

STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph Sullivan	Vice Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

**In the Matter of Xcel Energy's 2020-2034
Upper Midwest Resource Plan**

PUC Docket No. E002/RP-19-368

SIERRA CLUB REPLY COMMENTS

Drafted with the assistance of

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Sierra Club respectfully offers these Reply Comments in response to key issues raised by various parties' Initial Comments.

I. All other modeling analysis filed in the docket supports our conclusion that the proposed Sherco combined cycle gas plant is not a needed or least-cost resource, and that Xcel should instead pursue significant amounts of renewable energy and storage.

A. DOC's Strategist modeling results confirm our EnCompass modeling findings regarding the lack of need for the Sherco CC, and also support our conclusion that the least cost plan should include early retirement of the coal units and not extending the Monticello nuclear license.

1. DOC's Strategist modeling confirms our finding that the Sherco CC is not part of a least cost resource plan.

The Minnesota Department of Commerce's ("DOC's") Initial Comments focused on reviewing and analyzing Xcel's Strategist modeling.¹ This modeling review found that the proposed Sherco combined cycle gas plant ("Sherco CC") would be an uneconomic resource addition. The DOC hard-coded the Sherco CC into almost every scenario, but ran one "no Sherco CC" scenario (Scenario 134a) as a variation of its lowest-cost preferred plan (Scenario 134).² Comparing the Department's results of its preferred plan with and without the Sherco CC shows \$205 million in savings from not building the plant in the base case, as illustrated in Figure 1, below.³ DOC's calculated savings from removing the Sherco CC exactly matched our own, as presented in our Initial Comments.⁴ According to DOC's modeling results, not building the Sherco CC was cheaper in all futures, averaging **\$289 million in savings** across the 24 cases modeled by the Department, as illustrated in the chart below.⁵

¹ DOC Initial Comments at 49-67.

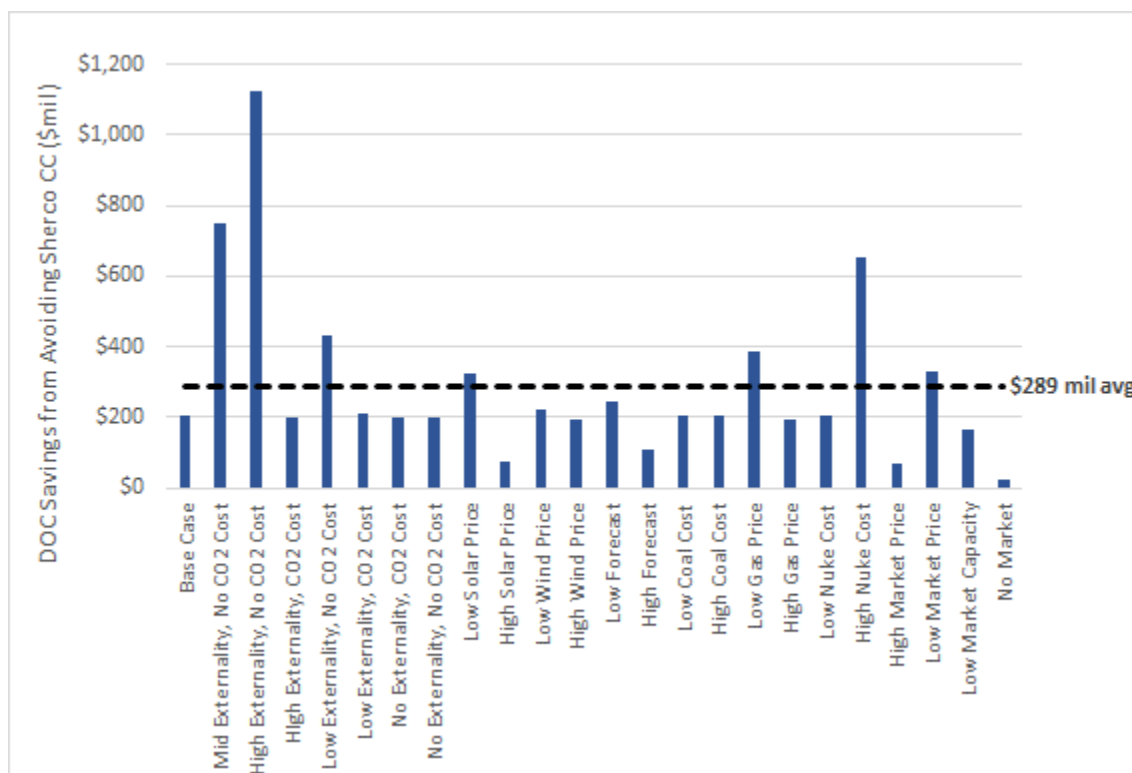
² *Id.* Attachment 1, p. 34 (Scenario 134 results) and Attachment 3, p. 1 (Scenario 134a results).

³ *Id.*

⁴ Sierra Club Initial Comments at 43.

⁵ DOC Initial Comments, Attachment 1, p. 34 (Scenario 134 results) and Attachment 3, p. 1 (Scenario 134a results).

Figure 1: DOC Modeled Savings from Not Constructing the Sherco CC (\$mil)⁶



The DOC’s Strategist modeling therefore confirms and supports our own modeling finding that the Sherco CC should not be approved as part of a prudent and least cost resource plan for Xcel.

2. DOC’s analysis of Xcel’s load forecast further supports our finding that the Sherco CC is not needed.

DOC conducted an extensive analysis of Xcel’s load forecasting over the last 15 years, and found that Xcel’s demand and energy forecasts have systematically been too high.⁷ DOC found that “[t]hree years out Xcel’s average error is about 325 MW, about the size of a large combustion turbine or the initial accredited capacity expected from about 650 MW of solar. By five years out Xcel’s average error is about 625 MW or two large CT units and by eight years out the average error is about 1,100 MW. Thus, the size of the error consistently grows the further into the future the calculations are taken.”⁸

⁶ *Id.*

⁷ DOC Initial Comments at 11, 17.

⁸ *Id.* at 17.

Sierra Club agrees with DOC that Xcel made several errors that significantly overstate its need for capacity. Once these errors are corrected, it becomes even clearer that the Sherco CC is unnecessary and is at risk of becoming a stranded asset.

We support DOC's recommendation that Xcel's peak load forecast should be reduced by 12%, and Xcel's energy forecast by 10%, because Xcel has a history of significantly overestimating load growth. DOC notes that for Xcel's peak load forecast, "by eight years out the average error is about 1,100 MW,"⁹ while "at eight years out Xcel's average energy forecast error is 4,200 GWh."¹⁰ For reference, an 835 MW combined cycle plant operating at a hypothetical 50% capacity factor would generate 3,657 GWh per year. As a result, **correcting for Xcel's forecast error alone more than eliminates the capacity and energy need Xcel has proposed to meet with the Sherco CC.**

We also agree with DOC that Xcel's modeling overvalued excess capacity, which created a bias for Xcel's modeling to overbuild capacity. As DOC explains, "The capacity market construct used by Xcel mimics the FRAP process (capacity hedging) and serves to limit the Company's exposure to reliability risks, while somewhat over-valuing excess capacity. For modeling purposes, while the capacity price is unlikely to impact the overall plan, the Department reduced the price for excess capacity."¹¹ We did not correct for that bias in our modeling and so, if anything, our results overstate the value of Xcel building new capacity like the Sherco CC.

Finally, it was reasonable for DOC to remove Xcel's spinning reserve capacity requirement, which further inflated Xcel's capacity needs. As DOC explained in their Initial Comments, "Xcel's capacity requirement was removed because there is no need to assume Xcel has to solve MISO's ancillary services issues."¹² DOC is correct that spinning reserves can typically be provided from anywhere within the MISO footprint, and Xcel can meet its reserve obligations through purchases in MISO's ancillary services markets instead of holding back capacity on its own resources. We did not correct for that error in our modeling, indicating our results may overstate the value of Xcel building new capacity like the Sherco CC.

Sierra Club and its experts did not analyze or critique Xcel's load forecast in our Initial Comments, and left Xcel's forecast unchanged in our EnCompass modeling assumptions. If we were to adjust Xcel's load forecast downwards according to DOC's findings, we expect that the lack of need for the Sherco CC would be even more apparent.

