MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	January 25, 2022 January 27, 2022 February 8, 2022	Agenda Item **1
Company	Xcel Energy (Xcel or the Company)	
Docket No.	**E002/RP-19-368**	
	In the Matter of Xcel Energy's 2020-2034 Integrated Resource Plan (IRP)	

Issues

1. Should the Commission approve, modify, or reject Xcel Energy's Alternate Plan, as described in the Company's June 25, 2021 Reply Comments?
2. If the Commission modifies the Alternate Plan, what modifications should the Commission make?
3. What findings should be made regarding the five-year action plan?
4. Should the life of the Monticello nuclear plant be extended by 10 years and does the Commission need to make that decision at this time and in this docket?
5. Should the Commission approve Xcel's proposal to build transmission tie-lines from the Sherco and King sites that can interconnect wind and solar resources?
6. Should the Commission adopt a proposed alternative plan under Minnesota Rules 7843.0300, subp. 11?
7. What resource acquisition process(es) should Xcel use to implement the approved resource plan?
8. When should Xcel file its next IRP?

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✓ Relevant Documents	Date
Commission Order,	Jan 11, 2017
Initial Filling	
Xcel Energy, Initial Filing - Cover Through Appendix F7	Jul 1, 2019
Xcel Energy, Initial Filing - Cover Through Resource Plan And Service	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix G1 Through L	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix J3	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix J4	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix M Through N1	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix N1	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix N2 Through N8	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix N3	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix N5	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix N7	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix N9 Part 1	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix N9 Part 2	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix N9 Part 3	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix N10 Through P1	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix P2 Through P3	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix Q Through S	Jul 1, 2019
Xcel Energy, Initial Filing - Appendix R	Jul 1, 2019
Xcel Energy, Supplement - Resource Plan Supplement - Public and Trade Secret	Jun 30, 2020
Xcel Energy, Supplement - Errata to Supplement	Aug 25, 2020
Initial Comments (Parties)	
IBEW Locals 23, 160, and 949, Initial Comments	Mar 17, 2020
Northern Natural Gas, Initial Comments - Exhibit 3, Appendix A, 3 of 3	Feb 8, 2021
Northern Natural Gas, Initial Comments - Exhibit 3, Appendix A, 2 of 3	Feb 8, 2021
Northern Natural Gas, Initial Comments - Exhibit 3, Appendix A, 1 of 3	Feb 8, 2021
Northern Natural Gas, Initial Comments - and Exhibit 1-3	Feb 8, 2021
Center of the American Experiment, Initial Comments	Feb 10, 2021
Clean Energy Organizations, Initial Comments - Public and Trade Secret	Feb 11, 2021

Relevant Documents	Date
City of Minneapolis, Initial Comments	Feb 11, 2021
Distributed Solar Parties, Initial Comments - Public and Trade Secret	Feb 11, 2021
Citizens Utility Board of Minnesota, Initial Comments	Feb 11, 2021
DOC DER, Initial Comments - Public and Trade Secret	Feb 11, 2021
Citizens Utility Board of Minnesota, Initial Comments - Appendix A	Feb 11, 2021
Clean Energy Organizations, Initial Comments - Attachment A - Public and Trade Secret	Feb 11, 2021
Clean Energy Organizations, Initial Comments - Attachment B - Public and Trade Secret	Feb 11, 2021
Sierra Club, Initial Comments - Attachment C	Feb 11, 2021
Xcel Large Industrials, Initial Comments - with Exhibit A	Feb 11, 2021
Sierra Club, Initial Comments - Public and Trade Secret	Feb 11, 2021
DOC, Initial Comments - Deputy Commissioner Letter	Feb 11, 2021
Citizens Utility Board of Minnesota, Initial Comments - Errata	Jun 25, 2021
Reply Comments (Parties)	
IBEW Locals 23, 160, and 949, Reply Comments	Mar 23, 2021
Center of the American Experiment, Reply Comments	Jun 24, 2021
Distributed Solar Parties, Reply Comments	Jun 25, 2021
City of Minneapolis, Reply Comments	Jun 25, 2021
Citizens Utility Board of Minnesota, Reply Comments	Jun 25, 2021
Sierra Club, Reply Comments - Public and Trade Secret	Jun 25, 2021
Northern Natural Gas, Reply Comments	Jun 25, 2021
DOC DER, Reply Comments	Jun 25, 2021
Clean Energy Organizations, Reply Comments - Attachment 1 - EFG Supplemental Report - Public and Trade Secret	Jun 25, 2021
Clean Energy Organizations, Reply Comments - Attachment 2 - AEG Report	Jun 25, 2021
Xcel Large Industrials, Reply Comments - with Exhibit B Reply Report	Jun 25, 2021
Clean Energy Organizations, Reply Comments - Public and Trade Secret	Jun 25, 2021
Xcel Energy, Reply Comments - Public and Trade Secret	Jun 25, 2021
Xcel Energy, Errata - June 30, 2021 Reply Comments	Aug 19, 2021
OAG-RUD, Reply Comments - Revised - Public and Trade Secret	Dec 7, 2021
Supplemental Comments (Parties)	

Relevant Documents	Date
Sierra Club, Supplemental Comments - Public and Trade Secret	Oct 15, 2021
OAG-RUD, Supplemental Comments - Public and Trade Secret	Oct 15, 2021
Citizens Utility Board of Minnesota, Supplemental Comments	Oct 15, 2021
Distributed Solar Parties, Supplemental Comments	Oct 15, 2021
Clean Energy Organizations, Supplemental Comments - Attachment 1 - Public and Trade Secret	Oct 15, 2021
Clean Energy Organizations, Supplemental Comments - Attachment 2 - Public and Trade Secret	Oct 15, 2021
DOC DER, Supplemental Comments	Oct 15, 2021
Clean Energy Organizations, Supplemental Comments - Public and Trade Secret	Oct 15, 2021
Xcel Large Industrials, Supplemental Comments - with Exhibit C	Oct 15, 2021
Center of the American Experiment, Supplemental Comments	Oct 15, 2021
City of Minneapolis, Supplemental Comments	Oct 15, 2021
Participant Comments (Initial, Reply, Supplemental)	
Litty Solar and Energy Releaf, Participant Comment - Initial	Oct 24, 2019
Hilda Martinez Salgado, Participant Comment - Initial	Oct 29, 2019
OAH, Participant Comment - Initial	Dec 18, 2019
Wright County Economic Development Partnership, Participant Comment - Initial	Dec 2, 2020
City of Burnsville, Participant Comment - Initial	Dec 17, 2020
Burnsville Chamber of Commerce, Participant Comment - Initial	Dec 23, 2020
Sustainable Growth Coalition, Participant Comment - Initial	Jan 12, 2021
Prairie Island Indian Community, Participant Comment - Initial	Jan 15, 2021
Goodhue County Board of Commissioners, Participant Comment - Initial	Jan 25, 2021
St. Paul Area Chamber, Participant Comment - Initial	Jan 28, 2021
Wright County, Participant Comment - Initial	Feb 8, 2021
City of Becker, Participant Comment - Initial	Feb 10, 2021
LiUNA Minnesota & North Dakota, Participant Comment - Initial	Feb 11, 2021
Coalition of Utility Cities, Participant Comment - Initial	Feb 11, 2021
Tim Wulling, Participant Comment - Initial	Feb 11, 2021
Fresh Energy, Community Stabilization Project, Green & Healthy Homes Initiative, Inquilinxs Unidxs Por Justicia, Minnesota Housing Partnership,	Feb 11, 2021

Relevant Documents	Date
National Housing Trust, and Natural Resources Defense Council (Eefa Partners), Participant Comment - Initial	
Clean Energy Economy Minnesota, Participant Comment - Initial	Feb 11, 2021
St. Paul 350, Participant Comment - Initial	Feb 11, 2021
City of Monticello, Participant Comment - Initial	Feb 11, 2021
Monticello Industrial & Economic Development Committee, Participant Comment - Initial	Feb 12, 2021
IUOE Local 49, Participant Comment - Initial	Apr 12, 2021
IUOE Local 49, Participant Comment - Reply	Jun 24, 2021
As You Sow, Boston Common Asset Management, Seventh Generation Interfaith Coalition For Responsible Investment, Participant Comment - Reply	Jun 25, 2021
US Solar, Participant Comment - Reply	Jun 25, 2021
Becker Township, Participant Comment - Reply	Jun 25, 2021
Coalition of Utility Cities, Participant Comment - Reply	Jun 25, 2021
Community Energy Justice Commenters, Participant Comment - Reply	Jun 25, 2021
Energy We Can't Afford, Participant Comment - Reply	Jun 25, 2021
Monticello Labor Coalition, Participant Comment - Reply	Jun 25, 2021
St. Paul 350, Participant Comment - Reply	Jun 25, 2021
LiUNA Minnesota & North Dakota, Participant Comment - Reply	Jun 28, 2021
Mark Schoennauer, Participant Comment - Supplemental	Oct 15, 2021
St. Paul 350, Participant Comment - Supplemental	Oct 15, 2021
City of Red Wing, MN, Participant Comment - Supplemental	Oct 15, 2021
Coalition of Utility Cities, Participant Comment - Supplemental	Oct 15, 2021
ILSR, Native Sun, Solar Bear, MNIPL, MN350, Community Power, St. Paul 350, Izaak Walton League - MN, UCS, Sierra Club, LSP, CURE, MEP, Honor the Earth, Participant Comment - Supplemental	Oct 15, 2021
PUC, Participant Comment - Supplemental	Oct 15, 2021
Tim Wulling, Participant Comment - Supplemental	Oct 15, 2021
PUC, Participant Comment - Supplemental	Oct 18, 2021
City of St. Paul, Participant Comment - Supplemental	Oct 18, 2021
Congressman Tom Emmer, Participant Comment - Supplemental	Oct 18, 2021
LiUNA Minnesota & North Dakota, Participant Comment - Supplemental	Oct 18, 2021
Monticello Labor Coalition, Participant Comment - Supplemental	Oct 18, 2021

✓ Relevant Documents	Date
Other	
PUC, Order - Referring IRP to OAH for Public Hearings	Jul 18, 2019
DOC DER, Letter - Completeness Review	Jul 25, 2019
City of Minneapolis, Letter - Completeness Review	Jul 31, 2019
Xcel Energy, Letter - Update	Oct 8, 2019
Xcel Large Industrials, Letter - Response to Xcel October 8 Letter	Oct 16, 2019
Clean Energy Organizations, Letter - Response to Xcel October 8 Letter	Oct 16, 2019
Citizens Utility Board of Minnesota, Letter - Response to Xcel October 8 Letter	Oct 16, 2019
PUC, Order -Suspending Schedule and Requiring Filing	Nov 12, 2019
Xcel Energy, Motion to Strike OAG's Reply Comments	Aug 13, 2021
DOC DER, Letter - Update	Aug 26, 2021
OAG-RUD, Response to Xcel Motion to Strike	Aug 27, 2021
Institute for Local Self-Reliance, Petition - Modeling Software Cost	Nov 2, 2021
PUC, Order Striking OAG Reply Comments	Dec 6, 2021

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II. Introduction

A. January 11, 2017 Commission Order and Resource Plan Implementation

1. Commission Order

On January 11, 2017, the Commission approved Xcel's 2016-2030 IRP (the 2015 IRP) with modifications.[1] Among other things, the Commission approved Xcel's proposal to retire the coal-fired Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026, which total about 1,360 megawatts (MW) and roughly 30 percent of Xcel's baseload generation capacity. Xcel proposed replacing the Sherco coal units with a natural gas combined cycle unit located at the Sherco site (the Sherco CC), but the Commission instead made a finding that there will likely be a need for approximately 750 MW of intermediate capacity as a result of the closures, and the Commission authorized a Certificate of Need process to "allow consideration of resources or resource combination alternatives that meet the identified resource and reliability need."[2]

[1] Docket No. 15-21

[2] In 2017, (Minn. Laws 2017, Chapter 5), was signed by the Governor on February 28, 2017, a law that allows, at its sole discretion, Xcel to construct, own, and operate the combined cycle gas plant it proposed in the 2015 resource plan.

In addition, Xcel's plan included 1,800 MW of wind over the planning period, with 800 MW by 2020. Based on modeling conducted by Xcel and the Department of Commerce (Department), the Commission authorized the acquisition of at least 1,000 MW of wind by 2019.

The acquisition of solar resources was complicated by the uncertainty in the growth of Xcel's community solar gardens (CSG) program. Xcel's 2015 IRP proposed 400 MW of large-scale solar, but Xcel also noted that significant interest in the CSG program could affect the Company's future need for large-scale solar. The Department recommended that no additional solar resources beyond CSG – which by the end of the proceeding was forecasted to be 650 MW – would be required during the five-year action plan. Ultimately, the Commission required that "Xcel shall acquire approximately 650 MW of solar in 2016–2021 through a combination of the Company's community solar gardens program or other acquisitions."[3]

The Commission also required Xcel to acquire no less than 400 MW of additional demand response (DR) by 2023. This level of potential DR was supported by a Brattle Group study prepared for Xcel, which examined the market potential for DR programs to reduce peak demand within the Northern States Power (NSP) System.

2. Xcel's Implementation of its 2016-2030 IRP

With the exception of new DR, Xcel's approved five-year action plan has already been implemented. Since the January 11, 2017 Order, Xcel has made significant investments in greenfield wind, repowered wind, and wind and solar resources to supply the Renewable*Connect program. In addition, Xcel has extended several power purchase agreements (PPAs) that were assumed to expire.[4] Xcel has also seen robust growth in its CSG program. In total, Xcel has acquired, repowered, or extended the following resources since the Commission approved Xcel's 2015 IRP with modifications:[5]

[3] Order Point 4.a. of the Commission's January 11, 2017 Order.

[4] As a matter of general practice, Xcel does not model any contract extensions (thermal or renewable) in resource planning because it would require too much speculation regarding future terms and pricing.

[5] The values in the table were based on Xcel's response to PUC Information Request No. 10.

Table 1. Resources Acquired Since the January 11, 2017 IRP Order

Investment Type	MW
Greenfield wind[6]	2,126
Wind repowering projects[7]	1,061
Renewable*Connect[8]	230
PPA Extensions[9]	164
CSG (2016-2021)	768

Finally, the Commission's January 11, 2017 Order approved an average annual energy savings level of 444 gigawatt-hours (GWh) for all planning years. Xcel has been able to consistently achieve annual energy savings above the Commission's approved amount.[10]

Table 2. Annual Energy Savings (GWh) in 2017-2021

	MN	SD	Total Annual Energy Savings
2017	658	6	664
2018	680	6	686
2019	529	9	538
2020	629	12	641
2021[11]	713	8	721

3. Demand Response Action Plan

Appendix G1 of Xcel's initial filing summarizes its demand-side management (DSM) progress and action plan. At the time of the initial filing, Xcel expected that most of its 400 MW by 2023 requirement would be met by expanding CIP programs and an interruptible tariff, but Xcel has

[6] Deuel Harvest, Glen Ullin Energy Center, Heartland Divide II, Blazing Star I, Crowned Ridge Wind, Crowned Ridge BOT, Foxtail, Northern Wind (20 MW out of 120 MW in total is greenfield), Freeborn, Blazing Star II, Dakota Range I & II, Dakota Range III, Lake Benton Wind Project.

[7] Nobles, Border Winds, Grand Meadows, Pleasant Valley, Northern Wind, Jeffers, Community Wind, North, Lake Benton Power Partners II, Mower County, and Ewington.

[8] Elk Creek Solar, Deuel Harvest Wind, and 50 MW of Heartland Divide II.

[9] Rock Ridge Power Partners, LLC, South Ridge Power Partners, LLC, Windvest Power Partners, LLC, Ewington Repowered Facility, Moraine Wind II, LLC, Rapidan Hydroelectric, LLC, City of St. Cloud Hydro, UMORE Park, LLC, KODA Energy, LLC, Hennepin Energy Recovery Center (HERC), and St. Paul Cogen.

[10] Xcel response to PUC Information Request No. 10.

[11] Actual annual energy savings for 2021 were not available at the time of Xcel's response. The 2021 savings above are the approved 2021 goals from the MN CIP 2021-2023 Plan (approved November 24, 2020) and from the SD DSM 2021 Plan (approved December 14, 2020)

since updated the action plan to incorporate its Load Flexibility pilots.[12,13] Staff notes that all iterations of Xcel's Preferred Plan (the initial filing, the Supplement, and the Reply Comments modeling) include the acquisition of 400 MW of incremental DR resources by 2023.

					Estimated Cumulative Potential (Gen. MW)		
	Program	**Regulatory Path**	**2018**	**2020**	**2021**	**2022**	**2023**
Existing Programs (including new 2020 programs)	Electric Rate Savings	CIP		495	453	503	517
	Residential Demand Response (Including Saver's Switch and AC Rewards)			360	381	420	437
	Commercial Demand Response (including Saver's Switch and AC Rewards)			84	86	93	99
	Peak Partner Rewards			3	10	37	63
	Subtotal Existing			**942**	**930**	**1,053**	**1,116**
Pilots (in review)	Peak Flex Credit	Load Flexibility Petition		-	0	21	36
	Load Shifting Commercial Thermal Storage Pilot			-	0	2	3
	Residential HVAC Optimization Pilot			-	0	1	1
	Demonstration Projects			-	0	1	1
	Static EV Optimization Pilot			-	0	1	2
	Subtotal New			**0**	**0**	**26**	**43**
Other	New Programs under Development[1]			-	-	2	5
	Third-Party Services	TBD		-	-	30	60
	Subtotal			**0**	**0**	**32**	**65**
	Total (Gen. MW)		824	942	930	1,111	1,224
	Incremental Gen. MWs[2]		0	118	106	287	400

4. Summary of 2020-2034 IRP

A summary of Xcel's most recent proposed plan, "the Alternate Plan," filed on June 25, 2021, is shown in Table 3-1 below.[14] The table compares large-scale resource additions on an annual basis to total capacity retired, including expiring PPAs. The most significant capacity removals are from the retirement of Sherco Unit 2 (680 MW) and Sherco Unit 1 (680 MW) in 2023 and 2026, respectively, which was approved in Xcel's 2015 IRP. The Alternate Plan proposes to retire the coal-fired Allen S. King Plant (511 MW) in 2028 and Sherco Unit 3 (517 MW) in 2030.

[12] Docket No. 21-101.

[13] The Commission took up Docket 21-101 at its January 6, 2022 agenda meeting. The Commission approved Xcel's Peak Flex Credit Rider pilot and expanded the program to include a second tranche that would allow third-party aggregators to participate in the program.

[14] This plan was proposed in Xcel's June 25, 2021 Reply Comments and does not include the 835 MW natural gas combined cycle facility at the Sherco site.

The first 700 MW of solar added in 2024 is "generic" solar – meaning a generically-defined resource without a location – but Xcel plans that the 460 MW Sherco Solar Project, currently pending in Docket No. 20-891, will replace a portion of that generic amount. The Firm Dispatchable units added in 2025-2026 are two specific brownfield repowered resources in Wisconsin and Minnesota that Xcel will use for blackstart needs.[15] The Firm Dispatchable units added in 2027 and 2029 are the Fargo natural gas combustion turbine (CT) and the Lyon County CT, respectively. The Fargo CT will fulfill a North Dakota regulatory commitment to build generation in North Dakota. The Lyon County CT is intended to provide stability, blackstart, and general energy needs.

Table 3-1: Planned Generation Retirements Through 2030

Year	Total MW Retired	Alternate Plan Resource Additions
2023	874 MW	
2024	358 MW	700 MW Solar
2025	695 MW	600 MW Solar 60 MW Firm Dispatchable
2026	1,311 MW	260 MW Firm Dispatchable
2027	210 MW	600 MW Solar 374 MW Firm Peak
2028	511 MW	200 MW Wind 150 MW Solar
2029	876 MW	400 MW Wind 400 MW Solar 374 MW Firm Dispatchable
2030	173 MW	200 MW Storage 950 MW Wind 100 MW Solar 374 MW Firm Dispatchable
2031	322 MW	50 MW Storage 350 MW Wind
2032		450 MW Wind 374 MW Firm Dispatchable
2033		100 MW Solar 748 MW Firm Dispatchable
2034	765 MW	500 MW Solar 500 MW Wind 374 MW Firm Dispatchable
2035	31 MW	600 MW Wind

Over the course of the proceeding, a lot of the controversy in the IRP has been eliminated, at least temporarily. After parties filed Initial Comments, Xcel withdrew its proposal to construct the Sherco gas facility and instead requested approval of two natural gas CTs that would not require new pipeline infrastructure. However, after discussions with some stakeholders, Xcel filed a letter on January 12, 2021 stating the Company is no longer requesting specific approval of the Lyon County CT and Fargo CT. Instead, Xcel requests the Commission make a finding that

[15] A blackstart unit is a generating unit that has equipment enabling it to start without an outside electrical supply or a high operating factor with the demonstrated ability to automatically remain operating, at reduced levels, when disconnected from the grid.

it is more likely than not that there will be a need for approximately 800 MW of generic firm dispatchable resources between 2027 and 2029, some of which could be located in North Dakota. Xcel asks that an applicable resource acquisition proceeding address this need.

Perhaps the most important decisions the Commission will need to make include:

What is the size, type, and timing of Xcel's resources need?

Several factors, including the accuracy of Xcel's load forecast, forecasted amounts of distributed energy resources (DER), and assumptions about accredited capacity can influence the ultimate resource need. The Department of Commerce (Department) and the Office of the Attorney General (OAG) argued that Xcel's load forecast was "systematically biased" and overstates Xcel's resource need. Staff notes that there are more ways than load forecast which suggest that Xcel's resource need might be overstated. For example, some parties argued that Xcel's distributed solar and CSG forecasts were unreasonably low.

What resource acquisition proceeding(s) should the Commission initiate and for which resources?

The Commission can restrict its decision to the five-year action plan, or it can authorize a resource acquisition proceeding for resources approved beyond the five-year action plan. Also, the Commission will need to weigh the advantages and disadvantages of different types of resource acquisition processes.

Should the Commission incorporate Company-ownership and locational aspects into its decision?

Xcel proposes to construct two 345-kV transmission lines ("gen-ties"[16]) at the Sherco and King sites to reutilize existing interconnection rights and add renewable energy onto the tie lines. As the table above shows, the Alternate Plan proposes a significant amount of new solar, which Xcel plans to own this solar in the 2020s and add along these tie lines. While there is general support for Xcel's solar acquisitions, not all parties support the gen-ties. The OAG, for example, argued that Sherco gen-tie line would likely be more expensive than procuring new solar through an open, competitive bidding processes and would subject Xcel's customers to unnecessary risks.

How should the Commission consider the reliability attributes of various resources?

As one example of comparing resource attributes of various resources, some parties argued that Xcel was overly dismissive of the capabilities of battery storage, and Xcel's assumptions for the costs of battery storage were inflated.

[16] Generation tie lines, or "gen-tie lines," are dedicated, interconnecting power lines that connect generation projects to a point of interconnection with the broader MISO transmission system. In the context of Xcel's Alternate Plan, the Sherco and King gen-tie lines are intended to connect renewable resources to existing points of interconnection for which the Company already has a generator interconnection agreement for its coal units.

Should the Commission approve Xcel's request to extend the life of the Monticello nuclear plant by ten years (to 2040)?

Some parties support the license extension, but some do not. Xcel and parties argued that extending Monticello is economic, needed for system reliability, and critical to helping achieve its carbon reduction goals. However, some modeling parties found the extension to be uneconomic, and there was some general opposition to nuclear power.

Xcel anticipates making the following regulatory filings within the five-year action plan:

- A Certificate of Need and Route Permit for a transmission line to the interconnection at Sherco;
- A Certificate of Need and Route Permit for a transmission line to the interconnection at King;
- Site permits needed for any acquisitions of generation, including generation to utilize the Sherco and King interconnections;
- A resource acquisition proceeding for 800 MW of firm dispatchable resources; and
- A new regulatory docket or series of planning meetings to discuss broader blackstart issues that would include the consideration of other blackstart additions in other zones in the out years of the planning period to consider optimal technologies.

5. Existing Resources

Xcel has a baseline generating capacity of over 15,000 MW,[17] approximated below by resource type:[18]

Table 2-1: Existing and Approved NSP System Resources as of the Resource Lock-in Date (Approximate)

Resource Type	MW (Max Cap)
Wind	4,200 (including capacity currently under development)
Solar	1,000
Other renewables (biomass, landfill gas, hydroelectric)	950
Nuclear	1,740
Natural gas or Oil	4,740
Coal	2,400

One issue for this IRP is whether Xcel has a need for additional firm dispatchable resources, or whether its existing portfolio is sufficient. Xcel defines firm dispatchable as:

[17] On a maximum capacity basis. Maximum capacity is approximately the same as Installed Capacity, or ICAP, but includes some adjustments for unit availability.

[18] Staff recreated this table from Xcel's June 2020 Supplement. The "Lock-in Date" means that Xcel's baseline includes all owned, contracted, or otherwise available resources on the system or resources that have received regulatory approval as of January 31, 2020.

> Firm dispatchable generation refers to resources that are guaranteed available at and for a given time ("firm") and can be dispatched within a designated amount of time at the request of grid operators. Firm dispatchable resources play an important role in maintaining reliability on our system, especially as we continue to integrate more variable renewable resources, which are not firm and dispatchable.

Throughout Xcel's filings, the Company uses the term "firm dispatchable" to refer to its thermal generation. Xcel's proposed firm dispatchable resources in the near-term refer to their blackstart units and "hydrogen-ready" natural gas CTs. In the later years of the planning period, Xcel characterizes firm dispatchable units as "technology-neutral" peaking resources.

Some parties argued that Xcel can rely on its existing firm dispatchable resource mix rather than acquire new firm dispatchable resources. Table V-3 of Xcel's June 30, 2020 supplemental filing (Supplement) shows Xcel's baseline natural gas and oil resources – the 4,740 MW listed in the table above – by facility, along with the end of life/PPA expiration of each facility. Note there are several units that are removed in the 2023-2026 timeframe.[19] (The 4,740 MW total does not include the italicized Sherco CC or placeholder blackstart capacity.)

