foundation to identify potential investment benefits associated with alternative scenarios.

RESOLVE's optimization capabilities allow it to select from among a wide range of potential new resources. The full range of resource options considered by RESOLVE in this study is shown in Table 2-2 below.

Figure 2-2. RESOLVE modeling methodology

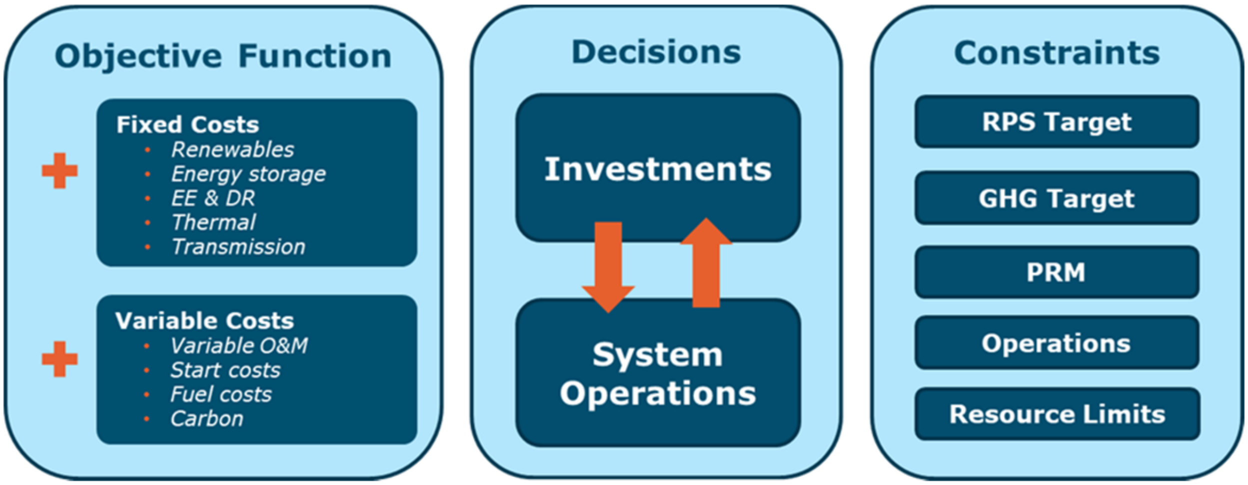


Table 2-2. Resource options considered in RESOLVE

Resource Option	Examples of Available Options	Capabilities
Natural Gas Generation	• Simple cycle gas turbines • Combined cycle gas turbines	• Dispatches economically based on heat rate, subject to operational constraints • Contributes to ramping & reserve needs • Provides large capacity value
Renewable Generation	• Solar PV • Wind	• Curtailable when needed to balance load • Provides limited capacity value based on ELCC
Energy Storage	• Batteries (4 hr)	• Balances hourly net load variability • Contributes to ramping & reserve needs • Provides limited capacity value based on ELCC
Energy Efficiency	• HVAC • Lighting	• Reduces demand throughout the year • Reduces resources need for reliability
Demand Response	• Interruptible tariff • Critical Peak Pricing	• Provides limited capacity value based on ELCC

To identify optimal investments in the electric sector, maintaining a robust representation of prospective resources' impact on system operations is fundamental to ensuring that the value each resource provides to the system is captured accurately. At the same time, the addition of investment decisions across multiple periods to a traditional unit commitment problem increases its computational complexity significantly. RESOLVE's simulation of operations has therefore been carefully designed to simplify a traditional unit commitment problem where possible while maintaining a level of detail sufficient to provide a reasonable valuation of potential new resources. The key attributes of RESOLVE's operational simulation are enumerated below:

+ **Hourly chronological simulation of operations:** RESOLVE's representation of system operations uses an hourly resolution to capture the intraday variability of load and renewable generation. This level of resolution is necessary in a planning-level study to capture the intermittency of potential new wind and solar resources, which are not available at all times of day to meet demand and must be supplemented with other resources.
+ **Planning reserve margin requirement:** When making investment decisions, RESOLVE requires the portfolio to include enough firm capacity to meet coincident system peak plus additional 3% of planning reserve margin (PRM) requirement. This value is Xcel's contribution as a utility to the overall MISO planning reserve margin of 8.4%. The contribution of each resource type towards this requirement depends on its attributes and varies by type: for instance, variable renewables are discounted compared to thermal generators because of limitations on their availability to produce energy during peak hours.
+ **Greenhouse gas cap:** RESOLVE also allows users to specify and enforce a greenhouse gas constraint on the resource portfolio for a region. As the name suggests, the emission cap requires that annual emission generated in the entire system to be less than or equal to the designed maximum emission cap. As it designs future portfolios, RESOLVE chooses both (1) how to dispatch new and existing resources to meet the goal (e.g. displacing output from existing coal plants with increased natural gas generation) and (2) what additional investments are needed to further reduce carbon in the system.

Additional detail on the methodology of the RESOLVE model is included in Appendix B.

2.1.2.3 Comparison to Strategist

The Xcel Upper Midwest team uses the Strategist model for answering questions on capacity expansion and planning optimization. Although in the same family of model as E3's RESOLVE model, there are key differences in how investments are evaluated in both models. These differences are highlighted in Table 2-3. below.

Table 2-3. Key differences between RESOLVE & Strategist

Model Feature	Strategist	RESOLVE
System Operations	Load duration curve heuristic	Chronological hourly dispatch with simplified unit commitment
Day Sampling	Representative weeks for each month	Smart sample of ~40 representative days
Market Interactions	Purchases & sales determined based on exogenous wholesale price forecast	Market interactions simulated endogenously with representation of external loads & resources
Resource Adequacy	Planning reserve margin with deemed credits for each resource	Planning reserve margin with dynamically updating ELCC values for renewables

Some implications of these differences are highlighted below:

+ Accurately capturing the impacts and operational value of resources like energy storage, for which simulation of chronological dispatch is important, is difficult in models that rely on load duration curve heuristics to approximate system operations—particularly as the penetrations of renewables and storage resources increase.
+ The assumption that Xcel is a price taker in the MISO market, implicit in the use of static wholesale prices to represent the external market, may not fully capture the effects that large changes in Xcel's own portfolio could have on the market itself. As the portfolios of Xcel and other utilities within the MISO footprint shift away from fossil resources and towards higher levels of renewables, capturing the changing market dynamics and implications of Xcel's own decisions on the market itself will become an increasingly important link in resource planning.

+ Similarly, the application of static capacity credits for resources like wind, solar, and storage will not capture the necessary evolution of capacity accreditation to ensure reliability at higher levels of penetration. Future resource planning efforts should consider how the capacity contributions of various future investments will change as penetrations increase rather than assuming capacity accreditation in the future remains consistent with today's rules.

Each of these implications suggests a need for resource planning practices in general to evolve towards a more dynamic, anticipatory paradigm to allow prudent planning in spite of a rapidly transforming system.

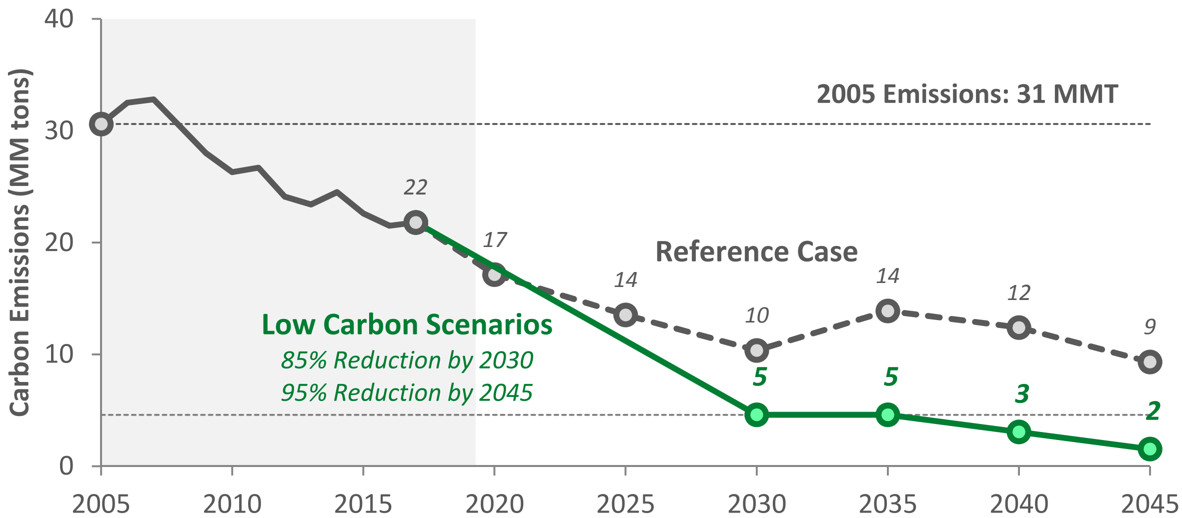
2.2 Scenarios & Sensitivities

2.2.1 OVERVIEW OF SCENARIOS

This study focuses on a suite of scenarios that examine the range of strategies Xcel could take to meet greenhouse gas reduction goals in the Upper Midwest system. Each of the scenarios and sensitivities, aside from the Reference Case, meet or surpass the carbon target shown in Figure 2-3; reaching an 85% reduction in carbon emissions by 2030 (beyond Xcel's actual 2030 target of an 80% reduction) and a 95% reduction in carbon emissions by 2045 (on track to meet Xcel's 2050 target of carbon neutrality).[2]

[2] The 2030 target modeled in this analysis is an assumption developed by E3 that reflects a plausible expectation that to achieve a company-wide goal of 80% carbon reductions by 2030 may require the Upper Midwest system to go beyond this target. This assumption (and the low carbon trajectory in its entirety) are not formally representative of carbon goals established by Xcel for its Upper Midwest system.

Figure 2-3. Future Upper Midwest carbon reduction pathway as modeled in this study compared to counterfactual Reference Case



The Reference Case modeled in this study is developed to provide a cost and emissions benchmark against which to compare each of the low carbon scenarios. It incorporates the following assumptions:

+ **Achievement of existing RPS goals** associated with existing statutes—including a 30% RPS by 2020 for Xcel (as Minnesota's largest utility);
+ **Planned new resources**, including over 2 GW of new renewable capacity by 2030, a new 835 MW combined cycle plant at the Sherco facility in 2027, and an additional 400 MW to Xcel's current DR program;
+ **Announced retirement dates of existing coal plants**, including Sherco units 1, 2, and 3 (2026, 2023, and 2040), AS King (2037)
+ **Retirement of nuclear plants at end of current licenses:** Monticello (2030), Prairie Island 1 and 2 (2033 and 2034)
+ **Forecasted cost reductions** for new solar, wind, and storage technologies consistent with industry expectations.

This study compares 21 “low carbon” scenarios against this Reference Case. The scenarios, listed in Table 2-4, were broadly designed in several categories to investigate key questions:

+ A set of **Coal Retirement Cases**, which informs the value of retiring various levels of Xcel’s coal fleet (AS King and Sherco 1, 2, and 3) to meet the carbon reduction goals;
+ A set of **New Gas Prohibition Cases**, which prohibits the construction of new gas generation (including or not including the new Sherco CCGT), forcing all future energy and capacity needs to be met by carbon-free resources; and
+ A set of **Nuclear Relicensing Cases**, which investigates the value of keeping the existing carbon-free, firm capacity (Monticello and Prairie Island 1 and 2) online through 2045.

Table 2-4. Matrix of scenarios evaluated

ID	AS King	Sherco 3	Prairie Island	Monticello	New Gas?
0	**Planned ret**	**Planned ret**	**Not relicensed**	**Not relicensed**	**Yes**
1	Planned ret	Planned ret	Not relicensed	Not relicensed	Yes
2	**Early retirement**	Planned ret	Not relicensed	Not relicensed	Yes
3	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	Yes
4	Planned ret	Planned ret	Not relicensed	Not relicensed	**Sherco CC only**
5	**Early retirement**	Planned ret	Not relicensed	Not relicensed	**Sherco CC only**
6	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	**Sherco CC only**
7	Planned ret	Planned ret	Not relicensed	Not relicensed	**None**
8	**Early retirement**	Planned ret	Not relicensed	Not relicensed	**None**
9	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	**None**
10	Planned ret	Planned ret	Not relicensed	**20-yr relicense**	Yes
11	**Early retirement**	Planned ret	Not relicensed	**20-yr relicense**	Yes
12	**Early retirement**	**Early retirement**	Not relicensed	**20-yr relicense**	Yes
13	Planned ret	Planned ret	**20-yr relicense**	**20-yr relicense**	Yes
14	**Early retirement**	Planned ret	**20-yr relicense**	**20-yr relicense**	Yes
15	**Early retirement**	**Early retirement**	**20-yr relicense**	**20-yr relicense**	Yes
16	Planned ret	Planned ret	**Early retirement**	Not relicensed	Yes
17	**Early retirement**	Planned ret	**Early retirement**	Not relicensed	Yes
18	**Early retirement**	**Early retirement**	**Early retirement**	Not relicensed	Yes
19	Planned ret	Planned ret	**20-yr relicense**	**20-yr relicense**	**Sherco CC only**
20	**Early retirement**	Planned ret	**20-yr relicense**	**20-yr relicense**	**Sherco CC only**
21	**Early retirement**	**Early retirement**	**20-yr relicense**	**20-yr relicense**	**Sherco CC only**

2.2.2 SENSITIVITY ANALYSIS

The long-term scenario analysis conducted in this type of study relies on projections of future conditions that are inherently uncertain. Utilities have historically incorporated uncertainty in such factors as fuel price forecasts and load growth into their integrated resource planning analyses to account for this uncertainty. With the transition of the industry towards resources that consume less fuel but are more capital intensive, new sources of uncertainty become important considerations for resource planners—for instance, future anticipated cost reductions for resources like wind, solar, and battery storage. This study conducts sensitivity analyses on a number of such uncertainties to evaluate the robustness of the conclusions reached in this analysis. The list of sensitivities explored within this analysis is shown in Table 2-5. Inventory of sensitivities explored in analysis—while no means meant to represent a comprehensive analysis of all uncertainties faced by utilities, these represent a number of the key factors that should be considered in resource planning and decision-making. Sensitivities are not tested against all scenarios—instead, a subset of scenarios is selected for more detailed examination through sensitivities.

Table 2-5. Inventory of sensitivities explored in analysis

Sensitivity	Description
High/Low Gas Prices	Alternative projections of natural gas natural gas prices (+/- 50% adjustment to CAGR) that tests how future gas prices will impact cost of decarbonization.
High/Low Technology Costs	Alternative price projections for renewable & storage technologies that evaluates impact of future technology costs on cost of decarbonization.
Low Exports	Assumes Xcel cannot sell surplus generation into the MISO market beyond 2030, reflecting a bookend scenario for adverse market conditions in which demand for surplus power throughout MISO is limited
High Electrification Loads	Assumed loads increase by ~21 TWh by 2045 due to space & water heating electrification, as well as electric vehicle integration

3 Inputs & Assumptions

This study relies on a wide range of inputs and assumptions to populate the RESOLVE and RECAP models. Wherever possible, inputs and assumptions are aligned with those used directly by Xcel to prepare its own IRP filing for the Upper Midwest system; in some cases, data from publicly available information was used as a supplement to information provided by Xcel. The key categories of inputs and assumptions to E3's two portfolio analysis models are summarized in Table 3-1. Additional detail on each specific input is included in subsequent sections.

Table 3-1. Summary of some key inputs and assumptions for RESOLVE and RECAP

Input Category	Used in Model	Description
Demand forecast	RESOLVE, RECAP	Annual demand and peak forecast for the Upper Midwest system
Existing resources	RESOLVE, RECAP	Capacity, commission dates, retirement dates and operating characteristics for all existing and planned resources within the Xcel Upper Midwest system
New resources	RESOLVE, RECAP	Costs and performance for candidate resources considered in the portfolio optimization
Hourly profiles	RESOLVE, RECAP	Hourly profiles for all the components of demand; hourly generation profiles for solar and wind resources; hourly profiles for all other chronological hourly dispatch resources like EE
Fuel price forecasts	RESOLVE	Fuel price forecast data for all thermal resources
MISO market representation	RESOLVE	Load and resource assumptions for other external MISO zones connected to Xcel's Upper Midwest service territory

3.1 Demand Forecast

3.1.1 BASE CASE

The demand forecast used in this study captures expected future changes in electricity demand within Xcel's Upper Midwest service territory. The demand forecast accounts for expected growth in loads due to future economic and demographic trends but does not account for the future impacts of Xcel's energy efficiency programs; these efficiency programs are represented instead in this analysis explicitly as a supply-side resource with a variable profile. The assumed demand forecast assumptions, shown in Table 3-2., align with Xcel's Upper Midwest IRP modeling assumptions.

Table 3-2. Xcel Base Case demand forecast

Category	Historical 2018	Forecast 2020	2025	2030	2035	2040	2045	CAGR '18-'45
Retail Sales (GWh)	44,348	45,129	46,589	49,704	51,577	53,007	53,921	0.7%
Peak Demand (MW)	9,241	9,399	9,927	10,628	11,426	11,956	12,420	1.1%

Retail sales represent the demand for electricity at the customer meter and are grossed up for transmission and distribution losses (7%) when simulating the operations of the bulk electric power system; peak demand is reported at the wholesale level and so already accounts for the impact of transmission & distribution losses.

3.1.2 HIGH ELECTRIFICATION SENSITIVITY

The results of the economy-wide deep decarbonization pathways analysis discussed in Section 1.1 suggests that achievement of deep decarbonization targets across the economy requires electrification of multiple end uses; particularly transportation, space heating, and water heating. To develop a High Electrification sensitivity for this study, E3 used projections of future electric sector load from the "High

Electrification" scenario in E3's pathways study, downscaled to represent the Upper Midwest service territory. This sensitivity explores the impact on the Xcel system of increased demand due to space and water heating electrification and increased electric vehicle integration. Table 3-3 shows the impacts of incremental electrification on Xcel's annual energy demand in this High Electrification sensitivity.

Table 3-3. Buildup of retail sales forecast used in High Electrification sensitivity

Category	Historical 2018	Forecast 2020	2025	2030	2035	2040	2045	CAGR '18-'45
Base Case	**44,348**	**45,129**	**46,589**	**49,704**	**51,577**	**53,007**	**53,921**	0.7%
Space Heating	-80	-87	-28	+315	+1,772	+4,030	+6,386	
Water Heating	+87	+145	+251	+160	+317	+713	+1,083	
Electric Vehicles	+38	+79	+338	+1,559	+4,733	+9,369	+13,639	
High Electrification	**44,393**	**45,266**	**47,149**	**51,738**	**58,400**	**67,118**	**75,030**	**2.0%**

Before 2030, the space heating component causes a decrease in total retail sales because the amount of electrified spacing heating is not yet enough to overcome the benefits from the increased efficiency. By 2045, all three components cause a 39% increase in annual retail sales relative to the Base Case. Through the modeling period, electric vehicle integration contributes the largest increase in retail sales on an annual basis.

The corresponding impact on peak demand from the high level of electrification is more significant (see Table 3-4), nearly doubling over the analysis horizon through 2045. The major driver of the significant increase in peak is the electrification of end use heating loads, which, beginning in the early 2030s, cause Xcel to shift from a summer to a winter peak. Thereafter, the magnitude of the winter peak rises dramatically with increased deployment of heat pumps and other newly electrified loads.

Table 3-4. Buildup of peak demand forecast used in High Electrification Sensitivity

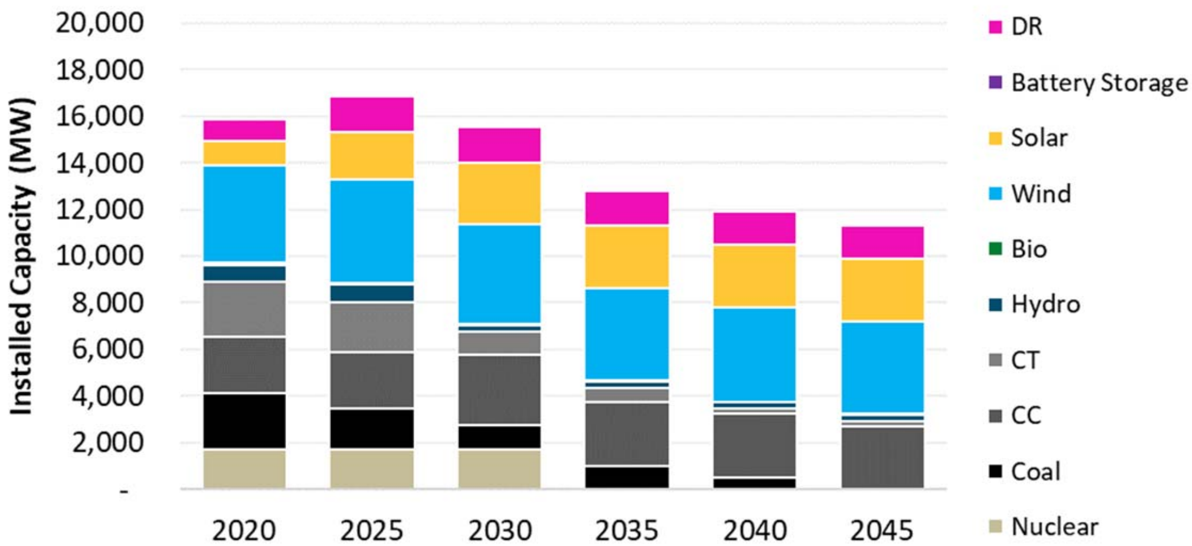
Category	Historical 2018	Forecast 2020	2025	2030	2035	2040	2045	CAGR '18-'45
Base Case	9,241	9,399	9,927	10,628	11,426	11,956	12,420	**1.1%**
Incremental Load From Electrification	8	+7	+77	+207	+855	+5,347	+10,369	
High Electrification	**9,249**	**9,406**	**10,004**	**10,835**	**12,281**	**17,302**	**22,789**	**3.4%**

3.2 Existing Resource Portfolio

The primary source for data on existing and planned generation is Xcel IRP modeling assumptions. The composition of Xcel's existing fleet is shown in Figure 3-1, reflecting Xcel's commitments and plans established by prior IRP. Key changes to the system captured in Figure 3-1 include:

+ **Planned new resources**, including nearly 2 GW of new renewable capacity by 2030, a new 835 MW combined cycle plant at the Sherco facility in 2027, and an additional 400 MW to Xcel's current DR program from 2023;
+ **Announced retirement dates of existing coal plants**, including Sherco units 1, 2, and 3 (2026, 2023, and 2040), AS King (2037); and
+ **Retirement of nuclear plants at end of current licenses:** Monticello (2030), Prairie Island 1 and 2 (2033 and 2034).

Figure 3-1. Existing resource assumptions for Xcel portfolio over time



3.2.1 NUCLEAR

Xcel's current generation portfolio includes three nuclear units:

- Monticello (646 MW), whose license expires in 2031;
- Prairie Island 1 (546 MW), whose license expires in 2033; and
- Prairie Island 2 (546 MW), whose license expires in 2034.

Together, these baseload carbon-free resources are capable of producing roughly 14,000 GWh on an annual basis, enough to meet approximately 30% of Xcel's annual energy needs.

This study examines multiple options for retirement and relicensing of these existing nuclear units across different scenarios; these assumptions are summarized in Table 3-5. The Reference Case assumes that all units retire upon the expiry of their existing licenses, which results in a significant need for new investment to meet energy and capacity needs in the early 2030s; alternative scenarios examine the potential effects of extending the licenses at one or both facilities through the analysis horizon, testing the impact of retaining baseload carbon-free generation within the context of Xcel's future carbon reduction goals.

Table 3-5. Xcel nuclear plant assumptions

	Reference Assumptions		
Plant	**Capacity (MW)**	**Retirement**	**Notes**
Monticello	646	2030	Plant life extended by 20 years in scenarios 10-15
Prairie Island 1	546	2033	Plant life extended by 20 years in scenarios 13-15
Prairie Island 2	546	2034	Plant life extended by 20 years in scenarios 13-15

Each nuclear plant is modeled as a baseload, must-run unit, available to produce energy at full capacity throughout the year but for several periods of assumed extended outage for maintenance and refueling.

3.2.2 COAL

Xcel currently owns four coal plants operating in the Upper Midwest service territory:

- Allan S King (511 MW), whose planned retirement date is in 2037;
- Sherco 1 (680 MW), whose planned retirement date is in 2026;
- Sherco 2 (682 MW), whose planned retirement date is in 2023; and
- Sherco 3 (517 MW), whose planned retirement date is in 2040.

This study examines multiple options for retirement of the two existing coal units with retirement dates beyond 2030; these assumptions are summarized in Table 3-6.

Table 3-6. Xcel coal plant assumptions

	Reference Assumptions		
Plant	**Capacity (MW)**	**Retirement**	**Notes**
AS King	511	2037	Retired early in all scenarios **EXCEPT** 1,4,7,10,13,16
Sherco 1	680	2026	Planned retirement
Sherco 2	682	2023	Planned retirement
Sherco 3	517	2040	Retired early in scenarios 3,6,9,12,15 & 18

Operating assumptions for these existing coal plants are aligned with the assumptions used in Xcel's IRP modeling; key parameters that affect their dispatch include:

+ Maximum power output (MW)
+ Minimum stable level (MW)
+ Heat rates at Pmin and Pmax (Btu/kWh)
+ Minimum up & down time (hrs)
+ Variable O&M cost ($/MWh)
+ Forced outage rate (%)

This study assumes that the coal generators are dispatched according to signals from the broader MISO territory and not solely on the Upper Midwest system's dynamics. As such, each coal plant is modeled as a baseload, must-run unit, which can be dispatched down to the minimum power (Pmin) value if needed.

3.2.3 OTHER THERMAL RESOURCES

The remainder of Xcel's existing remaining thermal resources consist of owned and contracted natural gas, fuel oil, and biomass resources. The existing natural gas and fuel oil plants in Xcel's current portfolio, along with assumed retirement dates are summarized in Table 3-7 below. In addition to these existing resources, most scenarios examined in this study (with the exception of Scenarios 6-9) assume that a new combined cycle plant is installed at the Sherco site following the closure of Sherco Units 1 & 2.

Table 3-7. Xcel natural gas and fuel oil plant assumptions

Plant	Plant Type	Capacity (MW)	Retirement
Black Dog CC	Combined Cycle	298	2032
High Bridge	Combined Cycle	606	2048
Riverside	Combined Cycle	508	2049
LS Power Cottage Grove	Combined Cycle	245	2027
Mankato Energy Center	Combined Cycle	762	2046
Angus Anson (Units 2 & 3)	Combustion Turbine	218	2035
Angus Anson (Unit 4)	Combustion Turbine	168	2035
Blue Lake (Units 7 & 8)	Combustion Turbine	351	2034
Inverhills	Combustion Turbine	369	2026
Wheaton (Units 1 - 4)	Combustion Turbine	241	2025
InvEnergy	Combustion Turbine	358	2024
Bayfront (Unit 4)	Combustion Turbine	15	2034
Black Dog CT	Combustion Turbine	232	2058
Blue Lake (Units 1 - 4)	Fuel Oil	191	2023
French Island	Fuel Oil	160	2027
Wheaton (Unit 6)	Fuel Oil	70	2025
Total		**4,792**	

Operating characteristics for Xcel's thermal resources were provided to E3 by Xcel's resource planning team. The input assumptions used in this study are the same operating characteristics as those used in Xcel's modeling in Strategist. In general, the inputs and assumptions used to characterize the costs and constraints on operating these units are the same parameters that are provided for coal plants (maximum and minimum power, heat rates and variable O&M cost, minimum up and down time, etc.). Together, these inputs affect the economics of how each plant can be dispatched to meet Xcel's load on an hourly basis, which in turn affects the economics and value of potential new resource additions.

Xcel's existing portfolio also includes a number of contracts with small biomass facilities; together, these contracts amount to 145 MW in 2020. This analysis assumes these contracts are not renewed upon expiration; the amount of contracted capacity contracts declines to 30 MW by 2030 and 4 MW by 2045.

3.2.4 HYDRO

The Xcel Upper Midwest portfolio also includes hydrogeneration facilities and contracts. The hydro resources modeled in the portfolio include:

+ Local run-of-river facilities within the Xcel Upper Midwest service territory totaling 312 MW; and
+ Contracts for hydro capacity with Manitoba Hydro that total approximately 850 MWs and expire in 2025.

3.2.5 RENEWABLES

Today, Xcel Upper Midwest's renewable portfolio includes 3,800 MW of wind resources, 323 MW of utility-scale solar PV, and 671 MW of customer solar PV associated with the Solar Rewards Community program. Based on recent solicitations as well as commitments made in the prior IRP cycle, this study assumes that the following resources are added to the Xcel portfolio across all scenarios:

+ 520 MW of new wind PPA by 2030;
+ 1,512 MW of utility-scale solar by 2030, and an additional 571 MW by 2045; and
+ 122 MW of additional customer solar by 2030.

3.3 New Resource Options

A broad range of new resources options are considered as candidates in the portfolio optimization process. These options generally align with those examined by Xcel in the development of its own IRP, including new gas, renewable, storage, and demand-side resources. The study also examines the impact of relicensing the nuclear plants in several scenarios. This section summarizes general assumptions on resource cost and performance used to characterize each of these options.

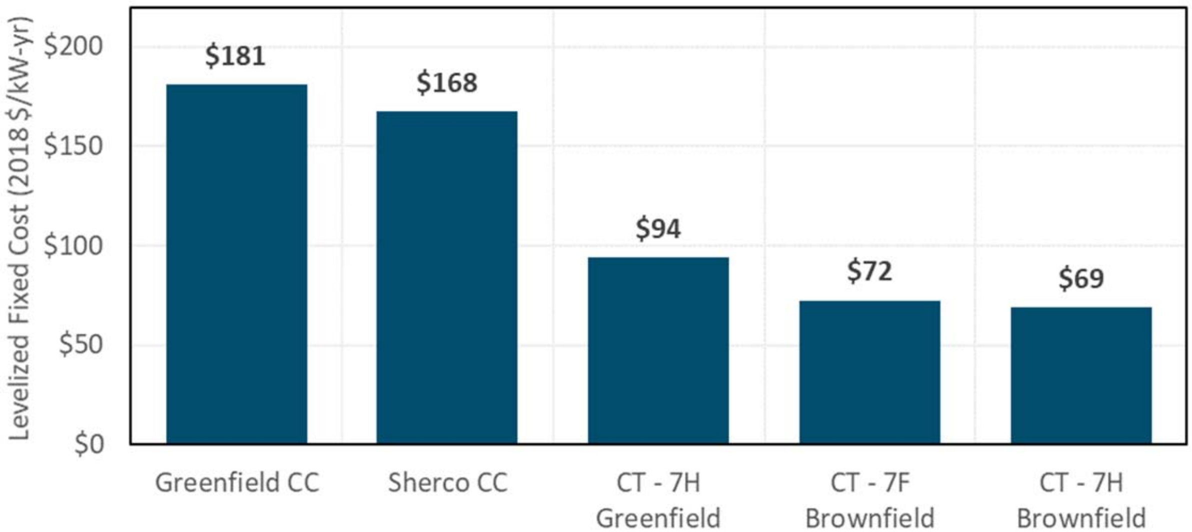
3.3.1 NATURAL GAS

Five generic gas generation resources are included as options for additional capacity:

+ **Greenfield CCGT:** a generic new combined cycle plant that reflects both generation and transmission capital costs and the ongoing costs of operating the plant;
+ **Sherco CC:** a new combined cycle plant located at the existing Sherco site that reflects generation costs but no interconnection or transmission costs (limited to 835 MW of potential);
+ **Greenfield CT:** Greenfield 7H frame CTs are available as resource options, though an interconnection fee is required. As with the greenfield CCGT, the capacity potential is uncapped.
+ **Brownfield CT:** Both 7H and 7F frames are available for selection, with the former more expensive. These resources are assumed to be built on existing sites and therefore do not require transmission costs. However, they are capacity limited to capture existing site availability constraints.

The levelized fixed costs associated with each generic gas resource in this analysis, as well as the estimated levelized cost of the Sherco combined cycle plant, were developed by Xcel Energy and provided to E3. As shown in Figure 3-2, the fixed cost per kW of CCGT is substantially higher than the cost of new combustion turbines. Gas-fired resources costs are expected to remain constant in real terms through 2050.

Figure 3-2. Levelized fixed costs of new gas generation resources.



3.3.2 RENEWABLES

Cost assumptions for new renewable resources in this study are based largely on NREL's Annual 2018 Technologies Baseline (ATB),[3] which provides an annual perspective on the current state of generation technology costs and a range of perspectives as to how those costs could change in the future. This study translates the 2018 ATB capital and fixed O&M cost assumptions for wind and solar PV (single-axis tracking) technologies into a levelized cost of energy (LCOE) metric for each type of resource that reflects an proxy for the price at which an independent developer might offer the resource to a credit-worthy utility through a long-term power purchase agreement (PPA). LCOEs for each resource vary through time due to assumed changes in technology cost, financing costs, and federal tax credits.

[3] The 2018 ATB was released in July 2018 and is available at: https://atb.nrel.gov/

The LCOEs for new renewable resources also include a component to capture the transmission upgrades needed to ensure that resources can be delivered to loads. Transmission costs are additive to the capital cost of the resource itself and are based on assumptions developed by Xcel as inputs for its IRP.

3.3.2.1 Wind

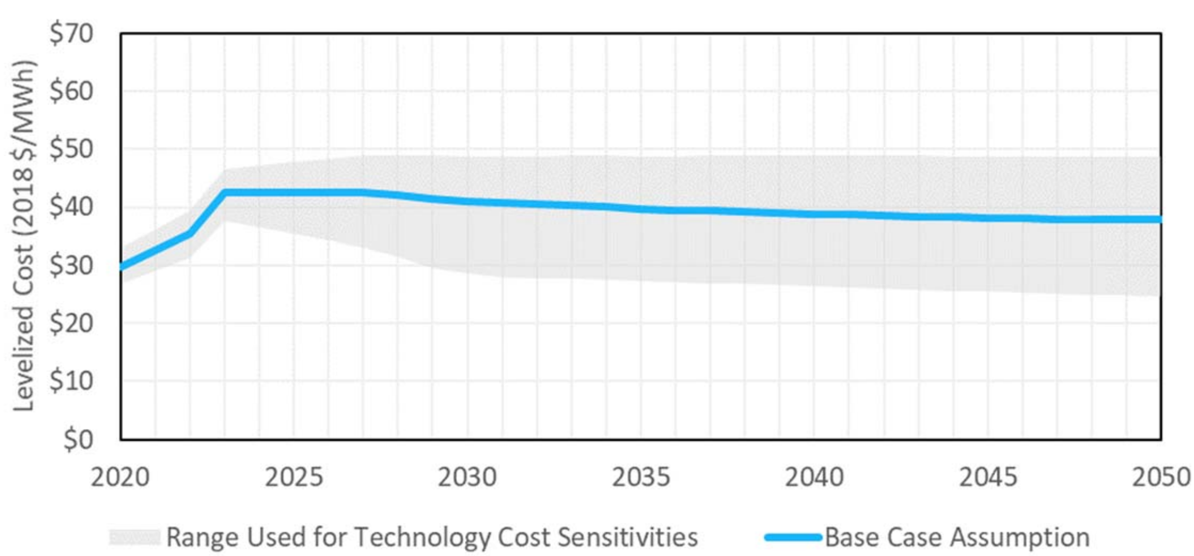
Table 3-8 shows the input assumptions and corresponding LCOEs for new wind resources in 2020 and 2030. Cost and performance assumptions for wind resources are translated into an LCOE that serves as an input to the portfolio optimization process. Near-term wind costs for high-quality resources are relatively low—in large part, due to the effect of the Federal Production Tax Credit (PTC); in the long run, the LCOE of wind is assumed to increase from today's level due to the expiration of the PTC, an effect that is partially offset by some improvements in capital costs.

LCOEs for new wind resources—both for the Base Case assumptions reported in Table 3-8 and the alternative high and low cost assumptions used in sensitivity analysis—are shown in Figure 3-3. The near-term trajectory of costs is heavily shaped by the expiration of the PTC, which results in a near-term cost increase; in the long run, the LCOE for new wind resources declines slightly in real terms as technology continues to improve at a modest pace.

Table 3-8. Key technology parameters for new wind resources

		Installation Year		
Assumption	**Units**	**2020**	**2030**	**Source**
Capital cost	$/kW	$1,531	$1,381	NREL Annual Technologies Baseline (TRG 2)
Transmission cost	$/kW	$400	$400	Xcel IRP assumption
Fixed O&M	$/kW-yr	$52	$48	NREL Annual Technologies Baseline (TRG 2)
Capacity factor	%	50%	50%	Xcel IRP assumption
Tax credit	$/MWh	$18	—	Federal Production Tax Credit
Financing costs				E3 standard pro-forma PPA assumptions
Hourly profile				Sites sampled from NREL WIND Toolkit
Levelized cost	**$/MWh**	**$30**	**$41**	**Calculated based on assumptions above**

Figure 3-3. LCOE projections for new wind resources: Base Case and High & Low Technology Cost sensitivities



3.3.2.2 Solar

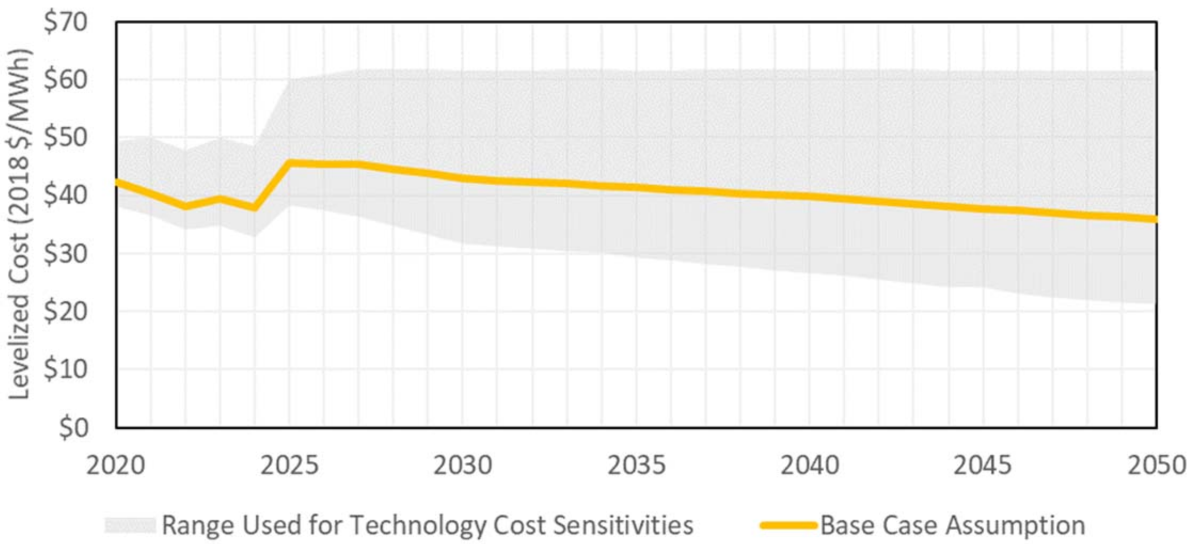
Table 3-9 shows the input assumptions and corresponding LCOEs for new solar resources in 2020 and 2030. Cost and performance assumptions for solar resources are translated into an LCOE that serves as an input to the portfolio optimization process. While the Federal Investment Tax Credit (ITC) available to solar resources today is scheduled to revert to a lower level of 10% in the next few years, continued anticipated cost reductions in capital costs over time helps to offset the effect of the sunsetting ITC on the resulting LCOEs for solar resources.

Figure 3-4 shows the trajectory of solar LCOEs through 2050 under the Base Case assumptions above, as well as the high and low ranges used in the technology cost sensitivities.

Table 3-9. Key technology inputs for new solar resources

		Installation Year		
Assumption	**Units**	**2020**	**2030**	**Source**
Capital cost	$/kW	$1,355	$1,154	NREL 2018 Annual Technologies Baseline
Transmission cost	$/kW	$140	$140	Xcel IRP assumptions
Fixed O&M	$/kW-yr	$11	$9	NREL 2018 Annual Technologies Baseline
Capacity factor	%	23%	23%	RESOLVE solar profiles
Tax credit	%	30%	10%	Federal Investment Tax Credit
Financing				E3 standard pro-forma PPA assumptions
Hourly profile				Sites sampled from NREL WIND Toolkit
Levelized cost	**$/MWh**	**$42**	**$43**	**Calculated based on assumptions above**

Figure 3-4. LCOE projections for new solar resources: Base Case and High & Low Technology Cost sensitivities



3.3.3 ENERGY STORAGE

The reliability and portfolio optimization analyses consider energy storage as a potential resource addition. Cost assumptions for new energy storage are based on Lazard's Levelized Cost of Storage 4.0,[4] which provides an assessment of the state of market for battery storage and a forward-looking projection of costs over a five-year period through 2022. Cost projections beyond this 2022 timeframe are derived by extrapolation of the cost declines anticipated in the next five years. While Lazard's study considers many technologies and applications in its assessment of the market, this study relies upon Lazard's characterization of a utility-scale battery system with four hours of duration. Table 3-10 presents the cost assumptions and corresponding levelized costs for a new four-hour battery.

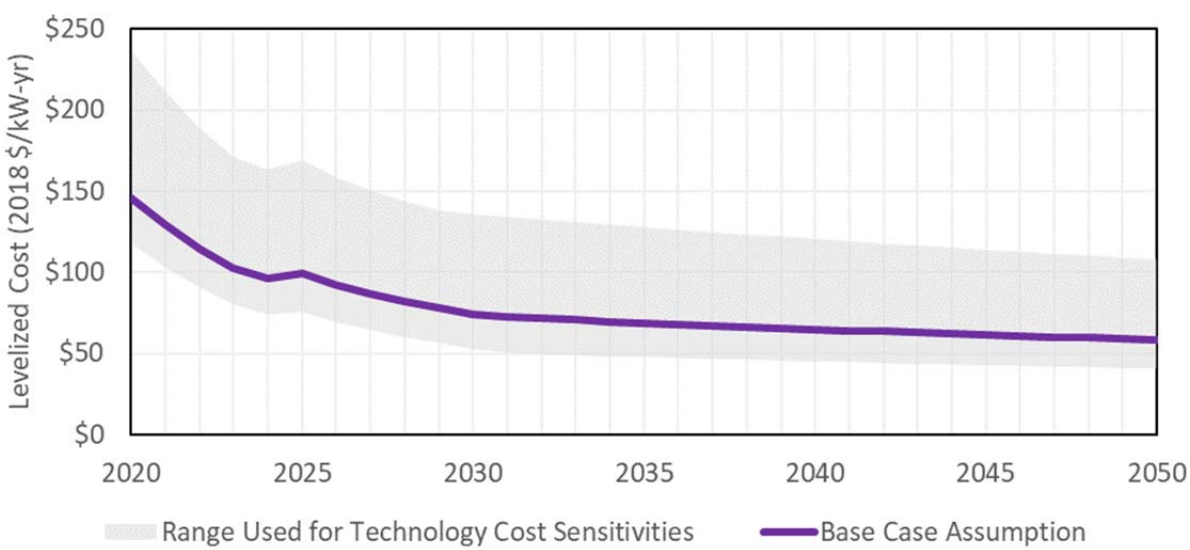
Figure 3-5 shows the levelized fixed cost assumptions for battery storage across the analysis horizon.