⁹ *Id.* at 17.

¹⁰ *Id.* at 24.

¹¹ *Id.* at 34.

¹² *Id.* at 56.

3. DOC's modeling clearly shows that the early retirement of Xcel's coal units and Monticello is the lowest-cost option.

DOC's modeling also found that early retirement of the coal units and not extending the Monticello license is the lowest cost option, and that extending the Monticello license "is not cost effective."¹³ DOC states that "[o]verall, Xcel's analysis in both [resource planning models] shows that adding a Monticello extension to a Prairie Island extension is a high-risk plan."¹⁴

DOC's Strategist modeling updated information that Xcel's modeling did not include (e.g., inclusion of recently approved wind and solar projects) and tested certain changes to Xcel's assumptions (e.g., lower load and energy requirements).¹⁵ DOC's modeling found that the lowest cost plan that included the Sherco CC (Scenario 134) included early retirement of King and Sherco 3, and no Monticello license extension.¹⁶ "The top performing plan involves early retirement of both coal units and Monticello," while "extending the life of Monticello is clearly the worst performing retirement option...."¹⁷ As discussed above, Scenario 134a, in which DOC excluded the Sherco CC, was an even lower-cost plan (by approximately \$200 million).

This result is consistent with our own modeling results. As discussed in our Initial Comments, Synapse's modeling shows that the Monticello extension is more costly than letting that license lapse, and we agreed with Xcel's choice of "early" retirement of the King and Sherco 3 units.¹⁸ It is noteworthy that Sierra Club and DOC are the only two intervenor parties that conducted modeling analysis examining the Monticello license extension, and both found that the Monticello extension is not in customers' interest.

We also explained in our Initial Comments that there was reason for exploring even earlier retirement of Xcel's coal units, especially the King unit, given the increasing economic pressure on these units from lower-cost replacement options.¹⁹ For instance, recent extensions of federal tax credits make renewable and hybrid resources even more attractive in the short-term. Unfortunately, as we explained in our comments, we could not analyze earlier retirement of the coal units because doing so required access to both the Strategist and Encompass models.²⁰ DOC

¹³ *Id.* at 53-54.

¹⁴ *Id.* at 54.

¹⁵ *Id.* at 55-59.

¹⁶ *Id.* at 60.

¹⁷ *Id.* at 60-61.

¹⁸ Sierra Club Initial Comments at 54.

¹⁹ *Id.* at 54-57.

²⁰ *Id.* at 54.

had access to both of these models but did not use that access to test whether earlier retirement of Xcel's coal units was economic.

As we address later in these reply comments, DOC's analysis did not address key problems with Xcel's modeling assumptions, and DOC's modeling results are therefore conservative. For instance, as we discuss in a later section, DOC's decision to prioritize Strategist over Encompass modeling was not conducive to exploring battery storage as a resource option. However, despite these shortcomings, we recognize that DOC explored many changes to input assumptions that ultimately lead to a similar conclusion as ours regarding the lack of need and excessive costs for the Sherco CC and the savings from retiring the King, Sherco 3, and Monticello units.

4. DOC's preferred plan adds significant amounts of new solar, consistent with our own modeling results.

DOC's preferred plan adds 5,500 MW of new utility scale solar by 2034.²¹ It appears that DOC did not make any adjustments to how Xcel modeled distributed solar (i.e., small-scale projects through Solar Rewards and community solar). The amount of utility-scale solar added under DOC's scenario is consistent with our preferred plan's utility-scale solar additions, but we also found that an additional 2,800 MW of distributed solar (on top of Xcel's plan) should be included.²² Our Clean Energy for All Plan, summarized in Table 1 of our Initial Comments,²³ includes 1,350 MW of standalone utility scale solar and over 4,000 MW of hybrid solar paired with over 1,000 MW of battery storage. As discussed in a later section, DOC's modeling did not correct for errors in Xcel's modeling methodology with respect to hybrid and battery storage resources, and so it is unsurprising that DOC's modeling results did not include these resources. DOC recommends that Xcel pursue adding utility-scale solar consistent with the amounts laid out in Table 13 of DOC's Initial Comments. While these amounts are fairly consistent with our own findings, for reasons discussed in the sections below and in our Initial Comments, we believe our Clean Energy for All Plan – which adds not only roughly the same amount of utility-scale solar but also over 2 gigawatts of battery storage, over 4,000 MW of new wind, and nearly 4,000 MW of new distributed solar and community solar, better satisfies the public interest standard.

²¹ DOC Initial Comments at 13.

²² Sierra Club Initial Comments at 2.

²³ *Id.*

B. Modeling conducted on behalf of CUB and the CEOs also confirmed a lack of need for the Sherco CC, as well as the need for significant amounts of utility-scale renewables, distributed generation, and battery storage as part of a least cost resource plan.

Modeling conducted on behalf of the Citizens Utility Board (CUB) and the Clean Energy Organizations (CEOs) also found that the Sherco CC is not a needed or least-cost resource addition. Their comments and analysis provide further support for a Commission finding that the Sherco CC should not be included in Xcel’s resource plan. Moreover, both parties’ analyses found that replacing retiring resources with large amounts of renewable energy and battery storage represents the least cost option for customers.

1. CUB’s Analysis

CUB used Vibrant Clean Energy’s WIS:DOM model to find that Xcel’s load can be reliably met in all hours without the need for any new fossil fuel-fired power plants, including the Sherco CC.²⁴ CUB’s plan, called the “Consumers Plan,” retires Xcel’s coal plants by 2025 and replaces them with 4,700 MW of new wind, 3,900 MW of new utility-scale solar, 1,900 MW of distributed solar, and 1,300 MW of 8-hour battery storage. A comparison of Sierra Club’s Clean Energy for All Plan and CUB’s Consumers Plan is presented in the table below.

Table 1 Comparison of Sierra Club’s Clean Energy for All Plan and CUB’s Consumers Plan

Resource Type	Sierra Club’s Clean Energy for All Plan	CUB’s Consumers Plan
Coal	Same as Xcel	Retire all coal by 2025
New Combined Cycle Gas	None	None
New Other Potential Gas	None	None
Utility Scale Renewables	1,350 MW new standalone utility-scale solar by 2034 4,320 MW new wind by 2034	3,950 utility-scale solar by 2035 4,522 MW new wind by 2035
Utility Scale Paired Solar-Plus-Storage (“hybrid solar”)	4,070 MW solar 1,080 MW battery	
Distributed Solar	2,050 MW Community Solar 1,851 MW DG solar	1,965 MW (does not distinguish between community or DG)
Battery Storage	1,020 MW by 2034	1,368 MW by 2035

²⁴ CUB Initial Comments at 1.

Nuclear	Monticello license ends 2030 (no license extension)	Extends Monticello license until 2040
Demand Side Management	Same as Xcel	622 MW/year energy savings, 2,134 MW total DR by 2035

Both the Clean Energy for All Plan and CUB’s Consumers Plan indicate that significant build-out of utility-scale solar, wind, battery storage, and distributed solar are all key components of a least-cost resource plan for Xcel.

The WIS:DOM model provides important additional evidence that, contrary to Xcel’s assertions, Xcel can meet its energy needs reliably and in accordance with the North American Electric Reliability Council’s (NERC’s) reliability standards without building more fossil gas plants.²⁵ As CUB astutely points out, achieving this level of reliability will require better utilization and optimization of both the distribution system and the bulk transmission system.²⁶ When these systems are co-optimized as allowed by the WIS:DOM model, it becomes apparent that significant amounts of distributed solar and battery storage are critical components of the least-cost, prudent resource plan for Xcel.