Table V-3: Baseline Natural Gas and Oil Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	Existing or Planned Retirement/Contract Expiration
Black Dog 5/2	CC	Own	298	2032
High Bridge	CC	Own	606	2048
Riverside	CC	Own	508	2049
Mankato Energy Center 1	CC	PPA	375	2026
Mankato Energy Center 2	CC	PPA	345	2038
LSP – Cottage Grove	CC	PPA	245	2027
Angus Anson 2-3	CT	Own	218	2040
Angus Anson 4	CT	Own	168	2044
Black Dog 6	CT	Own	232	2058
Blue Lake 7, 8	CT	Own	351	2044
Inver Hills 1-6	CT	Own	369	2026
Wheaton 1-4	CT	Own	241	2025
Cannon Falls Energy Center	CT	PPA	358	2025
Blue Lake 1-4	CT	Own	191	2023
French Island 3, 4	CT	Own	160	2030
Wheaton 6	CT	Own	70	2025
Sherco CC	*CC*	*Own*	*835*	*No retirement date assigned*
Black Start, MN and WI	*CT*	*Own*	*~620*	*Extended to 2030*

Xcel has also stated a need to acquire blackstart resources. Xcel's filings discuss how firm dispatchable resources support system stability and how some units can or cannot provide

[19] "CC" means combined cycle and "CT" means combustion turbine.

blackstart capabilities. Xcel has also worked to further develop a blackstart plan that can incorporate increasing amounts of renewable resources.

Finally, staff notes that a substantial amount of Xcel's discussion of system restoration and blackstart is non-public information. Xcel explained that the volume of non-public information pertaining to system restoration and blackstart is necessary due to security concerns:

> System Restoration Plans are required by the NERC EOP-005-3 standard and are considered non-public Critical Energy Infrastructure Information (CEII). The underlying analyses are similarly CEII, as they contain further highly sensitive information regarding black start assets, cranking paths, switching, and plant start-up plans and protocols in the event of a catastrophic event that impacts the grid. We do not provide our System Restoration Plan or underlying analyses to any entity, not even the Midcontinent Independent System Operator (MISO) or the Midwest Reliability Operator (MRO). Although we have provided some information regarding our System Restoration Plan in this proceeding to a limited number of entities that either are regulatory agencies or that have entered into non-disclosure agreements with the Company, we have intentionally kept the information we provided as limited as practicable even when protected as security or trade secret information. Public disclosure of this highly sensitive information could reveal vulnerabilities in the NSP System and provide bad actors with a roadmap of how to disrupt the grid for maximum impact and duration.

B. Commission Review of Resource Plans

Xcel's IRP is filed pursuant to Minn. Stat. § 216B.2422 and Chapter 7843 of Minnesota Rules. Minn. R. 7843.0050, subp. 2 states that "[i]f the commission concludes that a set of resource options would be optimal, considering the desirable attributes listed in subpart 3, it may identify that set of resource options as a preferred resource plan." Minn. R. 7843.0050, subp. 3 states that resource plans must be evaluated on their ability to:

A. maintain or improve the adequacy and reliability of utility service;
B. keep the customers; bills and the utility's rates as low as practicable, given regulatory and other constraints;
C. minimize adverse socioeconomic effects and adverse effects upon the environment;
D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

In the discussion below, staff provides brief comments on how the Commission may consider Xcel's IRP using the criteria established in the Commission's IRP Rules.

1. Reliability

Over the course of the IRP proceeding, Xcel transitioned from the Strategist capacity expansion model to the EnCompass model, which is a full chronological hourly model that can optimize[20] capacity expansion, unit commitment and dispatch (including storage), economic market interaction, and ancillary service.[21] Examining energy and capacity availability over 8,760 hours allows Xcel to evaluate whether there are time periods with capacity shortfalls, periods of unserved energy, or significant ramping events. Thus, a key component of Xcel's consideration of reliability was the Company's analysis of customer needs and resource capabilities across every hour of every day, including during extreme weather events.

2. Bills and Rates

All three rounds of Xcel's modeling include a rate impact analysis. And, in all three rounds Xcel projected average bill and rate *growth* to be below national averages for bill and rate growth. However, Xcel projects slightly higher *rates* when compared to national average rate estimates. In addition, the rate estimates were higher in later rounds of modeling than the initial filings, for the following reasons:

- Xcel's sales forecast decreased relative to the forecast used in the initial filing;
- Xcel's total revenue requirements have increased relative to the initial filing, which is partially due to increased fixed costs from renewable capacity expansion and increased fuel and variable operating and maintenance (O&M) costs since the initial filing; and
- Xcel is now using the EnCompass model's outputs rather than the Strategist model's outputs, and several modeling inputs and assumptions have been changed, which has impacted Xcel's assumed revenue requirements and sales.

Staff notes that in IRP, rate impact estimates require several speculative assumptions, which is why IRP generally aims to minimize the net present value cost of a utility's revenue requirement and societal costs for a particular resource plan. Least-cost planning uses capacity expansion modeling that can assess costs and risks across a broad range of outcomes for load growth, fuel prices, capital costs, and so on. But since capacity expansion modeling related to generation-related costs captures only about half of Xcel's total revenue requirements, and long-term financial models are not available, assumptions need to be made for all other areas of Xcel's business. According to Xcel, "these assumptions are speculative, and the resulting total rate forecast would be similarly speculative."[22] Of course, this is not to say rate impacts should not be examined or considered at all in IRP, but estimating rate impacts over long-term time horizons has limitations.

[20] "Optimize" in this context means a resource is selectable and selected as part of a cost-optimized portfolio.

[21] EnCompass performs the production cost function simultaneously with the capacity expansion process, some simplifications in the commitment and dispatch assumptions are required for computational and time limitations.

[22] Xcel initial filing, p. 127.

3. Socioeconomic Effects and Environmental Impacts

Socioeconomic effects cover a broad range of issues, such as the affordability of electricity, impacts of power plant retirements to host communities, equity considerations, workforce planning, and so on. To a limited extent, environmental impacts can be taken into account in capacity expansion modeling, which ascribes costs to pollutants using the Commission's environmental externalities and carbon dioxide (CO_2) regulatory costs, but Xcel's filings and parties' comments raise several other environmental issues.

4. Financial, Social, and Technological Factors

The fourth and fifth criteria refer to financial, social, and technological factors outside of the utility's control. Essentially, these factors pertain to managing risk.

C. Resource Acquisition Processes

There have been a number of types of resource acquisition processes Xcel has employed in various dockets in recent years. Three common resource acquisition processes include:

- Track 1;
- Track 2; and
- Modified Track 2;[23]

The Track 1 and Track 2 processes were established by the Commission's May 31, 2006 Order in Xcel's 2004 IRP.[24] The Track 1 process involves competitive bidding where Xcel does not submit its own bid. Xcel used the Track 1 process in 2013 to acquire the Courtenay, Odell, Pleasant Valley, and Borders Wind projects and in 2014 to acquire North Star Solar and Marshall Solar.

The Track 2 process is a certificate-of-need-like process designed to ensure that independent developers have the opportunity to compete against an Xcel-ownership proposal. The Track 2 process was used for Docket No. 12-1240, in which the Commission selected the Aurora solar project, Xcel's Black Dog 6 facility, and the Mankato Energy Center II PPA. Generally, the Track 2 process follows an IRP Order that identifies the size, type, and timing of the resource need; Xcel and competitors file proposals on the same day, and a contested case is conducted before an Administrative Law Judge (ALJ).

The Modified Track 2 process was established by the Commission's January 11, 2017 Order in Xcel's 2015 IRP.[25] The Commission approved the Modified Track 2 process for wind and solar resources through 2021, and the Modified Track 2 process was used to acquire the 1,550 MW wind portfolio in Docket No. 16-777. Xcel did not issue a solar RFP following the 2015 IRP. The Modified Track 2 process will be discussed at length in later sections of the briefing papers, but in short, the Commission's January 11, 2017 Order outlines the process as follows:

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[23] Xcel used the Modified Track 2 process to acquire the 1,550 MW wind portfolio in Docket No. 16-777. That portfolio includes a mix of PPAs and Xcel-owned wind projects.

[24] Docket No. 04-1752.

[25] Docket No. 15-21.

1. Xcel issues an RFP for wind resources.

2. The day prior to receiving wind bids, Xcel will submit its own self-build proposal including estimates of final costs.

3. Xcel will evaluate the bids and select projects for negotiations based on a list of factors (factors which Xcel outlined in its [2015 IRP] Reply Comments).

4. Xcel will file with the Commission the results of the bidding process, project rankings, its analysis, and the results of a third-party auditor's report of its bidding and review process. Additionally, Xcel will evaluate the criteria outlined in the Minn. Stat. § 216B.243, subd. 9 certificate of need exemption for renewable energy standard (RES) facilities.

III. Iterations of Xcel's Modeling

A. Initial Plan, Supplement Plan, and Alternate Plan

Since the beginning of this proceeding, Xcel has filed three iterations of its preferred plan:

- The July 1, 2019 Initial Filing (Initial Plan), using the Strategist model;
- The June 30, 2020 Supplement Plan, using Version 4.2 of the EnCompass model;[26] and
- The June 25, 2021 Alternate Plan, using Version 5.0 of the EnCompass model.

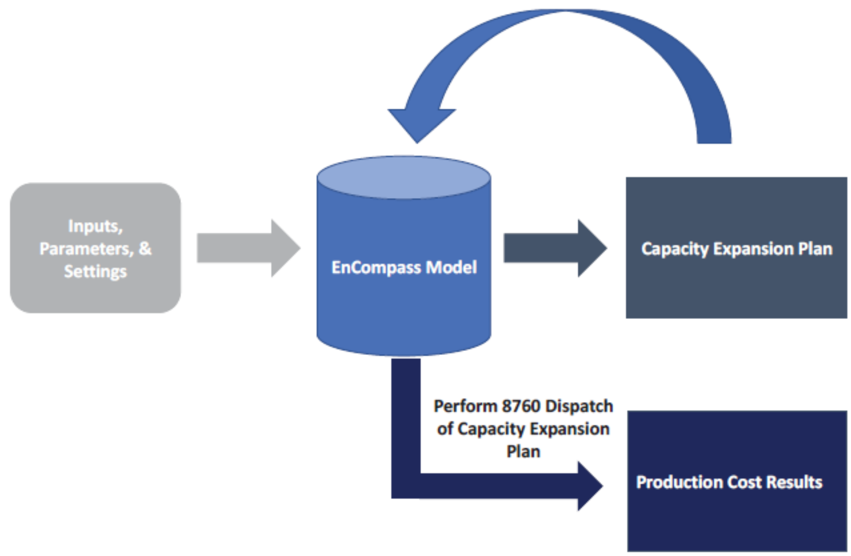
Xcel explained that Strategist was a valuable, but limited, tool because resource decisions were based on load duration curves, which do not fully capture the challenges of balancing large quantities of renewable energy that produce hour-by-hour fluctuations in system energy needs. Moreover, Strategist's dispatch functionality was simplified to representative weeks. Therefore, it did not provide complete information about a given portfolio's ability to meet flexibility or other essential reliability service attributes. Xcel's transition to the EnCompass modeling software allowed both expansion plan modeling and hourly production cost modeling.

The Clean Energy Organizations' (CEOs') modeling expert, Energy Futures Group (EFG), provided a helpful explanation about differences between Strategist and EnCompass, which complements Xcel's discussion:

> EnCompass differs from Strategist, Xcel's prior IRP software, in several ways including the manner in which it is used. Strategist performed capacity expansion

[26] Since the June 2020 Supplement was filed, Xcel upgraded its EnCompass software from Version 4.2 to Version 5.0. One of the changes between these versions has a relatively significant effect on modeling outcomes, namely, how the model selects representative days for its hourly generation shaping. In Version 4.2, a straight average approach is used to convert an 8670-hour renewable generation profile to representative days for each calendar month of the year. Version 5.0, on the other hand, uses a ranked peak algorithm for the typical day conversion, which preserves the maximum and minimum value and avoids flattening renewable shapes. This especially affects wind shapes, although solar shapes also change somewhat.

and simplified dispatch using sampled days and the results were then mapped onto the entirety of each year. EnCompass creates capacity expansion plans in the same manner, but there is a second step that was not part of Strategist. The modeler redispatches the plan while simulating all 8760 hours. The combination of the capital costs from the first run and the production costs from the redispatching of the plan are used to create the plan costs. This process is shown in Figure 2.



The change to hourly dispatch capability allowed Xcel to analyze system reliability in an important way: For the Initial Plan, Xcel imposed a "Reliability Requirement," which was a floor of firm dispatchable capacity; this was done because the Strategist model was incapable of modeling reliability needs in every hour of the year. (The simplified load duration curve used load from only one representative week in each month, or 2,016 hours per year.)

The Reliability Requirement in Strategist resulted in the addition of 1,700 MW of firm peaking resources in the later years of the planning period. EnCompass selected approximately 2,600 MW of firm peaking resources,[27] which according to Xcel validated the Company's initial decision to include a Reliability Requirement at the start. This is because regardless of whether firm dispatchable resources were forced into the model or selected to meet load in every hour of every year, dispatchable resources were part of a least-cost, reliable expansion plan.

Xcel used an upgraded version of EnCompass for Reply Comments. As noted above, the Supplement Plan used EnCompass Version 4.2, and the Alternate Plan was developed using Version 5.0. One important change was the difference in wind and solar profiles, which was more significant for wind than for solar. Version 4.2 used an "average approach" to convert an 8,760-hour generation profile to a representative day – meaning it flattened renewable shapes – whereas Version 5.0 preserves the maximum and minimum value.

[27] Because these additions do not occur for more than ten years, we are intentionally leaving them technology neutral, recognizing that they could be non-emitting resources like storage or DR.

Figures 4-1 (wind) and 4-2 (solar) of Xcel's Reply Comments below portray this difference; the orange line represents the Version 5.0 renewable shapes, while the blue line represents Version 4.2. According to Xcel, this change in typical day conversions for wind and solar in Version 5.0 better represents real system conditions.

Figure 4-1: Typical Day Conversions for Wind Shapes, EnCompass Versions 4.2 versus 5.0

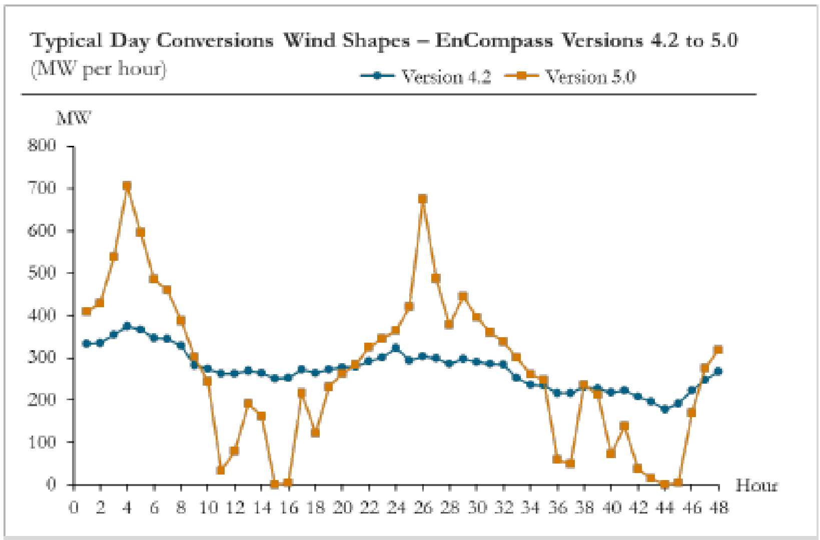
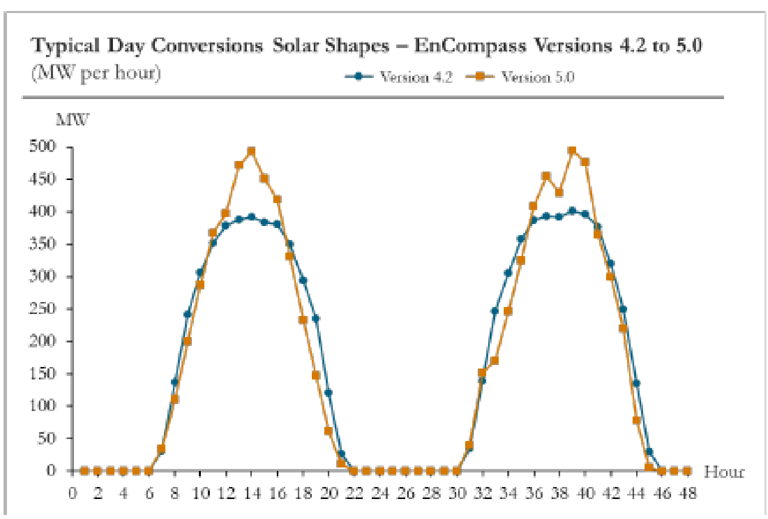


Figure 4-2: Typical Day Conversions for Solar Shapes, EnCompass Versions 4.2 versus 5.0



A point of emphasis throughout Xcel's filings is that hourly production cost models like EnCompass also have limitations because essential reliability services occur on a sub-hourly basis. For example, an hourly model may not capture responses to frequency drops or ramping needs, and hourly modeling cannot replace the more detailed power flow modeling and dynamic system modeling that occurs in transmission system planning processes. The table below describes different models' general capabilities and limitations for capacity expansion, production cost, and network reliability planning.

Figure VI-2: Planning Model Capabilities[28]

	Capacity expansion	Production Cost	Network Reliability
Objective	• Solve for a least cost expansion plan for medium-long term generation portfolio	• Simulates hourly chronological dispatch and system operations for a CE-defined portfolio	• Test essential reliability service conditions of a defined portfolio
Functionality	• High level system simulation to determine capacity adequacy needs and least cost portfolios, given assumptions about future demand, fuel and technology costs, and policy parameters • Provides annual generation portfolios and associated costs, carbon emissions estimates	• Uses outputs of capacity expansion to conduct hourly chronological system dispatch simulations • Evaluates unserved energy/loss of load; zonal or nodal marginal pricing; some ancillary services	• Analyzes transmission network to simulate essential reliability service conditions under contingencies, uncover potential failures • Includes power flow, system dynamics modeling; typically run by ISOs/RTOs
Time granularity	• Annual, based on representative days or weeks	• Generally hourly, some capable of sub-hourly assessment	• Minute-by-minute, or shorter durations
Attributes assessed	• Capacity adequacy, some flexibility	• Capacity adequacy, energy adequacy, flexibility (e.g. ramp rates)	• Essential reliability services, such as frequency response and transient stability
Examples	• **Strategist, EnCompass,** RESOLVE, Aurora	• **EnCompass**, PLEXOS, RECAP, PROMOD	• Positive Sequence Load Flow, Power System Simulator for Engineering

B. Updated Modeling Inputs and Changes to the Preferred Plan

Across the three Preferred Plans, Xcel made several changes to the baseline assumptions but tried to keep as many inputs as possible constant. This was because, rather than continually updating modeling assumptions, and to aid the Commission's ability to review multiple rounds of modeling, Xcel relied on a robust sensitivity analysis. For example, Xcel and some modeling parties used the National Renewable Energy Laboratory's Annual Technology Baseline (NREL ATB) report for renewable energy price assumptions. While parties updated the NREL ATB assumptions as NREL updated them annually, Xcel maintained its use of the 2019 ATB, arguing that it would be "neither practical nor useful to attempt to continually maintain the latest version of every input used."[29]

[28] Staff recreated this table due to the blurriness of the text in pdf form.

[29] Xcel reply comments, p. 95.

1. Updated Peak Demand and Energy Forecasts

Load forecasting is a key component of IRP because it provides the foundation for determining the size, type, and timing of Xcel's resource need over the planning period. For the Initial Plan, Xcel used its fall 2018 forecast. The load and energy demand forecasts were updated with a fall 2019 forecast for the 2020 Supplement (the Alternate Plan used the same forecast).
Figures II-10 and II-11 below indicate that the fall 2018 and 2019 energy and demand forecasts are lower than the forecast provided in Xcel 2015 IRP, due to lower and declining actual sales. The fall 2019 forecast is also slightly lower than fall 2018 forecast used for the Initial Plan. There is an increase in the later years of the planning period to account for increased electric vehicle (EV) adoption. The updated corporate peak **demand** forecast shows an average annual growth rate of 0.7 percent over the full 2020-2034 planning period, and the updated corporate **energy** forecast expects a 0.2 percent annual growth rate over the same timeframe.

Figure II-11: Base Peak Demand – Comparison of Current and Previous Demand Forecast
Median (50th Percentile) Forecast

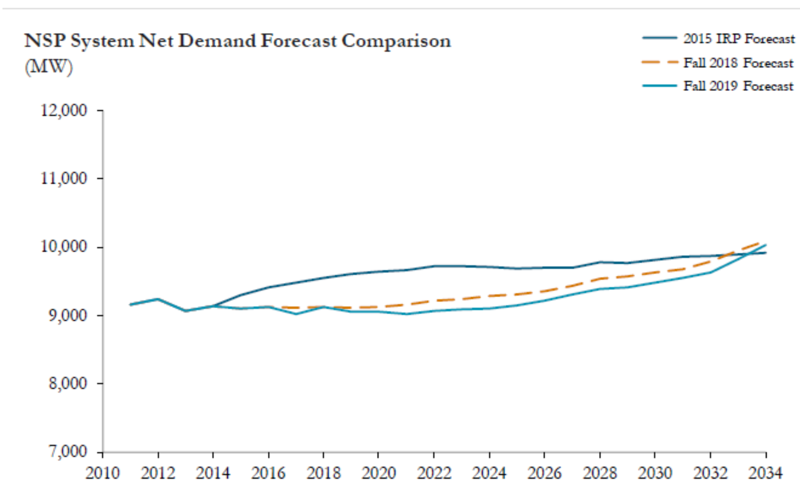
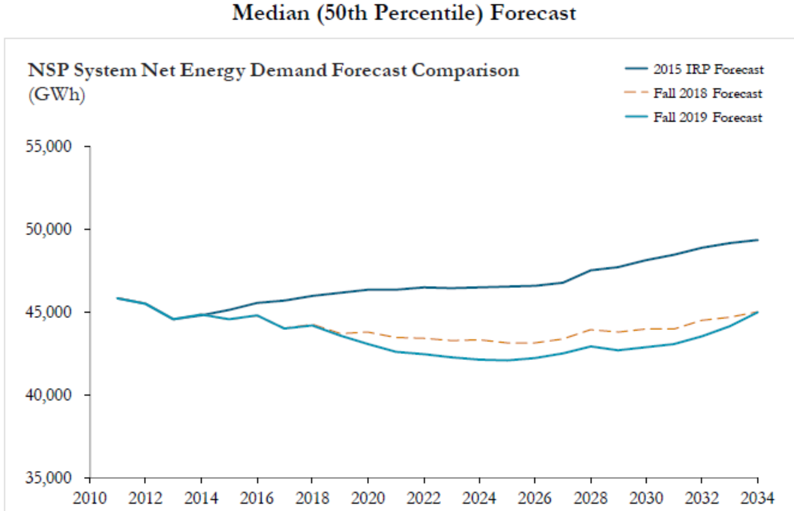


Figure II-10: Net Energy Requirements– Comparison of Current and Previous Energy Forecast
Median (50th Percentile) Forecast



Importantly, while corporate forecasts form the basis of Xcel's EnCompass modeling, the actual EnCompass modeling incorporates adjustments to load-modifying resources such as energy efficiency (EE), DR, and distributed generation so they can compete with supply-side resources. In prior IRPs, Xcel netted out load-modifying resources at an assumed fixed level of adoption across the planning period; the corporate forecast continues to use this method. In EnCompass, Xcel tested various "bundles" of EE and DR at an assumed average cost, and Xcel developed base and high customer adoption scenarios for distributed solar.[30]

2. Updated Baseline Resources

As the Commission is aware, Xcel has added and repowered a substantial amount of renewable resources since the initial filing, and many were not incorporated into the modeling prior to Reply Comments. Table 4-2 of Xcel's Reply Comments below shows an update to the Company's Reference Case. In total, the resource additions shown in Table 4-2 amount to approximately 1,150 MW of new, repowered, or contractually extended capacity incorporated into the modeling since the Supplement Plan. Note that the updated baseline resources include those approved prior to June 1, 2021, which means the modeling still does not include the 120 MW Northern Wind Repower Project or the 460 MW Sherco Solar project.[31] However, since Sherco Solar partially fulfills 700 MW of generic solar already included in Xcel's Alternate Plan, Sherco Solar could be viewed as the first replacement resource that will reutilize interconnection rights at the Sherco site.

[30] See pages 46-49 of Xcel's initial filing and pages 19-21 of Xcel Supplement.

[31] Pending dockets 21-189, 190, and 191 involve site and route permits for generation and transmission at the Sherco site. And pending docket 20-891 involves Xcel's proposal to build, own, and operate a 460 MW solar project at the Sherco generation facility site.

Table 4-2: Resources Approved Since January 2020 and Reflected in Modeling

Resource	Addition or Extension	Fuel Type	MW (installed capacity)	Achieved/Expected Online Date
Mower County	Extension (repower)	Wind	99	January 2021
Elk Creek	Addition	Solar	80	December 2021[3]
Deuel Harvest	Addition	Wind	100	December 2021
Heartland Divide II	Addition	Wind	200	December 2021
St. Cloud Hydro	Extension	Hydro	8.5	November 2021
Nobles	Extension (repower)	Wind	201	December 2022
Grand Meadow	Extension (repower)	Wind	101	December 2023
Border Winds	Extension (repower)	Wind	150	December 2024
Pleasant Valley	Extension (repower)	Wind	200	December 2024
Ewington	Extension (repower)	Wind	20	December 2021[4]

3. Removing the Sherco Combined Cycle Gas Plant

Many stakeholders – including both intervening parties and public commenters – opposed the Sherco CC and its associated pipeline infrastructure. To explore options without the Sherco CC, Xcel analyzed the impact that removing the Sherco CC would have on system reliability, Xcel's blackstart plan, and on the costs and expansion units in the Company's Preferred Plan. Xcel created three teams to evaluate these impacts:

- A transmission and system stability team determined whether system stability can be maintained without the Sherco CC and the replacement of the retiring Sherco capacity largely with renewable generation and any necessary supporting CT capacity. This team also ensured that voltage is maintained within Nuclear Regulatory Commission (NRC) requirements at the Monticello plant.

- A blackstart team conducted an analysis to determine alternative Target Units and blackstart paths assuming no Sherco CC and the proposed retirement dates of Xcel's coal units.

- A renewable integration and replacement resources team analyzed if dispatchability needs can be economically met without the Sherco CC and combinations of replacement generation that could be viable economic alternatives.

Based on the analysis conducted by each team, Xcel identified alternative dispatchable units and a refined blackstart plan that would enable removing the Sherco CC while reducing emissions, lowering costs, and improving system reliability.[32]

Staff notes that the Commission does not need to deny the Sherco CC because Xcel is no longer proposing it; however, the Commission could make a general finding about the record evidence, which shows, according to Xcel's analysis, that reliability can be improved and costs could be lowered without the Sherco CC.