[4] Report available at: https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf

Table 3-10. Key technology inputs for new storage capacity (4-hr duration)

		Installation Year		
Assumption	**Units**	**2020**	**2030**	**Source**
Capital cost	$/kW	$1,311	$720	Lazard Levelized Cost of Storage 4.0
Transmission cost	$/kW	—	—	Xcel IRP assumptions
Fixed O&M	$/kW-yr	$17	$8	Lazard Levelized Cost of Storage 4.0
Periodic replacement	$/kW-yr	$41	$16	Lazard Levelized Cost of Storage 4.0
Financing costs				E3 standard pro-forma PPA assumptions
Levelized cost	**$/kW-yr**	**$146**	**$74**	**Calculated based on assumptions above**

Figure 3-5. Levelized cost projections for new storage resources: Base Case and High & Low Technology Cost sensitivities



3.3.4 NUCLEAR RELICENSING

Costs associated with maintaining and operating existing nuclear plants are broken into three categories:

+ Ongoing fixed O&M: routine annual non-fuel costs associated with operating and maintaining the plant, incurred each year it is in operations;
+ Fuel costs: costs associated with procurement of uranium to fuel reactors, incurred for each unit of energy generated; and
+ Incremental relicensing cost: additional costs incurred on an annual basis associated with plant relicensing that are incurred beginning in the year after relicensing (applicable only in scenarios in which the plants are relicensed).

All cost assumptions for nuclear plants, including the increase in fixed costs associated with license extensions, were provided by Xcel.

3.3.5 DEMAND RESPONSE

New demand response resources are included as options to satisfy the need for new generation capacity. The cost and potential for new demand response is consistent with the Xcel IRP data assumptions. In the Xcel system there are three demand response programs capable of contributing to the need for peaking capability: (1) Saver's Switch, (2) Interruptible tariffs, and (3) Critical Peak Pricing (CPP). A supply curve of three bundles, each bundle comprising all three measures, is available for selection within the optimization; these bundles are summarized in Table 3-11 below.

Table 3-11. Assumed cost and potential for new demand response resources

Program Type	Levelized Cost ($/kW-yr)	Maximum Technical Potential (MW)					
		2020	2025	2030	2035	2040	2045
Bundle 1	$54	270	380	456	567	717	717
Bundle 2	$71	107	145	189	257	352	352
Bundle 3	$130	89	110	110	116	135	135
Total		**467**	**635**	**755**	**940**	**1,204**	**1,204**

3.3.6 ENERGY EFFICIENCY

In this study, the model can optimize Xcel's new energy efficiency (EE) programs to meet a portion of future energy and capacity needs; this may also contribute to meeting carbon reduction goals. The data for capacity, potential, impacts shapes, and costs for energy efficiency is consistent with the Xcel IRP data. Measures were grouped into three categories according to cost and potential: (1) Program Achievable, (2) Optimal, (3) Maximum Achievable. The Program Achievable and Maximum Achievable bundles were developed based on the Minnesota Energy Efficiency Potential Study[5], while the Optimal bundle was developed by Xcel. This study optimizes the EE programs through 2034 and then holds the resulting level constant through the rest of the modeling period. The supply curve used in this study is shown in Figure 3-6. The levels of potential load reduction shown in Figure 3-6 represent the maximum impacts from the supply curve through 2034. The potential annual load and peak load impacts of the EE bundles are cumulative over time. The impacts on annual load and peak load assumptions are shown in Figure 3-7.

[5] Minnesota Energy Efficiency Potential Study: 2020-2029. December 2018, available at: https://www.mncee.org/MNCEE/media/PDFs/MN-Potential-Study_Final-Report_Publication-Date_2018-12-04.pdf

Figure 3-6. Supply curve of available energy efficiency measures (2034)

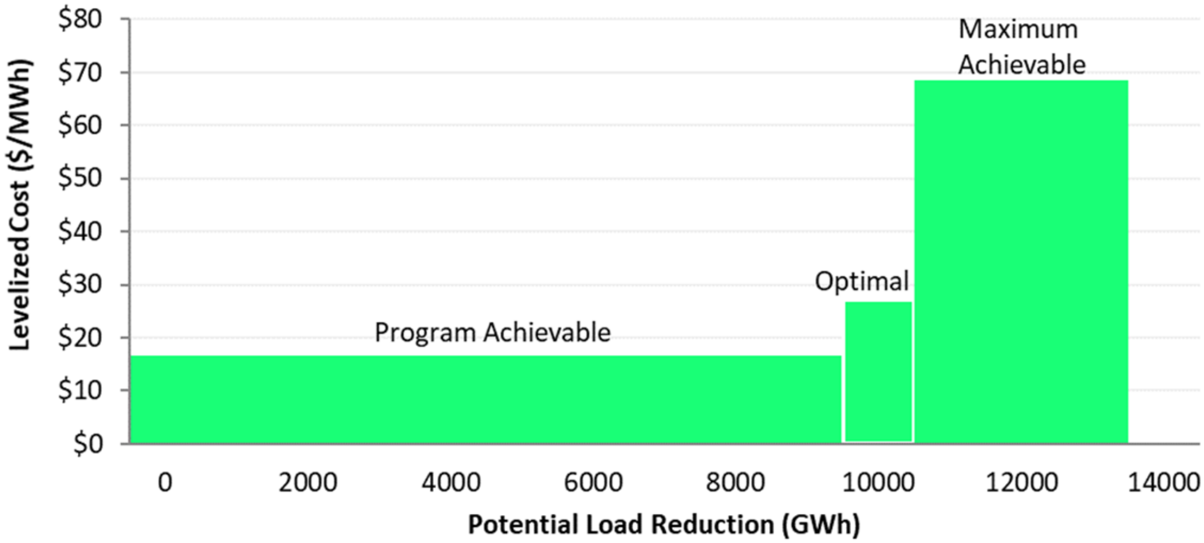
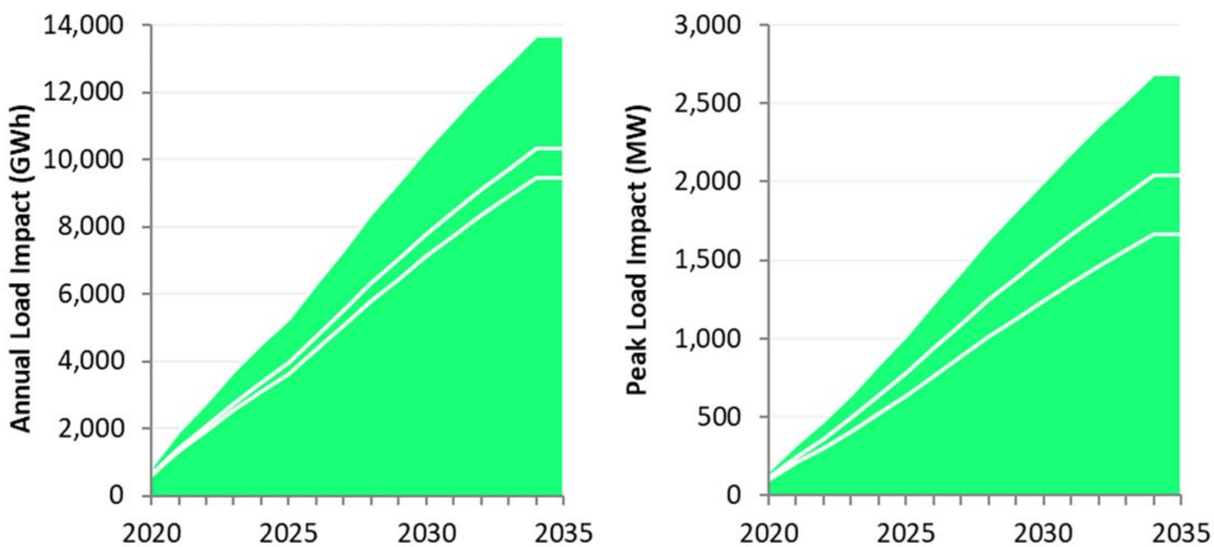


Figure 3-7. Xcel EE bundles annual load and peak load impacts assumptions



3.4 Hourly Profiles

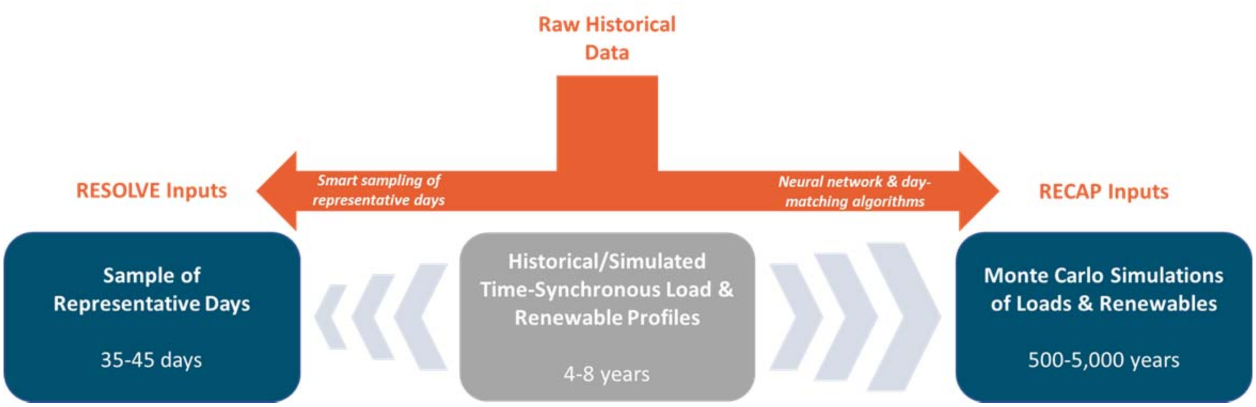
Hourly profiles for load and wind and solar resources are key inputs to this study. Load, wind, and solar each vary on an hourly, daily, and seasonal basis, and their variations are often correlated due to underlying meteorological phenomena that affect all three. Capturing these patterns in a statistically rigorous manner is crucial to enable planning of a system that can operate efficiently on a day-to-day basis and is resilient in spite of an increasingly intermittent and variable energy supply.

This study relies on a library of hourly load, wind, and solar profiles that reflect the meteorological conditions across the four-year time span from 2009 through 2012. Developing profiles that are weather-matched and time-synchronized in this manner ensures consistency across the data set, preserving the key underlying correlations among the variables. The hourly profiles for this study are based on the following sources:

+ Load profiles for current end uses on the Xcel Upper Midwest system are based on actual metered historical loads for the 2009-2012 period;
+ Load shapes for end uses that may be electrified in the future (e.g. space heating, water heating)—used only in the High Electrification sensitivity—are simulated based on hourly historical weather data using building simulation software;
+ Wind profiles are developed for the same period using data from NREL's WIND Toolkit, which provides detailed geospatial simulations of wind speed and generation profiles for a large number of sites throughout the United States;
+ Solar PV profiles are simulated using NREL's System Advisor Model (SAM) and solar irradiance data from the National Solar Radiation Database (NSRDB) for a variety of plausible locations throughout the Xcel Upper Midwest territory;

This library of profiles serves as a foundational dataset of inputs for both the reliability and the portfolio analysis. However, the series themselves are used in different ways, as depicted in Figure 3-8. In RECAP, these series are extended through simulation of a much longer historical weather record; capturing such a broad set of plausible weather conditions is essential when examining whether a system is designed to meet a "one-day-in-ten-year" reliability standard. In contrast, in RESOLVE, a reduced representative subset of 37 days is used to enable portfolio optimization across multiple decades, sampled to reflect representative combinations of loads and associated renewable production profiles, from the time series described. For additional information on this process, see Appendix C.1.

Figure 3-8. Schematic of development of hourly profile inputs for RECAP & RESOLVE



3.5 Fuel Price Forecasts

Fuel prices were derived from Xcel's data of generators and their associated fuels and fuel costs. To arrive at a representative fuel price trajectory by resource, plants were binned into their respective fuel types and the average annual fuel price of each resource was then calculated. Fuel oil and biomass prices are both expected to decline in real terms through 2050 while coal and natural gas are expected increase in price. Fuel price projections used in this study are summarized in Table 3-12.

Table 3-12. Fuel price forecasts ($/MMBtu)

Fuel Type	2020	2025	2030	2035	2040	2045	CAGR ('20-'45)
Coal	$2.03	$2.11	$2.18	$2.26	$2.34	$2.35	**0.6%**
Fuel Oil	$16.44	$15.52	$15.31	$15.11	$14.93	$14.77	**-0.4%**
Natural Gas	$2.59	$3.06	$3.44	$3.74	$4.01	$4.08	**1.8%**

Fuel prices are shaped on a monthly basis to capture the seasonal differences in costs; the degree of seasonal adjustment depends on the fuel. Natural gas, whose demand varies significantly on a seasonal basis due to heating loads in the winter, has the most significant differences in assumed pricing by month, whereas other fuels' prices remain relatively constant throughout the year. Seasonal shaping factors for each fuel are shown in Table 3-13.

Table 3-13. Seasonal shaping factors, expressed as a percentage of annual average price

Month	Coal	Fuel Oil	Natural Gas
January	100%	97%	111%
February	100%	101%	109%
March	100%	101%	103%
April	100%	101%	95%
May	100%	101%	93%
June	100%	101%	93%
July	100%	100%	95%
August	100%	100%	96%
September	100%	100%	96%
October	100%	100%	97%
November	100%	100%	104%
December	100%	99%	109%

In addition to the Base Case forecast for natural gas, this study also tests the impacts of high and low gas price sensitivities on key results and conclusions. These high and low sensitivities begin to diverge from the base forecast in 2022 and are based on adjustments of the base forecast 2018 – 2057 nominal CAGR, which is consistent with Xcel's modeling. In the Low Gas Price and High Gas Price sensitivities, prices grow at rates 50% lower and 50% higher than the Base Case (in nominal terms). The corresponding gas price forecasts associated with each sensitivity are shown in Table 3-14.

Table 3-14. Sensitivities on natural gas price forecasts in 2018 $

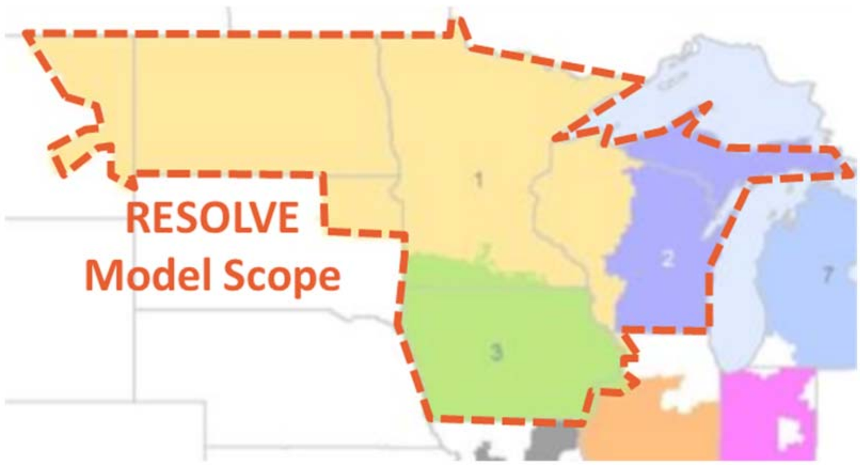
Fuel Type	2020	2025	2030	2035	2040	2045	CAGR ('20-'45)
Base Case	$2.59	$3.06	$3.44	$3.74	$4.01	$4.08	**1.8%**
Low Gas Price	$2.59	$2.88	$2.99	$3.00	$2.98	$2.80	**0.3%**
High Gas Price	$2.59	$3.26	$3.96	$4.64	$5.38	$5.92	**3.4%**

One area where this analysis does deviate notably from the analysis conducted by Xcel to support its integrated resource plan is in the treatment of carbon emissions costs. Under direction from the Public Utilities Commission, Xcel includes an explicit carbon cost in the evaluation and comparison of costs among portfolios in its IRP. Because the scenarios in this study are instead designed to meet a specific carbon goal, and to measure the cost associated with achieving that level of carbon reduction, an explicit carbon price adder is not included.

3.6 MISO Market Representation

Xcel's Upper Midwest system is a part of the Midwest Independent System Operator (MISO) pool. Membership in MISO provides Xcel with numerous benefits, including the ability to trade energy in a deep and liquid wholesale market on an hourly (and subhourly) basis, sharing of operating reserves across a broad pool, and a lower planning reserve margin requirement that captures the benefit of load diversity across the MISO footprint.

Figure 3-9. Geographic scope of RESOLVE analysis



Each of these dynamics is accounted for in the optimization of Xcel's long-term resource portfolio to meet carbon reduction objectives.

+ In addition to optimizing the investments and operations of the Xcel portfolio, RESOLVE simulates least-cost dispatch of the broader MISO pool (Load Resource Zones [LRZ] 1-3, as shown in Figure 3-9) on an hourly basis. This simulation thus allows for both purchases from and sales to the wholesale market, which are priced at the marginal cost of energy in the relevant zone. The assumed buildout and retirement of new resources to serve loads other than Xcel's own are based on MISO's "Continued Fleet Change" scenario as developed in its 2018 MISO Transmission Expansion Plan (MTEP) planning process. Market transactions between Xcel and the MISO are limited to 1,800 MW through 2023; thereafter, the limit is expanded to 2,300 MW through the rest of the modeling period.
+ Operating reserve requirements are maintained at the current level that Xcel must provide today as a member of MISO:

1. Load following reserves requirements are set at 3% of load;
2. Frequency regulation reserve requirements are 27 MW; and
3. Spin reserve requirements are set at 1% of load.

+ The planning reserve margin requirement imposed upon Xcel's portfolio in this study—3% above Xcel's own system peak demand—reflects the benefit of diversity among Xcel's load profile and the other members of MISO.

Detailed load and resource assumptions for the external zones are presented in Appendix C.2.

4 Reliability Analysis Results

4.1 Effective Load Carrying Capability Analysis

The capacity contribution towards resource adequacy of dispatch-limited resources – variable resources like wind and solar PV, and energy-limited resources, like storage and DR – is evaluated dynamically within RESOLVE based on the metric of ELCC. The concept of ELCC is most widely used to quantify the capacity contribution of a resource whose availability changes on an hourly basis; it represents the quantity of perfectly dispatchable generation that could be removed from the system by an incremental dispatch-limited generator. Essentially, the ELCC represents the capacity value each resource can contribute to the resource adequacy needs of the Xcel Upper Midwest system. This value depends on both the coincidence of each resource with peak loads and the characteristics of the other dispatch-limited resources on the system.

In this study, E3 used RECAP – a loss of load probability (LOLP) model – to evaluate the ELCC provided by a range of different portfolios of wind, solar, storage, and DR resources under specific conditions of load and generation resources in the Upper Midwest service territory; these ELCC values are not representative of ELCC values of resources in the broader MISO territory. The capacity value results from each RECAP run, associated with varying penetrations of wind, solar PV, storage, DR, are used to calculate marginal ELCC curves.

The marginal ELCC values for variable and use-limited resources used in this study are shown in Figure 4-1 and Figure 4-2. below.

Figure 4-1. Marginal ELCC of wind and solar resources for the Upper Midwest system in 2030

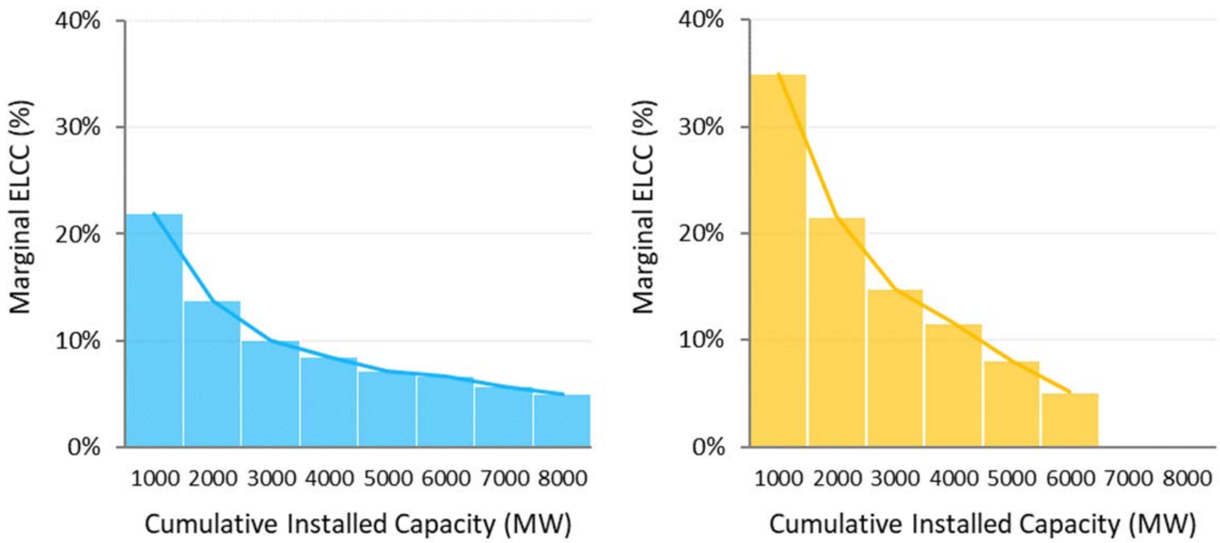
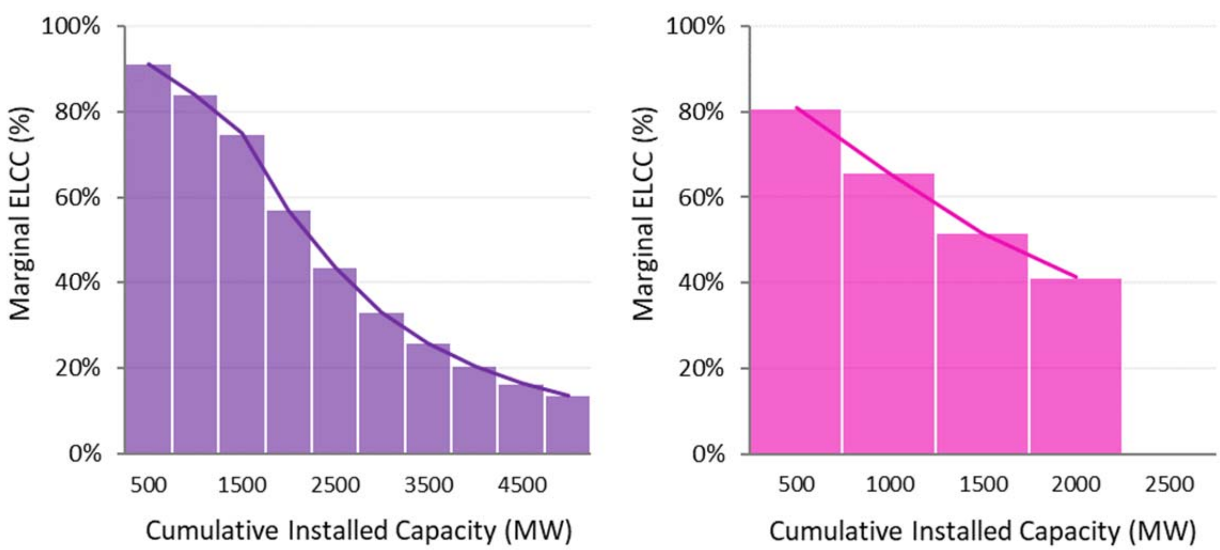


Figure 4-2. Marginal ELCC of 4-hr storage and DR resources for the Upper Midwest system in 2030



Generally, as the penetration of any individual resource type grows, the its marginal capacity value decreases. This effect is well-established and understood for variable resources such as wind and solar; adding incremental quantities of these resources generally shifts periods of loss-of-load-probability towards periods when the resources produce less energy. For instance, as shown in Figure 4-1, the first 1,000 MW of wind resource has an ELCC of approximately 22%; the next 1,000 MW has an ELCC of about 15%; and the third 1,000 MW has an ELCC of 10%. Solar exhibits a similar decline in ELCC with increasing levels of deployment, an effect that results primarily from the shifting of the period of the net peak away into the evening hours when solar resources do not produce energy.

Despite significant differences in their characteristics compared to variable resources, use-limited resources like storage and DR also exhibit declining marginal ELCC; this effect is shown in Figure 4-2.. Initially, the marginal ELCC of a four-hour storage resource is relatively close to 100%: this reflects the fact that small amounts of storage can be dispatched when called upon to reduce load during periods of peak demand. However, as progressive amounts of storage are added to the system, their dispatch has the effect of flattening and broadening the peak period, eventually requiring resources that are capable of dispatching (or discharging) over longer extended periods. As a result, the relative effectiveness of a battery system with limited duration (when compared with a traditional firm resource) diminishes. This effect may be countered by extending the duration of the storage system (i.e. adding more cells to the battery system), though the cost of the additional cells may outweigh the incremental value it provides.

To ensure that the optimized generation fleet is sufficient to meet the Xcel Upper Midwest system's resource adequacy needs throughout the year, the ELCC curves shown above are incorporated into RESOLVE as input assumptions. These inputs enable RESOLVE to solve for a portfolio that meets a target planning reserve margin while accounting for the inherent cumulative limitations of variable and use-limited resources.

4.2 100% Carbon-Free Portfolio Analysis

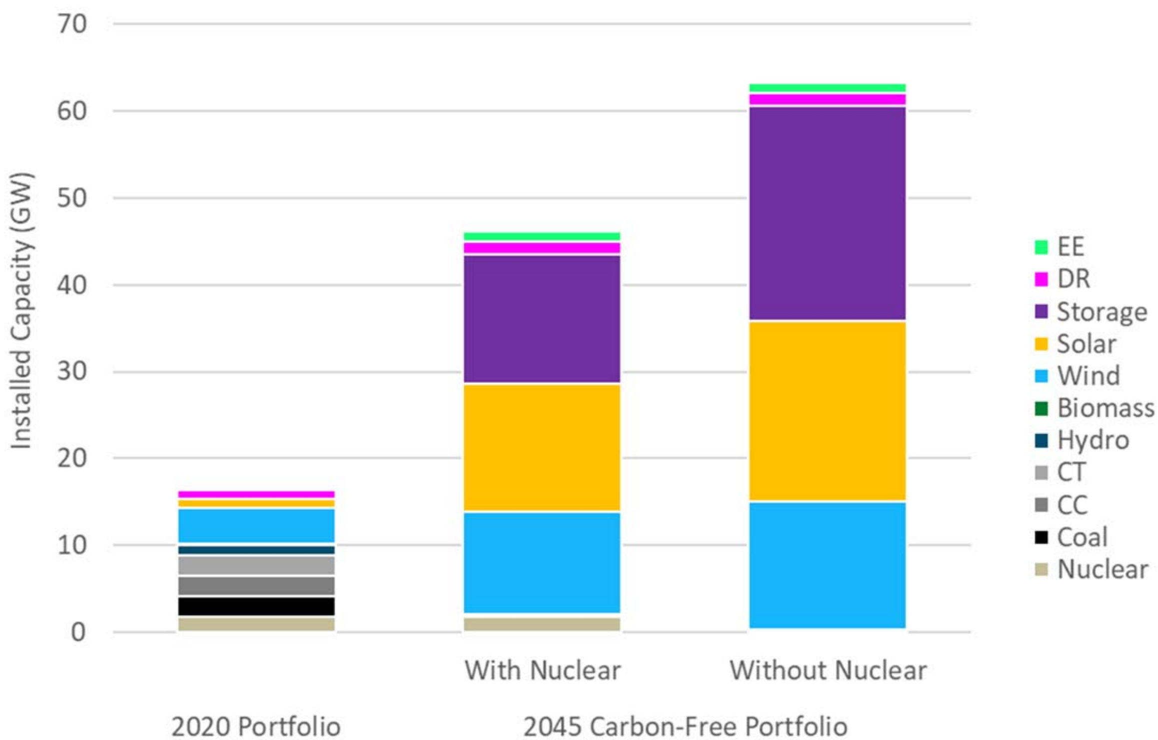
A secondary question explored through the reliability analysis is the extent to which the future needs of Xcel's customers can be met exclusively through reliance on carbon-free resources. The declining ELCC curves shown above hint at the idea that the potential contributions of variable and use-limited resources towards reliability needs is pragmatically limited. This study uses RECAP to design two hypothetical portfolios that rely exlusively on a combination of carbon-free resources to meet Xcel's long-term reliability needs under a one-day-in-ten-year reliability standard: (1) a first porfolio that includes Xcel's existing nuclear plants and a combination of wind, solar, and storage resources; and (2) a second portfolio that relies exclusively on wind, solar, and storage. These portfolios are constructed to adhere to the following criteria:

+ Each portfolio must comprise only carbon-free resources;
+ Each portfolio must adhere to an LOLE standard of one day in ten years; and
+ Each portfolio may not rely on the MISO market to supply wholesale power beyond the carbon-free resource that specifically make up the portfolio due to the fact that such generic wholesale purchases cannot be certified as carbon-free.

Each portfolio is created directly in RECAP through an iterative addition of wind, solar, and storage to Xcel's existing carbon-free resources until the appropriate reliability standard has been met;[6] this approach inherently achieves the goal of a carbon-free energy system. The resulting portfolios are shown in Figure 4-3.

[6] Resources are added in this iterative process according to an algorithm that adds small quantities of individual resources one at a time, in each step adding a discrete quantity of the resource that provides the highest marginal reliability benefit (i.e. reduction in LOLE) per unit of fixed cost.

Figure 4-3. Total installed capacity to meet 2045 reliability needs with a fully decarbonized portfolio.

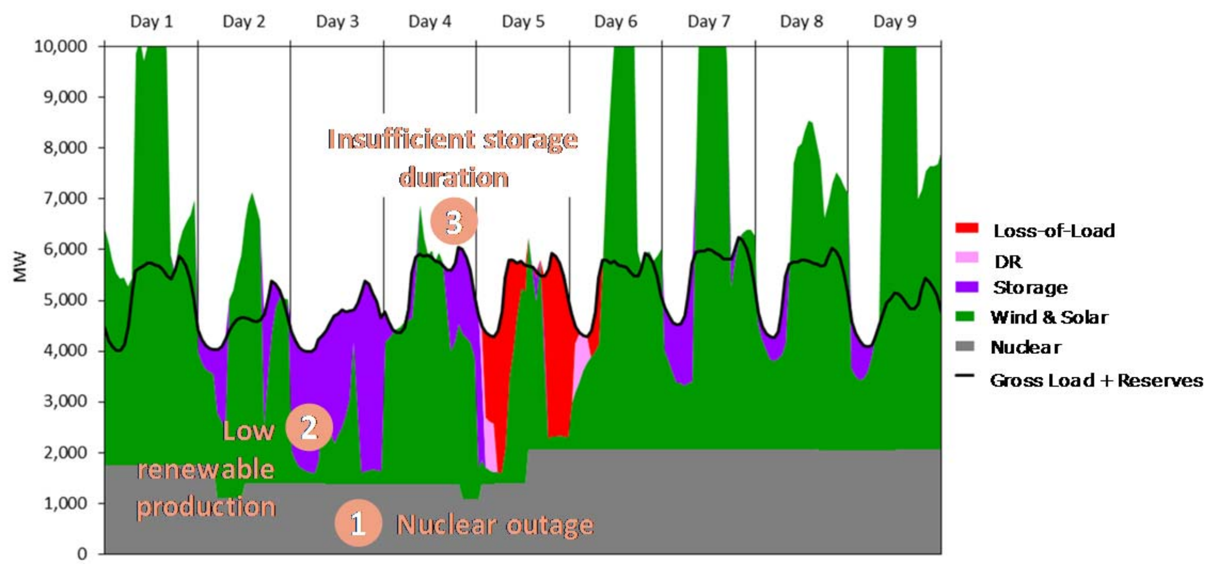


As shown above, the infrastructure requirements associated with meeting such objectives are incredibly large: while Xcel's projected system peak (not considering impacts of additional efficiency) is slightly larger than 12 GW in 2045, the total installed capacity needed to achieve reliability ranges from 45-60 GW, the vast majority of which comprises a mix of wind, solar, and storage. On an annual basis, these portfolios are capable of producing more than double the amount of energy needed to satisfy Xcel's Upper Midwest system demand; the overbuild is a consequence of the requirement that resources must be sufficient to meet demand not only under average conditions but under all but the most stringent conditions, including both periods of extreme high demand and sustained low renewable availability.

To illuminate the drivers of the large quantity of infrastructure needed to meet reliability needs with a combination of wind, solar, and storage, Figure 4-4 shows a nine-day snapshot of resource availability extracted from RECAP's loss-of-load-probability simulation in the portfolio that includes Xcel's existing nuclear plants. While traditionally loss-of-load-probability modeling has focused on ensuring resource sufficiency during periods of peak demand, these nine days highlight a new type of event that would ultimately lead to potential resource shortages on such a system: extended periods of low resource availability. Specifically, the loss-of-load event highlighted below—one of the rare events permitted under a "one-day-in-ten-year" standard—is a result of the following sequence of events:

+ A unforced outage at one of Xcel's existing nuclear plants begins on the second day, reducing the amount of firm, baseload generation available to serve Xcel's load.
+ This outage extends into the third day, coinciding with a period of low renewable availability, when the combined output of wind and solar resources is substantially lower than most typical days in that season (see, for example, Day 1 or Days 6-9) and is insufficient to meet load on its own in any hour.
+ These two factors, in turn, require Xcel to discharge energy stored in its battery storage resources to meet load throughout the third day, depleting a large portion of their state of charge.
+ While the level of renewable production increases on the fourth day, it remains below "typical" levels for this season and is merely sufficient to meet Xcel's load in most hours—but does not provide a surplus to restore state of charge to the energy storage systems.
+ By the beginning of the fifth day, the state of charge of the energy storage systems has been fully depleted, and the lack of available renewable resources during non-daylight hours leaves the operator with no other option but to shed significant quantities of load—a major loss-of-load event that extends across most of the day and represents a substantial portion of Xcel's customers.

Figure 4-4. Illustrative sample of hourly dispatch patterns in a 100% Carbon Reduction Scenario



This illustrative sequence of events demonstrates that the challenge of relying exclusively on carbon-free resource options to serve load shifts from meeting peak hourly demands to meeting load across extended periods of low renewable availability; the types of weather events of concern on such a system shift from those that drive extreme levels of load (e.g. summer heat waves) to those that inhibit renewable production across extended periods (e.g. extended/extreme winter storms). This type of event hints at the types of resources that would provide the most value, from a reliability perspective, in a system that is heavily reliant on renewables: those that can be dispatched on demand at full capacity for periods of up to several days, but are rarely called upon to do so. Based on today's commercially available technologies and at current prices, natural gas combustion turbines arguably remain the most viable candidate resource to complement a portfolio of wind, solar, and storage resources due to their relatively low up-front cost and expectation of limited operations.

This analysis also underscores the value of Xcel's participation in the MISO wholesale market, if only indirectly. Today, Xcel and MISO's other member utilities benefit from the diversity of loads and resources through a collective reduction in the capacity needs to meet resource adequacy requirements; this is manifest as a lower planning reserve margin target for each member than would be required if they were to plan exclusively to meet their own reliability needs. Under a requirement that all load be served by carbon-free generation, this analysis assumes that Xcel would forego this benefit, magnifying the system's resource need while restricting the available options to meet it. This, in turn, suggests that careful consideration be given in clean energy target-setting and policy design to balance the aggressiveness of goals with their implications for the efficiency of markets, as imprudent choices could negate the widely-recognized benefits achieved through centralization of wholesale market operations.

5 Portfolio Analysis Results

This section highlights the results of some of the main cases and sensitivities used to help answer the key questions surrounding Xcel's strategy to meet their climate goals. These results are presented in sections aligned with these questions: how much coal, if any, should Xcel retire; is new gas necessary or unnecessary to serve load reliably; and what value does Xcel's current nuclear fleet provide, given its carbon-free generation attribute? While all the cases were modeled from 2020 through 2045 in increments of five years, for many of these questions, focusing on one specific year helps provide the answer. This section focuses primarily on analytical results in 2030 or 2045, which generally coincide with Xcel's near-term and long-term climate goals.

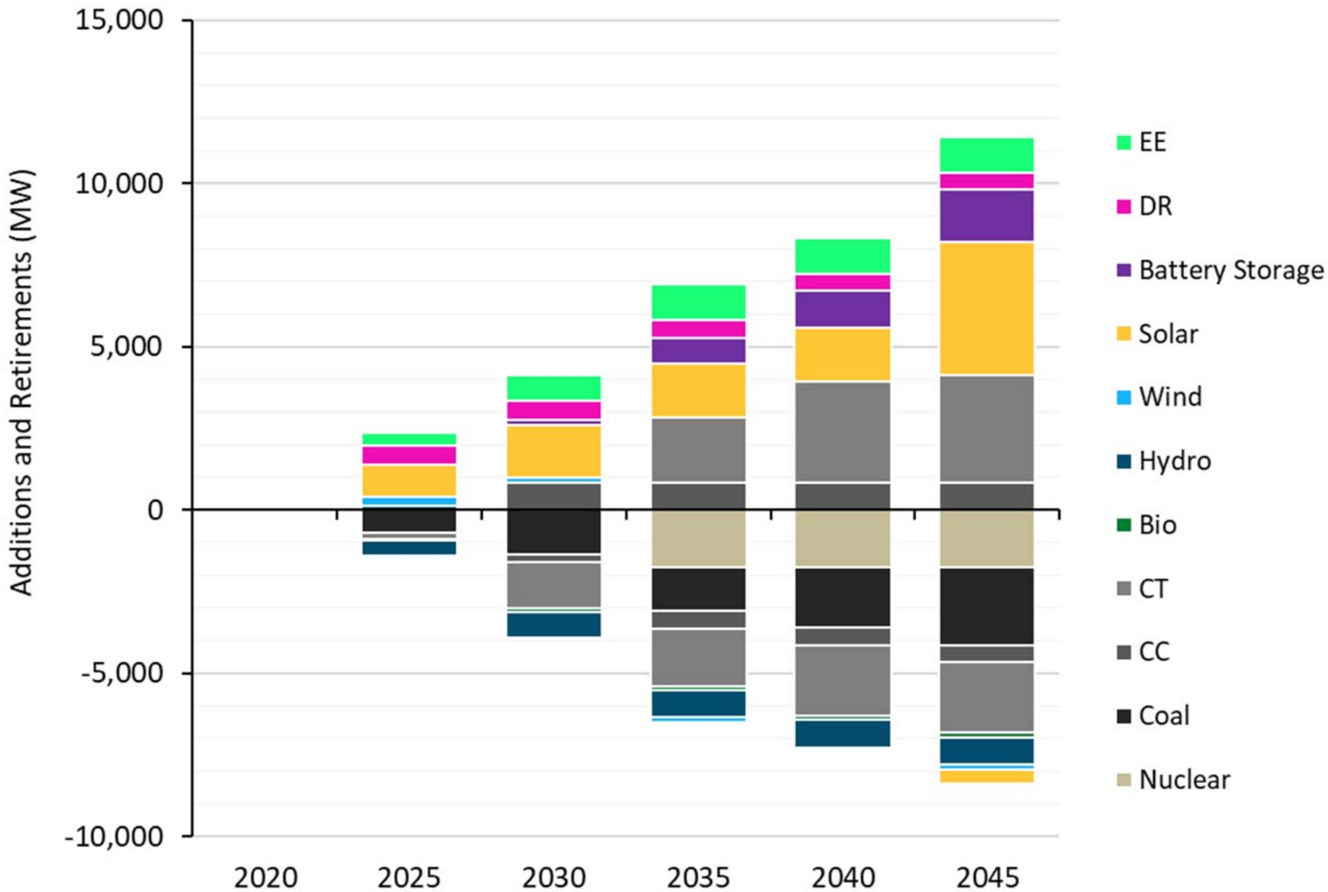
5.1 Reference Case

The Reference Case represents a least-cost plan to meet future energy and capacity needs of Xcel's Upper Midwest system through 2045 given expected growth in demand and anticipated plant retirements across this period, absent any specific clean energy or carbon goals beyond current state policy. Accordingly, the Reference Case is not compliant with Xcel's current greenhouse gas goals. Instead, this case represents a "business-as-usual" scenario that serves as a useful point of comparison against which to measure cost and greenhouse gas impacts of more aggressive decarbonization scenarios.

