UPPER MIDWEST
LAW CENTER

February 10, 2021

Via E-filing

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101

Re: In the Matter of Xcel Energy's 2020-2034 Upper Midwest Integrated Resource Plan
Docket No. E-002/RP-19-368

Dear Mr. Seuffert:

I represent, along with my colleague Attorney James Dickey, also of the Upper Midwest Law Center ("UMLC"), the Center of the American Experiment ("CAE"), which wishes to offer comments on Xcel Energy's Supplemental Integrated Resource Plan at issue in this proceeding.

CAE's comments, prepared by Isaac Orr and Mitch Rolling of CAE, are attached hereto.

UMLC reserves the right on CAE's behalf, to submit further comments and replies to the comments of other parties through the close of the comment and reply period, currently set at April 12, 2021, and to proceed with any applicable appeals or challenges to any forthcoming decision of the PUC.

Respectfully,

Douglas Seaton, Esq., President of UMLC
Attorney for Center of American Experiment

Attachment

cc: Service List
James V.F. Dickey, Esq., UMLC
Isaac Orr, CAE
Mitch Rolling, CAE

8421 Wayzata Boulevard ★ Suite 105 ★ Golden Valley, MN 55426
612-428-7000 ★ Fax 763-710-7429 ★ UMWLC.org

Center of the American Experiment

8421 Wayzata Boulevard, Suite 110 | Golden Valley, MN 55426

Phone: 612-338-3605 | Fax: 612-338-3621 | Email: info@americanexperiment.org

Prepared by Isaac Orr and Mitch Rolling

Table of Contents

Center of the American Experiment submits the following comments in response to the supplemental integrated resource plan filed by Xcel Energy on June 30, 2020.

About Center of the American Experiment

Center of the American Experiment is Minnesota's leading public policy organization. The Center is more than a think tank. It researches and produces papers on Minnesota's economy, education, health care, energy, environment, employee freedom, and state and local governance. It also crafts and proposes creative solutions that emphasize free enterprise, limited government, personal responsibility and government accountability.

American Experiment's staff advances those solutions by drafting legislation, testifying before legislative committees, placing op-eds in newspapers and magazines across the state of Minnesota and nationally, appearing on radio and television news programs, holding town hall meetings, and lobbying. Furthermore, American Experiment conducts grassroots advertising campaigns on the radio and online, which bring the key findings of the Center's research papers to millions of Minnesotans. And the Center carries out investigative reporting, uncovering waste, abuse of power, and ineptitude in Minnesota's state and local governments, schools and unions.

For more than 30 years, Center of the American Experiment has been the most impactful and effective public policy organization in Minnesota. It leads the way in creating and advocating policies that make Minnesota a freer, more prosperous, and better-governed state.

Executive Summary and Policy Recommendations

Xcel Energy is currently seeking approval for a supplemental integrated resource plan (IRP) filed on June 30, 2020 [Docket No. E002/RP-19-368]. Xcel's intent with this IRP, as stated in the opening sentences of the introduction, is to chart "the path toward achieving some of the most ambitious carbon reduction goals of any utility in the U.S. Specifically — we aim to reduce carbon emissions 80 percent by 2030, and provide 100 percent carbon-free energy by 2050."

In this same IRP, Xcel states the following:

"In a future more reliant on non-dispatchable resources, a more detailed examination of total "all in" costs - costs for modifications to the transmission and distribution systems, and costs to provide necessary ancillary services - will be required. These considerations will ensure the decisions about future resources represent the most cost-effective approach to achieving reduced-carbon future."

The following report authored by Center of the American Experiment (American Experiment) aims to do exactly that: determine the “all-in” costs required to accommodate a transition to renewable energy, as Xcel’s supplemental plan seeks to do.

American Experiment has developed a model to calculate the additional costs or savings of Xcel’s resource plan compared to the current cost of providing electricity by Xcel.

For inputs, our model uses documents and filings provided by Xcel, the Federal Energy Regulatory Commission (FERC), and the Energy Information Administration (EIA). These sources provide the basis of our assumptions for current capacity and generation levels, future capacity additions and retirements, power purchase agreements (PPA), Levelized Cost of Energy (LCOE) values for existing and new energy sources, capital costs for new facilities, rate of return structure, property taxes, and per megawatt-hour (MWh) power plant CO_2 emissions. These assumptions are detailed in the “Assumptions” section in this report.

While many analyses of the future economics of utilizing non-dispatchable resources — or renewable energy sources such as wind and solar – focus on the Levelized Cost of Energy (LCOE) values for each resource, our study calculates expenses that LCOE estimates fail to consider.

Additional expenses considered in our study include utility returns and property taxes on new power plant infrastructure, as well as increased transmission expenses necessary to upgrade the electrical grid to accommodate larger levels of production from remote energy sources like wind and solar facilities. Furthermore, our model quantifies the cost of “load balancing” the grid for renewable energy generation — meaning it accounts for the cost of building and operating the backup energy sources required to maintain reliability on a grid powered by a significant amount of intermittent wind and solar electricity production.

We included these expenses because they give a more comprehensive view of the extra costs Minnesota ratepayers will endure if Xcel’s plan is approved.

Our model has found that the additional cost to ratepayers through 2050 would be over $57 billion — equating to an average annual increase of $1,428 per year for each Xcel customer. These costs include nearly $20 billion for additional generation costs, over $24 billion for additional utility profits, over $6 billion for additional property taxes, and just under $6 billion for transmission expenses.

As we detail in the pages below, the costs imposed on ratepayers by prematurely retiring Xcel’s existing coal fleet and building wind turbines and solar panels go far beyond the cost of producing renewable electricity.

Our model serves as the basis for our key findings:

Key Findings

Xcel Energy's proposed Integrated Resource Plan would:

- Increase Total Additional Costs Through 2050 by $57.131 Billion.
- Increase Average Annual Customer Bill by $1,428.
- Increase Total Additional Generation Costs by $19.712 billion.
- Increase Total Additional Property Taxes by $6.086 billion.
- Increase Total Additional Utility Profits - $24.243 billion.
- Increase the Average Cost per MWh from $41.66 to $64.81.
- Cause a Net Capacity Increase of 7,240 MW.
- Add a Total Capacity of 11,582 MW.
- Retire 4,342 MW of Capacity.
- Drop Grid Utilization Rate From 65.4 Percent to 36.3 Percent.
- Cost an Average of $135.11 per Short Ton of CO2 Reduced
- Increase the Renewable Energy Resource Mix From 23.6 Percent to 62.9 Percent.
- Increase the Carbon-Free Energy Resource Mix From 50.8 Percent to 89.2 Percent.
- Avert 422,862,788.5 Short Tons of Carbon Dioxide.

Policy Recommendations

We offer five policy recommendations based on our key findings:

1. **Recommendation 1:** The Commission should reject Xcel Energy's proposal to close Sherco 3 and A.S. King before the end of their engineering lives in 2035 and 2038, respectively.
    a. If the Commission approves these closures, Xcel should not be allowed to recover costs on the remaining book value of these projects. Xcel customers paid for these facilities with the intent of receiving their full value. Since Xcel plans to retire these facilities beforehand, ratepayers should not be required to pay for them.
2. **Recommendation 2:** Any proposed capacity addition that does not provide cost savings to ratepayers, meet future electricity demand growth, improve reliability, or satisfy legislative mandates should not be allowed into Xcel's rate base and charged to ratepayers.

3. **Recommendation 3**: Xcel should be required to analyze a more accurate RES Rate Impact Report. As it stands, the methodology of Xcel's rate impact report overestimates the cost of not having to comply with a renewable energy mandate, and thus underestimates the true rate impact of RES compliance. For instance, the RES Rate Impact Report replaces renewable additions that utility companies include in utility resource planning with non-renewable additions. However, in the absence of a renewable energy standard, little to no additional capacity would be required in its place. The RES Rate Impact Report should instead compare the cost of RES compliance with the cost of maintaining the existing grid including only the additions required to replace aging infrastructure.

Recommendation 4: Xcel should study the feasibility of replacing Sherco 3 and A.S. King with new nuclear generation facilities. This study should include existing technologies, such as the Korean APR 1400, and emerging technologies, such as small modular reactors.

Recommendation 5: Any non-dispatchable resource built by Xcel should be owned and operated through an unregulated subsidiary that generates no rate of return from captive ratepayers. These assets would sell into wholesale power markets.

Introduction

Center of the American Experiment's report consists of the following sections.

Section 1 discusses the impact that Xcel's resource plan and transition to renewable energy will have on ratepayers. Our analysis finds ratepayers will not see cost savings, and they will, on average, pay an additional $1,400 per year.

Section 2 argues that the PUC lacks a basis to approve Xcel Energy's proposed plan because it does not provide cost savings to consumers, is not necessary to meet an increase in electricity demand, does not improve reliability, and is not required to satisfy legislative mandates.

Section 3 details the likely environmental impact resulting from Xcel's resource plan. In this section, we demonstrate that the enormous cost of Xcel's IRP exceeds Minnesota's Social Cost of Carbon estimates, meaning the costs of averting carbon dioxide using the generation resources in the IRP outweigh the environmental benefits. Additionally, research from Harvard shows wind turbines cause high degrees of localized surface warming, which must also be considered as part of the IRP.

Sections 4 and 5 explain the impact that the retirement of Xcel's baseload facilities will have on the electrical system as a whole in terms of reliability and sustainability.

Section 6 details how the Renewable Energy Standard (RES) Rate Impact Report in Xcel's resource plan overestimates the cost of not having to comply with renewable energy mandates, and thus underestimates the additional cost of complying with Minnesota's renewable energy mandate. This demonstrates the need for a better metric for evaluating the difference in costs between relying on existing infrastructure and building new generating units to satisfy renewable energy requirements.

Section 7 highlights the results of two alternative scenarios conducted by our modeling. These scenarios replace wind and solar energy with that of nuclear power and they are designed to achieve the same level of carbon-free generation as the proposed IRP — one by 2030, and another by 2050. We demonstrate that achieving a carbon-free future using nuclear power instead of wind and solar would reduce the costs of Xcel's resource plan significantly.

Section 8 will give our conclusions and reiterate our policy recommendations for Xcel's resource plan.

Finally, section 9 details our assumptions and methodology for our modeling of Xcel's resource plan.

Section 1. Implications for Ratepayers for Xcel Energy Preferred Integrated Resource Plan

Xcel is the largest electric utility company in Minnesota, covering the most-populated areas within the state as the only available electricity provider. Any proposal Xcel puts forward regarding future capacity additions and retirements will have a direct impact on the cost of electricity for millions of Minnesotans.

Because Xcel is the largest provider and Minnesota families and businesses within their service territory are not able to switch providers, it is incredibly important to understand the cost of Xcel's resource plan and how it will affect ratepayers before it is implemented.

Furthermore, Xcel is currently the most expensive electric utility provider in the state of Minnesota, with residential electricity rates already far above the national average as Figure 1 shows.[1] In 2020, Xcel requested to raise rates by 20 percent over the next three years. Therefore, any further increase in the cost of electricity compounds the hardship experienced by millions of Minnesotans who will be forced to confront rising electricity bills.

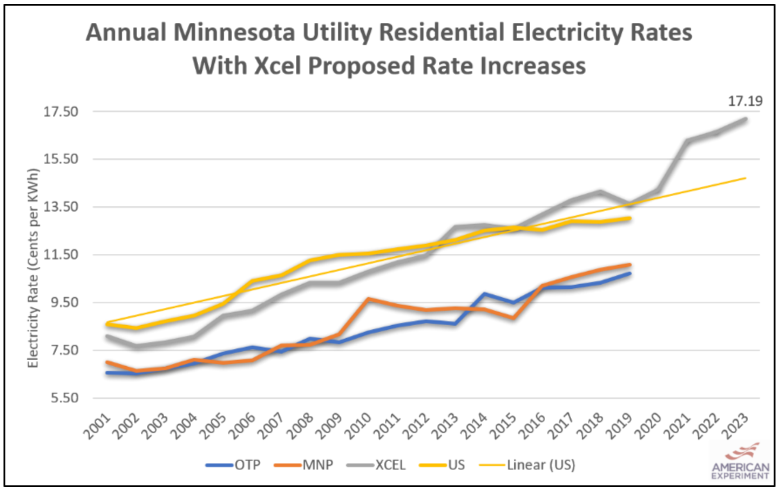


Figure 1. Data from the U.S. Energy Information Administration show residential electricity rates for Xcel Energy customers far exceed the rates paid by other Minnesota utilities. Xcel's rates are also higher than the national average, and this trend will grow worse if the PUC approves Xcel's proposal for a 20 percent rate increase.

Xcel's already high electricity rates are important to consider given Minnesota statue 216B.01 which states the following:

*"It is hereby declared to be in the public interest that public utilities be regulated as hereinafter provided in order to provide the retail consumers of natural gas and electric service in this state with adequate and reliable services **at reasonable rates**, consistent with the financial and economic requirements of public utilities and their need to construct facilities to provide such services or to otherwise obtain energy supplies, **to avoid unnecessary duplication of facilities which increase the cost of service to the consumer** and to minimize disputes between public utilities which may result in inconvenience or diminish efficiency in service to the consumers" **[Emphasis Added].***

Additionally, Minnesota Statute 216C.05 subd. 2(4) establishes a goal that rates for all classes be five percent below the national average.[2] Xcel Energy is already out of compliance with this statutory goal, and their preferred plan will continue to increase rates for all Xcel Energy customers, relative to the national average.

[1] Utility rate data is taken from U.S. Energy Information Administration Form 861 data.
[2] Minnesota State Statute 216C.05 subd. 2(4), https://www.revisor.mn.gov/statutes/cite/216C.05.

Xcel's electricity rates have been increasing primarily due to large renewable energy capacity additions, which unnecessarily duplicate capacity on the electrical grid because of the intermittent nature of wind turbines and solar panels.

For instance, electricity rates at Xcel have been steadily rising as more renewable energy is generated in Minnesota (See Figure 2). In fact, electricity rates were decreasing, in inflation-adjusted values, before the onset of large renewable energy source additions sparked by the passage of the Next Generation Energy Act (NGEA) in 2007.[3]

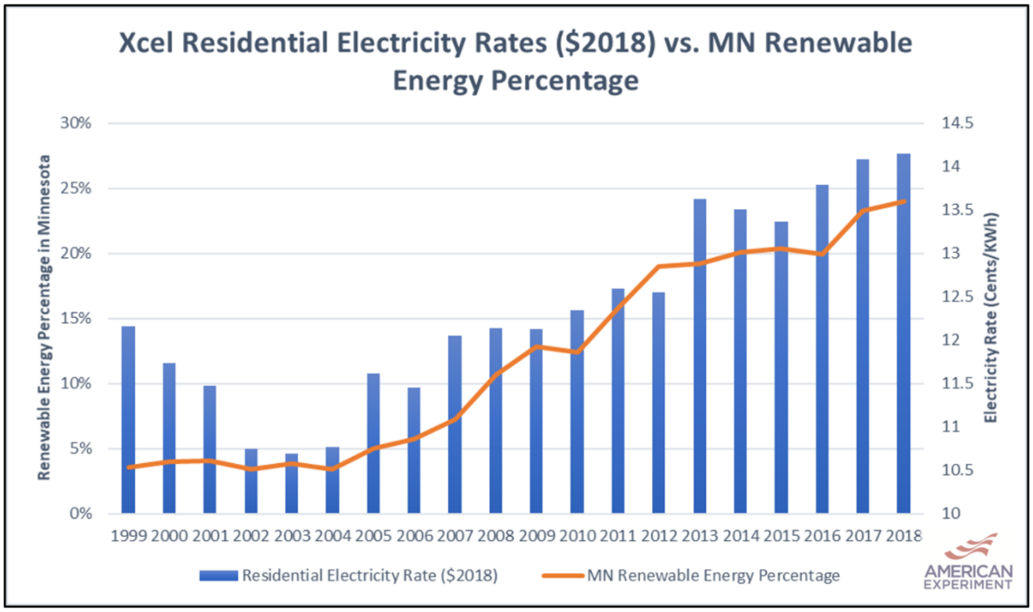


Figure 2. Residential electricity rates for Xcel Energy customers decreased in 2018 dollars from 1999 through 2003. In 2005, Xcel was required to build wind capacity as part of a deal to continue operating their nuclear fleet. Since that time, rate increases have been strongly correlated with rising renewable energy generation.

Industrial electricity prices have also been impacted by Xcel's rising electricity rates. In 2002, industrial electricity rates for Xcel were nearly 18 percent lower than the national average. Now, Xcel's industrial rates are nearly 18 percent *higher* than the national average. Xcel's industrial rates have increased by 100 percent from 2002 to 2019, rising 2.5 times faster than the national average (See Figure 3).

[3] EIA Form 861 Utility Rate Data and EIA Minnesota Electricity Profiles.

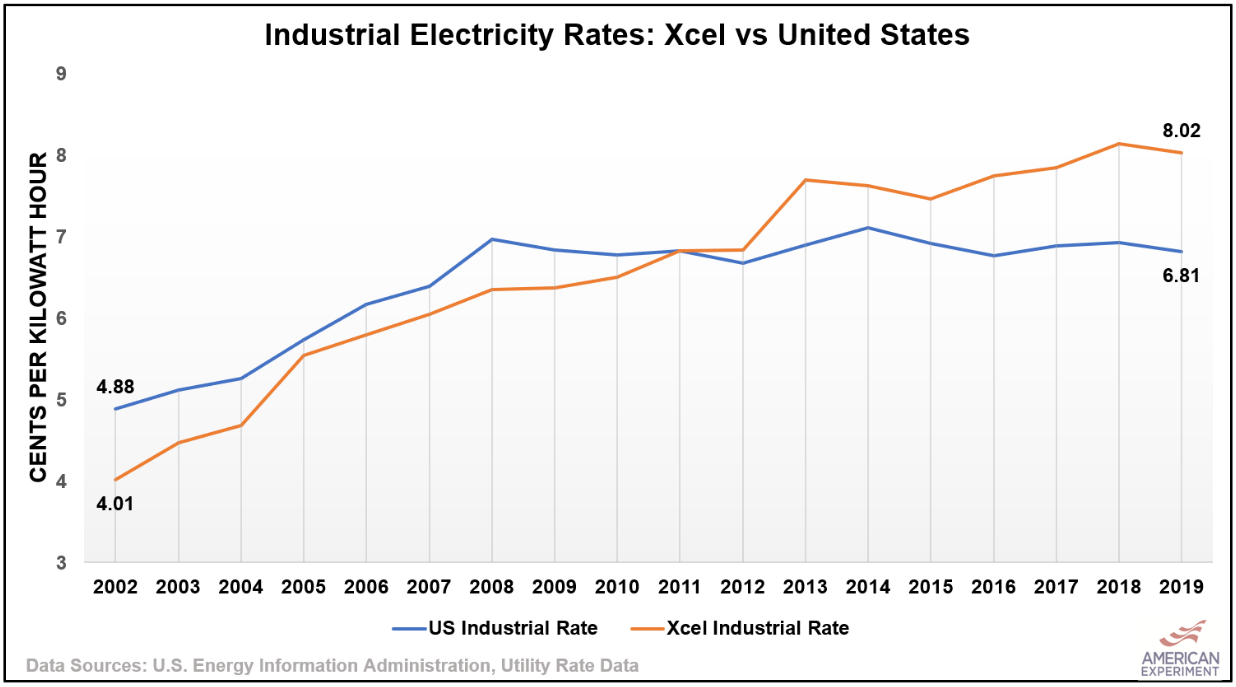


Figure 3. EIA data show Xcel's industrial rates have doubled since 2002, putting Minnesota businesses at a competitive disadvantage relative to firms in other states or nations.

The introduction of renewable energy sources such as wind and solar facilities has inflated costs for Xcel Energy and other utility companies because they cannot replace the value of existing dispatchable capacity due to their intermittency. Since wind and solar cannot be ramped up or down to react to changes in electricity demand instantaneously, they cannot replace fuel-based generators on a one-to-one basis.

Figure 4 shows renewable energy sources have not truly replaced any of Xcel's retired capacity over the years. The addition of wind and solar energy facilities has only added to Xcel's owned capacity, despite electricity sales for the company trending downward since 2001 and the fact that over 1,000 MW of coal capacity has been retired from Xcel's energy mix.[4]

Despite the fact that Xcel had roughly 500,000 MWh fewer retail electricity sales in 2019 than 2001, the company had 1,541 MW more capacity on the grid. Unfortunately, this means that the cost of building additional capacity is being spread over fewer electricity sales and is a key reason why the cost of providing electricity through Xcel has soared higher than the national average.

[4] FERC Form 1, "Electric Utility Annual Data," July 01, 2020, https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-1-electric-utility-annual

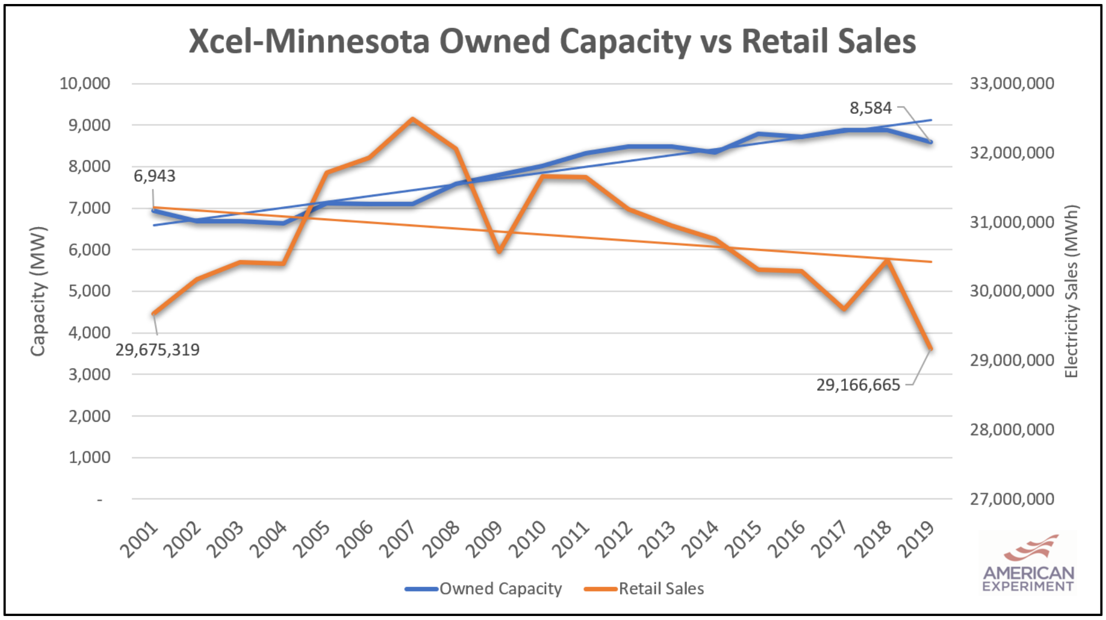


Figure 4. Xcel Energy's owned capacity has increased by 23.6 percent from 2001 through 2019 even though the company generated nearly 500,000 fewer MWh.