4. Gen-ties at Sherco and King

Reutilizing existing interconnections at Sherco and King is a core piece of Xcel's coal retirement and renewable energy acquisition plan. However, as will be discussed below, reutilizing existing interconnection rights means Xcel must own the generation, which could have ratepayer implications due to a lack of competition. Xcel's gen-tie concept also means that the Commission is asked in this case to incorporate ownership and locational aspects into its decision, in addition to the typical size, type, and timing determinations in IRP dockets.

The two Company-owned gen-tie lines and interconnection rights available after coal plant retirements at Sherco and King will enable Xcel to own the first 2,600 MW of renewable energy acquired in the Alternate Plan. The gen-ties will also enable 4,000 MW of renewables and approximately 400 MW of supportive CT capacity, so later additions along the tie-lines, which occurs in the 2030s, could be owned or PPA resources.

For modeling purposes, the Sherco gen-tie line is a double circuited 140-mile 345-kV line terminating at a single location going south from Sherco to Lyon County in southern Minnesota. The King gen-tie line is one, approximately 15-mile 345-kV line going east from King into Wisconsin where Xcel will reutilize the King interconnection to build 650 MW of solar.

There are two main reasons Xcel requests Company-ownership of new renewable resources. First, the MISO tariff requires that replacement facilities cannot transfer interconnection rights between entities. (Xcel stated this reflects FERC's policy of prohibiting the buying and selling of interconnection rights.) Xcel has a three-year window, per MISO's generator replacement rules set out in Attachment X of the MISO Tariff, to reuse interconnection rights. Therefore, as proposed, Xcel must acquire replacement renewable resources at existing interconnections prior to acquiring the generic renewable resources proposed in the Alternate Plan.

Table 4-8 of Xcel's Reply Comments shows the interconnection rights, replacement resources made available to EnCompass, and the three-year windows following plant closures. Note that EnCompass was able to select various mixes of solar only, solar + wind + CT, and solar + wind.[33] Again, note that Sherco Solar will replace a portion of the solar selected to replace Sherco 2,

[32] Xcel reply comments, p. 38.

[33] Note that these rules have the effect of prohibiting the first 2,000 MW of Sherco interconnection reuse and the first 600 MW of King interconnection reuse from being fulfilled by PPA resources. According to Xcel, this reflects FERC's policy of prohibiting the buying and selling of interconnection rights.

and the 400 MW Lyon County CT will provide stability on the Sherco gen-tie in order to support solar and wind additions.

Table 4-8: Retiring Coal Units and Selection Windows for Gen-tie Resources

Retiring Unit	Open Interconnection	Replacement Resource Window	Replacement Resources Allowed
Sherco 2	720 MW	2024-2026	Solar only
Sherco 1	710 MW	2027-2029	Solar, and Wind + ~400 MW of CTs (2028-2029)
Sherco 3	566 MW	2030-2032	Solar + Wind
AS King	591 MW	2028-2030	Solar only

The second reason for constructing the transmission lines is that due to transmission system constraints, congestion in the broader MISO queue, and the resulting high interconnection costs, the levelized costs of renewable resources along the Sherco and King gen-tie (under Xcel's assumptions) are significantly lower than generic renewable resources. Xcel explained:

> [T]he average cost per kW for resources on the Sherco gen-tie line is under $140/kW and on the King line it is approximately $55/kW, as compared to the estimated average MISO queue costs, based on observed queue results, of $500/kW for wind and $200/kW for solar.[34]

Xcel acknowledged that, while less expensive than generic solar and wind on a levelized cost basis, the investments in the Sherco and King gen-ties are significant. Table 12 of Appendix A of Xcel's Reply Comments shows the total costs of the gen-tie lines, which includes capital costs plus VAR support, such as installing synchronous condensers,[35] and the total interconnection rights available for reuse at each generator.

Table 12: Sherco and King Gen-tie Assumptions

	Total Costs (in 2021 Dollars)	Interconnection Rights
Sherco gen-tie	$528 million	1996 MW
King gen-tie	$ 36 million	591 MW

[34] Xcel reply comments, p. 12.

[35] Synchronous Condensers (SCs) are one of many VAR support technologies that can be used on the transmission system to provide voltage and other ancillary support services. The SC is a generator that is started up, usually by a smaller generator, acts as a motor load on the system. However, rather than burning fuel, electricity from the system is used to maintain the spinning speed of the generator/motor while the voltage controls (excitation system) are then used to supply or consume VARs on the system. This is how SC's provide voltage control. Further, the SC, through the rotating mass of the generator, provides inertial and short circuit response to the system, which not all VAR support technologies are able to provide. There are several ways to design a SC system, both through retrofitting or standalone options. The CT capacity contemplated at Lyon County would utilize a design that places a clutch between the turbine shaft and generator, which allows the unit to be used either as a generation facility or a SC with minimal time needed for switching.

Xcel also acknowledged that the gen-tie concept is "an early conceptual idea with initial cost estimates that – while consistent with past project experience – are subject to some uncertainty."[36] Xcel tested a scenario where the Sherco tie line increased from 140 miles to 175 miles; this would increase the modeled cost of the Sherco gen-tie from $578 million to $713 million and reduce customer savings of the Alternate Plan by approximately $132 million.

5. Updated Blackstart Plan

Currently, Xcel has two blackstart critical units in Minnesota and Wisconsin are scheduled to retire within the planning period, and these units are critical to jumpstart the grid "from black" in the event of a widespread outage.   In the Supplement, Xcel included placeholder capacity and associated life extension costs for the Minnesota and Wisconsin blackstart units to 2030. In Reply Comments, Xcel requested specific approval to repower these units to serve both system restoration and blackstart needs. These are shown in Table 4-9 of Reply Comments below but designated as non-public information.

Table 4-9 System Restoration Units Modeled in Alternate Plan

[PROTECTED DATA BEGINS

Area	Modeled Type	Number of Units	Total MW, Installed	Modeled Year In-Service
Minnesota				
Wisconsin				
Total planned near-term blackstart investments				

PROTECTED DATA ENDS]

Xcel proposed to initiate a new Commission Investigation docket to develop and refine a new approach to blackstart and system restoration, which would shift away from its current centralized approach to a zonal approach that will build small, geographically-dispersed islands. However, in Xcel's January 12, 2022 Joint Decision Options filing, Xcel modified its request to review Xcel's future blackstart needs in a future planning meeting or set of planning meetings.

Section 3 of Xcel's Reply Comments discusses the following:

- Xcel's current blackstart plans in the Minnesota and Wisconsin systems;[37]
- Changes to the system restoration plan;
- Change to a zonal approach with the Alternate Plan;
- Selection of the current Minnesota blackstart unit replacement; and
- A specific plan to implement the new blackstart Initial Units

[36] Xcel reply comments, p. 151.

[37] The Xcel Energy Minnesota and Wisconsin systems each have separate System Restoration Plans because they are separate operating companies. In practice, however, the two plans comprise an overall plan to restore the NSP System in whole.

IV. Xcel's Proposed Resource Plan

A. Load Forecasting

Load forecasting is a key component of IRP because it provides the foundation for determining the size, type, and timing of a utility's resource need over a planning period. Xcel's general process is shown in Figure 3-1 below.

Figure 3-1: Net Resource Need/Surplus Calculation

Customer Needs Forecast
Plus MISO Reserve Margin

Equals **Total Capacity Obligation**
Minus Demand Response Capability
Minus Generation Capacity (measured by UCAP)
Minus Generation Adjustments

Equals **Net Resource Need/Surplus**

1. Customer Needs

As noted above, the Supplement and Reply Comment modeling relied on an updated, fall 2019 forecast. The average annual growth rate in the corporate peak demand forecast is 0.7 percent over the planning period, after accounting for EE. Xcel's corporate energy forecast is approximately 0.2 percent over the planning period, after accounting for EE. One difference between the most recent corporate forecast and prior IRP forecasts is the inclusion of EVs.

As indicated by Figure 3-1 above, Xcel adjusts its needs forecast to reflect MISO's Resource Adequacy requirements. Load-serving entities (LSE) must maintain resources that exceed their level of demand by a specific planning reserve margin (PRM). For 2020, MISO applied an unforced capacity (UCAP)[38] PRM of 8.9 percent. The coincidence factor, which is an adjustment reflecting the NSP system load at the time of the MISO system peak, is 95 percent.

Altogether, these factors reflect Xcel's resource obligation, which is shown below in an excerpt of its Load and Resources table from the Supplement:

[38] UCAP refers to a unit's Unforced Capacity Rating, which is a function of the unit's installed capacity (ICAP) and its anticipated forced outage rate. MISO calculates the UCAP value for each resource to determine its expected contribution to Resource Adequacy. These are calculated differently depending on the resource's dispatchability or variability.

Table IX-1: EnCompass Reference Case (Scenario 1) System Load and Resources, UCAP

	2022	2023	2024	2025	2026	2027	2028
Forecast gross Load	10,635	10,711	10,780	10,842	10,911	10,982	11,053
EV Forecast	17	25	35	44	53	65	79
Forecast EE (reduction)	1,550	1,625	1,723	1,817	1,907	1,975	2,052
Forecasted Net Load	9,101	9,111	9,092	9,068	9,057	9,072	9,080
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,646	8,655	8,638	8,615	8,604	8,618	8,626
MISO PRM	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%
NSP Obligation	9,416	9,426	9,406	9,382	9,370	9,385	9,393

Table 4-3 of Xcel's Reply Comments below shows Xcel's net capacity position (the bottom row). Xcel forecasts a 1 MW capacity deficit in 2026, but its capacity deficit rises significantly in 2027 as Sherco 1 retires and PPAs expire.

Table 4-3: 2020-2034 Reference Case System Net Accredited Capacity Surplus/Deficit Prior to Expansion Planning (MW, Unforced Capacity[5])

Resource Type	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Coal	2,295	2,295	2,295	2,295	1,647	1,647	1,647	994	994	994	994	994	994	994	994
Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,019	1,019	1,019	498	0
Combined Cycle	2,078	2,078	2,078	2,078	2,078	2,078	1,787	1,551	1,551	1,551	1,551	1,551	1,275	1,275	1,275
Combustion Turbine	1,781	1,781	1,781	1,781	1,635	1,325	1,325	1,280	1,280	1,280	1,280	737	737	737	737
Hydro, Large - Diversity Summer	342	342	342	342	342	0	0	0	0	0	0	0	0	0	0
Hydro	539	659	657	657	657	168	168	168	168	168	168	168	162	158	158
Renewable, Biomass	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Renewable, Wind	500	624	733	680	755	681	676	675	672	650	649	633	630	565	561
Renewable, Solar	495	531	614	647	632	612	591	570	548	526	503	480	456	431	435
Demand Response	1,045	1,192	1,273	1,349	1,407	1,454	1,470	1,485	1,499	1,511	1,518	1,526	1,536	1,547	1,560
Total existing and approved resources	**10,826**	**11,253**	**11,524**	**11,556**	**10,881**	**9,668**	**9,368**	**8,426**	**8,383**	**8,350**	**7,711**	**7,128**	**6,828**	**6,225**	**5,740**
NSP total obligation	**9,430**	**9,380**	**9,416**	**9,426**	**9,406**	**9,381**	**9,370**	**9,385**	**9,393**	**9,341**	**9,354**	**9,362**	**9,404**	**9,459**	**9,523**
Net Position	**1,396**	**1,873**	**2,108**	**2,131**	**1,475**	**287**	(1)	(959)	(1,011)	(991)	(1,643)	(2,234)	(2,576)	(3,234)	(3,783)

2. Adjustments for Distributed Solar, Energy Efficiency, and DR

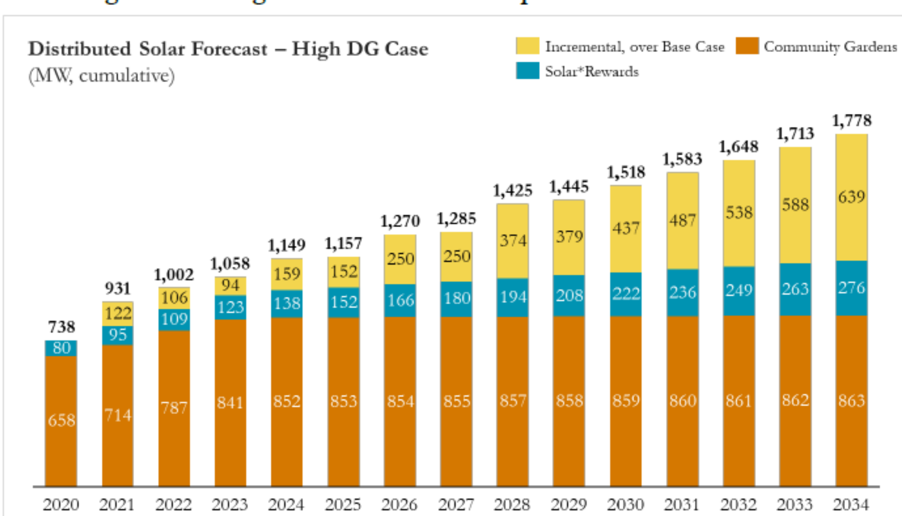
There is a difference between how load-modifying resources – distributed solar, energy efficiency (EE), and DR – are incorporated into Xcel's corporate load forecast versus how they are modeled in EnCompass. Importantly, the 0.7 percent demand forecast growth rate and 0.2 percent energy growth rate reflects Xcel's *corporate* forecast. In past IRPs, Xcel incorporated the expected effects of existing DSM programs into the load forecast. For this IRP, however, EE and distributed solar was modeled as a supply-side resource, not a load modifier.[39] For distributed solar, Xcel explained:

[39] Xcel reply comments, Appendix A, p. 7.

> We have historically considered customer adoption of distributed solar (i.e. DG solar as well as CSG) installations as a modification to load in the resource planning process. In this Resource Plan, we have accounted for DG solar including CSG resources as a supply-side resource with assumed adoption levels, as shown in the Loads and Resources calculation below. Reference Case assumptions currently take into account interconnection requests and expectations based on policy-driven programs. However, we also conduct sensitivity testing around potential increased levels of adoption and are working to develop new tools that improve our understanding of how key market drivers will affect customer distributed solar adoption going forward.[40]

Xcel's sensitivity analysis included a Reference Case Distributed Solar Forecast (see Figure III-1 of the Supplement) and a High Distributed Solar Adoption Scenario Forecast (see Figure III-2 of the Supplement). To develop the High Distributed Solar adoption scenario, Xcel forecasted incremental solar using a Payback adoption model that assumes a 10 percent reduction to the solar installation cost curve, relative to the base case, starting in 2020. The Payback model results in 1,778 MW of total installed distributed solar by 2034, which is 639 MW above the Reference Case. Xcel explained that the 639 MW could be any combination of net metering and CSG—these programs can generally be thought of as substitutes for each other. Thus, the amount of distributed solar indicated by the orange and blue bars in Figures III-1 and III-2 are the same.[41] The yellow bar is incremental solar over the base case.

Figure III-2: High Distributed Solar Adoption Scenario Forecast



Xcel modeled incremental EE and DR as "bundles." Each bundle represents a combination of DSM program achievements at an estimated blended cost. EE bundles are reductions in overall energy usage throughout the year, whereas DR bundles are customer commitments to reduce

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[40] Xcel initial filing, p. 49.

[41] Figures III-1 and Figure III-2 are on pages 38 and 39 of the Supplement.

demand. Xcel tested EE and DR selection with model optimizations, which evaluated different combinations of three EE bundles and three DR Bundles. Cost-effective combinations of bundles were locked into the final optimization runs.

Xcel tested three DR bundles and three EE bundles under both the PVSC and PVRR metrics. Table 5-2 of the initial filing shows that a combination of 0 DR bundles and 2 EE bundles had the lowest PVSC and PVRR results.

Table 5-2: Scenario 9 (Preferred Plan) DR and EE Cost Effectiveness Analyses ($2019 millions)

PVSC				
	0 DR	1 DR	2 DR	3 DR
0 EE	$48,486	$48,203	$48,502	$48,745
1 EE	$45,390	$45,670	$45,947	$46,152
2 EE	$45,173	$45,512	$45,726	$45,910
3 EE	$45,847	$46,166	$46,389	$46,596

PVSC Deltas (as compared to 0 DR/2 EE)				
	0 DR	1 DR	2 DR	3 DR
0 EE	$3,313	$3,030	$3,329	$3,572
1 EE	$217	$497	$774	$979
2 EE	-	$339	$553	$737
3 EE	$674	$993	$1,217	$1,423

PVRR				
	0 DR	1 DR	2 DR	3 DR
0 EE	$40,029	$40,216	$40,478	$40,653
1 EE	$37,657	$37,910	$38,182	$38,344
2 EE	$37,476	$37,784	$37,925	$38,143
3 EE	$38,374	$38,589	$38,802	$39,009

PVRR Deltas (as compared to 0 DR/2 EE)				
	0 DR	1 DR	2 DR	3 DR
0 EE	$2,554	$2,741	$3,003	$3,177
1 EE	$181	$435	$706	$869
2 EE	-	$308	$450	$668
3 EE	$899	$1,113	$1,327	$1,533

While the model optimization did not select any of the DR bundles, because of the Commission's January 2017 IRP Order requiring 400 MW of incremental DR by 2023, Xcel added DR Bundle 1 to its Preferred Plan. (There are no DR bundles in Xcel's North Dakota Plan.)

B. Scenarios Considered

1. Fifteen Baseload Scenarios

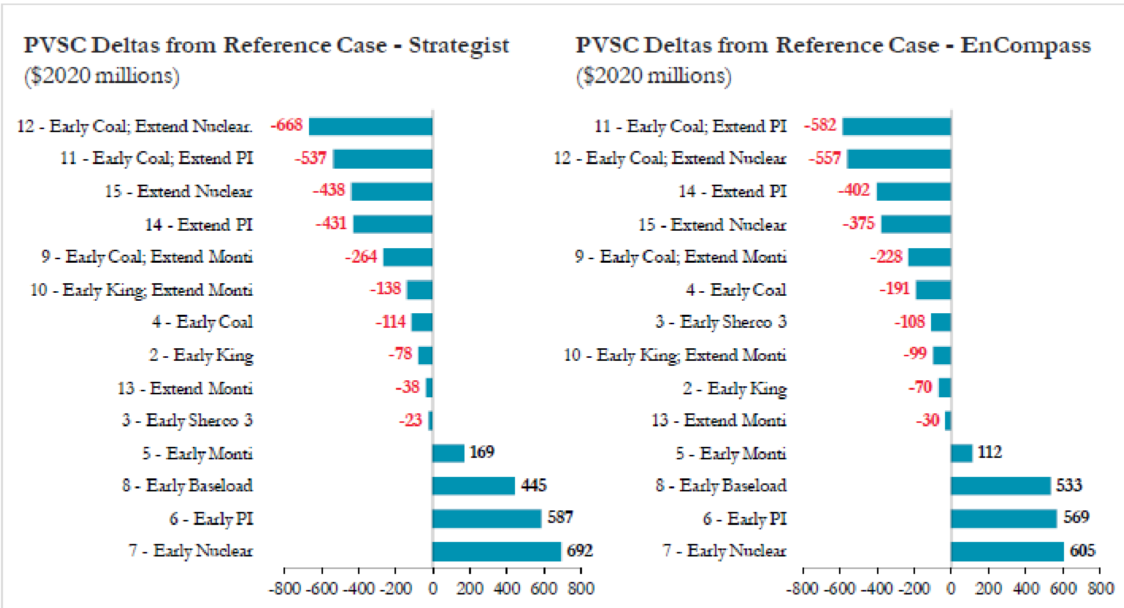
Throughout the three preferred plans proposed in the initial filing, Supplement, and Reply Comments, Xcel occasionally refers to its proposed IRP as "Scenario 9." Scenario 9 is one of 15 baseload scenarios developed for the Initial Plan and updated for subsequent filings. These 15 baseload scenarios consist of groups, or "families," of modeling runs testing different permutations of retirement dates for Xcel's coal and nuclear units. (Xcel did not examine any coal plant extension scenarios.) For example, the "Early Coal" family tested early retirement of King, Sherco 3, and both as separate scenarios, each tested across a range of sensitivities (which resulted in several hundred runs for each round of modeling). A summary of the baseload scenarios with retirement dates is shown in the table below. Scenario 1 is the Reference Case, and Scenario 9 is in the "Nuclear Extension Family."

Scenario	Family	Retirement Dates
1	Base	**(Reference)** – All units retire at their current dates (King in 2038, Sherco 3 in 2034, Monticello in 2030 and Prairie Island 1 and 2 in 2033 and 2034 respectively)
2	Early Coal	**(Early King)** – King is retired in 2028.
3	Early Coal	**(Early Sherco 3**) – Sherco 3 is retired by 2030.
4	Early Coal	**(Early All Coal)** – King is retired in 2028, Sherco 3 is retired by 2030
5	Early Nuclear	**(Early Monticello)** – Monticello is retired at the end of 2026.
6	Early Nuclear	**(Early Prairie Island)** – Prairie Island is fully retired by the end of 2025.
7	Early Nuclear	**(Early All Nuclear)** – Prairie Island and Monticello are both retired early per the years above
8	Early Nuclear	**(Early All Baseload)** – All baseload units, including coal and nuclear, are retired early per the years indicated above.
9	Nuclear Extension	(**Early Coal, Extend Monticello)** – All coal was retired at the early dates and Monticello is extended for 10 years. Prairie Island is unchanged.
10	Nuclear Extension	(**Early King, Extend Monticello)** – King was retired at the early date and Monticello is extended for 10 years.
11	Nuclear Extension	**(Early Coal, Extend Prairie Island)** – All coal was retired at the early dates and Prairie Island is extended for 10 years.
12	Nuclear Extension	**(Early Coal, Extend All Nuclear)** – All coal was retired at the early dates and both Monticello and Prairie Island are extended for 10 years.
13	Nuclear Extension	**(Extend Monticello)** –Monticello is extended for 10 years. King, Sherco 3 and Prairie Island are unchanged.
14	Nuclear Extension	**(Extend Prairie Island)** – Prairie Island is extended for 10 years. King, Sherco 3 and Monticello are unchanged.
15	Nuclear Extension	**(Extend All Nuclear)** –Both Monticello and Prairie Island are extended for 10 years. King and Sherco 3 are unchanged.

As noted above, each of the 15 baseload scenarios were run with 22 sensitivities (A through V).

In general, plans that favored early coal retirements and nuclear extensions were the lowest cost plans, both in terms of PVSC and PVRR. Scenario 9 – despite being Xcel's Preferred Plan – is not the lowest cost of the baseload scenarios. This is because, as Xcel explained, "several lesser cost scenarios included an extension of Prairie Island's operating license,"[42] but Xcel decided to defer making a decision on a Prairie Island extension until the next IRP. The ranking of scenarios relative to the Reference Case is shown in Figure 2-8 of the Supplement below.

Figure 2-8: Baseload Scenario PVSC Deltas, Relative to the Reference Case



2. Alternate Plan

Xcel's modeling for Reply Comments updated the modeling assumptions for the Reference Case and recalculated the PVSC/PVRR for four of the original 15 baseload scenarios:

- Scenario 1 – the Reference Case;
- Scenario 9 – Preferred Plan;
- Scenario 4 – Early Coal, No Nuclear Extension; and
- Scenario 12 – Early Coal, Extend All Nuclear.

Staff notes that the original baseload Scenario 4 was Early Coal only. Xcel updated Scenario 4 to address the Department's finding that extending the Monticello license was uneconomic. Updated Scenario 4 again retired King and Sherco 3 early, but Xcel also explored retiring Monticello in 2030 as well. According to Xcel's analysis, when the nuclear units are removed, the model does not achieve the same PVSC savings, it chooses additional CT resources, and there will likely be an increase in emissions. Considering these factors, Xcel disagreed with the Department's recommendations related to the retirement of Monticello.

Table 4-5 of Reply Comments below shows the expansion plan by fuel type for the Updated Reference Case. This is important because the calculated cost savings of the Alternate Plan is expressed as its cost relative to the Reference Case expansion plan. Again, under the Reference Case, all baseload units retire at their current dates. Approximately 1,000 MW of solar is added

[42] Xcel initial filing, p. 116.

in 2025, the Sherco CC is added in 2027, and a firm dispatchable unit is added in 2029. No wind is added until 2031.

Table 4-5: Updated Reference Case Annual Capacity Additions Through 2034, (MW, installed capacity)

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Wind	-	-	-	-	-	-	-	-	-	-	-	250	450	800	800	2,300
Solar	-	-	-	-	-	1,000	-	-	-	-	1,150	450	-	-	250	2,850
Firm Dispatch-able	-	-	-	-	-	-	-	-	-	374	-	374	374	748	374	2,244
Sherco CC	-	-	-	-	-	-	-	835	-	-	-	-	-	-	-	835
Demand Response	33	132	67	62	47	41	12	14	15	17	19	20	21	22	24	545
Energy Efficiency	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	2,041
Distributed Solar	173	72	87	68	25	16	15	15	15	15	15	15	15	15	15	575

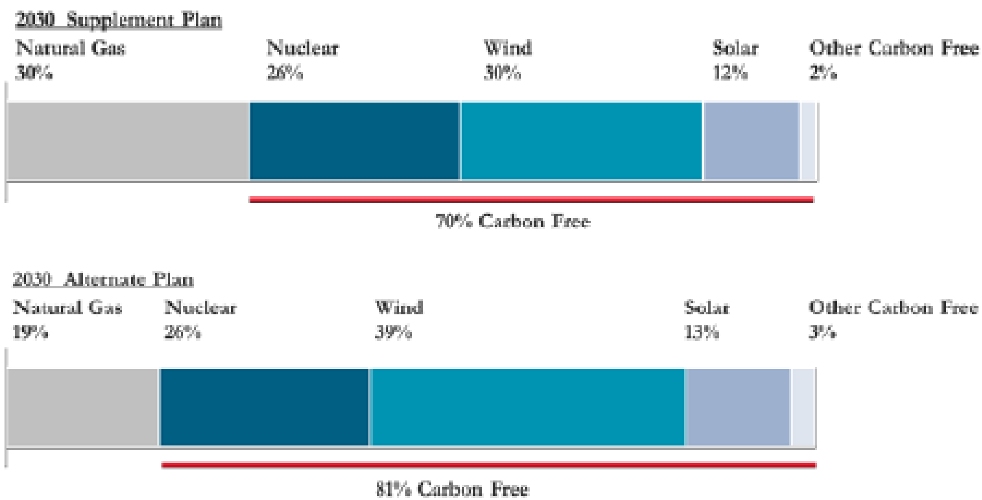
Table 4-10 of Reply Comments shows the Alternate Plan expansion plan. The Alternate Plan adds four CTs in 2025-2029—two brownfield units for blackstart, a Fargo CT, and the Lyon County CT (which is also in the Reference Case). The Alternate Plan has only slightly more solar than the Reference Case, but significantly more solar is added in the 2020s. The Alternate Plan also adds 250 MW of storage in 2030-2031. In total, excluding the rows showing incremental DR, EE, and distributed solar, the Alternate Plan adds over 9,000 MW of new, large-scale resources by 2034.