Figure 5-1 below shows the resource additions and retirements across the analysis horizon, including both Xcel's prior commitment as well as new resources selected in RESOLVE's to meet future needs. By

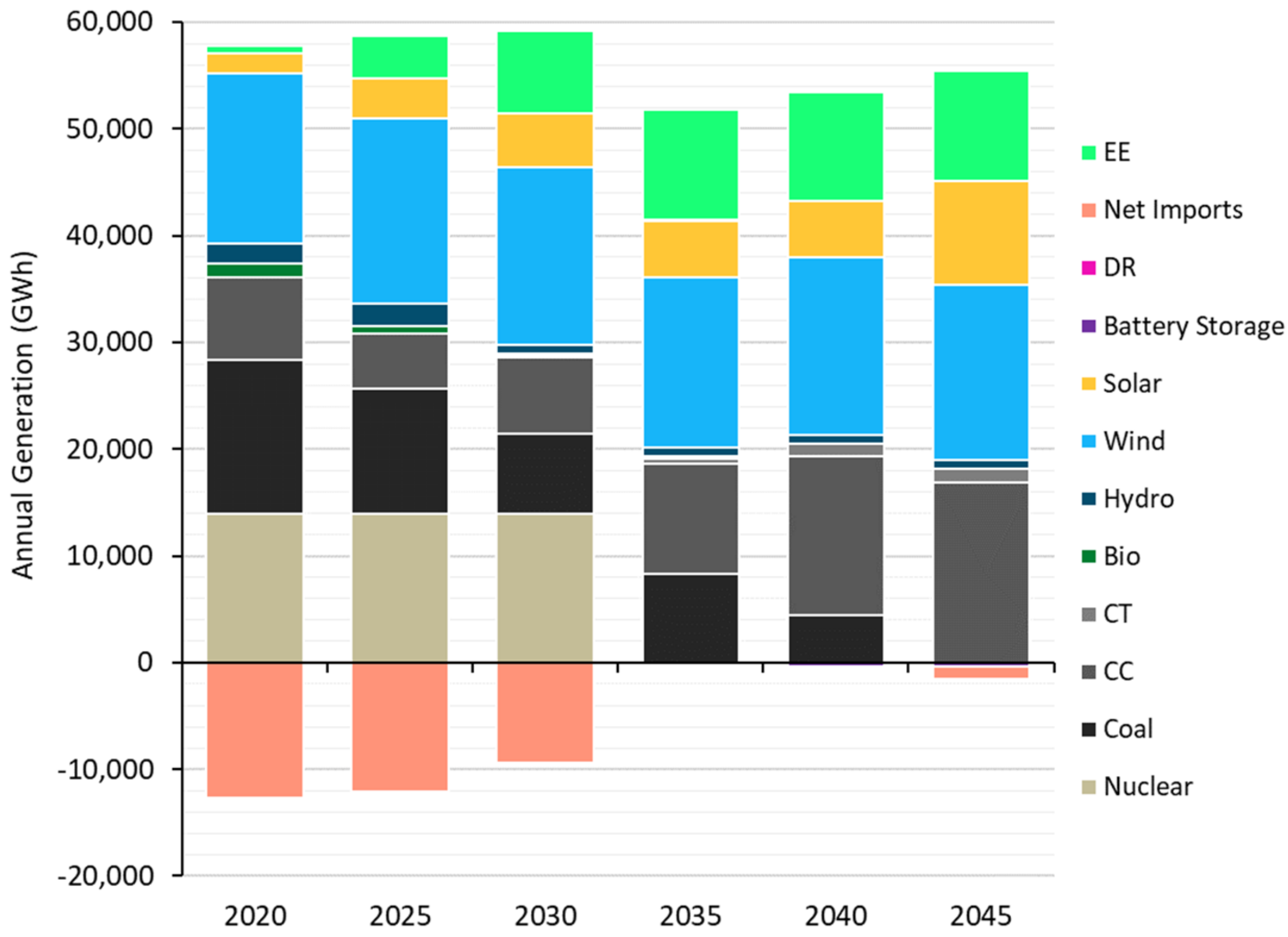
2030, Sherco Units 1 and 2, representing 1.4 GW of firm capacity, as well as a total of 1.6 GW of existing gas plants are retired. This retiring capacity is replaced by a diverse portfolio of resources that includes battery storage, utility-scale solar, a new combined cycle plant at the Sherco site, an expansion of existing DR programs, and deployment of energy efficiency at levels above historical state standards. Similar general dynamics continue through the analysis horizon: by 2045, the remaining coal and nuclear capacity, as well as some aging gas units, are retired, replaced primarily by additional energy storage, solar, and new gas combustion turbines.

Figure 5-1. Reference Case capacity additions and retirements over study horizon



The annual generation mix in Figure 5-2 shows that despite the absence of a carbon target, the Reference Case generation mix across this period generally shifts away from the most carbon intensive resources (coal) and towards carbon-free alternatives (wind, solar, efficiency), the notable exception resulting from the retirement of existing nuclear plants shortly after 2030, prompting an increase in gas generation. These trends yield some carbon reductions in the near term—Xcel's 2030 emissions are roughly 60% below 2005—but are insufficient to achieve the level contemplated in this study.

Figure 5-2. Reference Case generation mix across analysis horizon



5.2 Summary of Carbon Reduction Scenarios

This study analyzes a wide range of scenarios to achieve its primary purpose—to examine the cost implications of viable strategies to meet its 2030 emissions goal and to achieve alignment with an emissions reduction pathway consistent with its ultimate 2050 goal of 100% carbon-free generation.

Each scenario is therefore designed to meet milestones of 85% carbon reductions by 2030 and 95% carbon reductions by 2045.

Each scenario achieves these milestones through a unique combination of plant retirements of key existing generation assets (coal and nuclear) and investment in new resources (efficiency, renewables, storage, and natural gas). Additions and retirements across the full set of scenarios are shown in Figure 5-3 for 2030 and Figure 5-4 for 2045.

Figure 5-3. Additions and retirements for full sets of scenarios in 2030

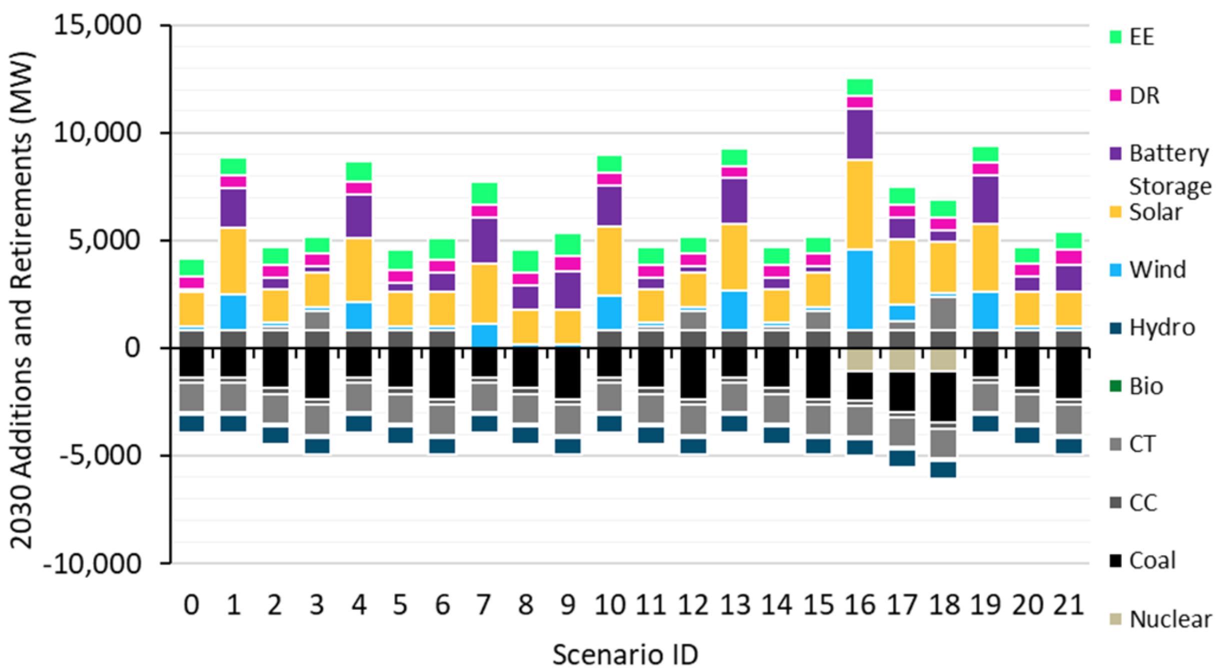
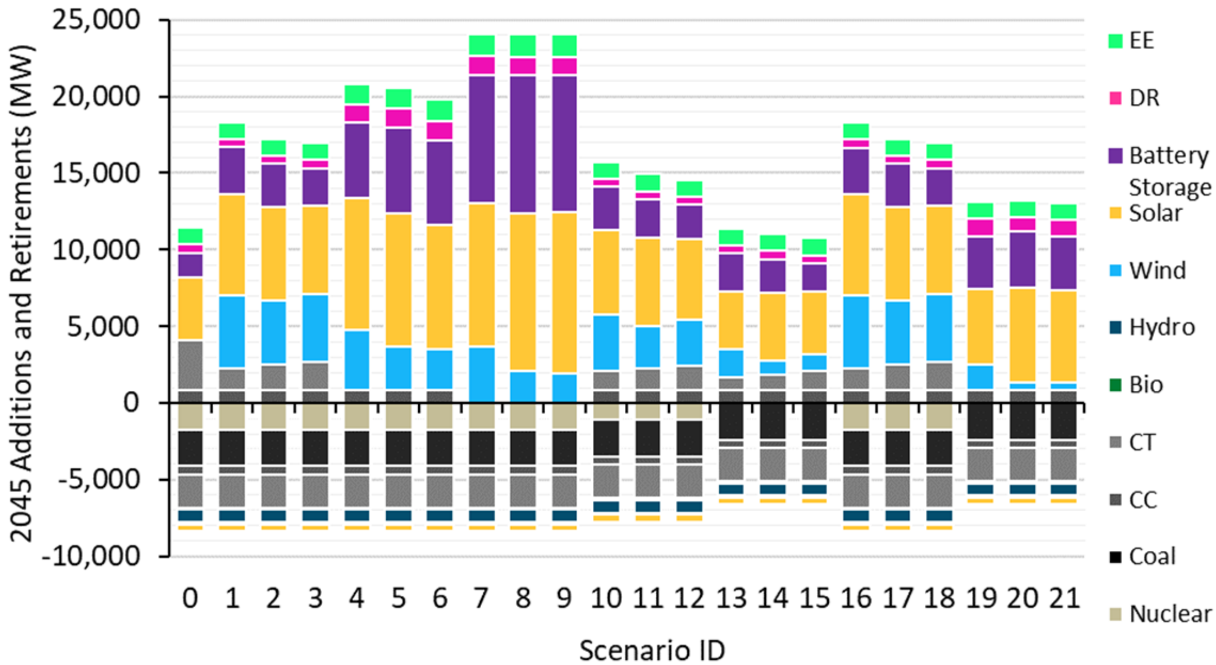


Figure 5-4. Additions and retirements for full set of scenarios in 2045



While the specific changes to Xcel's portfolio vary widely depending on the design of each scenario, several common themes are immediately apparent across all:

- Xcel's least-cost portfolios rely heavily on energy efficiency to mitigate future load growth; across all scenarios, the level of efficiency (at least 1.6%/yr through 2035) exceeds previous standards for program achievement (1.5%/yr).
- Significant investment in new wind and solar capacity (6-14 GW by 2045) as a source of carbon-free generation will be needed across all scenarios.
- Substantial investments in energy storage (2-9 GW by 2045) will help to facilitate integration of renewable resources while also helping to meet peak capacity needs;

- By 2045, Xcel's generation portfolio will rely predominantly on carbon-free resources to meet annual energy needs, while gas generation will help to meet resource adequacy needs but will operate infrequently.

The various strategies to achieve greenhouse gas reductions reflected in the scenarios examined in this study produce a wide range of portfolios and resulting cost outcomes. Table 5-1 highlights several key results that help distinguish the various scenarios from one another, including:

- **Levelized cost of carbon abatement ($/ton),** the unit cost of carbon abatement across the analysis horizon (2020-2045) measured relative to the Reference Case;
- **2045 rate impact (cents/kWh),** the change in the average retail rate measured relative to the Reference Case;
- **2045 effective RPS (%),** the level of renewable penetration achieved in each scenario expressed as a percentage of annual retail sales;
- **2045 renewable curtailment (%),** the level of curtailment experienced in 2045 due to the imbalance between variable resource availability and hourly demand;
- **2045 new storage capacity,** the cumulative total capacity of new storage resources added from 2020-2045 to enable renewable integration and help meet resource adequacy needs; and
- **2045 new gas capacity,** the cumulative total capacity of new gas resources added from 2020-2045 to meet residual resource adequacy needs as part of a least-cost portfolio.

Table 5-1. Key metrics for all scenarios

Scenario	Levelized Cost of Abatement ($/ton)	2045 Portfolio Metrics				
		Average Rate Impact (cents/kWh)	Effective RPS (%)[7]	Renewable Curtailment (%)	New Storage Capacity (MW)	New Gas Capacity (MW)
Scenario 1	$62	+1.2	112%	7%	3,032	2,293
Scenario 2	$25	+0.7	107%	6%	2,786	2,541
Scenario 3	$21	+0.7	107%	6%	2,484	2,708
Scenario 4	$69	+1.5	118%	9%	4,968	835
Scenario 5	$37	+1.2	110%	7%	5,636	835
Scenario 6	$40	+1.2	108%	6%	5,589	835
Scenario 7	$72	+1.8	121%	10%	8,346	—
Scenario 8	$47	+1.6	113%	7%	8,984	—
Scenario 9	$54	+1.7	112%	7%	8,885	—
Scenario 10	$54	+0.9	99%	6%	2,819	2,060
Scenario 11	$20	+0.6	93%	5%	2,484	2,275
Scenario 12	$17	+0.5	93%	4%	2,273	2,453
Scenario 13	$41	+0.6	75%	4%	2,434	1,711
Scenario 14	$13	+0.3	70%	3%	2,187	1,872
Scenario 15	$13	+0.3	70%	3%	1,867	2,081
Scenario 16	$71	+1.2	112%	7%	3,032	2,296
Scenario 17	$28	+0.7	107%	6%	2,786	2,541
Scenario 18	$22	+0.7	107%	6%	2,484	2,708
Scenario 19	$43	+0.7	78%	5%	3,484	835
Scenario 20	$16	+0.5	73%	4%	3,726	835

[7] Effective RPS levels that exceed 100% result from two factors: (1) the effective RPS is calculated based on retail sales, which is lower than total generation needed to serve load due to transmission & distribution losses; and (2) the total annual generation in the portfolio exceeds the Upper Midwest load and a portion of the excess is sold into the MISO market.

Scenario	Levelized Cost of Abatement ($/ton)	2045 Portfolio Metrics				
		Average Rate Impact (cents/kWh)	Effective RPS (%)[7]	Renewable Curtailment (%)	New Storage Capacity (MW)	New Gas Capacity (MW)
Scenario 21	$18	+0.5	73%	4%	3,499	835

The remainder of this section is dedicated to a detailed investigation into a specific subset of scenarios that illuminate tradeoffs among strategic choices of how to achieve long-term goals while containing costs to Xcel's customers and inform key questions on the nature of decarbonizing electricity, namely:

- What potential effect could an early exit from coal resources have upon the costs of meeting 2030 greenhouse gas goals?
- How would future restrictions upon Xcel's ability to invest in natural gas generation capacity to meet resource adequacy needs affect the cost of meeting greenhouse gas goals?
- What impact could extensions to the operating licenses of Xcel's existing nuclear plants have upon the costs of meeting long-term greenhouse gas goals?

Each question is investigated in depth in the subsequent three sections.

5.3 Scenario Analysis: Timing of Coal Exit

Xcel's coal resources are the most carbon-intensive source of generation in its portfolio. While Xcel has already committed to retire Sherco Units 1 & 2 (1.6 GW) in 2026 and 2023, respectively, retention of AS King and Sherco 3 through their current existing lifetimes (2037 and 2040, respectively) has direct implications upon the ability of the Upper Midwest system to achieve significant incremental carbon reductions by 2030. Thus, one of the key assumptions varied across scenarios in this study is the timing of their retirement, as acceleration of the closure of one or both plants prior to 2030 has a direct effect upon the investments needed and consequent costs to achieve Xcel's interim milestones. This section compares the scenario results for three scenarios shown in Table 5-2.

Table 5-2. Scenarios examined to test impact of early coal retirements

ID	AS King	Sherco 3	Prairie Island	Monticello	New Gas?
0	**Planned ret**	**Planned ret**	**Not relicensed**	**Not relicensed**	**Yes**
1	Planned ret	Planned ret	Not relicensed	Not relicensed	Yes
2	**Early retirement**	Planned ret	Not relicensed	Not relicensed	Yes
3	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	Yes

5.3.1 PORTFOLIO RESULTS

Each of these scenarios achieves at least an 85% carbon reduction by 2030, but the range of approaches represented highlights the implications associated with retaining existing coal resources. Figure 5-5 and Figure 5-6 show the total installed capacity and annual generation mix associated with each of these three scenarios, along with the Reference Case.

Figure 5-5. 2030 snapshot: installed capacity (MW) for Scenarios 1, 2 & 3

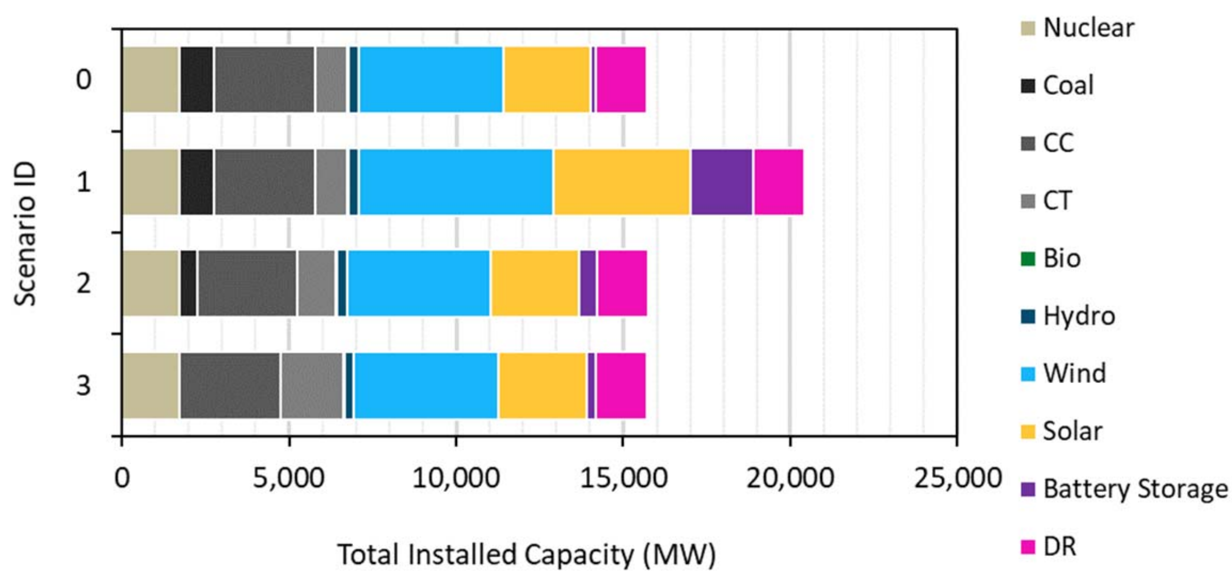
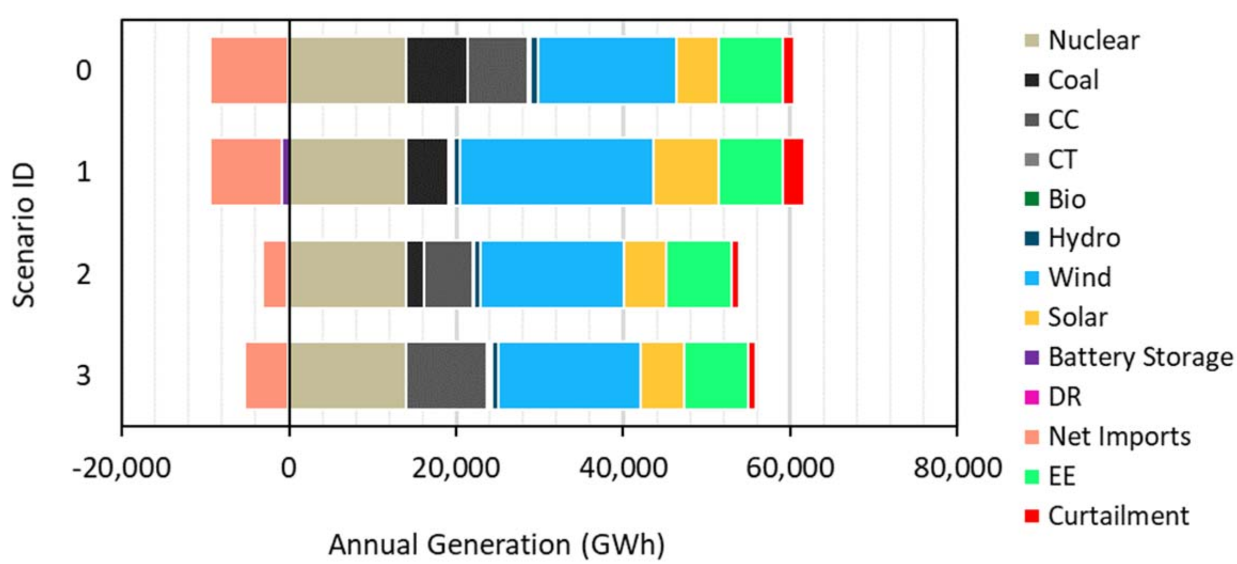


Figure 5-6. 2030 snapshot: annual generation (GWh) for Scenarios 1, 2 & 3

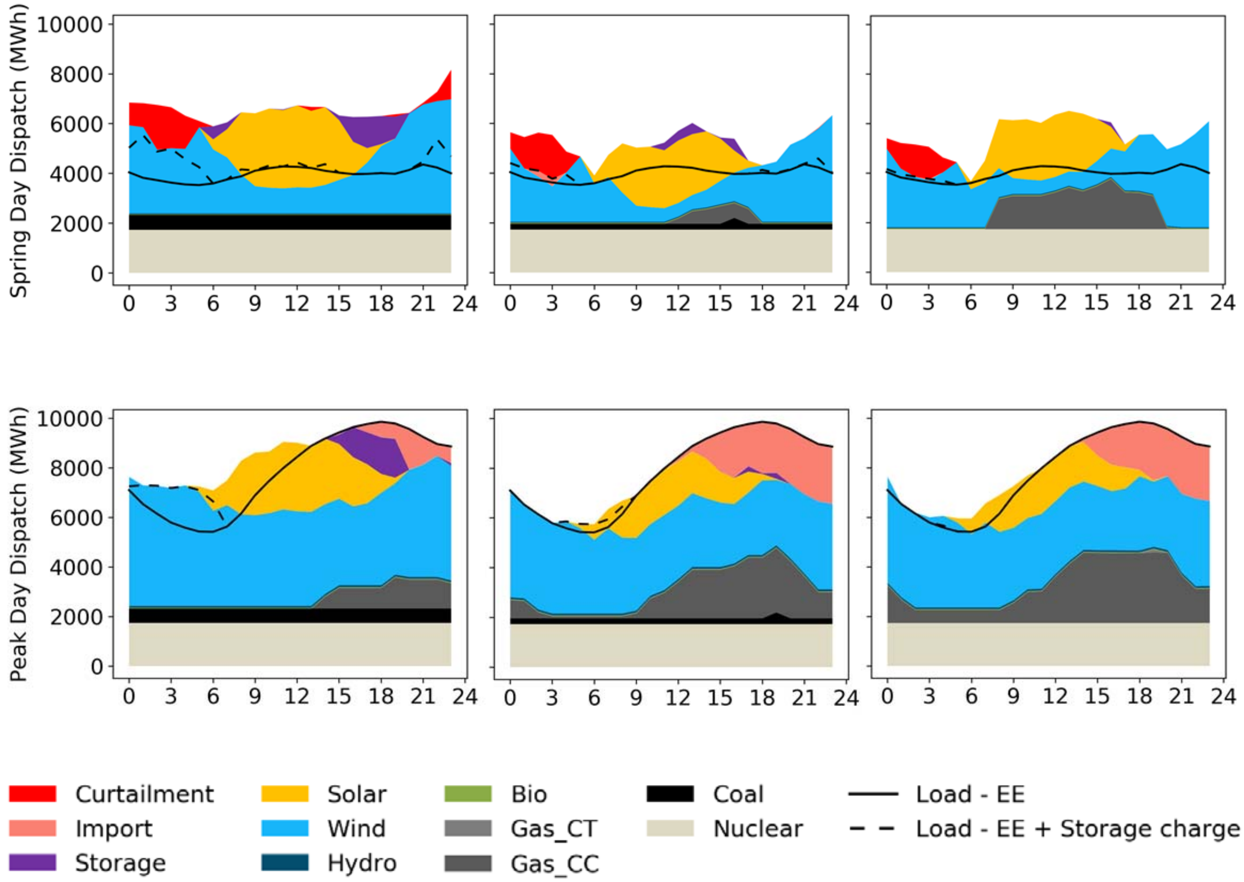


The contrast among portfolios informs several significant findings:

+ Meeting Xcel's interim greenhouse gas goals while continuing to operate AS King and Sherco 3 will require very large investments in renewable generation and storage prior to 2030. Relative to the Reference Case, the corresponding carbon reduction scenario requires an additional 3 GW of wind and solar generation and an additional 1.9 GW of energy storage by 2030; these investments are needed to displace flexible gas generation from Xcel's portfolio. The level of renewables needed results in an "effective" renewable penetration of 74% by 2030—significant enough that storage investments are needed to help balance its variability.
+ Scenarios that close one or both of Xcel's remaining coal plants by 2030 can achieve Xcel's 2030 carbon goals without significant need for carbon-free resources beyond those already specified in the Reference Case; however, additional investment in gas or other resources will be needed to meet resource adequacy needs absent the contributions of AS King and Sherco 3 to Xcel's resource adequacy needs.

The contrast among these portfolios is even more stark on an hourly basis. Figure 5-7 compares snapshots of hourly operations on two representative days: one in the spring, during which relatively low loads and high levels of renewable production tend to result in periodic surpluses of renewable generation; and one in the summer, when peaking loads require the full capability of Xcel's fleet to meet loads throughout the day.

Figure 5-7. Dispatch patterns for Scenarios 1, 2, and 3 (left to right) on a representative spring day and peak summer day



The hourly operations in the representative spring day reveal how significant the renewable integration challenges associated with the scenarios that retain both coal plants through 2030 would be: the level of carbon-free resource production during the midday periods in 2030 exceeds the hourly demand of the Xcel system; the renewable integration challenge is compounded by the lack of flexibility of coal resources to accommodate their output; and despite the capability of energy storage to absorb some surplus and the ability to sell a relatively large quantity of surplus into the MISO market, 7% of available renewable generation is curtailed in 2030. This level of curtailment is substantially larger than the level observed in scenarios that reduce reliance on coal (and, as a result, face a more manageable burden of renewable integration), which yield levels of curtailment in 2030 of approximately 4%.

5.3.2 COST IMPACTS

Two key cost metrics are used throughout this study to compare the impacts of various scenarios: (1) the **levelized cost of carbon abatement** and (2) the **annual rate impact** in five- year increments. The two metrics are intended to be complementary: the former serves as a useful means of summarizing the impacts associated with a scenario in a single metric, but obscures the some of the interesting dynamics related to the timing associated with those costs; the latter provides more resolution on how costs are incurred by Xcel's customers through time but makes one-to-one comparisons across scenarios more difficult.

Table 5-3 shows the levelized cost metric for these three scenarios. Scenario 1, which preserves both coal plants through their current existing lives, has a cost of carbon abatement significantly higher than either of the scenarios; this is driven by the large amount of infrastructure investment needed to meet near-term greenhouse gas goals while continuing to operate the coal plants through their current lifetimes. The levelized costs of abatement in Scenarios 2 and 3 are much closer—generally indicating that accelerating one retirement provides very large benefits to Xcel's customers in the context of meeting 2030 goals, while the accelerating the retirement of the second plant provides some additional benefit, though not as much as the first.

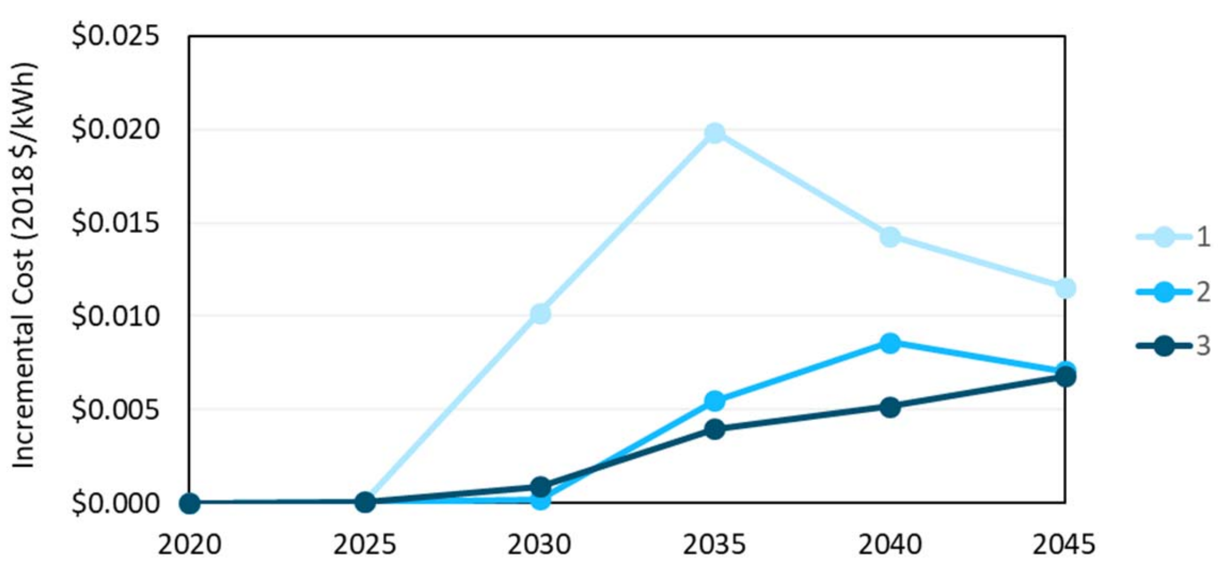
Table 5-3. Levelized costs of carbon abatement across scenarios.

Scenario	AS King Retirement	Sherco 3 Retirement	Levelized Cost of Abatement ($/ton)
Scenario 1	2037	2040	$62
Scenario 2	pre-2030	2040	$25

Scenario	AS King Retirement	Sherco 3 Retirement	Levelized Cost of Abatement ($/ton)
Scenario 3	pre-2030	pre-2030	$21

Figure 5-8 shows how the incremental costs (measured relative to the Reference Case) would be borne by ratepayers over time. In Scenario 1, the need for significant investments in renewables in the 2030 begins to drive substantial increases in rates; this effect is exacerbated by 2035 due to the assumed retirement of Xcel's nuclear plants with in this five-year window; only after 2035 does the incremental cost associated with Scenario 1 begin to drop as AS King and Sherco 3 reach the ends of their useful lives. In contrast, both Scenarios 2 and 3 meet the 2030 emissions reductions goals with minimal impact on rates, and lead to moderate impacts in the long run as additional renewable and storage resources are added to displace gas and help to replace retiring nuclear plants. Scenarios 2 and 3 do show some separation in rate impact in 2035 and 2040; Scenario 3, having retired both coal plants early, exhibits the lowest impact on rates associated with the more stringent greenhouse gas goals imposed in this decade.

Figure 5-8. Annual rate impact (relative to Reference Case) associated with Scenarios 1-3

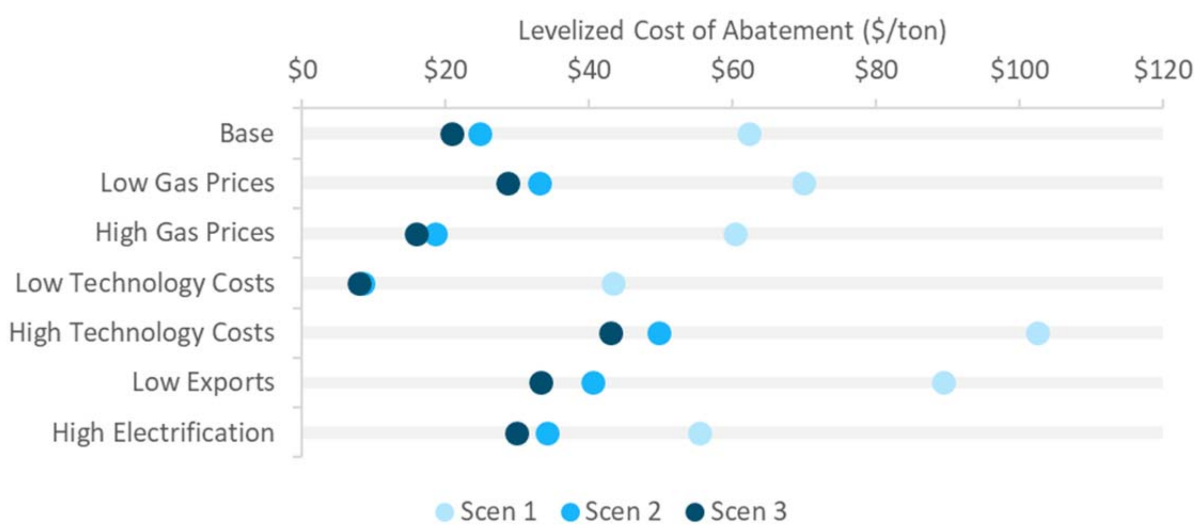


5.3.3 SENSITIVITY ANALYSIS

Sensitivity analysis on key uncertain inputs helps to highlight the level of confidence in the directional results that these results point towards. The four categories of sensitivity tested—gas prices, future technology costs, levels of electrification load, and the ability to export to the MISO market—lend further support to the conclusion that an accelerated shutdown of some combination of AS King and Sherco 3 will result in a more cost-effective pathway to achieving 2030 emissions goals.

Figure 5-9 summarizes the impact of the range of sensitivities on the levelized cost of abatement for the scenarios that vary the timing of Xcel's coal exit.

Figure 5-9. Sensitivity analysis on levelized cost of abatement across scenarios



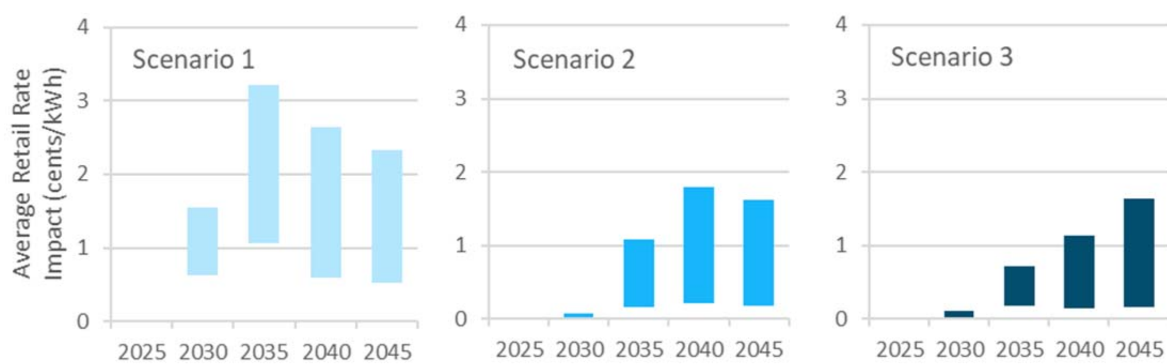
Several findings are apparent from the range of sensitivities analyzed:

+ Most importantly, across all sources of uncertainty considered in this study, no alternative assumptions would alter the directional relationship among the scenarios examined: across all sensitivities, a long-term strategy that maintains coal assets through their current existing lifetimes results in the highest costs to meet interim and long-term reduction goals.

+ The cost of abatement is relatively insensitive to natural gas prices. Lower gas prices will tend to increase the costs of achieving carbon reductions across the analysis horizon. Because the Reference Case portfolio relies more heavily on gas across the horizon than any of the carbon reduction scenarios, lower gas prices result in a higher cost premium for the new sources of carbon-free generation. However, the overall exposure to gas price uncertainty is relatively low.
+ The scenarios do notably exhibit a wider range of sensitivity to future technology costs for renewables and storage than to gas prices: higher technology costs increase the cost of abatement by 50-60%; lower technology costs reduce the cost of abatement by 30-40%. The sensitivity to future costs highlights a changing paradigm for utilities whose long-term planning exercises focus not only on cost but on risk as well: as exposure to fossil fuel prices decreases, traditional sources of uncertainty (e.g. natural gas prices) will become less significant drivers of uncertainty than forecasts of technological evolution and innovation (e.g. assumptions on the future rate of decline of storage costs).
+ A common trend in the scenarios presented is reliance on market interactions to meet load in times of low renewable output, and to generate revenue by selling surplus renewable energy to offset a portion of its costs. However, if surrounding jurisdictions in MISO also move towards decarbonization, the ability to export in the times of overgeneration may be limited; assuming similar investment in low-carbon technologies to decarbonize. Compared to the Base Case assumptions, the level of curtailment is between 2.5 to 2.8 times greater for these sensitivities in 2045. The results suggest that in a world in which the region collectively pursues aggressive decarbonization, the cost of carbon abatement will increase.
+ Carbon abatement cost exhibits limited sensitivity to future load levels: while additional investment in carbon-free resources and complementary investments for reliability will be needed, the associated incremental costs are spread across a larger base of retail sales such that the overall cost of abatement does not increase substantially.

The sensitivities conducted also provide useful information on how the costs of achieving long-term goals might vary through time in any single scenario. Figure 5-10 shows the range of costs, expressed as the impact on average retail rates, through time in each scenario. This perspective highlights the fact that not only is a strategy that preserves both remaining coal plants through their remaining lives a higher cost pathway to low carbon goals, but it also has a higher level of risk: the range of potential cost outcomes for this portfolio is considerably larger than its counterparts due to the uncertain costs of the large amounts of renewable and storage investment needed to meet near-term carbon goals with both coal plants on line. Not only are costs lower in Scenarios 2 & 3, but they are generally more certain as well.

Figure 5-10. Year-by-year range of cost impacts for Scenarios 1, 2 & 3 across all sensitivities



5.3.4 IMPLICATIONS

The contrast among scenarios that retain AS King and Sherco 3 through their remaining useful lives and those that accelerate their shutdown to facilitate achievement of interim greenhouse gas goals provides insight into the impact of each potential decision. This analysis suggests that retiring the first coal plant reduces the necessary overbuild of renewables to meet Xcel's near-term climate goals. There is a significant decrease in levelized cost of carbon abatement by retiring AS King early. While the subsequent early retirement of Sherco 3 also reduces the levelized cost of abatement, the benefit is smaller than that of the first retirement.

5.4 Scenario Analysis: Limits on New Gas Infrastructure

Up to 7 GW of existing firm capacity in Xcel's Upper Midwest system may be retired by 2045. While significant investments in renewable energy and battery storage will be needed to meet Xcel's long-term carbon reduction target, the question of how much (if any) additional fossil-based firm capacity is necessary to ensure a reliable system cost-effectively remains. The reliability analysis described in Section 4 showed the sizeable investments in renewables and storage needed to serve load in the absence of any firm generation resources, indicating that retention of some level gas capacity in the Upper Midwest system that operates at low capacity factors would help meet Xcel's goals. This section investigates the cost implications of a range of limitations on new gas investments. One case (Scenario 6) restricts new investment to allow for only the development of a new combined cycle plant at the Sherco site; another (Scenario 9) prohibits any new gas capacity. The subset of scenarios examined in this section also assume that the retirements of the Sherco 3 and King plants are accelerated to pre-2030, as this was identified above as a key component of a least-cost strategy to meet near-term carbon reduction objectives. Table 5-4 shows the scenarios examined in this section.

Table 5-4. Scenarios examined to test impacts of new gas prohibition

ID	AS King	Sherco 3	Prairie Island	Monticello	New Gas?
0	**Planned ret**	**Planned ret**	**Not relicensed**	**Not relicensed**	**Yes**
3	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	Yes
6	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	**Sherco CC only**
9	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	**None**

5.4.1 PORTFOLIO RESULTS

These scenarios all achieve at least a 95% carbon reduction by 2045, but the range of new infrastructure investment shows the impact of potential restrictions on new gas investments. Figure 5-11 and Figure 5-12 show the total installed capacity and annual generation mix associated with each of these three scenarios, along with the Reference Case.