Xcel's owned wind energy facilities have increased by more than 950 MW, with hundreds more coming online in the near future. However, a much larger portion of Xcel's new generating capacity has been natural gas, which has grown by nearly 2,000 MW since 2001. Natural gas generating units were needed to compensate for the retirement of over 1,000 MW of coal capacity on Xcel's grid. Wind energy, due to its intermittent nature, could not replace the power production from the loss of Xcel's coal facilities, which provided inexpensive and reliable baseload power for millions of Minnesotans.

Thus, transitioning to renewable energy has duplicated capacity on the system, acting as an expensive premium for Xcel ratepayers that has resulted in enormous increases in electricity costs. We will discuss reliability issues more thoroughly in Section 5, Reliability Concerns and Capacity Values.

Xcel's Resource Plan Would Continue These Cost Increases for Years to Come

Unfortunately, costs will continue to rise if Xcel's supplemental resource plan is approved.

Far from saving customers money, Xcel's most recent resource plans will impose an additional $57 billion in costs through 2050 onto ratepayers. This would translate to an average annual increase of $1,428 per Xcel customer from 2020 to 2050.[5] In later years, from 2031 to 2050, the average annual increase per Xcel customer grows to an average of $1,860 and reaches a height of $2,245 in 2034. Figure 5 shows the future impact on electricity rates based on our modeling.

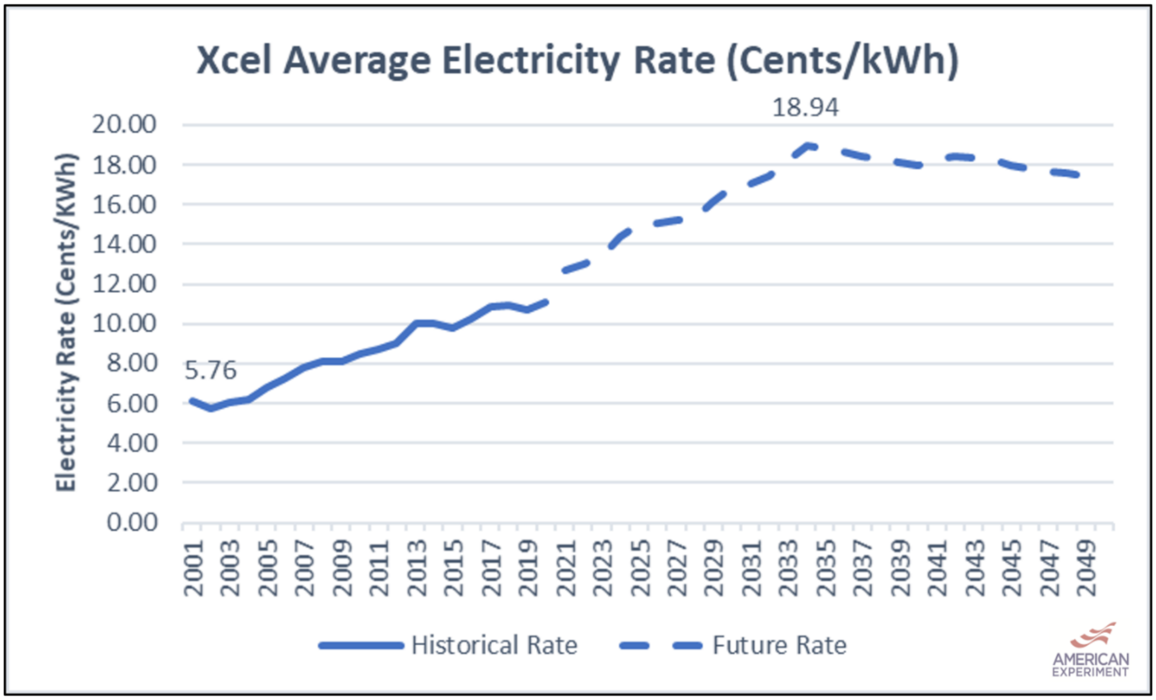


Figure 5. Average electricity rates for all Xcel Energy customer classes will increase from 10.72 in 2019 to a high of 18.94 cents per kilowatt hour in 2034.

It's also important to note that Xcel has asked the PUC for rate increases that exceed our projections in Figure 5. Therefore, our modeling represents a conservative estimate of the rate increases that will result if Xcel is allowed to follow through with this supplemental resource plan.

Given decreasing electricity retail sales and the surplus capacity Xcel currently has on the grid, it would be highly irresponsible to allow the utility company to build over 11,500 MW of additional capacity through 2034 — more than the total amount of capacity it currently owns in Minnesota. The capital cost alone of building 11,500 MW of capacity would exceed $12.5

[5] This figure takes the increase in costs divided by all Xcel Energy customers in EIA's residential, commercial, industrial, and transportation rate classes.

billion, not including the cost of repowering wind facilities, which often occurs before the end of their 20-year financial lives, as Xcel has done in prior years.[6]

Detailing the Expenses in Xcel's Resource Plan

If approved, Xcel's resource plan would result in over $57 billion in additional expenses for Xcel ratepayers, resulting from increased generation costs, utility returns, property taxes and transmission costs. These costs are detailed in Figure 6.

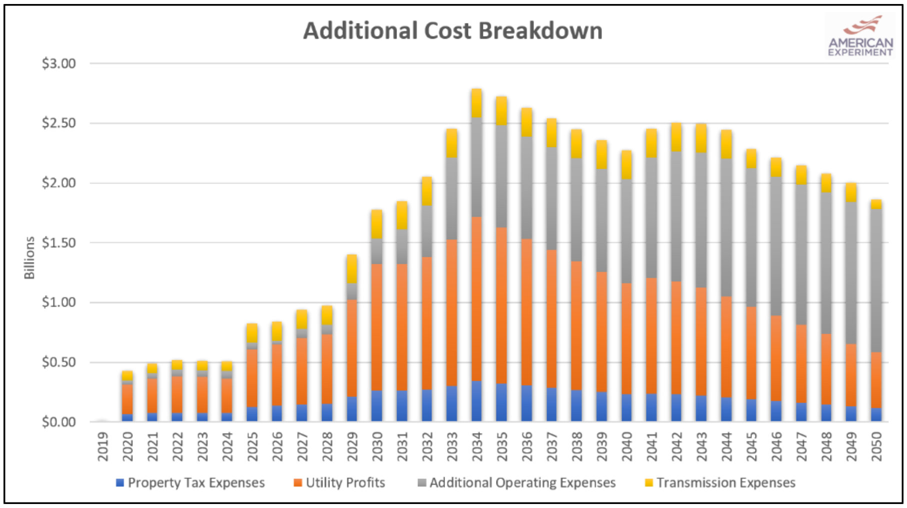


Figure 6. Additional expenses incurred by Xcel as a result of the proposed IRP include rising property tax expenses, utility profits, additional operating expenses, and transmission expenses. These additional costs exceed $2.5 billion in 2034.

Utility Returns

The largest additional expense resulting from Xcel's resource plan would come from utility returns, based on the rate of return on equity of 10.2 percent determined by Xcel's most recent rate case, a return on debt of 4.8 percent, and a capital structure using 52.5 percent common equity.[7] Through 2050, Xcel would generate nearly $25 billion in utility returns — all at the expense of customers who have no choice but to purchase electricity from Xcel no matter how high rates become (See Figure 7).

[6] Mike Hughlett, "Minnesota Regulators Approve $750 Million Xcel Wind-Power Project," Minneapolis Star Tribune, December 4, 2020, https://www.startribune.com/minnesota-regulators-approve-750m-xcel-wind-power-project/573469851/?refresh=true.

[7] John J. Reed, "Return on Equity," Docket No. E002/GR-19-564, November 1, 2019, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={B057276E-0000-C15B-9E17-8F1C41083D5B}&documentTitle=201911-157100-08.

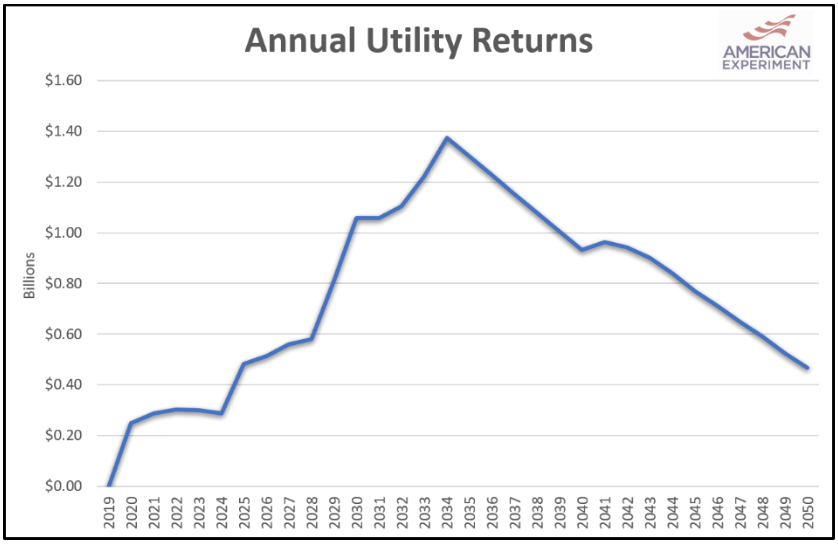
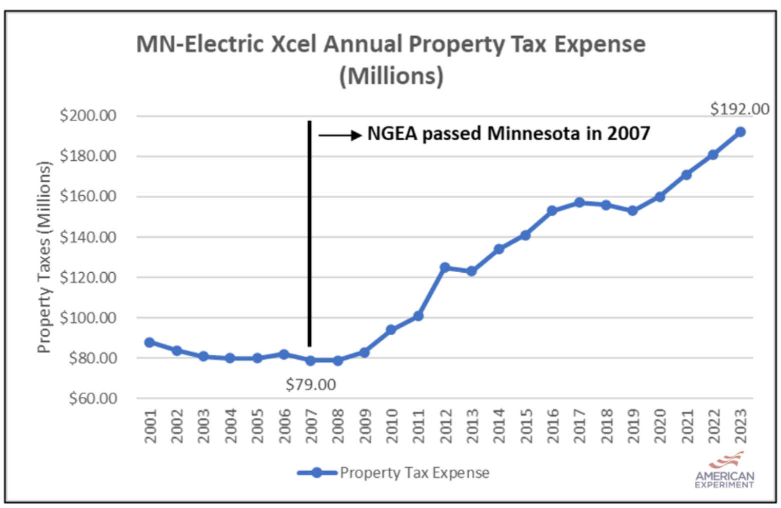


Figure 7. Xcel's annual profits stemming from the approval of this integrate resource plan will reach nearly $1.4 billion in 2034. In total, the proposed IRP will yield nearly $25 billion for the monopoly utility.

Property Taxes

Furthermore, Xcel customers will see rates rise to pay for an additional $6.2 billion in property tax expenses, consistent with historical trends from Xcel. As the graph below shows, Xcel's property tax expense has grown by nearly 145 percent since 2007 following the passage of the NGEA, from $79 million to $192 million forecasted into 2023 (See Figure 8).[8] This is due to the inherent growth in capacity and power facilities on Xcel's electrical grid caused by the transition to renewable energy. In simpler terms, Xcel Energy's property taxes are increasing because the company has more property to tax.



[8] Xcel Energy, "Property Taxes", Notice of Change of Rates and Interim Rate Petition, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={50CF8A75-0000-C42C-AD80-ED7A1FDB89C3}&documentTitle=202011-167934-03

Figure 8. Xcel Energy reports its property taxes have risen by over $90 million from 2007 through 2021. The company estimates it will owe $192 million in 2023.

With the approval of Xcel's resource plan, our model projects this increase in property tax expenses to continue. Figure *9* shows annual additional property tax costs increase sharply from 2021 through 2034 as Xcel builds new generation capacity. Annual additional property taxes fall after 2034 due to the depreciation of Xcel's assets.

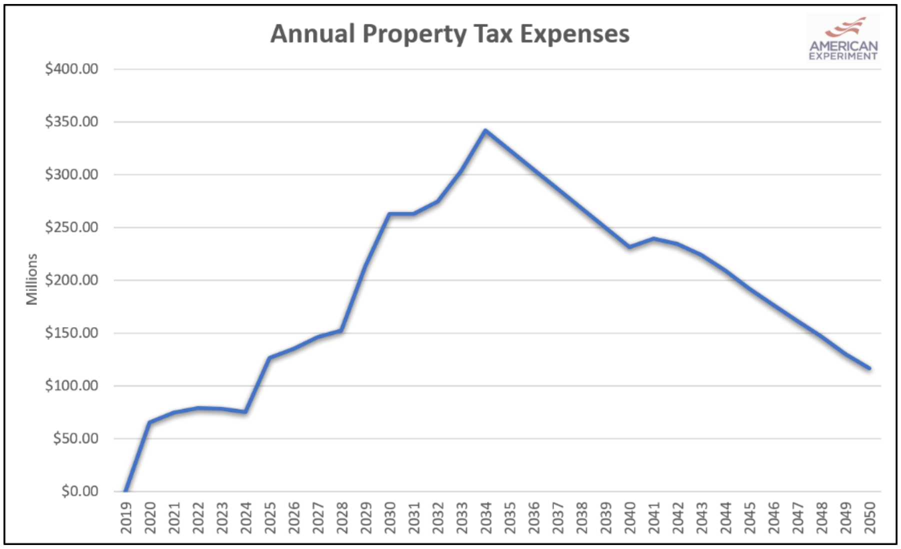


Figure 9. Annual additional property taxes from Xcel Energy's proposed resource plan reach a high of nearly $350 million in 2034.

Transmission Expenses

In addition, our model estimates another $6 billion will need to be invested in the transmission system to accommodate significant renewable energy additions through 2034. These estimates were based on prior CAPX projects undertaken by the utility company. This is likely a conservative estimate, however, as transmission expenses are expected to become even more expensive in the future as the penetration of renewable energy sources increases on the grid.

Without a significant transformation of the transmission system to accommodate a large increase in intermittent power production, much of the new generation from renewable energy sources would need to be curtailed, as the grid would be ill-equipped to transfer the electricity to Minnesotans or import it from elsewhere.

Transmission expenses for Xcel alone will likely need to be in the tens of billions of dollars to fully accommodate new renewable generation, but our model chose to err on the side of caution because no detailed studies or reports investigating these costs are currently available.

Generation Expenses and Load Balancing Costs

Additional generation expenses will account for nearly $19 billion in additional expenses discovered in our model. The significant increase in the cost of generating electricity results from two main factors: higher LCOE values for new generation facilities relative to existing sources and increasing amounts of idle capacity on the grid.

Existing electricity generation sources, such as Xcel's coal, natural gas and nuclear plants, are either largely or completely depreciated, and thus generate electricity at a significant discount compared to new sources that will need to pay off billions of dollars of capital expenses for decades to come. Figure 10 details the increase in generation costs.

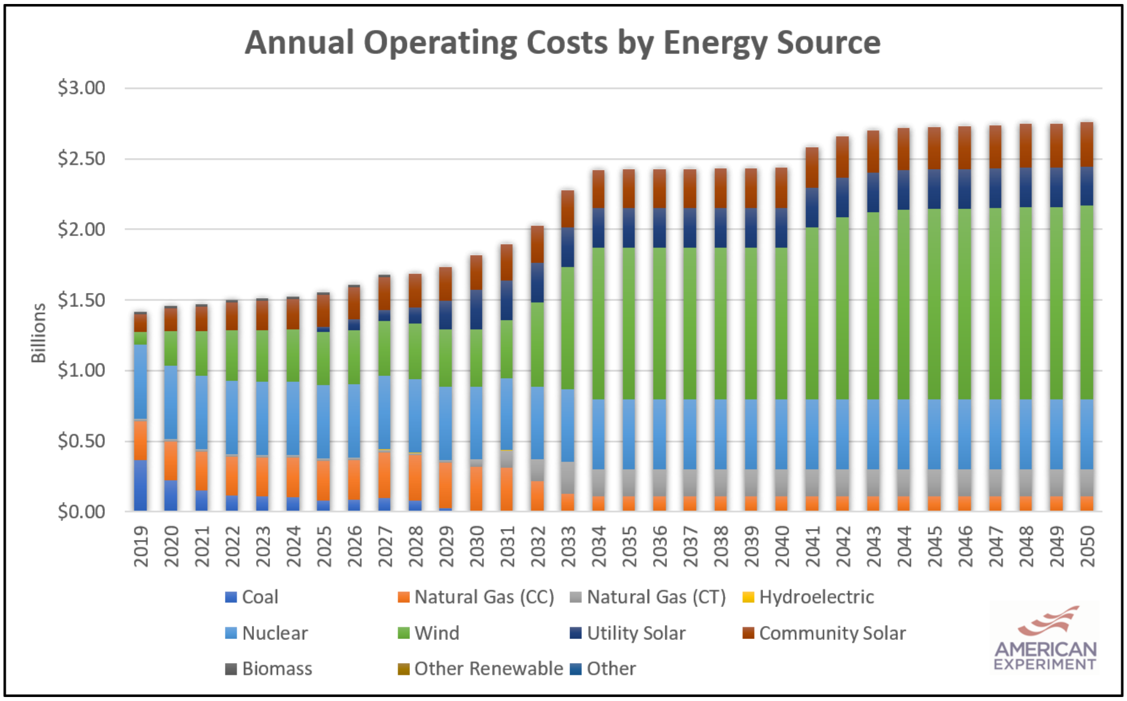


Figure 10. Annual operating expenses increase as the coal fleet is retired and replaced by a combination of wind, solar, and natural gas capacity.

In addition, existing facilities will be forced to ramp down production to make room for renewable energy sources, forcing their fixed costs to be recovered over fewer MWhs.

We account for the cost of the idle natural gas combustion turbine capacity needed to maintain the reliability of the grid in a metric called the load balancing costs. Because these natural gas plants would not be needed if wind and solar were dispatchable, we feel it is most appropriate to attribute these costs to wind and solar, as you can see in Figure 11.

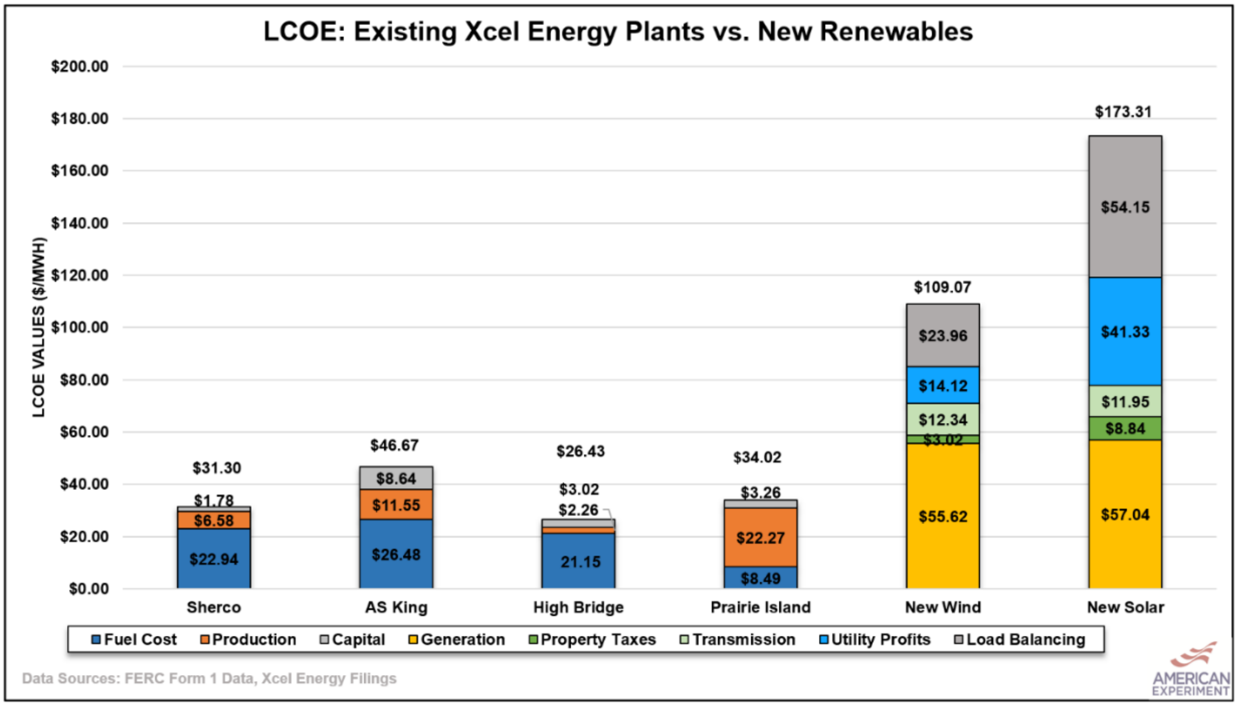


Figure 11. The cost of new wind and solar facilities are much higher than Xcel's existing fleet of fuel-based generators. The cost differences are primarily due to the fact that the existing fleet is largely depreciated, and it is dispatchable, allowing the plants to meet electricity demand without redundant idle capacity.

Repowering Wind Facilities

Another significant cost of Xcel's IRP will come from the need to repower wind turbines anywhere from five to 20 years after coming into operation. As such, Xcel's resource plan will saddle ratepayers with high costs for years to come with almost no hope of rates coming back down, unlike grids powered primarily by fuel-based facilities such as coal, natural gas and nuclear.

Because fuel-based electricity generators routinely outlast the end of their financial lives, ratepayers have the chance of seeing significant cost decreases over time. Wind and solar, however, experience the opposite, as they are typically repowered either exactly at or before the end of their financial lives. This presents a situation where utility companies must perpetually spend billions of dollars on repowering wind and solar facilities.