Table 4-10: Alternate Plan Annual Expansion Plan, by Fuel Type (MW, installed capacity)

Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Storage	-	-	-	-	-	-	-	-	-	-	200	50	-	-	-	250
Wind	-	-	-	-	-	-	-	-	200	200	950	350	450	-	500	2,650
Solar	-	-	-	-	700	600	-	600	150	400	100	-	-	100	500	3,150
Firm Dispatch-able	-	-	-	-	-	60	259	374	-	374	374	-	374	748	374	2,937
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Demand Response	33	132	67	62	47	41	12	14	15	17	19	20	21	22	24	545
Energy Efficiency	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	2,041
Distributed Solar	173	72	87	68	25	16	15	15	15	15	15	15	15	15	15	575

By comparing Tables 4-5 and 4-10 above, Table 4-5 shows 835 MW Sherco CC in 2027 and no wind through 2030, whereas Table 4-10 shows no Sherco CC and 1,350 MW of wind by 2030, plus several firm dispatchable units.

In the modeling conducted for the Supplement Plan, the 835 MW Sherco CC operated at an approximately 80 percent capacity factor—in other words, like a baseload plant. In fact, output from the Sherco CC (in GWh) was greater than the Monticello plant. Without the Sherco CC, and without a dispatchable, intermediate unit or baseload unit replacing it, the energy is largely replaced by new wind added to the Sherco interconnection. An excerpt of Figure 1-2 of Reply Comments below portrays the relative generation mix between the Supplement and Alternate plans in 2030, by percentage.[43] Note that generation from wind increases (from 30 percent to 39 percent), generation from natural gas decreases (from 30 percent to 19 percent), and nuclear and solar output remain about the same.[44]



As discussed previously, through 2029, the renewable energy is Xcel-owned because the Company claims it needs to own the first 2,000 MW at the Sherco interconnection[45] and 600 MW at King, per FERC's prohibition on the sale of interconnection rights. Once Xcel reutilizes all existing interconnection rights, Xcel makes no assumption regarding ownership structure, and resources are modeled as generic units that could ultimately be either owned or PPA resources. In total, the Alternate Plan includes 5.8 GW of new renewable resources, as shown by Figure 4-7 below. Owned resources are shown by the blue bar, and generic resources – which increase once the interconnection rights are fulfilled – are shown by the orange bar.

[43] Xcel reply comments, p. 5.

[44] In 2020, Xcel's generation mix was 18% coal, 20% natural gas, 30% nuclear, 21% wind, 3% solar, and 8% other.

[45] Xcel's capacity expansion modeling assumed 2,000 MW of open interconnection at Sherco rather than 2,400 MW to reflect SMMPA's partial ownership stake of Sherco Unit 3 and related interconnection rights.

Figure 4-7: Modeled Wind and Solar Additions in Alternate Plan, by Required Ownership Type

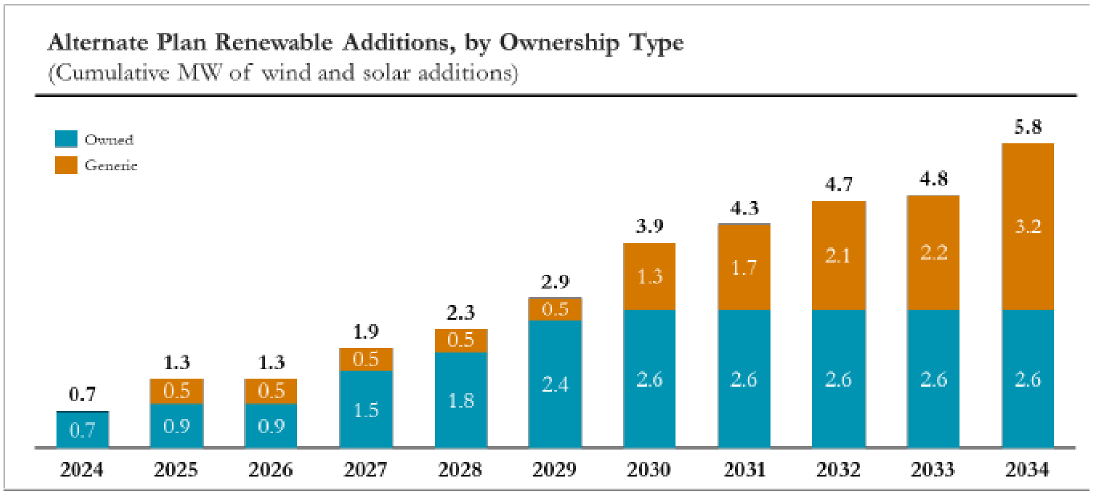


Figure 4-6 breaks down total resource additions by ownership and by gen-tie.[46] In total, over 4,000 MW of renewables and approximately 400 MW of CT capacity is added on the gen-tie lines.

Figure 4-6: Alternate Plan Cumulative Capacity Additions, by Interconnection Type

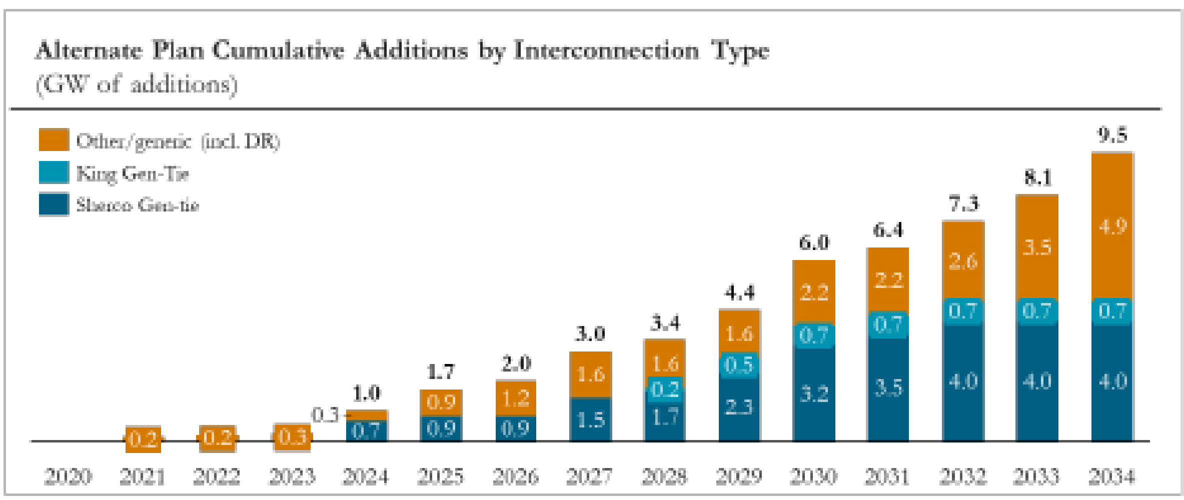


Table 1-1 of Xcel's Reply Comments shows that this proposal lowers system costs relative to the Reference Case and Supplement Plan.[47]

[46] The figure shows 9.5 GW in total, not 9 GW as in previous figures, because Figure 4-6 includes DR.

[47] **PVSC (Present Value Societal Costs)**: The Present Value of Societal Costs (PVSC) is the net present value cost of a utility's revenue requirement for a particular resource addition or portfolio plan when environmental externality and regulatory cost of carbon values are incorporated into a production cost run. The calculation of PVSC is required using Commission-approved values for the regulatory cost of carbon dioxide and externality values for

Table 1-1: Alternate Plan Cost/Savings, Relative to the Reference and Supplement Plan

Scenario	PVSC ($ millions)	PVSC Delta to Reference Case ($ millions)	PVRR ($ millions)	PVRR Delta to Reference Case ($ millions)
Reference Case (Scenario 1)	41,067	--	37,165	--
Supplement Plan (Scenario 9)	40,833	(234)	37,261	96
Alternate Plan – Current Policy	40,461	(606)	37,120	(46)

In summary:

- Xcel's Reference Case assumes no changes to the baseload unit retirement dates. New capacity additions include 1,000 MW of solar in 2025; 835 MW from the Sherco CC in 2027; and a 374 MW gas CT in 2029. Xcel's Scenario 9 proposes retiring the Allen S. King Plant (511 MW) in 2028 and Sherco Unit 3 (517 MW) in 2030.[48] (Both scenarios retire Sherco Unit 1 (680 MW) and Sherco Unit 2 (680 MW) in 2026 and 2023, respectively, as part of Xcel's 2015 IRP.) In addition, Monticello (646 MW) will be extended through 2040 (10 years longer than its current license).[49] For this IRP, Xcel plans to operate Prairie Island Unit 1 (546 MW) and Prairie Island Unit 2 (546 MW) at least through the end of their current licenses, which expire in 2033 and 2034, respectively.

- The Alternate Plan removed the Sherco CC from the Preferred Plan. Without the Sherco CC, which would have made use of approximately 40 percent of the Company's interconnection rights as the existing Sherco coal units retire, a significant amount of interconnection rights will become available for reuse. Xcel proposes to own the first 2,000 MW at the Sherco interconnection and 600 MW at King along newly constructed 345kV transmission lines at the Sherco and King sites. A 400 MW CT will also be added at the end of the Sherco line in Lyon County, Minnesota. In total, Xcel's proposal to reutilize interconnection rights with wind and solar additions fulfills just over 4,000 MW, with a requirement to own the first 2,600 MW of these additions, between the King and Sherco gen-ties.

criteria pollutants.

PVRR (Present Value Revenue Requirements): The Present Value of Revenue Requirements (PVRR) is the net present value cost of a utility's revenue requirement for a particular resource addition or portfolio plan without consideration of carbon and environmental externality values over a modeling period in a production cost run.

[48] Southern Minnesota Municipal Power Agency (SMMPA) owns 41% of Unit 3 (approximately 380 MW).

[49] Xcel's related request to expand spent fuel storage capacity at it Monticello Nuclear plant is pending in Docket 21-668.

- The baseload retirement plan proposed in the Alternate Plan is the same baseload plan as Scenario 9 from the Initial Plan and Supplement Plan.

- The Alternate Plan proposes four gas CTs totaling about 1,100 MW in 2025-2029; two are existing gas-powered sites, while the other two are greenfield sites in Fargo, ND and Lyon County, MN. Additional firm peaking resources are selected in later years of the planning period. However, Xcel stated this peaking capacity is considered technology neutral for the purposes of the current IRP.

3. Modeling Assumptions

This section will discuss a few of Xcel's modeling assumptions, particularly those that parties challenge and others that are important to highlight to explain the modeling results.

Battery storage. Some parties recommend the Commission modify Xcel's plan to replace gas CTs with battery storage, arguing that Xcel used flawed battery storage assumptions. Xcel based its battery storage costs on the 2019 NREL ATB, and while some modeling parties used the NREL ATB as well, the assumptions have been updated and incorporated into alternative plans, which include lower battery costs. However, cost is only one of many reasons Xcel prefers CTs to battery storage. Nevertheless, the table below shows Xcel's levelized capacity costs for the base case and the low sensitivity battery costs in 2024-2029 (the years when the model begins to add large amounts of new resources) compared to a CT unit:[50]

Table 3. Levelized Capacity Costs for Battery Storage, in $/kW-mo.

COD	2024	2025	2026	2027	2028	2029
CT	$9.07	$9.25	$9.44	$9.63	$9.82	$10.02
Low Batt.	$16.84	$12.30	$11.75	$11.18	$10.60	$10.00
Base Batt.	$17.52	$16.84	$16.63	$16.41	$16.19	$15.95

Table 139 of Xcel's Reply Comments shows Xcel's operational assumptions for storage. The effective load carrying capacity (ELCC) assigned to a generic 4-hour battery is equal to 100 percent of the alternating current (AC) equivalent capacity.

[50] This table uses information from Table 20, Appendix A, p. 25 of Xcel's Reply Comments.

Table 139: Storage Generic Information (Costs in 2018 Dollars)

Storage Generic Information	
Resource	Battery
Technology	Li Ion
Location Type	NA
Book life	40
Nameplate Capacity (MW)	50
Summer Peak Capacity (MW)	50
Storage Volume (hrs)	4
Cycle Efficiency (%)	1
Equivalent Full Cycles per Year	250
Electric Transmission Delivery ($000) 2018$	0
Levelized $/kw-mo (All Fixed Costs) $2023	$18.18

As noted above, some inputs are not up-to-date with the latest NREL ATB, which Xcel stated was a choice to keep baseline inputs consistent with its Supplement. Sierra Club opposed this approach, stating that the 2021 NREL ATB showed continuing decline of battery storage costs. The table below shows Xcel's base and low battery costs – the same values as the table above showing the comparison to CTs – and the 2021 NREL ATB assumptions, which is from Sierra Club's Supplemental Comments. Note that the 2021 NREL ATB levelized costs for battery storage is lower than Xcel's low end of the range for battery costs.

Table 4. Levelized Capacity Costs for Battery Storage, in $/kW-mo.

COD	2024	2025	2026	2027	2028	2029
Base Batt.	$17.52	$16.84	$16.63	$16.41	$16.19	$15.95
Low Batt.	$16.84	$12.30	$11.75	$11.18	$10.60	$10.00
NREL 2021	$11.20	$10.53	$10.35	$10.17	$9.97	$9.76

Solar. Some parties remarked that Xcel's solar pricing was too high and questioned whether Xcel-owned gen-tie investments are better for ratepayers than a PPA. The table below shows Xcel's assumed price for generic utility-scale solar from 2023-2028.[51] Staff notes that this information was collected from Tables 21 (base), 22 (low) and 23 (high) of Xcel's Reply Comments.

[51] Staff used 2023-2028 assumptions only because these years are most relevant to Xcel's solar acquisition following the IRP.

Utility-Scale Solar
LCOE by Year ($/MWh)

COD	Low	Base	High
2024	$38.49	$46.62	$51.94
2025	$39.29	$48.51	$55.12
2026	$42.57	$53.97	$62.79
2027	$41.82	$53.99	$64.04
2028	$41.04	$54.01	$65.32

As excerpt of Table 24 of Xcel's Reply Comments below shows Xcel's assumptions for Sherco and King gen-tie solar. (Xcel's full table shows wind and solar through 2050.) These are based on the 2019 NREL ATB, but they do not include incremental transmission costs.

Table 24: Sherco and King Gen-Tie Solar
LCOE by Year ($/MWh)

COD	Low	Base	High
2024	$25.43	$33.56	$38.88
2025	$25.97	$35.19	$41.80
2026	$28.98	$40.38	$49.20
2027	$27.96	$40.14	$50.18
2028	$26.90	$39.87	$51.19

Importantly, the Sherco and King gen-tie solar costs as shown do not include incremental transmission costs and a full accounting of the Company's owned revenue requirements. OAG Information Request No. 16 requested that Xcel recalculate the LCOE for the gen-tie solar with the full revenue requirement included. (Xcel's response is non-public information.) Based on this calculation, the OAG concluded that the LCOE for gen-tie renewables becomes exceedingly high and likely much higher than projects Xcel may receive in a bidding process where developers typically bear interconnection costs.

Distributed Solar. The next table shows Xcel's assumed costs for distributed solar. This information was also taken from Tables 21, 22, and 23 of Xcel's Reply Comments.

Distributed Solar – Commercial/Residential

LCOE by In-Service Year ($/MWh)

COD	Low		Base		High	
	Comm.	Res.	Comm.	Res.	Comm.	Res.
2023	$49.46	$82.47	$60.46	$84.12	$88.34	$126.50
2024	$48.30	$76.99	$59.99	$81.21	$90.11	$129.03
2025	$47.11	$71.34	$62.70	$82.40	$91.91	$131.61
2026	$45.87	$65.52	$71.70	$91.23	$93.75	$134.24
2027	$44.59	$59.54	$71.00	$87.23	$95.63	$136.93
2028	$43.26	$53.38	$69.41	$83.07	$97.54	$139.67

These assumptions are important because they are obviously much higher than utility-scale solar, yet they assume all costs for distributed solar are borne by the utility. The Distributed Solar Parties[52] (DSP) argued that "optimizing a resource plan to include distributed resources requires identifying the benefits to the system but separating the cost to the utility from costs to the customers who own the generation and using only the utility costs as a model input." DSP explained:

> The "cost" to the utility consists only of the incentives, if any, provided by the utility to the distributed generation owner. In fact, one of the largest benefits to the system from distributed generation is that private investment, rather than the utility and ratepayers, pay the capital costs of the generation.[53]

Xcel responded that treating distributed solar as an optimized resource in EnCompass under an incentive-only assumption approach does not reflect the full cost of distributed solar:

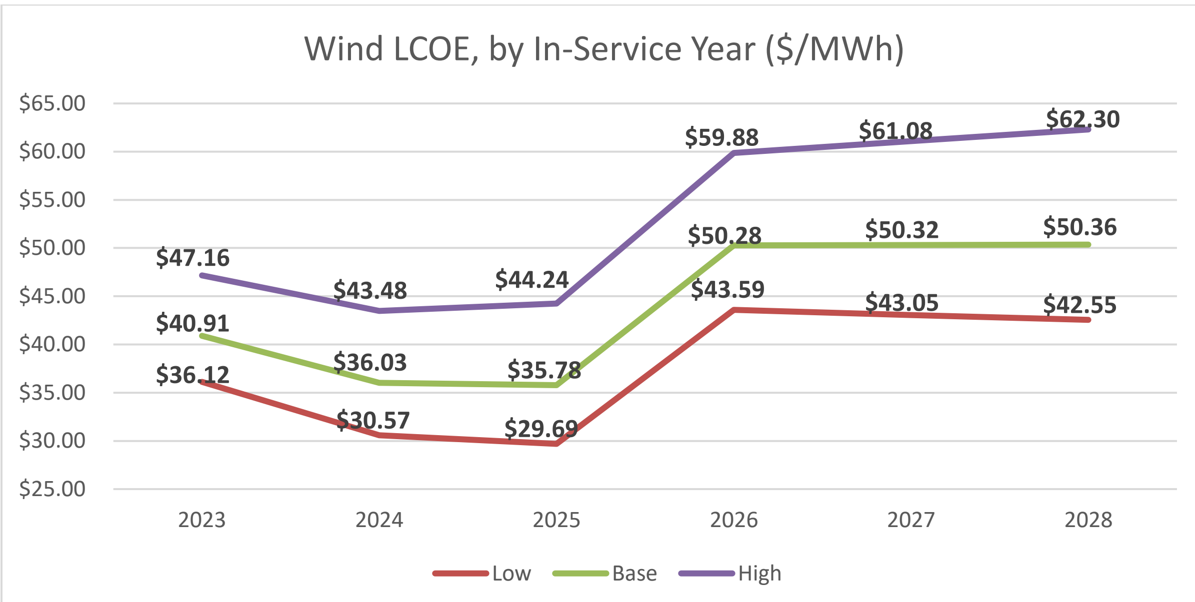
> The present value of societal costs and revenue requirements associated with resource additions in our Resource Plan do not just represent incremental cost to incentivize, rather it is intended to represent the costs associated with the resources selected to serve our system. In other words, if an "optimal amount" of customer-procured resource is going to be identified through modeling in the context of the broader system, then either the full cost of that resource must be evaluated through modeling, or the bundles of distributed solar would need to be assessed through an alternative cost effectiveness test and reflect achievable potential levels – like the EE bundles in our modeling were – before the model could select them.[54]

[52] The Distributed Solar Parties (DSP) is comprised of Vote Solar, the Institute for Local Self-Reliance, Cooperative Energy Futures, and the Environmental Law and Policy Center.

[53] DSP initial comments, p. 12.

[54] Xcel reply comments, p. 155.

Wind. In the Supplement, Xcel did not make generic wind resources available for the model to select until 2026 due to ongoing transmission constraints in MISO and congestion in the broader MISO queue.[55] According to Xcel, incremental greenfield wind will face significant barriers in the near-term. In fact, the Supplement did not add new wind resources until 2032. The Alternate Plan adds new wind beginning in 2028 because adding wind onto the Sherco gen-tie circumvents the MISO queue. The table below shows Xcel's range of generic wind prices on a levelized cost (LCOE) basis. Staff notes that Xcel's wind price assumptions are quite higher than wind projects the Commission has approved over the last ten years.



Capacity accreditation. An important assumption impacting Xcel's total resource need is how much MISO-accredited capacity is assigned to wind and solar resources. Xcel modeled a 16.7 percent effective load carrying (ELCC) for wind, which reflects MISO's Zone 1 ELCC. For solar, Xcel modeled a 50 percent ELCC, declining thereafter by 2 percent per year through 2033, until it reaches and remains at 30 percent for the remainder of the modeling period. This aligns with assumptions used in MISO's Transmission Expansion Process (MTEP) 2019 modeling. The table below shows the ELCC capacity credit percentage and capacity factor for wind and solar resources.

Table IV-15: Renewable Generic Information (Costs in 2018 Dollars)

Renewable Generic Information				
Resource	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
ELCC Capacity Credit (%)	16.7%	50% declines to 30%		
Capacity Factor	50.0%	22.0%	18.0%	18.0%
Book life	25	25	25	25
Electric Transmission Delivery ($/kW)	500	200	0	0

[55] According to Xcel, "Transmission constraints in the near term are highly cost prohibitive, such that most greenfield projects are withdrawing from the interconnection queue."

Carbon pricing. Environmental externalities and CO_2 regulatory costs have significant impacts on the cost delta between the Alternate Plan and the Reference Case. The table below shows the savings of the Alternate Plan relative to the Reference Case under the base PVRR, base PVSC (High Externality/High Regulatory), Low Externality/Low Regulatory, and Mid-Externality/Mid-Regulatory (this is not a complete list of externality sensitivities). Xcel's PVSC base case CO_2 values are based on the Commission's high environmental cost values for CO_2 through 2024,[56] and the PVSC base case values starting in 2025 are based on the high end of the range of regulated costs.[57] Staff notes that Xcel argued the Department's base case, which used Mid-Externality/Mid-Regulatory, disadvantaged renewables and nuclear. From staff's perspective, it is not particularly important what externality/CO_2 cost values are used in the base case because the important part to understand is how the Preferred Plan performs over a range of sensitivities under both the PVRR and PVSC measures.

Table 4-16: Company Plans Cost/(Savings) Results, Across Sensitivities

Sensitivity	Reference Case (Updated Scenario 1) *Total NPV Cost 2020-2045 ($ millions)*	Alternate Plan *$ million cost/(savings) relative to Reference Case*
PVSC Base	40,067	(606)
PVRR Base	37,165	(46)
Low Externality/Low Regulatory	38,035	(198)
Mid-Externality/Mid-Regulatory	39,571	(409)

4. Sensitivity Analysis

Table 4-16 of Xcel's Reply Comments below shows Xcel's sensitivity analysis. Relative to the Reference Case, the Alternate Plan lowered costs in all but one run. Relative to the Supplement Plan, the Alternate Plan lowered costs in every run.[58]

[56] Commission Order Updating Environmental Cost Values in Docket No. 14-643 issued January 3, 2018, p. 31.

[57] Commission Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Dockets No. CI-07-1199 and DI-17-53 issued June 11, 2018, p. 12.

[58] Xcel reply comments, pp. 139-140.

Table 4-16: Company Plans Cost/(Savings) Results, Across Sensitivities

Sensitivity	Reference Case (Updated Scenario 1) *Total NPV Cost 2020-2045 ($ millions)*	Supplement Plan (Updated Scenario 9) *$ million cost/(savings) relative to Reference Case*	Alternate Plan *$ million cost/(savings) relative to Reference Case*
PVSC	40,067	(234)	(606)
A. PVRR	37,165	96	(46)
Standard sensitivities			
B. Low Gas/Coal/Market Prices	40,888	(192)	(442)
C. High Gas/Coal/Market Prices	41,284	(313)	(849)
*D. Low Load**	42,254	(236)	(553)
*E. High Load**	43,667	(212)	(569)
F. Low Resource Cost	39,626	(75)	(865)
G. High Resource Cost	43,128	(447)	(345)
I. Low Externality	39,086	(189)	(505)
J. Low Externality/Low Regulatory	38,035	(35)	(198)
K Mid Externality, Mid Regulatory	39,571	(141)	(409)
L. High Externality	46,203	(1,090)	(2,163)
M. No Regulatory or Externality Cost	36,898	124	16
Futures Sensitivities and Other Special Cases			
*Future P. High DG Adoption**	40,644	(100)	(536)
*Future Q. High Electrification**	42,257	(478)	(1,638)
*Increased Planning Reserve Margin Requirement (PRMR) **	41,354	(223)	(581)
Tax Reform[64] (Alternate Plan only)	40,067	n/a	▪ PVSC: (990) ▪ PVRR: (429)
North Dakota planning standards[65]	36,458	PVRR: 239	▪ PVRR: 254 ▪ Tax reform sensitivity: (108)

* Indicates a plan that is reoptimized in capacity expansion modeling, due to changes in assumed customer load or different optimization assumptions. In all other scenarios the capacity expansion plan for each Scenario is held constant with the "base" PVSC runs.

The table below is an excerpt of Table 2 of Appendix C; it includes the same information as in Table 4-16, but in addition, it shows that a sensitivity analysis was limited to Scenario 1, Scenario 9 – Updated Supplement Plan, and Scenario 9 – Alternate Plan. That is why the two versions of Scenarios 4 and 12 do not include sensitivity values.