Figure 5-11. 2045 snapshot: installed capacity (MW) for Scenarios 3, 6 & 9

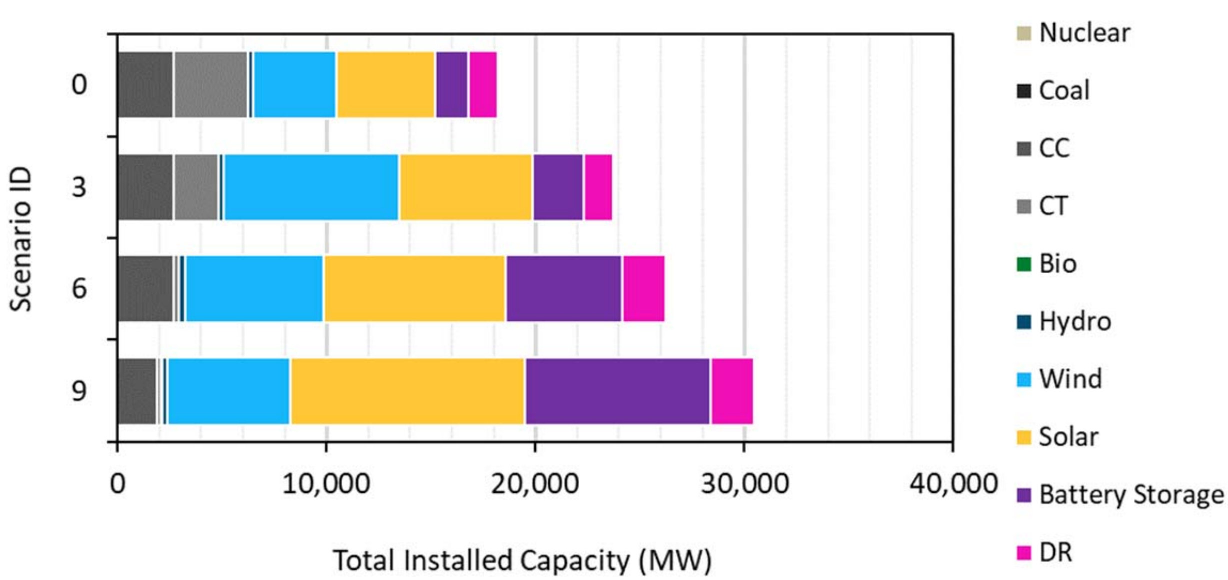
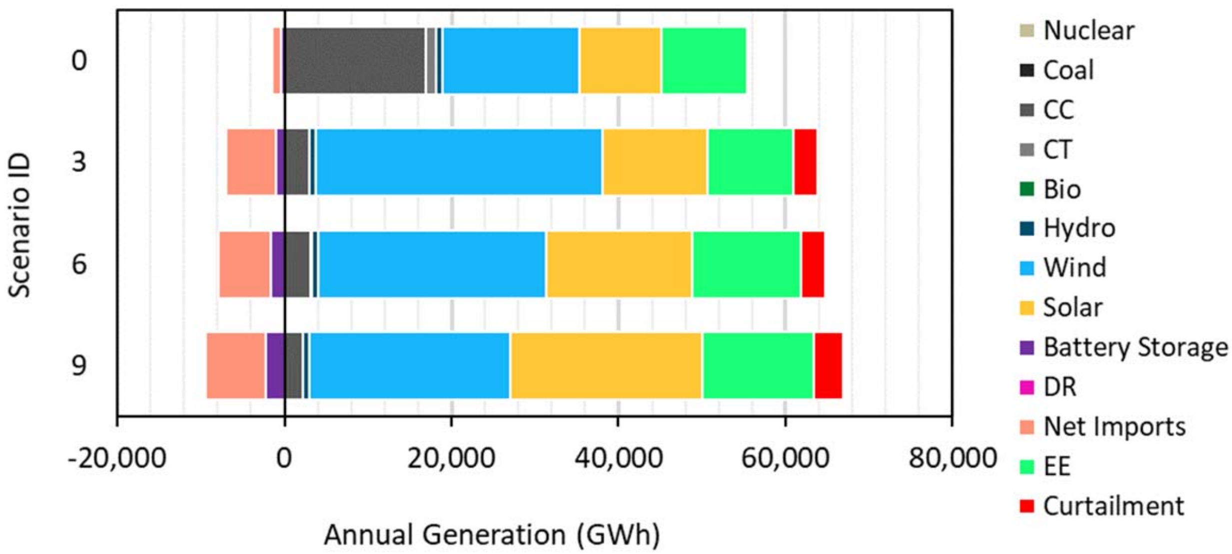


Figure 5-12. 2045 snapshot: annual generation (GWh) for Scenarios 3, 6 & 9

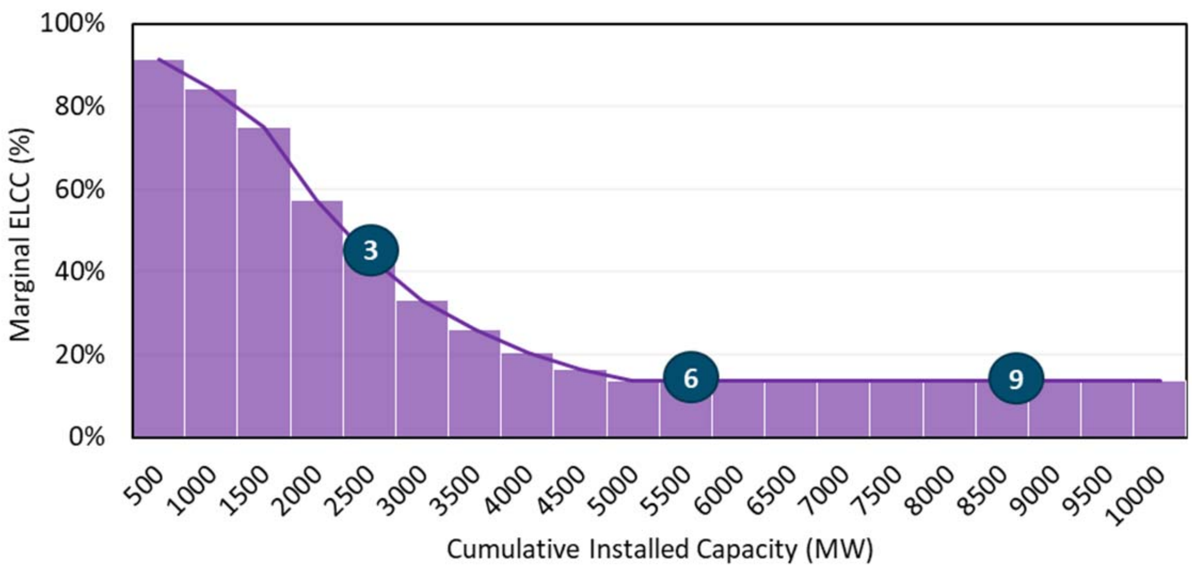


Comparing the portfolios informs several significant findings:

- The amount of capacity needed to meet reliability goals with limits on new gas resources is substantially higher than in scenarios that do not restrict new gas resources. Most of this additional capacity comes in the form of battery storage, but also includes some increases in high-cost tranches of efficiency and DR. The restrictions on gas resources in Scenarios 6 and 9 induce a limited increase in renewable capacity, as well as a shift from wind to solar, whose diurnal production pattern enables more frequent cycling of energy storage resources.
- Despite significant difference in capacity, the three scenarios result in very similar levels of annual gas generation (and corresponding greenhouse gas emissions). Despite the comparatively large buildout of CTs in Scenario 3, the total energy provided by those units in 2045 is insignificant, as they are built to meet resource adequacy needs but run infrequently. New gas units are valuable resources for preserving reliability and help reduce the costs of serving load in a largely decarbonized world. Scenarios 6 and 9 require a level of battery storage buildout that is much higher than any other scenario – 5.6 GW and 8.9 GW, respectively. As

detailed in Section 4, the ELCC of battery storage declines over time. Figure 5-13 shows where the scenarios studied in this section fall on the ELCC curve.

Figure 5-13. Marginal ELCC for storage resources in Scenarios 3, 6, and 9 in 2045



The level of battery capacity on the system in Scenarios 6 and 9 reach the minimum marginal ELCC contribution in the curve. To put this in perspective, the last 3.5 GW of batteries in scenario 9 receive about the same capacity credit as 500 MW of new combustion turbines. New CT capacity is typically used for reliability purposes and infrequently dispatched, as depicted for Scenario 3 in Figure 5-12, so giving preference to battery storage to provide these services seems an improper assignment of purpose when high levels of storage are already on the system.

5.4.2 COST IMPACTS

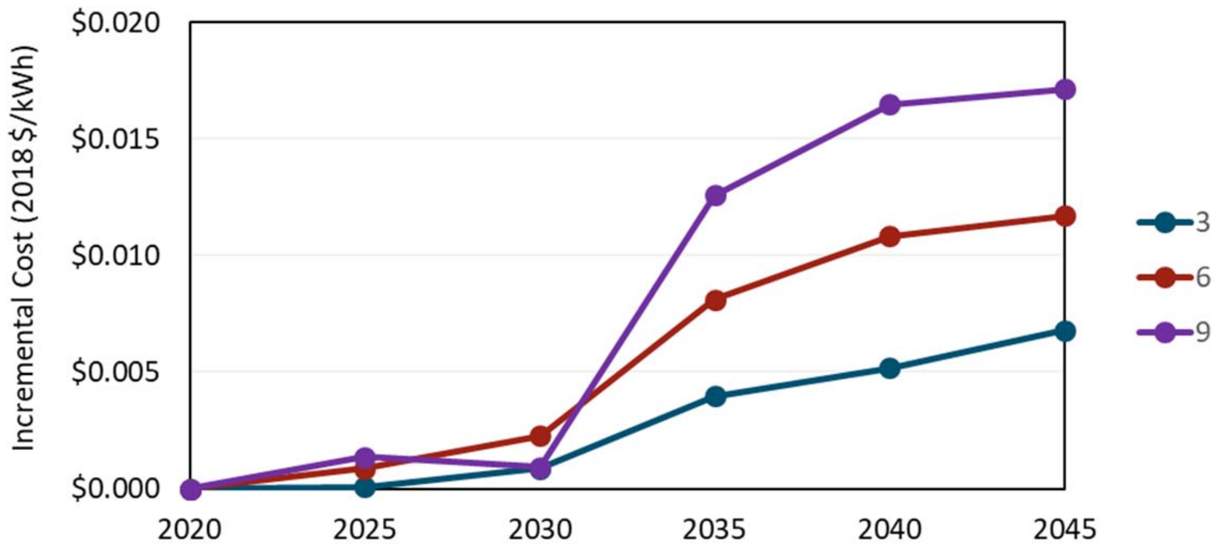
Table 5-5 shows the levelized cost of carbon abatement for these three scenarios. Scenario 3, seen previously, has the lowest cost of carbon abatement, while Scenarios 6 and 9 are almost two and three times more expensive, respectively. This premium represents the cost of meeting reliability needs with a greater share of batteries, DR, EE, and renewables, given that each of these scenarios has the exact same carbon emissions in 2045.

Table 5-5. Levelized cost of carbon abatement across scenarios

Scenario	Gas Build Restriction	Levelized Cost of Abatement ($/ton)
Scenario 3	Unrestricted	$21
Scenario 6	Only Sherco CC	$40
Scenario 9	No New Gas	$54

Figure 5-14 highlights the annual rate impact over time, as shown in the previous results section. While the near-term impact is relatively small, the impacts grow substantially beyond 2030 due to continued load growth and the retirement of Xcel's existing nuclear plants, with the trend mirroring the trend in levelized cost of carbon abatement. The investment in capacity for reliability that would otherwise be cheap gas CTs increases 2045 rates by an additional $0.005/kWh and $0.010/kWh for Scenarios 6 and 9, respectively, compared to Scenario 3.

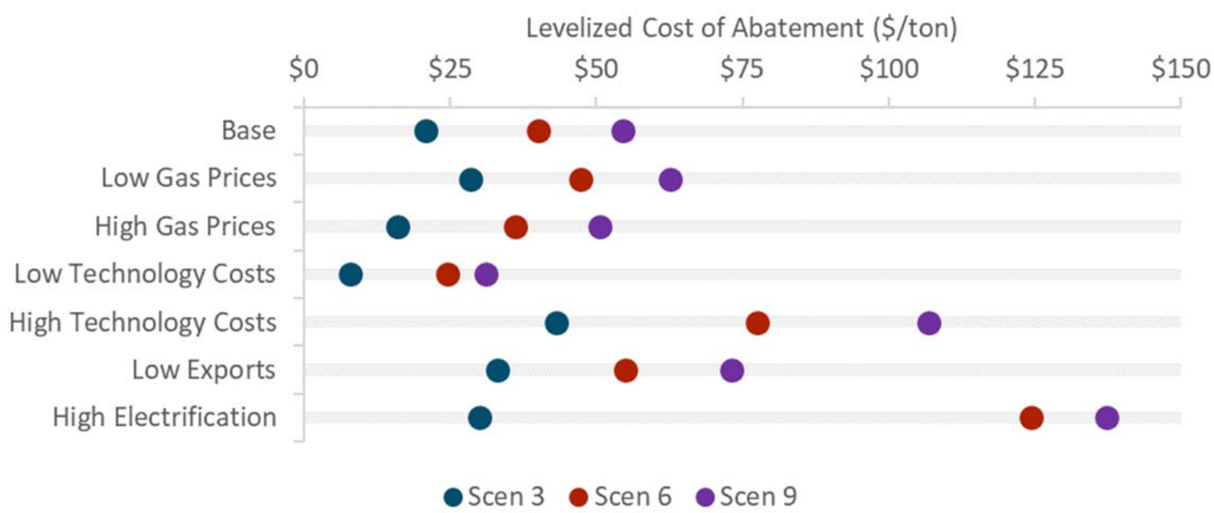
Figure 5-14. Annual rate impact (relative to Reference Case) associated with Scenarios 3, 6, and 9



5.4.3 SENSITIVITY ANALYSIS

The three sensitivity categories—gas prices, future technology costs, and levels of electrification load—again support the conclusion that prohibiting new gas units is not a cost-effective way to reach Xcel's 2045 emissions goal. Figure 5-15 shows how each sensitivity affects the levelized cost of abatement for these scenarios.

Figure 5-15. Sensitivity analysis on levelized cost of abatement across scenarios



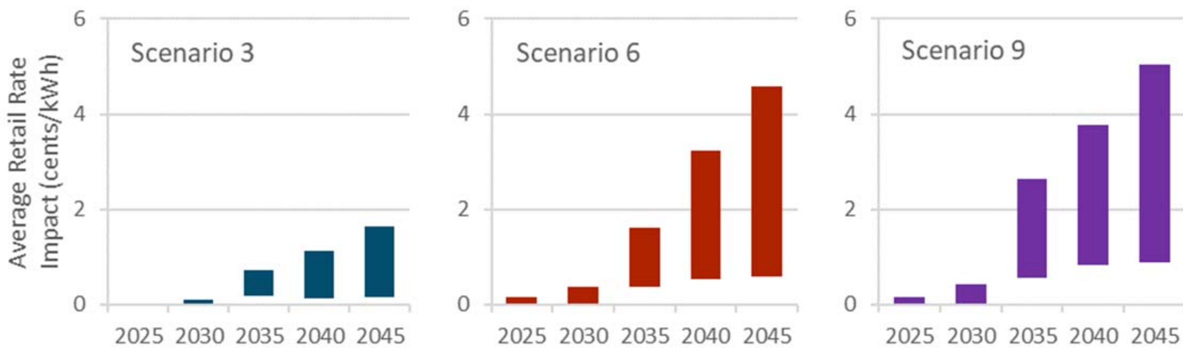
The following are key takeaways from the sensitivities for these scenarios:

+ As in the previous set of scenarios, none of the sensitivities alter the directional relationship among the scenarios examined: across all sensitivities, a long-term strategy that includes new gas investment ensures a cost-effective way to achieving Xcel's carbon reduction goals.
+ The cost of abatement is, again, relatively insensitive to natural gas prices. Lower gas prices will tend to increase the costs of achieving carbon reductions across the analysis horizon due to the Reference Case portfolio relying more heavily on gas, while higher gas prices decrease the levelized cost of carbon abatement slightly.
+ Because disallowing new gas build requires more investment in renewable energy and battery storage, the sensitivities around the costs of renewables and storage show a larger impact than gas prices. Lower technology costs reduce the levelized cost of abatement, but the difference between Scenario 3 and 6 still stays nearly the same. Higher technology costs almost double the abatement cost differences between the cases.

- Eliminating market revenues from exporting beyond 2030 shifts levelized costs of abatement upward, but the directional relationship between scenarios is preserved. Curtailment in these sensitivities is, again, over double the amount found using the Base Case assumptions in 2045.
- In a world with higher loads from electrification, prohibiting new gas buildout will have even greater implications. The overbuild seen in Scenarios 6 and 9 increases substantially in this sensitivity and is reflected by the extremely high cost of carbon abatement.

The range of impacts associated with individual scenarios provides another useful perspective on the potential consequences and implications of choosing a pathway towards decarbonization that prohibits new natural gas investments (see Figure 5-16). These scenarios (Scenarios 6 & 9) generally exhibit a wider range of cost outcomes than scenarios that allow new gas investments to contribute to reliability needs (here, Scenario 3). This range is driven by two factors. First, scenarios that prohibit new gas investment will require much larger investments in battery storage to meet reliability needs; future costs of battery storage are inherently highly uncertain. Second, the cost of meeting reliability needs in a high electrification future without new investments in natural gas proves to be considerably more challenging and costly than under the Base Case assumptions. The substantial increase in load also increases the level of resources needed to meet future resource adequacy needs; meeting all these future needs with energy storage and renewables will prove costly due to the inherent limits on their contributions to resource adequacy.

Figure 5-16. Year-by-year range of cost impacts for Scenarios 3, 6 & 9 across all sensitivities



5.4.4 IMPLICATIONS

This comparison of scenarios highlights the value of investments in new natural gas resources to enable achievement of deep carbon reductions while meeting reliability goals and minimizing costs. These gas investments—with the exception of the Sherco CC, all combustion turbines—provide a low-cost option to meet reliability standards but would operate rarely. While combinations of renewables, battery storage, DR, and EE, in conjunction with the remaining gas fleet in the Upper Midwest system, can serve load reliably, pursuing this pathway while excluding natural gas as an option is likely to contribute to significantly higher cost outcomes.

5.5 Scenario Analysis: Nuclear Relicensing

Xcel's two nuclear plants facilities, Monticello and Prairie Island, represent over 1.7 GW of firm capacity and have licenses that expire shortly after 2030. As depicted in the previous section, retaining some level of conventional firm capacity will help Xcel meet its long-term carbon reduction goal in a cost-effective way; the relicensing of Xcel's nuclear plants provides one possible option to meet a portion of that need. In this section, the value Xcel's nuclear fleet is examined by testing different combinations of relicensing Xcel's nuclear fleet. Keeping some level of nuclear capacity online should reduce the need for investments to meet carbon goals (primarily renewables, efficiency) and to ensure a reliable system (primarily storage, gas, and DR). The scenarios analyzed in this section are shown in Table 5-6.

Table 5-6. Scenarios examined to test impact of nuclear relicensing

ID	AS King	Sherco 3	Prairie Island	Monticello	New Gas?
0	**Planned ret**	**Planned ret**	**Not relicensed**	**Not relicensed**	**Yes**
3	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	Yes
12	**Early retirement**	**Early retirement**	Not relicensed	**20-yr relicense**	Yes
15	**Early retirement**	**Early retirement**	**20-yr relicense**	**20-yr relicense**	Yes

5.5.1 PORTFOLIO RESULTS

The scenarios in this section again achieve a 95% reduction in carbon emissions in 2045. The installed capacity and annual generation, shown in Figure 5-17 and Figure 5-18, highlight the different strategies available to meet the long-term goal.

Figure 5-17. 2045 snapshot: installed capacity (MW) for Scenarios 3, 12 & 15

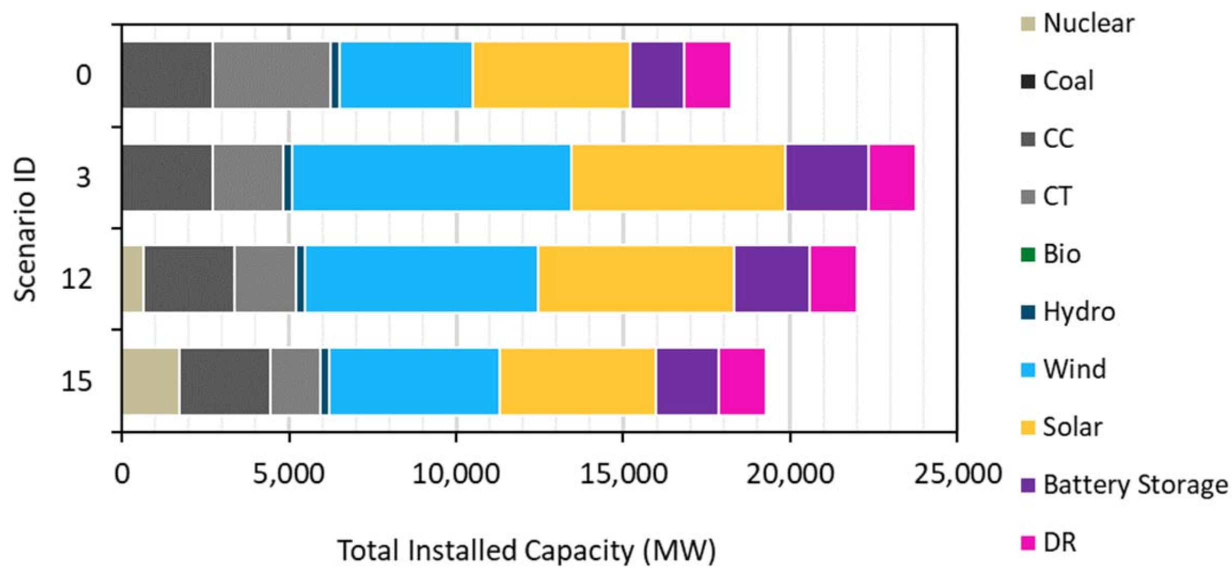
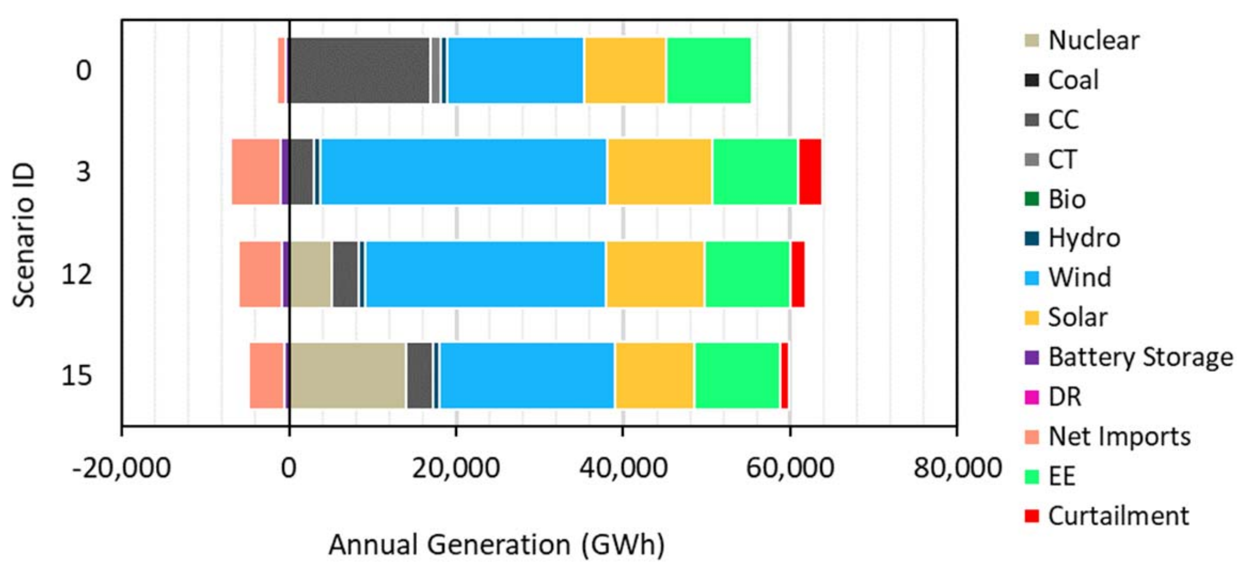


Figure 5-18. 2045 snapshot: annual generation (GWh) for Scenarios 3, 12 & 15

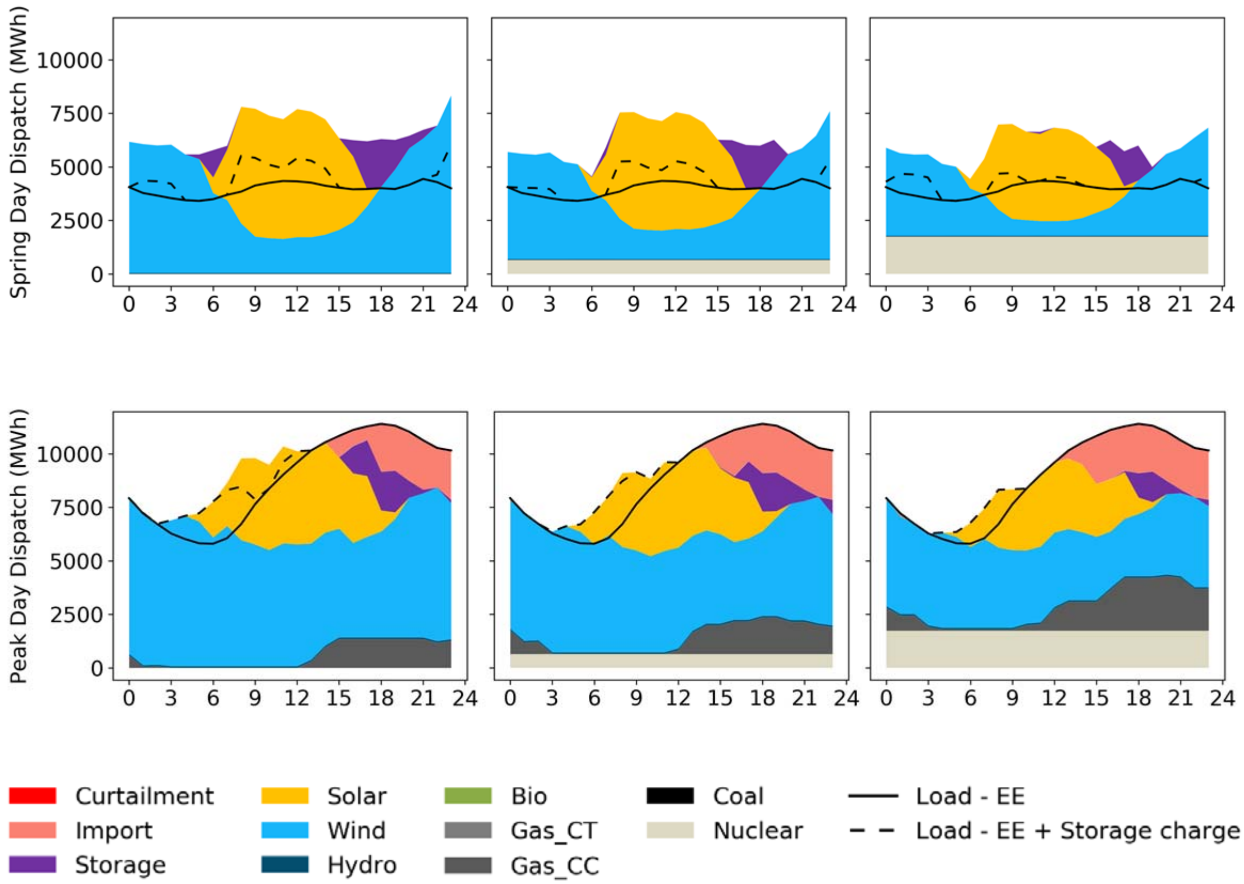


The key differences between these scenarios are as follows:

+ Each incremental nuclear relicense significantly reduces investment in renewables, storage, and gas capacity. Relicensing a single plant (Monticello) reduces the amount of investment in new resources needed to meet the target by roughly 2,500 MW (2,000 MW of renewables, 200 MW gas, and 200 MW storage). Relicensing Prairie Island avoids an additional 5,000 MW of renewables and over 600 MW of both gas and storage. The baseload and carbon-free attributes of nuclear energy reduces the renewable overbuild needed in a low-carbon world.
+ The relicensing of the nuclear plants reduces each portfolio's reliance on renewables as the primary source of carbon-free energy, and, in doing so, provides a valuable source of diversity that enables more efficient balancing of loads and resources. Each level of nuclear relicensing reduces the amount of renewable overgeneration that must be curtailed to manage periods of surplus renewable availability. In 2045, curtailment levels of 6% in Scenario 3 are reduced to 4% in Scenario 12 and then to 3% in Scenario 15. An Upper Midwest system with more nuclear relicensed thereby enables more efficient utilization of renewables.

The operations in each of the scenarios are shown for the typical spring and peak days in Figure 5-19.

Figure 5-19. Dispatch patterns for Scenarios 3, 12, and 15 (left to right)



On the spring day, Scenarios 12 and 15 replace wind generation with nuclear energy almost one-to-one, and the renewable overgeneration, ultimately sold to the market, persists. The only behavior noticeably different is that of the battery capacity on the system, which cycles more frequently when less nuclear energy is available; often to sell to the market. That general trend also carries over to the peak day dispatch; but, instead of charging to sell to the market later in the day, the batteries charge up on renewable overgeneration to meet the evening peak. With less battery capacity and renewable overgeneration in Scenarios 12 and 15, a larger portion of the peak load is met with imports and Upper Midwest gas.

5.5.2 COST IMPACTS

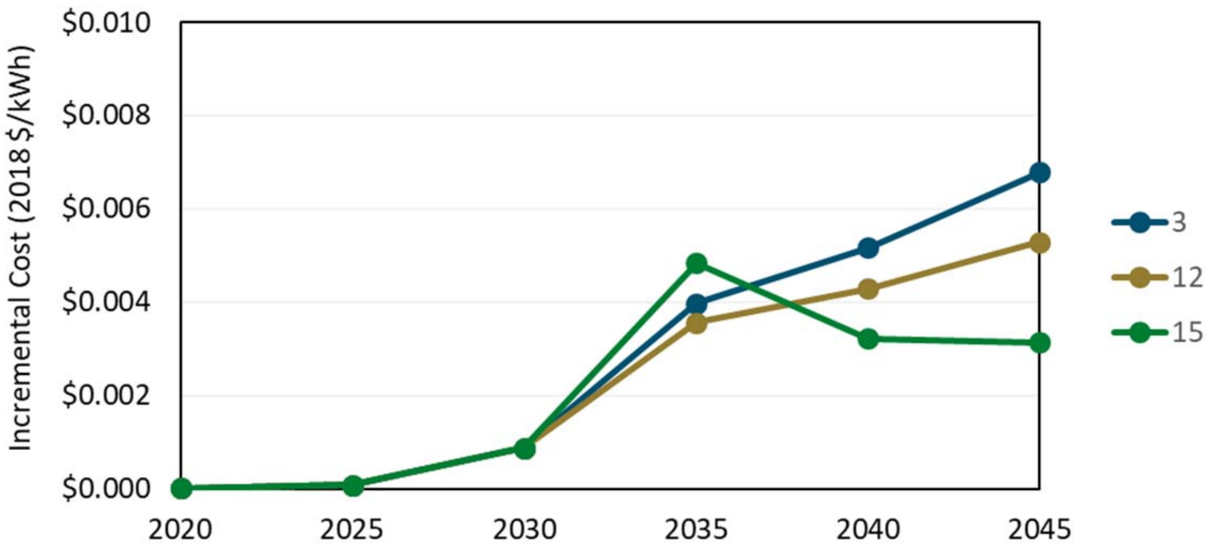
Each incremental relicensing of Xcel's nuclear plants reduces the levelized cost of carbon abatement by $4/ton compared to Scenario 3, as shown in Table 5-7. The trend is indicative of the avoided investments in renewables and batteries; the alternative to the firm, carbon-free capacity that nuclear energy provides.

Table 5-7. Levelized cost of carbon abatement across scenarios

Scenario	Monticello Relicensing	Prairie Island Relicensing	Levelized Cost of Abatement ($/ton)
Scenario 3	No	No	$21
Scenario 12	Yes	No	$17
Scenario 15	Yes	Yes	$13

Figure 5-20 shows the corresponding impact on average retail rates. The scenarios diverge beginning in 2035, when various levels of nuclear remain online for these scenarios. In that year, relicensing one nuclear plant reduces rates while relicensing both increases rates, compared to Scenario 3. Because the carbon goal in 2035 is not as stringent, relicensing the second unit exceeds the target and a premium is paid to do so. However, the following years show the value of relicensing both nuclear plants, as more renewable and battery investment is avoided. By 2045, rates are $0.004/kWh cheaper than Scenario 3, as opposed Scenario 12 which is only $0.001/kWh cheaper.

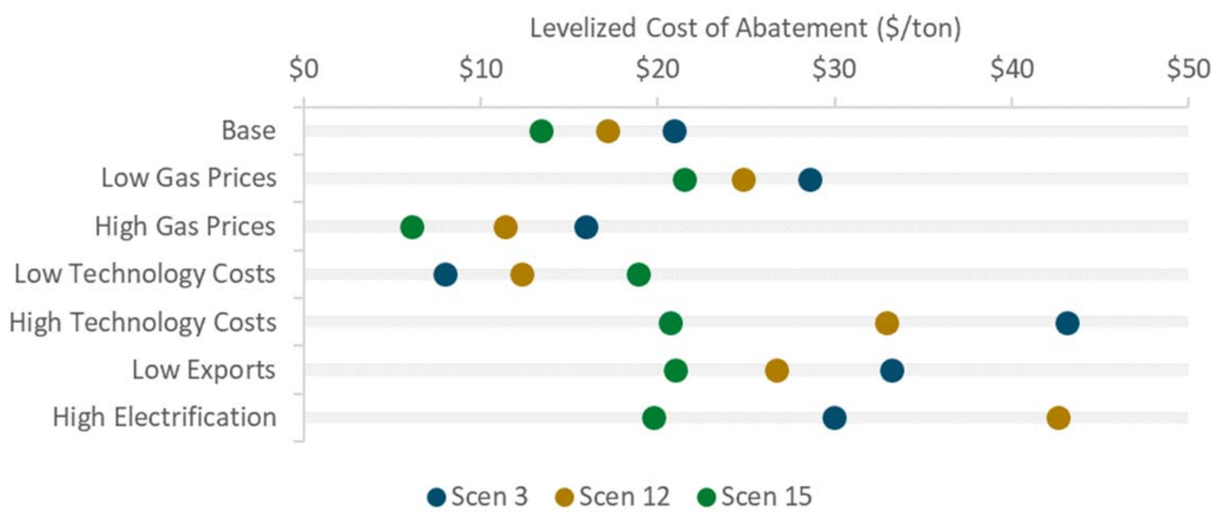
Figure 5-20. Annual rate impact (relative to Reference Case) associated with Scenarios 3, 12, and 15



5.5.3 SENSITIVITY ANALYSIS

For this set of cases, all but one sensitivity convey the same general takeaways as the Base Case assumptions. Figure 5-21 below shows the affects each sensitivity has on the levelized cost of carbon abatement.

Figure 5-21. Sensitivity analysis on levelized cost of abatement across scenarios



These are the takeaways from this sensitivity analysis:

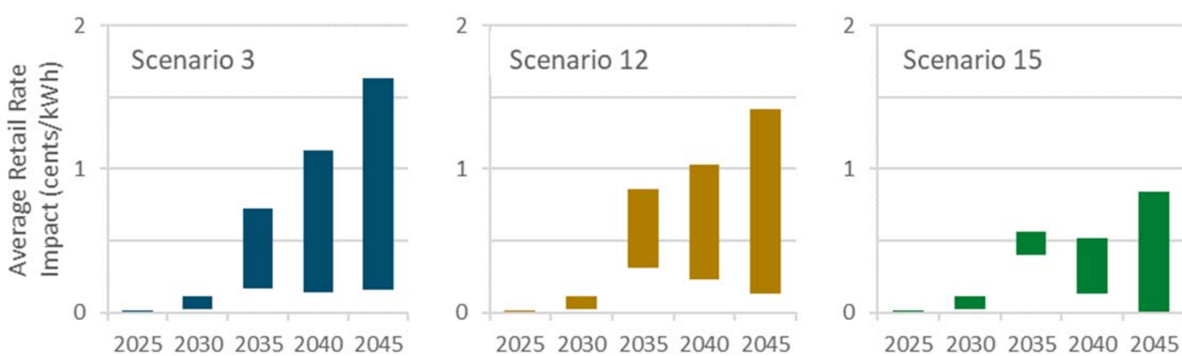
+ The High and Low Gas Price sensitivities again do not affect the general relationships among this set of scenarios. Lower gas prices increase the levelized cost of carbon abatement while higher gas prices decrease the levelized cost of abatement. Overall, the shift up or down for each scenario stays consistent with shifts for previously discussed scenarios.
+ The Low Technology Cost sensitivity for this set of scenarios is the only sensitivity that changes the directional relationship among scenarios: under a low technology cost future, relicensing Xcel's nuclear plants may result in a higher cost to meet carbon reduction goals than replacement with a combination of wind, solar, storage, and gas. On the other hand, the High Technology Cost sensitivity has the opposite effect of the low technology sensitivity; making relicensing appear an even more cost-effective strategy to meeting long-term carbon goals.
+ A long-term limit on exports beyond 2030 increases 2045 curtailment for Scenarios 12 and 15 by substantial amounts—from levels between 3 and 4% to 13%. the largest increases among this

set of sensitivities. Despite the significant increase in curtailment, the levelized cost of carbon abatement increases similarly to the other low export scenarios.

+ For the High Electrification sensitivity, the costs only shift upwards, as seen previously. However, the magnitude of the shift is smallest for these scenarios compared to other High Electrification sensitivities.

Figure 5-22 shows the range of costs to Xcel's customers resulting from the range of sensitivities examined. In general, these results highlight a narrower band of uncertainty in future costs that results from scenarios that pursue nuclear relicensing. One characteristic of all three scenarios shown here, though (which are generally among the lowest cost options examined in this study) is a growing uncertainty with respect to cost over time. This crescendo of uncertainty reflects the reality that the cost of decarbonizing electricity in the long run remains inherently uncertain, and while this study highlights promising options and opportunities to mitigate this cost, precise measurement of how that will impact Xcel's customers is ultimately difficult to predict.

Figure 5-22. Year-by-year range of cost impacts for Scenarios 3, 12 & 15 across all sensitivities



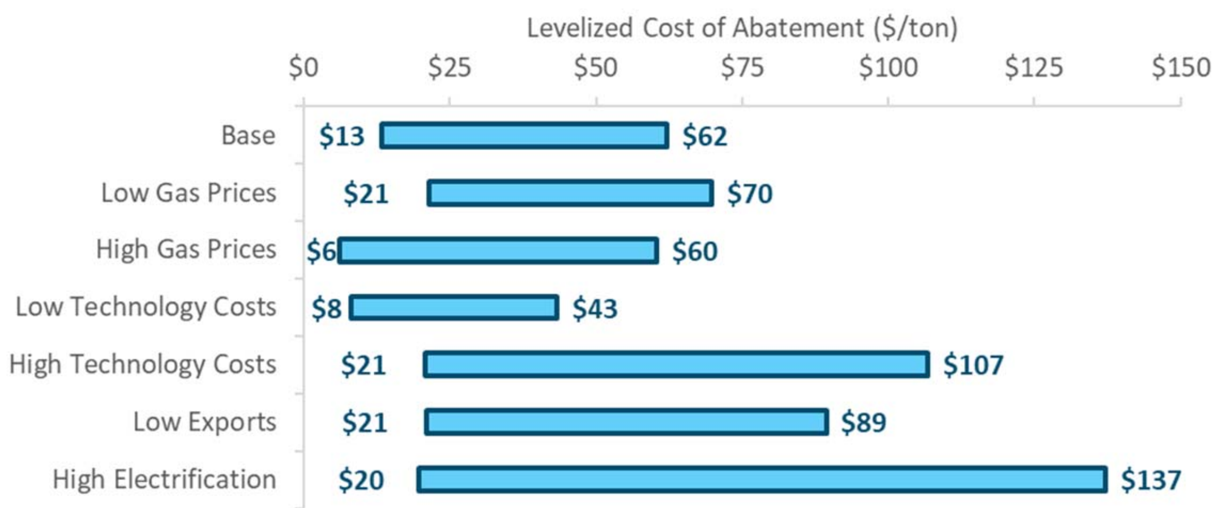
5.5.4 IMPLICATIONS

The comparisons between scenarios illustrate the substantial value of Xcel's nuclear plants as a firm, carbon-free resources. The analysis shows benefits to Xcel resulting from a relicensing of both Monticello and Prairie Island as Xcel's carbon targets become increasingly stringent; the levelized cost of carbon abatement and 2045 rate impacts in the dual relicensing case are among the lowest of all the scenarios examined in this study.

6 Conclusions

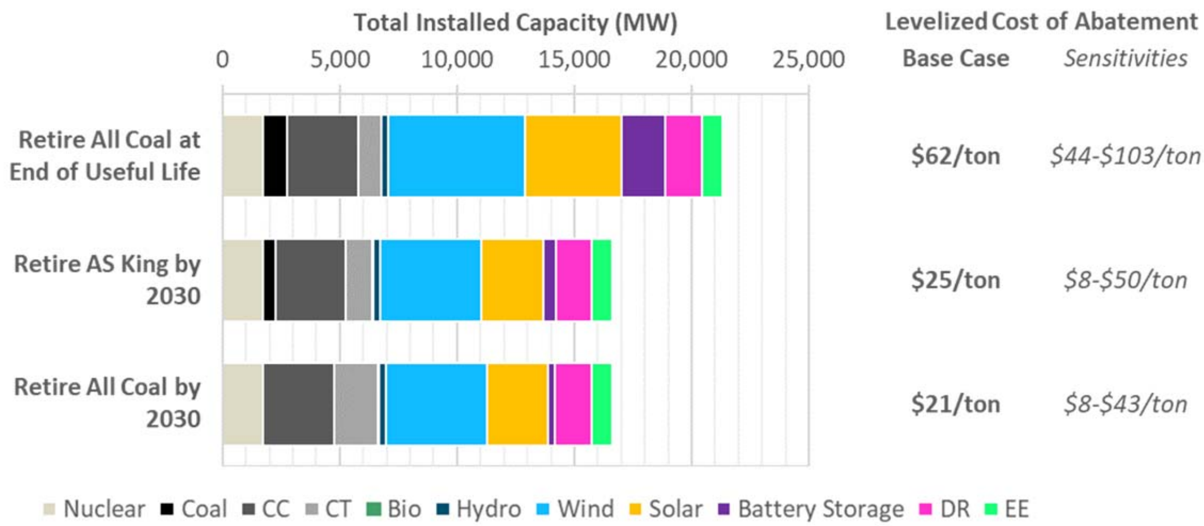
First—and perhaps most significantly—this study suggests that Xcel Energy can achieve substantial reductions in carbon emissions from its Upper Midwest portfolio at relatively low cost. Across the 21 scenarios examined in this study that achieve deep carbon reductions during the study horizon, the lowest-cost scenarios reduce carbon at a levelized cost of $15-20 per ton. The ability to achieve such large emissions reductions at such a relatively low cost results from several converging factors: (1) low natural gas prices, which enable low-cost fuel switching from coal to gas; (2) the relatively low (and falling) costs of new wind and solar resources due to technology improvements over the past decade; (3) a potential to increase deployment of energy efficiency and other demand-side programs to manage load growth; and (4) anticipated reductions in future battery storage costs, which enable integration of high penetrations of renewable generation.

Figure 6-1. Range of carbon abatement costs across all scenarios and sensitivities.



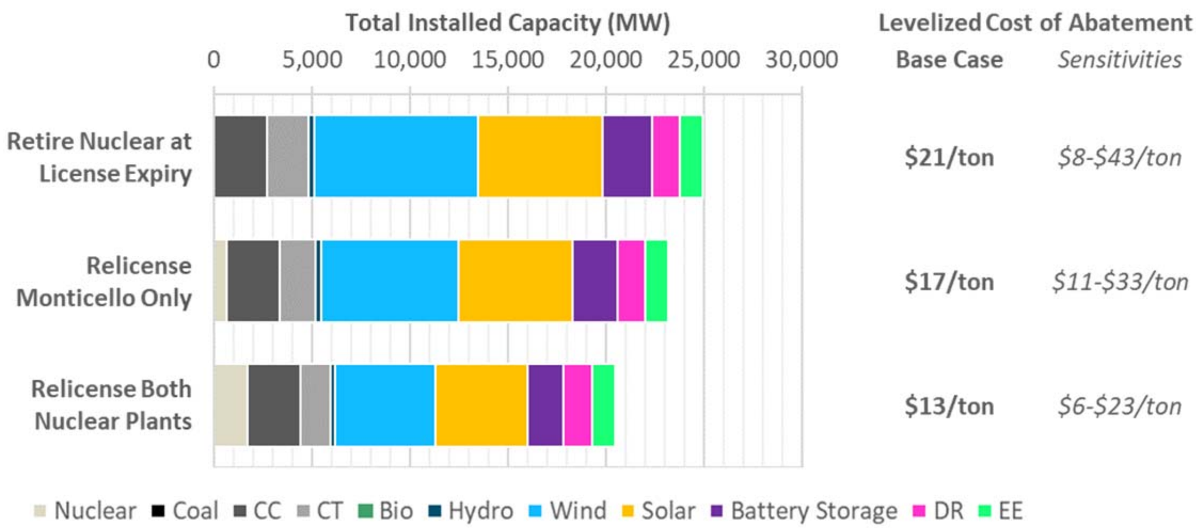
The lowest-cost near-term opportunity to reduce carbon in Xcel's Upper Midwest system is to replace coal generation with a combination of renewables, storage, efficiency, and natural gas generation. The four coal plants owned by Xcel produce approximately 85% of the Upper Midwest system's greenhouse gas emissions in the 2020 Reference Case; while Xcel has already established plans to retire two of these plants prior to 2030, this analysis suggests that accelerating the retirement of its remaining two plants and replacing them with a portfolio of efficiency, renewables, storage, and natural gas generation provides the least-cost pathway to reducing emissions consistent with Xcel's 2030 goals (see Figure 6-2).