Sierra Club strongly agrees with CUB’s findings that Xcel must consider resource planning in tandem with co-optimization of its distribution and transmission systems, and that significant amounts of both distributed solar and battery storage will reduce customer costs and transition Xcel to a low carbon grid of the future. We also agree with CUB’s recommendation that “Xcel should pursue a robust expansion of DER [Distributed Energy Resources], coupled with additional energy efficiency and demand flexibility measures. Through innovative ratemaking, incentives, and appropriate valuation of distributed energy services, Xcel can leverage large amounts of private investment in small-scale solar and battery storage projects to benefit all consumers.”²⁷ We further agree that Xcel should “evaluate appropriate mechanisms to encourage thoughtful and equitable DER expansion.”²⁸ In our view, these statements are consistent with our recommendation from our Initial Comments that the Commission should “order Xcel to bring forward a proposal by January 2022 for programs that could incentivize the growth of solar distributed generation within its territory at levels consistent with Sierra Club’s Clean Energy For All Plan, and in a manner that would advance the goals of equity and access.”²⁹

²⁵ *Id.* at 3.

²⁶ *Id.*

²⁷ *Id.* at 17.

²⁸ *Id.* at 18.

²⁹ Sierra Club Initial Comments at 110.

2. CEOs' Analysis

The CEOs, like Sierra Club, conducted modeling analysis using EnCompass. While the adjustments their experts made to Xcel's assumptions were not identical to ours, they nevertheless reached a similar conclusion: the Sherco CC is not in customers' interests.³⁰ The CEOs' experts found that when the EnCompass model was given the choice to select the Sherco CC, it did not.³¹ This is consistent with Synapse's findings and DOC's findings using Strategist. The CEOs' Preferred Plan includes 1,000 MW of hybrid solar and 250 MW of hybrid battery storage in 2027, and significant additional buildout of wind, solar, and solar hybrids in 2029 and thereafter.³² The CEOs did not examine removal of the Monticello license extension, and their modeling did not examine additional levels of distributed solar generation, both of which likely account for some of the differences between the timing of resource additions in our plans. Our plans are consistent in their conclusion that a least cost future for Xcel customers includes large amounts of wind, solar, storage, and hybrids, and that Xcel should be directed to pursue these resources instead of additional fossil gas plants.

II. Other Parties' Legal Analyses of the Sherco CC Statute Support Our Conclusion that the Commission Has Oversight Over Whether the Sherco CC Is In Customers' Interests.

The Department of Commerce, CUB, and the CEOs all included analysis in their initial comments showing that the Commission continues to have the authority to review the prudence and reasonableness of Xcel's proposal to build the Sherco CC. DOC states that it "interprets Section 1 (b) of the Sherco CC Statute as generally maintaining the Commission's standard authority regarding rate recovery. This implies that the Company's investment in the Sherco CC unit is not risk free."³³ DOC suggests that the Commission could review and disapprove costs in a rate case.³⁴ DOC also observes that a Certificate of Need or a site permit could be needed for any new gas pipeline.³⁵

Sierra Club agrees that the Commission has authority to review the reasonableness of costs in a future rate case, and to review any new pipeline. We disagree, however, with DOC's suggestion that the Sherco CC's exemption from a Certificate of Need means that it is exempted from the need to obtain approval under the IRP statute. As we explained in our Initial Comments, the so-

³⁰ CEOs' Initial Comments at 21.

³¹ *Id.* at 12.

³² CEOs' Initial Comments at 14.

³³ DOC Initial Comments at 45.

³⁴ *Id.*

³⁵ *Id.*

called Sherco CC statute (H.R. 113 (2017)) does not exempt Xcel from demonstrating the need for the plant under Section 216B.2422. A finding that the plant is not needed under the resource planning statute would then be relevant to a Certificate of Need determination regarding a related pipeline and in any docket regarding the reasonableness of costs for the gas plant. Such a finding now, before construction has commenced, would put Xcel on notice that recovery of its costs is at risk, and would prevent Xcel from later arguing that it should be entitled to cost recovery once the plant is already built.

In its initial comments, CUB points out that the Commission has the ability to put Xcel on notice that it will not allow Xcel to recover for any undepreciated costs of the plant “if and when the plant is no longer used and useful,” as well as “any costs attributable to oversizing the plant if it is run at a low capacity factor,” particularly in light of the fact that there is ample evidence today that the gas plant is likely to become a stranded asset.³⁶ CUB also recommends that the Commission “clarify that, if Xcel ever needs to retrofit the Sherco plant to use carbon free fuels such as hydrogen, Xcel will not be permitted to recover any costs that could have been avoided had Xcel invested in carbon-neutral resources from the outset, and the plant will be required to meet ordinary certificate of need and permitting requirements.”³⁷ Sierra Club supports both of these reasonable and common-sense recommendations, which will help protect customers from an imprudent decision by Xcel to move forward with the gas plant.

Sierra Club also fully agrees with the thorough and persuasive analysis of the Sherco CC Statute presented in the CEOs’ initial comments, as well as their conclusion that the Commission’s IRP authority was unaffected by the legislation and that the Commission therefore “has the duty in this docket to evaluate whether Xcel’s Preferred Plan, including the Proposed Gas Plant, is in the public interest, consistent with Minn. Stat. 216B.2422, subd. 2.”³⁸

III. Including lifecycle greenhouse gas emissions further supports our conclusion that the Sherco CC should not be included as part of Xcel’s resource plan.

In our Initial Comments, we pointed out that in evaluating whether a resource plan is in the public interest, the Commission is required to assess whether a plan minimizes adverse effects on the environment and whether a plan helps a utility achieve Minnesota’s statutory greenhouse gas reduction goals.³⁹ We noted that Xcel’s proposal to build a massive and long-lasting new source of greenhouse gas emissions, the Sherco combined cycle gas plant, is inconsistent with those state priorities. We observed in our comments that the Sherco gas plant would, according to

³⁶ CUB Initial Comments at 9-10

³⁷ *Id.*

³⁸ CEOs’ Initial Comments at 5-8.

³⁹ SC Initial Comments at 93, citing Minn. R. 7843.0500, subp. 3 and Minn. Stat. § 216B.2422, subd. 2c.

Xcel's EnCompass modeling, emit over **[PROTECTED DATA BEGINS...**

... PROTECTED DATA ENDS] tons of carbon dioxide in 2030,⁴⁰ or an average of more than 2,140,000 tons CO₂ per year once it begins operation in 2027.⁴¹

DOC Deputy Commissioner Aditya Ranade filed a letter dated February 11, 2021, in this docket arguing that the lifecycle greenhouse gas emissions associated with fossil gas combustion, not just the emissions from direct combustion, should be considered in resource planning decisions. His letter noted that "new estimates of lifecycle emissions for natural gas in Minnesota have been released from Center for Energy and Environment (CEE), putting the lifecycle emissions at 138 lbs/mmbtu, significantly higher than the combustion only value (118 lbs/mmbtu) used by Xcel Energy and others." He indicated that this number is conservative because it does not account for the emissions from flaring during gas production. He pointed out that "[t]he potentially higher emissions factor will make it significantly more difficult to meet the greenhouse gas emission targets set in the Next Generation Energy for 2050, or Walz administration's proposed target of 100% carbon free electricity by 2040."

We strongly support consideration of lifecycle greenhouse gas emissions when assessing the climate impact of burning fossil gas in resource planning decisions. Using the lifecycle emissions rate from CEE, in 2030 the Sherco CC would be expected to emit over **[PROTECTED DATA BEGINS... ... PROTECTED DATA ENDS]** tons of carbon dioxide equivalent (CO₂-e) in 2030, or an average of over 2,500,000 tons CO₂-e per year through the planning period. However, in our view, CEE's upstream emissions calculation is low. Our own analysis indicates that the lifecycle greenhouse gas emissions from fossil gas are 224 lb CO₂-e/mmbtu.⁴²

⁴⁰ *Id.* at 95.

⁴¹ Emissions averaged from 2027-2034, the years of operation in the planning period.