Table 2: Net Present Value Deltas (Relative to S

Scenario label	PVSC	_A	_B	_C	_D	_E	_F	_G
Scenario	PVSC	PVRR	Low Gas/Coal/Mkts	High Gas/Coal/Mkts	Low Load	High Load	Low Resource Cost	High Resource Cost
Scenario 1 - Updated Reference Case	0	0	0	0	0	0	0	0
Scenario 9 - Updated Supplement Plan	(234)	96	(192)	(313)	(236)	(212)	(75)	(447)
Sceanrio 9 - Alternate Plan	(606)	(46)	(442)	(849)	(553)	(569)	(865)	(345)
Scenario 4 - Updated	(210)	55						
Scenario 4 - Alternate	(543)	(84)						
Scenario 12 - Updated	(636)	(163)						
Scenario 12 - Alternate	(965)	(277)						

In contrast to sensitivities that change only one price input at a time (e.g., high natural gas prices), Xcel tested "special cases," which test changes to a combination of assumptions. Xcel explained that purpose of the special cases was to examine "the potential outcome of a confluence of multiple assumptions changes described in the standard sensitivities."[59] The special cases include High Electrification, High DG adoptions, increased PRMR, and the North Dakota Plan. Because these scenarios made changes to system load or optimization assumptions, not a price input, the special cases resulted in different expansion plans.

Assumptions in the special cases are shown in Table 4-17 of Xcel's Reply Comments.

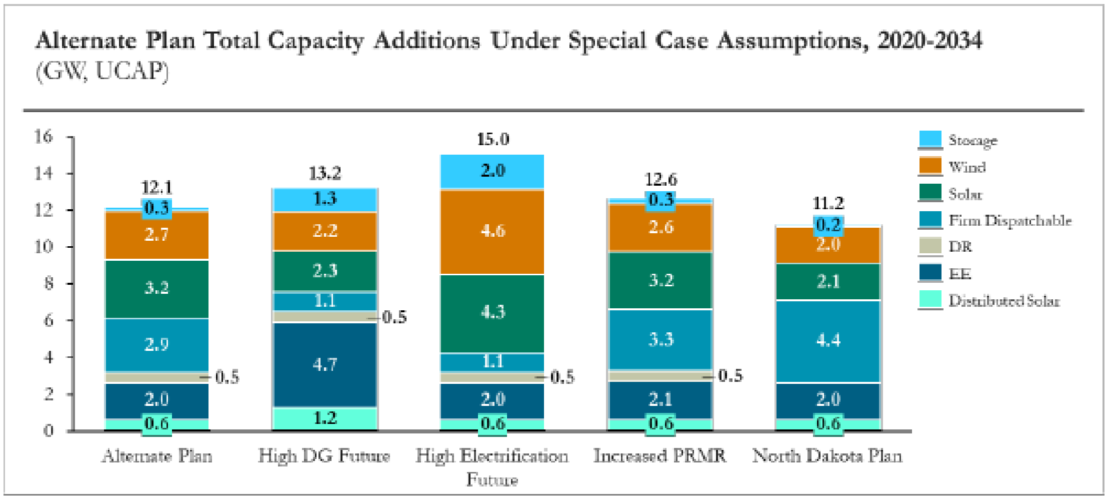
Table 4-17: Special Case Parameters

Special Scenarios	Description	Gas/Coal/Market Prices	Load Forecast	Carbon & Externality Costs	New Resource Costs
P. High DG Adoption and Low Technology Cost Future	Similar to MISO MTEP Limited Fleet Change Scenario	Low	High DG Solar Forecast, Higher EE Levels	High/High	Low
Q. High Electrification and Low-Tech Costs Future	Similar to MISO MTEP Accelerated Fleet Change Scenario	High	High Electrification	High/High	Low
Z. Increased PRMR	Reflects higher PRMR per recent MISO guidance	Base	Base, but adjusted to reflect a 9.4% planning reserve margin and 98% coincidence factor	High/High	Base
North Dakota Planning Standards	Optimizes expansion plan based on PVRR, with no externality or regulatory cost of carbon prices included; also removes incremental DR and CSG solar	Base	Base	None	Base

59 Xcel reply comments, p. 141.

Figure 4-13 compares the total capacity additions by fuel type under the special cases. Note that the High DG Future adds more than twice the amount of EE than any other special case, and the High Electrification Future adds significantly more wind than any other special case.

Figure 4-13: 2020-2034 Cumulative Resource Additions Under Special Case Assumptions



V. System Restoration and Blackstart

A. Xcel's System Restoration Plan

On page 56 of Xcel's Reply Comments, the Company provided an overview of its system restoration planning process:

> At a high level, a System Restoration Plan specifies the process we use to restore our system to full operation following a full- or partial-black out across not only our system, but the broader transmission network. When the grid is operating normally, the electric power used within a generating plant (i.e. "station power") is provided from the plant's own generators. If all of the plant's main generators are shut down, station power is provided by drawing power from the transmission grid, which can be used to start the plant. However, during a wide-area outage, power from the grid will not be available. In the absence of grid power, a so-called "blackstart" needs to be performed to "bootstrap," or self-start the power grid into operation.
>
> System Restoration Plans are required by the North American Electric Reliability Corporation (NERC), developed in concert with neighboring utilities, and are subject to review and approval by MISO. Developing such a plan involves developing models, strategies and procedures to configure the system such that one or more generators can be brought online while also picking-up sufficient customer load to balance the generators' and transmission network's minimum requirements for stability. The process begins by starting the "Initial Unit(s)"

> (sometimes also referred to as a "Blackstart Unit"). These are generating units that have an on-site, independent power source that can provide the Initial Unit the capability to start its primary generators without reliance on the external transmission network. Energy from the Initial Unit is utilized to provide start-up energy to the "Target Unit(s)," which are typically larger units with output that can be controlled and adjust to fluctuations on the grid as customer load is added. Energy from the Initial and Target Unit(s) is used to support bringing subsequent units and load back online until our system is fully restored and reconnected to the Eastern Interconnection.
>
> As each unit starts, its generation is balanced with customer load along the connected transmission and distribution lines to maintain stability on the system. This process sets up "islands," where part of the transmission and distribution systems in a geographic area begin serving at least part of the customer load in that area. Once we determine an island is stable, we can synchronize and reconnect/restore more generators and load, essentially expanding the island and restoring our interconnections with other utilities until the system is fully restored. The longer the system is down, the harder it is to restore, so we work to determine the most efficient paths possible.[60]

Xcel explained that existing System Restoration Plan currently uses a state-by-state approach, with restoration focused primarily on restoring load in the large population/load centers in Minnesota, Wisconsin, and the Dakotas. Its plan primarily relies on the Company's own thermal resources, although in some cases Xcel relies on other utilities to help get portions of its system started, and vice versa.

A key step when designing a System Restoration Plan is to identify the generating units in a system that can be used as Initial Unit(s) and Target Unit(s). Only certain unit types and sizes are appropriate for consideration as Initial Units or Target Units; the Initial Unit should be maintained to as high of a degree of start reliability as possible, because the rest of the system depends on the unit working, including under adverse conditions. Moreover, the Initial Unit must be large enough to stabilize transmission to a Target Unit and provide power to start that Target Unit. The ideal design includes several small units rather than fewer large units because the plant as a whole needs to be big enough to energize the high voltage transmission system and restore a larger Target Unit.

Target Units are the subsequent generating units on the restoration path and are started by the Initial Unit(s). A generator's fuel type, dispatchability, and its ability to provide and absorb reactive power are a few of the most important considerations for suitability as a Target Unit. Eligible Target Units include coal, natural gas, hydro, and fuel oil. Renewable generation, such as solar and wind, are not currently considered eligible Initial or Target Units due to their intermittency and general inability to provide or absorb reactive power. Nuclear units are also not eligible as they can only come online after the balance of the system is fully stable. Xcel is exploring longer-duration battery storage, but Xcel claims this is not yet a proven technology.

[60] Xcel reply comments, p. 56.

After fuel source and reactive power response considerations, Xcel considers several other items when choosing Target Units:

- Availability of multiple generating Units at the site;
- Minimum operating limits for the site;
- Ramp rate of the Units;
- How fast a Unit can come online once it receives station power;
- Unit's ability to act as a stabilizing Unit in the Island;
- Amount of stabilizing load in close proximity to the Target Unit(s); and
- Amount of switching required in order to energize the Unit.

The transmission system is another critical piece of the System Restoration Plan and has bearing on which Initial Units and Target Units are the most suitable.

Section 3.B. on pages 63-65 of Xcel's Reply Comments discusses the Company's current blackstart plans in the Minnesota and Wisconsin system. Nearly all of the information is protected information, so staff does not discuss that here. The same is the case for Section 3.E., the selection of the current Minnesota blackstart unit replacement.

B. Transition to a Zonal Restoration Approach

Because the current centralized approach is focused on load centers, there are very few renewable resources in proximity to the island that Xcel is building out from the Twin Cities metro area. This minimizes the role of renewables, which are generally in rural areas distant from the load centers. The zonal approach will build small, geographically-dispersed islands so Xcel will be in a better position to incorporate renewable resources to restore customers. Figure 3-1 below summarizes the change from the current approach.

Figure 3-1: Summary of Change in System Restoration Plan Approach

Blackstart Overview: Centralized to Zonal Restoration

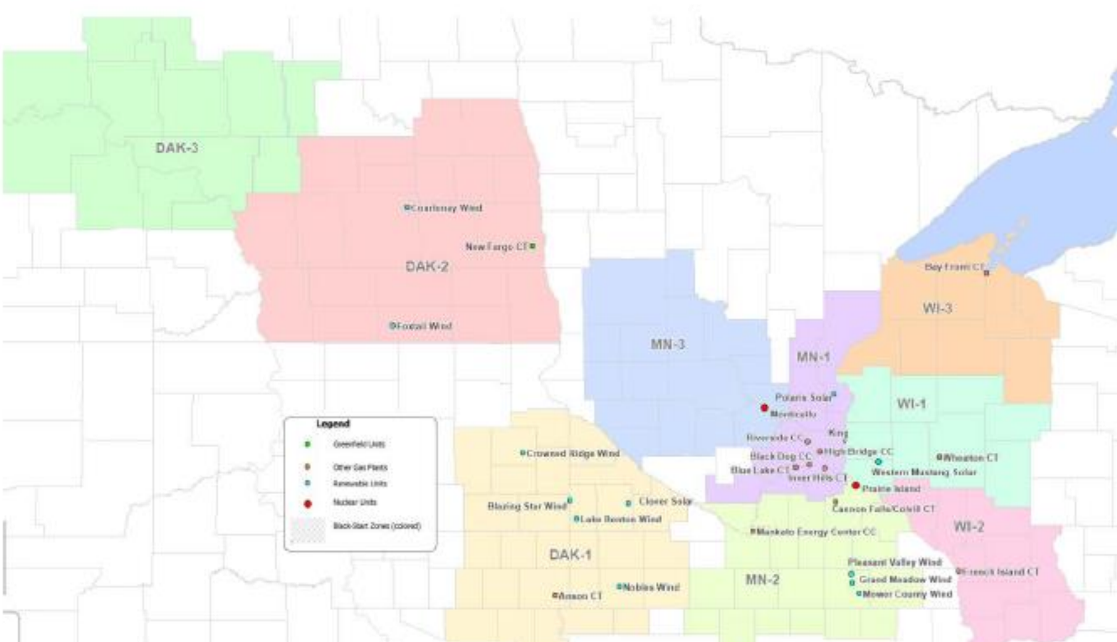
- Large Loads & Large Generators
  - Focus restoration and large load centers (Twin Cities, Eau Claire, Sioux Falls)
  - Dependent on existing base load generation near large load centers
- Nuclear Restoration: Focus on restoring off-site power to nuclear plants within 4 hours
- No Reliance on Renewables: Does not fully utilize renewables as a restoration resource due to geographic remoteness from load centers

→

- Regional Islands
  - Focus restoration strategy on regional islands and connecting those islands
  - Provide a more diversified blackstart approach
- Nuclear Restoration: Maintain focus on restoring off-site power to nuclear plants within 4 hours.
- Renewables Play a Role: Ability to take full advantage of renewable resources that are geographically dispersed.

As shown in Figure 3-2 below, Xcel plans to have nine zones throughout the NSP System footprint. (Since the image might be too blurry to read, staff refers the Commission to page 69 of the Company's Reply Comments.) Xcel stated that the Company will transition to the zonal approach likely over the next ten years.

Figure 3-2: Anticipated System Restoration Plan Zones



The zonal approach introduces blackstart capabilities in each new zone. Xcel stated that a zonal approach is beneficial because it:

- is more diversified;
- does not rely on one or two large generators;
- allows for the incorporation of renewables as part of the start-up process by creating a series of smaller islands that will eventually be joined together; and
- has the potential to restore greater numbers of customers faster than the current plan.[61]

Table 3-3 below illustrates the difference between the resources involved with the current centralized plan and the new zonal plan. By 2030, Xcel will go from utilization of approximately 50 MW of solar resources located near the Twin Cities today to nearly 6,000 MW of renewables located across its footprint. The 2021 Centralized EP Plan column includes all resources (including PPAs) that are currently part of the Company's restoration plan. The 2030 Modified Zonal Plan column includes all resources in-service as of 2030 and available for system restoration based on Xcel's proposed zonal approach.

Table 3-3: Comparison of Centralized Plan and Modified Zonal Restoration Plan

	NSP 2021 Centralized EP Plan	2030 Modified Zonal Plan with Alternate Plan
Firm Dispatchable (FD) Generation Available	6,595 MW	5,175 MW
Restoration % by XE only FD generation (Summer)	45-70%	55%
Restoration % by XE only FD generation (Winter)	80-90%	75%
XE-owned Renewables Available for Utilization	1,691 MW	5,930 MW
XE-owned Renewables Utilization Rate	50 MW	2,025 MW
Total XE owned Resources for restoration	6,645 MW	7,200 MW
Total % Restored (Summer)	45-70%	80%
Total % Restored (Winter)	80-90%	105%
Resource Gap without Renewables	2,445 MW	3,865 MW
Resource Gap after using Renewables	2,395 MW	1,840 MW

Xcel proposes a separate proceeding or series of planning meetings to more broadly discuss restoration of the Minnesota system from a catastrophic event. Xcel intends to discuss the

[61] Xcel reply comments, p. 69.

specific resources needed to meet system restoration needs under a zonal approach. In the meantime, Xcel proposes changes to some of its current blackstart units.

VI. Alternative Plans Proposed by Intervenors

Under Minn. R. 7843.0300, subp. 11, parties may file alternative plans and explain why a different resource plan is in the public interest. An alternative plan must be accompanied by a narrative and quantitative discussion of why the proposed changes would be in the public interest and must consider the Commission's five factors to consider in Minn. R. 7843.0500, subp. 3. Alternative preferred plans were submitted by:

- CEOs – CEO Preferred Plan (Initial Comments) and CEO Alternate Plan (Supplemental Comments)
- CUB – Consumers Plan
- Department – DOC Scenario 11
- Sierra Club – Clean Energy for All Plan

The table below is a comparison of Xcel's Alternate Plan to parties' alternative plans. For space, staff includes only the 2024-2030 timeframe (large units are not added sooner than 2024, and the 2031-2034 timeframe can be addressed in subsequent IRPs). Also, the CUB and Sierra Club plans were developed based on earlier versions of Xcel's modeling, so they were modeled prior to Xcel's proposal to remove the Sherco CC and build two transmission lines. Next, staff notes that CUB used the WIS:dom model, which adds resources in five-year timesteps, so resource additions are not shown annually. Finally, both the CUB and Sierra Club plans add significant amounts of distributed solar, but staff opted to include only the large unit additions.

Table 5. Alternative Plans Proposed by Parties

Year	Xcel Energy Alternate Plan	CEO Alternate Plan	CUB Consumers Plan	DOC Scenario 11	Sierra Club Clean Energy for All Plan
2024	700 MW solar	750 MW solar (Sherco)		700 MW solar	
2025	600 MW solar 60 MW Firm Disp.	50 MW solar (Sherco) 300 MW solar (system)	3,000 MW wind 1,400 MW solar	100 MW solar	
2026	260 MW Firm Disp.	Blackstart unit		Blackstart units	480 MW wind
2027	600 MW solar 374 MW Firm Peak	Blackstart unit 800 MW solar hybrid (Sherco) 200 MW battery (Sherco) 11 MW battery (Sherco) 101 MW battery (system)		700 MW solar	480 MW wind 450 MW solar 40 MW battery
2028	200 MW wind 400 MW solar 374 MW Firm Disp.	200 MW wind (Sherco) 800 MW solar hybrid (King) 200 MW battery hybrid (King)		200 MW solar	60 MW battery 80 MW wind
2029	400 MW wind 400 MW solar 374 MW Firm Disp.	300 MW wind (Sherco) 4 MW battery (King)		374 MW CT	280 MW battery 400 MW wind
2030	200 MW storage 950 MW wind 100 MW solar 374 MW Firm Disp.	687 MW battery (Sherco) 1,500 MW wind (Sherco) 157 MW battery (system)	1,400 MW wind 2,100 MW solar	1,122 MW CT 350 MW solar 350 MW wind	640 MW battery 1,200 MW wind 900 MW solar

A. CEO Preferred Plan

The Clean Energy Organizations (CEOs) include Fresh Energy, Clean Grid Alliance, Union of Concerned Scientists, and the Minnesota Center for Environmental Advocacy.

1. CEO Original Preferred Plan

Energy Futures Groups (EFG) reviewed Xcel's EnCompass modeling and performed new modeling on behalf of CEOs. EFG's modeling approach was to examine three portfolios:

- Xcel's Preferred Plan as filed;
- a reoptimized Revised Xcel Preferred Plan that includes the Sherco CC; and
- an alternative, all renewable and storage expansion plan (CEO Preferred Plan).

For CEOs' Initial Comments, EFG reviewed Xcel's Preferred Plan from the June 2020 Supplement and made changes to Xcel's base case (Xcel Corrected Base Case). In addition, EFG used the

Xcel Corrected Base Case *and* included new inputs to create a CEO Base Case. Tables 1 and 2 of CEOs' Initial Comments below show the corrections and changes made.[62]

Table 1. Xcel Corrected Base Case Changes

Items Changed	Description of Changes
Approved Projects	• Included 3 approved wind and solar projects
Battery Storage Costs	• Corrected LCOE calculation to be consistent with real dollars • Converted fixed O&M to an annual expense
Battery Storage Size	• Allowed EnCompass to select battery storage projects in smaller sizes
Solar Costs	• Corrected LCOE calculation to only apply the ITC to capital costs
Solar Hybrid Resources	• Allowed the model to select solar hybrid resources between 2025-2040
Flow Batteries	• Included 6 and 8-hour flow batteries between 2040 and 2045

Table 2. CEO Base Case Scenario Changes

Input Changed	Description of Changes
Wind Costs	• Updated costs to 2020 ATB • Corrected capacity factor to incorporate Xcel's modeled capacity factor
Solar Costs	• Updated costs to 2020 ATB • Updated capacity factor to 25.4%
Battery Storage Costs and Operating Life	• Costs based on pricing from PNM projects with the application of the NREL Mid Case Cost Curve • 20 year operating life based on the PNM projects
Interconnection Costs	• Incorporated costs into the LCOE calculation to be consistent with NREL methodology

With all changes from Tables 1 and 2 above incorporated, CEOs ran a third scenario that lowered interconnection costs starting in 2031. EFG explained that it is reasonable to assume that as new transmission is built or as existing lines are upgraded, interconnection costs may return to more normal levels.

Lastly, CEOs tested a Manitoba Hydro extension but found that a much lower contract price would have to be in place to make an extension worthwhile for customers.

Also note from Table 1 that the Xcel Corrected Base Case allowed the model to select solar hybrid resources beginning in 2025. CEOs described this resource option on page 11 of their Initial Comments. CEOs stated that Xcel constrained the model to allow hybrids in 2025 only.

[62] PNM is Public Service of New Mexico.

> *Hybrids*: CEOs added solar-battery hybrid resources as an option for the model. Solar-battery hybrid projects are solar PV panels paired with battery storage at the same point of interconnection. Hybrids have a number of benefits compared to stand-alone solar and storage, can leverage the federal Investment Tax Credit ("ITC"), and already have a significant presence in the Midcontinent Independent System Operator ("MISO") interconnection queue.[29] Despite this, Xcel did not include solar-battery hybrids as a resource option in the Company's modeling except in a single sensitivity run. Moreover, in that sensitivity, Xcel constrained the model and only allowed hybrids to be selected in 2025 and in no other years. CEOs corrected this flaw by allowing hybrids to be selected as a resource in 2025-2040 for all modeling runs with our resource portfolios.

CEOs explained that the Sherco CC was a fixed unit in all of Xcel's modeling runs. By giving the model the option to select it, and with more reasonable assumptions, CEOs' EnCompass modeling shows that the Sherco CC is not an economic resource, and the facility emitted a significant amount of CO_2 over its lifetime.

Instead of the Sherco CC, the CEO Preferred Plan selected a substantial number of battery storage hybrid and solar hybrid resources, along with standalone battery storage. In 2025-2027 – 2027 being the year when the Sherco CC was fixed into Xcel's model – the CEO Preferred Plan added 420 UCAP MW of solar hybrid and 250 UCAP MW of battery storage hybrid.

Figure 1 of CEOs Initial Comments shows the cumulative resource additions under the Xcel's Supplement Plan, the CEO Preferred Plan, and the Revised Xcel Preferred Plan. Note that new wind, in orange, is not selected until the 2030s.

Overall, the CEO Preferred Plan had lower costs than Xcel's Preferred Plan under both the PVSC and PVRR measures. The cost comparison is shown in Tables 4 and 5 of CEOs Initial Comments. The lowest cost scenario run was the CEO Preferred Plan with Lower Interconnection Costs.[63]

[63] CEO initial comments, Tables 4 and 5, p. 17.

2. CEO Alternate Plan

After Xcel withdrew the Sherco CC from its Preferred Plan, EFG performed additional EnCompass modeling around Xcel's Alternate Plan, which largely aimed to (1) evaluate solar-battery hybrid resources, with revisions to Xcel's battery storage cost assumptions, and (2) examine whether the Lyon County or Fargo CTs were economic or needed for reliability.

As discussed previously, Xcel assumed different combinations of resource options available to EnCompass in the three-year replacement windows for the Sherco and King retirements. A primary change EFG made was to allow the model to consider options in addition to Xcel's resources available. Specifically, Xcel allowed combinations of solar, solar + wind, and solar + wind + CTs to replace the retiring coal units (see Table 13 of Xcel's Reply Comments). EFG considered these resource options but also allowed solar-battery hybrid options to replace King and standalone battery and solar-battery options to replace Sherco. Table 1 of CEOs' Supplemental Comments shows a comparison of resources available to EnCompass.

Table 1. Resources Available for Replacement Capacity in CEOs' Alternate Plan compared to Xcel's Alternate Plan

	Resources available in Xcel's Alternate Plan			Additional resources made available in CEOs' Alternate Plan	
Gen-Tie Line Capacity replacement	Solar	Wind	CT	Battery Storage standalone	Solar-Battery Hybrid
Sherco 1*	X	X	X	X	X
Sherco 2*	X			X	X
Sherco 3*	X	X	X	X	X
AS King*	X				X
NSP System	X	X	X	X	X

**Replacement capacity for the gen-tie lines*

Thus, EFG made four main changes to Xcel's model when developing the CEO Alternate Plan:

- Solar-battery hybrids were allowed as a resource option.
- Standalone battery storage was allowed as a Sherco replacement resource.
- The battery storage option was set to 321 MW, but with the partial unit setting in EnCompass, EnCompass could optimize the battery size.
- Consistent with the CEO Initial Comments, EFG used battery cost assumptions that were consistent with information from project bids received by the Public Service Company of New Mexico. EFG stated this was reasonable since the cost reflects actual bids received for battery projects.[64] Staff notes that for Supplemental Comments, EFG showed two

[64] Staff notes that Xcel's battery storage cost assumptions decline over time to reflect technological improvements, but they are considerably higher than the CEOs' assumption. For a battery unit with a 2027 COD, for example, Xcel's base battery cost is $16.41/kW-month, and $11.18/kW-mo. at the low end of the range.

new projects that were even lower in price, but to maintain consistency with modeling performed in Initial Comments, EFG kept the original assumptions.

Table 1. PNM Battery Storage Pricing with New Projects provided in EFG's CEO Reply Comment Report

	With ITC $/kW-Mo	No ITC $/kW-Mo
Jicarilla	$9.97	$13.47
Arroyo	$7.46	$10.08
Bidder #5	$7.99	$10.80
Bidder #2	$7.70	$10.41
New Bid	$6.68	$9.03
New Bid	$7.56	$10.22
Avg	**$7.89**	**$10.67**

An excerpt of Table 4 of the EFG report shown below is the CEO Alternate Plan expansion plan by resource type from 2024-2029. Staff added red boxes to indicate whether resources are on the Sherco gen-tie, the King gen-tie, or standalone system resources.

CEO Alternate Plan Capacity Expansion Plan (2024-2029)

Resource	2024	2025	2026	2027	2028	2029
Solar (standalone) Sherco tie line	750	50	-	-	-	-
Solar (hybrid) Sherco tie line	-	-	-	800		-
Battery (hybrid) Sherco tie line	-	-	-	200		-
Battery (standalone) Sherco tie line	-	-	-	11		4
Wind Sherco	-	-	-	-	200	300
Solar (hybrid) King tie line	-	-	-	-	800	-
Battery (hybrid) King tie line	-	-	-	-	200	-
Wind (system)	-	-	-	-	-	-
Solar (hybrid) system	-	-	-	-	-	-
Battery (hybrid) system	-	-	-	-	-	-
Solar (standalone) system	-	300	-	-	-	-
Battery (standalone) system	-	-	-	101	-	-

For the 2027-2029 timeframe, in total, Xcel's Alternate Plan includes more standalone solar, but the CEO Alternate Plan adds more solar overall because EnCompass selected solar hybrids. The CEO Alternate Plan also has more battery storage and slightly more wind. Table 7 of the EFG report compares the Xcel Alternate Plan to the CEO Alternate Plan by resources added in 2027-2029.

Table 7. Resources Added (MW) Between 2027 and 2029

Resource Type	CEO Alternate Plan	Xcel Alternate Plan as Filed
Solar	-	1150
Solar Hybrid	1600	-
Battery Storage	116	-
Battery Storage Hybrid	400	-
Wind	500	400
New CTs	-	800

As shown in Table 7, because the CEO Alternate Plan results in 450 MW more solar, 116 MW standalone storage, 100 MW more wind, and no CTs, CEOs recommend modifying Xcel's Alternate Plan by either:

- replacing the CTs with 450 MW of solar hybrid, 400 MW of battery storage hybrid, 116 MW of standalone storage, and 100 MW of wind in 2027-2029, consistent with the CEOs Alternate Plan; or

- designating the 800 MW of CT capacity in 2027 and 2029 as "generic firm peaking," consistent with Xcel's treatment of additional CT capacity in the Alternate Plan.