Figure 6-2. Snapshot of portfolios achieving 85% carbon reductions in 2030



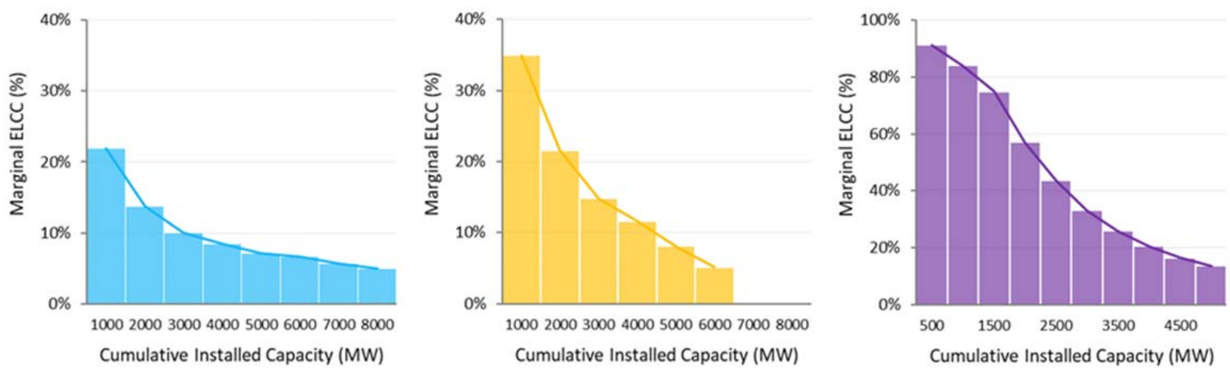
A diverse portfolio of resources—including nuclear—offers the least-cost long-term pathway to deep carbon reductions. Beyond 2030, meeting Xcel's long-term carbon goals will require continued development of new carbon-free energy resources. At the same time, the expiration of existing licenses at both of Xcel's nuclear facilities in the early 2030s raises questions about the role of nuclear in Xcel's long-term generation portfolio. The scenario analysis conducted in this study suggests that under most circumstances, extending the licenses of both Monticello and Prairie Island to allow continued operation provides a least-cost option to meeting long-term carbon goals (Figure 6-3). This is due not only to the plants' ability to generate carbon-free electricity at relatively low cost but also, and perhaps more significantly, to the fact that nuclear generation (unlike wind, solar, or energy storage), as a "firm" resource, can generate at its full nameplate capacity for sustained periods when needed to meet Xcel's reliability needs. This unique combination of characteristics makes Xcel's existing nuclear plants inherently valuable to meeting Xcel's long-term carbon goals.

Figure 6-3. Xcel resource portfolios that achieve 95% carbon reductions in 2045



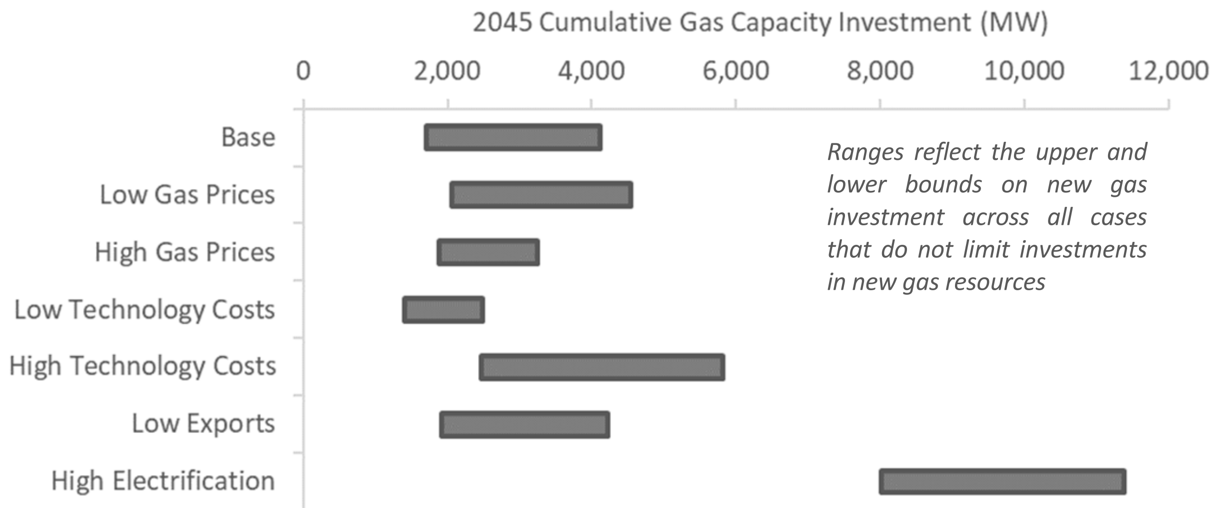
While new resources like wind, solar, and storage will play a central role in supplying carbon-free energy to Xcel's customers, these resources alone cannot meet Xcel's resource adequacy needs at reasonable costs. The reliability analysis conducted in this study highlights the limitations of renewable and storage resources to meet resource adequacy needs: due to variability and limits on duration, these resources offer less capacity value than firm resources that can produce at full capacity when needed. Further, because their marginal capacity value declines with increasing penetration, wind, solar, and storage offer a relatively poor substitute for traditional firm capacity resources in meeting reliability needs at scale (see Figure 6-4). Taken to an extreme, this study shows that a system designed to rely solely on renewables and storage to meet reliability needs would require prohibitively large investments. These findings underscore the need for an evolving approach to resource adequacy—by both Xcel and MISO—as renewables and storage reach greater levels of penetration. Such an approach is critical to ensure that sufficient resources are available even when variable renewables and storage alone cannot produce sufficient levels of generation to meet load.

Figure 6-4. Marginal capacity values of wind, solar, and storage resources in Xcel's 2030 portfolio



Natural gas plants will be critically important to ensure a reliable system but will operate at low capacity factors. Because of the inherent limitations of renewables and storage resources to satisfy resource adequacy needs alone, some form of firm, dispatchable capacity will be needed to complement large anticipated investments in efficiency, renewables, and storage that needed to decarbonize Xcel's energy supply. While Xcel's existing nuclear plants are highly valuable because of their firm attributes, they alone are not sufficient to satisfy the need for firm capacity; natural gas resources will continue to play a crucial role in meeting system reliability. Figure 6-5 shows the range of new investments in natural gas resources across all the cases and sensitivities that allowed gas investment as part of the least-cost plan. Under Base Case assumptions, the level of new gas investments needed by 2045 spans a range from 2,000 to 4,000 MW (depending on whether existing nuclear plants are relicensed); among most other sensitivities, a similar range is observed. One sensitivity stands out for its outsized effect: in the High Electrification sensitivity, due to large new loads that increase winter peak significantly, the level of investment in new gas resources in least-cost portfolios is dramatically higher—8,000 to 11,000 MW. Collectively, these observations point to a more general finding: investment in new natural gas resources to meet capacity needs enables a low-cost pathway to decarbonize electricity and to facilitate levels of electrification needed to meet economy-wide carbon reduction goals.

Figure 6-5. Range of investments in new natural gas capacity resources by 2045 as part of a least-cost plan to achieve deep carbon reductions



Finally, while this study identifies a number of promising pathways towards Xcel's long-term carbon goals, the cost of achieving carbon reductions remains highly uncertain and subject to impacts of factors beyond the company's control. Even in the scenario that this study identifies as a least-cost plan—one that combined nuclear relicensing, accelerated coal retirements, and investments in renewables, storage, efficiency, and gas to meet long-term goals—the potential impacts upon retail rates calculated at the study's endpoint in 2045 spans a broad range from 150% above to 125% below the rate impact under Base Case assumptions. The largest potential sources of risk identified in this study result from uncertainty on the future cost of new renewable and storage resources and the uncertainty of how the changing generation mix in the broader MISO system will impact Xcel's opportunities to manage costs through market transactions. The exposure of Xcel's portfolio to such uncertainty and the associated risks underscores the importance of constant vigilance and responsiveness to rapidly changing market conditions as Xcel transitions towards a low carbon system.

Appendix A. RECAP Methodology

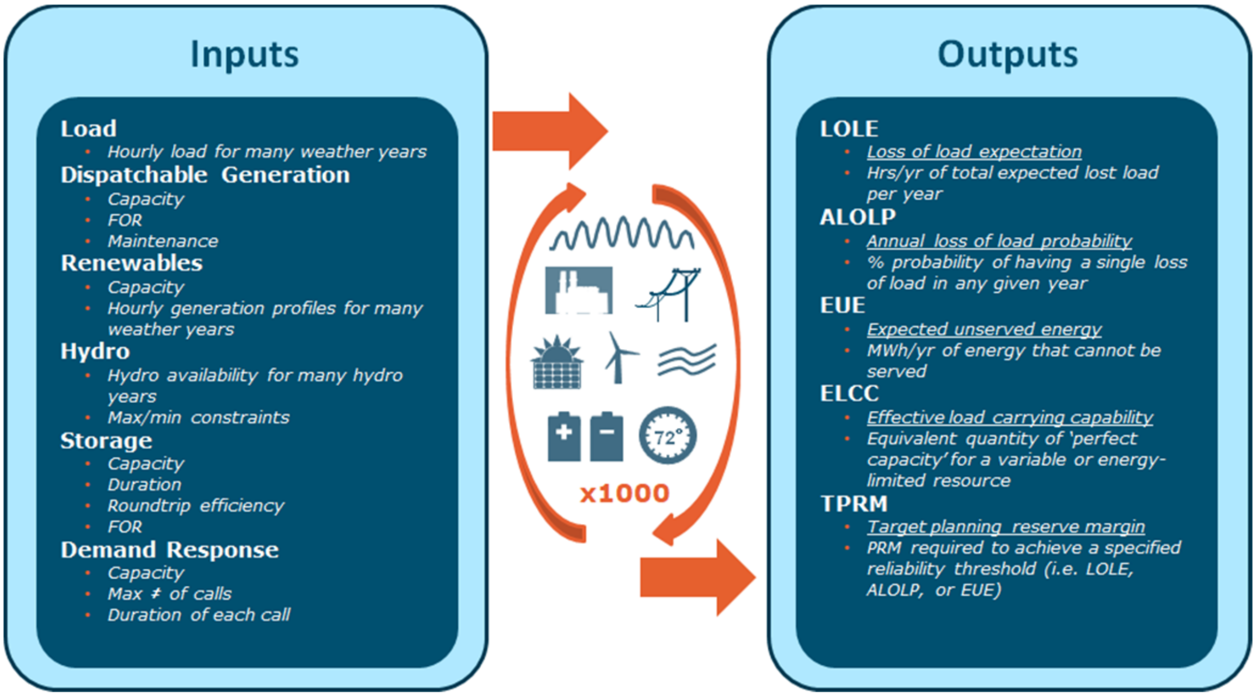
A.1 Background

E3's **Renewable Energy Capacity Planning Model (RECAP)** is a loss-of-load-probability model designed to evaluate the resource adequacy of electric power systems, including systems with high penetrations of renewable energy and other dispatch-limited resources such as hydropower, energy storage, and demand response. RECAP was initially developed for the California Independent System Operator (CAISO) in 2011 to facilitate studies of renewable integration and has since been adapted for use in many jurisdictions across North America.

RECAP evaluates resource adequacy through time-sequential simulations of thousands of years of plausible system conditions to calculate a statistically significant measure of system reliability metrics as well as individual resource contributions to system reliability. The modeling framework is built around capturing correlations among weather, load, and renewable generation. RECAP also introduces stochastic forced outages of thermal plants and transmission assets and time-sequentially tracks hydro, demand response, and storage state of charge.

Figure A-1 provides a high-level overview of RECAP including key inputs, Monte Carlo simulation process, and key outputs.

Figure A-1. RECAP model overview



A.2 Model Inputs

RECAP is designed to allow loss of load probability simulation on a wide range of electricity systems that may comprise a diverse mix of generating resources, each with different constraints and characteristics that affect their availability to serve load at different times. The input data for RECAP, summarized in Table A-1, enables a robust evaluation of loss-of-load-probability that can account for a broad variety of technologies and resource types, including:

+ **Firm resources** capable of producing at their full rated capacity when called upon by operators (except during periods of maintenance and unforced outages);
+ **Variable resources**, typically wind and solar, whose availability will vary on an hourly basis as a result of weather and solar irradiance patterns;

+ **Hydroelectric resources** that can be dispatched relatively flexibly but have constraints related to streamflow and underlying hydrological conditions;
+ **Storage resources** that can be dispatched flexibly but have limited durations across which they are available due to limits on state of charge; and
+ **Demand response programs** that can be called upon as a last resort by operators to maintain reliability but typically have limits on the frequency and duration of calls that vary depending on the type of program.

Table A-1. Key inputs to RECAP model

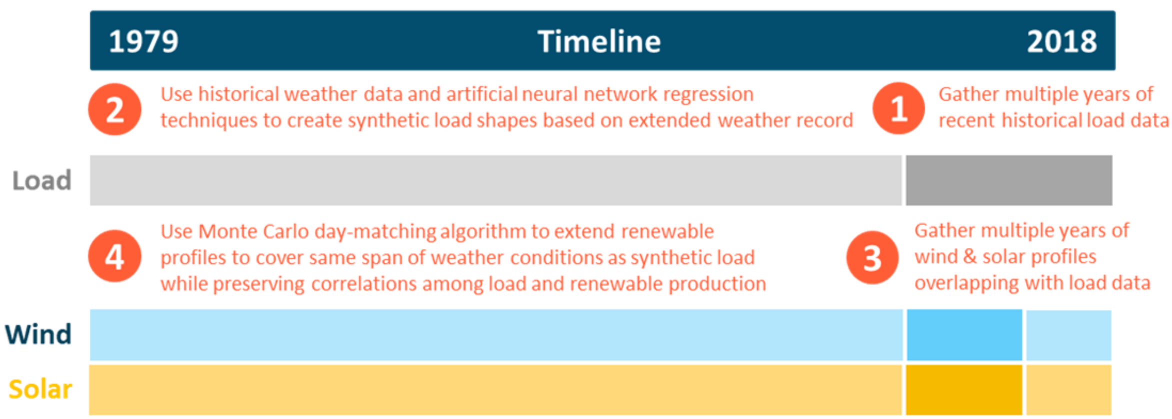
Module	Inputs Needed
Load	• Annual energy demand • Annual 1-in-2 peak demand • Hourly profiles corresponding to a wide range of weather conditions (20+ years)
Firm Resources *(e.g. nuclear, coal, gas, biomass, geothermal)*	• Installed capacity by resource • Forced outage rate by resource • Maintenance profiles by resource
Variable Resources *(e.g. wind, solar, run-of-river hydro)*	• Installed capacity by resource • Hourly profiles for multiple years, ideally including multiple years of overlap with hourly load profile data
Imports/Market Purchases	• Assumed level of imports available from external markets available to contribute to portfolio reliability needs
Hydroelectric Resources	• Installed capacity by resource • Monthly/daily energy budgets across a range of plausible hydro conditions • Minimum output levels by month/day • Sustained peaking limitations by month/day
Storage Resources *(e.g. batteries, pumped storage)*	• Installed capacity by resource • Storage reservoir size by resource • Round-trip efficiency by resource
Demand Response Resources	• Program size by program • Limits on program calls (e.g. number of calls per year/month/day, length of calls)

A.3 Model Methodology

A.3.1 LOAD & RENEWABLE SIMULATION

Generating an extensive record of load and renewable profiles that capture both the range of variability of each as well as the key correlations between them is a necessary but challenging step in reliability modeling. To generate such a record, RECAP relies upon historical time-synchronous load and renewable profiles but also uses statistical approaches to extend what is typically a limited historical record. The four-step process used in RECAP is shown in Figure A-2.

Figure A-2. Illustration of processes used to generate load & renewable profiles for RECAP



Step 1: Gather historical load data for multiple recent years

The hourly and seasonal patterns of load are typically captured in RECAP through the actual observed patterns of hourly load metered by utilities, RTOs, or others. In general, multiple years of recent historical load data (5-10 years) is collected to provide a reasonable breadth of potential underlying weather conditions.

Step 2: Use neural network regression to simulate hourly loads across long-run weather record

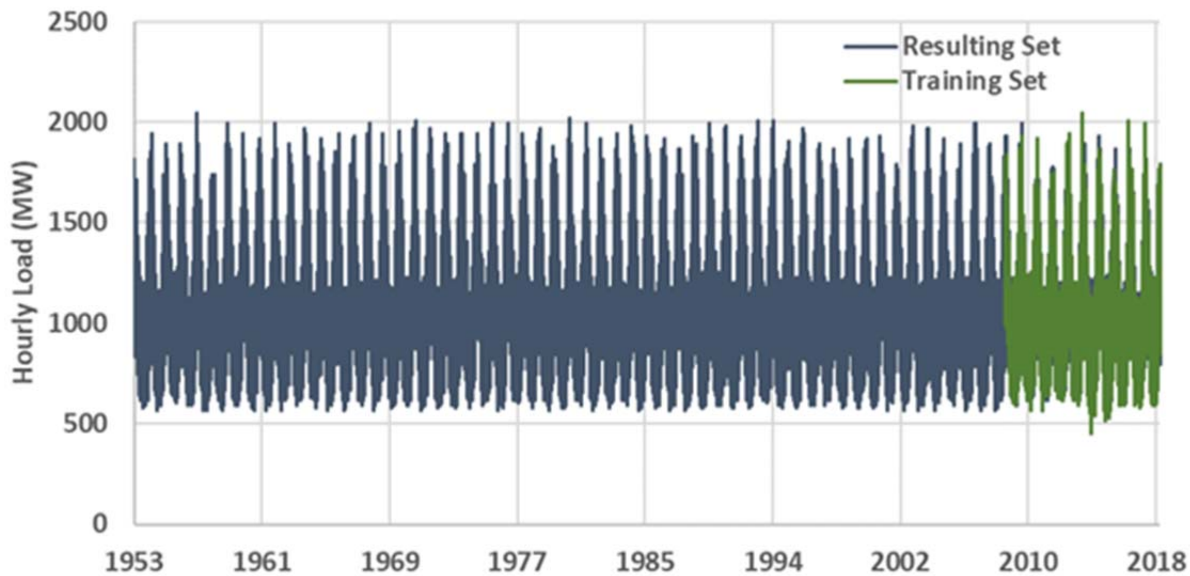
Typically, the availability of historical hourly load data that can be practically incorporated into RECAP is limited—both by data availability and by the fact that historic load shapes from previous years may not appropriately reflect the composition of end uses and customers that make up today's system (an issue that becomes increasingly pronounced farther back in time). At the same time, a rigorous approach to measuring reliability requires consideration of a breadth of potential weather conditions.

To allow consideration of a broad range of potential weather conditions observed across multiple decades in spite of the lack of useful historical load data during most of that period, RECAP uses a neural network regression algorithm to extend a relatively shorter sample of actual historical load data across a longer period based on key weather indicators and drivers across that longer period. The neural network algorithm is trained with a set of historical loads and associated underlying weather data and then used to simulate load levels that reflect the composition of end uses and the underlying economic conditions that reflect today's electricity demands while also capturing the underlying weather conditions across a much broader record. The key variables included in the neural network regression include:

+ Daily minimum and maximum temperatures at multiple weather stations;
+ An indicator for month (+/- 15 days);
+ A flag for day-type (weekend vs. weekday);
+ A day index to account for any growth observed during the training period.

Figure A-3 shows an example of the results of this process. The resulting shape can be scaled upward or downward to the appropriate level of annual and peak demand to match a future system's expected demand growth.

Figure A-3. Example of results of neural network regression to extend load across long weather record



Step 3: Gather historical (or simulated) renewable profiles for multiple recent years

Multiple years of actual and/or simulated hourly profiles for wind and solar resources are a key input to RECAP. Whenever possible, actual historical metered data is preferred, but in its absence (given the relatively small amount of renewable generation existing today), simulated hourly profiles from sources like NREL's WIND Toolkit and NREL's System Advisor Model provide coverage across multiple historical years (2007-'12 and 1998-'18, respectively). Several considerations are important in developing this data set:

+ Hourly profiles should capture multiple years. The potential variability of renewable generation, particularly during periods of extreme load, is high enough that a single year may not appropriately capture its expected production during those periods. Therefore, multiple years (typically at least four) are needed.

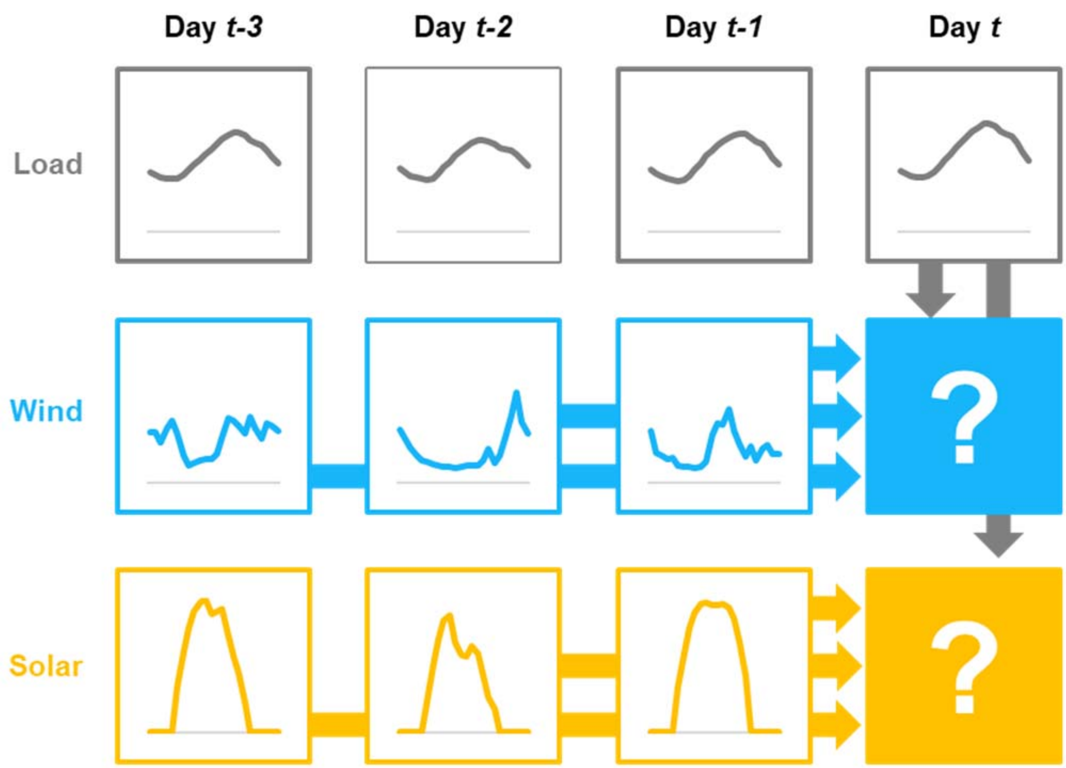
+ Hourly profiles should correspond to a period for which load data is also available. Developing a dataset of load and renewables that is weather-matched based on actual historical conditions allows the modeling to account for the actual observed correlations between load and renewables.
+ Hourly profiles for wind and solar should (ideally) cover the same historical period. Like above, this allows the model to preserve actual observed correlations between wind and solar—not just between load and each renewable technology independently.

Step 4: Use a probabilistic day-matching algorithm to match renewable profiles to extended weather record

A stochastic rolling day-matching algorithm is used to match the limited sample of renewable profiles with the extended record of simulated load data using the observed relationship for years with overlapping data i.e., years with available renewable data. The day matching algorithm, illustrated in Figure A-4, selects a renewable profile for each day of the simulation based the corresponding level of load in that day and the level of renewable generation in the prior day(s).[8] The potential sample of renewable profiles from the historical record that are considered as potential matches for each day in the extended record is also restricted to days within +/- 15 calendar days of that day to ensure that seasonal factors (e.g. variations in patterns of insolation, which affects solar production on a seasonal basis) are also accounted for in the process. Ideally, this day matching algorithm can be run on both wind and solar profiles simultaneously—this is possible when the historical records for wind and solar profiles are contiguous—but the algorithm can also be run independently on wind and solar if overlapping records are not available.

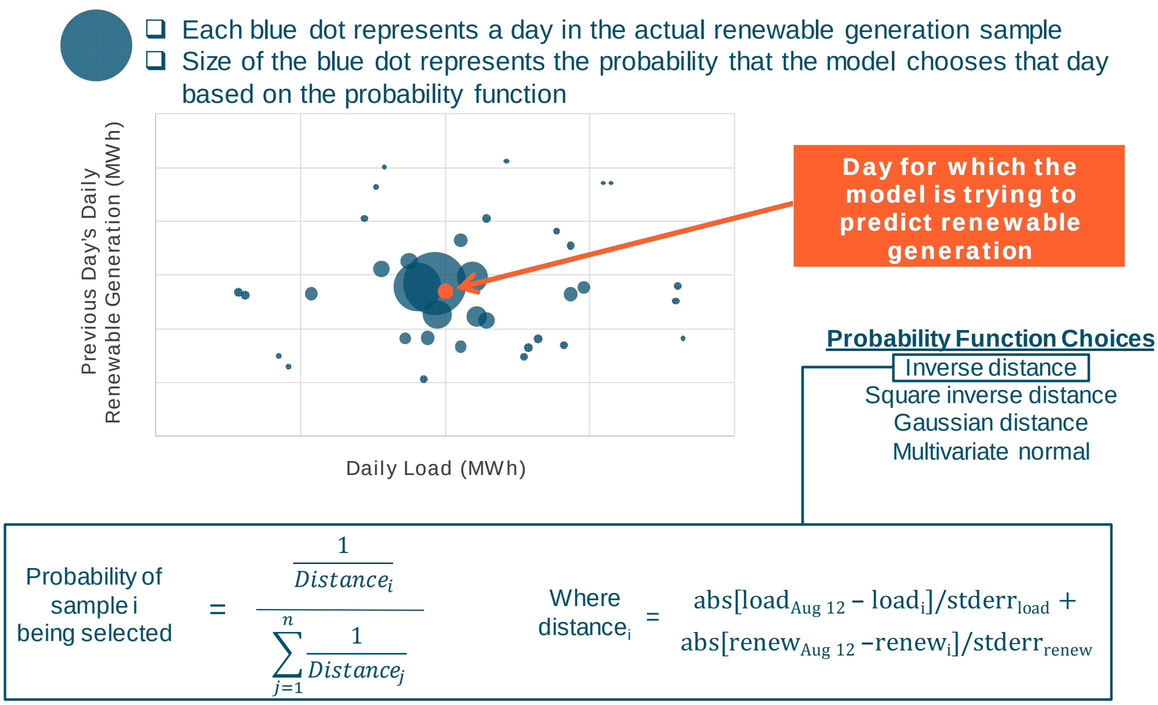
[8] The number of prior days' renewable generation included in the matching algorithm can be varied as needed to ensure that extended weather events observed in the historical record (e.g. multi-day storm systems) occur within the stochastic simulation.

Figure A-4. Illustration of day-matching algorithm used to extend record of renewable profiles to match loads



The algorithm used to select renewable profiles is a probabilistic one that allows for stochastic pairings of load and renewable shapes—in other words, multiple plausible combinations of load and corresponding renewable profiles are generated for the extended weather record. The probability that any specific day from the historical weather record will be selected as a match is based on an inverse distance algorithm that measures the similarity between each possible day of renewable profiles in the historical record and the desired day in the longer record and assigns a probability to each one. Figure A-5 illustrates the assignment of probabilities for a specific individual day; the days in the historical record that are "closest" to that day (in terms of that day's load and the previous day's renewable generation) are assigned the highest probability.

Figure A-5. Renewable profile selection process



A.3.2 LOSS OF LOAD PROBABILITY SIMULATION

Based on the inputs described above, RECAP simulates the loss of load probability for an electric system using a Monte Carlo approach to capture plausible combinations of load, variable renewables, and outages across hundreds of potential years. For each broad class of resource enumerated above, RECAP includes a module that evaluates the ability of each resource in that class to contribute to load in each hour of the simulation. The methodology used in each module is presented in

Table A-2. Overview of methodology used to compare load and resource availability

Module	Methodology
Load	The hourly profile of electricity demand is determined based on an hourly load shape that covers a broad range of historical weather conditions (multiple decades) that is scaled to the desired level of annual and peak demand. The underlying load shape itself is a result of a pre-processing neural network regression that simulates hourly load shapes for the full available weather record based on recent historical loads and a longer record of weather data.
Firm Resources *(e.g. nuclear, coal, gas, biomass, geothermal)*	Available dispatchable generation is calculated stochastically in RECAP using forced outage rates (FOR) and mean time to repair (MTTR) for each individual generator. These outages are either partial or full plant outages based on a distribution of possible outage states. Over many simulated days, the model will generate outages such that the average generating availability of the plant will yield a value of (1-FOR).
Variable Resources *(e.g. wind, solar, run-of-river hydro)*	Availability of variable renewable resources is simulated stochastically based on the rolling probabilistic day-matching algorithm described above. This results in an hourly timeseries profile for all variable resources that aligns with the hourly load profile.
Imports/Market Purchases	Availability of generic resources from external areas (i.e. assumed wholesale market purchases) can be specified at an hourly, monthly, or annual level. This is an input to RECAP.
Hydroelectric Resources	To determine hydro availability, the model uses a monthly historical record of hydro production. For every simulated load year, a hydro year is chosen stochastically from the historical database. Associated hydro budgets are typically assigned on either a weekly or daily basis and then “dispatched” to minimize net load (load less variable resources and hydro) during that period while accounting for a number of constraints, including: • Minimum output levels that capture the lower limit on the level of generation that a system may produce when considering hydrological and other physical constraints on the system • Sustained peaking limits, which limit the output of the hydro system across a range of rolling time windows (e.g. 1-hour, 2-hour, 4-hour, and 10-hour) to capture how hydrological factors may limit the ability to discharge water through a dam for sustained periods of time.
Storage Resources *(e.g. batteries, pumped storage)*	The model dispatches storage if there is insufficient generating capacity to meet load net of renewables and hydro. Storage is reserved specifically for reliability events where load exceeds available generation. It is important to note that storage is not dispatched for economics in RECAP which in many cases is how storage would be dispatched in the real world. However, it is reasonable to assume that the types of reliability events that storage is being dispatched for (low wind and solar events), are reasonably foreseeable such that the system operator would ensure that storage is charged to the extent possible in advance of these events. (Further, presumably prices would be high during these types of reliability events so that the dispatch of storage for economics also would satisfy reliability objectives).

Module	Methodology
Demand Response Resources	The model dispatches demand response if there is still insufficient generating capacity to meet load even after storage. Demand response is the resource of last resort since demand response programs often have a limitation on the number of times they can be called upon over a set period of time. For this study, demand response was modeled using a maximum of 10 calls per year, with each call lasting for a maximum of 4 hours.

To the extent the portfolio of resources whose availability is determined through the steps above is insufficient to meet demand in any hour, a loss of load event is recorded. After simulating hundreds of years of possible Monte Carlo outcomes, RECAP calculates the system's LOLE and a variety of other reliability statistics.

A.3.3 EFFECTIVE LOAD CARRYING CAPABILITY CALCULATION

The simulation of LOLE for a given electric system enables the calculation of "effective load carrying capability" (ELCC) for individual resources, or, in more colloquial terms, their capacity value: a measure of the equivalent amount of "perfect capacity" that could be replaced with the addition of a specified resource while maintaining the same level of reliability. ELCC for individual resources (or combinations of resources) is calculated through iterative simulations of an electric system:

1. The LOLE for the electric system without the specified resource is simulated. If the resulting LOLE does not match the specified reliability target, the system "adjusted" to meet a target reliability standard (most commonly, one day in ten years). This adjustment occurs through the addition (or removal) of perfect capacity resources to achieve the desired reliability standard.
2. The specified resource is added to the system and LOLE is recalculated. This will result in a reduction in the system's LOLE, as the amount of available generation has increased.
3. Perfect capacity resources are removed from the system until the LOLE returns to the specified reliability target. The amount of perfect capacity removed from the system represents the ELCC of the specified resource (measured in MW); this metric can also be translated to percentage terms by dividing by the installed capacity of the specified resource.

This approach can be used to determine the ELCC of any specific resource type evaluated within the model. In general, ELCC is not widely used to measure capacity value for firm resources (which are generally rated either at their full or unforced capacity) but provides a useful metric for characterizing the capacity value of renewable, storage, and demand response resources.

The ELCC of a resource depends not only on the characteristics of load in a specific area (i.e. how coincident its production is with load) but also upon the resource mix of the existing system (i.e. how it interacts with other resources). For instance, ELCCs for variable renewable resources are generally found to be higher on systems with large amounts of inherent storage capability (e.g. large hydro systems) than on systems that rely predominantly on thermal resources and have limited storage capability. ELCCs for a specific type of resource are also a function of the penetration of that resource type; in general, most resources exhibit declining capacity value with increasing scale. This is generally a result of the fact that continued addition of a single resource or technology will lead to saturation when that resource is available and will shift reliability events towards periods when that resource is not available. The diminishing impact of increasing solar generation as the net peak shifts to the evening illustrates this effect.

A.3.4 PLANNING RESERVE MARGIN CALCULATION

The results of RECAP can also be translated into a simpler and more widely used planning reserve margin requirement (PRM), a target for system reliability expressed as a percentage requirement above expected peak demand. PRM requirements are used by many utilities and RTOs in their administration of resource adequacy requirements. Thus, RECAP also expresses its outputs in terms of the PRM:

+ The "actual" PRM of a system is calculated based on the summation of capacity provided by all resources; firm resources are rated at nameplate capacity, while hydro, variable, and use-limited resources are rated based on ELCC endogenously calculated as described above. This total amount of capacity is divided by the expected peak to provide a planning reserve margin.

+ The "target" PRM of a system (i.e. the PRM needed to achieve a corresponding specified LOLE target) is calculated by adjusting the starting system as needed with perfect capacity resources to achieve the desired LOLE. The PRM for this adjusted system then represents the reserve margin needed to meet the comparable LOLE standard.

A.4 Key Model Outputs

A primary benefit of the RECAP model is the ability to produce an array of summary results that give insight into system reliability and the nature of frequency, magnitude, and duration of loss of load events on an electric system. The summary reliability statistics produced include:

+ **Loss of load expectation (LOLE, measured in days per year),** the expected number of days in which loss-of-load events occur in each year;
+ **Loss of load hours (LOLH, measured in hours per year),** the expected number of hours of lost load in each year;
+ **Loss of load events (LOLEV, measured in events per year),** the expected number of reliability events that occur within each year;
+ **Annual loss of load probability (ALOLP, measured in %),** the probability that at least one loss-of-load event will occur within a year; and
+ **Expected unserved energy (EUE, measured in MWh per year),** the expected amount of unserved load within each year.

RECAP also produces a number of metrics that help translate these detailed reliability statistics into a more typical planning reserve margin framework. If the user specifies a specific reliability target (for example 0.1 days/yr LOLE, or "one day in ten years"), the model calculates the required quantity of capacity necessary to achieve that level of reliability through an internal search algorithm. Comparing the required quantity of capacity to the median (1-in-2) peak load yields the target planning reserve margin while comparing it to the quantity of existing firm capacity on the system yields a net capacity shortage. Included in this measure of firm capacity is the effective load carrying capability (ELCC) of all non-firm resources including wind, solar, hydro, demand response, and battery storage.

Appendix B. RESOLVE Methodology

B.1 Overview

RESOLVE is a resource investment model that uses linear programming to identify optimal long-term generation and transmission investments in an electric system, subject to reliability, technical, and policy constraints. Designed specifically to address the capacity expansion questions for systems seeking to integrate large quantities of variable resources, RESOLVE layers capacity expansion logic on top of a production cost model to determine the least-cost investment plan, accounting for both the up-front capital costs of new resources and the variable costs to operate the grid reliably over time. In an environment in which most new investments in the electric system have fixed costs significantly larger than their variable operating costs, this type of model provides a strong foundation to identify potential investment benefits associated with alternative scenarios.

RESOLVE's optimization capabilities allow it to select from among a wide range of potential new resources. In general, the options for new investments considered in this study are limited to those technologies that are commercially available today. This approach ensures that the greenhouse gas reduction portfolios developed in this study can be achieved without relying on assumed future technological breakthroughs. At the same time, it means that emerging technologies that could play a role in a low-carbon future for the Midwest—for instance, small modular nuclear reactors—are not evaluated within this study. This modeling choice is not meant to suggest that such emerging technologies should not have a role in meeting regional greenhouse gas reduction goals, but instead reflects a simplifying assumption made in this study. The full range of resource options considered by RESOLVE in this study is shown in Table B-1.

Table B-1. Resource options considered in RESOLVE

Resource Option	Examples of Available Options	Functionality
Natural Gas Generation	• Simple cycle gas turbines • Reciprocating engines • Combined cycle gas turbines	• Dispatches economically based on heat rate, subject to ramping limitations • Contributes to meeting minimum generation and ramping constraints
Renewable Generation	• Solar PV • Wind • Biogas	• Dynamic downward dispatch (with cost penalty) of renewable resources to help balance load
Energy Storage	• Batteries (>1 hr)	• Stores excess energy for later dispatch • Contributes to meeting minimum generation and ramping constraints
Energy Efficiency	• HVAC • Lighting • Dryer, refrigeration, etc.	• Reduces load, retail sales, planning reserve margin need
Demand Response	• Saver's Switch • Interruptible tariff • Critical Peak Pricing	• Contributes to planning reserve margin needs

B.2 Operational Simulation

To identify optimal investments in the electric sector, maintaining a robust representation of prospective resources' impact on system operations is fundamental to ensuring that the value each resource provides to the system is captured accurately. At the same time, the addition of investment decisions across multiple periods to a traditional unit commitment problem increases its computational complexity significantly. RESOLVE's simulation of operations has therefore been carefully designed to simplify traditional unit commitment problem where possible while maintaining a level of detail sufficient to provide a reasonable valuation of potential new resources. The key attributes of RESOLVE's operational simulation are enumerated below:

+ **Hourly chronological simulation:** RESOLVE's representation of system operations uses an hourly resolution to capture the intraday variability of load and renewable generation. This level of resolution is necessary in a planning-level study to capture the intermittency of potential new wind and solar resources, which are not available at all times of day to meet demand and must be supplemented with other resources.
+ **Aggregated generation classes:** rather than modeling each generator within the study footprint independently, generators in each region are grouped together into categories with other plants whose operational characteristics are similar (e.g. nuclear, coal, gas CCGT, gas CT). Grouping like plants together for the purpose of simulation reduces the computational complexity of the problem without significantly impacting the underlying economics of power system operations.
+ **Linearized unit commitment:** RESOLVE includes a linear version of a traditional production simulation model. In RESOLVE's implementation, this means that the commitment variable for each class of generators is a continuous variable rather than an integer variable. Additional constraints on operations (e.g. Pmin, Pmax, ramp rate limits, minimum up and down time) further limit the flexibility of each class' operations.
+ **Zonal transmission topology:** RESOLVE uses a zonal transmission topology to simulate flows among the regions represented in the analysis as model zones. In this study RESOLVE includes four zones: Xcel's Upper Midwest territory, NSP – the Primary Zone; MISO Load Resource Zone (LRZ) 1, MISO LRZ2, and MISO LRZ3. Given Xcel's territory exists primarily in MISO LRZ1, the NSP zone can only interact with LRZ1; while LRZ1 has ties to both LRZ2 and LRZ3.
+ **Co-optimization of energy and ancillary services:** RESOLVE dispatches generation to meet load across the modeled regions, while simultaneous reserving flexible capacity within the Primary Zone to meet the contingency and flexibility reserve needs. As systems become increasingly constrained on flexibility, the inclusion of ancillary service needs in the dispatch problem is necessary to ensure a reasonable dispatch of resources that can serve load reliably.

- **Smart sampling of days:** whereas production cost models are commonly used to simulate an entire calendar year (or multiple years) of operations, RESOLVE simulates the operations of the modeled system for a number of sampled independent days. Load, wind, and solar profiles for these selected days, sampled from the historical meteorological record over a specified period, are selected and assigned weights so that taken in aggregate, they produce a reasonable representation of complete distributions of potential conditions.[9] This allows RESOLVE to approximate annual operating costs and dynamics while simulating operations for only the selected days. In this study, a sample of 37 days is used, based on historical meteorological record from 2009 to 2012.
- **Hydro dispatch informed by historical operations:** RESOLVE captures the inherent limitations of the generation capability of the hydroelectric system by deriving constraints from actual operational data. Three types of constraints govern the operation of the hydro fleet as a whole: (1) daily energy budgets, which limit the amount of hydro generation in a day;[10] (2) maximum and minimum hydro generation levels, which constrain the hourly hydro generation; and (3) maximum multi-hour ramp rates, which limit the rate at which the output of the collective hydro system can change its output across periods from one to four hours. Collectively, these constraints limit the generation of the hydro fleet to reflect seasonal limits on water availability, downstream flow requirements, and non-power factors that impact the operations of the hydro system. The derivation of these constraints from actual hourly operations makes this representation of hydro operations conservative with respect to the amount of potential flexibility in the resource.

[9] An optimization algorithm is used to select the days and identify the weight for each day such that distributions of load, net load, wind, and solar generation match long-run distributions. For further detail on the smart sampling algorithm used in RESOLVE, see **Error! Reference source not found.**.

[10] Sometimes hydro operators can shift hydro energy from day to day: for example, if hydro operators know that tomorrow will be a peak day, they can save some hydro energy today and use them tomorrow to meet the system need. This flexibility can help integrating renewable into the system and it is going to be more and more valuable as the % of system renewable penetration increases. To capture this flexibility, model allows up to 5% of the hydro energy in each day to be shifted around within two months.

B.3 Additional Constraints

RESOLVE layers investment decisions on top of the operational model described above. Each new investment identified in RESOLVE has an impact on how the system operates; the portfolio of investments, as a whole, must satisfy a number of additional conditions.