Indeed, Xcel has recently asked the PUC for approval to repower several of its wind farms — two of which only 5 years after coming into operation.[9] Repowering all of Xcel's wind facilities will add hundreds of millions of dollars to the capital costs the company is already paying off. Since

[9] Sean Staples, "In the Matter of Xcel Energy's Wind Repower Portfolio," Minnesota Public Utilities Commission, Docket No. E002/M-20-620, December 23, 2020, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b20AC6C76-0000-CF19-BB79-017673934A60%7d&documentTitle=202012-169079-01.

these facilities are still paying off their initial capital expenditures, Xcel's decision to repower these facilities so early will likely double the cost of the LCOE at these wind facilities.

While this may be good for the bottom line of utility companies and their shareholders, it results in a situation in which electricity rates never fall for the millions of ratepayers that Xcel serves.

Replacing Replacement Power Plants

Another expensive aspect of Xcel's plan stems from the utility's desire to retire its current existing dispatchable resources and replace them with new dispatchable baseload facilities. These actions, in addition to the billions spent on new wind and solar facilities, would add billions of dollars to Xcel's "rate base."

In other words, Xcel is closing existing baseload energy sources — which could be relied upon as "firm dispatchable" capacity for years to come at an inexpensive cost to ratepayers — and replacing them with intermittent resources that will require Xcel to build additional "firm dispatchable" energy sources in the near future. Xcel's plan creatively shuts down fuel-based facilities that the company is no longer receiving a return from on the basis of transitioning to renewable energy sources, even while it affirms the necessity of building new fuel-based energy sources in the near future in order to maintain reliability.

To illustrate this idea, Xcel states in its resource plan, "As we retire these coal units, we continue to be mindful of the need to maintain a resilient and reliable grid. This informs the inclusion of the Sherco CC and other firm peaking resources in the Supplement Preferred Plan." As already mentioned above, Xcel's resource plan would cost nearly $25 billion in additional utility returns through 2050 — **the largest additional cost discovered within our model**. Allowing Xcel to close existing baseload generators only to replace them with new baseload generators in the near future adds significantly to this cost.

We believe it is inappropriate to require Xcel customers to pay these expenses given the reality that Xcel already has perfectly useful facilities that can provide reliable and inexpensive electricity for years to come.

Premature Retirements Harm Ratepayers

In addition, our model shows a direct contradiction to Xcel's claim in its original IRP filing that "The modest cost of our [Xcel's] plan is facilitated by our strategy of deferring resource additions until later in the plan and making use of existing assets on our system."

Xcel is planning to retire all three Sherco coal units and Allen S. King before the end of their useful lives — and was planning to do so in its original resource plan — demonstrating that the utility company is not making use of existing assets to its full ability. Not utilizing these facilities through the end of their useful engineering lives prevents ratepayers from being able to take advantage of cost savings, as these facilities have much lower or zero capital payments.

As Xcel itself notes:

"The need for [2,600 MW of] dispatchable resources emerges in this later timeframe due to the major plant retirements already discussed, as well as the expiration of several PPAs."

If Xcel were truly making use of existing assets to limit cost increases, there would be no need for 2,600 MW of new capacity from 2030 to 2034 that is required solely to maintain reliability in the absence of a significant amount of existing assets that Xcel is retiring early.

Furthermore, capacity additions are not being deferred to later years. Xcel plans to build more than 1,500 MW of wind capacity before 2025 and is also planning 3,500 MW of solar capacity additions before 2030. This may be the reason why Xcel excluded the claims about "modest costs" due to "deferring resource additions until later" from its supplemental resource plan.

Customer Costs

Xcel's proposed plan will greatly increase costs for consumers (See Figure 12). From 2020 through 2030, the average Xcel Energy customer will see their costs rise by nearly $650 per year. From 2031 through 2050, this cost will exceed $1,850, on average, for each of Xcel's customers.

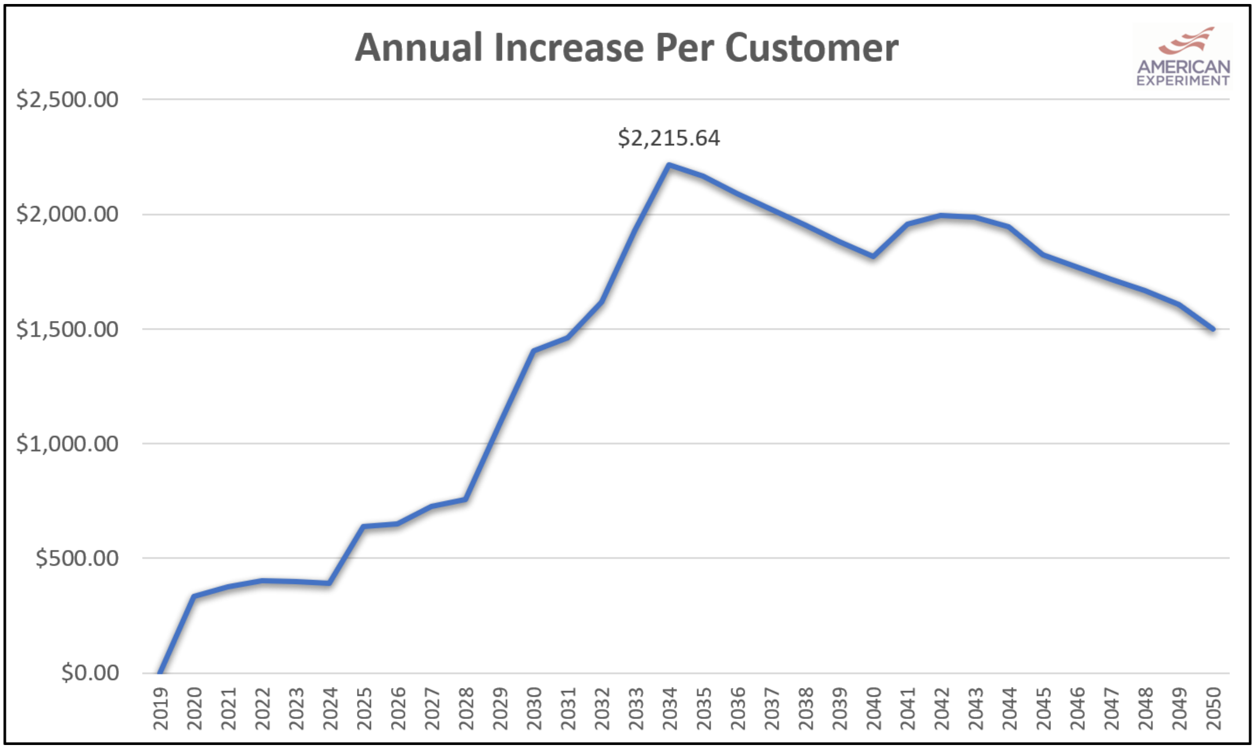


Figure 12. Xcel's resource plan will greatly increase the annual cost for their customers. This graph shows the annual average cost increase spread evenly across all customer classes.

As it stands currently, Xcel's resource plan will impose high costs onto its customers for decades to come. We ask the PUC to consider the lack of opportunity for cost savings this plan presents to Xcel's customers when deciding to approve or reject this IRP.

2. Lack of Basis for Approval of Capacity Additions

Xcel is seeking approval for building over 7,500 MW of additional renewable generating capacity solely to achieve internal company goals — which American Experiment does not believe is an acceptable basis for increasing electricity rates for millions of Minnesota ratepayers. These capacity additions will not result in cost savings for its customers, they are not required to meet future demand growth, they will not improve system reliability, nor are they required to satisfy legislative mandates.

As such, there is no legitimate or appropriate basis for the approval of these additions. In fact, approving a renewable capacity buildout of this scale along with significant baseload retirements — capacity that is needed to maintain reliability — will result in incredibly high electricity rates and significant reliability concerns that will expose millions of Minnesotans to the possibility of widespread power outages.

American Experiment believes there are three appropriate reasons for the approval of new capacity additions in the absence of providing cost savings:

1. Meeting projected growth in electricity demand;
2. Improving reliability;
3. Satisfying legislative mandates.

Achieving internal company goals, on the other hand, is not a suitable basis for approval and the subsequent electricity rate increases that follow.

We demonstrate that Xcel's resource plan satisfies none of the appropriate reasons for approval. Rather, the resource plan submitted by Xcel is based solely on achieving an internal company goal that is not required to decrease costs to ratepayers, meet demand growth, improve reliability, or satisfy legislative mandates.

To begin, Xcel explains in its resource plan that it expects a "relatively slow load growth." As stated by Xcel:

"The updated corporate peak demand forecast shows relatively slow load growth, with an average annual growth rate of 0.7 percent over the planning period, after accounting for reductions to demand from the future energy efficiency (EE) achievements embedded in the forecast. Our corporate energy demand forecast also indicates that we expect net energy requirements to be somewhat lower than those forecasted in our initial filing. The fall 2019 forecasts indicate relatively flat growth of approximately 0.2 percent over the full 2020-2034 planning period. In general, we expect both load and energy demand to be slightly lower than the forecast used in our initial filing through most of the planning period – due to factors such as weather driven near-term energy demand declines, additional anticipated EE savings, and adjustments to anticipated commercial and industrial load."

Given that Xcel itself predicts load growth to be "relatively flat" over the next 15 years, there is no demand basis for approving the addition of over 11,500 MW of new generating capacity — more than the company currently owns — over that same time (See Figure 13).

Figure 2-3: Net Energy Requirements Forecast Adjustments for Resource Plan Modeling

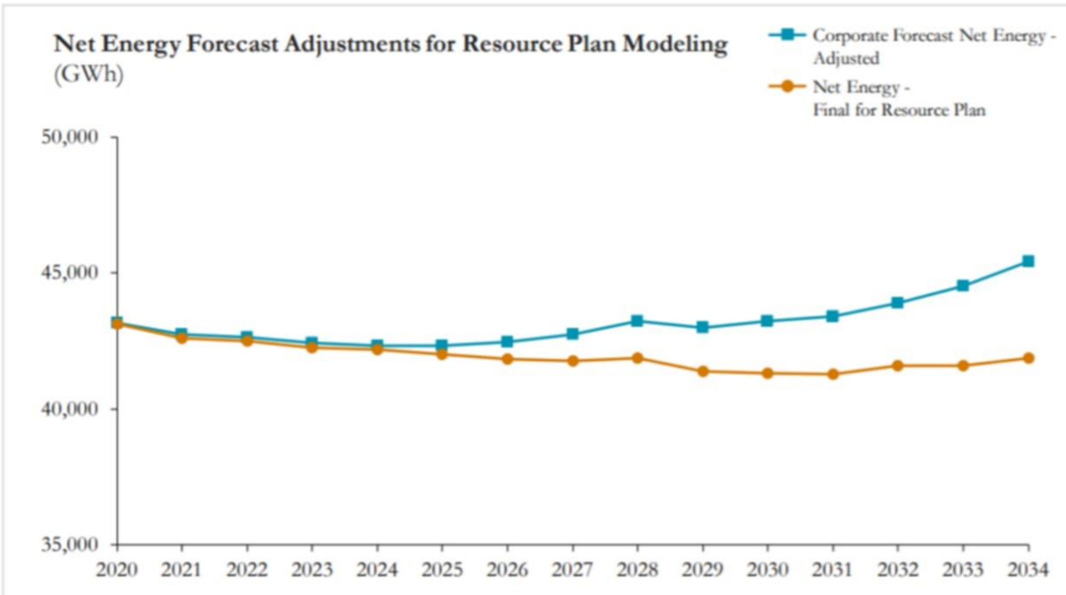


Figure 13. Xcel Energy projects load growth to remain relatively flat, which means new power plants are not needed to meet demand.

Second, retiring baseload, dispatchable generating capacity to make room for intermittent renewable energy sources does not improve reliability concerns for Xcel customers. In fact, the opposite is true. Approving such measures will lead to a decrease in reliability in the years to come. Furthermore, it would invite reliability concerns for the millions of Xcel customers that depend on the utility company to provide electricity at all times of the day and through any circumstances that may arise.

As stated by John Bear of the Midcontinent Independent System Operator (MISO) during his testimony to the House Committee on Energy and Commerce, Subcommittee on Energy in 2019:[10]

"Already we have learned from that study that renewable penetration of 30% would present challenges in terms of our ability to maintain the planning reserve margin and operate the system within acceptable voltage and thermal limits. The study indicates that maintaining grid reliability at the 40% renewable penetration level becomes significantly more complex. In addition to the challenges described at the 30% level, we would encounter the need to balance

[10] Testimony of John Bear, "Building a 100 Percent Clean Economy: Solutions for the U.S. Power Sector," House Committee on Energy and Commerce, Subcommittee on Energy, October 30, 2019, https://www.congress.gov/116/meeting/house/110174/witnesses/HHRG-116-IF03-Wstate-BearJ-20191030.pdf

the system over a very large area to reduce renewable curtailments and regional transmission reliability issues. The system stability issues would drive the need for non-traditional transmission devices like High Voltage Direct Current (HVDC) lines or other advanced technologies. We are currently looking at the implications of a 50% renewable penetration level…

The implications have been very real. Tight operating conditions, and more specifically the need to utilize emergency procedures to manage reliability risk, used to occur very rarely and only during peak demand periods. We now experience those situations on a much greater periodicity and during the non-peak periods when risk was historically very low."

Xcel's resource plan increases renewable penetration past 30 percent by 2020, 40 percent by 2025, 50 percent by 2032, and 60 percent by 2034. As MISO, Minnesota's electricity system operator, suggests in the statement above, renewable penetration levels above 40 percent bring with it "significantly more complex" reliability issues. They have not studied levels above 50 percent, but it can be assumed that this will present even greater reliability challenges.

Reliability issues have already arisen in recent years in Minnesota, during the Polar Vortex of 2019 and other moments, which will be discussed in greater detail in Sections 4 and 5.

The statement by John Bear and recent reliability issues caused by the inclusion of renewable energy sources at Xcel make clear: there is simply no reliability basis for the inclusion of over 7,500 MW of new wind and solar energy in Minnesota.

Lastly, the renewable energy mandate for Xcel is 30 percent plus 1.5 percent of solar energy. By 2020, Xcel will have satisfied this mandate by having 32.3 percent renewable energy — 2.5 percent of which will be supplied by solar energy. This will be achieved through the utility company's integrated resource plan approved in 2015. Several additions from this resource have yet to come online, which will push Xcel over what is mandated.

Because none of the renewable energy additions in Xcel's supplemental resource plan are needed to satisfy Minnesota's renewable energy mandate, there is no basis for approving them.

Indeed, Xcel makes it known that the renewable capacity additions are the result of the company's own internal goal by stating in the RES Rate Impact Report in Appendix N6 of its original resource plan filing:

"We excluded any of the new 1,850 MW of wind, and also excluded additional future renewables contained in the "Reference Case," as these renewable additions are driven by economics as opposed to RES compliance."

As is clearly stated by Xcel, renewable energy additions found in this resource plan are not required by legislative mandates.

Xcel's resource plan and decarbonization goals need to be understood for what they are: an incredibly expensive internal campaign that does nothing to support growing demand. Xcel's plan will lead to complex reliability issues that become more difficult to assess and prevent as renewable penetration levels increase, and the Commission has no legislative basis for approval.

If Xcel wants to pursue internal company goals that are not mandated or required for reliability benefits to the electrical system, it should not come at the expense of ratepayers who will see electricity rates go up as a result.

With these facts in mind, we ask the PUC to reject Xcel's resource plan and/or not allow Xcel to rate base capacity additions without proper basis. Far from serving its customers with capacity additions for load growth, improving reliability or satisfying legislative mandates, Xcel's request to build over 11,500 MW of additional capacity is serving its own agenda, rate base and shareholder profit margins.

3. Environmental Impacts of Xcel's Resource Plan

Xcel Energy wishes to close the Allen S. King and Sherco 3 coal plants down before the end of their useful engineering lifetime and replace them with a combination of wind, solar, natural gas and an unknown "firm peaking" resource, all to supposedly benefit the environment.

However, our analysis finds the cost of averting carbon dioxide emissions under Xcel's plan would exceed Minnesota's social cost of carbon estimates and produce immeasurably small reductions in future global temperatures. Furthermore, recent academic research from Harvard finds that wind turbines cause localized warming due to atmospheric boundary layer mixing, which would exceed the warming averted by emitting fewer greenhouse gases.

Without considering this information, the Commission and other stakeholders cannot make informed decisions and evaluate tradeoffs based on a holistic variety of factors, such as reliability, affordability and benefits to the environment.

The Cost of Carbon Dioxide Emissions Reductions Vastly Exceeds Minnesota's Social Cost of Carbon

In 2018, the Commission established a Social Cost of Carbon for the state of Minnesota with "the goal of producing usable results that will aid the Commission and the parties in the evaluation and selection of future utility resources."[11]

American Experiment's modeling indicates that Xcel Energy's proposed plan would cost $57 billion through 2050 and avert a total of 422 million short tons of carbon dioxide. This results in an average cost of $135 for each short ton of carbon dioxide averted from the resource plan.

[11] Minnesota Public Utilities Commission, "Order Updating Environmental Cost Values," Docket No. E-999/CI-14-643, January 3, 2018.

This cost exceeds even the highest estimates of Minnesota's Social Cost of Carbon values, meaning the costs of Xcel's resource plans vastly exceed the benefits.

Figure 14 shows that at no time during the modeled 30-year period do the benefits of reducing carbon dioxide exceed the costs. In 2034, the cost of reducing carbon dioxide emissions costs 187 percent more than the high-end social cost of carbon for that year.

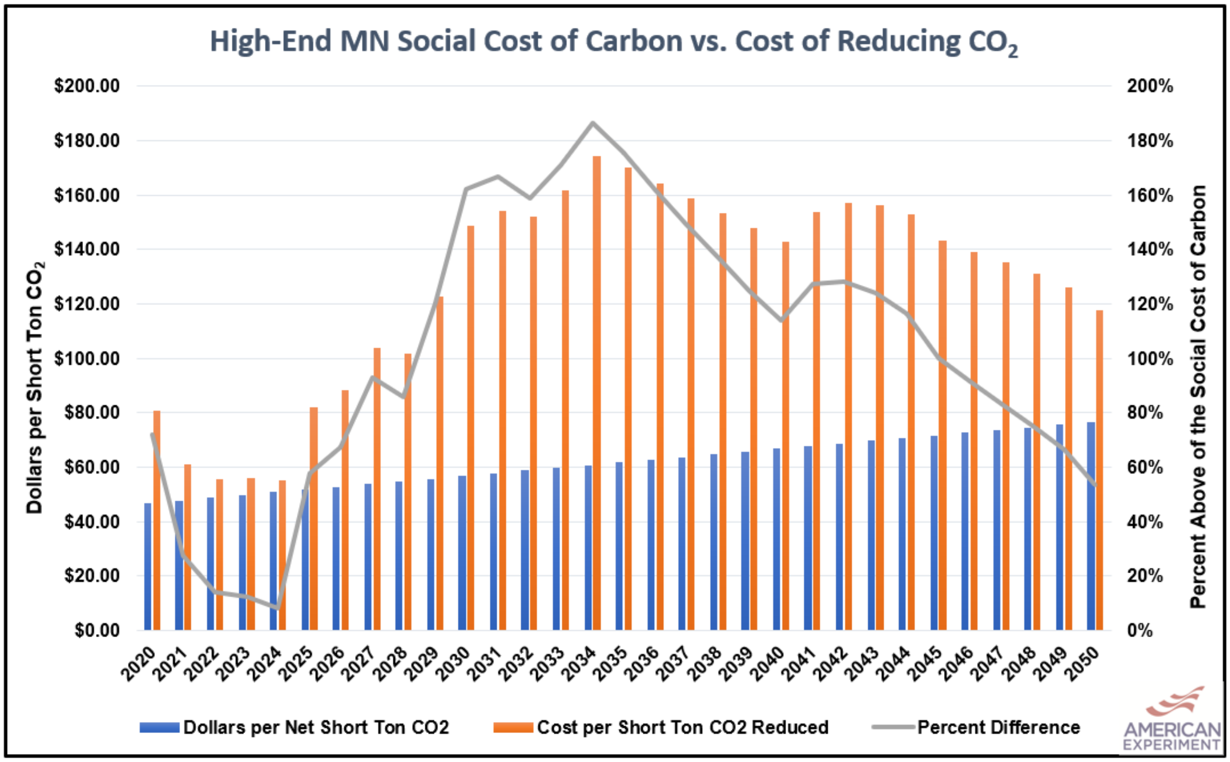


Figure 14. The cost of reducing carbon dioxide emissions in Xcel's proposed plan exceeds the highest values for the PUC's social cost of carbon in every year modeled. The costs of reducing emissions vastly outweigh the benefits.

The Commission has a duty to keep rates just and reasonable, and ensure that consumers are protected against excessive costs. There is simply no way in which the Commission can approve this plan while adhering to their own values for the social cost of carbon.

Temperature Impact from Carbon Dioxide Emissions Reductions from Xcel's IRP

Xcel Energy's IRP discusses the reductions in carbon dioxide emissions that would result from their proposal. However, they never discuss the likely impact that these emissions reductions would have on future global temperatures. This omission is unacceptable because the entire point of reducing emissions is to reduce future global temperatures. Emissions reductions are merely a means to reduce future temperatures.

Therefore, the Commission should require all resource plans filed by any investor-owned utility to disclose the likely reduction in global temperatures and local temperatures (within the IOU footprint) that a proposed resource plan would achieve.

American Experiment's modeling shows Xcel Energy's preferred plan within the IRP would avert 384 million metric tons through 2051. Annual reductions would fall from 15.1 million metric tons in 2019 to 309,210 metric tons by 2034, a reduction of 14.8 million metric tons per year after that time.

To understand the global-temperature impact of reducing Xcel's carbon dioxide emissions by 14.8 million metric tons, it helps to examine the temperature impact of the Clean Power Plan (CPP), which was widely considered to be the Obama administration's signature climate change initiative.

The Obama administration claimed the CPP would have reduced annual CO2 emissions nationally by 730 million metric tons (804,687,256 short tons) by 2030. The Obama administration's Environmental Protection Agency used a climate model called the Model for the Assessment of Greenhouse-Gas Induced Climate Change (MAGICC) to determine the CPP's temperature impact. Using MAGICC, the Obama administration estimated the CPP would have reduced future warming by only 0.019° C by 2100, an amount too small to be accurately measured with even the most sophisticated scientific equipment.[12]

The 14.8 million metric tons of CO2 (16.4 million short tons) no longer emitted from Xcel Energy's power plants in Minnesota would account for 2 percent of the 730 million metric tons averted by the CPP. From this figure, we can extrapolate that this IRP would avert two percent of the 0. 019° C by 2100, for a future temperature reduction of 0.00039° C by 2100, meaning the reductions will have no measurable impact on future global temperatures.