⁴² Upstream emissions are calculated as follows: 1) Leakage emissions = 47.67 kg CO₂e/mmbtu * 2.205 lb/kg = 105.12 lb CO₂e/mmbtu. 2) Gas lease and plant fuel emissions = 0.000002 g CH₄/Btu * 0.0022 lb/g * 1,000,000 btu/mmbtu * 86 (20-year GWP of methane from IPCC AR5) = 0.39 lb CO₂e/mmbtu. 3) Pipeline fuel = 0.000008 g CH₄/Btu * 0.0022 lb/g * 1,000,000 btu/mmbtu * 86 (20-year GWP of methane from IPCC AR5) = 1.54 lb CO₂e/mmbtu. Sources: IPCC 5AR WG, sec.8.7.1.2, pp.714 http://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf; leakage rate of 2.9% from well to power plant derived from: Littlefield et. al., 2017, Synthesis of recent ground-level methane emission measurements from the U.s. natural gas supply chain, <https://www.sciencedirect.com/science/article/pii/S0959652617301166>; National Energy Technology Laboratory, 2016, Life Cycle Analysis of Natural Gas Extraction and Power Generation, https://www.netl.doe.gov/energy-analyses/temp/LifeCycleAnalysisofNaturalGasExtractionandPowerGeneration_083016.pdf; Environmental Protection Agency (EPA), 2018, Inventory of U.S. Greenhouse Gas Emissions and Sinks, <https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks>; Howarth et. al., 2011, Methane and the greenhouse-gas footprint of natural gas from shale formations, <https://link.springer.com/content/pdf/10.1007%2Fs10584-011-0061-5.pdf>; Burnham et. al., 2011, Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum,

Using this number, the lifecycle emissions from the Sherco CC would average over 4,000,000 tons CO₂-e annually.

As we pointed out in our Initial Comments, Xcel assumes that the Sherco CC will remain online for 40 years, or until 2067 – well after scientific consensus has made clear that the electricity grid must become 100% carbon-free. Approving a new massive source of greenhouse gas emissions is simply not consistent with the Commission’s rule and governing statutes, nor with the State’s climate goals, and is not in the public interest.

IV. Limitations of DOC’s Analysis

A. DOC’s modeling findings are conservative because DOC did not correct Xcel’s assumptions regarding solar, wind and battery costs or project sizes—despite evidence that Xcel’s cost assumptions were overstated and the project sizes were unreasonably large.

As discussed above, the DOC’s modeling shows that the Sherco CC is not a cost-effective resource addition, a finding with which we agree. However, the DOC’s modeling did not address problems with Xcel’s renewable energy, storage, and distributed generation assumptions, and so DOC’s results overlook the opportunity presented by those resources to lower Xcel’s costs. In our Initial Comments, our experts conducted a thorough review and critique of Xcel’s modeling assumptions regarding the size and cost of solar, wind, hybrids, and battery storage.⁴³ Assessing the reasonableness of these core assumptions is instrumental to evaluating the prudence of any proposed long-term resource plan, and therefore require close scrutiny. DOC tested several changes to Xcel’s modeling assumptions, but did not make any changes to costs or project sizes for new solar, wind and battery storage additions.⁴⁴

As discussed at length in our Initial Comments, in our experts’ views, the costs of these three resource types were all overstated. For instance, the capital costs for solar PV projects were based on an outdated source and did not address the economies of scale for large solar projects.⁴⁵

<https://pubs.acs.org/doi/pdf/10.1021/es201942m>; Miller et. al., 2013, Anthropogenic emissions of methane in the United States, <http://www.pnas.org/content/110/50/20018>; Brandt et. al., 2014, Methane Leaks from North American Natural Gas Systems, <http://science.sciencemag.org/content/sci/suppl/2014/02/12/343.6172.733.DC1/1247045.Brandt.SM.revision2.pdf>; Alvarez et. al., 2018, Assessment of methane emissions from the U.S. oil and gas supply chain, <https://science.sciencemag.org/content/361/6398/186>.

⁴³ Sierra Club Initial Comments at 12-30.

⁴⁴ DOC Initial Comments at 55-56

⁴⁵ Sierra Club Initial Comments, Figure 3.

Xcel also set unreasonably large project size minimums, making it more unlikely that the model would select those resources. For example, Xcel assumed a minimum new solar project size of 500 MW, and minimum wind project size of 750 MW. Xcel's generic battery storage project was 321 MW, which would be the largest battery project in the world.⁴⁶ Xcel also only allowed hybrid resources to be built in one year (2025), rather than treating them like any other new resource that was available throughout the modeling period. These unreasonable modeling assumptions had a substantial impact on Xcel's modeling results: when our experts modeled more reasonable project sizes and costs, our EnCompass selected a plan that included significantly more wind, solar hybrids, and battery storage than did Xcel's, resulting in more than \$2 billion in savings relative to Xcel's preferred plan.⁴⁷

Although DOC did not correct Xcel's problematic size, cost and availability assumptions for renewable projects, DOC's modeling still resulted in substantial solar additions. But with our corrections, DOC's modeling likely would have also resulted in more wind, hybrid, distributed generation, and battery storage replacement. If DOC has not corrected these issues when conducting any new EnCompass modeling it may present in its reply comments, it would therefore be unsurprising, though problematic, if its modeling results were to contain new gas CTs, and no battery storage or hybrid resources.

The lack of battery storage in DOC's preferred plan is particularly concerning because the resource's attributes should be attractive for addressing the Department's concerns about market hedging and balancing renewables. DOC asserts in its Initial Comments the value of owned or contracted generating resources for providing Xcel with a market hedge, and states that "a resource that is perfectly flexible—can be ramped up and down at will—represents the ideal resource from a hedging perspective."⁴⁸ That description of an ideal hedging resource applies to battery storage, which is almost perfectly flexible and has an ability to ramp between fully charging and fully discharging in a matter of seconds or less. Yet the Department does not even mention battery storage or hybrid resources in this hedging discussion, nor does its modeling address Xcel's flaws regarding battery storage and hybrid resource size, cost and availability.

B. DOC's Initial Comments fail to contemplate reasonable solutions to its transmission and interconnection concerns.

DOC's Initial Comments also raised concerns regarding the feasibility of Xcel adding significant amounts of new utility-scale renewable generation, citing costs and delays in the MISO generation interconnection process as well as congestion and renewable curtailment, all due to

⁴⁶ *Id.* at 13.

⁴⁷ *Id.* at 42.

⁴⁸ DOC Initial Comments at 32.

challenges in building new transmission lines through the MISO process.⁴⁹ As discussed in detail in our Initial Comments, battery storage is an ideal solution for facilitating the low-cost interconnection of renewable generation and reducing transmission congestion.⁵⁰ Once we corrected Xcel’s flawed modeling assumptions regarding battery storage and hybrids, we found that the EnCompass modeling optimized for a plan that includes more than 2 gigawatts of battery storage—of which approximately half was standalone and half was paired with solar PV.

The DOC’s Initial Comments also failed to consider the numerous other near-term transmission solutions identified in our comments,⁵¹ such as using grid-enhancing technologies like dynamic line ratings, adding circuits and other upgrades to existing lines, strategically siting storage to reduce renewable curtailment and regulate voltage and power flows, transmission expansion outside of the MISO process, and upgrading substation equipment.⁵²

Even if Xcel does not implement those near-term solutions, there is no reason to believe the long lead time for building new transmission will significantly constrain Xcel’s deployment of renewable resources. Under Sierra Club’s plan, most new wind resources are not added until 2030, while Xcel does not add wind resources until 2032.⁵³ DOC even notes that transmission concerns did not limit its renewable expansion: “the Department did not limit availability of new expansion units in the early years because they were rarely selected by Strategist and there is no reason at this time to limit resource planning based on MISO’s GIQ since there are other potential paths to obtain projects.”⁵⁴

In supplemental comments, DOC argued for an extension of Monticello’s license based on the premise that Xcel’s modeling did not account for transmission interconnection concerns, stating that “[t]he IRP as presented and the analytic parameters set forth as part of these proceedings, do not fully consider ... uncertainties associated with the transmission build, and so may not meet the state’s greenhouse emission targets. To fully consider these impacts, I recommend that the Commission favor an extension of the Monticello Nuclear Power Plant...”⁵⁵

⁴⁹ DOC Initial Comments at 37-44.

⁵⁰ Sierra Club Initial Comments at 17-22.

⁵¹ DOC’s response to SC1 argues that these factors may have been accounted for in DOC’s analysis, to the extent such solutions are reflected in MISO’s interconnection queue and studies. However, most of these solutions, such as grid-enhancing technologies, the strategic siting of storage, and transmission expansion outside of the MISO process, are not considered at all in MISO’s interconnection studies.

⁵² Sierra Club Initial Comments at 17-22.

⁵³ *Id.* at 3

⁵⁴ DOC Initial Comments at 40.