+ **Planning reserve margin:** When making investment decisions, RESOLVE requires the portfolio to include enough firm capacity to meet 1-in-2 system peak plus an additional specified amount of planning reserve margin (PRM) requirement. The contribution of each resource type towards this requirement depends on its attributes and varies by type: for instance, variable renewables are discounted more compared to thermal generations because the uncertainties of generation during peak hours. In this study, a PRM requirement of 3% is used for the Xcel Upper Midwest system.
+ **Renewables Portfolio Standard (RPS) requirement:** RPS requirements have become the most common policy mechanism in the United States to encourage renewable development. RESOLVE enforces an RPS requirement as a percentage of retail sales to ensure that the total quantity of energy procured from renewable resources meets the RPS target in each year.
+ **Greenhouse gas cap:** RESOLVE also allows users to specify and enforce a greenhouse gas constraint on the resource portfolio for a region. As the name suggests, the emission cap type policy requires that annual emission generated in the entire system to be less than or equal to the designed maximum emission cap. This type of policy is usually implemented by having limited amount of emission allowances within the system. As a result, thermal generators need to purchase allowances for the carbon they produced from the market or from carbon-free generators.
+ **Resource potential limitations:** Many potential new resources are limited in their potential for new development. This is particularly true for renewable resources such as wind and solar. RESOLVE enforces limits on the maximum potential of each new resource that can be included in the portfolio, imposing practical limitations on the amount of any one type of resource that may be developed.

RESOLVE considers each of these constraints simultaneously, selecting the combination of new generation resources that adheres to these constraints while minimizing the sum of investment and operational costs.

B.4 Key Model Outputs

RESOLVE produces a large amount of results from technology level unit commitment decisions to total carbon emission in the system. This extensive information gives users a complete view of the future system and makes RESOLVE versatile for different analysis. The following list of outputs is produced by RESOLVE and are the subject of discussion and interpretation in this study:

+ **Total revenue requirement ($/yr):** The total revenue requirement reports the total costs incurred by utilities in the study footprint to provide service to its customers. This study focuses on the relative differences in revenue requirement among scenarios, generally measuring changes in the revenue requirement relative to the Reference Case. The cost impacts for each scenario comprise changes in fixed costs (capital & fixed O&M costs for new generation resources, incremental energy efficiency, new energy storage devices, and the required transmission resources with the new generation) and operating costs (variable O&M costs, fuel costs, costs of market purchases and revenues from surplus sales).
+ **Greenhouse gas emissions (MMTCO2e):** This result summarizes the total annual carbon emission in the system with imports and exports adjustments. By comparing the carbon emissions and total resource costs between different scenarios, we can conclude the relative effectiveness of the strategic measure in enabling carbon reductions.
+ **Resource additions for each period (MW):** The selected investment summarizes the cumulative new generation capacity investments by resources type. It provides an overview of what is built to meet both operational and emissions constraints over time.
+ **Annual generation by resource type (GWh):** Energy balance shows the annual system load and energy produced by each resource type in each modeled year. It provides insights from a different angle than capacity investments. It can help answer questions like: Which types of

resources are dispatched more? How do the dispatch behaviors change over the years? And how do curtailment, imports, and exports vary year by year?

+ **Renewable curtailment (GWh):** RESOLVE estimates the amount of renewable curtailment that would be expected in each year of the analysis as a result of "oversupply"—when the total amount of must-run and renewable generation exceeds regional load plus export capability—based on its hourly simulation of operations. As the primary renewable integration challenge at high renewable penetrations, this measure is a useful proxy for renewable integration costs.
+ **Wholesale market prices ($/MWh):** outputs from RESOLVE can be used to estimate wholesale market prices on an hourly basis. As an optimization model, RESOLVE produces "shadow prices" in each hour that represent the marginal cost of generation given all the resources available at the time; these marginal costs serve as a proxy for wholesale market prices.
+ **Average greenhouse gas abatement cost ($/metric ton):** RESOLVE results can also be used to estimate average and marginal costs of greenhouse gas abatement by comparing the amount of greenhouse gas abatement achieved (relative to a Reference Case) and the incremental cost (relative to that same case).

For this study, most results focus on the snapshots of the system in 2030 and 2045, which correspond to key milestones for Xcel. However, in some cases, intermediate results are also presented when relevant to the study's objectives and key messages.

Appendix C. Additional Inputs & Assumptions

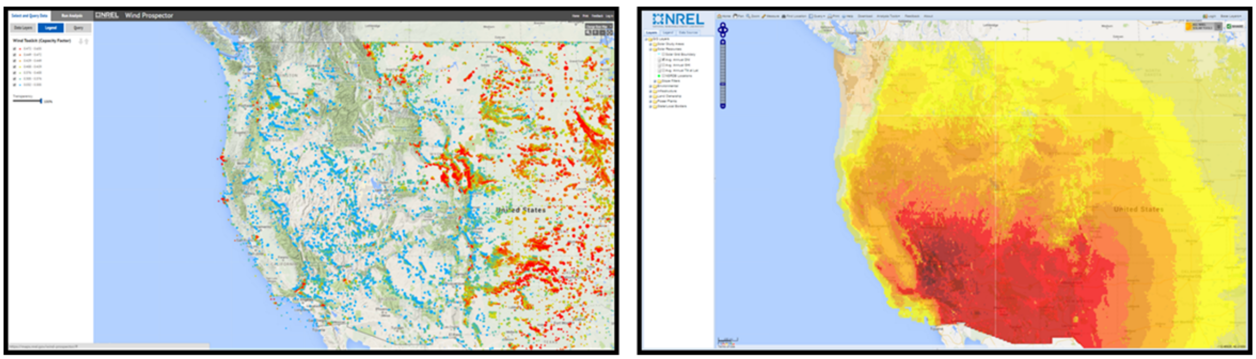
C.1 Load & Renewable Profiles

C.1.1 PROFILE DEVELOPMENT

Xcel provided hourly load information from 2009 – 2012 for the Upper Midwest system. These loads were normalized to create a shape based on real data that could be applied to forecasted peak and demand for the study. While we acknowledge that these hourly profiles will change in the future, the statistical methods used in the RESOLVE day sampling methodology and RECAP neural network capture realistic relationships between load and renewable generation – all driven primarily by weather patterns – that should remain consistent in the future. For the portions of future load growth that represent inherently different characteristics than seen today – namely, electric space heating, electric water heating, and electric vehicles for the High Electrification sensitivity – the E3 PATHWAYS team worked with Xcel to generate separate load profiles that are layered on top of the base load discussed. PATHWAYS, which is a stock rollover model developed by E3 used to analyze economy-wide pathways to achieve deep decarbonization goals, was used to forecast the gross levels of electrification loads. These Minnesota-wide loads were scaled down proportionally for the Xcel Upper Midwest system, but the hourly profiles for each technology stayed consistent.

Hourly profiles for wind and solar generation are derived from the National Renewable Energy Laboratory's (NREL) WIND Toolkit and Solar Prospector, respectively (see Figure C-1), for the same set of load years. The WIND Toolkit provides simulated output for a large number of selected sites throughout the western United States derived using a mesoscale weather model. The Solar Prospector provides historical hourly irradiance data, which is used to simulate the output of hypothetical solar PV plants throughout the west. Various sites were chosen to create aggregate profiles that represent different regions in the broad Xcel Upper Midwest service territory. These sites were screened and aggregated considering general location, MISO LRZ, and relatively close-by transmission interconnections. This resulted in four representative regions in Minnesota, two in Wisconsin, four in Iowa, and four in North Dakota. Each region was assigned a unique solar and wind profile. Both wind and solar profiles used in this study are scaled to match anticipated regional capacity factors.

Figure C-1. Screenshots from NREL's Wind Prospector (left) and Solar Prospector (right)



C.1.2 RECAP NEURAL NETWORK

As is often the case, the historical load record available to Xcel is far exceeded by historical weather data. RECAP relies on a neural network model to predict load given the relationship observed between real weathers and load data. Given a set of temporally matching historical temperature and load, the neural network develops a regression model by which it can then use to predict historical load given temperature data and other predictor data. In doing so, the available load data is effectively extended from a few years to fifty years or more.

E3 modeled hourly load in Xcel under consistent set of economic conditions using the weather years 1950-2012 using a neural network model. This process develops a relationship between recent daily load and the following independent variables:

+ Max and min daily temperature (including one and two-day lag)
+ Month (+/- 15 calendar days)
+ Day-type (weekday/weekend/holiday)
+ Day index for economic growth or other linear factor over the recent set of load data

The neural network model establishes a relationship between daily load and the independent variables by determining a set of coefficients to different nodes in hidden layers which represent intermediate steps in between the independent variables (temp, calendar, day index) and the dependent variable (load). The model trains itself through a set of iterations until the coefficients converge. Using the relationship established by the neural network, the model calculates daily load for all days in the weather record (1950-2012) under 2012 economic conditions. The final step converts these daily load totals into hourly loads. To do this, the model searches over the actual recent load data (4 years) to find the day that is closest in total daily load to the day that needs an hourly profile. The model is constrained to search within identical day-type (weekday/weekend/holiday) and +/- 15 calendar days when making the selection. The model then applies this hourly load profile to the daily load MWh.

This hourly load profile for the weather years 1950-2012 under 2012 economic conditions is then scaled to match the load forecast for future years in which RECAP is calculating reliability. This ”base” load profile only captures the loads that are present on the electricity system today and do not very well capture systematic changes to the load profile due to increased adoption of electric vehicles, building space and water heating, industrial electrification. Load modification through demand response is captured through explicit analysis of this resource.

Operating reserves of 200 MW are also added onto load in all hours with the assumption being that the system operator will shed load in order to maintain operating reserves of at least 200 MW in order to prevent the potentially more catastrophic consequences that might result due to an unexpected grid event coupled with insufficient operating reserves.

C.1.3 RESOLVE DAY SAMPLING

Computation can be challenging for a model like RESOLVE that makes both investment and operational decisions across a long period of time. To alleviate this challenge, instead of simulating the system operation for an entire year, a subset of days is modeled to approximate the annual operating costs. In order to approximate the annual system operating costs while simulating only a subset of the number of days in a year, RESOLVE relies on a pre-processing sampling algorithm to select a combination of days whose characteristics are, together, representative of the conditions experienced by an electricity system over the course of multiple years. This pre-processing step uses optimization to sample a subset of conditions that, when taken in aggregate and weighted appropriately, provide a reasonable representation of the breadth of load, wind, and solar conditions observed in the historical record.

A multi-objective optimization model is used to pick a set of days (and associated weights) to match historical conditions for key indicators while also minimizing the number of days selected. The process for selecting the set of representative days follows several steps:

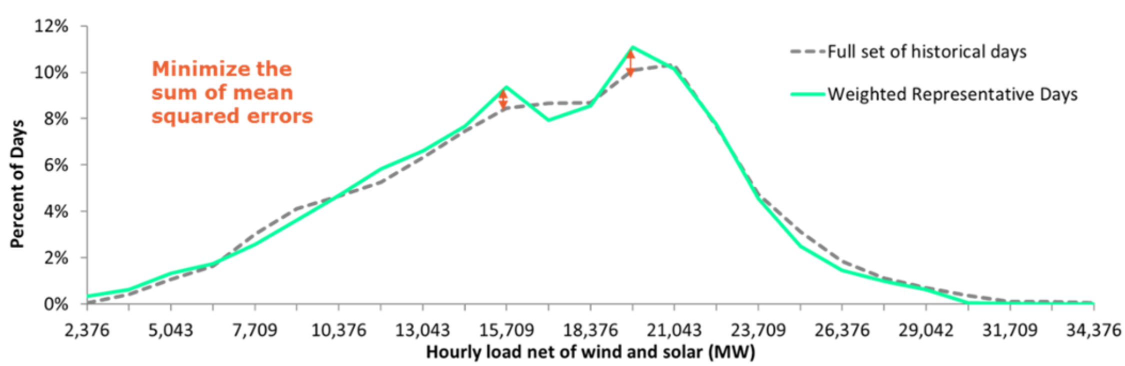
1. **Determine the number and type of days to select:** The user defines the number of days to be selected in the final subset, the minimum day weight to be assigned (so that each day selected has at least a certain importance associated), and optional day types for categorizing different selected days.
2. **The candidate pool of days is created:** Load, wind, and solar profiles are sampled from timeseries data as a representative sample of shapes. In the 2016 PSIP cases, we used simulated 2016 data for the representative sample; however, the algorithm can use multiple years of data to capture different weather years within its sample.
3. **Key variables are selected:** Key variables are selected as indicators for system conditions. In this study, the variables used to characterize the representation of a sample include: (1) distributions of hourly and daily load, net load, wind, and solar production; (2) distribution of hourly ramps of load net of wind and solar; (3) number of days per month; and (4) site-specific annual capacity factors for wind and solar profiles. These variables can also be weighted

differently, which allows the optimization model to prioritize the more important variables with higher weights when matching the distribution. This study prioritizes fit on the distributions for load, wind, and hydro conditions, as these three factors have a significant effect on the operations of the electric system.

4. **Optimization model selects an optimal set of days: From the candidate pool of days established in the first step, the optimization selects a set of days while minimizing the absolute errors for each of the criteria. If optional day types have been assigned by the user, t**he day selection algorithm will attempt to select at least one of each day type in the final sample. **The output from the optimization algorithm includes a set of days, as well as associated weights through which those days may be weighted to represent a** historic average year.

An optimization model is used in the day sampling process. As shown in Figure C-2 below, one component of the minimization is the alignment between historical and sampled hourly load distributions: the distribution of historical hourly net load is plotted as dotted gray line in the chart, and the model selects and weights a subset of days to match the historical distributions.

Figure C-2. Example of net load distribution



The mathematical formulation to minimize absolute error is show below:

$$\textbf{min}: \sum_{b \in Bins} \left| OverallFreq_b - \sum_{d \in Days} \left(weight_d \times DailyFreq_{d,b} \right) \right|$$

subject to:

$$\sum_{d \in Days} weight_d = 1$$

$$weight_d \geq LowerBound \quad \forall\, d \in Days$$

$$SelectedDayIndicator_d \geq weight_d \quad \forall\, d \in Days$$

$$\sum_{d \in DayTypes(d)} SelectedDayIndicator_d \geq 1 \quad \forall\, DayTypes$$

where:

Bins = set of bins in histogram of criteria timeseries

Days = set of days in the historical timeseries

Overall Freq $_b$ *= historical frequency of bin across timeseries*

Daily Freq $_{d,b}$ *= historical frequency in each day*

TUNING = tuning parameter value

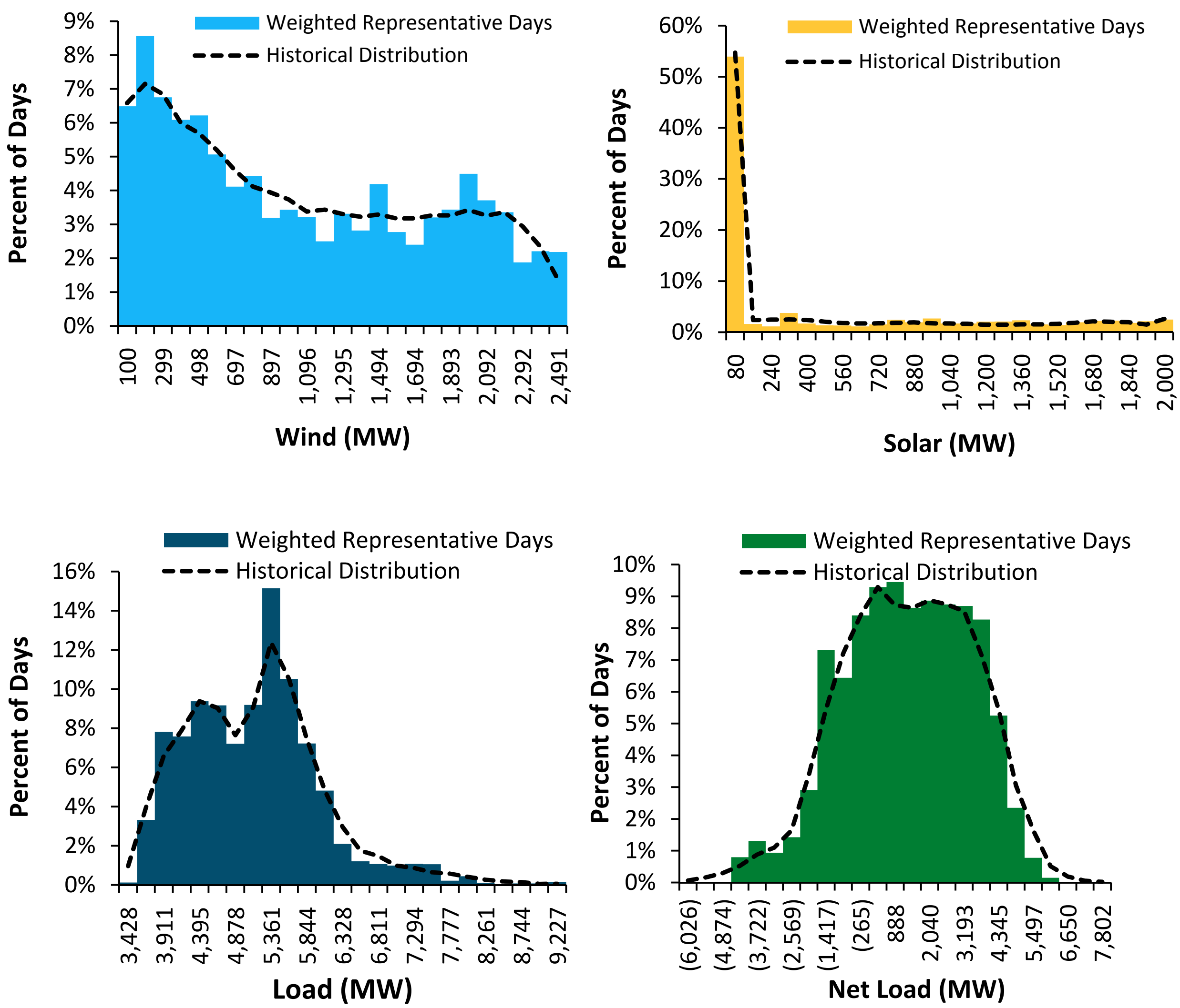
weight $_d$ *= normalized weight for each day*

The day sampling process yielded a set of days that show very small deviations from the historical distributions. The details for each of these days—the calendar days used for load, wind, and solar PV, and the associated weight attributed to the day—are shown in Table -1. Figure C-3 shows the comparison of distribution between the full set of candidate days and the representative days.

Table -1. Details for 37 days sampled for operational simulation in RESOLVE

Day Index	Weather Date	Day Weight	Day Index	Weather Date	Day Weight
1	12/22/2009	20.0	20	6/16/2012	10.4
2	8/26/2011	17.2	21	10/9/2010	9.4
3	10/26/2012	16.8	22	9/21/2012	8.4
4	5/10/2012	16.6	23	7/31/2009	7.3
5	4/17/2012	15.1	24	5/13/2010	7.0
6	4/2/2011	14.8	25	5/23/2010	7.0
7	2/27/2012	14.5	26	7/4/2011	6.0
8	3/9/2012	14.2	27	11/27/2010	5.8
9	6/12/2009	13.9	28	1/16/2011	5.7
10	1/17/2012	13.1	29	6/1/2011	5.6
11	7/13/2012	12.9	30	12/19/2010	5.5
12	11/18/2010	12.6	31	12/29/2011	5.5
13	1/2/2009	12.2	32	10/7/2010	4.8
14	3/22/2009	12.2	33	3/27/2010	4.7
15	11/14/2011	11.5	34	7/17/2010	4.1
16	2/10/2012	11.5	35	7/16/2012	3.1
17	8/5/2012	11.4	36	2/25/2012	2.3
18	9/11/2012	10.8	37	5/14/2009	0.4
19	9/9/2012	10.8	**Total**		**365.0**

Figure C-3. The hourly distribution of wind, solar, load, and net load for historical and representative days



C.2 External Load & Resources

In this study, three MISO Load Resource Zones (LRZ) were modeled to represent Xcel Upper Midwest's interaction with the broader MISO market. The demand forecast for the external zones was based on data from the 2017 MISO Independent Load Forecast Update.[11] The assumed existing and planned resource portfolio was based on MISO's "Continued Fleet Change" in its 2018 MTEP report. The MTEP report only contains data till 2032, so beyond that this study assumes that coal plant retirements are replaced with natural gas combustion turbine generators.

Table C-2, Table C-3, and Table C-4 below show a summary of the load and resource assumptions for the three MISO zones modeled.

[11] MISO Independent Load Forecast Update, available at: https://www.purdue.edu/discoverypark/sufg/miso/reports-presentations.php

Table C-2. Load and resource assumptions for MISO LRZ 1*

	2018	2020	2025	2030	2035	2040	2045
Annual Energy (GWh)	59,791	60,390	61,915	63,478	65,081	66,725	68,409
Annual Peak Demand (MW)	9,608	9,704	9,949	10,201	10,458	10,722	10,993
	Installed Capacity (MW)						
Technology	**2018**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**
Nuclear	-	-	-	-	-	-	-
Coal	4,506	4,010	3,624	3,160	3,160	1,735	138
Gas	2,874	2,874	3,654	4,613	4,604	6,277	8,150
Biomass	225	225	225	225	225	225	225
Hydro	252	252	252	252	252	252	252
Wind	3,201	3,201	3,451	4,415	4,975	4,975	4,975
Solar	146	146	206	329	583	583	583
Storage	-	-	-	-	-	-	-
DR	559	559	559	587	645	645	645
Total	**11,267**	**11,267**	**11,971**	**13,580**	**14,443**	**14,691**	**14,968**

***The load and resources report here do not include resources owned or contracted by Xcel to serve its Upper Midwest customers**

Table C-3. Load and resource assumptions for MISO LRZ 2

	2018	2020	2025	2030	2035	2040	2045
Annual Energy (GWh)	69,451	69,729	70,429	71,136	71,850	72,572	73,301
Annual Peak Demand (MW)	13,029	13,081	13,213	13,345	13,479	13,614	13,751
	Installed Capacity (MW)						
Technology	**2018**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**
Nuclear	1,203	1,203	1,203	1,203	1,203	1,203	1,203
Coal	6,923	5,735	5,026	4,167	4,093	2,659	2,289
Gas	7,882	8,584	8,520	8,977	9,130	10,702	10,435
Biomass	105	105	105	105	105	105	105
Hydro	381	381	381	381	381	381	374
Wind	1,074	1,074	1,190	1,409	1,630	1,630	1,630
Solar	2	2	82	243	614	614	614
Storage	-	-	-	-	-	-	-
DR	1.211	1,441	1,441	1,501	1,630	1,630	1,630
Total	**18,780**	**18,524**	**17,947**	**17,986**	**18,786**	**18,924**	**18,280**

Table C-4. Load and resource assumptions for MISO LRZ 3

	2018	2020	2025	2030	2035	2040	2045
Annual Energy (GWh)	47,939	48,323	49,298	50,291	51,305	52,340	53,395
Annual Peak Demand (MW)	8,922	8,994	9,175	9,360	9,549	9,741	9,937
	Installed Capacity (MW)						
Technology	**2018**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**
Nuclear	640	640	640	640	640	640	640
Coal	5,140	5,140	4,927	4,654	4,619	2,473	839
Gas	3,603	3,603	3,849	4,499	4,714	6,989	8,508
Biomass	7	7	7	7	7	7	7
Hydro	7	7	7	7	7	7	7
Wind	7,106	7,306	7,610	8,929	10,100	10,100	10,100
Solar	8	8	140	404	860	860	860
Storage	-	-	-	-	-	-	-
DR	684	684	684	720	798	798	798
Total	**17,194**	**17,394**	**17,864**	**19,860**	**21,745**	**21,875**	**21,759**

Appendix D. Detailed Scenario Results

This section shows detailed results for each scenario and sensitivity analyzed.

D.1 Base Case Portfolios

Table D-1. Total installed capacity in 2030 by scenario (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	1,738	1,028	3,009	984	30	291	2,627	4,320	150	1,532	887
Scenario 1	1,738	1,028	3,009	984	30	291	4,097	5,830	1,876	1,532	887
Scenario 2	1,738	517	3,009	1,141	30	291	2,627	4,320	531	1,532	887
Scenario 3	1,738	—	3,009	1,882	30	291	2,627	4,320	286	1,532	887
Scenario 4	1,738	1,028	3,009	984	30	291	3,977	5,467	2,035	1,532	1,027
Scenario 5	1,738	517	3,009	984	30	291	2,627	4,320	438	1,532	1,027
Scenario 6	1,738	—	3,009	984	30	291	2,627	4,320	892	1,532	1,101
Scenario 7	1,738	1,028	2,174	984	30	291	3,821	5,283	2,159	1,532	1,148
Scenario 8	1,738	517	2,174	984	30	291	2,627	4,320	1,154	1,532	1,148
Scenario 9	1,738	—	2,174	984	30	291	2,627	4,320	1,801	1,666	1,148
Scenario 10	1,738	1,028	3,009	984	30	291	4,254	5,723	1,924	1,532	887
Scenario 11	1,738	517	3,009	1,141	30	291	2,627	4,320	531	1,532	887
Scenario 12	1,738	—	3,009	1,882	30	291	2,627	4,320	286	1,532	887
Scenario 13	1,738	1,028	3,009	984	30	291	4,113	5,988	2,126	1,532	887
Scenario 14	1,738	517	3,009	1,141	30	291	2,627	4,320	531	1,532	887
Scenario 15	1,738	—	3,009	1,882	30	291	2,627	4,320	286	1,532	887
Scenario 16	646	1,028	3,009	984	30	291	5,181	7,907	2,387	1,532	887
Scenario 17	646	517	3,009	1,375	30	291	4,055	4,930	1,063	1,532	887
Scenario 18	646	—	3,009	2,520	30	291	3,435	4,320	531	1,532	887
Scenario 19	1,738	1,028	3,009	984	30	291	4,194	5,906	2,252	1,532	887
Scenario 20	1,738	517	3,009	984	30	291	2,627	4,320	718	1,532	887
Scenario 21	1,738	—	3,009	984	30	291	2,627	4,320	1,273	1,666	887

Table D-2. Total installed capacity in 2045 by scenario (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	3,518	4	278	4,703	3,995	1,599	1,419	1,178
Scenario 1	—	—	2,711	1,690	4	278	7,252	8,706	3,032	1,419	1,178
Scenario 2	—	—	2,711	1,938	4	278	6,727	8,147	2,786	1,419	1,178
Scenario 3	—	—	2,711	2,105	4	278	6,386	8,357	2,484	1,419	1,178
Scenario 4	—	—	2,711	232	4	278	9,182	7,953	4,968	2,020	1,416
Scenario 5	—	—	2,711	232	4	278	9,260	6,872	5,636	2,096	1,416
Scenario 6	—	—	2,711	232	4	278	8,696	6,653	5,589	2,096	1,490
Scenario 7	—	—	1,876	232	4	278	10,002	7,654	8,346	2,096	1,537
Scenario 8	—	—	1,876	232	4	278	10,952	6,054	8,984	2,096	1,537
Scenario 9	—	—	1,876	232	4	278	11,213	5,881	8,885	2,096	1,537
Scenario 10	646	—	2,711	1,457	4	278	6,150	7,668	2,819	1,419	1,178
Scenario 11	646	—	2,711	1,672	4	278	6,366	6,772	2,484	1,419	1,178
Scenario 12	646	—	2,711	1,850	4	278	5,840	6,975	2,273	1,419	1,178
Scenario 13	1,738	—	2,711	1,108	4	278	4,399	5,807	2,434	1,419	1,178
Scenario 14	1,738	—	2,711	1,269	4	278	5,023	4,907	2,187	1,419	1,178
Scenario 15	1,738	—	2,711	1,478	4	278	4,688	5,085	1,867	1,419	1,178
Scenario 16	—	—	2,711	1,693	4	278	7,220	8,716	3,032	1,419	1,178
Scenario 17	—	—	2,711	1,938	4	278	6,727	8,147	2,786	1,419	1,178
Scenario 18	—	—	2,711	2,105	4	278	6,386	8,357	2,484	1,419	1,178
Scenario 19	1,738	—	2,711	232	4	278	5,544	5,636	3,484	2,020	1,178
Scenario 20	1,738	—	2,711	232	4	278	6,783	4,484	3,726	1,789	1,178
Scenario 21	1,738	—	2,711	232	4	278	6,634	4,471	3,499	2,020	1,178

D.2 Sensitivity Analysis Portfolios

Table D-3. Total installed capacity in 2045 by scenario (Low Gas sensitivity) (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	3,948	4	278	2,688	3,995	1,558	1,419	1,178
Scenario 1	—	—	2,711	1,722	4	278	6,930	8,672	3,104	1,419	1,178
Scenario 2	—	—	2,711	1,947	4	278	6,185	8,207	2,967	1,419	1,178
Scenario 3	—	—	2,711	2,174	4	278	5,726	8,437	2,568	1,419	1,178
Scenario 4											
Scenario 5											
Scenario 6	—	—	2,711	232	4	278	8,682	6,114	5,589	2,096	1,537
Scenario 7											
Scenario 8											
Scenario 9	—	—	1,876	232	4	278	11,323	5,282	9,446	2,096	1,537
Scenario 10											
Scenario 11											
Scenario 12	646	—	2,711	1,830	4	278	5,138	7,108	2,484	1,419	1,178
Scenario 13											
Scenario 14											
Scenario 15	1,738	—	2,711	1,464	4	278	4,274	5,084	2,007	1,419	1,178
Scenario 16											
Scenario 17											
Scenario 18											
Scenario 19											
Scenario 20											
Scenario 21											

Table D-4. Total installed capacity in 2045 by scenario (High Gas sensitivity) (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	2,650	4	278	6,650	6,543	1,863	1,419	1,178
Scenario 1	—	—	2,711	1,633	4	278	7,496	8,827	3,023	1,419	1,178
Scenario 2	—	—	2,711	1,791	4	278	7,469	8,307	2,790	1,419	1,178
Scenario 3	—	—	2,711	1,978	4	278	7,112	8,369	2,484	1,419	1,178
Scenario 4											
Scenario 5											
Scenario 6	—	—	2,711	232	4	278	8,672	8,180	5,042	2,096	1,416
Scenario 7											
Scenario 8											
Scenario 9	—	—	1,876	232	4	278	11,179	7,219	7,454	2,096	1,537
Scenario 10											
Scenario 11											
Scenario 12	646	—	2,711	1,648	4	278	6,600	7,297	2,338	1,419	1,178
Scenario 13											
Scenario 14											
Scenario 15	1,738	—	2,711	1,289	4	278	5,510	5,545	1,863	1,419	1,178
Scenario 16											
Scenario 17											
Scenario 18											
Scenario 19											
Scenario 20											
Scenario 21											

Table D-5. Total installed capacity in 2045 by scenario (Low Technology Cost sensitivity) (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	1,883	4	278	7,688	7,208	2,842	1,419	1,178
Scenario 1	—	—	2,711	1,346	4	278	7,705	8,971	3,676	1,419	1,178
Scenario 2	—	—	2,711	1,561	4	278	7,688	8,453	3,221	1,419	1,178
Scenario 3	—	—	2,711	1,619	4	278	7,688	8,380	3,081	1,419	1,178
Scenario 4											
Scenario 5											
Scenario 6	—	—	2,711	232	4	278	9,368	8,431	5,866	2,020	1,276
Scenario 7											
Scenario 8											
Scenario 9	—	—	1,876	232	4	278	11,119	7,995	8,202	2,096	1,416
Scenario 10											
Scenario 11											
Scenario 12	646	—	2,711	1,264	4	278	7,350	7,156	2,940	1,419	1,178
Scenario 13											
Scenario 14											
Scenario 15	1,738	—	2,711	806	4	278	6,510	5,374	2,484	1,419	1,178
Scenario 16											
Scenario 17											
Scenario 18											
Scenario 19											
Scenario 20											
Scenario 21											

Table D-6. Total installed capacity in 2045 by scenario (High Technology Cost sensitivity) (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	5,212	4	278	2,688	3,995	67	1,419	1,178
Scenario 1	—	—	2,711	1,861	4	278	5,971	8,763	2,312	1,419	1,416
Scenario 2	—	—	2,711	2,607	4	278	4,536	8,674	1,847	1,419	1,276
Scenario 3	—	—	2,711	2,960	4	278	4,395	9,035	1,358	1,419	1,276
Scenario 4											
Scenario 5											
Scenario 6	—	—	2,711	232	4	278	8,173	6,791	5,202	2,096	1,563
Scenario 7											
Scenario 8											
Scenario 9	—	—	1,876	232	4	278	11,464	6,301	7,788	2,096	1,563
Scenario 10											
Scenario 11											
Scenario 12	646	—	2,711	2,737	4	278	3,808	7,685	1,152	1,419	1,276
Scenario 13											
Scenario 14											
Scenario 15	1,738	—	2,711	2,514	4	278	3,106	5,840	826	1,419	1,178
Scenario 16											
Scenario 17											
Scenario 18											
Scenario 19											
Scenario 20											
Scenario 21											

Table D-7. Total installed capacity in 2045 by scenario (High Electrification sensitivity) (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	10,779	4	278	7,688	4,891	3,418	1,419	1,178
Scenario 1	—	—	2,711	7,935	4	278	7,830	14,893	5,697	1,419	1,178
Scenario 2	—	—	2,711	7,973	4	278	7,688	14,862	5,697	1,419	1,178
Scenario 3	—	—	2,711	7,904	4	278	7,688	14,893	5,894	1,419	1,178
Scenario 4											
Scenario 5											
Scenario 6	—	—	2,711	232	4	278	24,349	9,156	33,603	2,096	1,537
Scenario 7											
Scenario 8											
Scenario 9	—	—	1,876	232	4	278	24,523	9,521	38,809	2,096	1,537
Scenario 10											
Scenario 11											
Scenario 12	646	—	2,711	7,539	4	278	7,688	13,401	5,697	1,419	1,178
Scenario 13											
Scenario 14											
Scenario 15	1,738	—	2,711	7,416	4	278	6,864	11,294	4,709	1,419	1,178
Scenario 16											
Scenario 17											
Scenario 18											
Scenario 19											
Scenario 20											
Scenario 21											

Table D-8. Total installed capacity in 2045 by scenario (Low Export sensitivity) (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	3,617	4	278	3,740	3,995	1,667	1,419	1,178
Scenario 1	—	—	2,711	1,608	4	278	6,800	8,257	3,679	1,419	1,178
Scenario 2	—	—	2,711	1,992	4	278	5,478	8,238	3,159	1,419	1,178
Scenario 3	—	—	2,711	2,089	4	278	5,110	8,433	3,026	1,419	1,178
Scenario 4											
Scenario 5											
Scenario 6	—	—	2,711	232	4	278	8,074	6,222	6,181	2,096	1,537
Scenario 7											
Scenario 8											
Scenario 9	—	—	1,876	232	4	278	8,901	5,880	11,538	2,096	1,537
Scenario 10											
Scenario 11											
Scenario 12	646	—	2,711	1,746	4	278	4,640	7,063	2,892	1,419	1,178
Scenario 13											
Scenario 14											
Scenario 15	1,738	—	2,711	1,319	4	278	3,771	5,067	2,427	1,419	1,178
Scenario 16											
Scenario 17											
Scenario 18											
Scenario 19											
Scenario 20											
Scenario 21											

Minnesota Decarbonization Scenarios

The Role of the Electric Sector

June 20, 2019

Prepared for Xcel Energy

By Energy and Environmental Economics, Inc.

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Sharad Bharadwaj

Amber Mahone

Contents

1 Background

The Next Generation Energy Act (NGEA), signed in 2007, sets greenhouse gas (GHG) emission targets for Minnesota of 80% reductions by 2050 relative to 2005 levels with interim targets of 15% reductions by 2015 and 30% reductions by 2025.

Xcel Energy Northern States Power (NSP) hired E3 to develop a set of long-term economy-wide, deep decarbonization scenarios for the state of Minnesota. These scenarios provide an exploration of the cross-sectoral implications of meeting economy-wide carbon reduction goals, and highlight the role of Xcel Energy, and the electric sector as a whole, in meeting the state's economy-wide carbon goal.

This report describes background, modeling approach, and results of the Minnesota economy-wide decarbonization scenario analysis. An additional E3 analysis focusing on Xcel Energy NSP system portfolio and reliability, is discussed in a separate report. The geography of each analysis is shown in Figure 1.

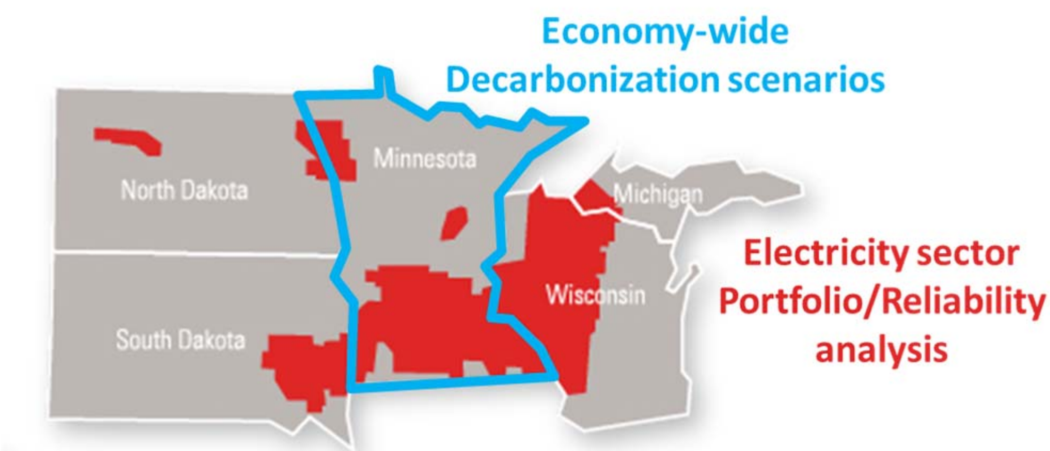

Figure 1. E3 Analysis Geographies for (1) Minnesota economy-wide decarbonization scenarios, and (2) Xcel Energy NSP portfolio and reliability analysis

Figure 2 shows all GHG emissions in the state of Minnesota by sector and subsector.[1] The largest sources of emissions in the state are electricity generation and transportation.[2] This analysis focused on the sectors that are most relevant to an electric utility: electricity generation, transportation, and buildings. Emissions from other sectors (agriculture, industry, and waste) were represented at a high level.

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[1] Data pulled from MPCA 2014 GHG Inventory

[2] This work was based on the Minnesota Pollution Control Agency (MPCA) 2014 greenhouse gas inventory. At the time of this report, the MPCA has released updated inventory data through 2016 and transportation is now the largest emitter of GHGs in the state.

Figure 2. Minnesota GHG emissions by category in 2014

2 Approach

2.1 PATHWAYS Model Philosophy

This study used a PATHWAYS model to develop the reference case emission projection. The PATHWAYS model is an economy-wide representation of infrastructure, energy use, and emissions within a specific jurisdiction. The PATHWAYS model represents bottom-up and user-defined emissions accounting scenarios to test "what if" questions around future energy and climate policies. PATHWAYS modeling typically includes the following features:

- Detailed stock rollover in residential, commercial and transportation subsectors
- Interactive effects with electricity demand and electricity supply sectors
- Sustainable biomass feedstock supply curves
- Non-combustion and non-energy emissions

The inclusion of both supply and demand sectors captures interactions between sectors such as increased penetration of electric vehicles and a changing mix of technologies supplying electricity. The focus of the Pathways model is to compare user-defined policy and market adoption scenarios and to track physical accounting of energy flows within all sectors of the economy.

2.2 PATHWAYS in LEAP

E3 built a bottom-up PATHWAYS model of the Minnesota economy using the LEAP tool (Long-range Energy Alternatives Planning system)[3]. This model quantifies the energy and emissions associated with the projected trends in energy use and complementary policies targeting future mitigated emissions. We modeled the period of 2015-2050.

LEAP is an integrated, scenario-based modeling tool that can be used to track energy consumption, production and resource extraction in all sectors of an economy. It can be used to account for both energy sector and non-energy sector greenhouse gas (GHG) emission sources and sinks. LEAP is not a model of a specific energy system, but rather a modeling framework that can be adapted for different jurisdictions.

[3] LEAP is developed by the Stockholm Environment Institute. More information on the LEAP software can be found at www.energycommunity.org

E3 built a model of Minnesota's energy and non-energy emission sources, projecting them through 2050 using different scenarios to understand current trajectories and different pathways that can be reached through complementary policies within the state.

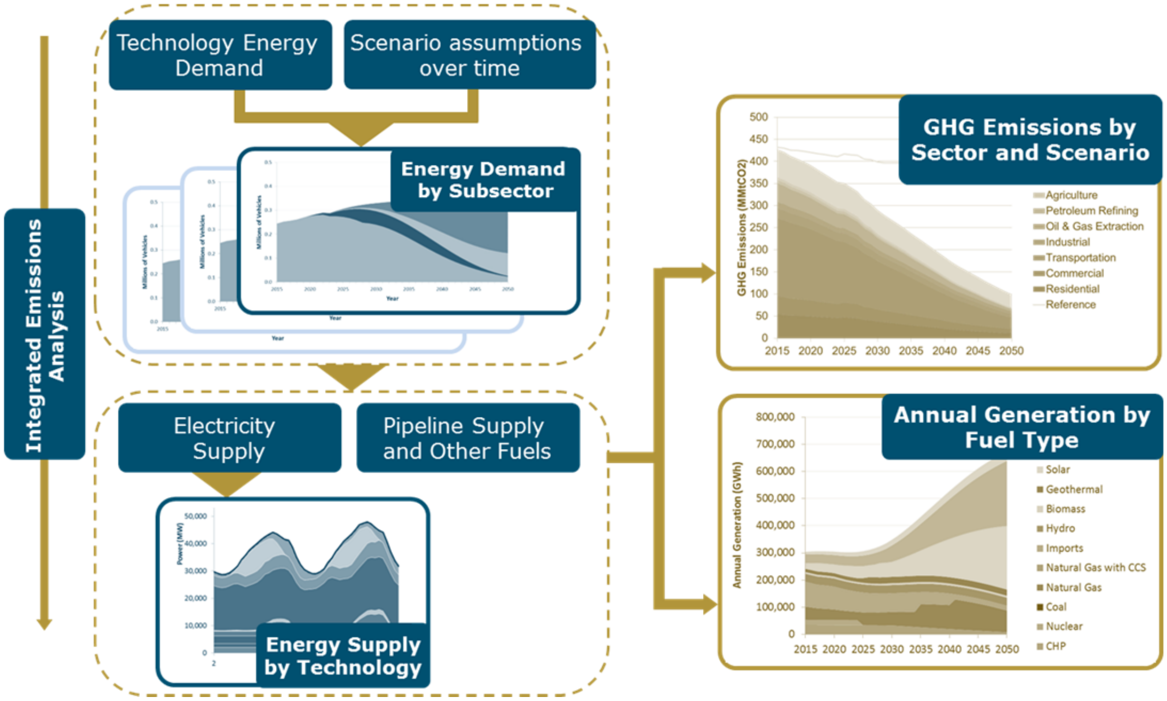

Figure 3. PATHWAYS Energy Modeling Framework

2.3 Scenarios

E3 modeled three scenarios to evaluate a range of emissions reductions from complementary policies.