The Commission should require Xcel Energy and all other investor-owned utilities to produce this information so Minnesotans can decide for themselves whether they believe the costs they will incur to reduce emissions will be worth the benefits of reduced future temperatures.

Climate Impacts from Wind Turbine Entrainment of Warmer Air

Peer-reviewed academic research conducted by scientists at Harvard has concluded that wind turbines cause significant local warming near the earth's surface.

Wind turbines do not add carbon dioxide into the atmosphere while generating electricity. However, a 2018 study in the academic journal *Joule* by the Harvard scientists found that wind turbines cause significant local surface warming near wind facilities because wind turbines redistribute heat within the upper and lower atmosphere by mixing boundary layers.[13]

The study finds this surface warming caused by wind turbines exceeds the amount of warming that would be averted through reduced emissions, defeating the purpose of building the wind turbines in the first place.

According to the study, at least 40 papers and 10 observational studies link wind power to climatic impacts.[14] Three of these studies relied on ground-based measurements, and seven relied upon satellite readings, thus demonstrating a real impact on local temperatures from turbine operation.

[12] Lee Miller Et al., "Climate Impacts of Wind Power," *Joule,* December 2018, https://www.cell.com/action/showPdf?pii=S2542-4351%2818%2930446-X.
[13] Lee Miller Et al., "Climate Impacts of Wind Power," *Joule,* December 2018, https://www.cell.com/action/showPdf?pii=S2542-4351%2818%2930446-X.
[14] Lee Miller Et al., "Climate Impacts of Wind Power," *Joule,* December 2018, https://www.cell.com/action/showPdf?pii=S2542-4351%2818%2930446-X.

The study describes how wind turbines affect surface temperatures in detail, which we believe merits extensive direct quotation:

"The climatic impacts of wind power may be unexpected, as wind turbines only redistribute heat within the atmosphere, and the 1.0 W m-2 of heating resulting from kinetic energy dissipation in the lower atmosphere is only about 0.6% of the diurnally averaged radiative flux. But wind's climatic impacts are not caused by additional heating from the increased dissipation of kinetic energy. Impacts arise because turbine-atmosphere interactions alter surface-atmosphere fluxes, inducing climatic impacts that may be much larger than the direct impact of the dissipation alone.

"As wind turbines extract kinetic energy from the atmospheric flow and slow wind speeds, the vertical gradient in wind speed steepens, and downward entrainment increases.15 These interactions increase the mixing between air from above and air near the surface. The strength of these interactions depends on the meteorology and, in particular, the diurnal cycle of the ABL.

During the daytime, solar-driven convection mixes the atmosphere to heights of 1–3 km.3

Wind turbines operating during the daytime are enveloped within this already well-mixed air, so climatic impacts such as daytime temperature differences are generally quite small.

At night, radiative cooling results in more stable surface conditions, with about 100–300 m of stable air separating the influence of surface friction from the winds aloft. Wind turbines operating at night, with physical extents of 100–150 m and an influence height at night reaching 500 m or more, can entrain warmer (potential temperature) air from above down into the previously stable and cooler (potential temperature) air near the surface, warming surface temperatures. In addition to the direct mixing by the turbine wakes, turbines reduce the wind speed gradient below their rotors and thus sharpen the gradient aloft. This sharp gradient may then generate additional turbulence and vertical mixing."

Because policies meant to limit carbon dioxide emissions are ultimately designed to limit the warming of future global temperatures, the Commission needs to consider the local surface temperature impacts of wind turbines and other generation resources as part of the resource planning process.

Xcel must be transparent about the likely temperature impact of reducing emissions and forthcoming about the impact their plans to build or repower wind turbines will have on the localities that host them.

Temperature Observations from Texas Wind Facilities

The study in *Joule* details real-life temperature observations from wind facilities in Texas. The study highlights a single Texas location where one of the world's largest clusters of operational wind turbines (200 km^2, consisting of open space and patchy turbine densities of 3.8–4.7 MW km 2) has been linked to differences in surface temperature in three observational studies.[15]

Weighting the observations by the number of observed-years, the Texas location is 0.01 degrees C warmer during the day and 0.29 degrees C warmer at night.

If similar warming occurs in Minnesota due to the operation of wind turbines, then the amount of increased warming from wind turbines would be 25.6 times greater than the global warming averted

[15] Lee Miller Et al., "Climate Impacts of Wind Power," *Joule,* December 2018, https://www.cell.com/action/showPdf?pii=S2542-4351%2818%2930446-X.

through lower emissions (0.0039 degrees C by 2100) during the day and 742 times greater at night (See Figure 15).

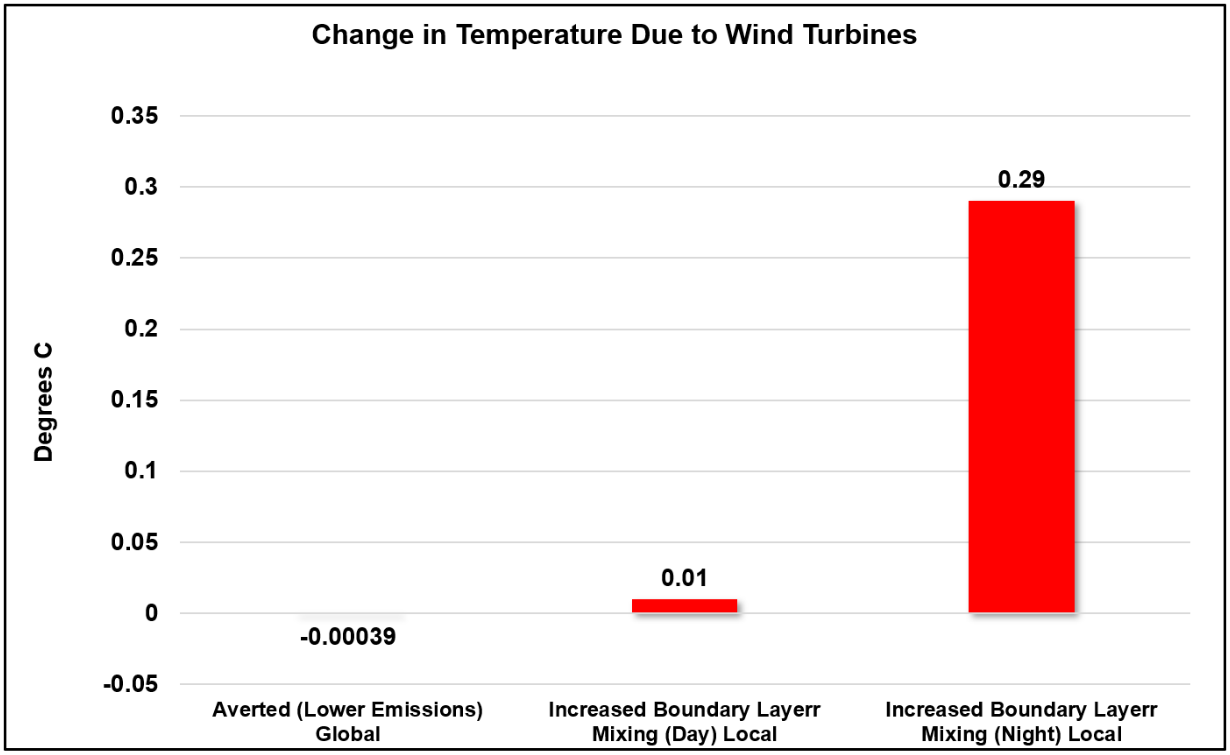


Figure 15. Comparing the expected decline in global temperatures from fewer emissions in Minnesota to the increase in local temperatures observed at operational wind facilities in Texas shows Xcel Energy's Plan to build more wind turbines will cause large, local surface warming to avoid much smaller increase in global atmospheric temperatures.

The warming observed at wind sites in Texas is significant. Still, the study in *Joule* determined that this warming would be small compared to the impact of attempting to meet today's U.S. electricity demand using wind turbines.

Future Temperature Projections

The Harvard study sought to model the local surface temperature impact of generating 0.5 TW_e of electricity in the United States using wind turbines. Temperature impacts were assessed using general circulation models (GCMs) and comparing these results to the observed warming impact measured by wind turbines in several other regions of the United States.

Figure 16 from the study shows that Minnesota would see temperatures rise by 0.3 to 1 degree C, on average, under this electricity generating scenario. This means that on average, such a resource mix would cause 769 to 2,564 times more warming in Minnesota than would be averted through Xcel's IRP.

This amount of warming would also be more than 75 to 250 times higher than would be averted by completely eliminating the 61 million metric tons of GHGs emitted by all sectors of Minnesota's economy in the state in 2018, which include transportation, electricity generation, agricultural, industrial, residential, commercial and waste.[16]

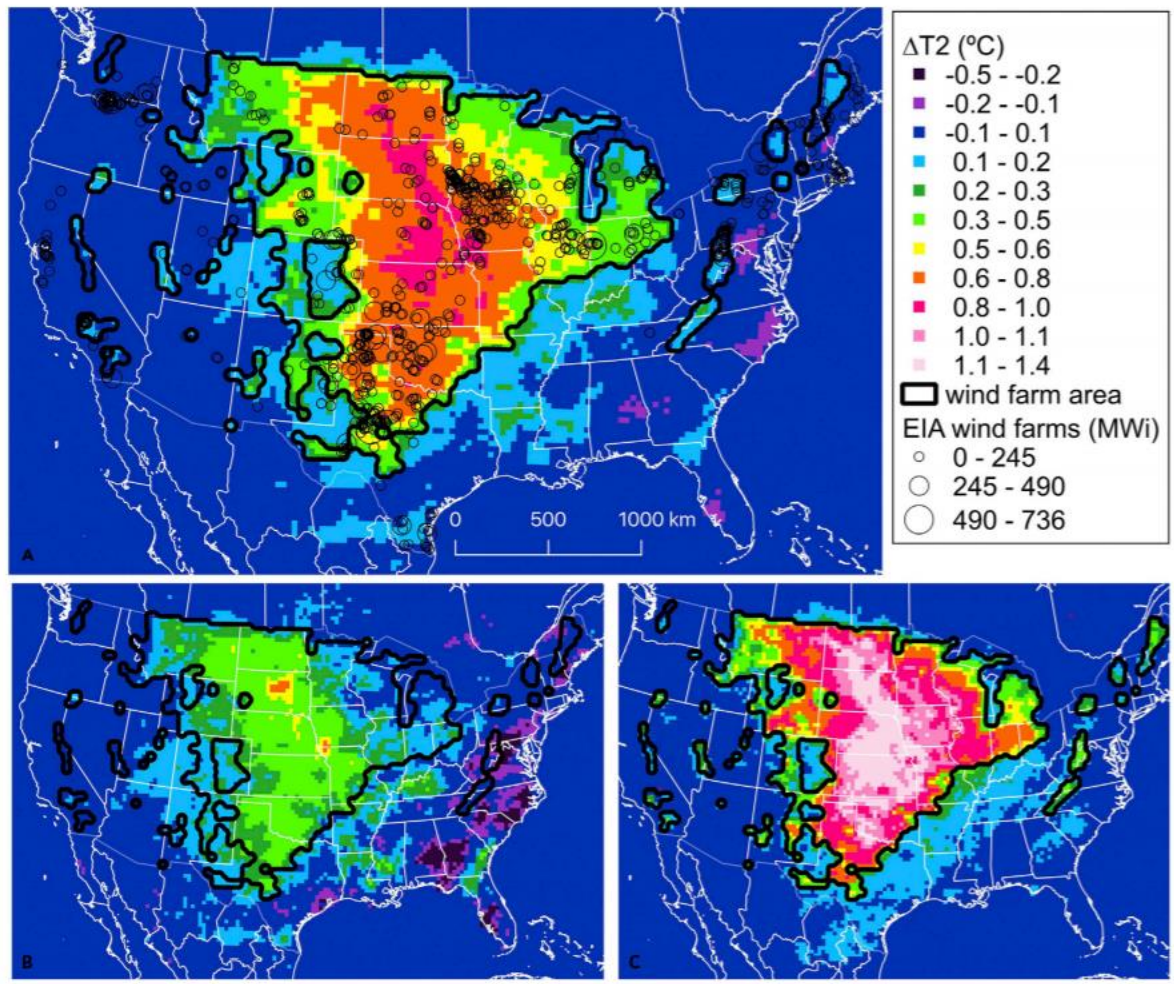


Figure 1. Temperature Response to Benchmark Wind Power Deployment (0.5 MW km^{-2})
(A–C) Maps are 3-year mean of perturbed minus 3-year mean of control for 2-m air temperatures, showing (A) entire period, (B) daytime, and (C) nighttime. The wind farm region is outlined in black, and, for reference, presently operational wind farms are shown as open circles in (A).

Figure 16. According to the study in Joule, temperatures in Minnesota would increase, on average, between 0.3- and 1-degree C due to increased atmospheric boundary layer mixing caused by wind turbines. The increase in temperatures would be most significant at night, increasing temperatures by up to 1.1 degrees C.

According to the study, the amount of warming Minnesota would experience by generated 0.5 TW_e of electricity (0.3 C to 1 C) would greatly outweigh the climate impact of achieving a net-zero electricity grid within the entire United States, which is below 0.2 degrees C in all emissions scenarios (See Figure 17).

---

[16] Minnesota Pollution Control Agency, "Greenhouse Gas Emissions Data," Climate Change in Minnesota, Accessed February 2, 2021, https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data.

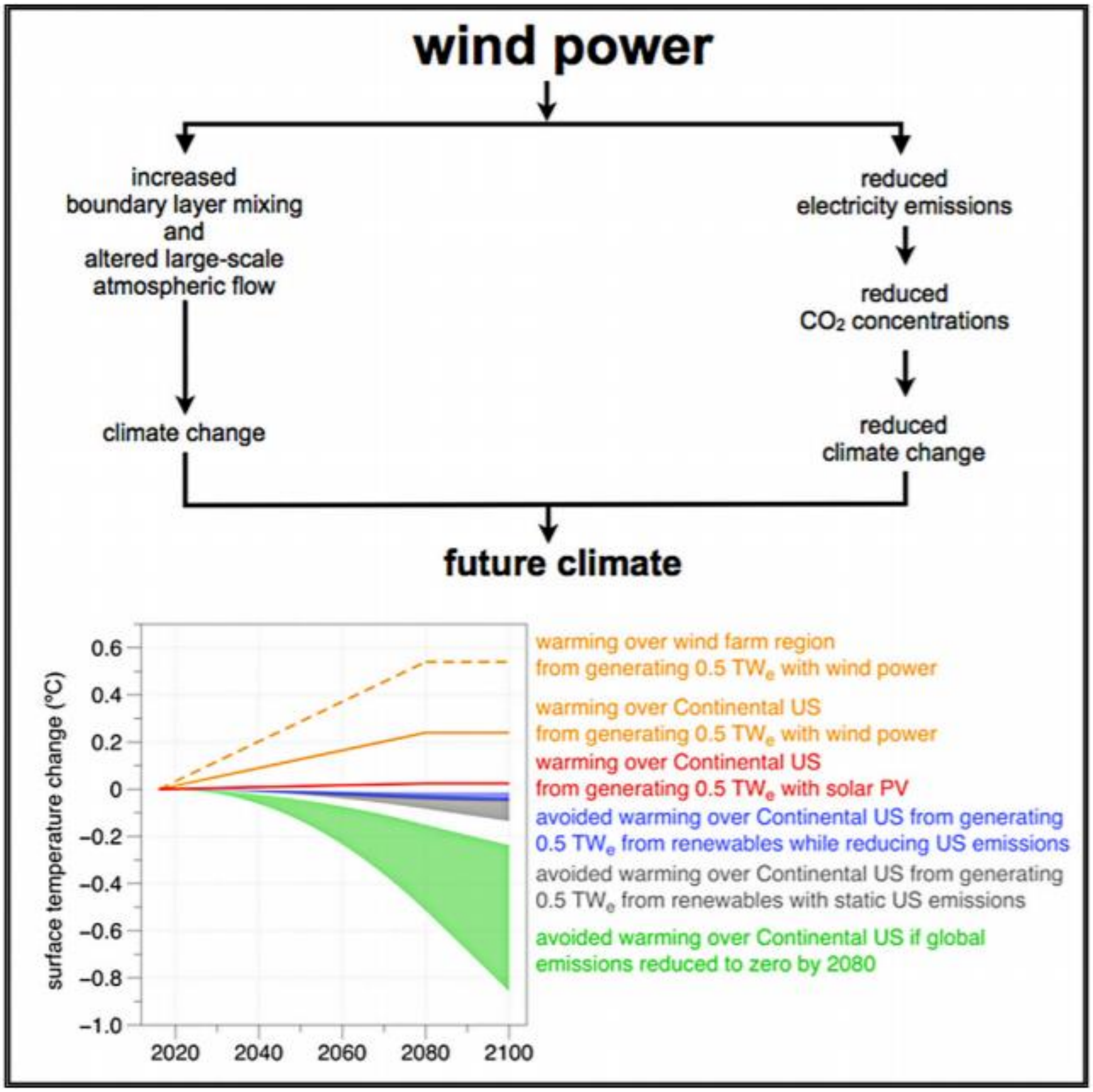


Figure 17. According to the study in *Joule*, generating 0.5 TWe of electricity with renewables will increase warming over the wind farm region by an average of 0.54 degrees C. In contrast, generating this amount of electricity would avert less than 0.2 degrees C in all emissions scenarios.

Therefore, we believe the academic research indicates that there is legitimate scientific evidence suggesting there are serious climate drawbacks to Xcel's resource plan that the Commission is currently not evaluating.

Effects of Turbine Density on Electricity Generation and Surface Warming

Two other significant findings from the study in *Joule* are the relationships between wind turbine density and electricity generation, and the relationship between turbine density and temperature increases. The authors write:

"Warming and power generation saturate with increasing turbine density. The temperature saturation is sharper, so the ratio of temperature change per unit energy generation decreases with increasing turbine density. This suggests that wind's climate impacts per unit energy generation may be somewhat larger for lower values of total wind power production."

According to Figure 18, capacity factors fall with increasing turbine density (See Figure 18 B), resulting in incrementally smaller increases in electricity output (Figure 18 C) per unit of wind capacity installed.

These findings indicate diminishing electricity returns for wind turbine densities exceeding 1.5 MWi per km-2. Such diminishing electricity returns could have significant impacts on reliability and cost for the proposed resource plan. The PUC should require Xcel to account for these diminishing returns in their modeling if the utility is not already doing so.

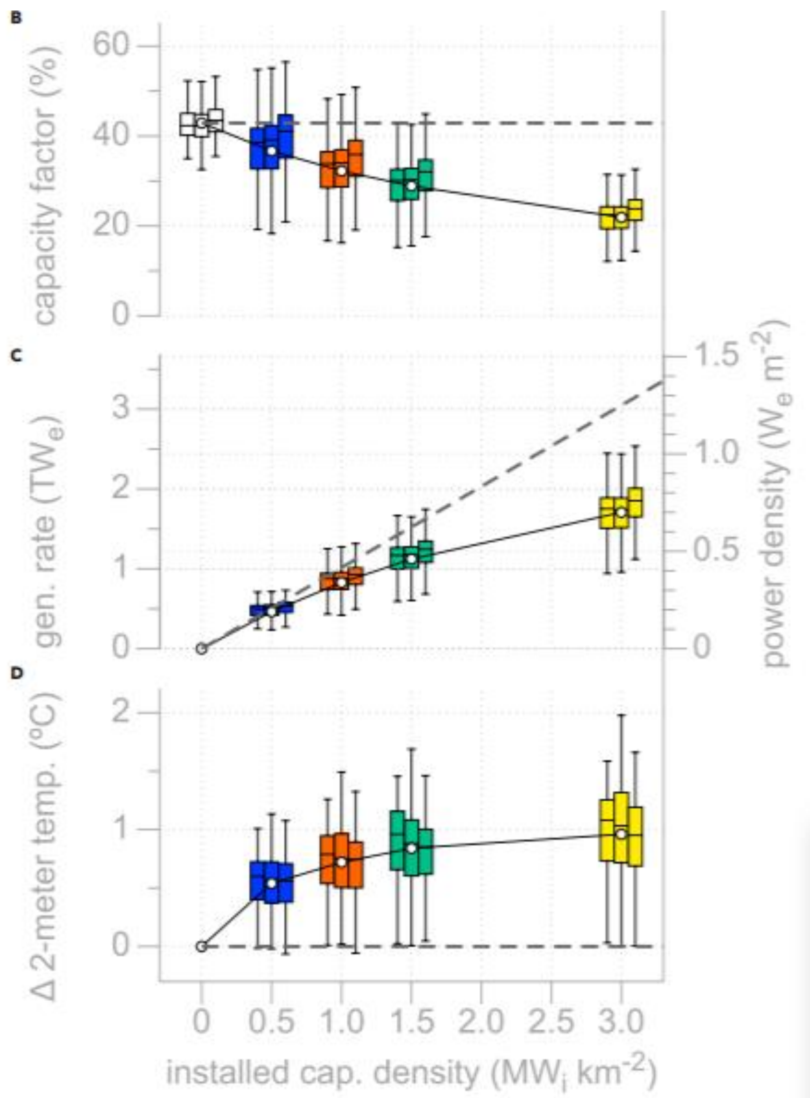


Figure 3. Variation in Mean Response to Changes in Installed Capacity Density
(A–D) The shared x axis is the installed electrical generation capacity per unit area. All values are averages over the wind farm region. (A) Eighty-four-meter hub-height wind speed, (B) capacity

Figure 18. The surface temperature impact of wind turbines is approximately 0.5 degrees C when installed capacity density is 0.5 MWi km-2.

Temperature effects of wind turbine density are depicted in Figure 18 D. The figure shows a warming impact of 0.5 degrees C occurs at wind turbine densities of 0.5 MWi/km-2, approximately 0.75 degrees C at turbine densities of 1 MWi/km-2, approximately 0.8 degrees C at densities of 1.5 MWi/km-2, and 0.9 degrees C at densities of 3 MWi/km-2.