⁵⁵ DOC February 11, 2021 supplemental comments from Deputy Commissioner Aditya Ranade.

There are several issues with this reasoning. First, Xcel's IRP explicitly notes that transmission challenges were evaluated and accounted for in its IRP,⁵⁶ most notably through Xcel's \$500/kW wind and \$200/kW solar interconnection cost assumptions. Second, as noted above, neither Xcel nor Sierra Club calls for significant wind additions in the next decade, which is more than enough time to complete new needed transmission projects given MISO's experience with building the Multi-Value Projects and other regions' similar success in completing large-scale transmission expansion for renewable energy within five to ten years. Many MISO MVPs were completed in less than five years,⁵⁷ given that FERC approved MISO's MVP cost allocation methodology in December 2010.

As a result, near-term transmission challenges do not raise concerns about Xcel's long-term ability to achieve emission reductions by deploying renewable resources. Even the DOC's initial comments note that there are many solutions within and outside of the MISO process for overcoming those concerns: "the Department concludes that either the transmission cost cap will increase, the cost of major transmission upgrades that increase interconnection capacity will be distributed beyond the GIQ (for example, as Market Efficiency Projects (MEP) or Multi-Value Projects (MVP)), or generation projects will not get built via the GIQ."⁵⁸

Separately, we note that the result of DOC's historical analysis of the maximum interconnection cost wind project developers can shoulder is almost perfectly consistent with the interconnection cost we assumed in our own modeling, as presented in our Initial Comments. DOC states that "it appears that the affordability upper limit for a project is around \$150,000 per MW for transmission costs, at least for wind projects."⁵⁹ That maximum cost of \$150,000/MW translates into \$150/kW, which almost perfectly matches the \$146/kW assumption we used as a transmission cost adder in our modeling.⁶⁰ As discussed in our Initial Comments, this \$146/kW transmission cost adder was based on the outputs of Vibrant Clean Energy's modeling for CUB using the WIS:DOM program, which (unlike EnCompass and Strategist) builds out the

⁵⁶ See Xcel supplemental IRP, Attachment A at 88. Xcel notes that "In our initial filing we assumed that a greenfield wind project would be subject to \$400/kW transmission interconnection costs. Since then, it has become apparent that transmission constraints in the MISO West region are increasingly severe, such that the average identified upgrade cost in some studies is upwards of \$2,000/kW. In order to account for these near-term constraints in our modeling, we have not made wind available to the model to select prior to 2026 in our baseload scenario modeling. Starting in 2026 we apply a \$500/kW interconnection cost to generic wind resources."

⁵⁷ <https://cdn.misoenergy.org/MVP%20Dashboard%20Q4%202020117055.pdf>

⁵⁸ DOC Initial Comments at 44.

⁵⁹ *Id.* at 41.

⁶⁰ Sierra Club Initial Comments at 18.

transmission and distribution system.⁶¹ Our modeling thus reasonably accounted for and addressed the transmission constraints raised by DOC.

C. DOC’s Prioritization of Strategist Over EnCompass Misses the Opportunity to Assess the Benefits of Storage and Hybrid Resources.

In its Initial Comments, DOC acknowledges that EnCompass may have benefits over Strategist as a resource planning model, given that EnCompass “has greater flexibility and potentially greater accuracy in dealing with time and issues that are related to time such as unit dispatch.”⁶² However, DOC only conducted Strategist modeling, because that is the model that DOC staff has in-house expertise in operating.⁶³

In our view, Strategist is not as well-suited as EnCompass for selecting a least-cost resource plan that adequately accounts for the benefits of renewables and storage. As DOC notes in its own comments, rather than being a chronological model, Strategist uses an hourly load shape represented by a “typical week” per month of 168 hours.⁶⁴ Similarly, wind and solar shapes are based on this typical week, which does not account for variation within the weeks in a month. When dispatching generating units, the Strategist model first dispatches all scheduled resources, and then dispatches thermal units against remaining load in a load duration curve, which sorts demand data in descending order. This assumes the traditional generating unit hierarchy of “baseload, intermediate, peaking” and assumes that slow-ramping units are the least expensive to operate. It does not account for either the rising costs of fossil-fueled units or the increasing penetration of renewable generators in a utility system. EnCompass, on the other hand, models each hour chronologically, and can consider start and shut down costs and times, as well as ramping constraints, when considering if and when to dispatch fossil units.

Strategist’s inability to operate chronologically at the hourly level means that it does not fully capture the benefits of flexible resources like renewables, hybrids, and battery storage. Storage in particular offers very specific benefits to the grid, including regulation, spinning reserve, and ancillary support services that are not recognized by the Strategist model. Lastly, Strategist cannot model hybrid resources, in which a battery is charged from a paired solar resource during periods when there is excess solar energy, and then discharged during peak periods to help meet demand in hours when solar resources are offline. As a result, EnCompass provides more useful insight into the value of additional renewables and battery storage to Xcel’s system.

⁶¹ *Id.* and CUB Initial Comments at 3.

⁶² DOC Initial Comments at 48.

⁶³ *Id.*

⁶⁴ *Id.*

DOC stated in its Initial Comments that it is halfway through its EnCompass modeling and that it has a goal of completing that modeling and presenting results in Reply Comments.⁶⁵ Given the Commission's historical interest in DOC's comments, if DOC does present EnCompass modeling in its Reply Comments, in our view it will be essential for other intervenors to have the opportunity to review that analysis and file supplemental comments on it.

D. DOC correctly criticizes Xcel for its excessive focus on on-system capacity.

DOC correctly offers a lengthy rebuttal of Xcel's attempt to use on-system dispatchable capacity as the metric of electric reliability.⁶⁶ Our initial comments similarly devoted ten pages to rebutting Xcel's unreasonable focus on on-system resources as the metric of reliability⁶⁷ and complete exclusion of market transactions from its reliability analysis.⁶⁸ We wholeheartedly agree with DOC's explanation that the "[l]ack of dispatchable capacity on Xcel's system is not a reliability issue because the load simply would be met by non-Xcel resources—in other words Xcel becomes a net importer in certain hours."⁶⁹

As explained in our Initial Comments, market transactions across a regional grid are essential for efficiently integrating large amounts of renewable energy. The variability of wind and solar energy causes periods of exports or imports when those resources may be locally abundant or in short supply. However, by using market transactions to aggregate diverse wind and solar resources over a much larger geographic area, including the entire MISO footprint and even neighboring power systems, the variability and uncertainty of wind and solar output is drastically reduced.⁷⁰ By focusing on on-system resources and ignoring imports, Xcel is moving in the wrong direction for achieving high renewable penetrations.

Markets and imports also help to reduce exposure to localized failures of conventional power plants or spikes in electricity demand due to extreme weather or other unexpected events, as noted in our Initial Comments.⁷¹ The reliability challenges that occurred in the South Central U.S. in February 2021, caused primarily by a loss of gas generation but also some outages of coal, nuclear, and renewable plants,⁷² further highlight the value of market transactions for addressing localized extreme weather events. MISO was able to escape with limited outages and electricity price spikes in parts of its southern footprint, despite widespread gas plant outages and

⁶⁵ *Id.* at 68.

⁶⁶ *Id.* at 34-36.

⁶⁷ Sierra Club Initial Comments at 90-93.

⁶⁸ *Id.* at 68-73.

⁶⁹ DOC Initial Comments at 34-36.