- **Reference Scenario**: a current policy scenario, including utility-driven energy efficiency, expected adoption of zero emission vehicles, federal fuel economy standards for light-duty vehicles (LDVs)
- **High Electrification Scenario:** a mitigation scenario that includes increased adoption of electric and hydrogen vehicles in medium-duty vehicles (MDVs) and heavy-duty vehicles (HDVs) as well as electric space heating and water heating appliances in buildings.
- **High Biofuels Scenario:** a mitigation scenario that includes lower levels of electrification in favor of higher shares of low-carbon biofuels.

Table 1. Key Assumptions in all scenarios[4]

	Reference Scenario	**High Electrification Scenario**	**High Biofuels Scenario**
Carbon-free electricity generation	48% by 2025, held constant through 2050	48% by 2025, 90% by 2050	
Nuclear power	Retires at end of license	Relicensed or replaced with other carbon-free generation	
Building energy efficiency	50% of appliance sales are high-efficiency by 2030	100% of appliance sales are high-efficiency by 2030 100% adoption of efficient building shell/weatherization measures by 2030 15% reduction in non-stock energy below Reference Scenario by 2030, 30% by 2050 5% reduction in key demands due to smart appliances and conservation by 2030	
Sales of electric heat pump equipment	None	50% by 2030, 100% by 2050, replacing electric, natural gas and LPG	20-30% sales by 2030, replacing only electric and LPG equipment
Zero-emission vehicles	10% of sales by 2030 (Xcel "likely" sales forecast) for LDVs	LDVs: 50% by 2030, 100% by 2050 MDVs: 50% by 2030, 100% by 2050 HDVs: 40% by 2030, 100% by 2050	LDVs: 50% by 2030, 100% by 2050 MDVs: 50% by 2030, 80% by 2050 HDVs: 20% by 2030, 50% by 2050
Vehicle fuel economy	Federal CAFE standards for LDVs by 2026		
Conventional biofuels	20% biodiesel blend in diesel by 2018 (MN239.77); 30% ethanol blend in gasoline by 2025 (MN239.7911)	Transition to advanced biofuels by 2050	
Advanced Biofuels	None	Advanced biofuels without purpose-grown biomass feedstocks	Advanced biofuels with purpose-grown biomass feedstocks
Other sectors (agriculture, waste, industry)	Energy consumption grows at AEO 2017 reference scenario rates by fuel; non-energy GHG emissions held constant at MPCA 2014 Inventory levels	Reduction of 64% below 2005 GHG Emissions by 2050	Reduction of 69% below 2005 GHG Emissions by 2050

[4] More detailed assumptions are included in the sections that follow

In addition to mitigation scenarios, we developed three sensitivities to test the impact on emissions of federal action and consumer adoption. The three sensitivities were defined as follows and are documented further in Section 3.2.4:

1. **Efficiency, Electrification, and Clean Electricity Only**: Evaluates the impact of only pursuing building efficiency, high adoption of electric vehicles and household devices, and clean electricity towards meeting GHG targets
2. **No CAFE Extension**: Evaluates the impact of EPA's proposal to freeze federal Corporate Average Fuel Economy (CAFE) standards at 2020 levels.
3. **Lower Electric Adoption**: Evaluates the combined impact of lower consumer adoption of electric vehicles and electric household devices.

2.4 Inputs

To populate the Minnesota PATHWAYS model, we focused on in-state data sources where possible, supplementing with national data sets to fill remaining data gaps. Specific inputs are listed below.

2.4.1 FIRST YEAR EMISSIONS BENCHMARKING

In 2014, Minnesota had a population of 5.45 Million people residing in 2.1 Million households.[5] In each sector of the economy, we create a representation of a base year (2014) of infrastructure and energy, and then identify key variables that drive activity change over the duration of each scenario (2015-2050). Table 2 shows emissions benchmarking from the MN PATHWAYS model created for this analysis and the Pollution Control Agency (PCA) 2014 GHG Inventory.

[5] Source: Minnesota State Demographic Center

Table 2. Emissions Benchmarking in Minnesota PATHWAYS model to Minnesota PCA GHG inventory in 2014. MST = million short tons.

Sector	MPCA 2014 [MST CO2e]	PATHWAYS 2014 [MST CO2e]	Difference [MST CO2e]	Difference [%]
Buildings	19.0	19.0	0.0	0%
Transportation	39.1	39.2	0.1	0%
Electricity Generation	46.7	46.6	0.0	0%
Other	53.4	53.4	0.0	0%
Total	**158.2**	**158.2**	**0.0**	**0%**

2.4.2 KEY DRIVERS AND DEMOGRAPHICS

Each sector includes assumptions about key drivers of activity within that sector. Table 3 identifies the key drivers behind each sector's energy consumption in the reference scenario. Additional detail is available in the sections that follow.

Table 3. Key Drivers by PATHWAYS Sector in the Reference Scenario

Sector	**Key Driver**	**Compound annual growth rate [%]**	**Data Source**
Buildings	Population	0.44%	MN State Demography Center
Industry	Energy growth	Varies by fuel	EIA AEO 2018 growth rates (2018-2050)
On Road Transportation	Vehicle-miles traveled (VMT)	0.5% LDV 1.3% MDV 1.2% HDV	EIA AEO 2018
Off Road Transportation	Energy growth	Varies by fuel	EIA AEO 2018 growth rates (2018-2050)
Electricity Generation	Electric load growth	-0.1% average 2015-2030 (0.2% 2015-2050)	Built up from Pathways demands in Buildings, Industry, Transportation

The sections that follow will detail scenario assumptions for each key sector in the Minnesota PATHWAYS model.

2.4.3 BUILDINGS SECTOR

2.4.3.1 Base Year

The Minnesota LEAP model includes a stock-rollover representation of 17 residential and 10 commercial building subsectors, including space heating, water heating, and lighting. Sectoral energy demand is benchmarked to energy consumption by fuel from the Minnesota GHG inventory for 2014 and is disaggregated by subsector based on the EIA National Energy Modeling System (NEMS) technology characterization. All residential and commercial subsectors are listed in Table 4.

Table 4. Representation of 2014 Building Energy Consumption by Subsector in Minnesota

Sector	Subsector	Modeling Approach	Energy Use in 2014 [Tbtu]	Percent of 2014 Energy Use [%]
Residential	Central Air Conditioning	Stock Rollover	3.2	1%
	Room Air Conditioning	Stock Rollover	0.2	0%
	Building Shell	Stock Rollover	-	0%
	Clothes drying	Stock Rollover	4.7	1%
	Clothes washing	Stock Rollover	0.7	0%
	Cooking	Stock Rollover	5.7	1%
	Dishwashing	Stock Rollover	1.9	0%
	Freezing	Stock Rollover	1.7	0%
	Reflector Lighting	Stock Rollover	0.8	0%
	General Service Lighting	Stock Rollover	3.7	1%
	Exterior Lighting	Stock Rollover	0.6	0%
	Linear fluorescent lighting	Stock Rollover	0.6	0%
	Single Family Space Heating	Stock Rollover	103.6	23%
	Multi Family Space Heating	Stock Rollover	16.3	4%
	Refrigeration	Stock Rollover	7.7	2%
	Water heating	Stock Rollover	43.2	10%
	Residential Other*	Total Energy by Fuel	59.2	13%
Commercial	Air conditioning	Stock Rollover	1.9	0%
	Cooking	Stock Rollover	15.9	4%
	General service lighting	Stock Rollover	7.0	2%
	High intensity discharge lighting	Stock Rollover	7.5	2%
	Linear fluorescent lighting	Stock Rollover	7.6	2%
	Refrigeration	Stock Rollover	3.5	1%
	Space heating	Stock Rollover	66.5	15%
	Ventilation	Stock Rollover	9.5	2%
	Water Heating	Stock Rollover	7.5	2%
	Commercial Other*	Total Energy by Fuel	64.2	14%
All Building Sectors			**444.7**	**100%**

*Residential Other includes furnace fans, plug loads (e.g. computers, phones, speakers, printers), secondary heating, fireplaces, and outdoor grills. Commercial Other includes plug loads, office equipment, fireplaces, and outdoor grills.

2.4.3.2 Reference Scenario

The primary reference measure represented in buildings is the achievement of electric energy efficiency. Energy efficiency in buildings is implemented in the PATHWAYS model in one of three ways:

1. As new appliance or lighting end use technology used in the residential and commercial sectors (e.g., a greater share of high efficiency appliances is assumed to be purchased). New equipment is typically assumed to replace existing equipment “on burn-out”, e.g., at the end of the useful lifetime of existing equipment.

2. As a reduction in energy services demand, due to smart devices (e.g. programmable thermostats), conservation, or behavior change.
3. For the sectors that are not modeled using specific technology stocks (Residential Other and Commercial Other), energy efficiency is modeled as a reduction in total energy demand.

Table 5. Reference Scenario Assumptions for Building Energy Efficiency

Category of Building Measures	Reference Scenario Assumption
Building retrofits for high efficiency building shells	None
New appliance sales	50% of new sales of all appliances are assumed to be efficient (e.g. EnergyStar) by 2030. See Figure 4.
Building electrification	None
Behavioral conservation and smart devices	None
Other non-stock sectors	None

Since the model is based on a bottom-up forecast of technology stock changes in the residential and commercial sectors, the model does not use a single load forecast or energy efficiency savings forecast as a model input. It is important to note that the modeling assumptions used in this analysis may not reflect specific future energy efficiency programs or activities.

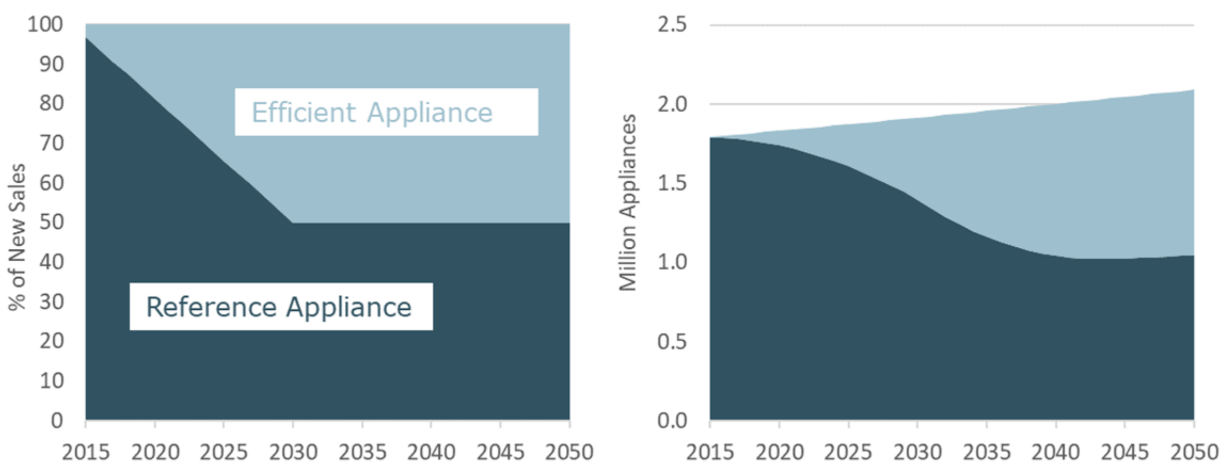

Figure 4. Assumed New Sales for Building Appliances (left) and Resulting Appliance Stocks (right), Reference Scenario

2.4.3.3 Mitigation Scenarios

Each Mitigation Scenario includes more aggressive energy efficiency and electrification in buildings. The High Electrification Scenario assumes more ambitious adoption of electric heat pumps for space heating and water heating, while the High Biofuels Scenario assumes electric heat pumps displace only existing electric and LPG equipment. See Table 6 for a full list of assumptions.

Table 6. Mitigation Scenario Assumptions for Building Energy Efficiency

Category of Building Measures	High Electrification Scenario	High Biofuels Scenario
Building retrofits for high efficiency building shells	100% adoption of efficient building shell and weatherization measures by 2030	
New appliance sales	100% of new sales of all appliances are assumed to be efficient (e.g. EnergyStar) by 2030.	
Building electrification	50% sales of electric heat pumps by 2030, 95% by 2050, replacing electric, natural gas and LPG systems	20-30% sales of electric heat pumps by 2030, replacing only electric and LPG equipment
Behavioral conservation and smart devices	10% reduction in energy services demand below Reference Scenario in residential lighting, space heating, and water heating	
Other non-stock sectors	30% reduction in energy consumption below Reference Scenario by 2050	

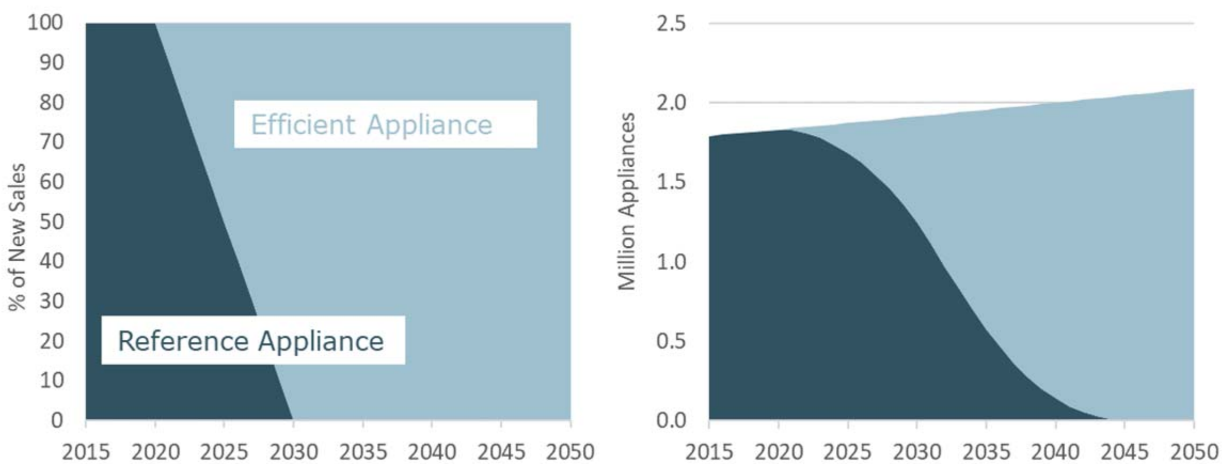

Figure 5. Assumed New Sales for Building Appliances (left) and Resulting Appliance Stocks (right), High Electrification Scenario

A key assumption across our scenarios is the adoption of high efficiency electric heat pumps for space heating and water heating. Currently in Minnesota electric heat pumps make up less than one percent of space heaters and water heaters.

In the High Biofuels Scenario we assume a shift to heat pump space heaters (20-30% of new sales by 2030), displacing sales of existing electric and LPG equipment. In the High Electrification Scenario, we assume significant adoption of heat pumps for both space heating and water heating, reducing sales of natural gas, existing electric, and LPG systems. The total number of electric heat pump space heaters in Minnesota residences is reported in Figure 6.

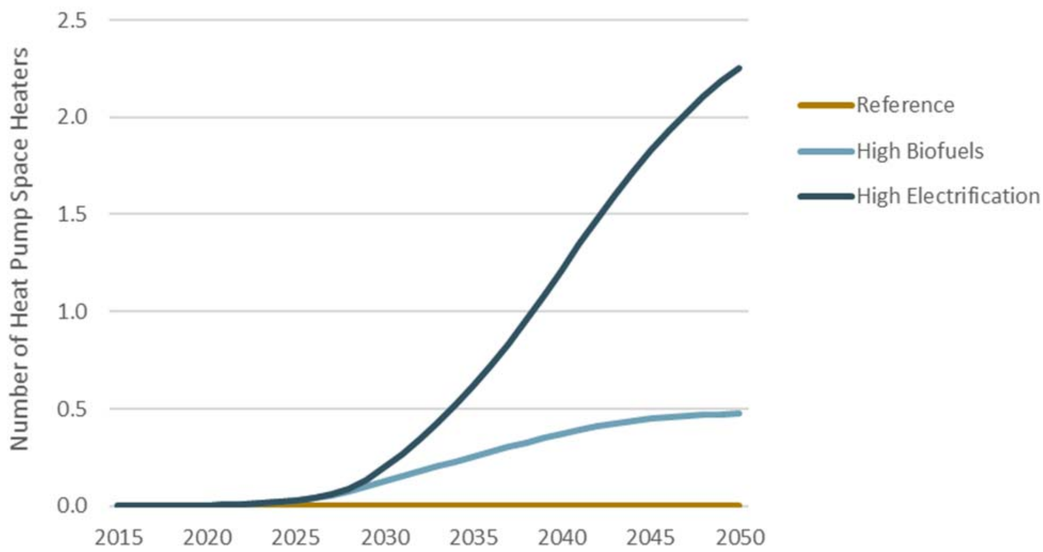

Figure 6. Total number of residential electric heat pump space heaters in all scenarios.

2.4.4 TRANSPORTATION SECTOR

2.4.4.1 Base Year

The Minnesota LEAP model includes a stock-rollover representation of four transportation sectors and an energy representation of six subsectors. Sectoral energy demand is benchmarked to energy consumption by fuel from the Minnesota GHG inventory for 2014 and is disaggregated by subsector based on the EIA National Energy Modeling System (NEMS) technology characterization and additional data from PCA. All subsectors represented in the transportation sector are listed in Table 7.

Table 7. Transportation 2014 Subsector Energy Consumption in Minnesota

Sector	Subsector	Modeling Approach	Estimated Energy Use in 2014 [TBtu]	Estimated % of 2014 Energy Use [%]
Light Duty Vehicles	Light Duty Autos	Stock Rollover	128	26%
	Light Duty Trucks	Stock Rollover	148	30%
Medium Duty Vehicles	Medium Duty Trucks	Stock Rollover	71	14%
Heavy Duty Vehicles	Heavy Duty Trucks	Stock Rollover	74	15%
Transportation Other	Aviation	Total Energy by Fuel	46	9%
	Rail	Total Energy by Fuel	15	3%
	Motorcycles	Total Energy by Fuel	3	1%
	Bus	Total Energy by Fuel	4	1%
	Military and Off-Highway	Total Energy by Fuel	7	1%
	Marine	Total Energy by Fuel	4	1%
All Transportation Sectors			**501**	**100%**

2.4.4.2 Reference Scenario

Two key measures were represented in the Minnesota PATHWAYS Reference Scenario: (1) Federal Light Duty Vehicle (LDV) Corporate Average Fuel Economy (CAFE) Standards, and (2) expected sales of zero-emission vehicles (ZEVs) in Minnesota. LDV CAFE Standards are represented in the marginal fuel economy of new gasoline vehicles sold in addition to an increased share of ZEVs sold. Increasing marginal fuel economy assumed is shown in Figure 7 for light-duty automobiles (LDA) and light-duty trucks (LDT).

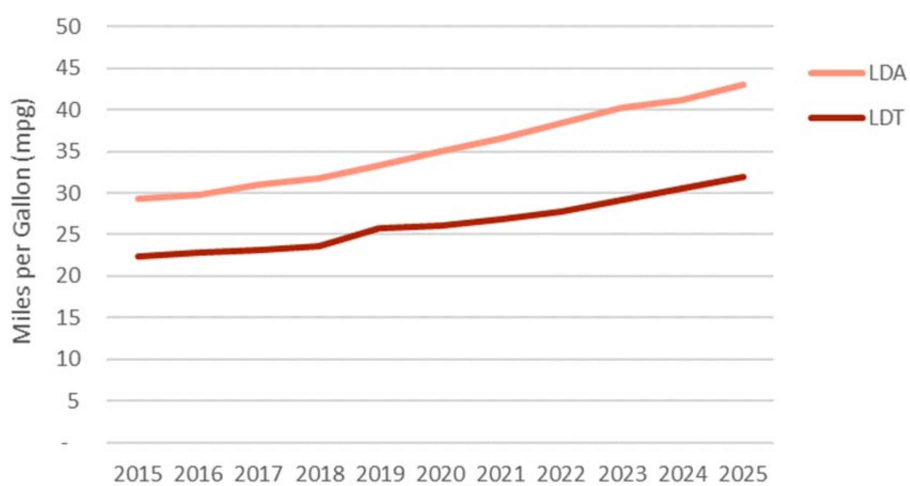

Figure 7. Marginal Fuel Economy for Gasoline LDVs in Minnesota

The second key measure, expected ZEVs in Minnesota, is represented through increasing sales of plug-in hybrid vehicles (PHEVs) and battery electric vehicles (BEVs) over time. We used Xcel Energy's "likely" sales of BEVs for their service territory and assumed that for the state of Minnesota. We assume that new sales increase linearly to be 20% ZEV sales by 2020. In our stock rollover methodology, this means that of all the cars that are purchased in 2020 (either due to retirement or new growth), 15% will be battery electric vehicles and 5% will be plug-in hybrid electric vehicles. This assumption is shown for light duty autos (LDAs) and light duty trucks (LDTs) in Figure 8. No changes were assumed in the heavy-duty fleet.

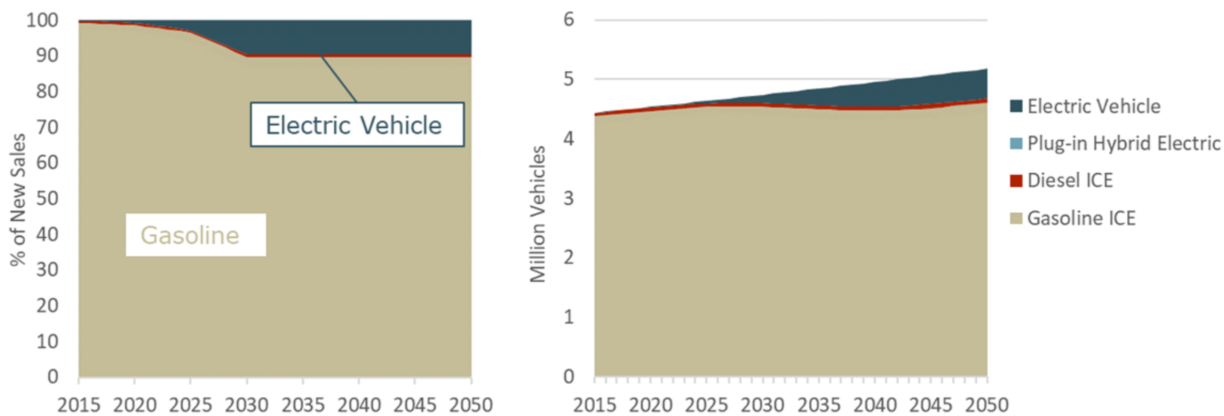

Figure 8. Assumed new light duty vehicle sales (left) and resulting stocks (right), Reference Scenario

In other subsectors of transportation, total energy consumption in Table 7 was assumed to grow at EIA AEO 2018 growth rates by fuel.

2.4.4.3 Mitigation Scenarios

Both Mitigation Scenarios assume significant reductions in light-duty vehicle-miles traveled (VMT), which could be achieved through urban design, transportation demand management, or mode shifting. Both scenarios assume aggressive electrification in light duty vehicles, up to 100% of new sales in 2050, representing no internal combustion vehicles being sold after that year. The High Electrification Scenario includes more aggressive zero-emission vehicle sales in medium- and heavy-duty vehicles, reaching 100% of new sales by 2050. The High Biofuels Scenario includes lower adoption of ZEVs in medium- and heavy-duty vehicles, where biofuels are assumed to be blended into transportation fuels.

Table 8. Mitigation Scenario Assumptions for Transportation

Category of Transportation Measures	High Electrification Scenario	High Biofuels Scenario
Vehicle Miles Traveled (VMT) reductions in light duty vehicles	Annual VMT is reduced by 15% below Reference by 2050	
Zero-emission Light Duty Vehicle (LDV) sales	50% sales by 2030, 100% by 2050	
Zero-emission Medium Duty Vehicle (MDV) sales	50% by 2030, 100% by 2050	50% by 2030, 80% by 2050
Zero-emission Heavy Duty Vehicle (HDV) sales	50% by 2030, 100% by 2050	20% by 2030, 50% by 2050
Aviation efficiency	Reduction in energy use of 40% below Reference Scenario by 2050	
Transportation Other	AEO 2018 reference scenario growth rates by fuel	

Assumptions for total new sales of light-duty vehicles and resulting total stocks is shown in Figure 9.

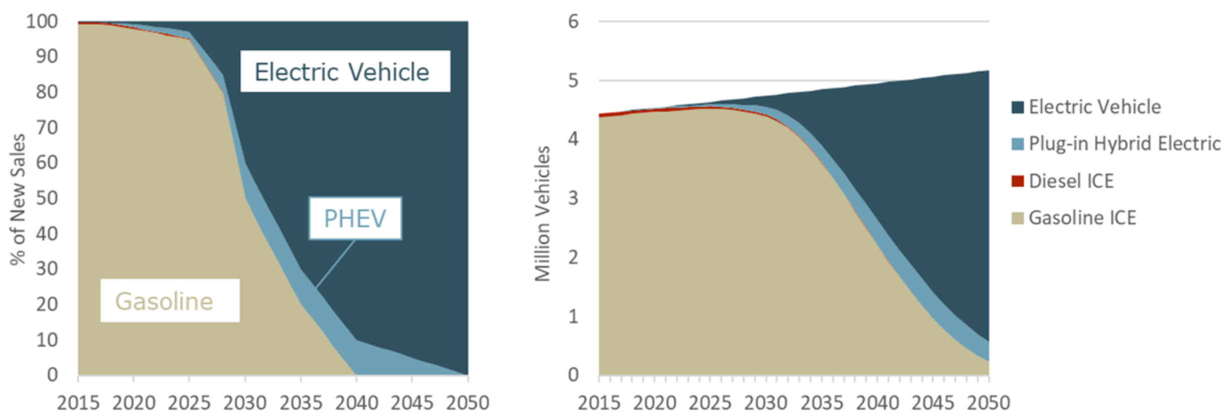

Figure 9. Assumed new light duty vehicle sales (left) and resulting stocks (right), High Electrification and High Biofuels Scenario

2.4.5 ELECTRICITY SECTOR

The Minnesota PATHWAYS model contains a dedicated branch for modeling electricity generation. Operations in the electricity sector are modeled on an annual basis, based on projected changes in electric capacity, generation, and changes in load. More detailed analysis of capacity expansion and operations for Xcel Energy Northern States Power were modeled in a parallel project with E3's RESOLVE and RECAP models.

2.4.5.1 Base Year

In-state generation capacity for Minnesota resources is based on EIA. Assumed generation by resource is shown in Table 9.

Table 9. Minnesota Electricity Generation in 2014[6]

Resource	Generation [TWh]	Share of 2014 Generation [%]
Nuclear	12.7	17%
Coal	28.0	38%
Natural Gas	3.9	5%
Oil	0.1	0%
Hydro	0.5	1%
Biomass	2.2	3%
Onshore Wind	9.7	13%
Utility Solar	0.0	0%
Net Imports	15.7	22%
Total	**72.7**	**100%**

2.4.5.2 Reference Scenario

In the Minnesota PATHWAYS model, total electricity demand is calculated from independent assumptions in each demand sector (buildings, transportation, industry, and agriculture). This approach ensures that we take into account linkages between sectors so that our generation and emissions from the electric sector are aligned with electrification loads in our mitigation scenarios. The Minnesota PATHWAYS model simulates dispatch of in-state generators and imported power from the Midcontinent Independent System Operator (MISO) to meet electricity demands in each year based on assumed percent shares of generation coming from generator types. All scenarios include an assumption of 6% transmission and distribution losses.

In the Reference Scenario, we assume that in-state nuclear facilities retire at the end of their license and are replaced with imported power. We assume moderate reductions in coal generation to reflect planned utility retirements. Table 10 shows the assumed share of electricity generation by resource.

Table 10. Assumed share of electricity generation by resource type, Reference Scenario

	2020	2030	2040	2050
Carbon-Free Generation*	43.6%	49.8%	33.7%	33.7%
Natural Gas	7.1%	10.0%	10.0%	10.0%
Oil	0.1%	0.1%	0.1%	0.1%
Coal	33.9%	30.0%	30.0%	30.0%

[6] US Energy Information Administration, Minnesota Electricity Profile, Table 5, full data available online: https://www.eia.gov/electricity/state/minnesota/index.php

Net Imports	15.3%	10.1%	26.2%	26.2%
Total	100.0%	100.0%	100.0%	100.0%

*Carbon-Free Generation includes utility-scale solar, onshore wind, biomass, hydro-electric, and nuclear generators

2.4.5.3 Mitigation Scenarios

Each Mitigation Scenario assumes significant ramp up of carbon-free generation over the next 30 years. Both Mitigation Scenarios are designed to meet the same share of carbon-free electricity by 2050, as shown in Table 11.

Table 11. Assumed share of electricity generation by resource type, Mitigation Scenarios

	2020	2030	2040	2050
Carbon-Free Generation*	42.5%	56.2%	73.6%	90.0%
Natural Gas	5.3%	5.3%	5.3%	5.3%
Oil	0.1%	0.0%	0.0%	0.0%
Coal	31.5%	20.0%	10.0%	0.0%
Net Imports	20.6%	18.4%	11.1%	4.7%
Total	100.0%	100.0%	100.0%	100.0%

*Carbon-Free Generation includes utility-scale solar, onshore wind, biomass, hydro-electric, and nuclear generators

Even though both scenarios have the same share of generation being met by carbon-free electricity, total generation is very different due to assumptions about electrification, as shown in Figure 10.

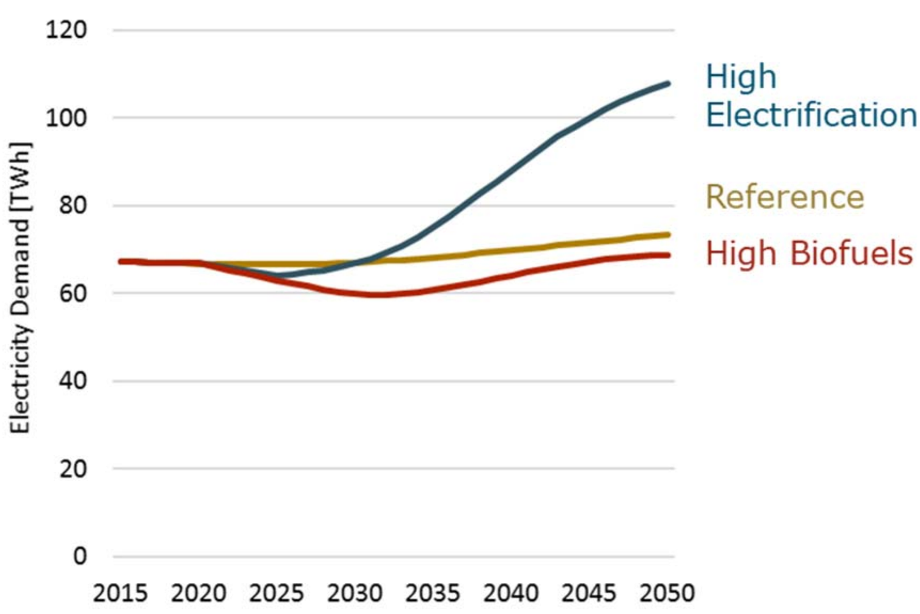

Figure 10. Electricity demand by scenario

2.4.6 BIOFUEL SUPPLY

The decarbonization transition will require strategic use of limited biomass and careful screening of sustainable feedstocks to ensure that bioenergy produces zero carbon emissions and is sustainably grown without producing adverse land-use impacts. Examples of biomass products that are used to produce biofuels include corn, soybeans, sugar cane, forest products, manure, switch grass and other agricultural waste products, such as corn stover.

Minnesota has a robust conventional biofuels industry that produces ethanol (from corn) and biodiesel (from soy and other waste oils). Our Reference Scenario assumes continued growth of the conventional biofuels industry, while our Mitigation Scenarios assume a transition after 2030 to an advanced biofuels industry. Note that both conventional biofuels and advanced biofuels are treated as having zero carbon emissions at the point of combustion from the Minnesota PCA Inventory accounting.

New sustainable biomass feedstock assessments are taken from the 2016 DOE Billion Ton Study (BTS) Update[7], which estimates sustainable yield of a variety of raw biomass sources, including agricultural (including dedicated energy crops), forestry (including new forests and residues), and waste streams (including municipal waste and forest residues).

2.4.6.1 Reference Scenario

The Reference Scenario assumes compliance with current targets for conventional ethanol and biodiesel. For ethanol, we assume a 30% blend of ethanol in motor gasoline by 2025.[8] For biodiesel we include the seasonal Minnesota B20 mandate, modeled as a 10% blend of biodiesel for the whole year.[9]

2.4.6.2 Mitigation Scenarios

In our Mitigation Scenarios, we assume a transition from conventional biofuel blends in the next 10 years to advanced biofuel production by 2050.

To determine available sustainable biomass supply through our study period, we assumed that Minnesota would have access to its population-weighted share of the total national feedstock supply, which is about 2% of the total supply. This approach assumes that all US states begin to transition to developing advanced biofuels with these resources. Minnesota has more biomass feedstocks within the state than its population-weighted share, which indicates that Minnesota would be able to sell excess biofuel products into a national market.

Figure 11 shows the national estimated biomass feedstock supply. The High Biofuel Scenario assumes that both residues and energy crops are available, while the High Electrification Scenario assumes only residue categories are available. The “Residues” category includes agricultural residues, food waste, forest residues, municipal solid waste, and manure. Residue feedstocks have fewer concerns about land-use constraints and competition with food crops.

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[7] DOE, 2016 Billion-Ton Report. Available online: https://www.energy.gov/eere/bioenergy/2016-billion-ton-report

[8] 239.7911 Petroleum Replacement Promotion: https://www.revisor.mn.gov/statutes/cite/239.7911

[9] 239.77 Biodiesel Content Mandate: https://www.revisor.mn.gov/statutes/cite/239.77

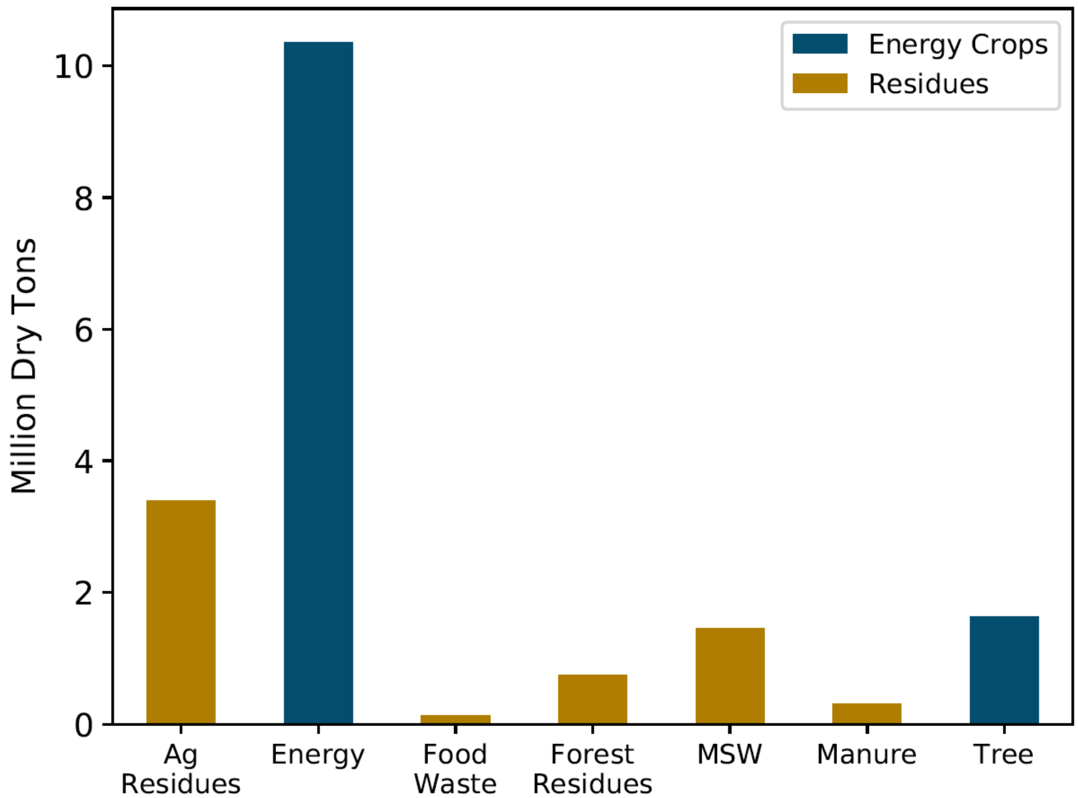


Figure 11. Minnesota Biomass Feedstock Supply by 2040 by Resource Category

To calculate the optimal portfolio of biofuels, E3 has developed a model which generates biofuel supply curves that determine the availability and cost of renewable liquid and gaseous fuels. The model optimizes the selection of combinations of feedstocks and conversion pathways. The model adds preparation, process, transportation, and delivery costs to BTS feedstock cost curves to achieve supply curves by feedstock and conversion pathway. To obtain biofuel demand, we apply the percentage biofuel penetration targets to aggregate calculated final energy demand.

Figure 12 shows the total resulting advanced biofuel consumption by fuel for each scenario. Because the High Biofuels Scenario includes feedstocks from energy crops and dedicated forests, that scenario is able to use more than two times the total quantity of biofuels than the High Electrification Scenario, which is limited to wastes and residues.

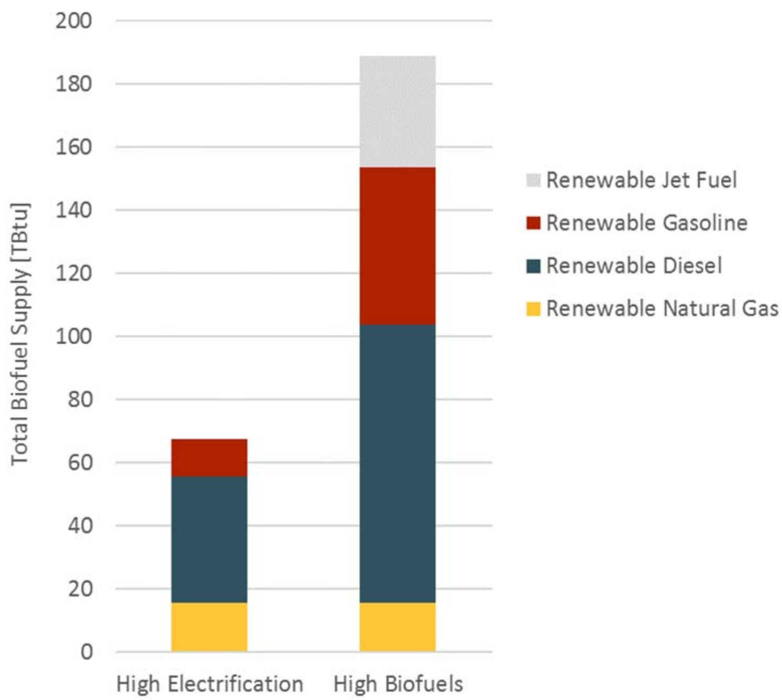


Figure 12. Total Advanced Biofuel Production by Biofuel in 2050, Mitigation Scenarios

Figure 12 highlights a different view of the same result, showing total consumption of gasoline, diesel, and natural gas by the share that is blended biofuel (and therefore zero-carbon) and the remaining share that is fossil.

2.4.7 OTHER SECTORS

This analysis focused in detail on the electricity generation, transportation, and buildings sectors. Additional sectors not modeled in significant detail are the agriculture, industry, and waste sectors.

2.4.7.1 Base Year

All energy consumption in industry, agriculture, and waste is represented as total annual energy consumption by fuel, as shown in Table 12.

Table 12. Energy Consumption in Industry, Agriculture, and Waste sectors by fuel in Minnesota, 2014

Sector	Fuel	Modeling Approach	Estimated Energy Use in 2014 [Tbtu]	Estimated % of 2014 Energy Use [%]
Industry (All Subsectors)	Electricity	Total Energy by Fuel	78.7	21%
	Gasoline	Total Energy by Fuel	2.7	1%
	Residual Fuel Oil	Total Energy by Fuel	0.1	0%
	Coal	Total Energy by Fuel	19.0	5%
	Petroleum Coke	Total Energy by Fuel	1.6	0%
	Refinery Feedstocks	Total Energy by Fuel	18.7	5%
	Wood	Total Energy by Fuel	27.2	7%
	Natural Gas	Total Energy by Fuel	154.1	41%
	LPG	Total Energy by Fuel	0.0	0%
	Diesel	Total Energy by Fuel	39.0	10%
	Renewable Diesel	Total Energy by Fuel	1.7	0%
	Coal Coke	Total Energy by Fuel	0.6	0%
Agriculture (All Subsectors)	Electricity	Total Energy by Fuel	-	0%
	Gasoline	Total Energy by Fuel	3.3	1%
	Natural Gas	Total Energy by Fuel	-	0%
	LPG	Total Energy by Fuel	10.5	3%
	Diesel	Total Energy by Fuel	16.4	4%
	Renewable Diesel	Total Energy by Fuel	0.7	0%
Waste (All Subsectors)	Natural Gas	Total Energy by Fuel	0.3	0%
	Diesel	Total Energy by Fuel	0.4	0%
	Renewable Diesel	Total Energy by Fuel	0.0	0%
All Sectors			**374.8**	**100%**

Additional non-energy emissions in industry, agriculture, and waste sectors were represented as total annual emissions, as shown in Table 13.