However, in Xcel's January 12, 2021 Joint Decision Options letter, Xcel noted that the Company and CEOs support a finding that there will be a need for approximately 800 MW of generic firm dispatchable resources between 2027 and 2029.

While the CEOs' recommended modifications are limited to the 2027-2029 timeframe, Table 5 of the EFG report below shows the total resources added over the full, 15-year planning period for the CEO Alternate Plan compared to Xcel's Alternate Plan. The trade secret information reflects the blackstart units. The notable difference is that the CEO plan adds 2,270 MW of battery storage and no CTs, whereas Xcel's plan adds 2,670 MW of firm peaking and 250 MW of battery storage.

Table 5. Capacity Expansion Plan Comparison (2020 – 2034)

Resource	CEOs' Alternate Plan (MW)	Xcel's Alternate Plan (MW)
Battery Storage	2270	250
Wind	2800	2650
Solar	3800	3150
[TRADE SECRET BEGINS.... ....TRADE SECRET ENDS]		
New CT	0	800
Generic Firm Peaking	0	1870

To simplify the cost comparison of each plan, EFG decided to keep Xcel's proposed repowered brownfield and greenfield units as fixed units as a partial reoptimization, using the four modeling changes listed above. Then a PVSC calculation was run for the CEO Alternate Plan as well. Table 6 of the EFG report shows that, of the three, Xcel's Alternate Plan is the highest cost plan, and the CEO Alternate Plan is the lowest cost plan.[65]

Table 6. PVSC Comparison of Alternate Plans (Millions of Dollars)

	PVSC ($M)
CEO Alternate Plan	$39,179
CEO Partial Reoptimization of Xcel Alternate Plan	$39,240
Xcel Alternate Plan as Filed	$40,461

B. Citizens Utility Board of Minnesota – "Consumers Plan"

1. Resource Additions

CUB proposed its "Consumers Plan," which was developed with support from Vibrant Clean Energy (VCE) using its WIS:dom® - P capacity expansion model (WIS:dom).[66] VCE's modeling captures the entire Eastern Interconnection, which allows the simultaneous evaluation of Xcel's service territory along with neighboring regions and the entirety of MISO. WIS:dom is optimized to meet load on a five-minute basis throughout every hour of the modeled year. The Consumers Plan determined a pathway from 2020 through 2040 with results outputted every five years.[67]

Perhaps the most notable distinctions between the Consumers Plan and other alternative plans – aside from being developed with a different modeling software – are the co-optimization of the distribution system with the bulk power system and the substantial amount of new wind, made possible by its transmission system buildout. The Consumers Plan adds 3,000 MW of wind by 2025, with another 1,400 MW of wind by 2030. The Consumers Plan also adds a significant amount of utility-scale and distributed solar, as shown in the table below.

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[65] Staff notes that the PVSC of Xcel's Alternate Plan ($40,461, in millions) can be seen in Table 1-1 of Xcel's Reply Comments.

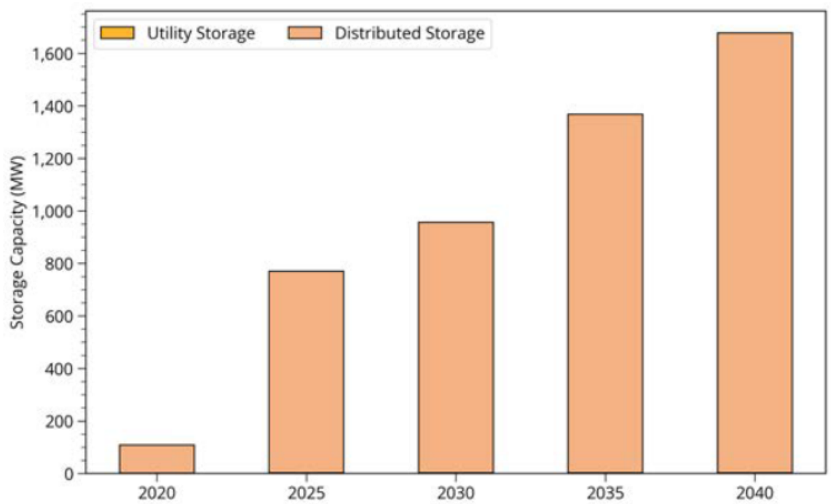
[66] CUB explained that the WIS:dom® - P modeling suite is a state-of-the-art capacity expansion and production cost model that has been used in jurisdictions across the country, including in nationally recognized energy systems studies, utility Integrated Resource Plans, and at the Midwestern Independent System Operator (MISO).

[67] CUB explained that because WIS:dom does not resolve interim years, it is impossible to pinpoint exact retirement dates.

Table 6. Resources Added in CUB Consumers Plan, 2020-2030

Resource Type	2020 - 2025	2026 - 2030
Wind	3,000	1,400
Utility-Scale Solar (UPV)[68]	1,400	2,100
Distributed Solar (DPV)	350	740

Appendix A of CUB's Initial Comments is VCE's report, "A 'Consumers Plan' For Clean Energy Across NSPM By 2035." Figure 3.8 of the VCE report shows utility-scale and distribution-scale storage installed over the investment periods, and notably, all new storage is distribution-scale. In total, WIS:dom installs about 800 MW of distribution-scale storage by 2025 and 1,400 MW of distribution-scale storage by 2035.



On pages 22-23 of its report, VCE explained the relationship between distribution-scale storage and distributed solar (DPV), as well as why DPV is preferred over utility-scale solar (UPV):

> The distribution-scale storage discharges behind the 69-kV substation during periods of high demand to reduce the peak load seen by the utility-scale generation. The distribution-scale storage works with the distributed solar, which makes up 45% of the total solar deployed in the NSPM region (see Fig. 3.9). WIS:dom-P chooses to install significant DPV apart from UPV in the NSPM territory as there is limited space for UPV deployment and its ability to work with the distributed storage to ameliorate the need for distribution upgrades during the electrification process. Therefore, DPV and distributed storage help meet demand in the NSPM territory with lower transmission losses, while deferring distribution system upgrades.

As noted above, the Consumers Plan adds 1,400 utility-scale solar by 2025 – which includes the 460 MW Sherco Solar project – and another 2,100 MW of utility-scale solar from 2025-2030.

[68] This includes the 460 MW Sherco Solar project.

After 2030, almost all new solar is distributed solar,[69] which occurs because the best utility-scale solar sites are taken, some distribution system upgrades are deferred, and there are avoided transmission costs.

A feature of the WIS:dom model is that it simultaneously co-optimizes utility-scale generation, storage, transmission, and DER. On page 3 of its Initial Comments, CUB described co-optimization as follows:

> Even while operating with over 75% variable renewable energy, power needs are met at every five-minute interval of the planning period. A critical component of ensuring this level of reliability is better utilization of both the distribution system and the transmission network. The Consumers Plan unlocks increased efficiency through the co-optimization of the distribution system with the bulk power system. This co-optimization, which allows distributed energy resources (DER) to reshape demand and utility-scale generation to serve that demand more effectively, results in a total of 2.6 GW of distributed PV and 1.4 GW of distributed storage by 2035.

CUB continued on pages 15-16:

> The Consumers Plan utilizes WIS:dom's unique ability to co-optimize distribution-level system operations with grid-scale generation and transmission. WIS:dom disaggregates DER on the distribution system, and then presents those technologies at the "grid edge," where electricity passes across to the bulk power system (on transmission lines larger than 69 kV). This results in two distinct model features: DER coordinates to shape and shift demand, while utility-scale generation and transmission coordinate to meet load that appears at the "grid-edge." The concept and modeling parameters are further described in Section 2.2 of the attached report. Further, WIS:dom's distribution co-optimization minimizes peak load and overall energy flow while minimizing back-flow of energy from the distribution system to the utility-interface. Inherent in this optimization is a calculation of hosting capacity, which WIS:dom calculates based on the nodal load, distributed DPV penetration, and load flexibility available. The model can increase and pay for increased hosting capacity through system upgrades or the installation of distributed storage. Using this information, as well as detailed weather, rooftop, and available land analysis, the model sites optimal combinations of distributed PV and storage to minimize system costs, meet load reliably, and prevent back-flow.

The table below shows total resource additions by 2035 under the Consumers Plan:

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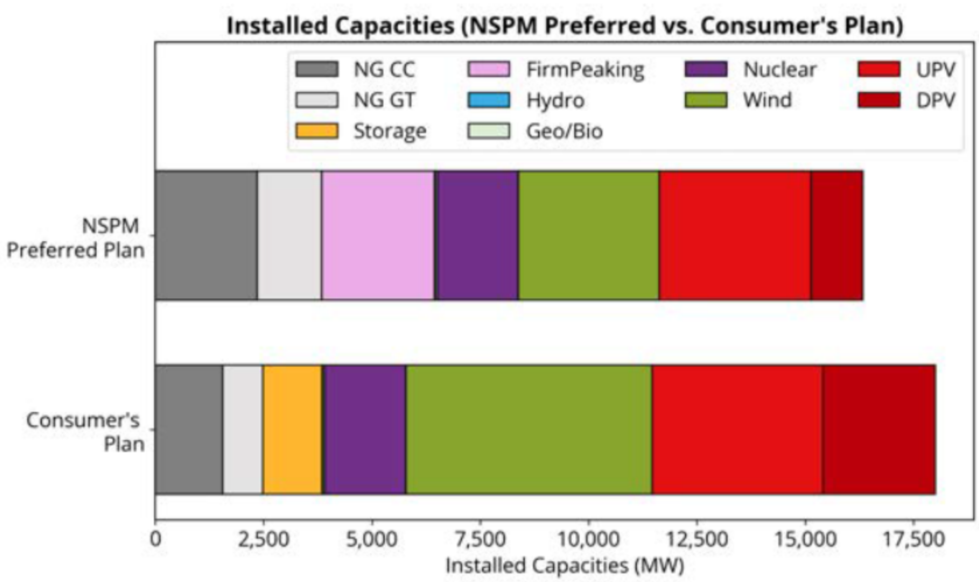
[69] VCE explained, "The median installed DPV size by 2040 is 880 kW within a 3-km grid cell indicating most of the installed DPV is rooftop solar. However, there are some larger DPV installations reaching a maximum value of 40 MW in a 3-km grid cell. It is important to note that the model does not have resolution beyond the 3-km grid size and hence the exact make-up of these larger DPV installation is not known. However, they do indicate WIS:dom-P deploys some community solar farms to meet demand behind the 69-kV substation."

Table 7. CUB Consumers Plan, Total Resource Additions

Resource Type	Additions by 2035 (MW)
Wind	5,682
Utility-Scale Solar (UPV)[70]	3,940
Distributed Solar (DPV)	2,589
Storage (7 hours)	1,368

By 2025, all of Xcel's coal plants (2,683 MW) are retired, and about 550 MW of existing natural gas CT capacity is retired. By 2040, another 186 MW of gas CT capacity is retired, leaving 741 MW of CTs. In addition, all existing nuclear is retained until 2040.

Figure 3.7 below compares installed capacities in Xcel's Supplement Plan (year 2034) to CUB's Consumers Plan (year 2035). The Consumers Plan has about 1,900 MW less natural gas generation by 2035, and the removed natural gas is replaced by wind, solar and storage. Xcel's EnCompass modeled selected 2,600 MW of firm peaking generation by 2034, but the Consumers Plan shows that load can be met reliably using renewable energy and extending Monticello and Prairie Island. By 2035, 89 percent of generation is carbon-free.



2. Transmission Buildout

CUB's modeling indicates that Xcel must pursue an aggressive transmission expansion plan in order to achieve its clean energy goals. In CUB's modeling, WIS:dom begins with 2018 existing generation and transmission topology. WIS:dom then determined the initial transmission required to meet load constrained by existing generators and existing transmission paths. Throughout the investment periods, transmission is added for optimal capacity expansion and dispatch.

70 This includes the 460 MW Sherco Solar project.

By 2035, in the Consumers Plan, Xcel builds 227 MW of new transmission connecting Xcel's territory to other areas of Minnesota. While WIS:dom models all incremental transmission capacity as new infrastructure, and models its cost as new infrastructure, much of this additional capacity could be achieved through existing infrastructure upgrades or grid enhancing technologies such as dynamic line rating. On top of this 227 MW of additional transmission capacity within Minnesota, WIS:dom also builds an additional 1,804 MW of transmission capacity connecting Xcel's territory to Iowa by 2035.

Figure 3.24 of VCE report shows the incremental inter-state transmission buildout (in MW) over the investment timeframe.

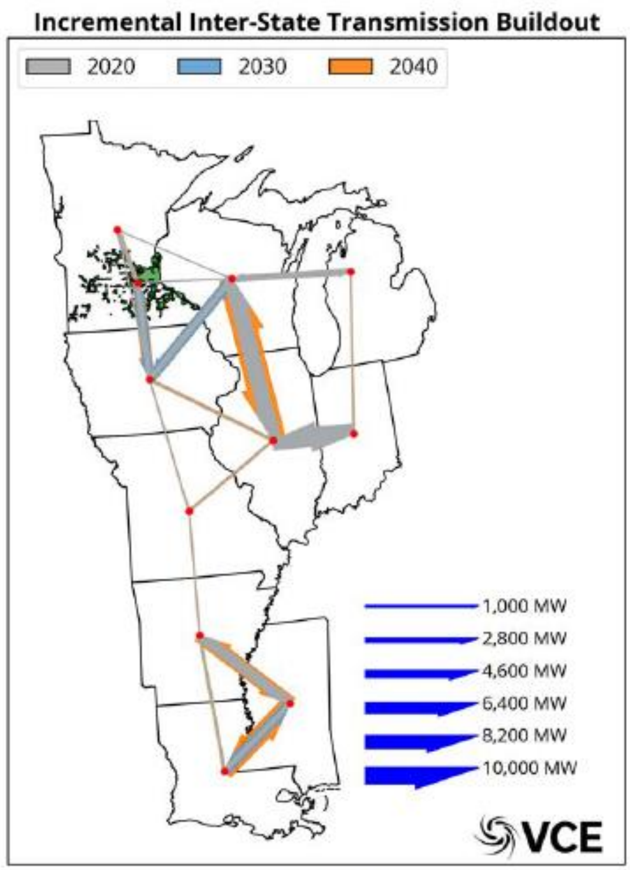


Figure 3.24: Incremental inter-state transmission added over the investment periods.

Figure 3.25 shows the transmission capacity (in MW) built from the NSPM region to other states over the investment periods.

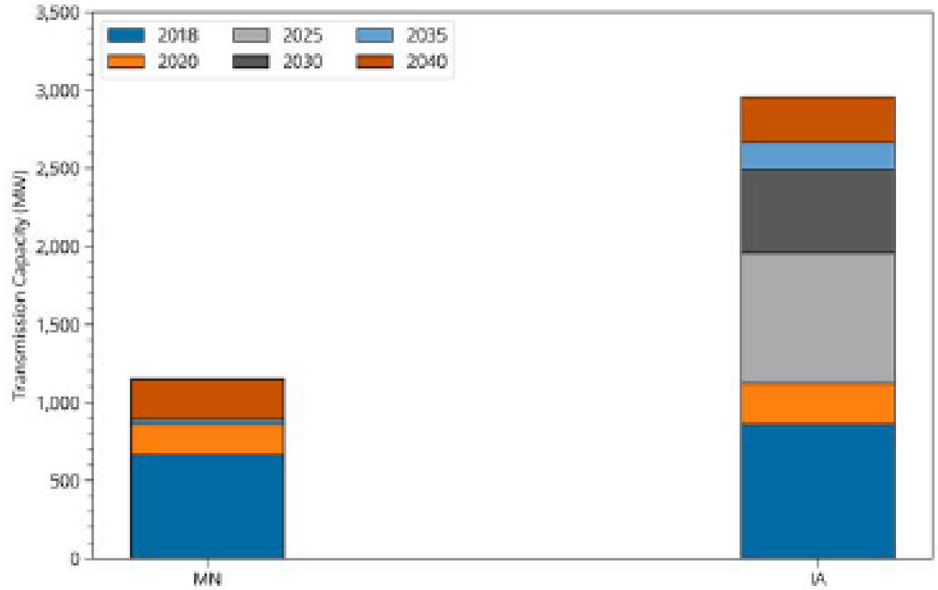


Figure 3.26 shows additional GW-miles of in-territory transmission built by Xcel after 2018 over the investment periods. A significant amount of new transmission is built between 2020 and 2030 to connect the large buildout of wind and solar and growing load due to electrification. New transmission built after 2030 slows as the rate of new generation also slows.

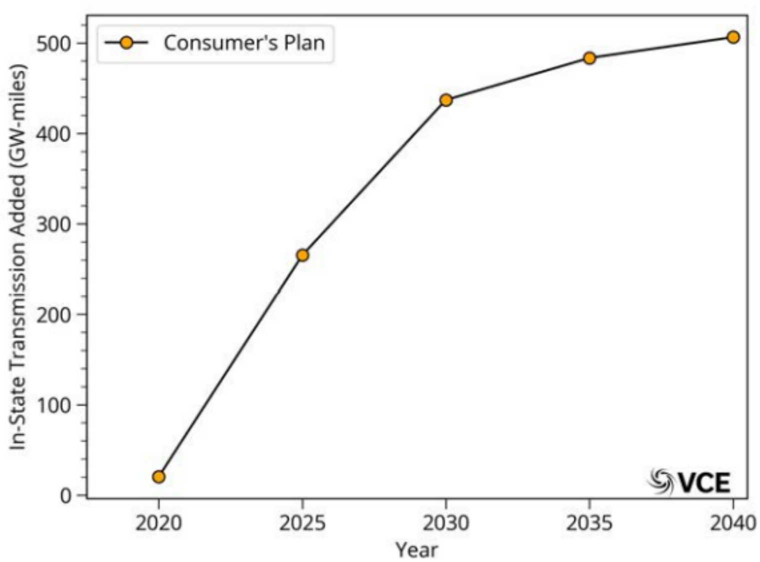


Figure 3.26: In-state transmission built in the NSPM region over the investment periods.

3. Siting

As noted above, WIS:dom modeled the entire MISO footprint. Figure 2.1 shows the modeled footprint in shaded blue, with the NSPM territory overlaid in yellow. For siting purposes, distributed solar and distributed storage was restricted to within the boundaries of the NSPM territory, but utility-scale generation was not. The left portion of the table is the WIS:dom area, and existing generators and transmission is on the right.

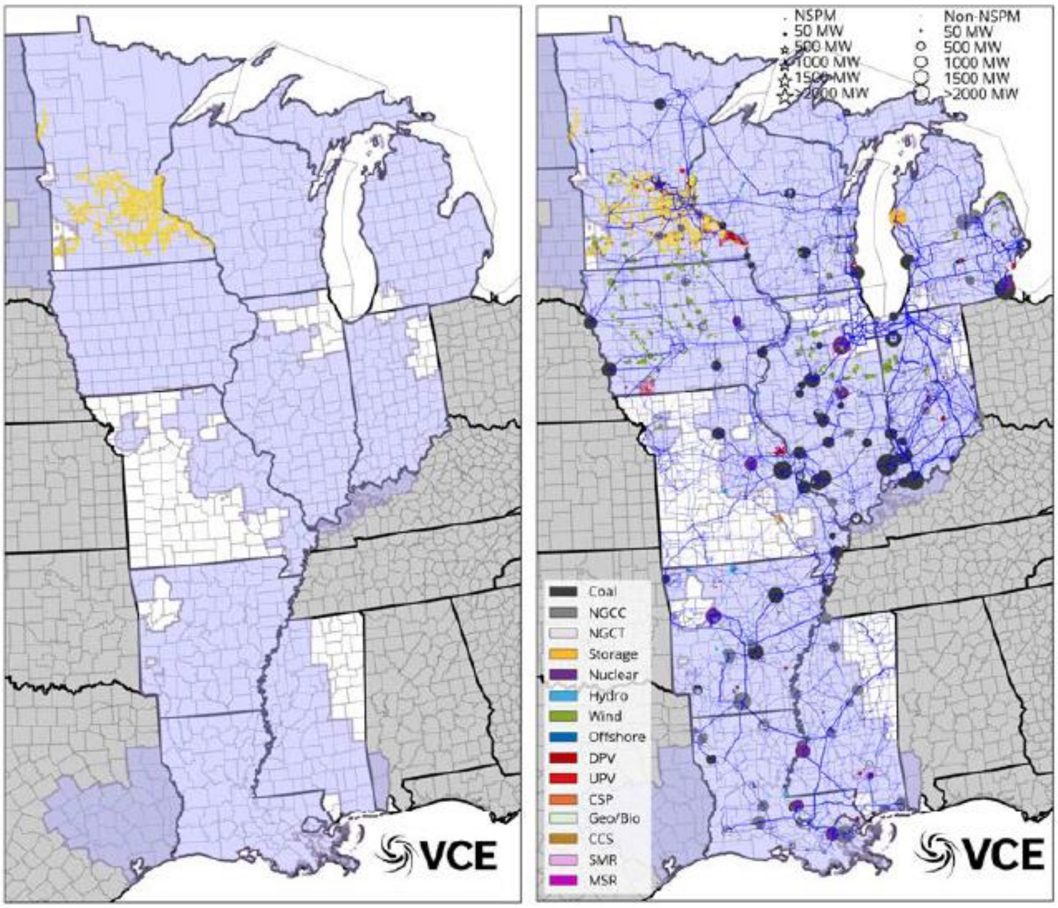


Figure 2.1: WIS:dom-P model domain (left) and existing generators with transmission (right).

When making siting decisions, WIS:dom takes several criteria into account to determine the optimal siting for the generators, including expected generation and distance from load. As a result of co-optimization of the distribution system, the amount of utility-scale solar and distribution-scale solar is about the same. The northern portion of the model domain deploys significant levels of solar in spite of the lower capacity factors due to higher correlation with the summer loads profiles. WIS:dom also installs utility-scale outside of Xcel's service territory due to lack of available space inside its service territory. As noted above, distributed generation is limited to the NSPM territory as this generation is installed behind the 69-kV substation. Most of the wind generation is sited outside of Xcel's service territory due to lack of space for large wind projects. Section 3.7 of the VCE report shows the siting of the capacity expansion performed for the Consumers Plan.

4. Rate Impacts

Over the 20-year analysis period, CUB estimates that the Consumers Plan will yield approximately $6.5 billion in electricity savings. Total system costs fall steadily through 2025 as Xcel's coal units are retired. In the subsequent years, total system costs rise as wind and solar are added; however, Xcel total system costs are offset through revenues from exports during periods of excess generation.

5. Jobs

In 2020, the electricity sector supported 20,000 direct full-time equivalent (FTE) jobs in the NSPM region. By 2040, the electricity sector in the NSPM region supports approximately 72,750 FTEs, a 350 percent increase over 2020 job numbers. A majority of the new jobs created are in the solar industry, with distributed solar being the largest job creator due to its higher labor requirements per MW installed.

6. Electrification

According to CUB, Xcel's IRP fails to evaluate the economy-wide electrification measures that are necessary for the state to achieve its greenhouse gas reduction goals, as well as how electrification can benefit Xcel's system and its ratepayers. The Consumers Plan applies enhanced demand-side resources and increased electrification to ensure both Minnesota and Xcel are on a path to achieve their aggressive decarbonization goals.

By 2035, the Consumers Plan serves 49.4 terawatt-hours (TWh) of total load, compared to 45 TWh in Xcel's Preferred Plan, an increase of 9 percent. Electrification of transportation is the largest contributor to demand growth. Other components of electrification such as space and water heating contribute only small portions to demand growth as most of the increase in demand is offset by EE.

C. Department of Commerce Preferred Plan

For the Department's Supplemental Comment modeling, the Department relied solely on EnCompass, whereas in earlier rounds of modeling the Department used both Strategist and EnCompass. The general process the Department employs to review utility modeling in IRP proceedings is outlined below.

1. Obtain a base case file and the commands necessary to recreate the utility's scenarios;
2. Re-run the base case to see whether the outputs match, which ensures that the Department is working with the correct files;
3. Review the base case's inputs and outputs for reasonableness;
4. Create a new base case if the Department determines changes are reasonable;
5. Run additional scenarios to evaluate ratepayers risks and alternative futures;
6. Assess the results to establish a new preferred case; and
7. Test the robustness of the preferred case.

Table 6 of the Department's Supplemental Comments provides a comprehensive list of the final components of Department's updated base case compared to Xcel's corresponding assumptions in the Company's updated base case. While not all are listed here, some include:

- using of mid-externalities/regulatory costs, rather than Xcel's high externalities/regulatory costs;
- using the Department's forecasts rather than Xcel's; and
- increasing nuclear construction cost inputs and the escalation factor.[71]

[71] Staff also notes that previous rounds of the Department's modeling already included Commission-approved

The next two sections will explain two important modifications the Department made to Xcel's modeling, which were a decrease to the load forecast and an increase to nuclear costs.

1. Load Forecast

The Department concluded that both Xcel's demand and energy forecasts are systematically biased and have consistently overstated its demand and energy requirements over time. Table 4b of the Department's Initial Comments below show Xcel's forecast vintages of October 2008 to July 2018. Percent error was calculated for the first forecast year, the second forecast year, and so on. The Department observed that one year out Xcel's average error equals 2.1 percent, three years out Xcel's average error is about 3.6 percent, by five years out Xcel's average error is 7.1 percent, and by seven years out Xcel's average error is 11 percent. Importantly, the Department noted that this reflects forecast *bias*, not forecast error, because over time a reasonable forecast should be too high some of the time and too low some of the time. Xcel's forecasts have consistently overstated its resource need.

Table 4b: Xcel's Demand Forecast Error, October 2008 to Present (percent)

Forecast Vintage	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Oct-08					10.0%	12.2%	6.7%	2.0%	4.8%	5.3%	14.5%	18.6%	14.7%	21.8%	17.3%
Apr-09						9.2%	3.1%	-1.7%	0.3%	0.4%	8.6%	12.1%	8.1%	14.5%	9.9%
Oct-09						0.1%	1.6%	-2.4%	0.3%	0.3%	8.4%	11.7%	7.5%	13.6%	8.9%
Apr-10							0.2%	-3.0%	0.3%	1.5%	11.0%	15.4%	12.0%	19.3%	15.3%
Jul-10							0.6%	-2.8%	0.4%	1.0%	10.1%	14.0%	10.1%	16.9%	12.4%
Apr-11								-5.0%	-2.4%	-2.4%	6.4%	10.5%	7.0%	13.8%	9.6%
Sep-11								1.8%	-2.8%	-3.3%	5.1%	9.0%	5.4%	12.0%	8.0%
Mar-12									-5.4%	-5.4%	2.7%	6.4%	2.9%	9.5%	5.6%
Jul-12									0.0%	-3.2%	4.9%	8.7%	4.9%	11.4%	7.2%
Mar-13										-3.7%	4.0%	7.5%	3.6%	10.0%	5.9%
Jul-13										-2.4%	5.7%	9.4%	5.5%	11.8%	7.3%
Sep-13										-3.7%	4.1%	7.2%	3.5%	10.0%	5.9%
Mar-14											5.0%	8.2%	4.4%	10.7%	6.6%
Aug-14											0.0%	7.9%	4.5%	10.9%	6.7%
Mar-15												7.2%	4.0%	10.5%	6.2%
Jul-15												6.6%	3.6%	10.0%	5.8%
Mar-16													1.5%	8.1%	3.6%
Aug-16													1.3%	7.4%	3.0%
Nov-16														7.4%	2.9%
Mar-17														7.5%	2.8%
Jul-17														6.9%	2.9%
Mar-18															1.3%
Jul-18															2.0%

In Initial Comments, the Department recommended that to address persistent bias in Xcel's forecasting, the Commission should require Xcel to file and use a forecast from an independent consultant in any future regulatory proceedings.