These results indicate that even small amounts of installed wind generation capacity will cause large increases in local surface temperatures. The incremental increase in wind turbine-induced warming diminishes as more capacity is installed but increasing turbine density also reduces capacity factors and generation per unit of installed capacity.

Climate Impact of Solar Panels

The study in *Joule* also estimates the temperature impact of generating electricity with solar photovoltaic panels and concludes that the warming associated with the use of solar panels is far less than that of wind turbines (See Figure 17). The authors write:

"The climate impacts of solar P.V.s arise from changes in solar absorption (albedo). A prior study estimated that radiative forcing per unit generation increased at 0.9 mWm-2 /TWe, in a scenario in which module efficiency reaches 28% in 2100 with installations over 20% rooftops, 40% grasslands, and 40% deserts. Assuming that the climatic impact is localized to the deployment area and using a climate sensitivity of 0.8K/Wm-2 , 53 generating 0.46 TWe of solar P.V.s would warm the Continental U.S. by 0.024C.

This warming effect is 10-times smaller than wind's (0.24C, Figure 5D) for the same energy generation rate. This contrast is linked to differences in power density and thus to the areal footprint per unit energy— U.S. solar farms presently generate about 5.4 We m-2 , while U.S. wind farms generate about 0.5 We m-2."

Solar panels produce less local warming than wind turbines. However, a regional warming rate of 0.024 degrees C would still create 74 times more warming in the continental United States that Xcel's proposed IRP would avert.

Furthermore, the low energy densities, capacity factors, and capacity values of both energy sources require an overbuilding of installed capacity to achieve higher penetrations of "renewable" electricity, which likely makes this equation less favorable to wind and solar and involves the operation of "back up" generation sources.

Changing the Social Cost of Carbon to the Social Cost of Warming

The Minnesota PUC currently attempts to quantify the economic costs of increasing global temperatures by assigning an externality cost to each ton of carbon dioxide emitted by an electricity generating resource. Because this cost, called the Social Cost of Carbon (SCC), attempts to assess the economic damage of electricity generation resources based upon carbon dioxide emissions, it does not adequately consider the local surface temperature impact of wind turbines or solar panels caused by atmospheric boundary layer mixing or an enhanced albedo effect.

This shortcoming must be remedied because the science has shown that the climate impacts of wind turbines are hundreds to thousands of times larger, more localized, and more immediate than the warming caused by carbon dioxide emissions, which are much smaller, global in scale, and on the timescale of decades to centuries.

Large, localized surface warming in Minnesota inflicts more economic damage on Minnesota residents than small global warming that is evenly spread over the entire globe because it has a much more significant effect on the lives of the people, plants and animals that call Minnesota home.

Impacts on Agriculture

For example, increasing local surface temperatures in rural Minnesota caused by wind facilities mixing atmospheric boundary layers will increase moisture evaporation rate in soils, especially at night. Higher rates of evaporation are concerning to Minnesota farmers and the people who rely upon them.

According to the Minnesota Department of Agriculture, farming is the backbone of Minnesota's economy, with $17 billion in agricultural sales per year. Agricultural production and processing industries generate over $112 billion annually in total economic impact and support more than 431,127 jobs.[17]

Figure 16 shows nighttime temperatures in Minnesota would increase by 0.8 to 1.1 degrees C in a high wind generation scenario. This increase in temperature is concerning because it could reduce crop production by evaporating moisture in soils and inflict more heat stress upon livestock.

According to the Minnesota Department of Health, increases in Minnesota temperatures could reduce food quality, safety, accessibility and availability.[18] It could also cause disruptions to the food system, resulting in higher prices for essential staple foods, making it harder for seniors and low-income families to afford to put food on their tables.

Conclusions

The authors of the study in *Joule* write: "Clearly, interactions of wind turbines with climate must be considered in estimates of technical wind power potential," and the science dictates we must also incorporate this impact in our calculations of economic externalities.

Wind turbines and solar panels produce significant local warming impacts on regional surface temperatures, and the degree of warming will increase if more wind turbines and solar panels are installed.

As such, the PUC must follow the science and consider whether the significant and immediate consequences for local surface temperatures relative to the expected decline in future global temperatures from reduced carbon dioxide emissions defeats the purpose of building wind turbines in the first place.

Under Xcel's current resource plan, Minnesotans, particularly rural Minnesotans, will suffer the economic and environmental damages that accompany higher local temperatures while reaping immeasurably small benefits of lower future temperatures from fewer greenhouse gas emissions.

This study's findings are critically important if Minnesotans care about how our energy choices will affect the temperature today, and tomorrow. To do this, we cannot only consider the temperature impact of emissions reductions.

---

[17] Minnesota Department of Agriculture, “Economic Analysis and Market Research,” Accessed December 31, 2020, https://www.mda.state.mn.us/business-dev-loans-grants/economic-analysis-market-research#:~:text=Agriculture%20is%20the%20foundation%20of,support%20more%20than%20431%2C127%20jobs.

[18] Minnesota Department of Health, “Agriculture and Food Security,” Climate and Health, Accessed December 31, 2020, https://www.health.state.mn.us/communities/environment/climate/docs/agfoodsummary.pdf.

American Experiment believes Xcel Energy can do more to reduce emissions and avoid regional surface temperature increases by building new nuclear power plants, purchasing electricity from large hydroelectric operators in Canada, and investing in carbon capture sequestration technology, rather than building wind turbines and solar panels.

Therefore, American Experiment does not believe it can be considered just or reasonable to allow Xcel to recoup the cost of wind and solar investments on the backs of their captive ratepayers when the company would be increasing the environmental and economic damages associated with higher regional temperatures.

Future Wind Resource Study Needed

Further problems with Xcel's proposed IRP stem from the company's reliance on historical wind turbine performance statistics to estimate future wind turbine performance. However, using historical base years without considering the likely reduction in future electricity from wind turbines located in the central region of the United States as global temperatures increase, as outlined in the academic literature, would be a mistake that would lead to lower capacity factors and higher associated costs with Xcel's wind fleet.

Academic research in *Nature Geoscience* finds that Minnesota, North Dakota and South Dakota are likely to experience a 17 percent decline in wind electricity output due to warming temperatures, which is the largest, in terms of percentage, of any part of the world (See Figure 19).[19]

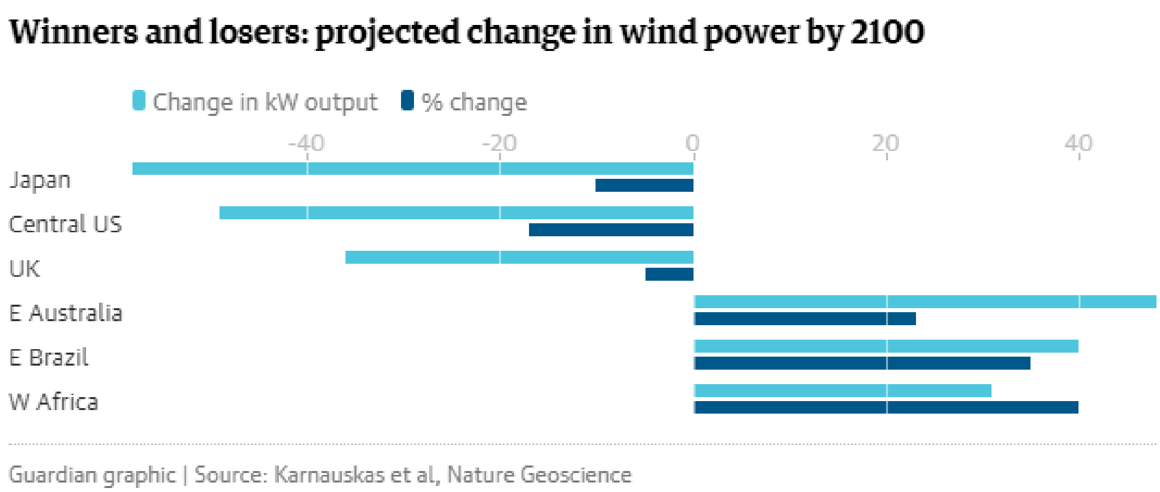


Figure 19. Wind production is expected to fall the most in Central U.S., which would significantly reduce wind generation output.

According to the models, wind output would fall the most in the northern mid-latitudes because the major driver of wind in these regions is the temperature difference between the Arctic and the tropics, and as the Arctic warms, it would reduce the difference between the arctic and the tropics, lowering wind speeds.[20]

---

[19] Kristopher B. Karnauskas Et al., “Southward Shift of Global Wind Energy Resource Under High Carbon Dioxide Emissions,” *Nature Geoscience,* December 2017, https://www.nature.com/articles/s41561-017-0029-9.

[20] Kristopher B. Karnauskas Et al., “Southward Shift of Global Wind Energy Resource Under High Carbon Dioxide Emissions,” *Nature Geoscience,* December 2017, https://www.nature.com/articles/s41561-017-0029-9.

If wind speeds fall by as much as they are modeled to fall, wind energy will be more expensive and less available than it is today.

Furthermore, the reductions in wind speed will likely occur even if Minnesota were to cut our carbon dioxide emissions to zero because Minnesota's share of global carbon dioxide emissions represents just 0.00075 of CO2 emissions worldwide. Given the uncertainties of future weather patterns in a warming climate, it makes little sense to rely upon energy sources that are dependent upon the weather.

The Public Utilities Commission should require Xcel Energy to model future wind speeds for proposed wind facilities under various emissions scenarios and disclose the financial risk that declining capacity factors pose to ratepayers.

4. Impact of Fossil Fuel Power Plant Retirements.

Xcel's most recent IRP becomes so expensive mainly because the utility company is prematurely retiring inexpensive and dispatchable power facilities to make room for expensive and intermittent renewable energy sources that require backup generating facilities and extensive changes to the transmission grid.

According to Xcel's IRP and reported future capacity retirements and additions, Xcel is planning to replace 4,342 megawatts (MW) of primarily coal and natural gas with 11,582 MW of wind, solar and "firm peaking" capacity, which is presumably natural gas.[21]

Several of the Xcel facilities up for retirement — Sherco units 1 and 2, AS King, and Sherco unit 3 — are being shut down before the end of their useful and economic lives. This means that Minnesota ratepayers will still be paying off the cost of capital and upgrades for these facilities despite the fact that these power plants are no longer producing electricity.

By not utilizing these facilities until the end of their useful lives, Xcel customers will not be receiving the full value from these facilities and will be forced to pay for wasted investments. In fact, because ratepayers pay for these facilities with the intention that they will eventually provide inexpensive electricity at a discount after initial capital expenses are paid off, Xcel customers will essentially be charged double for electricity they've already paid for.

The massive transformation of the electricity grid that Xcel seeks does not simply end with the retiring of coal power plants and the building of renewable energy facilities.

For instance, the entire transmission system is currently based around receiving large amounts of electricity from baseload energy providers, such as coal facilities like Sherco and AS King, and nuclear plants like Monticello and Prairie Island. Shutting down these power plants means Xcel must also redesign large portions of the transmission grid to accommodate intermittent power coming from new renewable energy facilities.

[21] While all capacity retirements and additions were based on Xcel documents and planned end-of-life schedules, some assumptions were made as to what resources Xcel will keep in the future, as planning has not extended far enough.

Xcel states in its latest IRP that transmission upgrades for the interconnection of new generating facilities in its resource plan will cost $1.8 billion. However, this cost is only for the interconnection of new capacity additions and does not address the kind of transmission overhaul to the bulk power system required to go from baseload power to renewable power. Affirming this notion, Xcel describes its cost estimate of $1.8 billion as "relatively conservative in comparison to results from recent MISO interconnection studies." Xcel also notes that it anticipates "future transmission investments that will support our and other utilities' goals." Xcel continues by saying "At this time, there are no formal plans for new, coordinated transmission expansion in the MISO West region, and as a result we assume that transmission expansion costs associated with new greenfield renewable additions could continue to be relatively high in the near term."[22]

Based on this, we estimate that Xcel's plan would require another $6 billion for transmission costs from 2020 to 2029 to accommodate such large amounts of renewable electricity coming from more remote locations across and outside of the state of Minnesota. While still conservative, we believe $6 billion for transmission costs is an appropriate estimate at this time based on prior CAPX expenditures, but still note that this figure is likely to be higher in the future.

Furthermore, baseload power plants offer even more crucial services to the electrical system in addition to supporting the transmission grid as currently designed, such as power deliverability, dynamic stability, fault current, black start capability, voltage support and system regulation. These are all discussed in detail in Appendix J of Xcel's IRP, but we summarize Xcel's comments briefly below.[23]

Power Deliverability — The transmission system is designed to receive large amounts of power from baseload generators and "deliver it to various area substations to meet the electrical power demands of customers." Also referred to as a transmission system's "transfer capability" because it transfers power from a few generators to other areas connected to the grid. Xcel also notes that "changing generator characteristics or locations requires corresponding changes to grid capabilities."

Dynamic Stability — As Xcel explains, the transmission grid acts as "a vast interconnected machine" with large and small gears spinning synchronously and reliably generating and delivering electricity to customers. Large generators (the large gears of the machine) provide a backbone to the transmission grid in the case that small generators (the small gears) — including wind turbines and solar panels — drop in and out of production due to their dependency on the weather. Because of these large generators, which continue to spin even as minor contingencies take place, the "interconnected machine" is able to keep producing electricity uninterrupted. Xcel stresses the importance of large generators, stating that, "Having the large gears in place also

[22] Xcel Energy, "Supplement 2020-2034 Upper Midwest Integrated Resource Plan," Docket No. E002/RP-19-36 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={F0AB0573-0000-C11C-B7B2-2FA960B89BD1}&documentTitle=20206-164371-01

[23] Xcel Energy, "Attachment J1: Baseload Study," Docket No. E002/RP-19-368, July 01, 2019, www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={10FBAE6B-0000-C040-8C1D-CC55491FE76D}&documentTitle=20197-154051-03

enables more small gears to be connected to the machine because they don't have as much impact with the large gears in place.”

Fault Current — The electrical grid needs protection equipment to differentiate between customer load and electric faults, which large generating units provide for the system. Without fault current, the protection equipment will not work properly. As Xcel notes, “Many of the electric devices that are deployed on the grid and in service today, such as wind generators and other assets, are engineered and designed to function properly with the amount of fault current that has been historically available on the grid. Therefore, changing the amount of fault current on the grid could not only impact protection systems, but could also impact other electric assets.”

Black Start Capability — Large generating units “with a secure fuel source” are necessary for “restarting the machine” in the case of a major grid outage. As Xcel notes, “Renewable generation, such as solar and wind are not currently considered eligible Target Units due to their inherent intermittent nature, and their inability to provide or absorb reactive power. A large battery energy storage system can be configured to be technically capable of providing black start service, likely as part of a relatively small Initial Black Start Unit. However, they may not yet be economically viable for this purpose. There are also technical concerns with regard to how batteries can absorb reactive power, which would be needed if the battery was not paired with another type of generation asset.”

Voltage Support — Xcel explains, “The real time conditions on the transmission system are constantly changing and require ongoing adjustments to maintain voltages at required levels. Large synchronous power sources like our current baseload units, provide significant system voltage support along with necessary “reactive power.” Reactive power is required to start and run motors, like in air conditioners and industrial equipment (called “inductive loads”). Large population centers generally require large generating units located reasonably nearby to support system voltage effectively. As in the dynamic stability discussion, without enough large units in place, the machine isn’t as capable and robust when it runs.”

System Regulation — The ability of the system to respond to changes in usage and keep generation and load “matched at all times” is known as system regulation. As Xcel notes, “When there are changes to the generation/load balance, as when wind speeds drop or a large industrial load comes online, the frequency drops if there is insufficient regulation capability on the system.”

With these factors in mind, it is unclear how an electrical grid can function without baseload and dispatchable generating facilities on the system. It becomes a question as to how Xcel plans to replicate these services after it has shut down a good portion of their baseload power plants and replaced them with energy sources that are inherently incapable of providing them.

Xcel, for its part, has offered a solution: simply building more baseload power plants.

From 2031 to 2034, Xcel plans to build over 2,600 MW of “firm dispatchable” capacity — which, in the absence of economical baseload battery storage, will most likely be natural gas facilities (we attributed these additions to combustion turbine natural gas capacity in our model due to the infeasibility of current battery storage technologies).

As Xcel notes:

"The need for these dispatchable resources emerges in this later timeframe due to the major plant retirements already discussed, as well as the expiration of several PPAs. Our reliability analysis demonstrates that these additions are necessary to continue to support grid reliability and resiliency in light of the increased renewables being added to the system and the baseload units being retired."[24]

Essentially, Xcel is requesting to shutter inexpensive baseload power plants prematurely only to necessitate spending billions on new baseload power plants to maintain reliability in the near future. All the while, Xcel seeks to spend billions of additional dollars on renewable energy facilities that provide none of the services needed to maintain the reliability and stability of the grid. As a result, these renewable resources constitute an expensive premium paid in addition to the costs associated with maintaining a reliable grid.

When we consider that utility companies primarily earn profit based on the capital expenses they incur when building new infrastructure, this plan is nothing short of ratepayer larceny.

Xcel customers paid for the company's existing baseload power plants on the basis that they would receive the full value of these facilities. It is not reasonable, just or appropriate to make them pay double or triple for services they have already paid for.

If renewable energy cannot provide the same services as baseload power facilities, then it is incredibly disingenuous to suggest that Xcel is "transitioning" to renewable energy — especially when Xcel simply plans to replace the retired dispatchable power plants with more dispatchable power plants.

Conclusion

Xcel is partaking in ratepayer "sleight of hand" on a massive scale, seeking to charge its customers for newly built renewable energy facilities *and* to replace existing baseload power plants that are partially or fully depreciated and are no longer padding Xcel profits.

Simply put, dispatchable power facilities are needed for a grid to maintain reliability because battery facilities are incapable of replacing them. Battery storage facilities are not able to provide the necessary services the electrical grid requires to fully replace fuel-based facilities with renewable energy sources. As Xcel states in its resource plan when discussing its aspirations to go carbon-free by 2050:

"We also made clear that our 2050 aspiration requires technologies not yet commercially available at the scale needed. This cannot be done with only wind, solar, and the short-duration

[24] Xcel Energy, "2020-2034 Upper Midwest Integrated Resource Plan," Docket No. E002/RP-19-36 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={00FBAE6B-0000-C414-89F0-2FD05A36F568}&documentTitle=20197-154051-01.

battery storage technologies available today. It will likely require some amount of carbon-free dispatchable generation, longer-duration storage than is available today, more electrification, and more flexible demand. The technologies needed may include gas with carbon capture and storage, power to gas (renewable hydrogen), seasonal energy storage, advanced nuclear or small modular reactors, deep rock geothermal, and other technologies yet to be identified."[25]

Since Xcel itself admits that the grid must rely on baseload power for years to come, and that the technology to do without fuel-based dispatchable energy sources simply does not exist, we argue it would be incredibly inappropriate for the Commission to approve Xcel's proposed resource plan. This view is not pessimistic about future technology breakthroughs. Rather, it is realistic about not moving forward too fast without the necessary technology required to maintain reliability.

Xcel's proposed resource plan adds thousands of megawatts of renewable energy sources to the grid while admitting that it is inherently incapable of maintaining reliability without backup generating facilities. We ask the PUC to consider this fact when it decides to approve or reject the significant cost increases that will result from Xcel's resource plan.

5. Reliability Concerns and Capacity Values

Xcel's proposed resource plan would see the utility shutter more than 4,300 MW of dispatchable capacity and increase the company's reliance upon imported market purchases from the Midcontinent Independent Systems Operator (MISO). This resource plan has concerning similarities to the composition of the grid in California, which experienced rolling blackouts during a heatwave in August 2020.

Several factors contributed to the rolling blackouts that occurred in California: thousands of megawatts of reliable nuclear and natural gas plants were shuttered from 2012 through 2019; an overreliance on non-dispatchable renewable resources and electricity imports from neighboring states resulted in inadequate supply when power was needed most; and utility regulators at the California Public Utilities Commission ignored warnings of potential capacity shortfalls issued by the California Independent Systems Operator (CAISO).

Reliable Capacity Closures

Figure 20 shows that California had more installed power plant capacity in 2019 than 2013, but the growth in capacity was almost entirely due to a 9,284MW increase in solar capacity. During this time, California reduced the amount of natural gas capacity on the grid by 7,750 MW.

[25] Xcel Energy, "Appendix H: Environmental Regulations Review," Docket No. E002/RP-19-36 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={10FBAE6B-0000-C040-8C1D-CC55491FE76D}&documentTitle=20197-154051-03.

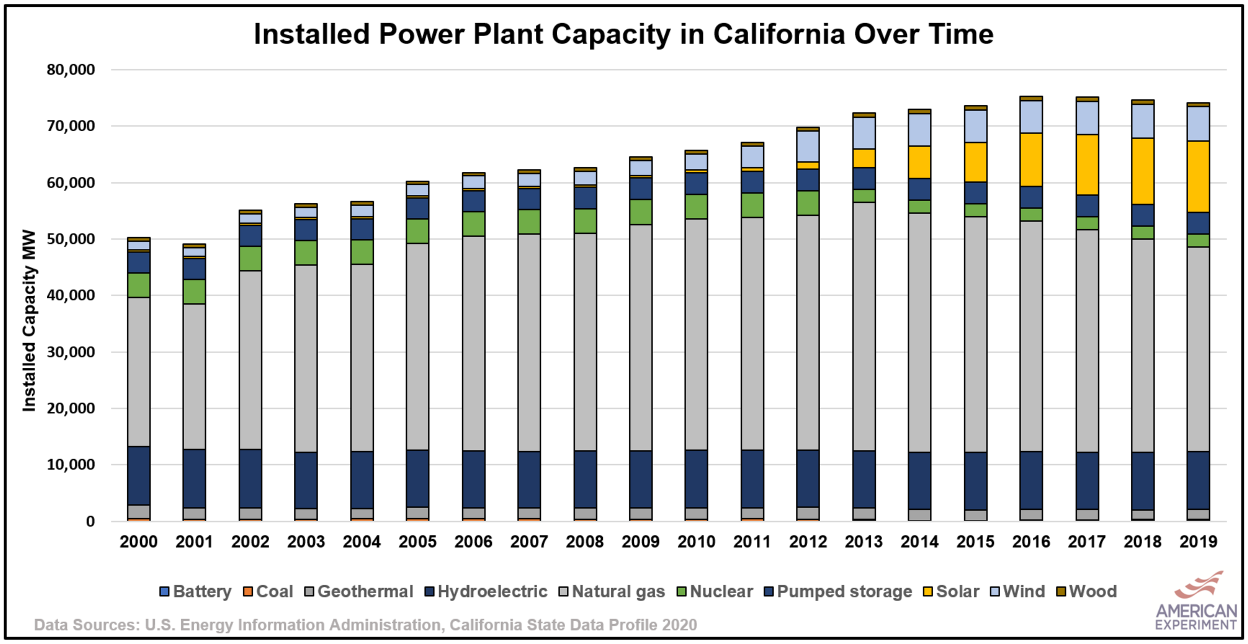


Figure 20. California increased the amount of installed capacity on the grid from 2013 through 2019. Solar capacity increased by 9,284 MW while natural gas capacity decreased by 7,750.