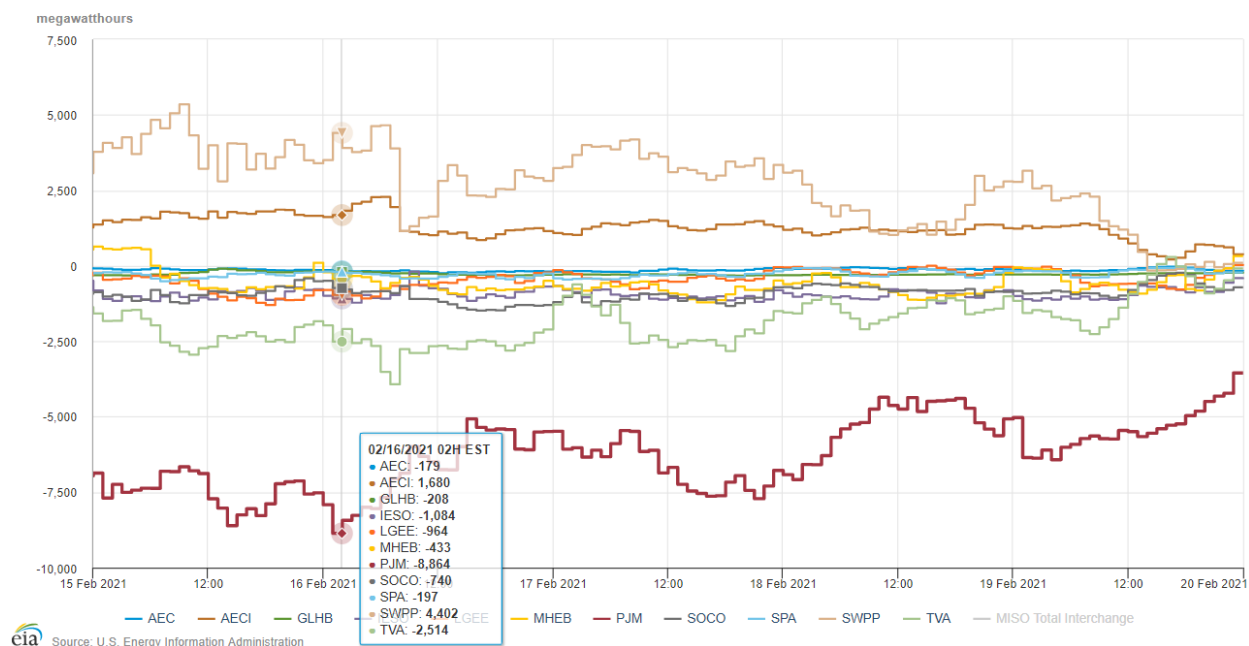
⁷⁰ Sierra Club Initial Comments at 72, 91-93.

⁷¹ *Id.* at 62, 92.

⁷² <https://energycentral.com/c/gr/observations-winter-electric-reliability-event-south-central-us>

interruptions of gas supplies, because it was able to import more than 13 GW of power from neighboring power systems. As shown in the bottom half of the EIA chart below,⁷³ during the February 2021 extreme weather event, at maximum MISO was importing nearly 9,000 MW from PJM, several thousand MW from TVA, and around an additional 1,000 MW each from Southern Company, Louisville Gas and Electric, and Canada. Total MISO imports were consistently over 13,000 MW during the most challenging period from midday February 15 to midday February 16.

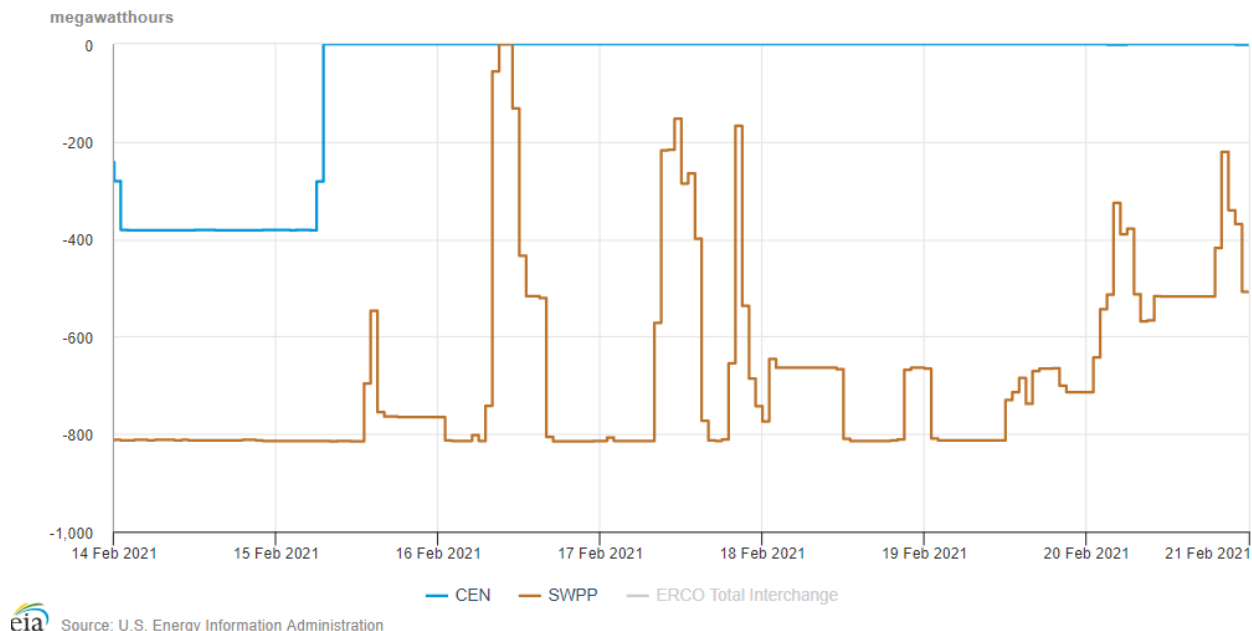
Midcontinent Independent System Operator, Inc. (MISO) electricity interchange with neighboring balancing authorities 2/15/2021 – 2/19/2021, Eastern Time




In contrast, the isolated ERCOT region was hit with days of extreme rolling outages, with curtailed load amounts regularly reaching 15 GW, because it lacks strong transmission inter-ties and was only able to import 800 MW from its neighbors. In contrast to the 13,000 MW MISO was importing during the peak of that event, ERCOT was only able to import about 800 MW of power, mostly from SPP, as shown below. ERCOT was initially able to import nearly 400 MW from Mexico, though those imports were cut early on February 15 when Mexico also experienced generator outages due to a loss of gas supply. Imports from SPP were also briefly cut at various points as SPP experienced its own shortages, particularly on February 16. If ERCOT had transmission ties comparable to MISO's, it likely could have weathered the event with little to no loss of load.

⁷³ This chart can be made at https://www.eia.gov/beta/electricity/gridmonitor/expanded-view/electric_overview/US48/US48/InterchangeWithNeighbor-5/edit

Electric Reliability Council of Texas, Inc. (ERCOT) electricity interchange with neighboring balancing authorities 2/14/2021 – 2/20/2021, Eastern Time



 Source: U.S. Energy Information Administration

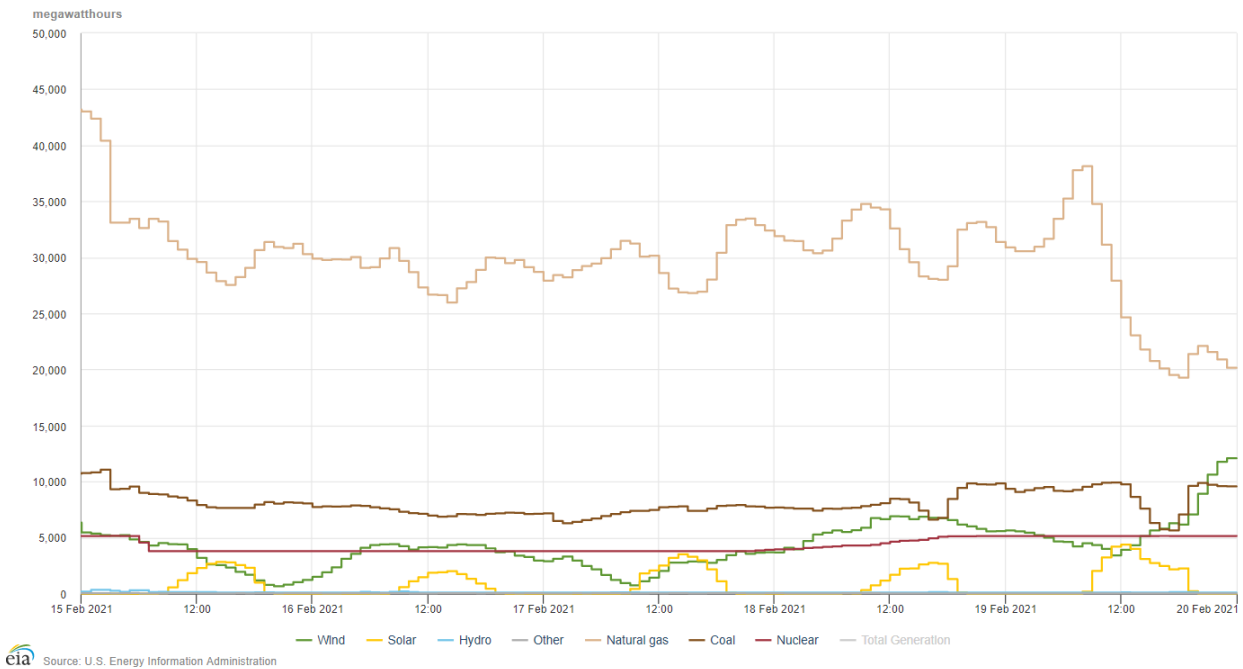
EIA⁷⁴ and ERCOT⁷⁵ data confirm that, while ERCOT coal, nuclear, wind, and solar plants also saw capacity taken offline due to the extreme cold, the loss of gas generation was the primary factor behind the extended outages in Texas. As shown below, a steep drop in gas and coal generation early on February 15 coincided with the start of the rolling outages in ERCOT, while wind output was relatively high. Solar output was high on each day of the event, as solar panels operate at a higher efficiency in lower temperatures.