Because the Department did not have time to examine the technical details of Xcel's forecast, the Department needed to establish an acceptable base forecast for long-term planning purposes. The Department decided the best way to accomplish this would be to adjust the

resources, such as the Wind Repower Portfolio, so no updates to baseline resources were necessary.

base case forecast to reflect increasing error over time, which meant adjusting the demand forecast downward by 2 percent in the early years of the forecast, then 4 percent, and later 8 and 12 percent in later years of the planning period. The energy forecast had less error than the demand forecast and thus received less of an adjustment. Tables 5 and 7 of the Department's Initial Comments show the demand and energy forecast adjustments.

Table 5: Demand Forecast Adjustment (percent)

Forecast Year	Average Forecast Error	Department Forecast Adjustment	Difference
1	2.1%	2.0%	-0.1%
2	2.8%	2.0%	-0.8%
3	3.6%	4.0%	0.4%
4	4.9%	4.0%	-0.9%
5	7.1%	8.0%	0.9%
6	8.7%	8.0%	-0.7%
7	11.0%	12.0%	1.0%
8	12.6%	12.0%	-0.6%
9	14.1%	12.0%	-2.1%
10	13.5%	12.0%	-1.5%
11	17.3%	12.0%	-5.3%
12		12.0%	
13		12.0%	
14		12.0%	
15		12.0%	

Table 7: Energy Forecast Adjustment (percent)

Forecast Year	Average Forecast Error	Forecast Adjustment	Difference
1	-0.1%	0.0%	0.1%
2	0.1%	0.0%	-0.1%
3	1.4%	2.0%	0.6%
4	2.4%	2.0%	-0.4%
5	3.7%	4.0%	0.3%
6	4.9%	4.0%	-0.9%
7	7.3%	8.0%	0.7%
8	9.5%	8.0%	-1.5%
9	11.3%	10.0%	-1.3%
10	12.5%	10.0%	-2.5%
11	12.3%	10.0%	-2.3%
12		10.0%	
13		10.0%	
14		10.0%	
15		10.0%	

In Reply Comments, Xcel identified five contributors to the historical forecast variance:

1. **Weather**;
2. **Wholesale load** (all of Xcel's forecasts prior to July 2012 assumed wholesale load that ultimately was not served by the Company);

3. **Large customer load changes** (in 2011, Xcel had several reductions in large customer load that previous forecasts assumed would be served load);
4. **Combined Heat and Power** (in 2017 a customer began serving part of its load from CHP); and
5. **Energy efficiency** (energy efficiency achievements have consistently been greater than assumed).

Xcel's response to the Department's analysis was that forecast variances are within ranges typically captured by a sensitivity analyses; as noted above, the Department countered that forecast errors are expected to randomly distributed over time, not consistently too high or too low most of the time.[72] Nevertheless, to conserve Department staff resources, the Department simply accepted Xcel's forecasting adjustments for planning purposes only, but even after accepting Xcel's adjustments, the revised data did not remove the bias. The Department found:

- about 90 percent of the demand forecast variances are still too high, and
- about 65 percent of the energy forecast variances are still too high.

After accepting Xcel's adjustments, the Department recalculated the demand and energy forecast adjustments as shown in Tables 1 and 2 below. This led to a 2 percent increasing to 10 percent reduction to the demand forecast starting in Year 3, and a 0 percent increasing to 6 percent reduction to the energy forecast starting in Year 5.

Table 1: Demand Forecast Variance and Adjustment

Forecast Year	Remaining Average Forecast Error	Department Forecast Adjustment	Difference
1	1.1%	0.0%	1.1%
2	1.6%	0.0%	1.6%
3	1.7%	-2.0%	-0.3%
4	2.3%	-2.0%	0.3%
5	3.0%	-2.0%	1.0%
6	3.6%	-4.0%	-0.4%
7	4.6%	-4.0%	0.6%
8	5.9%	-6.0%	-0.1%
9	7.7%	-6.0%	1.7%
10	8.9%	-10.0%	-1.1%
11	12.0%	-10.0%	2.0%
12		-10.0%	
13		-10.0%	
14		-10.0%	
15		-10.0%	

[72] Department supplemental comments, p. 11.

Table 2: Energy Forecast Variance and Adjustment

Forecast Year	Remaining Average Forecast Error	Department Forecast Adjustment	Difference
1	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%
3	0.6%	0.0%	0.6%
4	1.0%	0.0%	1.0%
5	1.4%	-2.0%	-0.6%
6	1.9%	-2.0%	-0.1%
7	3.2%	-4.0%	-0.8%
8	4.5%	-4.0%	0.5%
9	5.7%	-4.0%	1.7%
10	6.6%	-6.0%	0.6%
11	5.5%	-6.0%	-0.5%
12		-6.0%	
13		-6.0%	
14		-6.0%	
15		-6.0%	

The Department considers Xcel's Reply Comments to have partially explained the poor quality of the Company's forecasts, and therefore instead of recommending using an independent consultant's forecast, the Department will continue to review Xcel's forecasts for accuracy in future proceedings as time and resources allow.

2. Nuclear Costs

This section will briefly summary the Department's nuclear cost changes. These adjustments are discussed in more detail in the Monticello section of the briefing papers.

In the Commission's March 26, 2019 Order, the Commission authorized the Commissioner of the Department of Commerce to seek authority from the Commissioner of Management and Budget to incur costs for specialized technical professional investigative services under Minn. Stat. § 216B.62, subd. 8, to continue investigating the causes of cost increases related to Xcel's Prairie Island and Monticello nuclear facilities and to assist the Department in Xcel's upcoming IRP and rate case proceedings. The Department retained Global Energy & Water Consulting, LLC. (Global) to review Xcel's analysis of its nuclear plant license extension or retirement scenarios, the capital and O&M costs and budget forecasts, short- and long-term fuel storage, and plant performance.

Based upon Global's report, the Department made two adjustments to Xcel's reference case modeling inputs. The Department's first adjustment was to escalate Xcel's O&M cost inputs. The Department explained its reasoning as follows:

> Global's report noted that Xcel has little ability to influence portions of the nuclear plant's O&M costs. Further, Xcel's forecasted O&M inflation costs (growing about 0.25 percent above inflation) is far below the level achieved by the Company historically any lengthy time period going back to the mid-1990s. While the Department agrees with Global that the Company's O&M costs assumptions are "aggressive but attainable" the modeling risk resulting from the inputs is one-sided—similar to Xcel's energy and demand forecasting discussed above. Therefore, to remedy the asymmetric nature of the risks, the Department included an additional one percent annual escalation (CAGR) in O&M costs in the base case changes. This leaves the Department's modeled O&M inflation rate lower than the best level achieved by the Company in the past for a long duration—the escalation in real dollars resulting from the Department's changes is about half the best long-term escalation achieved by the Company. Thus, the Department's inputs assume Xcel will be able to manage O&M costs very well for the foreseeable future.[73]

The Department's second adjustment was to increase Xcel's capital cost inputs. Global's report stated, "Global's primary concern with the capital forecast is Xcel's use of contingencies. Xcel does apply contingencies; however, these contingencies appear to be under forecast, particularly for capital items in outlying years."[74] To reflect this planning and budgeting risk directly in the modeling inputs, the Department increased Xcel's nuclear capital cost estimates by 10 percent as part of the base case changes.

3. Base Cases

The Department tested three different versions of its updated base case:
- Base case 1: All of the Department's changes;
- Base case 2: No forecast changes; and
- Base case 3: No nuclear cost changes.

In addition, the Department ran scenarios covering all possible combinations of baseload retirements:
- King—early and normal;
- Sherco unit 3—early and normal;
- Monticello—early, normal, and extended; and
- Prairie Island—early, normal, and extended.

In total, the Department ran 36 scenarios. Each scenario was run through the following 14 "contingencies" (which Xcel calls sensitivities):
- high, middle, low, and no externalities/CO_2 regulatory costs;
- high and low solar prices (±$5 per MWh);

[73] Department initial comments, p. 58.

[74] Global report, p. 8.

- high/low wind prices (±$5 per MWh);
- high/low natural gas/spot market prices (per Xcel); and
- high/low energy and demand forecast.

Recall that from Xcel's modeling, Xcel re-tested scenarios of particular importance for the Company's Reply Comments: Scenario 1 (Reference Case); Scenario 9 (Preferred Plan), Scenario 4 (Early coal, Nuclear unchanged) and Scenario 12 (Early coal, Extend nuclear).

From the Department's Supplemental Comments, the Department refers to its own list of numbered scenarios (1-36). To avoid confusion, staff will refer the Department's scenarios as "DOC Scenarios."

The Department's recommended plan is DOC Scenario 11. However, a consistently least-cost scenario is DOC Scenario 21. The Department recommends DOC Scenario 11 by taking into account non-cost factors, such as CO_2 emitted (DOC Scenario 11 emits less CO_2) and socioeconomic concerns (DOC Scenario 21 closes Monticello early, while DOC Scenario 11 closes Monticello at the end of its current license).

There were four particular scenarios that were consistently the best ranked plans:

- DOC Scenario 21—ranked among top 6 scenarios 13 times, in all but:
    - low gas prices and no externalities.

- DOC Scenario 23—ranked among top 6 scenarios 10 times, in all but:
    - low gas prices, low externalities, low externalities with low regulatory cost, mid externalities, and no externalities.

- DOC Scenario 11—ranked among top 6 scenarios 12 times, in all but:
    - low gas prices, low externalities with low regulatory cost, and no externalities.

- DOC Scenario 29—ranked among top 6 scenarios 10 times, in all but:
    - low gas prices, low externalities, low externalities with low regulatory cost, mid externalities, and no externalities.

DOC Scenarios 21, 23, 11, and 29 had the following baseload retirement plans:

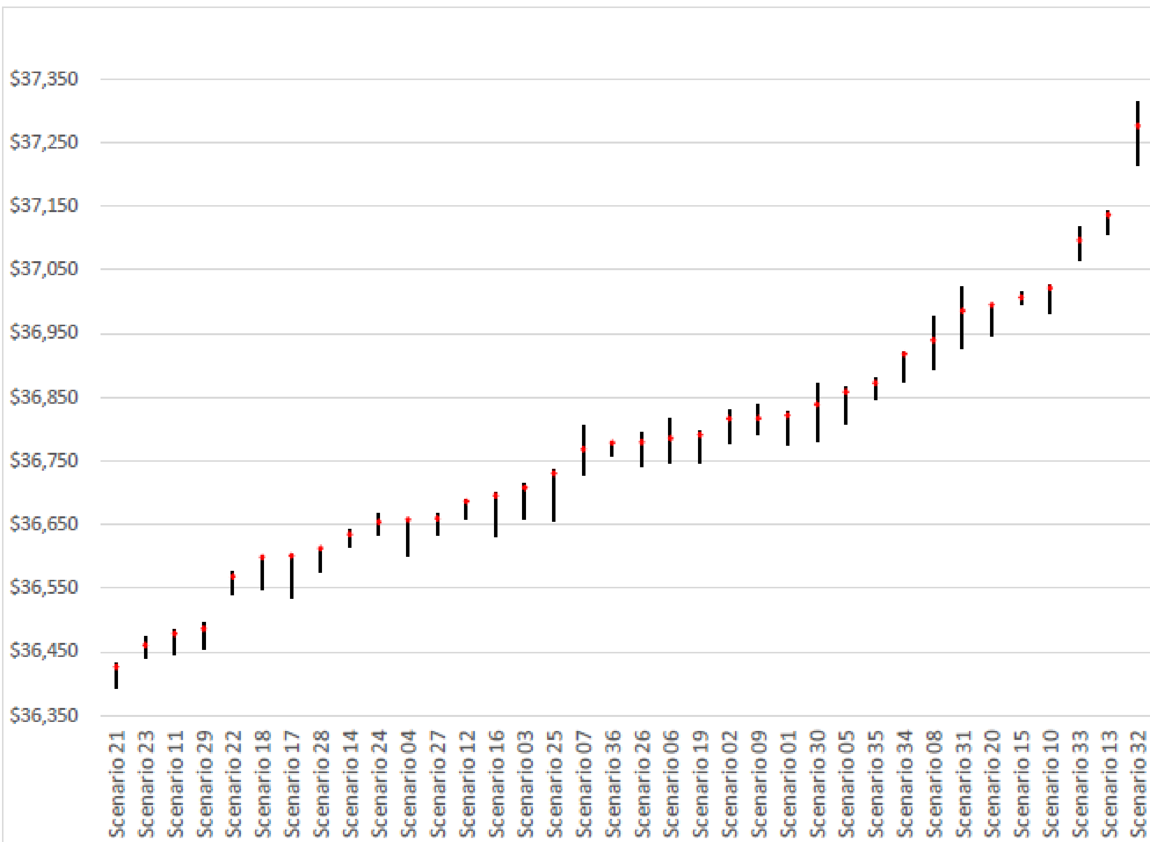
King Retirement	Sherco Retirement	Monti Retirement	Prairie Isl. Retirement	Scenario Number
Early	Early	Early	Extend	21
Early	Early	Norm	Extend	11
Norm	Early	Norm	Extend	29
Norm	Early	Early	Extend	23

4. Modeling Observations

This section provides a brief list of modeling observations discussed in the Department's Supplemental Comments:

- The Department determined that DOC Scenario 21 was clearly the least-cost scenario, and DOC Scenarios 11, 29, and 23 were indistinguishable under "mixed integer programming" (MIP) convergence tolerance calculations. Chart 2 below shows that Scenario 21 is clearly the least cost scenario under the MIP convergence tolerance calculations. The range of acceptable costs for each scenario is represented by the black bar and the feasible plan that was selected is represented by the red dot.

Chart 2: MIP Convergence Results (million dollars PVSC)



- DOC Scenarios 11 and 21 both add 1,870 MW of capacity units and 2,050 MW of wind units between 2020 and 2034. The difference is that Scenario 11 adds 2,400 MW of solar while DOC Scenario 21 adds 2,550 MW. For the five-year action plan (2020 to 2024), both plans add 700 MW of solar and no wind or capacity units.

- In years 2026-2031, DOC Scenario 11 has more spot market price risk than DOC Scenario 21 due to much larger net sales, triggered by the presence of Monticello.[75]

- Among the baseload scenarios, extending the life of Prairie Island is the best-performing retirement option. Among the bottom half of the scenarios, extending the life of Monticello is clearly the worst-performing retirement option.

- Removing the nuclear fixed cost increases clearly leaves extending the life of Prairie Island as the best-performing retirement option. Normal or extended retirement dates for Monticello performed better, with four of the top six scenarios all involving either a normal or extended retirement date. However, as shown by an excerpt of Table 8a, early or normal closure of Monticello still ranked in the top four plans without adjusting nuclear costs. Also note that DOC Scenarios 21, 11, 29, and 23 rank in the same order in the No Nuclear Adjustment base case as in the All Changes Incorporated base case:

Table 8a: Retirement Scenarios Ranked, No Nuclear Adjustment (top half

Plan Rank	King Retirement	Sherco Retirement	Monti Retirement	Prairie Isl. Retirement	Scenario Number
1	Early	Early	Early	Extend	21
2	Early	Early	Norm	Extend	11
3	Norm	Early	Norm	Extend	29
4	Norm	Early	Early	Extend	23
5	Early	Early	Extend	Extend	12

- By removing the Department's forecast adjustment, DOC Scenarios 21, 11, 23, and 29 are still ranked in the top five. Normal Sherco 3 retirement appeared in one of the top ranked scenarios.

Table 9a: Retirement Scenarios Ranked, No Forecast Adjustment (top half

Plan Rank	King Retirement	Sherco Retirement	Monti Retirement	Prairie Isl. Retirement	Scenario Number
1	Early	Early	Early	Extend	21
2	Early	Early	Norm	Extend	11
3	Norm	Early	Early	Extend	23
4	Early	Norm	Early	Extend	22
5	Norm	Early	Norm	Extend	29

- Tables 7b, 8b, and 9b of the Department's Supplemental Comments show the worst-performing plans under the All Changes Incorporated, No Nuclear Adjustment, and No Forecast Adjustment base cases. Scenario 32 ranked at the bottom of every base case, and the retirement plan is shown below:

[75] Net sales in DOC Scenario 11 are larger by between about 800 and 2,700 GWh annually during 2026 to 2031.

Plan Rank	King Retirement	Sherco Retirement	Monti Retirement	Prairie Isl. Retirement	Scenario Number
36	Norm	Early	Extend	Early	32

- As can be seen by the tables above, extending Prairie Island was consistently in the top ranked baseload plans. However, Xcel does not propose extending Prairie Island in this IRP. The highest any Prairie Island—Normal scenario ranked was sixth, which was when DOC Scenario 18 ranked sixth in the All Changes Incorporated base case. DOC Scenario 18 included King—Early, Sherco 3—Early, and Monticello—Early:

Table 7a: Retirement Scenarios Ranked (top half)

Plan Rank	King Retirement	Sherco Retirement	Monti Retirement	Prairie Isl. Retirement	Scenario Number
6	Early	Early	Early	Norm	18

- Regarding solar pricing, the Department's analysis found that small decreases in solar prices through 2029 are immaterial. Importantly, however, small *increases* in solar prices have a large impact; when solar prices were increased by $5/MWh, solar was eliminated from the five-year action plan (through 2024). The Department recommends that this modeling result be taken into account in subsequent resource acquisition proceedings.

- No capacity units (modeled both as CT units and as battery units) were added in any run during the five-year action plan.

5. Solar and Wind Resources

DOC Scenario 11 adds the following amounts of wind and solar (note these are expansion units selected by EnCompass, which is separate from Xcel's distributed solar forecast):

Table 10: Renewable Expansion Unit Capacity (MW)

Year	Solar	Wind
2020	-	-
2021	-	-
2022	-	-
2023	-	-
2024	700	-
2025	100	-
2026	-	-
2027	700	-
2028	200	-
2029	-	-
2030	350	350
2031	-	800
2032	-	900
2033	250	-
2034	100	-

There is about 425 MW of distributed solar in the five-year action plan (years 2020-2024). Thus, the Department recommends the Commission approve a five-year action plan that requires Xcel to acquire approximately 1,125 MW of solar capacity by 2024, contingent upon prices being reasonable (1,125 MW is the sum of 700 MW of EnCompass units in 2024 and about 425 MW of distributed solar by 2024). Solar resources beyond the action plan will be reanalyzed in the next IRP.

As noted above, small increases in solar pricing are significant. Table 13 below shows that under DOC Scenario 11, the High Solar contingency adds 900 MW less solar overall relative to the base case. Also, the 700 MW addition in 2020-2024 is deferred to 2025-2029.

Table 13: Scenario 11 Solar Expansion Unit Additions (MW)

Time Frame	Base Case	Y–Low Solar	Change from Base	Z–High Solar	Change from Base
2020-'24	700	750	50	-	(700)
2025-'29	1,000	1,050	50	900	(100)
2030-'34	700	900	200	600	(100)

The Department recommends the Commission approve a five-year action plan that does not include any wind additions. (Wind is not selected until 2030, so new wind can be reanalyzed in the next IRP.)

In summary, while the Department's recommendations were limited to the five-year plan, the table below shows the 2020-'29 timeframe for supply-side EnCompass units for the base case of DOC Scenario 11.

Department Preferred Plan – DOC Scenario 11

Resource Type	2020-'24	2025-'29	Total
Solar	700	1,000	1,700
Wind	-	-	-
Peaking (CT proxy)	-	374	374

6. Gen-ties

The Department considered the feasibility of Xcel's ability to acquire at least 700 MW of new solar projects in the near future, and in doing so, the Department reviewed the latest data in the MISO generation interconnection queue (GIQ) in the region. Table 12 of the Department's Supplemental Comments shows solar projects classified as Done, Active, or Withdrawn. The Department observed that of the three most recent Definitive Planning Phase (DPP) groups that have Done projects, at least 75 percent of the solar projects in the upper Midwest withdrew.

Table 12: Status of Solar Projects (MW)[50]

DPP Group	Done	Active	Withdrawn	Percent Withdrawn
DPP-2015-FEB	162.5	-	-	0.0%
DPP-2015-AUG	-	-	24.4	100.0%
DPP-2016-FEB	50.0	-	50.0	50.0%
DPP-2016-AUG	-	-	-	0.0%
DPP-2017-FEB	50.0	-	173.0	77.6%
DPP-2017-AUG	182.5	-	575.0	75.9%
DPP-2018-APR	250.0	130.0	2,617.5	87.3%
DPP-2019-Cycle	-	1,050.0	930.0	47.0%
DPP-2020-Cycle	-	1,824.0	1,156.0	38.8%
DPP-2021-Cycle	-	2,440.0	129.5	5.0%

At this withdrawal rate, to acquire the amount of solar EnCompass selects in 2024, Xcel would have to acquire a large fraction of all of the solar projects in the region that make it through the MISO GIQ, which the Department argued is unrealistic. The Department concluded that acquiring projects outside of the MISO GIQ is necessary and re-using Xcel's existing generation interconnection rights at the Sherco and King sites is reasonable. Thus, the Department recommends the Commission approve Xcel ownership of the Sherco and King gen-tie lines plus renewable resources added on the lines.

D. Sierra Club – "Clean Energy for All Plan"

1. Resource Additions

Sierra Club proposed its Clean Energy for All Plan as an alternative plan. Resources proposed in Sierra Club's plan include:

- 1,350 MW of standalone utility-scale solar (450 MW in 2027 and 900 MW in 2030);

- 4,320 MW of wind beginning in years 2027 and 2026;
- 4,070 MW of utility-scale solar paired with 1,080 MW of battery storage starting in 2031;
- 1,020 MW of standalone battery storage beginning in 2027;
- 2,050 MW of community solar; and
- 1,851 MW of distributed generation solar.

The table below compares the Clean Energy for All Plan to Xcel's Alternate Plan in planning years 2024-2030. Notably, in the near-term, Xcel's Alternate Plan consists of several peaking resources, with no wind additions until 2028. Sierra Club's Clean Energy for All Plan adds some solar and battery peaking capacity beginning in 2028, but there is significantly more wind added in Sierra Club's five-year action plan, with nearly 1 GW of wind added in 2026-2027. A distinguishing feature of Sierra Club's plan, which partially explains why there are fewer large-scale peaking resources, is that the Clean Energy for All Plan adds much more distributed solar.

Year	Sierra Club "Clean Energy for All Plan"	Xcel Energy "Alternate Plan"
2024		700 MW solar
2025		600 MW solar 60 MW Firm Dispatchable
2026	480 MW wind	260 MW Firm Dispatchable
2027	480 MW wind 450 MW solar 40 MW battery	600 MW solar 374 MW Firm Peak
2028	60 MW battery 80 MW wind	200 MW wind 400 MW solar 374 MW Firm Dispatchable
2029	280 MW battery 400 MW wind	400 MW wind 400 MW solar 374 MW Firm Dispatchable
2030	640 MW battery 1,200 MW wind 900 MW solar	200 MW storage 950 MW wind 100 MW solar 374 MW Firm Dispatchable

2. Summary of Capacity Expansion Modeling Assumptions

Sierra Club contracted with Synapse Energy Economics, Applied Economics Clinic, and Grid Strategies to review Xcel's EnCompass capacity expansion modeling assumptions. As shown by an excerpt of Table 6 of Sierra Club's comments, Synapse modeled ten scenarios on behalf of Sierra Club. Each scenario was run with and without the extension of the Monticello nuclear license. Staff notes the following:

- The gray-shaded scenarios reflect Sierra Club's replication of Xcel's preferred scenario and the preferred scenarios with Elk Creek Solar, Deuel Harvest Wind, and Mower County Repower ("Approved Projects"). These scenarios kept the Sherco CC as a fixed unit in the model.
- The purple-shaded scenario removed the constraint that locked-in the Sherco CC and updated Xcel's renewable energy assumptions by using the NREL 2020 ATB.
- Scenarios 4-10 applied a "Corrected RE Base," which starts with the NREL 2020 data, and then corrects all errors identified by Sierra Club's experts.
- Scenario 9 is the Clean Energy for All Plan, which uses a DG/CSG forecast developed by the Distributed Solar Coalition.

Scenario
Xcel's Preferred Plan ("Scenario 9") (1)
Xcel's Preferred Plan + Approved Projects (2)
NREL2020 + Unforce Sherco CC (3)
Corrected Base RE Base/Unforce Sherco CC (4)
Corrected RE Base + Force Sherco CC (5)
Corrected RE Base + Increased DG (6)
Corrected RE Base + Increased DG+CSG (7)
Corrected RE Base + VCE Interconnection (8)
Corrected RE Base + Increased DG+CSG+VCE Interconnection (9) (Sierra Club Preferred Plan or "Clean Energy For All Plan")
Corrected RE Base + Increased DG+VCE Interconnection (10)

Sierra Club's modeling adjustments are discussed on pages 32-41 of its Initial Comments. In addition updating the NREL assumptions, other modifications that used to create the Corrected RE Base in Scenario 4-10 described above include:

- Increasing the wind capacity factor from 47% to 50%.
- Using a 20-year project life for battery storage, instead of the 15 years in the "NREL 2020" case or 10 years used in Xcel's modeling.
- Applying in some scenarios the Distributed Solar Coalition's "Increased DG" forecast noted above, whereby DG adoption was attached to an incentive level, rather than Xcel's approach of treating distributed solar as strictly a utility cost.
- Applying in some scenarios an "Increased CSG" forecast, based on recent average CSG installations.