The closure of this reliable natural gas capacity unquestionably contributed to the rolling blackouts because there was not enough dispatchable capacity online in California to compensate for a loss of generation from solar and wind, in addition to a lack of available electricity for import.

An Overreliance on Wind, Solar, and Imports

Reports detailing the rolling blackouts conclude poor planning was the root cause, but the reason the planning was so poor was because it left the state overly reliant upon wind turbines, solar panels and electricity imports from other states.

The heatwave caused a confluence of factors that led to an inadequate supply of electricity. Hot temperatures led to high electricity demand through the evening hours when the state's fleet of solar panels is unable to provide the much-needed power.

The regional heatwave also increased demand for electricity in other states, reducing California's ability to buy power from neighboring states. Lastly, the state suffered from a loss of nearly 1,000 MW of wind, and an outage at a 470 MW power plant.[26]

According to CAISO's president, Stephen Berberich, "On Saturday night, we were within an hour of being able to service the load without incident…We lost a 400 MW [power station] unit

[26] California Independent Systems Operator, "ISO Requested Power Outages Following Stage 3 Emergency Declaration; System Now Being Restored," Press Release, August 15, 2020, http://www.caiso.com/Documents/ISORequestedPowerOutagesFollowingStage3EmergencyDeclarationSystemNowBeingRestored.pdf.

and, the wind had been very good, but ran out. If the wind hadn't run out on us, we would have been ok."[27]

Warnings Ignored

The rolling blackouts were not an unforeseeable event. In fact, CAISO issued several warnings that a heatwave across the southwest could trigger rolling blackouts in Calfironia. CAISO's warnings were ignored by the California PUC.

"For many years, we have pointed out to the [Public Utilities Commission] that there was inadequate power available during the net peak," said Berberich, CAISO's president.[28]According to the Los Angeles Times: "Berberich faulted the commission for failing to ensure adequate power capacity on hot summer evenings, when electricity from the state's growing fleet of rooftop solar panels and sprawling solar farms rapidly drops to zero but demand for air conditioning remains high. It's a challenge that will only intensify as California adds more solar panels and wind turbines to meet its targets of 60% renewable electricity by 2030 and 100% emissions-free power by 2045."[29]

California Isn't Alone

Xcel also noted in Appendix J1 of its resource plan that Australia experienced similar power shortages due to renewable energy facilities tripping offline.[30] As explained by Xcel:

"[I]n 2016, the Australia power system experienced storm damage that forced several transmission lines to open. The wind farms that were being relied upon on at that time were not able to survive multiple ride-through capability cycles, and started to trip offline – resulting in a large-scale power outage in southern Australia. While there are standards and practices in place in the Eastern Interconnection, MISO and Minnesota transmission systems to help avoid this same scenario, ***the rapid escalation of renewable resources and the earlier than expected retirement of baseload generation places a greater strain on the transmission system to deliver***

---

[27] Tom Tapp, "California Governor Gavin Newsom Declares Statewide Emergency, Mobilizes National Guard Amid Fires, Record Heat, "Imminent" Rolling Power Outages That Could Hit Millions," *Deadline,* August 18, 2020, https://www.yahoo.com/entertainment/california-governor-gavin-newsom-declares-224446293.html?guccounter=1&guce_referrer=aHR0cHM6Ly93d3cuZ29vZ2xlLmNvbS8&guce_referrer_sig=AQAAAMzOMAj7GIkNW89XTt-29dBIklxQyBeERL9Mq6iIuDDSnFpQuOTEexNjZwOa_VTf6lwy0qj2uUILHrJY3ipcF3qaQ0uy6Fq9ie6V2oXONElF40l4OF7xmQ6bz-fumcUFd1RQKlp2S5JrCZ3dtmvEXLkibVhllDpk8VPjjzvQtECO.

[28] Sammy Roth, "California blackouts are Public Utilities Commission's Fault, Grid Operator Says," Los Angeles Times, August 17, 2020, https://www.latimes.com/environment/story/2020-08-17/public-utilities-commission-to-blame-for-blackouts-caiso-says.

[29] Sammy Roth, "California blackouts are Public Utilities Commission's Fault, Grid Operator Says," Los Angeles Times, August 17, 2020, https://www.latimes.com/environment/story/2020-08-17/public-utilities-commission-to-blame-for-blackouts-caiso-says.

[30] Xcel Energy, "Attachment J1: Baseload Study," Docket No. E002/RP-19-368, July 01, 2019, www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={10FBAE6B-0000-C040-8C1D-CC55491FE76D}&documentTitle=20197-154051-03

more remote sources of generation, and increases the likelihood of events similar to the Australia power outage occurring on the local transmission system."

Given the track record of California and Australia, Commissioners in Minnesota should ensure that Xcel Energy is not placing millions of Minnesotans at similar risk of losing power.

Xcel's IRP plans to build over 11,500 MW of capacity to replace over 4,300 MW from the baseload power facilities it is seeking to retire, such as Sherco units 1, 2, and 3 and Allen S. King. This represents nearly a 3:1 ratio, and the utility is still seeking to rely on market purchases to meet projected supply shortfalls.

More Capacity, Lower Capacity Values

It is important to understand why, exactly, Xcel must replace its retiring facilities with such a disproportionate amount of capacity. Simply put, Xcel must do this because renewable energy capacity is not as valuable or reliable to an electricity system as fuel-based power facilities, which means more renewable capacity must be built to maintain reliable electricity service.

What our model has shown is that maintaining reliability has additional costs that are not accounted for in LCOE calculations — which is exactly why the Energy Information Administration (EIA) advises not to compare LCOE values of dispatchable resources (fuel-based) with that of non-dispatchable resources (renewable). [31] As EIA states:

"Because load must be continuously balanced, generating units with the capability to vary output to follow demand (dispatchable technologies) generally have more value to a system than less flexible units (nondispatchable technologies) that use intermittent resources to operate."

Our model was designed to capture the additional cost that intermittent renewable energy sources impose on the electrical grid and explain why relying on traditional LCOE values to guide energy policy is misguided and dangerous for utility planning.

For example, overbuilding the electric grid at a nearly 3:1 ratio is not a result of Xcel forecasting an increase in electricity usage. Instead, Xcel is building this additional capacity because the capacity value of wind and solar is half that of fuel-based energy sources, or worse.

According to the National Renewable Energy Laboratory (NREL), capacity value is defined as "the contribution of a power plant to reliably meet demand."

While solar energy is typically rated with a 50 percent capacity value by Minnesota's system operator, the Midcontinent Independent System Operator (MISO), this value is primarily a placeholder percentage until the penetration levels of solar energy increases to high enough levels to determine a suitable rating. MISO's accredited capacity value for wind energy is as low as 15.7 percent.

---

[31] U.S. Energy Information Administration, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020 ," February 2020, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

The low capacity value of wind energy is highlighted by the chart below from Xcel's rate case filed on Nov. 2, 2020. The "Net Dependable Capacity" (NDC) rating – which is similar to that of capacity value – of Xcel's wind facilities are 16.65 percent, 15.69 percent, 15.72 percent, 16.67 percent, 15.74 percent, 15.66 percent, 15.72 percent and 15.68 percent. Thus, for every 100 MW of wind capacity Xcel owns, anywhere between 15.6 and 16.7 MW is considered to be reliable capacity (See Table 1).

Location and Capacity Rating in MWs

Plant Description	Address	Unit Type	Net Max Capacity (NMC)	Net Dependable Capacity (NDC)	Net Max Capacity (NMC)	Net Dependable Capacity (NDC)	Net Max Capacity (NMC)	Net Dependable Capacity (NDC)	Net Max Capacity (NMC)	Net Dependable Capacity (NDC)
			2017	2017	2018	2018	2019	2019	2020	2020
Base Load Coal										
Allen S King 1	1103 King Plant Road, Bayport MN 55003	FC/Steam	511.0	511.0	511.0	511.0	511.0	511.0	511.0	511.0
Sherburne 1,2,3*	13999 Industrial Blvd., Becker MN 55308	FC/Steam	1879.0	1879.0	1879.0	1879.0	1879.0	1879.0	1879.0	1879.0
Intermediate										
Black Dog 2	1400 Black Dog Road, Burnsville, MN 55337	Gas CC	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
Black Dog 5**	1400 Black Dog Road, Burnsville, MN 55337	FC/Steam	181.0	165.0	181.0	165.0	181.0	165.0	181.0	165.0
High Bridge 7,8**	501 Shepard Road, St. Paul MN. 55102	Gas CC	370.0	304.0	370.0	304.0	370.0	304.0	370.0	304.0
High Bridge 9	501 Shepard Road, St. Paul MN. 55102	FC/Steam	236.0	226.0	236.0	226.0	236.0	226.0	236.0	226.0
Riverside 9,10**	3100 Marshall Street NE, Minneapolis, MN 55418	Gas CC	342.0	294.0	342.0	294.0	342.0	294.0	342.0	294.0
Riverside 7	3100 Marshall Street NE, Minneapolis, MN 55418	FC/Steam	160.0	160.0	160.0	160.0	160.0	160.0	16.0	16.0
Biomass / RDF										
Red Wing 1,2	801 E 5th Street, Redwing MN 55066	RDF/Steam	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Wilmarth 1,2	800 Summit Ave, Mankato MN 56001	RDF/Steam	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Wind										
Blazing Star I	600 E Railroad St, hendricks,MN 56136	Wind	0	0	0	0	0	0	200.0	33.3
Border Wind	5190 107th Street NE, Rolla, ND 58367	Wind	148.00	23.10	148.00	23.10	148.00	22.50	147.9	23.2
Courtenay Wind	1401 Hwy 9 SE, Courtenay, ND 53426	Wind	195.00	30.40	195.00	30.40	195.00	29.60	190.2	29.9
Foxtail	7208 91st SE, Kulm, ND 58456	Wind	0	0	0	0	0	0	150.0	25.0
Grand Meadow	228 Industrial Park Dr, Dexter, MN 55926	Wind	100.50	15.70	100.50	15.70	100.50	15.30	99.4	15.6
Lake Benton	1973 170th Ave Holland,MN 56139		0.0	0.0	0.0	0.0	99.0	15.5	99.0	15.5
Nobles Wind	19469 McCall Avenue, Reading, MN 56165	Wind	200.00	31.20	200.00	31.20	200.00	30.40	197.2	31.0
Pleasant Valley Wind	228 Industrial Park Dr, Dexter, MN 55926	Wind	196.00	30.60	196.00	30.60	196.00	29.80	195.8	30.7

Table 1. This table shows the Net Dependable Capacity for power plants owned by Xcel Energy.

Compare this to Xcel's "Base Load Coal" facilities, which have a NDC rating of 100 percent, or Xcel's "Intermediate" natural gas power plants, which range from 82 percent to 100 percent.

Because fuel-based facilities are 5 to 7 times more "dependable" than wind and solar, to maintain reliability based on capacity values, you would need at least 5 to 7 times more renewable capacity than the retiring fuel-based capacity. In other words, for every MW of fuel-based energy capacity retired, 5-7 MW of wind or solar will need to be built to replace it if not accompanied by baseload capacity additions such as natural gas.

Furthermore, while the capacity value of wind energy is 15.7 percent of total capacity, there are times when wind turbines are using more electricity than they are producing, resulting in a deficit on the electricity grid that must be made up elsewhere by fuel-based energy sources. These instances don't necessitate extreme weather either. Often, it is the *lack* of extreme weather that causes a decrease in electricity production from wind turbines. As noted by Xcel:

"Because low temperatures and other conditions unique to winter are not the only cause of low renewable generation in MISO, we also looked to the summer months as potential case studies. July 29, 2018 was an especially windless day. During the 8:00 a.m. hour, ***the entire MISO wind portfolio (over 17,000 MW at that time) had a combined output of minus 11 MW*** *– meaning the wind turbines that were online were taking more power than they were producing. This hour was part of an approximately 110 hour sustained stretch in which the combined output of all wind resources in the MISO footprint fell well below the accredited values used in present*

planning processes. We again encountered sustained low wind conditions in early 2019, with 370 hours of wind production below accredited values before May 1."[32]

This testimonial from Xcel — that 17,000 MW of wind capacity on MISO's system had a combined output of minus 11 MW — should dispel any notion that "the wind is blowing somewhere." Sometimes, it isn't blowing *anywhere.* As such, American Experiment believes that a 15.7 capacity value for wind energy overvalues the reliability wind energy provides to an electrical grid.

Xcel makes the lack of reliability of renewable energy sources very clear in appendix J1 of its latest resource plan filing, stating the following:

"Simply increasing the amount of solar and wind generation on the Company's system is an unrealistic approach to addressing capacity shortfalls. In order to have sufficient capacity to meet the customer demand discussed in the scenarios above [100 percent renewable energy], the Company would need in excess of 180,000 MW of nameplate capacity wind and solar generation. And, even this amount of renewable generation may be insufficient given the declining capacity value of renewable generation, as discussed above, and the probability there will be times with extremely low levels of wind and sunlight."

As you can see, renewable energy sources such as wind and solar will never be able to provide the reliability attributes the system needs on their own, because, as Xcel explains, they are "inexorably tied to the variability of weather patterns, and at times they are simply not available."

Furthermore, as already discussed, the technological ability of battery storage is nowhere near adequate enough to "firm" intermittent renewable energy resources. As detailed by Xcel itself:

"[C]urrent storage technologies and demand management programs are also insufficient to meet the duration of real events like those discussed above. Current battery storage systems are limited (typically to 4 hour discharge periods) with significant time needed to recharge. Unless overbuilt many times over, these resources would not be able to provide energy for the full duration of such events; they also may not be able to recharge fast enough to be a viable resource during the consecutive periods of low renewable output."[33]

The cost of replacing Xcel's baseload power facilities with battery storage would likely be in the hundreds of billions of dollars based on the cost of these facilities and the amount needed to maintain reliability.

As stated in Minnesota law, it is the duty of the PUC to regulate utility companies in a way that they provide customers "with adequate and reliable services at reasonable rates." Our model

---

[32] Xcel Energy, "Attachment J1: Baseload Study," Docket No. E002/RP-19-368, July 01, 2019, www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={10FBAE6B-0000-C040-8C1D-CC55491FE76D}&documentTitle=20197-154051-03

[33] Xcel Energy, "Attachment J1: Baseload Study," Docket No. E002/RP-19-368, July 01, 2019, www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={10FBAE6B-0000-C040-8C1D-CC55491FE76D}&documentTitle=20197-154051-03

shows that Xcel's plan to incorporate over 7,500 MW of renewable capacity does not provide its ratepayers with reliable services, nor at reasonable rates. John Bear of MISO makes this clear in his testimony to the House Committee on Energy and Commerce, Subcommittee on Energy.[34]

We ask the PUC to consider the lack of reliability Xcel's plans presents when approving or rejecting its proposal. We also ask the Commission to consider the significant cost increases it will result in for Xcel's customers.

6. Xcel's RES Rate Impact Report and Why It Underestimates Rate Impact

Since the passage of the Next Generation Energy Act (NGEA) in 2007, Xcel and every other Minnesota utility company has been required to conduct a Renewable Energy Standard (RES) and Solar Energy Standard (SES) Rate Impact Report.

The purpose of the rate impact report is "to provide a mechanism for determining and communicating to legislators and constituents what utility rates would be if the 2007 Minnesota Next Generation Energy Act (NGEA) had never been implemented."

If the goal of the rate impact report is to show the rate impact of having to comply with the NGEA, the methodology Xcel uses does not succeed in this endeavor.

As Xcel states in Attachment B of its supplemental filing:

"Future RES rate impacts were derived by comparing NSP electric system cost projections within the Strategist computer modeling for two different futures: 1) a "RES" future that reflects the Reference Case in the 2020-2034 Resource Plan, and, 2) a "No RES" future in which all renewable generation capacity (MW) and energy (MWh) contained in the "RES" future case are removed and replaced with nonrenewable generation."

As you can see, Xcel is merely comparing the cost of building renewable energy sources with the cost of building non-renewable energy sources in its place. This underestimates the true rate impact of the renewable energy standard for one fundamental reason: without the mandate from the RES, there would be no need to build any new generation capacity at all because Xcel already has enough non-renewable capacity on the grid to meet electricity demand and maintain reliability. Renewable energy additions brought on by the RES are merely a premium on top of what rates would be without them – apart from avoided fuel costs.

A true rate impact report would be to compare the cost of building renewable energy sources that are used to comply with Minnesota's RES with the cost of maintaining existing energy sources already on the grid that are fully capable of meeting electricity demand without the need for new capacity additions.

By including the cost of building non-renewable energy sources in the absence of a renewable energy standard, Xcel is grossly overestimating the cost of not having to comply with the RES and is therefore underestimating the true rate impact caused by the existence of such a mandate.

[34] https://www.congress.gov/116/meeting/house/110174/witnesses/HHRG-116-IF03-Wstate-BearJ-20191030.pdf

In addition, Xcel does not state whether replacing "all renewable generation capacity (MW)" means accredited capacity or nameplate capacity. As mentioned in the previous section, non-renewable, dispatchable generating capacity is much more reliable to electricity system operators than renewable energy sources. As such, much less of it is needed to maintain reliability on the electrical grid, reflected by higher accredited capacity ratings for dispatchable energy sources.

If Xcel is replacing renewable *nameplate* capacity, rather than *accredited* capacity, in a 1:1 ratio with new dispatchable energy capacity, this would result in Xcel greatly underestimating the cost of the renewable energy standard. In addition, it would overestimate the cost of not complying with the standard relative to continuing to use existing generation facilities.

As it stands currently, Xcel's RES Rate Impact Report is incapable of showing the true rate impact of complying with Minnesota renewable energy mandate. As a result, we ask the PUC to disregard Xcel's rate impact report in making its decision on whether to approve or reject Xcel's resource plan.

7. Nuclear Power Scenarios

Nuclear power is a carbon-free and dispatchable electricity source that can be used for baseload power. As such, it can mitigate the reliability issues that accompany renewable and non-dispatchable energy sources.

Despite being an incredibly reliable source of CO2-free electricity, nuclear power is often dismissed as being too expensive for the job. Our modeling determines that this is only half true.

Indeed, building nuclear power in the aims of decreasing CO2 emissions would be more expensive than continuing to utilize existing carbon-emitting power plants. When compared to Xcel's current IRP, however, nuclear power would be much less expensive while meeting the same carbon-free percentage as Xcel's current IRP.

In addition to modeling Xcel's IRP, we conducted two hypothetical scenarios in which nuclear power replaced renewable energy sources as the carbon-free energy source – a "short-term" and a "long-term" nuclear energy scenario. In both scenarios, we found that adding enough nuclear power to achieve the same level of carbon-free energy sources as Xcel's IRP (89 percent) would be less expensive than Xcel's current plan.

In both scenarios, coal is retired completely (on different schedules) and the current wind fleet would also be phased out as these facilities reach the end of their 20-year useful lifetimes.

The short-term nuclear scenario would be nearly $13 billion less expensive than Xcel's current IRP, for a total of over $44.4 billion in additional costs. This scenario would retire Xcel's coal plants on the same schedule as stated in the utility company's IRP and would add 3,000 MW of nuclear power. By 2030 all coal is retired, and Xcel would achieve a carbon-free percentage of 79.7 percent. By 2050, this percentage would increase to 89.5 percent (See Figure 21).

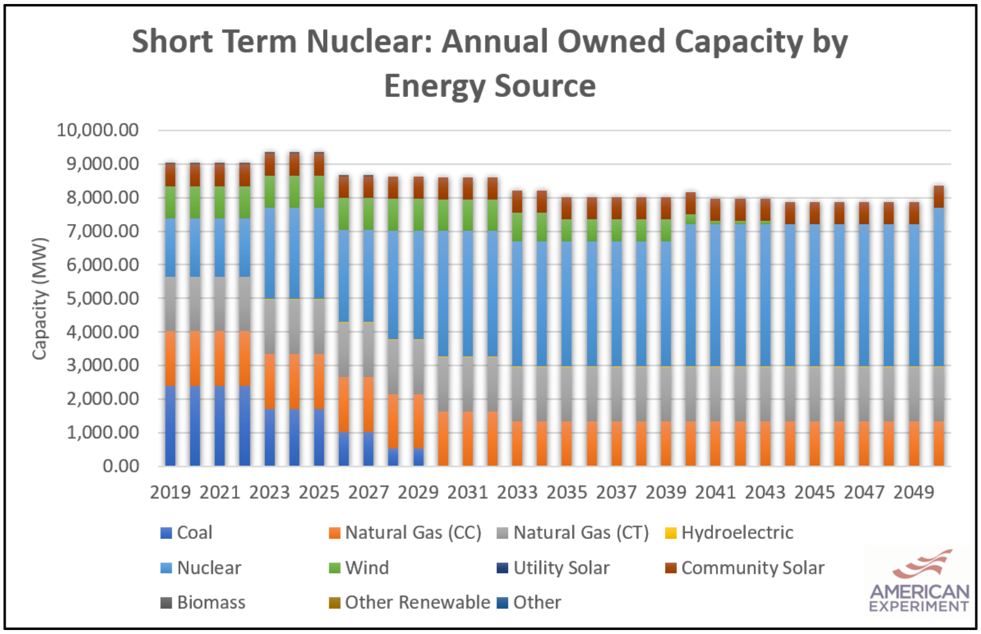


Figure 21. Nuclear capacity additions would allow Xcel Energy to meet their carbon emissions reduction goals at a much lower cost.

The long-term nuclear scenario would cost $36.5 billion, a savings of over $20 billion compared to Xcel's current plan while still achieving 89.5 percent carbon-free generation by 2050.