Table 13. Non-Energy Emissions in Industry, Agriculture, and Waste sectors in Minnesota, 2014

Sector	Fuel	Modeling Approach	Estimated Emissions 2014 [MST CO2e]	Estimated % of 2014 Non-Energy Emissions [%]
Agriculture	Animals	Total emissions	10.1	30%
	Crops	Total emissions	16.4	49%
	Other	Total emissions	0.0	0%
Industrial	Coal Storage	Total emissions	0.0	0%
	Industrial Process	Total emissions	0.6	2%
	Industrial Other	Total emissions	0.0	0%
	Oil Refining	Total emissions	0.0	0%
	Refinery Processes	Total emissions	1.7	5%
	Semiconductor Manufacture	Total emissions	0.3	1%
	Taconite Induration	Total emissions	2.1	6%
Waste	Industrial Landfills	Total emissions	0.1	0%
	Landfill gas combustion and flaring	Total emissions	0.0	0%
	MMSW Landfills	Total emissions	2.1	6%
	Medical	Total emissions	0.0	0%
	Rural Open Burning	Total emissions	0.0	0%
	Sludge	Total emissions	0.0	0%
	Waste Processing	Total emissions	0.2	1%
	Waste Solvent	Total emissions	0.0	0%
	Wastewater Treatment	Total emissions	0.4	1%
	Yard Waste Composting	Total emissions	0.0	0%
	Sequestration in landfills	Total emissions	-0.6	-2%
Total			33.7	100%

2.4.7.2 Reference Scenario

In the Reference Scenario, all energy consumption is assumed to grow at EIA AEO 2018 growth rates by fuel. All non-combustion emissions are held constant at 2014 levels.

2.4.7.3 Mitigation Scenarios

The overall approach for Mitigation Scenarios is to first calculate emission reductions from other sectors, and then to calculate the required reduction from remaining sectors in order to hit economy-wide NGEA goals by 2050. In both scenarios, we find that industry, agriculture, and waste sectors require a reduction that is lower than that in buildings, transportation, and electricity generation. This might be a fair assumption if it would be more expensive to decarbonize these sectors or if new technologies and measure would take longer to ramp up. The one specified assumption is that in the High Electrification Scenario, we assumed half of agricultural equipment could be electrified by 2050. Mitigation Scenario assumptions for other sectors are documented in Table 15.

Table 14. Mitigation Scenario Assumptions for Industry, Agriculture, Waste, and Non-Combustion Emissions

Category of Other Measures	**High Electrification Scenario**	**High Biofuels Scenario**
Electrification	50% of agricultural equipment energy use was assumed to be electrified by 2050.	None
Emissions Reductions for All Sectors below 2005 Levels	64%	69%

3 Results

3.1 GHG Emissions

Based on the assumptions outlined in Section 2 above, GHG emissions are calculated for Minnesota as shown in Figure 13. In the Reference Scenario, emission reductions are achieved in the initial years due to energy efficiency in buildings and transportation, as well as cleaner electricity generation. Emissions begin to rise after current policies no longer have an incremental effect and increased population and economic activity continue to increase energy use. Mitigation Scenarios fall short of the 2025 goal but meet the 2050 NGEA target.

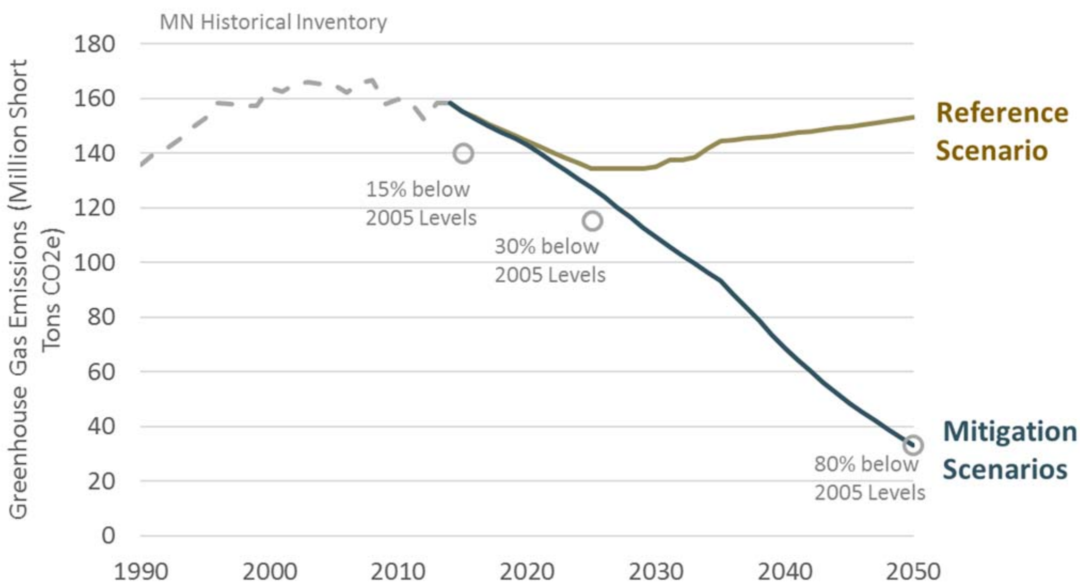


Figure 13. Minnesota GHG Emissions Results for Reference Scenario, 2015-2050

Emissions by Scenario are shown in Table 15 below.

Table 15. Total GHG Emissions by Scenario [Million Short Tons CO2e]

	2015	2020	2025	2030	2035	2040	2045	2050
Reference Scenario	155	144	134	135	144	147	150	153
High Electrification Scenario	155	143	127	109	93	69	48	33
High Biofuels Scenario	155	143	127	108	93	71	50	33
NGEA GHG Goals	140		115					33

Emissions for each modeled sector are shown over time in Figure 14 in the Reference Scenario. The largest direct reductions are in electricity generation, due to the retirement of in-state coal units and reduced demand due to efficiency, and transportation, due to federal CAFE standards and increased sales of ZEVs.

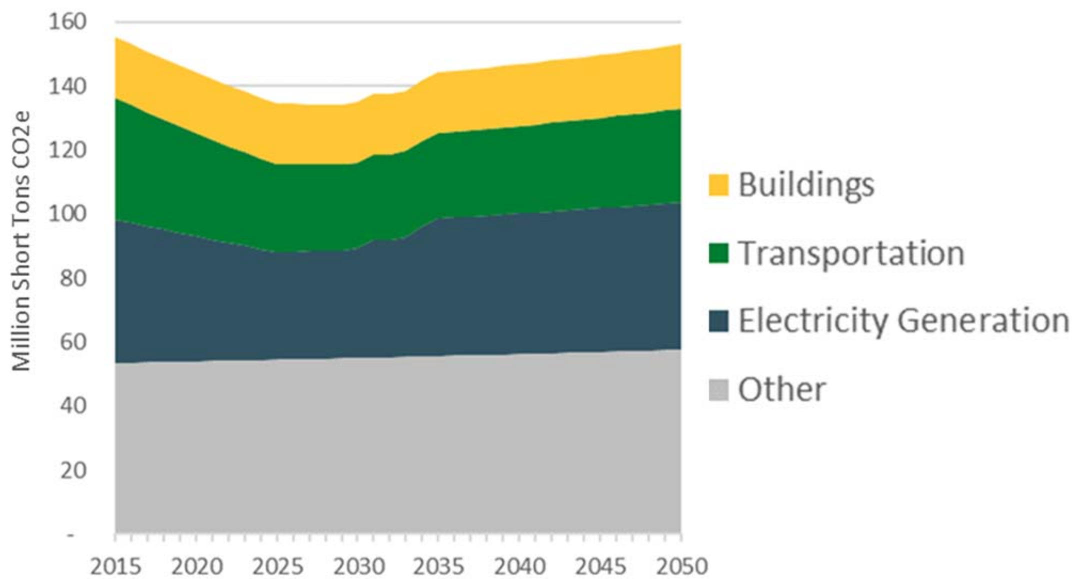


Figure 14. Minnesota GHG Emissions by Sector in the Reference Scenario, 2015-2050[10]

Emissions reductions by sector for each mitigation scenario is shown in Figure 15 and Increased electrification in the High Electrification scenario requires fewer reductions in "Other" sectors, but increases electricity generation demands, allowing for greater reductions in the High Biofuels Scenario.

Table 16. The High Electrification Scenario shows significant reductions in buildings and transportation due to adoption of electric appliances. The High Biofuels Scenario achieves fewer reductions in buildings and greater reductions in transportation due to allocating increased biofuels largely to on road vehicles.

[10] Other includes Agriculture, Industry, and Waste emissions

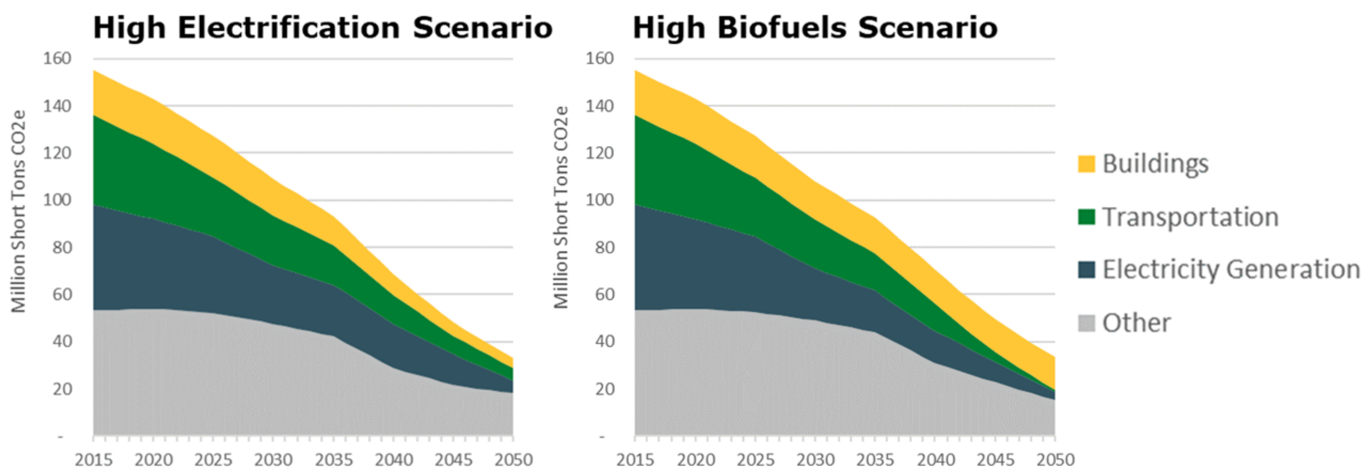


Figure 15. Minnesota GHG Emissions by Sector in Mitigation Scenarios, 2015-2050

Increased electrification in the High Electrification scenario requires fewer reductions in "Other" sectors, but increases electricity generation demands, allowing for greater reductions in the High Biofuels Scenario.

Table 16. GHG Reductions in Mitigation Scenarios in 2050 relative to 2005 emissions by sector

	High Electrification Scenario	High Biofuels Scenario
Buildings	-74%	-14%
Transportation	-87%	-98%
Electricity Generation	-91%	-94%
Other	-64%	-69%
Total	**-80%**	**-80%**

3.2 Sectoral Findings

3.2.1 BUILDINGS

The focus of measures in buildings is on energy efficiency and electrification. Increased sales of more efficient appliances and devices result in increased stock of those devices over time as old devices retire. Increased sales of efficient devices along with behavioral conservation and reductions in non-stock energy consumption results in significant reductions in total energy consumption as shown in Figure 16. Both scenarios achieve significant energy efficiency relative to the Reference Scenario, but the High Electrification Scenario achieves greater reductions in final energy consumption due to switching from natural gas appliances to more efficient electric heat pumps. Figure 16 also breaks out the impact of conventional efficiency and efficiency through electrification. The section between the black and grey lines highlights the reduction in building energy consumption from measures like improved device efficiency, improved building shell (e.g. insultation), and smart devices. The section below the grey line highlights the additional reduction in energy consumption from switching to high-efficiency electric heat pump technologies in space heating and water heating.[11]

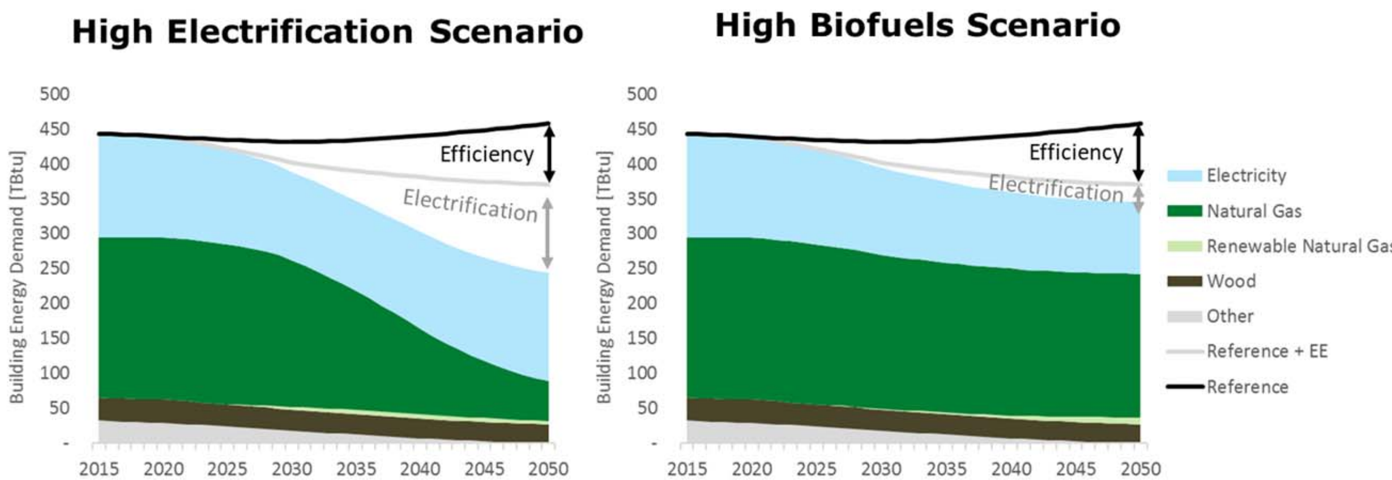


Figure 16. Total energy consumption by fuel and scenario in buildings

3.2.2 TRANSPORTATION

Reductions in emissions in the transportation sector are achieved through efficiency, electrification, and biofuels. Energy efficiency is included in two forms: (1) federal CAFE standards for new vehicle sales, and (2) VMT reductions due to transit and smart growth measures. New sales of vehicles with more efficient electric drive trains achieve significant efficiency and the potential to reduce emissions further by consuming cleaner electricity. Benefits of displacing fossil fuels with renewable diesel, renewable gasoline, and renewable jet fuel further reduces emissions within the transportation sector.

Figure 17 highlights the impacts of energy efficiency on total final energy demand in transportation. Both Mitigation Scenarios show significant reductions in total energy consumption relative to the Reference Scenario due to reductions in vehicle miles traveled and more efficient electric drive trains. In the High Electrification Scenario, hydrogen fuel cell heavy-duty trucks and electric medium-duty trucks are used. In the High Biofuels Scenario, advanced biofuels displace all remaining petroleum fuels by 2050.

[11] Note that these scenarios do not include a detailed analysis of electric heat pump performance in Minnesota.

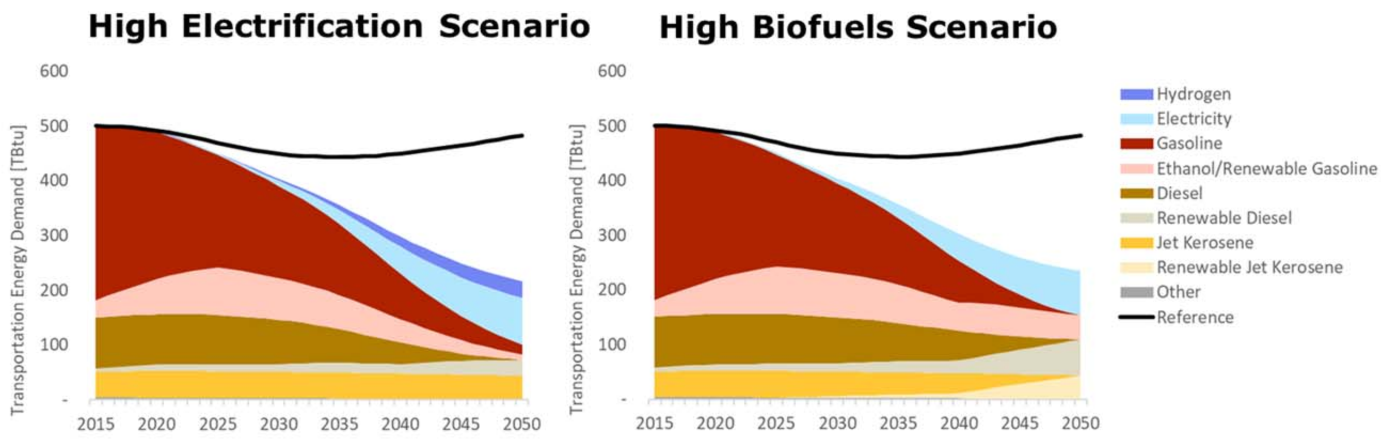


Figure 17. Total energy consumption by fuel and scenario in transportation

3.2.3 ELECTRICITY GENERATION

Each mitigation scenario has very different assumptions about adoption of electric technologies and therefore different projections of electricity demand, as shown in Figure 18. The High Electrification Scenario includes high adoption of electric household appliances, electric vehicles, and electrolysis to produce hydrogen for heavy-duty vehicles. The High Biofuels Scenario includes adoption of electric vehicles in light and medium duty vehicles, but lower electrification in other sectors. This leads to a load increase of 60% relative to 2015 in the High Electrification Scenario, and a much smaller load increase in the High Biofuels Scenario.

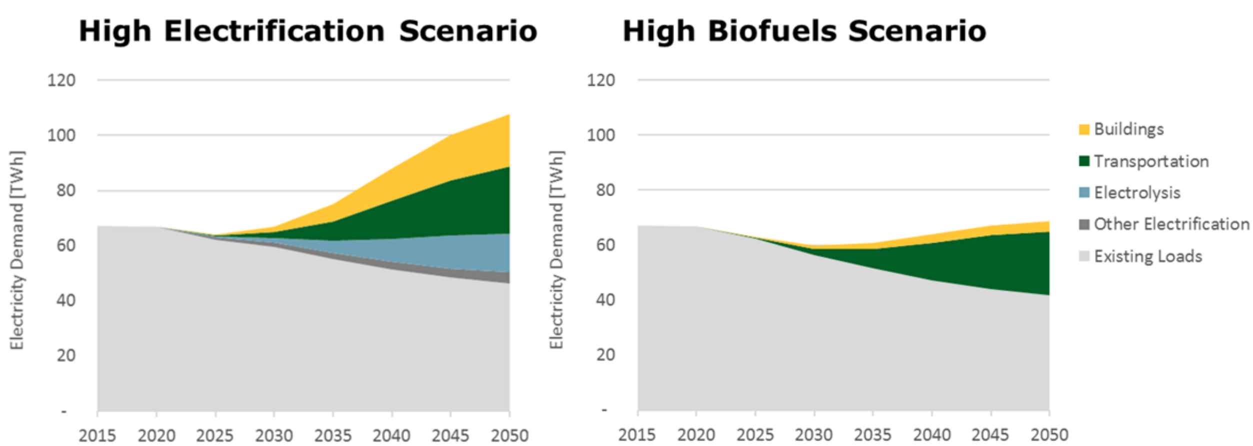


Figure 18. Electricity demand by sector and mitigation scenario

Demands for electricity determine required electricity generation. Each mitigation scenario achieves a 90% share of carbon-free electricity by 2050, but serves very different electricity demand, as shown in Figure 19.

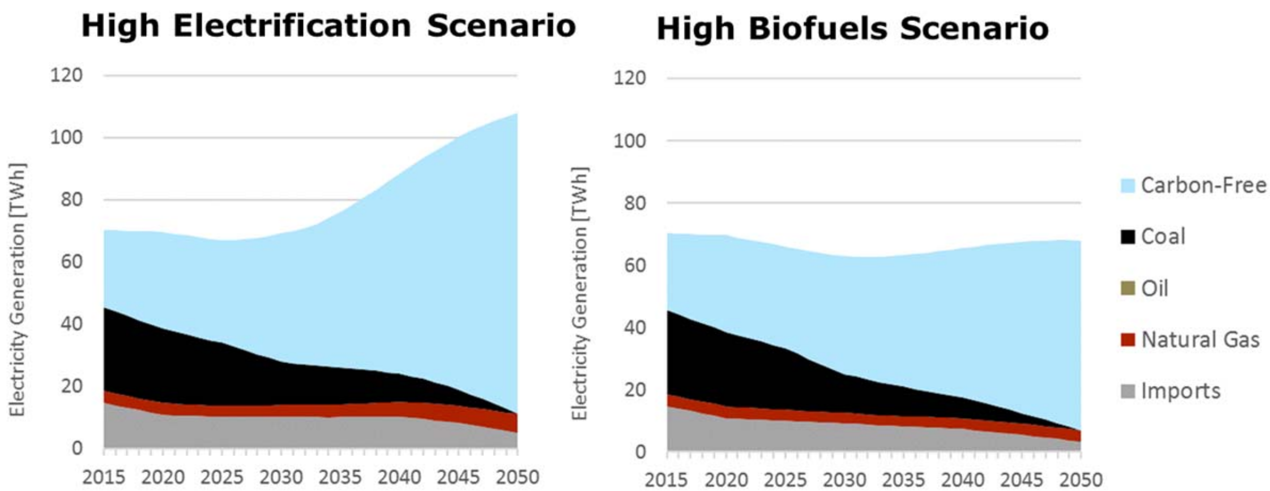


Figure 19. Total electricity generation by sources and mitigation scenario

Our accounting of GHG emissions aligns with the approach taken in the PCA's GHG Inventory, which accounts for all emissions from production of electricity in the electricity generation sector. In our scenarios, this shows a significant reduction in direct GHG reductions due to transitioning to carbon-free resources in our mitigation scenarios (see solid blue bars in Figure 20). In addition to those emission reductions, additional emissions are avoided in buildings and transportation, where electrification avoids emissions from direct combustion of natural gas, gasoline, and diesel fuels. Both Mitigation Scenarios reach 90% carbon-free electricity in 2050, but since the High Electrification scenario serves about 60% higher loads, total emissions in that scenario are 2 Million Short Tons higher, as shown in Table 17Table 18. Also shown are enabled emissions reductions in buildings and transportation in negative hatched bars, representing the petroleum and natural gas emissions avoided by switching to electric vehicles and appliances. Both Mitigation Scenarios see additional emission reductions due to electrification in buildings and transportation. The High Electrification scenario has increased direct electricity emissions of serving higher loads, but avoids an additional 20 MST CO2e elsewhere in the economy through electrification compared to the High Biofuels scenario

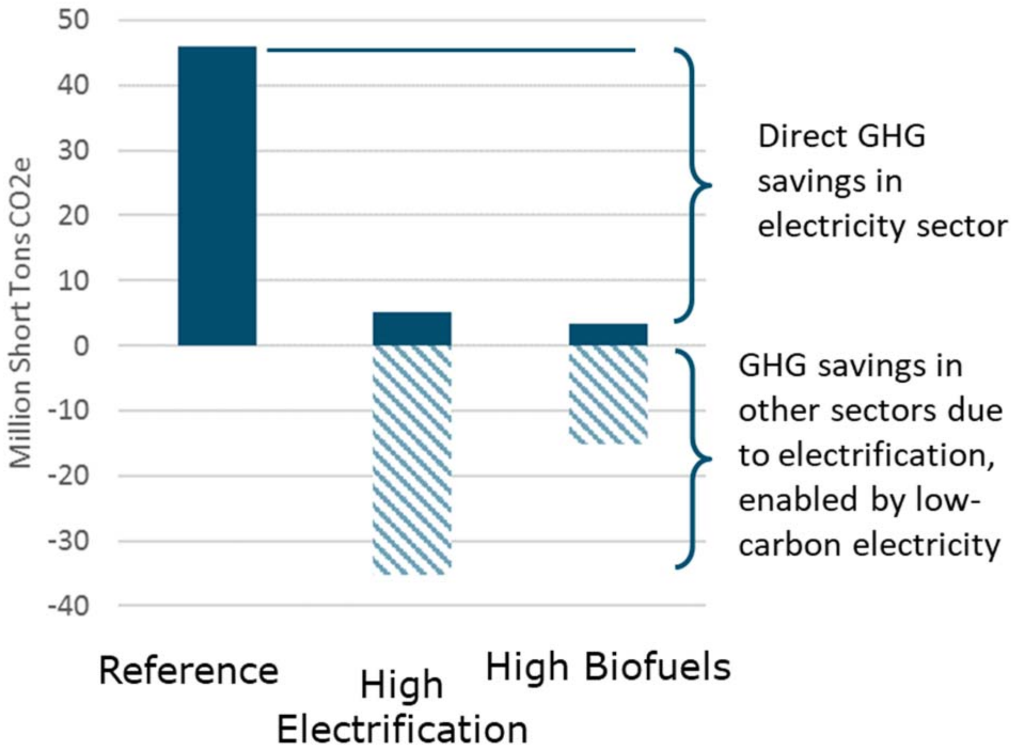


Figure 20. Electric sector GHG emissions by scenario in 2050

Table 17. Electric sector direct GHG emissions and indirect GHG reductions in 2050 [MST CO2e]

	Reference Scenario	High Electrification Scenario	High Biofuels Scenario
Total Direct Emissions from Electricity Generation	46	5	3
Total Emission Reductions from Other Sectors by Switching to Electric Devices		-35	-15

3.2.4 SENSITIVITY ANALYSIS

In addition to mitigation scenarios, we developed three sensitivities to test the impact on emissions of federal action and consumer adoption. The three sensitivities were defined as follows:

1. **Sensitivity #1: Efficiency, Electrification, and Clean Electricity Only**: Evaluates the impact of only pursuing building efficiency, high adoption of electric vehicles and household devices, and clean electricity towards meeting GHG targets
2. **Sensitivity #2: No CAFE Extension**: Evaluates the impact of freezing federal Corporate Average Fuel Economy (CAFE) standards from at 2020 levels.

3. **Sensitivity #3: Lower Electric Adoption**: Evaluates the combined impact of lower consumer adoption of electric vehicles and electric household devices.

3.2.4.1 Sensitivity #1: Efficiency, Electrification, and Clean Electricity

The first sensitivity we tested was a mitigation scenario that focused first on the emissions benefits of pursuing aggressive efficiency and electrification with higher shares of carbon-free electricity. This sensitivity is different from the High Electrification Scenario, which includes measures in other sectors such as industry, agriculture, and waste that allow the scenario to meet economy-wide goals

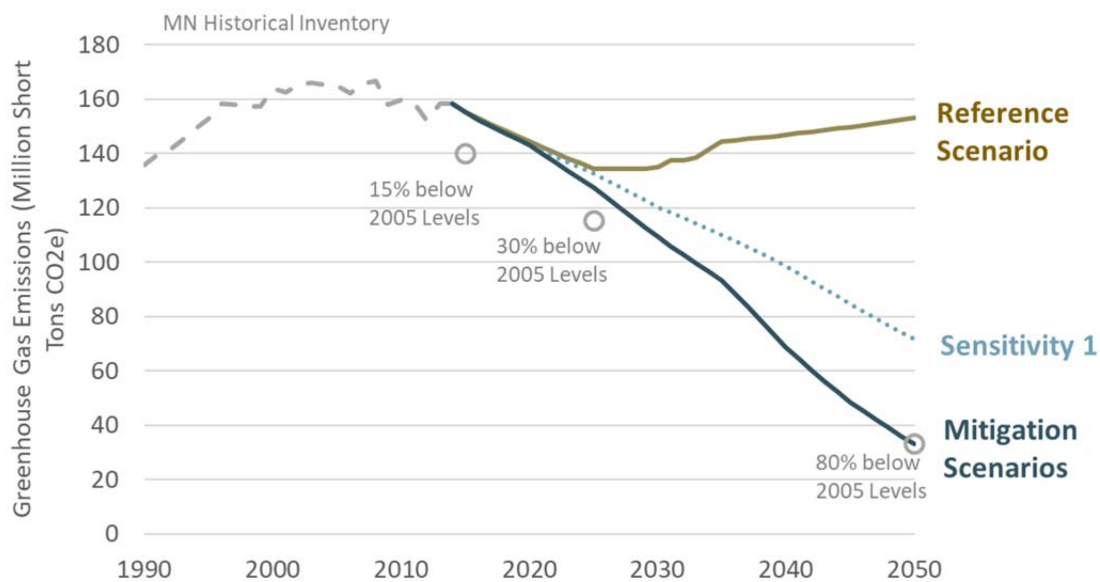


Figure 21. GHG Emissions from Sensitivity 1 relative to Reference and Mitigation Scenarios

This scenario highlights the need for additional measures and actions to meet the economy-wide GHG goal.

3.2.4.2 Sensitivity #2: No CAFE Extension

Federal Corporate Average Fuel Economy (CAFE) Standards impact the on-road efficiency of new light-duty vehicles sold in the US. The current federal administration has proposed freezing the standards at 2020 levels, removing the extension of the program from 2021 to 2026. We ran a sensitivity on our Reference Scenario and High Electrification Scenarios to quantify the impact of removing this federal program.

All scenarios benefit from CAFE improvements through 2020, but the sensitivity assumes no incremental improvement in new vehicles sold starting in 2021.

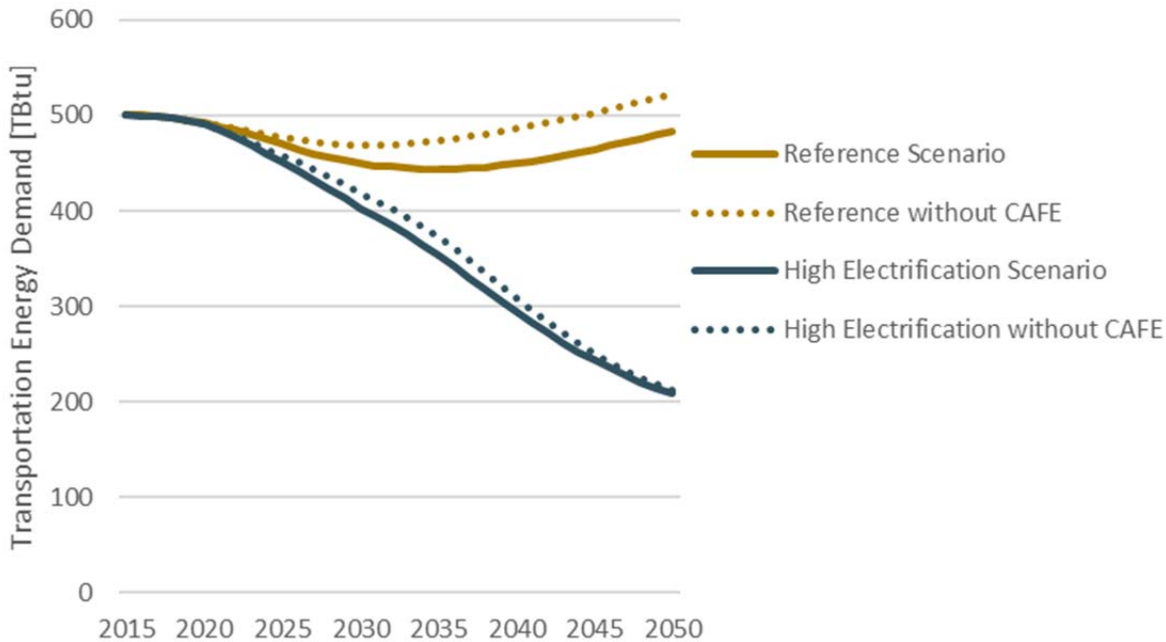


Figure 22. Total energy consumption in transportation by scenario and sensitivity

As shown in Figure 22, federal fuel economy standards have a larger impact on the Reference Scenario, which assumes more internal combustion engine vehicles are sold. Impacts are smaller in the High Electrification Scenario, especially by 2050, due to increasing share of electric vehicles on the road.

Emissions impacts are small relative to economy-wide emissions (see Figure 23). Incremental emissions are 1.5 MST CO2e in 2050 in the Reference Scenario and 0.1 MST CO2e in the High Electrification Scenario.

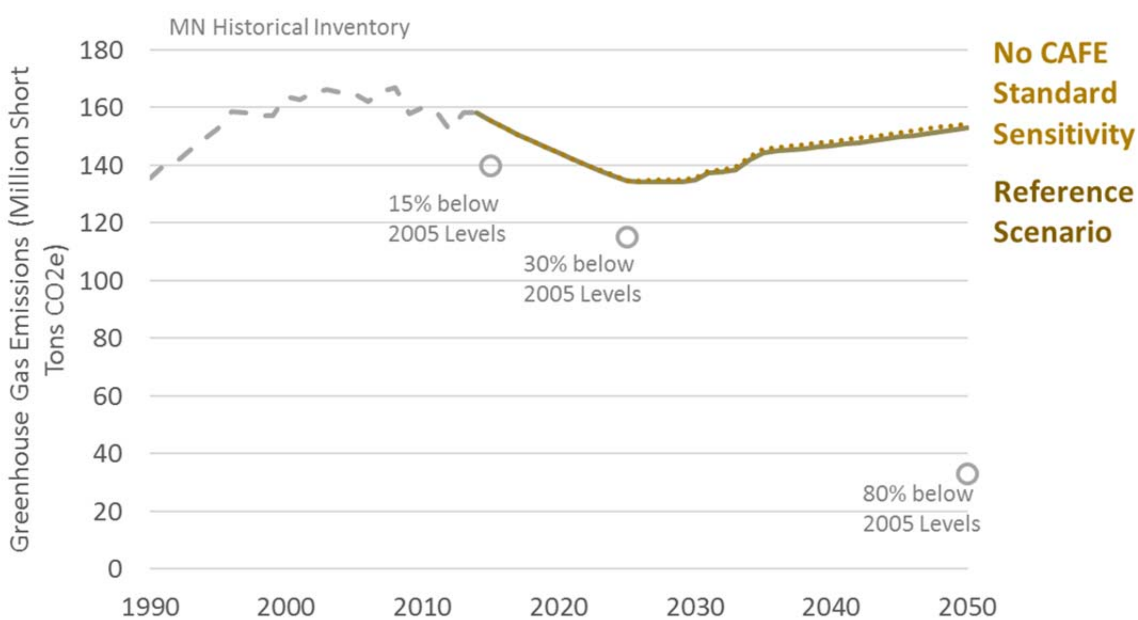


Figure 23. Total Minnesota GHG Emissions in the Reference Scenario and No CAFE Standard Extension Sensitivity

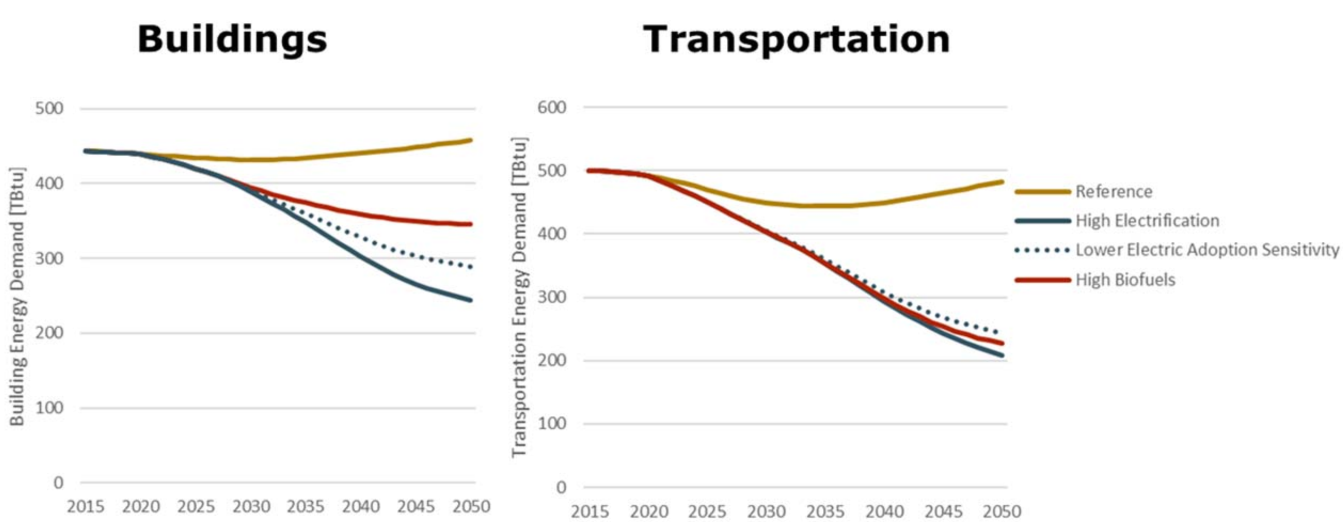
3.2.4.3 Sensitivity #3: Lower Electric Adoption

Rates of consumer adoption for new electric vehicles and electric appliances are uncertain. Our High Electrification Scenario assumes that no internal combustion engine vehicles or natural gas furnaces are sold by 2050. This sensitivity tests a lower level of adoption of key electric technologies, aligning with assumptions from NREL's Electrification Futures Study.[12] Full assumptions are shown in Table 18.

Table 18. New sales assumptions for key electric technologies in Mitigation Scenarios and Sensitivity #3 [% of new sales]

	High Electrification Scenario	High Biofuels Scenario	Lower Electric Adoption Sensitivity
Medium Duty ZEVs	100%	80%	60%
Heavy Duty ZEVs	100%	50%	40%
Heat Pumps in Residential Space Heating	100%	22%	80%
Heat Pumps in Residential Water Heating	100%	33%	30%
Heat Pumps in Commercial Space Heating	98%	2%	60%
Heat Pumps in Commercial Water Heating	100%	8%	30%

Impacts on energy consumption of the Lower Electric Adoption Sensitivity are shown by sector in Figure 24. The largest impacts are seen in buildings, representing the NREL assumption of lower adoption of heat pump water heaters and commercial space heaters than assumed in the High Electrification Scenario.



[12] Report available online: https://www.nrel.gov/docs/fy18osti/71500.pdf

Figure 24. Total energy consumption in buildings and transportation by scenario and sensitivity

Figure 25 shows the emissions gap of 7.9 MST CO2e in 2050 created by lower levels of adoption relative to the High Electrification Scenario. If adoption is lower than expected in the High Electrification Scenario, emissions in Minnesota will fall short of the 2050 NGEA goal and additional measures would need to compensate.

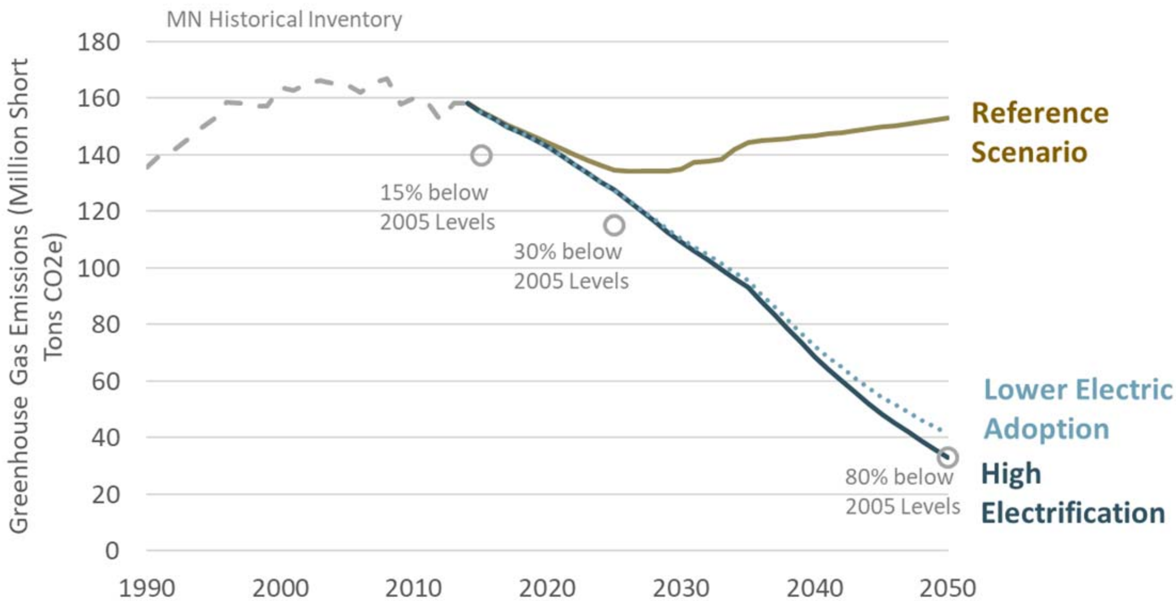


Figure 25. Total Minnesota GHG emissions in Lower Electric Adoption Sensitivity

3.3 Key Findings

The goal of this analysis was to develop a set of long-term economy-wide scenarios that reach the Next Generation Energy Act GHG emission targets for Minnesota of 80% reductions by 2050 relative to 2005 levels. These scenarios provide an exploration of the cross-sectoral implications of meeting economy-wide carbon reduction goals and highlight the role of the electric sector in meeting the state's economy-wide carbon goal. Based on the detailed analysis of Minnesota's statewide energy and emissions, we find the following:

Significant action is needed in every sector to decarbonize the state of Minnesota. This analysis highlights the need for aggressive action across all sectors of Minnesota's economy to meet a statewide goal of 80% reduction below 2005 levels. Reaching the NGEA goal of 80% GHG reductions by 2050 is challenging and will require significant effort beyond current policies within the state.

Buildings and transportation have significant potential to drive load growth, especially after 2025. The High Electrification Scenario highlights the significant potential for adoption of new electric appliances and vehicles, and the potential impact on total electricity requirements for Minnesota utilities. Transportation and building electrification drive electric load growth, especially after 2030, particularly in a future with less biofuels. Electrification of space heating has a particularly large impact on both total load (MWh) and peak demand (MW).

Reasonable electric rates and low costs for new electric devices are essential for electrification. The levels of electrification modeled in buildings and transportation are dependent on consumer adoption, which will benefit from reductions in capital costs and reasonable electric rates, even as the electric grid continues to decarbonize.

Electrification and zero-carbon electricity are necessary but not enough to reach statewide goals. Each Mitigation Scenario shows that increased reliance on low-carbon electricity enables emission reductions by avoiding direct combustion of fossil fuels in households, businesses, and vehicles. We also show that electrification and carbon-free electricity are necessary building blocks of a Mitigation Scenario but are not sufficient without additional measures and actions within the state.

This work highlights areas of future research. The scenarios modeled in this analysis represent an initial modeling assessment of required emission reductions in the state. This analysis has focused on emissions in electricity generation, buildings, and transportation, but further research is needed to explore building electrification impacts in Minnesota's climate and next steps for policy implementation within the state. In other sectors, further research is needed around opportunities in biofuels, agriculture, waste, and industrial sectors.