⁷⁴ This chart can be made at https://www.eia.gov/beta/electricity/gridmonitor/expanded-view/electric_overview/US48/US48/GenerationByEnergySource-4/edit

⁷⁵

[http://www.ercot.com/content/wcm/key_documents_lists/225373/Urgent Board of Directors Meeting 2-24-2021.pdf](http://www.ercot.com/content/wcm/key_documents_lists/225373/Urgent_Board_of_Directors_Meeting_2-24-2021.pdf)

Electric Reliability Council of Texas, Inc. (ERCOT) electricity generation by energy source 2/15/2021 – 2/19/2021, Eastern Time



Lessons learned from this event make clear that a utility’s position in a regional grid system is fundamental to understanding potential reliability issues. As discussed at length in our Initial Comments, when Xcel’s ability to import and export energy is appropriately considered, even Xcel’s own analysis identifies no reliability concerns under high renewable penetration scenarios.⁷⁶

E. DOC overstates the economic risk of power markets and understates the risks of local gas supply interruptions and price spikes.

While correctly noting that being a net importer is not a reliability risk, DOC argues that a lack of on-system capacity can be an economic risk. Specifically, DOC asserts that a “[l]ack of dispatchable capacity on Xcel’s system is not a reliability issue because the load simply would be met by non-Xcel resources—in other words Xcel becomes a net importer in certain hours. Instead, it is an economic risk (hedging) issue. As explained above, to the extent Xcel is a net importer the Company pays the Spot Market price for energy and thus is exposed to an unhedged economic risk.”⁷⁷

DOC focuses on an anomalous event, however, to assert the economic risk of markets, claiming:

⁷⁶ Sierra Club Initial Comments at 69-74.

⁷⁷ DOC Initial Comments at 35.

In general, Spot Market LMPs can be somewhat volatile. For example, Spot Market LMPs at the Minnesota Hub for 2008 averaged \$46.16 per MWh and the LMP was over \$100 per MWh for 813 hours. The next year (2009) Spot Market LMPs fell about 50 percent, averaging \$23.70 per MWh and exceeded \$100 per MWh in only 61 hours—a decrease of over 90 percent. While Spot Market LMPs have remained somewhat stable in the decade since, there is no reason to expect such stability to continue for another 15 years, or through the duration of an IRP.⁷⁸

The events of 2008 and 2009, with a record spike in natural gas prices in 2008 causing high power prices, followed by a massive drop in gas and electricity prices in 2009 due to the Great Recession, are at most an extreme anomaly and most likely will never happen again. Moreover, the greatly expanded use of renewable resources since 2008, and the continued renewable expansion advocated in our Clean Energy for All Plan, greatly reduces the sensitivity of power prices to gas prices. This makes the 2008-2009 volatility even less likely to recur. Renewables provide this benefit both by providing generation that is not dependent on fuel prices, and by reducing the risk of gas demand exceeding gas supply by reducing electric sector demand for gas. As noted above, the expanded use of storage resources in Sierra Club’s plan can also mitigate Xcel’s exposure to market price volatility. DOC’s comments could have more accurately described the risk as gas price volatility and not power market price volatility. This would have pointed to the expanded use of renewable and storage resources as the solution for mitigating, if not eliminating, the risk of a recurrence of 2008-2009 price volatility.

F. DOC understates the risk of gas supply interruptions.

DOC appears to accept Xcel’s contention that its gas power plants are not vulnerable to correlated failures or the risk of fuel supply interruptions, despite the abundant evidence of those risks presented in our initial comments⁷⁹ and confirmed by rolling outages in MISO South, ERCOT, and SPP in February 2021. DOC correctly notes “the main risk that remains is that all of Xcel’s plants ultimately draw their natural gas supplies using the same interstate pipeline—Northern Natural Gas (NNG). This is a risk which cannot be mitigated at this time.” However, DOC then points to Xcel’s statement that “Firm [gas] service can only be interrupted under a force majeure situation which is very rare,” to conclude “Therefore, based on the Company’s response above, it appears that even if something catastrophic were to happen to NNG’s transportation system, Xcel expects that it would not significantly impact Xcel’s generation capability.”⁸⁰

⁷⁸ *Id.* at 28.

⁷⁹ Sierra Club Initial Comments at 74-78.

⁸⁰ DOC Initial Comments at 27.

Even if such gas interruptions were rare, it is undeniable that their impact is commensurate with the reliance on gas generation. Thus, more gas generation puts Xcel ratepayers at further economic and reliability risk. Curtailment of gas supplies due to force majeure events and other disruptions is a real risk. Minnesota is at the very end of the Northern Natural Gas pipeline, which delivers gas primarily from the Permian Basin in West Texas and Anadarko Basin in Oklahoma. Those gas fields saw extreme loss of production due to wellheads freezing and gas processing facilities being taken offline during the February 2021 cold snap, with Texas gas production dropping by 7 Bcf/day,⁸¹ nearly 1/3 of the state's typical gas production.⁸² As a result, the Northern Natural Gas pipeline was forced to declare a critical day and impose a standard operating limit. The large explosion on the Northern Natural Gas pipeline in Nebraska in December 2020 similarly highlights the vulnerability of this and other gas pipelines.⁸³ In other regions, failures of gas pipelines⁸⁴ and storage facilities⁸⁵ have taken them offline for months or longer, causing extreme disruption to gas and power markets and electric reliability risks. While such events may be rare, their potentially catastrophic impact on electric reliability and affordability should not be dismissed.

G. DOC's views in opposition to all-source bidding are contradicted by the strong evidence that all-source RFPs have benefited customers elsewhere.

In its Initial Comments, the Department opposes conducting all-source bidding, but its reasoning for this opposition does not hold water.⁸⁶ First, the Department claims that the process failed in Minnesota in the past, but the processes to which it refers began 20 years ago or more. These examples are not relevant to whether all-source bidding is feasible today and—as we will explain—such processes have delivered significant cost savings to customers elsewhere in recent years. Second, the Department overlooks how all-source RFPs and IRPs can be mutually beneficial. DOC asserts that if an all-source RFP is done after an IRP then “the purpose of the IRP process becomes unclear” because it would mean essentially repeating the IRP process with the new bid information.⁸⁷ But this does not have to be the case. An all-source RFP can follow from an IRP process without re-doing the IRP itself. Alternatively, the RFP can precede the IRP

⁸¹ <https://www.naturalgasintel.com/historic-cold-snap-drives-record-natural-gas-demand-prices-as-freeze-cuts-supply/>

⁸² <https://www.eia.gov/todayinenergy/detail.php?id=45377>

⁸³ https://norfolkdailynews.com/news/explosion-near-lyons-caused-by-gas-line-rupture-northern-natural-gas-says/article_1b180268-478d-11eb-a9d7-9f3125237f06.html

⁸⁴ <https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2019/market-snapshot-impacts-enbridges-bc-pipeline-rupture-natural-gas-flows.html>

⁸⁵ https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20Short-Term%20Special%20Assessment%20Gas%20Electric_Final.pdf

⁸⁶ DOC Initial Comments at 98-99.