The key difference between the long-term and short-term nuclear scenarios is the coal retirement schedule. Unlike the short-term scenario, Allen S. King and Sherco Unit 3 would remain in Xcel's fleet until the end of their useful lives in 2037 and 2035, respectively (See Figure 22). This would allow ratepayers a chance at significant cost savings by taking full advantage of the inexpensive electricity coal sources.

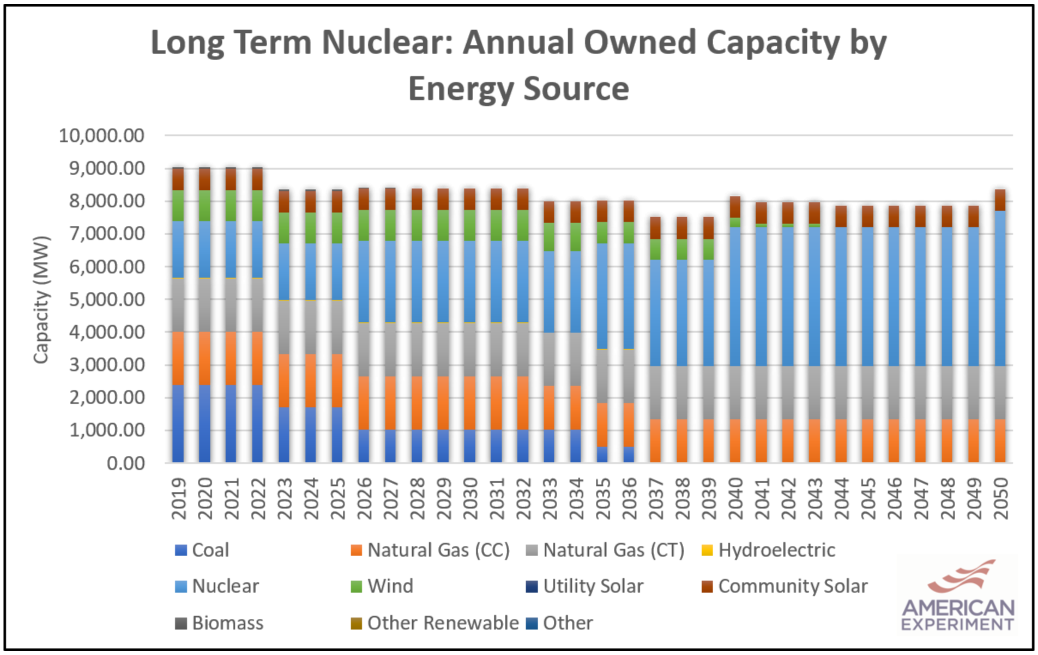


Figure)22. The long-term nuclear scenario produces $20 billion in ratepayer savings because it allows existing power plants to operate through the end of their useful engineering lives.

Additionally, new nuclear facilities would come onto the system more gradually, rather than concentrating these investments over a shorter time span than would be necessary when retiring coal facilities prematurely. The gradual addition of 3,000 MW of nuclear capacity reduces the ratepayer costs by spreading investments over a longer and more gradual time frame.

Even while nuclear power facilities have much larger capital costs than wind and solar facilities, as well as nearly the same, if not higher LCOE values than wind energy, the two nuclear energy scenarios result in fewer additional costs because of the factors we have already discussed.

Mainly, nuclear power does not require load balancing from other energy sources, such as natural gas or battery storage. Nuclear energy also requires far fewer transmission expenses because it can be located closer to large population centers. In addition, it does not require a complete transformation of the grid, as the current transmission system is much more equipped to handle baseload, dispatchable power than intermittent, non-dispatchable power from wind and solar energy sources. Lastly, nuclear facilities can last for 80 years, whereas wind and solar facilities last 20 to 25 years. This necessitates higher long-term capital costs for wind and solar than for nuclear power plants per MWh of electricity generated.

The low cost of the long-term nuclear energy scenario is achieved by the utilization of the current generation resources on Xcel's system. Indeed, it is the only plan that would fulfill Xcel's description of its original IRP, in which it says, "The modest cost of our plan is facilitated by our strategy of deferring resource additions until later in the plan and making use of existing assets on our system." No utility company is truly "making use of existing assets" when it is planning to retire several of the largest units on their grid before the end of their useful lives, as Xcel is doing. The long-term nuclear scenario, which allows these units to phase out naturally, is the only scenario that takes advantage of the low costs offered by Xcel's existing assets.

8. Conclusion

We believe Xcel's plan to close Sherco 3 and AS King before the end of their useful lifetimes will harm ratepayers and achieve no measurable environmental benefits. In fact, the use of wind and solar facilities to replace the generation from these units would cause more local surface warming than would be averted by reducing carbon dioxide emissions from the plants.

American Experiment believes the most prudent and responsible resource plan would allow Sherco 3 and AS King to operate until the end of their useful engineering lives and gradually replacing them with new nuclear power plants. This strategy will optimize reliability, affordability and sustainability.

Furthermore, we believe that any proposed capacity addition that does not provide cost savings to ratepayers, meet future electricity demand growth, improve reliability, or satisfy legislative mandates should not be allowed into Xcel's rate base and charged to ratepayers.

9. Assumptions & Methodology

Capacity Additions and Retirements:

All capacity additions in our model are based directly on Xcel's preferred plan in its integrated resource plan. Based on the current state of large-scale battery storage, which is still too expensive and ill-equipped to deploy as a baseload and dispatchable energy source, our model assumes that all "firm-dispatchable" capacity listed in Xcel's IRP will consist of natural gas combustion turbine (CT) capacity, which is consistent with current modeling by Xcel. As the utility company explains when speaking about the 2,600 MW of firm dispatchable capacity, "As discussed in our initial filing… we modeled these units as CTs." Our model also assumes that all capacity additions will be owned and operated by Xcel.

Capacity retirements for owned and power purchase agreements (PPA) are based on Xcel's IRP and retirements listed in the Annual Electric Utility Report.[35] In addition, several assumptions for capacity retirements were made that were not listed in these filings, such as Angus Anson (2034) and Black Dog (2032), not covered by the Annual Electric Utility Report. These retirements were necessary to avoid significant overbuild on Xcel's system.

The net capacity added to Xcel's system, based on the utility company's planned additions and retirements, is 7,240 MW. The total capacity built by Xcel based on its IRP, including community solar, exceeds 11,500 MW, while the total capacity retired exceeds 4,300.

Generation and Electricity Demand:

Our model assumes that electricity demand will remain constant based on 2019 generation. This is because the additions in Xcel's IRP are not to satisfy demand growth, but renewable energy

---

[35] Xcel Energy, "Future Capacity Additions, Future Capacity Retirements," Annual Electric Utility Report, July 31, 2020
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={3068A673-0000-C788-AFD4-67C0289F05AA}&documentTitle=20207-165437-09

and carbon-free goals set forth by the state and the utility itself. As Xcel explains in its supplemental IRP, "We believe the Supplement Preferred Plan best positions the Company to achieve our ambitious carbon reduction goals while maintaining a reliable system…"

In addition, Xcel itself projects a "relatively flat growth" in electricity demand through 2034.[36]

LCOE Estimates for Existing Resources:

LCOE estimates for existing energy sources are based on FERC Form 1 filings from Xcel Energy. We calculated the cost of each Xcel facility and averaged the cost of each plant type (coal, natural gas, nuclear) according to each energy source owned by Xcel.

New Wind and Solar Capacity Factors:

For wind resources, we assumed a capacity factor of 50 percent for all new capacity additions. We base this assumption on the improvements in wind energy sources in recent years. For example, wind facilities put into operation in 2015 or later, such as Border and Pleasant Valley, operated at 46 and 44 percent capacity factors, respectively, in 2019. These capacity factors are much improved from older facilities such as Nobles, which was built in 2010 and operates at a 36 percent capacity factor.

Newly built solar resources are assumed to operate at a 17.7 percent capacity factor based on Xcel's assumptions in its IRP.

New LCOE Estimates for Wind and Solar:

[36] Xcel Energy, "Supplement 2020-2034 Upper Midwest Integrated Resource Plan," Docket No. E002/RP-19-36 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={F0AB0573-0000-C11C-B7B2-2FA960B89BD1}&documentTitle=20206-164371-01

For new LCOE estimate for wind and solar, our model makes no assumptions of its own and relies solely on Xcel's Strategist modeling for in-service year additions for wind and solar energy sources (See Table 2)

Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$29.79	$40.00	$73.92	$97.93
2021	$29.65	$40.00	$71.77	$91.35
2022	$34.04	$40.00	$70.71	$88.46
2023	$38.61	$49.48	$69.59	$87.04
2024	$43.39	$49.90	$68.41	$85.55
2025	$52.15	$50.32	$67.18	$83.98
2026	$52.55	$50.74	$65.88	$82.34
2027	$52.98	$51.17	$64.53	$80.63
2028	$53.42	$51.59	$63.11	$78.83
2029	$53.89	$52.01	$61.62	$76.95
2030	$54.39	$52.43	$60.07	$74.98
2031	$54.95	$53.10	$60.66	$75.15
2032	$55.54	$53.78	$61.25	$75.28
2033	$56.16	$54.47	$61.84	$75.40
2034	$56.80	$55.16	$62.43	$75.49
2035	$57.47	$55.86	$63.02	$75.56
2036	$58.17	$56.57	$63.61	$75.60
2037	$58.91	$57.28	$64.20	$75.61
2038	$59.67	$58.00	$64.78	$75.60
2039	$60.47	$58.72	$65.37	$75.56
2040	$61.30	$59.45	$65.95	$75.49
2041	$62.17	$60.13	$66.88	$76.33
2042	$63.07	$60.81	$67.82	$77.18
2043	$64.01	$61.50	$68.77	$78.04
2044	$64.99	$62.18	$69.74	$78.89
2045	$66.01	$62.87	$70.71	$79.76
2046	$67.07	$63.57	$71.70	$80.62
2047	$68.17	$64.27	$72.70	$81.49
2048	$69.32	$64.97	$73.71	$82.36
2049	$70.52	$65.68	$74.73	$83.24
2050	$71.76	$66.38	$75.76	$84.07
2051	$73.20	$67.71	$77.28	$85.75
2052	$74.66	$69.07	$78.83	$87.47
2053	$76.16	$70.45	$80.40	$89.22
2054	$77.68	$71.86	$82.01	$91.00
2055	$79.23	$73.29	$83.65	$92.82
2056	$80.82	$74.76	$85.32	$94.68
2057	$82.43	$76.25	$87.03	$96.57

Table 2. Our LCEO estimates are based on Xcel's in-service year cost estimates for wind and solar.

Capital Costs

Capital costs used for rate base expenses are based on EIA's Annual Energy Outlook from 2020.[37] Minnesota-specific costs were calculated using capital costs from MISW 3 on page 7 of the document.

Community Solar Costs:

The LCOE for community solar is based on Xcel's latest cost estimates listed in the 2019 Annual Report for the community solar garden program.[38] Xcel lists this cost estimate as $129 per MWh.

[37] U.S. Energy Information Administration, "Assumptions to the Annual Energy Outlook 2020," Electricity Market Module, January 2020, https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

[38] Xcel Energy, "Compliance – 2019 Annual Report," Community Solar Gardens Program, Docket No. E002/M-13-867, April 1, 2020,

Additionally, based on historical cost increases per year for the community solar garden program, our model assumes the cost per MWh to increase by 0.93 percent each year for the entirety of the model.

New LCOE Estimates for CC and CT Gas:

Our model utilizes an LCOE calculator to estimate costs for new natural gas combined cycle (CC) and combustion turbine (CT) energy sources.

Assumptions for capital costs, fixed O&M costs, and variable O&M costs are based on the Energy Information Administration's (EIA) Annual Energy Outlook. Fuel costs are $3 per MMBTU based on EIA's state electricity profile for Minnesota. Mortgage periods were determined to be 30 years based on historical lifespans of natural gas facilities.

Transmission Expenditures:

Transmission costs for renewable transitions, such as the one Xcel is seeking, do not end at simply interconnection costs for wind and solar facilities.

The current transmission grid, as already explained, is based around supporting large facilities such as Sherco and Allen S. King — both of which are being retired before their useful lives expire. Because of this, significantly more transmission costs will be required to support the system Xcel is planning for the future. These costs will greatly exceed the cost of interconnecting wind and solar energy sources to the grid.

Because no study has been conducted on this matter, we assume that $6 billion in transmission costs will be needed to transform Xcel's grid from supporting large, baseload facilities to that of distant wind and solar farms. While Xcel estimates $1.825 billion for transmission expenditures, the utility states that "these costs were estimated using transmission interconnection cost assumptions of $500/kW for wind additions and $200/kW for solar additions." Thus, the $1.825 billion noted by Xcel is for interconnection costs, and not a complete transformation of the grid. In addition, Xcel explains that this estimate is "relatively conservative in comparison to results from recent MISO interconnection studies."

Based on these revelations, we are confident our model's assumption for $6 billion for transmission expenditures is a reasonable estimate.

Existing Nuclear Power Facilities:

Our model assumes that Xcel's existing nuclear fleet will remain in operation for the entirety of the model — that is, through 2050. To accommodate this assumption, our model assigns $1.4 billion upgrades for each facility, Monticello and Prairie Island.

Renewable Curtailment:

---

https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bB0193771-0000-C513-BD6E-2C6DD7DFD833%7d&documentTitle=20204-161729-01

Curtailment for renewable electricity is gradually increased until 2034 when it reaches a maximum of 11 percent and remains at this rate for the remainder of the model. This assumption is based off MISO’s RIIA study, where curtailment of renewable energy reaches as high as 15 percent in certain scenarios. Because the RIIA study only forecasts for renewable penetration levels up to 50 percent, while Xcel’s IRP will likely bring its renewable percentage above 60 percent, this curtailment estimate is likely conservative.

Appendix I: Annual Generation Data by Source

Energy Source	2019	2020	2021	2022	2023	2024	2025
Total Generation	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99
Coal	10,203,396.41	5,695,648.72	3,457,545.17	2,298,750.46	2,450,271.48	2,422,494.65	1,683,943.88
Natural Gas (CC)	8,304,546.44	8,304,546.44	8,304,546.44	8,304,546.44	8,304,546.44	8,304,546.44	8,304,546.44
Natural Gas (CT)	194,462.89	194,462.89	194,462.89	194,462.89	171,146.57	171,146.57	171,146.57
Hydroelectric	64,179.00	64,179.00	64,179.00	64,179.00	64,179.00	64,179.00	64,179.00
Nuclear	14,104,541.98	14,104,541.98	14,104,541.98	14,104,541.98	14,104,541.98	14,104,541.98	14,104,541.98
Wind	3,048,352.41	7,354,068.88	9,522,168.88	10,823,028.88	10,748,145.13	10,799,489.16	10,879,357.66
Utility Solar	0.00	0.00	0.00	0.00	0.00	0.00	752,002.20
Community Solar	972,317.95	1,228,737.17	1,333,972.80	1,462,923.50	1,563,712.56	1,600,767.36	1,624,482.43
Biomass	242,732.91	242,732.91	242,732.91	242,732.91	242,732.91	242,732.91	242,732.91
	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Generation	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99
Coal	2,225,621.23	2,597,735.89	2,143,973.94	584,801.95	0.00	0.00	0.00
Natural Gas (CC)	8,304,546.44	8,304,546.44	8,304,546.44	8,304,546.44	8,119,911.43	7,945,201.15	5,129,602.33
Natural Gas (CT)	126,196.56	126,196.56	126,196.56	126,196.56	133,527.98	223,428.00	268,378.02
Hydroelectric	64,179.00	64,179.00	64,179.00	64,179.00	64,179.00	64,179.00	64,179.00
Nuclear	14,104,541.98	14,104,541.98	14,104,541.98	14,104,541.98	13,702,392.00	13,702,392.00	13,702,392.00
Wind	10,954,662.24	11,036,812.69	11,048,222.48	11,170,307.18	10,957,870.82	11,020,448.20	13,877,400.53
Utility Solar	1,504,004.40	1,504,004.40	2,256,006.60	3,760,011.00	5,155,479.00	5,155,479.00	5,046,942.60
Community Solar	1,646,715.31	1,668,948.19	1,691,181.07	1,713,413.95	1,735,646.83	1,757,879.71	1,780,112.59
Biomass	242,732.91	242,732.91	0.00	0.00	0.00	0.00	0.00
	2033	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Total Generation	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas (CC)	2,057,777.65	324,870.24	324,870.24	324,870.24	324,870.24	324,870.24	324,870.24
Natural Gas (CT)	358,278.04	229,336.80	229,336.80	229,336.80	229,336.80	229,336.80	229,336.80
Hydroelectric	64,179.00	64,179.00	64,179.00	64,179.00	64,179.00	64,179.00	64,179.00
Nuclear	13,702,392.00	13,093,396.80	13,093,396.80	13,093,396.80	13,093,396.80	13,093,396.80	13,093,396.80
Wind	16,945,628.70	19,496,847.30	19,496,847.30	19,496,847.30	19,496,847.30	19,496,847.30	19,496,847.30
Utility Solar	4,938,406.20	4,829,869.80	4,829,869.80	4,829,869.80	4,829,869.80	4,829,869.80	4,829,869.80
Community Solar	1,802,345.47	1,830,507.12	1,830,507.12	1,830,507.12	1,830,507.12	1,830,507.12	1,830,507.12
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2040	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**
Total Generation	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas (CC)	324,870.24	324,870.24	324,870.24	324,870.24	324,870.24	324,870.24	324,870.24
Natural Gas (CT)	229,336.80	229,336.80	229,336.80	229,336.80	229,336.80	229,336.80	229,336.80
Hydroelectric	64,179.00	64,179.00	64,179.00	64,179.00	64,179.00	64,179.00	64,179.00
Nuclear	13,093,396.80	13,093,396.80	13,093,396.80	13,093,396.80	13,093,396.80	13,093,396.80	13,093,396.80
Wind	19,496,847.30	19,496,847.30	19,496,847.30	19,496,847.30	19,496,847.30	19,496,847.30	19,496,847.30
Utility Solar	4,829,869.80	4,829,869.80	4,829,869.80	4,829,869.80	4,829,869.80	4,829,869.80	4,829,869.80
Community Solar	1,830,507.12	1,830,507.12	1,830,507.12	1,830,507.12	1,830,507.12	1,830,507.12	1,830,507.12
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2047	**2048**	**2049**	**2050**			
Total Generation	51,744,685.99	51,744,685.99	51,744,685.99	51,744,685.99			
Coal	0.00	0.00	0.00	0.00			
Natural Gas (CC)	324,870.24	324,870.24	324,870.24	324,870.24			
Natural Gas (CT)	229,336.80	229,336.80	229,336.80	229,336.80			
Hydroelectric	64,179.00	64,179.00	64,179.00	64,179.00			
Nuclear	13,093,396.80	13,093,396.80	13,093,396.80	13,093,396.80			
Wind	19,496,847.30	19,496,847.30	19,496,847.30	19,496,847.30			
Utility Solar	4,829,869.80	4,829,869.80	4,829,869.80	4,829,869.80			
Community Solar	1,830,507.12	1,830,507.12	1,830,507.12	1,830,507.12			
Biomass	0.00	0.00	0.00	0.00			

Appendix II: Annual Installed Capacity Data by Source

Energy Source	2019	2020	2021	2022	2023	2024	2025	2026
Coal	2,390.00	2,390.00	2,390.00	2,390.00	1,708.00	1,708.00	1,708.00	1,028.00
Natural Gas (CC)	1,632.00	1,632.00	1,632.00	1,632.00	1,632.00	1,632.00	1,632.00	1,632.00
Natural Gas (CT)	1,618.00	1,618.00	1,618.00	1,618.00	1,424.00	1,424.00	1,424.00	1,050.00
Hydroelectric	13.90	13.90	13.90	13.90	13.90	13.90	13.90	13.90
Nuclear	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00
Wind	951.50	1,951.50	2,451.50	2,751.50	2,751.50	2,751.50	2,751.50	2,751.50
Utility Solar	0.00	0.00	0.00	0.00	0.00	0.00	500.00	1,000.00
Community Solar	656.00	829.00	900.00	987.00	1,055.00	1,080.00	1,096.00	1,111.00
Biomass	36.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00
Total:	9,035.40	10,208.40	10,779.40	11,166.40	10,358.40	10,383.40	10,899.40	10,360.40
Energy Source	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Coal	1,028.00	517.00	517.00	0.00	0.00	0.00	0.00	0.00
Natural Gas (CC)	2,467.00	2,467.00	2,467.00	2,467.00	2,467.00	2,169.00	2,169.00	2,169.00
Natural Gas (CT)	1,050.00	1,050.00	1,050.00	1,111.00	1,859.00	2,233.00	2,981.00	2,618.00
Hydroelectric	13.90	13.90	13.90	13.90	13.90	13.90	13.90	13.90
Nuclear	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00
Wind	2,751.50	2,751.50	2,751.50	2,751.50	2,751.50	3,501.50	4,251.50	5,001.50
Utility Solar	1,000.00	1,500.00	2,500.00	3,500.00	3,500.00	3,500.00	3,500.00	3,500.00
Community Solar	1,126.00	1,141.00	1,156.00	1,171.00	1,186.00	1,201.00	1,216.00	1,235.00
Biomass	36.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total:	11,210.40	11,178.40	12,193.40	12,752.40	13,515.40	14,356.40	15,869.40	16,275.40
Energy Source	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas (CC)	2,169.00	2,169.00	2,169.00	2,169.00	2,169.00	2,169.00	2,169.00	2,169.00
Natural Gas (CT)	2,618.00	2,618.00	2,618.00	2,618.00	2,618.00	2,618.00	2,618.00	2,618.00
Hydroelectric	13.90	13.90	13.90	13.90	13.90	13.90	13.90	13.90
Nuclear	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00
Wind	5,001.50	5,001.50	5,001.50	5,001.50	5,001.50	5,001.50	5,001.50	5,001.50
Utility Solar	3,500.00	3,500.00	3,500.00	3,500.00	3,500.00	3,500.00	3,500.00	3,500.00
Community Solar	1,235.00	1,235.00	1,235.00	1,235.00	1,235.00	1,235.00	1,235.00	1,235.00
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total:	16,275.40	16,275.40	16,275.40	16,275.40	16,275.40	16,275.40	16,275.40	16,275.40
Energy Source	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas (CC)	2,169.00	2,169.00	2,169.00	2,169.00	2,169.00	2,169.00	2,169.00	2,169.00
Natural Gas (CT)	2,618.00	2,618.00	2,618.00	2,618.00	2,618.00	2,618.00	2,618.00	2,618.00
Hydroelectric	13.90	13.90	13.90	13.90	13.90	13.90	13.90	13.90
Nuclear	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00	1,738.00
Wind	5,001.50	5,001.50	5,001.50	5,001.50	5,001.50	5,001.50	5,001.50	5,001.50
Utility Solar	3,500.00	3,500.00	3,500.00	3,500.00	3,500.00	3,500.00	3,500.00	3,500.00
Community Solar	1,235.00	1,235.00	1,235.00	1,235.00	1,235.00	1,235.00	1,235.00	1,235.00
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total:	16,275.40	16,275.40	16,275.40	16,275.40	16,275.40	16,275.40	16,275.40	16,275.40