⁸⁷ *Id.* at 98.

and inform the resource costs modeled in the latter's process. Another option is to use a previous RFP's bids in an existing planning process, with the plan to issue another RFP following that IRP. DOC's view of the interaction between an all-source RFP and an IRP is too limited. The resource planning process in Colorado—in which Xcel's affiliate in that state participates—includes 1) "Phase I" modeling with generic resources and costs; 2) after a preferred plan is approved, "Phase II" starts where the utility issues an all-source RFP; and 3) the utility's modeling incorporates actual bid information in order to choose specific resources. Xcel's Colorado process has yielded record-low prices for renewable, storage, and hybrid resources,⁸⁸ and there is no reason this success cannot be replicated in Minnesota.

Two other examples of how the RFP and IRP processes can work successfully in concert, but in a different order, are seen in Public Service Company of New Mexico's (PNM) planning in recent years. In its 2017 IRP, PNM modeled generic resource costs and found that retirement of the San Juan coal plant was cheaper than continuing to operate the plant. As a result of this IRP finding, PNM issued an all-source RFP in October 2017 and a subsequent storage-only RFP in April 2019 in order to find particular replacement resources.⁸⁹ That all-source RFP resulted in 345 bids, including two low-cost solar/battery hybrid projects: 1) one with 300 MW of solar at \$18.65 per MWh paired with 40 MW of battery storage at \$7.46 per kW-month capacity charge; and 2) another that included 50 MW of solar at \$19.73 per MWh paired with a 20 MW battery at \$9.97 per kW-month capacity charge.⁹⁰ PNM did not re-do its IRP but rather screened the many bids it received based on costs and some qualitative attributes in developing a replacement portfolio. (Ultimately, another party's portfolio was chosen based on other bids received in response the RFP.) More recently, PNM used the results from that previous RFP in order to explore the possibility of retiring its share of the Four Corners coal plant. Using the older bid information as a proxy, PNM identified substantial savings from replacing the coal generation. Based on those results, PNM stated that would later issue another RFP in the near future in order to identify specific replacement resources.⁹¹

⁸⁸ <https://www.utilitydive.com/news/xcel-record-low-price-procurement-highlights-benefits-of-all-source-compete/600240/>

⁸⁹ Direct Testimony of Roger W. Nagel at 13, Docket No. 19-00195-UT (N.M. Public Reg. Comm'n July 1, 2019), available at https://edocket.nmprc.state.nm.us/AspSoft/HandlerDocument.ashx?document_id=1179834.

⁹⁰ PNM Consolidated Application for the Abandonment, Financing and Replacement of the San Juan Generating Station Pursuant to the Energy Transition Act at 16, Docket No. 19-00195-UT (N.M. Public Reg. Comm'n, July 1, 2019), available at

https://edocket.nmprc.state.nm.us/AspSoft/HandlerDocument.ashx?document_id=1179824

⁹¹ Direct Testimony of Nicolas L. Phillips at 18, Docket No. 21-00017-UT (N.M. Public Reg. Comm'n January 8, 2021), available at <https://www.pnmresources.com/~media/Files/P/PNM-Resources/rates-and-filings/Four%20Corners%20Filing/7%20Direct%20Testimony%20of%20Nicholas%20L%20Phillips.pdf>.

Other utilities have successfully incorporated all-source RFPs into their planning processes, including Xcel Colorado and Northern Indiana Public Service Company. We continue to encourage Xcel-Northern States Power to follow their example and pursue an all-source RFP in order to foster a wide, competitive pool of resource options.

V. **Equity Remains a Critical Consideration in this IRP.**

As we discussed in our initial comments, we believe it is essential that utilities craft their IRPs through a lens of equity and access to the benefits of clean energy. Thousands of comments in the docket call on Xcel to address racial and economic justice and equity in its plan. Many parties made recommendations to Xcel as a part of their initial comments that would help support a just transition from fossil fuels to clean energy. In particular, we support the following recommendations:

- **Program Accessibility:** Sierra Club supports Energy Efficiency for All's (EEFA's) recommendations to adopt practices to support procedural justice, including deeper engagement with renters, affordable rental property owners, BIPOC communities, and under-resourced individuals by providing resources for engagement and participation. In our initial comments, we discussed the need to work with community members to develop programs to expand access to energy efficiency and distributed solar. Providing structure and resources to participate in dockets and decision-making processes is critical to ensuring community members have access to the process. We also support the recommendations of the Distributed Solar Parties and the City of Minneapolis to develop incentive programs for distributed generation programs that provide equitable access to BIPOC and low-income customers.
- **Workforce diversification:** In our initial comments, we noted we would like to see Xcel make firm quantitative commitments around workforce diversity, including benchmarks with dates, and make the information publicly available. We support recommendations from EEFA, City of Minneapolis and CEOs that Xcel develop and report on comprehensive workforce and leadership diversity goals, including recruitment, hiring, retention, and supplier and vendor diversity. goals for workforce and leadership.
- **Just transition for plant communities and workers:** Part of a just transition is supporting host communities and power plant workers through the retirement of large power plants. Sierra Club supports IBEW's recommendation for Xcel to develop a just transition plan and standing task force to address worker transition and the Coalition for Utility Cities' recommendation that Xcel develop a community transition plan with communities facing plant retirements.
- **Distributed generation:** A key element of Sierra Club's Clean Energy for All plan is the addition of 1,851 MW of distributed solar generation. As the City of Minneapolis

discusses in its comments, Minneapolis and several other cities in Xcel service territory have set 100% renewable energy or other climate goals and will rely on local solar generation. The combined renewable goals for Minneapolis, Saint Paul, St Louis Park, Eden Prairie, Northfield & Red Wind adds up to 580 MW of locally sited solar. We urge Xcel to work with the City of Minneapolis and other cities to develop programs that can support these municipal goals by developing local renewable resources and supporting distributed solar goals.

- **Community solar:** Many commenters have advocated for including substantial amounts of community solar in Xcel's IRP. The Sierra Club's Clean Energy for All plan includes 2,050 MW of community solar – more than double what Xcel included in its modeling – based on more reasonable forecasts of community solar growth. For renters and those who cannot afford an upfront payment for rooftop solar, community solar can be an option that removes barriers to transitioning to clean energy. The increased diversity in ownership that accompanies community solar will also allow for more wealth-building opportunities for solar businesses and communities. The distributed solar and community solar pieces of our Clean Energy for All Plan are thus key elements of a more just and equitable resource plan for Xcel's customers.
- **Rejecting the Sherco gas plant:** Many commenters called on the Commission to exclude the Sherco gas plant from Xcel's resource plan. Rejecting Xcel's proposed Sherco gas plant is important not only because of its cost and risk but also from an equity perspective. As discussed in our initial comments, it has been thoroughly documented that BIPOC and low-income communities will suffer a disproportionate burden from climate change – from greater vulnerability to extreme weather, to paying more for energy that comes with extreme temperatures, and less access to sufficient home heating and cooling.
- **Ongoing Community Engagement:** Although consultation with impacted communities is especially important in informing resource planning, many commenters also made clear that there is an equally important need for ongoing relationship building and accountability to the community to ensure Xcel's most vulnerable customers are served equally. We therefore support the request by commenters⁹² for Xcel to form an environmental justice accountability board, which would develop environmental justice-focused initiatives to be incorporated throughout the utility, and to engage in relationship building and meetings with BIPOC community leaders that can inform ongoing program development, improvement, and implementation.

⁹² See comments filed by a coalition including Fresh Energy; CUB; Community Power; Center for Earth, Energy and Democracy; the City of Minneapolis; the University of Minnesota's Energy Transition Lab; Inquilinx Junidxs Por Justicia; and others.

VI. Conclusion

For the reasons detailed above and for the reasons offered in our Initial Comments, we respectfully request that the Commission adopt the recommendations set forth in our Initial Comments and the additional recommendations contained herein.

Dated: June 25, 2021

Respectfully submitted,

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