Appendix III: Annual Capacity Factors by Source

Energy Source	2019	2020	2021	2022	2023	2024	2025	2026
Coal	48.74%	27.20%	16.51%	10.98%	16.38%	16.19%	11.25%	24.71%
Natural Gas (CC)	58.09%	58.09%	58.09%	58.09%	58.09%	58.09%	58.09%	58.09%
Natural Gas (CT)	1.37%	1.37%	1.37%	1.37%	1.37%	1.37%	1.37%	1.37%
Hydroelectric	52.71%	52.71%	52.71%	52.71%	52.71%	52.71%	52.71%	52.71%
Nuclear	92.64%	92.64%	92.64%	92.64%	92.64%	92.64%	92.64%	92.64%
Wind	36.57%	43.45%	44.79%	45.36%	45.97%	46.19%	46.53%	46.85%
Utility Solar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	17.70%	17.70%
Community Solar	16.92%	16.92%	16.92%	16.92%	16.92%	16.92%	16.92%	16.92%
Biomass	76.97%	76.97%	76.97%	76.97%	76.97%	76.97%	76.97%	76.97%
Total	65.38%	57.86%	54.80%	52.90%	57.03%	56.89%	54.19%	57.01%
Energy Source	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Coal	28.85%	47.34%	12.91%	0.00%	0.00%	0.00%	0.00%	0.00%
Natural Gas (CC)	38.43%	38.43%	38.43%	37.57%	36.76%	27.00%	10.83%	1.71%
Natural Gas (CT)	1.37%	1.37%	1.37%	1.37%	1.37%	1.37%	1.37%	1.00%
Hydroelectric	52.71%	52.71%	52.71%	52.71%	52.71%	52.71%	52.71%	52.71%
Nuclear	92.64%	92.64%	92.64%	90.00%	90.00%	90.00%	90.00%	86.00%
Wind	47.21%	47.25%	47.78%	47.86%	48.13%	48.65%	50.00%	50.00%
Utility Solar	17.70%	17.70%	17.70%	17.70%	17.70%	17.70%	17.70%	17.70%
Community Solar	16.92%	16.92%	16.92%	16.92%	16.92%	16.92%	16.92%	16.92%
Biomass	76.97%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	52.69%	52.84%	48.44%	46.32%	43.71%	41.14%	37.22%	36.29%
Energy Source	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Coal	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Natural Gas (CC)	1.71%	1.71%	1.71%	1.71%	1.71%	1.71%	1.71%	1.71%
Natural Gas (CT)	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Hydroelectric	52.71%	52.71%	52.71%	52.71%	52.71%	52.71%	52.71%	52.71%
Nuclear	86.00%	86.00%	86.00%	86.00%	86.00%	86.00%	86.00%	86.00%
Wind	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Utility Solar	17.70%	17.70%	17.70%	17.70%	17.70%	17.70%	17.70%	17.70%
Community Solar	16.92%	16.92%	16.92%	16.92%	16.92%	16.92%	16.92%	16.92%
Biomass	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	36.29%	36.29%	36.29%	36.29%	36.29%	36.29%	36.29%	36.29%
Energy Source	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
Coal	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Natural Gas (CC)	1.71%	1.71%	1.71%	1.71%	1.71%	1.71%	1.71%	1.71%
Natural Gas (CT)	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Hydroelectric	52.71%	52.71%	52.71%	52.71%	52.71%	52.71%	52.71%	52.71%
Nuclear	86.00%	86.00%	86.00%	86.00%	86.00%	86.00%	86.00%	86.00%
Wind	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Utility Solar	17.70%	17.70%	17.70%	17.70%	17.70%	17.70%	17.70%	17.70%
Community Solar	16.92%	16.92%	16.92%	16.92%	16.92%	16.92%	16.92%	16.92%
Biomass	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	36.29%	36.29%	36.29%	36.29%	36.29%	36.29%	36.29%	36.29%

Appendix IV: Annual Additional Cost Schedule

Add'l Cost Source	2020	2021	2022	2023	2024	2025	2026
Rate Base	$3,260,000,000.00	$3,747,000,000.00	$3,950,500,000.00	$3,915,860,000.00	$3,771,222,000.00	$6,314,249,000.00	$6,741,466,000.00
Property Taxes	$65,200,000.00	$74,940,000.00	$79,010,000.00	$78,317,200.00	$75,424,440.00	$126,284,980.00	$134,829,320.00
Transmission	$80,000,000.00	$80,000,000.00	$80,000,000.00	$80,000,000.00	$80,000,000.00	$160,000,000.00	$160,000,000.00
Utility Returns	$248,636,940.00	$285,779,943.00	$301,300,684.50	$298,658,726.34	$287,627,330.72	$481,581,456.98	$514,164,870.35
Operating	$34,941,818.31	$45,682,831.33	$59,194,938.80	$56,294,830.63	$62,661,549.46	$56,071,202.91	$27,675,752.59
Total Add'l Costs	$428,778,758.31	$486,402,774.33	$519,505,623.30	$513,270,756.97	$505,713,320.18	$823,937,639.89	$836,669,942.94
Add'l Cost/MWh	$8.29	$9.40	$10.04	$9.92	$9.77	$15.92	$16.17
Increase/Customer	$332.39	$377.06	$402.72	$397.88	$392.02	$638.71	$648.58
Add'l Cost Source	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Rate Base	$7,324,230,000.00	$7,617,916,166.67	$10,665,832,333.33	$13,141,623,500.00	$13,133,682,800.00	$13,734,918,366.67	$15,179,467,066.67
Property Taxes	$146,484,600.00	$152,358,323.33	$213,316,646.67	$262,832,470.00	$262,673,656.00	$274,698,367.33	$303,589,341.33
Transmission	$160,000,000.00	$160,000,000.00	$240,000,000.00	$275,000,000.00	$275,000,000.00	$275,000,000.00	$275,000,000.00
Utility Returns	$558,611,697.87	$581,010,848.12	$813,472,366.23	$1,057,335,601.94	$1,056,696,717.04	$1,105,070,327.03	$1,221,294,381.78
Operating	$72,147,397.53	$80,890,053.26	$133,261,390.41	$217,476,255.10	$289,870,552.79	$434,394,351.64	$687,957,477.47
Total Add'l Costs	$937,243,695.40	$974,259,224.71	$1,400,050,403.31	$1,812,644,327.04	$1,884,240,925.83	$2,089,163,046.00	$2,487,841,200.59
Add'l Cost/MWh	$18.11	$18.83	$27.06	$35.03	$36.41	$40.37	$48.08
Increase/Customer	$726.54	$755.24	$1,085.31	$1,405.15	$1,460.65	$1,619.50	$1,928.55
Add'l Cost Source	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Rate Base	$17,086,101,033.33	$16,166,926,133.33	$15,247,751,233.33	$14,328,576,333.33	$13,409,401,433.33	$12,490,226,533.33	$11,571,051,633.33
Property Taxes	$341,722,020.67	$323,338,522.67	$304,955,024.67	$286,571,526.67	$268,188,028.67	$249,804,530.67	$231,421,032.67
Transmission	$310,000,000.00	$310,000,000.00	$310,000,000.00	$310,000,000.00	$310,000,000.00	$310,000,000.00	$310,000,000.00
Utility Returns	$1,374,696,430.84	$1,300,742,375.91	$1,226,788,320.98	$1,152,834,266.05	$1,078,880,211.12	$1,004,926,156.19	$930,972,101.26
Operating	$831,764,933.53	$860,093,106.94	$855,490,870.59	$858,061,199.65	$860,655,432.77	$863,273,792.26	$869,290,180.77
Total Add'l Costs	$2,858,183,385.03	$2,794,174,005.51	$2,697,234,216.23	$2,607,466,992.37	$2,517,723,672.56	$2,428,004,479.12	$2,341,683,314.70
Add'l Cost/MWh	$55.24	$54.00	$52.13	$50.39	$48.66	$46.92	$45.25
Increase/Customer	$2,215.64	$2,166.02	$2,090.87	$2,021.29	$1,951.72	$1,882.17	$1,815.25
Add'l Cost Source	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**
Rate Base	$11,974,876,733.33	$11,717,201,833.33	$11,194,926,933.33	$10,442,450,033.33	$9,582,810,133.33	$8,836,245,233.33	$8,084,388,333.33
Property Taxes	$239,497,534.67	$234,344,036.67	$223,898,538.67	$208,849,000.67	$191,656,202.67	$176,724,904.67	$161,687,766.67
Transmission	$310,000,000.00	$310,000,000.00	$310,000,000.00	$310,000,000.00	$230,000,000.00	$230,000,000.00	$230,000,000.00
Utility Returns	$963,462,657.33	$942,730,907.90	$900,710,236.28	$840,168,202.33	$771,004,154.90	$710,937,782.74	$650,445,632.14
Operating	$1,012,828,024.91	$1,088,546,362.34	$1,130,644,072.02	$1,153,063,518.26	$1,160,289,823.55	$1,167,639,544.35	$1,174,974,599.64
Total Add'l Costs	$2,525,788,216.91	$2,575,621,306.91	$2,565,252,846.96	$2,512,080,721.25	$2,352,950,181.12	$2,285,302,231.75	$2,217,107,998.44
Add'l Cost/MWh	$48.81	$49.78	$49.58	$48.55	$45.47	$44.16	$42.85
Increase/Customer	$1,957.97	$1,996.60	$1,988.56	$1,947.34	$1,823.99	$1,771.55	$1,718.68

Add'l Cost Source	2048	2049	2050
Rate Base	$7,340,469,433.33	$6,514,524,533.33	$5,816,910,633.33
Property Taxes	$146,809,388.67	$130,290,490.67	$116,338,212.67
Transmission	$230,000,000.00	$230,000,000.00	$150,000,000.00
Utility Returns	$590,592,149.20	$524,139,100.38	$468,011,178.83
Operating	$1,182,973,430.25	$1,186,594,724.85	$1,197,868,706.17
Total Add'l Costs	$2,150,374,968.11	$2,071,024,315.89	$1,932,218,097.67
Add'l Cost/MWh	$41.56	$40.02	$37.34
Increase/Customer	$1,666.95	$1,605.44	$1,497.84

Appendix V: Annual Existing-LCOE Data by Source

Energy Source	2019	2020	2021	2022	2023	2024	2025	2026
Coal	$35.90	$39.00	$43.54	$49.37	$43.64	$43.78	$48.95	$39.71
Natural Gas (CC)	$33.37	$33.37	$33.37	$33.37	$33.37	$33.37	$33.37	$33.37
Natural Gas (CT)	$88.86	$88.86	$88.86	$88.86	$88.86	$88.86	$88.86	$88.86
Hydroelectric	$20.35	$20.35	$20.35	$20.35	$20.35	$20.35	$20.35	$20.35
Nuclear	$36.86	$36.86	$36.86	$36.86	$36.86	$36.86	$36.86	$36.86
Wind	$31.00	$31.00	$31.00	$31.00	$31.00	$31.00	$31.00	$31.00
Solar	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Community Solar	$129.00	$130.20	$131.41	$132.63	$133.87	$135.11	$136.37	$137.64
Biomass	$72.57	$72.57	$72.57	$72.57	$72.57	$72.57	$72.57	$72.57
Energy Source	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Coal	$38.60	$36.01	$46.77	$0.00	$0.00	$0.00	$0.00	$0.00
Natural Gas (CC)	$34.76	$34.76	$34.76	$34.85	$34.94	$36.50	$45.22	$122.96
Natural Gas (CT)	$88.86	$88.86	$88.86	$88.86	$88.86	$88.86	$88.86	$97.72
Hydroelectric	$20.35	$20.35	$20.35	$20.35	$20.35	$20.35	$20.35	$20.35
Nuclear	$36.86	$36.86	$36.86	$37.26	$37.26	$37.26	$37.26	$37.91
Wind	$31.00	$31.00	$31.00	$31.00	$31.00	$31.00	$31.00	$31.00
Solar	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Community Solar	$138.92	$140.21	$141.51	$142.83	$144.16	$145.50	$146.85	$148.22
Biomass	$72.57	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Energy Source	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Coal	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Natural Gas (CC)	$122.96	$122.96	$122.96	$122.96	$122.96	$122.96	$122.96	$122.96
Natural Gas (CT)	$97.72	$97.72	$97.72	$97.72	$97.72	$97.72	$97.72	$97.72
Hydroelectric	$20.35	$20.35	$20.35	$20.35	$20.35	$20.35	$20.35	$20.35
Nuclear	$37.91	$37.91	$37.91	$37.91	$37.91	$37.91	$37.91	$37.91
Wind	$31.00	$31.00	$31.00	$31.00	$31.00	$31.00	$31.00	$31.00
Solar	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Community Solar	$149.59	$150.99	$152.39	$153.81	$155.24	$156.68	$158.14	$159.61
Biomass	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Energy Source	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
Coal	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Natural Gas (CC)	$122.96	$122.96	$122.96	$122.96	$122.96	$122.96	$122.96	$122.96
Natural Gas (CT)	$97.72	$97.72	$97.72	$97.72	$97.72	$97.72	$97.72	$97.72
Hydroelectric	$20.35	$20.35	$20.35	$20.35	$20.35	$20.35	$20.35	$20.35
Nuclear	$37.91	$37.91	$37.91	$37.91	$37.91	$37.91	$37.91	$37.91
Wind	$31.00	$31.00	$31.00	$31.00	$31.00	$31.00	$31.00	$31.00
Solar	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Community Solar	$161.09	$162.59	$164.10	$165.63	$167.17	$168.72	$170.29	$171.88
Biomass	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Appendix VI: Annual New-LCOE Data by Source

Energy Source	2019	2020	2021	2022	2023	2024	2025	2026
Natural Gas (CC)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Natural Gas (CT)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Wind	$32.19	$29.79	$29.65	$34.04	$38.61	$43.39	$52.15	$52.55
Solar	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$50.32	$50.74
Energy Source	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Natural Gas (CC)	$46.89	$46.89	$46.89	$47.58	$48.31	$58.68	$118.40	$991.86
Natural Gas (CT)	$0.00	$0.00	$0.00	$739.67	$739.67	$739.67	$739.67	$739.67
Wind	$52.98	$53.42	$53.89	$54.39	$54.95	$55.54	$56.16	$56.80
Solar	$51.17	$51.59	$52.01	$52.43	$53.10	$53.78	$54.47	$55.16
Energy Source	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Natural Gas (CC)	$991.86	$991.86	$991.86	$991.86	$991.86	$991.86	$991.86	$991.86
Natural Gas (CT)	$739.67	$739.67	$739.67	$739.67	$739.67	$739.67	$739.67	$739.67
Wind	$57.47	$58.17	$58.91	$59.67	$60.47	$61.30	$62.17	$63.07
Solar	$55.86	$56.57	$57.28	$58.00	$58.72	$59.45	$60.13	$60.81
Energy Source	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
Natural Gas (CC)	$991.86	$991.86	$991.86	$991.86	$991.86	$991.86	$991.86	$991.86
Natural Gas (CT)	$739.67	$739.67	$739.67	$739.67	$739.67	$739.67	$739.67	$739.67
Wind	$64.01	$64.99	$66.01	$67.01	$68.17	$69.32	$70.52	$71.76
Solar	$61.50	$62.18	$62.87	$63.57	$64.27	$64.97	$65.68	$66.38

Appendix VII: Annual Emissions Data by Source

Energy Source	2019	2020	2021	2022	2023	2024	2025	2026
Coal	10,917,634.2	6,094,344.1	3,699,573.3	2,459,663.0	2,621,790.5	2,592,069.3	1,801,819.9	2,381,414.7
Natural Gas (CC)	4,152,273.2	4,152,273.2	4,152,273.2	4,152,273.2	4,152,273.2	4,152,273.2	4,152,273.2	4,152,273.2
Natural Gas (CT)	124,456.2	124,456.2	124,456.2	124,456.2	109,533.8	109,533.8	109,533.8	80,765.8
Total Emissions	15,194,363.6	10,371,073.6	7,976,302.8	6,736,392.5	6,883,597.5	6,853,876.3	6,063,627.0	6,614,453.7
Energy Source	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Coal	2,779,577.4	2,294,052.1	625,738.1	0.0	0.0	0.0	0.0	0.0
Natural Gas (CC)	4,152,273.2	4,152,273.2	4,152,273.2	4,059,955.7	3,972,600.6	2,564,801.2	1,028,888.8	162,435.1
Natural Gas (CT)	80,765.8	80,765.8	80,765.8	85,457.9	142,993.9	171,761.9	229,297.9	146,775.6
Total Emissions	7,012,616.4	6,527,091.1	4,858,777.1	4,145,413.6	4,115,594.5	2,736,563.1	1,258,186.8	309,210.7
Energy Source	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas (CC)	162,435.1	162,435.1	162,435.1	162,435.1	162,435.1	162,435.1	162,435.1	162,435.1
Natural Gas (CT)	146,775.6	146,775.6	146,775.6	146,775.6	146,775.6	146,775.6	146,775.6	146,775.6
Total Emissions	309,210.7	309,210.7	309,210.7	309,210.7	309,210.7	309,210.7	309,210.7	309,210.7
Energy Source	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas (CC)	162,435.1	162,435.1	162,435.1	162,435.1	162,435.1	162,435.1	162,435.1	162,435.1
Natural Gas (CT)	146,775.6	146,775.6	146,775.6	146,775.6	146,775.6	146,775.6	146,775.6	146,775.6
Total Emissions	309,210.7	309,210.7	309,210.7	309,210.7	309,210.7	309,210.7	309,210.7	309,210.7

Appendix VIII: Comparing Cost of CO_2 Emissions with Cost of Averting CO_2

Environmental Cost Values for CO2 (2020-2050) vs. CO2 Reduction Cost - (Adjusted for $2020)			
Year	Dollars per Net Short Ton CO2	Cost per Short Ton CO2 Reduced	Percent Difference
2020	$46.87	$80.65	72%
2021	$47.86	$61.13	28%
2022	$48.86	$55.72	14%
2023	$49.85	$56.03	12%
2024	$50.84	$55.01	8%
2025	$51.84	$81.86	58%
2026	$52.83	$88.46	67%
2027	$53.83	$103.92	93%
2028	$54.83	$101.97	86%
2029	$55.82	$122.89	120%
2030	$56.81	$148.83	162%
2031	$57.81	$154.29	167%
2032	$58.80	$152.13	159%
2033	$59.79	$161.95	171%
2034	$60.79	$174.19	187%
2035	$61.78	$170.29	176%
2036	$62.77	$164.38	162%
2037	$63.77	$158.91	149%
2038	$64.76	$153.44	137%
2039	$65.77	$147.98	125%
2040	$66.76	$142.72	114%
2041	$67.75	$153.94	127%
2042	$68.75	$156.97	128%
2043	$69.74	$156.34	124%
2044	$70.73	$153.10	116%
2045	$71.73	$143.40	100%
2046	$72.72	$139.28	92%
2047	$73.71	$135.12	83%
2048	$74.71	$131.06	75%
2049	$75.70	$126.22	67%
2050	$76.69	$117.76	54%

Appendix IX: Ratepayer Impact

Impact of Xcel Rate Classes			
Average Monthly Increase (Residential)	$27.81	Annual	$333.71
Average Monthly Increase (Commercial)	$265.17	Annual	$3,182.08
Average Monthly Increase (Industrial)	$33,446.21	Annual	$401,354.52
Average Monthly Increase (Residential) Through 2030	$12.62	Annual	$151.50
Average Monthly Increase (Commercial) Through 2030	$120.38	Annual	$1,444.62
Average Monthly Increase (Industrial) Through 2030	$15,184.10	Annual	$182,209.20
Average Monthly Increase (Residential) From 2031 to 2050	$36.13	Annual	$433.60
Average Monthly Increase (Commercial) From 2031 to 2050	$344.55	Annual	$4,134.66
Average Monthly Increase (Industrial) From 2031 to 2050	$43,458.61	Annual	$521,503.33

Cost Impact per Customer	
Number of Customers in Territory	1,290,004
Average Annual Increase Per Customer	$1,428.65
Average Annual Increase Per Customer Through 2030	$648.59
Average Annual Increase Per Customer From 2031 to 2050	$1,856.33

Appendix X: LCOE Values for New and Existing Resources

Final LCOE-New Chart For New Grid							
Energy Source	**Average Annual Capacity Factor**	**Levelized Generation**	**Levelized Property Taxes**	**Levelized Transmission**	**Levelized Utility Profits**	**Levelized Load Balancing**	**Adjusted LCOE**
Natural Gas (CC)	**21.4%**	$67.57	$5.53	$4.60	$25.86	NA	$98.96
Natural Gas (CT)	**1.2%**	$739.67	$101.30	$88.36	$553.12	NA	$1,394.09
Wind	**50.0%**	$55.62	$3.02	$12.34	$14.12	$23.96	$109.07
Utility Solar	**17.7%**	$57.04	$8.84	$11.95	$41.33	$54.15	$173.31

Final LCOE-Old Chart For New Grid		
Energy Source	**Average Annual Capacity Factor**	**Average Annual LCOE**
Coal	**23.7%**	$40.03
Natural Gas (CC)	**22.5%**	$37.65
Natural Gas (CT)	**1.2%**	$92.86
Hydro	**52.7%**	$23.43
Nuclear	**88.8%**	$37.45
Wind	**36.6%**	$31.00
Utility Solar	**0.0%**	$0.00
Community Solar	**16.9%**	$149.45
Biomass	**77.0%**	$72.57
Other Renewable	**0.0%**	$0.00
Other	**0.0%**	$0.00