- Assuming for Scenarios 8-10 interconnection costs of $146/kW, instead of Xcel's assumptions of $500/kW for wind and $200/kW for solar.[76] The $146/kW assumption was calculated using VCE's model used in CUB's Consumers Plan. Also, interconnection costs were financed in the same manner as the rest of the capital costs, rather than Xcel's approach of layering interconnection costs on top of the NREL assumptions.

Sierra Club also argued that Xcel's assumption of a 50 percent solar capacity value is too low, and the assumption that solar capacity value will decline by 2 percent per year is unjustified. Pages 65-69 of Sierra Club's comments describe its analysis of the capacity value for solar resources on the NSP system. This analysis examined load and solar output data from Xcel's three largest solar plants during Xcel's 100 highest load hours over the last three years, which was used to calculate an average and marginal solar capacity value. By estimating a reduction to net load as incremental MW of solar are added to the system, Sierra Club found that the average and marginal solar capacity value "remains at 58% until solar nameplate capacity penetrations reach 16% of Xcel's peak load, or 1,368 MW,"[77] which suggests Xcel's modeling understates the capacity value of solar. Despite this finding, Sierra Club's modeling experts chose to maintain as much consistency with Xcel's modeling as possible, so Sierra Club's modeling used Xcel's assumption. However, Sierra Club noted that "a better approach would be to model solar's capacity value over time as a function of Xcel's and MISO's solar penetration and overall resource mix."[78]

3. Distributed Solar

Sierra Club argued that Xcel's distributed solar forecast is too low and ignores Xcel's ability to encourage additional DG adoption. After 2023, Xcel assumes that only around 15 MW of new distributed solar (including CSG) is added per year. This is a flawed assumption because it assumes Xcel has no control over distributed solar levels. One of Xcel's rationale for minimal DG growth is the elimination of new funding for Solar*Rewards, but Xcel's solar programs have shown clearly that customers respond to incentives and are willing to use their private capital to build a resource to the net benefit of all of Xcel's customers if those incentives are available. Therefore, Sierra Club recommends the Commission "order Xcel to bring forward a proposal in 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."[79]

Another reason why Xcel's distributed solar forecast has essentially no growth is because distributed solar has a lower capacity factor and higher levelized costs than utility-scale solar. Sierra Club responded that treating distributed solar strictly as a utility cost is flawed:

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[76] Staff notes that Xcel's assumed interconnection cost for renewables on Sherco for the gen-tie is $140/kW.

[77] Sierra Club comments, p. 66.

[78] Sierra Club, p. 68-69.

[79] Sierra Club supplemental comments, p. 39 (Recommendation No. 6)

it would be inappropriate to use the levelized cost of distributed solar in the modeling, because this is not the cost paid by the utility and the utility's ratepayers. Instead, most of the capital cost of distributed solar is borne by the individual purchasing the system (e.g., the homeowner installing solar on their roof). Distributed solar can also provide other high-value benefits such as reducing the need for distribution system upgrades and avoiding the need for new transmission. [80]

In several of Sierra Club's modeling runs, Sierra Club used DG and CSG forecasts developed by the Distributed Solar Coalition. Rather than modeling distributed generation as a fixed forecast, the Distributed Solar Coalition modeled distributed solar similar to how Xcel models its EE bundles, where bundles are made available for selection at different price points. For Sierra Club's analysis, "EnCompass was allowed to select the economic amount of DG to add in a given year based on program incentive level."[81]

Table 5 shows Distributed Solar Coalition's "Increased DG" forecast. For example, their forecast estimates that 33 MW of additional DG solar (on top of Xcel's base DG forecast) will be built in Minnesota in 2021 if no incentive is offered, and that an additional 14 MW of DG could be built with a $10/MWh incentive, 17 MW with a $20/MWh incentive, and so on. Put another way, 47 MW (33 MW + 14 MW) of additional DG would be on Xcel's system in 2021 with a $10/MWh incentive, but DG would increase as the incentive level increases.

Table 5. "Increased DG" Forecast: Cumulative Distributed Generation Resource Options, by Price (MW AC) – Incremental Additions, from left to right

Year	$0/MWh	$10/MWh	$20/MWh	$30/MWh	$35/MWh	$40/MWh
2021	33	14	17	21	12	14
2022	60	26	33	40	23	26
2023	65	33	41	51	29	33
2024	74	40	51	63	37	41
2025	89	49	62	77	45	50
2026	109	60	75	94	55	61
2027	136	72	90	112	66	73
2028	169	86	108	134	78	86
2029	211	102	127	158	92	101
2030	262	120	149	184	107	118
2031	322	140	174	214	124	137
2032	393	163	201	247	143	157
2033	476	188	231	283	163	179
2034	572	215	265	322	185	203

Sierra Club argued that Xcel's CSG forecast in unreasonable because CSG essentially flattens in 2023, reaching 863 MW in 2034—only 22 MW more than the level forecasted for 2023. This is inconsistent with recent trends, and well-below even what is in the existing queue:

[80] Sierra Club comments, p. 25.

[81] Sierra Club comments, p. 38.

> Over the last two years, community solar in Minnesota has been growing at a rate of approximately 167 MW per year. Another 483 MW of community solar projects are in Xcel's queue. Just the addition of the projects in the existing queue would far exceed Xcel's community solar forecast for 2034. If community solar projects continue to grow at the same rate as in the last two years, Xcel could be expected to reach 1,400 MW of community solar by 2024, and over 3,000 MW by 2034.[82]

Sierra Club's "Increased CSG" assumption was based on CSG installations from the end of 2018 through July 2020. On average, there were 140 MW of new CSG installations annually. Xcel reported 1,308 MW of available hosting capacity for CSG as of August 2020, so the combination of existing installations and available hosting capacity leads to a maximum of 2,046 MW of CSG potential. Therefore, Sierra Club modeled 140 MW of incremental CSG per year until that potential maxed out the hosting capacity in 2030, which to Sierra Club makes its assumption conservative since there will likely be an increase in hosting capacity in the next nine years.

Sierra Club's scenarios began with Xcel's CSG and DG forecast – which, again, stays relatively flat – then Sierra Club applied the Increased DG + Increase CSG forecasts to arrive at about 3,900 MW of DG+CSG by 2034. Staff reproduced Table 21 of Sierra Club's Initial Comments below to show the 2022-2030 timeframe and the final year of the planning period.[83]

Table 21. Incremental CSG and DG additions in Sierra Club's Preferred Plan vs. Xcel's

	2022	2023	2024	2025	2026	2027	2028	2029	2030		2034
Xcel CSG	787	841	852	853	854	855	857	858	859		863
Xcel DG	109	123	138	152	166	180	194	208	222		276
SC CSG	277	363	491	630	769	907	1,045	1,183	1,188		1,188
SC DG	125	145	171	378	460	553	652	767	899		1,575
Total	1,299	1,472	1,651	2,013	2,249	2,495	2,747	3,016	3,167		3,903

4. Interconnection Costs, Transmission, and New Wind

Sierra Club stated that Xcel's interconnection costs are unreasonably inflated and create a barrier to the model selecting renewable energy. Sierra Club provided the following examples to justify their argument:

- The recent MISO queue does not account for future changes in transmission system flows due to generation retirements and additions that may alleviate some transmission constraints.[84]
- Battery storage resources could be strategically-sited to reduce or even eliminate interconnection upgrade costs.

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[82] Sierra Club comments, p. 26.

[83] 863 (Xcel CSG) + 1,188 (SC CSG) = 2,051 MW CSG; 276 (Xcel DG) + 1,575 (SC DG) = 1,848 MW DG.

[84] Sierra Club comments, p. 17.

- A recent investigation of transmission capital costs conducted by Lawrence Berkeley National Laboratory (LBNL), examining 27 GW of utility-scale wind and solar projects, found that average wind and solar interconnection costs were much lower than Xcel's estimates. Xcel's assumption is merely a snapshot in time and does not reflect a large sample of projects over a longer historical timeframe.

Additionally, Xcel's approach of layering a separate calculation for interconnection costs, with a different financing mechanism, on top of the levelized costs from NREL ATB was flawed. Sierra Club also noted that under a typical PPA structure, a developer would finance the interconnection costs along with the other capital costs.

While Sierra Club's Clean Energy for All plan adds a substantial amount of wind, the model doesn't select it under 2026. In other words, neither Sierra Club's nor Xcel's preferred plans add new wind resources prior to 2026, so it is unreasonable to assume the transmission system will look the same well into the future. The issues Xcel raises to justify high interconnection costs may not be an issue by the time Sierra Club's plan begins to add wind. Sierra Club cited dynamic line ratings, power flow control devices, and topology optimization techniques as ways to quickly increase interconnection capacity on the existing transmission system.

5. Need Assessment

Sierra Club's modeling experts did not analyze or critique Xcel's load forecast; however, Sierra Club agreed with the Department that Xcel's need could be overstated.[85] Sierra Club supported the Department's recommendation to reduce the peak load and energy forecast "because Xcel has a history of significantly overestimating load growth."[86]

Sierra Club noted other factors which could reduce Xcel's need. One could be PPA extensions; Xcel assumed that no existing PPAs would be extended, even though Xcel has historically extended a large share of expiring PPAs. For example, Xcel assumes the 350 MW diversity sharing agreement with Manitoba Hydro expires in 2025, but this contract was extended when the predecessor agreements expired in 2015, which have been in place since 1987 and 1991. In total, according to Sierra Club, the assumption that all existing PPA will expire could overstate Xcel's need for peaking resources by around 2,000 MW.[87]

Moreover, while Sierra Club's EnCompass modeling used Xcel's 16.7 percent wind capacity value, Sierra Club believes it is reasonable to account for a higher wind capacity value, due in part to wind technology improvements. If, for example, wind accreditation increased from 16.7 percent to 20 percent, Xcel's accredited capacity would increase by 139 MW.

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[85] Sierra Club reply, p. 4.

[86] Sierra Club reply comments, p. 4.

[87] Sierra Club comments, p. 29.

6. Supplemental Comments Modeling

In Supplemental Comments, Sierra Club maintained its recommendation that the Commission adopt the Clean Energy for All Plan. However, Synapse conducted additional modeling on behalf of Sierra Club to examine the Alternate Plan with and without Xcel's greenfield CTs. This was necessary because Xcel hardwired the greenfield CT plants into its modeling runs, preventing the model from determining whether they are a reasonable, least-cost resource addition. According to Sierra Club, "Xcel's pre-selection of CT resources subverts that optimization process in its Alternate Plan and, while the Company has shown that this Alternate Plan is clearly superior to its previous Supplemental Plan, it has not proven that it is in the public interest."[88]

Synapse left Xcel's hard-coded aeroderivative turbines (2025), reciprocating engines (2026), and the brownfield CT (2026) unchanged, but this was mostly due to limited time, not general support for the units.

In the updated modeling, Synapse corrected a limited number of Xcel's input assumptions by:

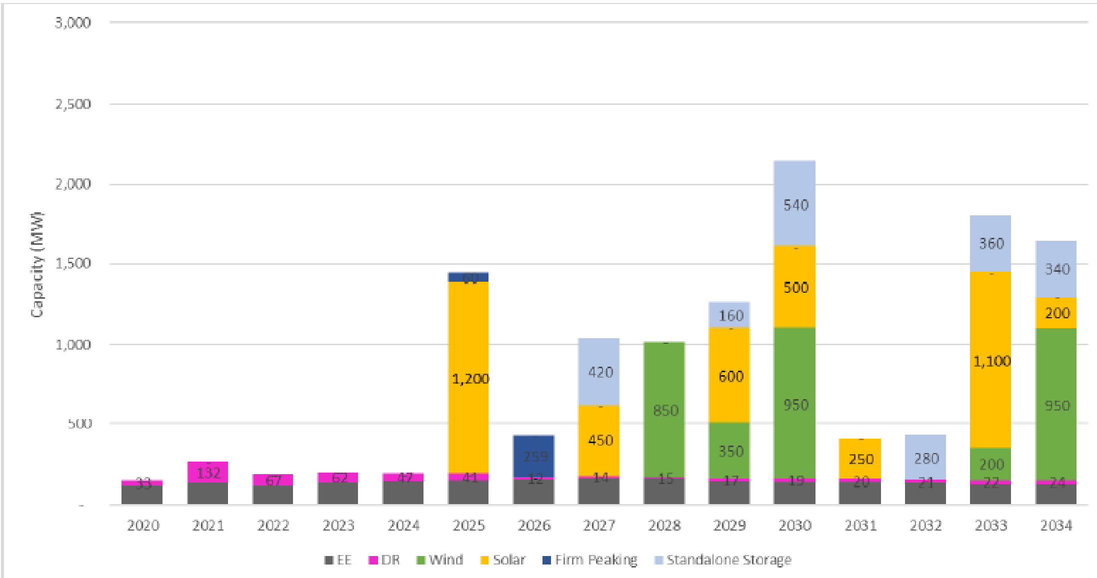
- using NREL 2021 data (instead of Xcel's NREL 2019 data);
- decreasing battery sizes to 20 MW while increasing the operating life to 15 years; and
- removing the hard-coded dates for the CTs at Fargo (2027) and Lyon County (2029).

Figure 6 below shows incremental resource additions in the No Forced CT Scenario. (Again, this is not Sierra Club's Clean Energy for All Plan.) Major resource additions in the No Forced CT Scenario include:

- 1,200 MW of solar in 2025 (yellow);
- the unchanged firm peaking units in 2026 (dark blue);
- a combination of 450 MW of solar (yellow) and 420 MW of standalone storage in 2027 (light blue); and
- 850 MW of wind in 2028 (green).

[88] Sierra Club supplemental comments, p. 7.

Figure 6. Annual Incremental Resource Additions, No Forced GR CTs scenario



In comparison to the Clean Energy for All Plan, the No Forced GR CTs scenario adds less large solar prior to 2030 (which staff presumes is due to the amount of DG and CSG in Sierra Club's plan), and the No Forced GR CTs scenario does not add wind as early as Sierra Club's plan. Both plans add a considerable amount of standalone storage in the 2027-2030 timeframe.

Sierra Club again argued that Xcel's modeling continued to rely on inflated battery storage costs. In particular, Sierra Club argued that if Xcel is going to use the NREL ATB, the assumptions should be updated to reflect NREL's reduced cost assumptions for battery storage. An excerpt of Table 4 below shows Xcel's levelized battery costs compared to the NREL 2021 battery costs. Also shown is Sierra Club's corrected base and solar hybrid assumptions.

Table 4: Battery Storage Levelized Costs ($/kW-month, nominal)

	Xcel	NREL 2021	NREL 2021 (solar hybrid w/ ITC)	Corrected Base RE	Corrected Base RE (solar hybrid w/ ITC)
2023	$18.18	$11.85	$9.42	$10.21	$8.21
2024	$17.52	$11.20	$8.91	$9.65	$7.76
2025	$16.84	$10.53	$8.71	$9.07	$7.57
2026	$16.63	$10.35	$9.54	$8.92	$8.25
2027	$16.41	$10.17	$9.37	$8.76	$8.10
2028	$16.19	$9.97	$9.19	$8.59	$7.94
2029	$15.95	$9.76	$8.99	$8.41	$7.77
2030	$15.71	$9.54	$8.79	$8.21	$7.60

Sierra Club summarized:

> The purpose of the No Forced GR CT Scenario that was modeled for these Surreply Comments was to test the cost-effectiveness of the Alternate Plan. The No Forced GR CT Scenario was $395 million cheaper than Xcel's Alternate Plan on a PVSC basis. Sierra Club is not offering the No Forced GR CT Scenario as its preferred

> plan. Sierra Club spent over a year developing the Clean Energy For All Plan, which robustly considered all relevant factors and would deliver clean, reliable energy at significantly lower cost than either the Alternate or Supplement Plan. Like the No Forced GR CT Scenario, the capacity optimization that resulted in the Clean Energy For All Plan also does not add any new gas-fired generating units to the long-term resource portfolio. It is this plan that Sierra Club respectfully requests that the Commission adopt.[89]

VII. Further Discussion of Monticello

This section summarizes Xcel's rebuttal and parties' recommendations on Monticello. Several members of the public also submitted comments about Monticello, and these are described later in the briefing papers.

A. Xcel

Xcel argued that the Department's increase of Monticello's O&M costs was contrary to the Global report, which stated on page 3 that the "Monticello forecast budget for O&M spending through 2040 is aggressive but attainable with Xcel's attention to cost controls." Thus, by the Department's own consultant's report, there was no need to escalate the Monticello O&M costs. Similarly, the Department's 10 percent increase to Xcel's capital costs at Monticello was also contrary to the conclusions in the Global report. Global concluded that the Monticello forecast budget for capital spending is well within reason considering the age and the need to prepare the unit for relicensing. The forecast capital spending for the next 20 years is well below capital spending during the last 10+ years.

In Reply Comments, Xcel discussed the results of an updated Scenario 4, which tested early coal retirement while also retiring Monticello in 2030:

> carbon reduction achievement under Scenario 4 is consistently less favorable than either of the cases where nuclear units are extended. This occurs in part due to the loss of Monticello's carbon-free generation capabilities – rated at over 640 MW, and operating at well over a 90 percent capacity factor – and in part because the model selects incremental firm dispatchable capacity (modeled as gas CTs) to fill the capacity need Monticello's retirement would create.[90]

Xcel also noted that the Department used the mid-point externality costs, whereas the Company used high externality and high regulatory cost of carbon values in its base PVSC modeling. While the mid-point externality costs are within the range approved by the Commission, Xcel's believes using the mid-point scenario disadvantages nuclear and any other clean energy resources.

[89] Sierra Club supplemental comments, p. 2, footnote 1.

[90] Xcel reply comments, p. 144.

B. CEOs

CEOs support the extension of Monticello to 2040. In modeling conducted for Reply Comments, CEOs examined the CEO Preferred Plan with higher nuclear costs. As shown in Table 2 of CEOs' Reply Comments, under base case conditions, which includes the Monticello extension, the CEO Preferred Plan was least-cost. With the higher contingency costs, the Monticello extension increased the cost of the CEO Preferred Plan by about 0.7 percent and was slightly more costly than the No Monticello Extension run. However, according to CEOs, other benefits and considerations concerning decarbonization and reliability outweigh the slightly higher cost.

Table 2. PVSC Comparison of Monticello Runs (Millions of Dollars)

Run Description	CEO Base Case
CEO Preferred Plan Additional Nuclear Costs	$38,740
CEO Preferred Plan (includes Monticello extension to 2040)	$38,482
No Monticello Extension	$38,605

C. CUB

In CUB's Consumers Plan, the Monticello and Prairie Island units are retained through 2040. Xcel's five-year action plan includes initiating a Certificate of Need proceeding in Minnesota and a SLR process with the NRC, which CUB supports.

D. Department

In the Department's analysis, with or without the nuclear adjustment, the Monticello extension was frequently a poor performing plan in EnCompass. Therefore, the Department concluded that the 2030 retirement date for Monticello is reasonable, but the Department will revisit this conclusion in Docket No. 21-668, Xcel's Certificate of Need petition for additional dry cask storage at Monticello.

As discussed previously, the Department made adjustments based on the Global report. Notable portions of Global's report include Charts 1 and 2 of the Global report on page 10 (Prairie Island) and page 12 (Monticello), respectively. Also, Charts 4 and 5 show Xcel's O&M forecasts for those units. Finally, pages 57-58 of the Department's Initial Comments include a discussion of nuclear costs and modeling adjustments.

Global's primary concern with the capital forecast was Xcel's use of contingencies. Global stated "Xcel does apply contingencies; however, these contingencies appear to be under forecast particularly for capital items in outlying years." Thus, the Department created a higher cost contingency to reflect this risk that was absent from Xcel's modeling.

Global observed that forecasted capital spending for the next 20 years is well below capital spending during the last 10+ years. Global stated, "[t]he high costs during the 2010 to 2014 period unfortunately were necessary to return the Unit to a condition of operating excellence."[91] In the forecast, two minor spikes in capital spending occur in 2028 and 2033 to cover the cost of additional dry cask storage needed to continue on-site spent fuel storage. However, Global noted, "while Xcel is only committing to 10 years of continuing operations at this time, planning for 20 years of additional operations must take into account the unknown factor of NRC requirements for the full extension."

The O&M forecast budgets for Monticello and Prairie Island are "aggressive but attainable," according to Global. Global explained:

> O&M is populated by two major cost categories; fuel and salaries. The fuel cost is based on contracts Xcel maintains with its fuel supplier and there is little Xcel can do to reduce the fuel impact on total O&M. The second cost category of O&M, fixed O&M, is constructed from plant personnel salaries, nuclear program salaries that include nuclear program management salaries, including salaries, personnel benefits and performance incentives. Each of these can be monitored and controlled within the annual budgeting process provided there is adequate monitoring of the O&M spend at the time of expenditures.[92]

Global found that the capital and O&M forecast used in the IRP filing are within reason, but since O&M costs are largely outside of Xcel's control, ratepayers are exposed to some degree of risk. As with the capital cost spending, the Department increased the cost to reflect ratepayers' exposure to risk. Moreover, the Department noted that Xcel's forecasted O&M inflation costs (growing about 0.25 percent above inflation) is far below the level achieved by the Company historically.

Overall, Global concluded:

> At this point in time Xcel's challenge is to continue to budget O&M and capital dollars to maintain the production costs at this lower threshold. It truly becomes a very large-scale balancing act to achieve the most economic production costs; too little O&M budget will negatively impact the daily operations, too little capital will impact the plant assets decreasing the plant reliability and availability, too much capital spend will impact revenue requirements demanding higher rates.[93]

E. City of Minneapolis

The City of Minneapolis recommends that the nuclear extensions be re-evaluated in the next IRP cycle, with tribal and host community input. Minneapolis, along with many other local jurisdictions within 33 counties, is within the 50-mile Ingestion Planning Zone, which is the priority area of concern in the case of a catastrophic event at Monticello or Prairie Island. Minneapolis cited information from the Minnesota Department of Public Safety, which

[91] Global report, p. 11.

[92] Global report, p. 17.

[93] Global report, p. 13.

discussed nuclear waste-related risks. Minneapolis believes catastrophic event considerations and nuclear waste storage should be considered before approving operating license extensions.

F. Sierra Club

The Clean Energy for All Plan does not extend Monticello. Table 7 of Sierra Club's Initial Comments shows that the No Monti Extension scenario saves $2.2 billion relative to Xcel's Supplement Plan.

Table 7. Comparison of Xcel Preferred Plan and Sierra Club Preferred Plan Under Corrected Assumptions

Scenario	Extended Monti NPV ($million)	No Monti Extension NPV ($million)
Xcel's Preferred Plan ("Scenario 9") Under Sierra Club Corrected Base RE + VCE Transmission Cost Assumptions	$37,395	N/A
Sierra Club Clean Energy For All Plan (Corrected RE Base + DG/CSG/VCE Interconnection)	$35,465	$35,190
Delta from Xcel's Preferred Plan	($1,930)	($2,205)

According to Sierra Club, retiring the Monticello nuclear plant could open up additional interconnection rights that could be re-used for renewable resources, and a gen-tie like the Sherco line could be run from the Monticello site to the wind-rich region of southwest Minnesota. The retirement of Monticello could also potentially reduce the need for voltage and reactive power support on those gen-ties.

In addition to cost, Sierra Club argued that another extension of Monticello would exacerbate the risks of burdening current and future generations with toxic pollution, which impact communities already disproportionately affected by environmental problems. Sierra Club explained:

> Nuclear power plants result in radioactive contamination throughout its life cycle, especially for low income and Indigenous communities living near uranium mines, mills, plants, and storage. In addition, significant safety weaknesses are inherent in reactors' operation. While the chance of an adverse incident is low, the plant's location on the banks of the Mississippi means that an accident would not only impact local communities but also millions of people downstream. The horrific disaster at the Fukushima Daiichi plant – which had a very similar design to Monticello, a boiling water reactor (BWR) nuclear steam supply system (NSSS) – reminded us that fundamental problems with nuclear power have not been addressed.[94]

Sierra Club stated that spent fuel stored in dry casks in an onsite location was intended to be temporary. There is no viable federal repository currently under consideration, and the Commission should not assume a long-term waste storage solution in the foreseeable future.

[94] Sierra Club initial comments, p. 109.

Sierra Club also responded to the claim that nuclear power is "an indisputable solution to climate change" by stating it has a large carbon footprint when the lifecycle of fuel extraction, milling, processing, conversion, enrichment, and transportation is considered.

VIII. Reliability Analysis

A. Xcel

Xcel's filings assess reliability across several metrics. An excerpt of Table 4-1 of Xcel's Reply Comments below shows a few metrics Xcel used to compare the risk and reliability of the Alternate Plan to parties' alternatives.

Table 4-1: Company Plan Performance Across Selected Key Planning Metrics

	Plan	Updated Scenario 9	Alternate Plan
Risk and Reliability	Firm capacity-to-peak demand ratio	0.63	0.58
	Sensitivities - range of cost deltas relative to Reference Case	(1,090) – 124 *Median: (202)*	(2,163)-16 *Median: (544)*
	2034 Native capacity shortfall events	0	0
	2034 expected unserved energy (EUE)	0	0
	Loss of Load Hours (LOLH)	0	0
	2034 maximum 3-hour net load ramp under base assumptions (MW)	4,081	4,484

Xcel explained these metrics from the table above as follows:

- The firm capacity-to-peak demand ratio compares the amount of accredited capacity from firm and dispatchable resources relative to system peak electricity demand. This ratio measures customers' exposure to capacity market risk.

- Native capacity shortfall is derived using hourly output from EnCompass runs. Each hour in which the available generation capacity resources are not sufficient to serve the demand on Xcel's system is a native capacity shortfall. Each group of consecutive hours with a shortfall is an event. Comparing the number of native capacity shortfall events observed provides information on how different portfolios react to more variability and which portfolios result in elevated risk to customers with demand being unhedged in the market.

- Expected Unserved Energy (EUE) refers to the amount of energy that is unmet in a production cost run even with access to MISO market energy and all of the Company's available generation resources.

- Net load ramp is the rate that net load changes during a given time period. Examining net load ramps helps understand grid flexibility needs during a variety of conditions, including during fall and spring months with lower demand levels and early evening hours during periods of higher load, such as summer. In these cases, future portfolios with larger amounts of renewable generation will experience more dramatic ramps due to the intermittent nature of these resources.

1. Firm Dispatchable Resource Need

To begin its discussion of system reliability, Xcel referred to the North American Electric Reliability Corporation (NERC) definition, which divides reliability into two categories:

1. Adequacy – having sufficient resources to provide a continuous supply of electricity at the proper voltage and frequency, virtually all of the time; and

2. Security – the ability of the bulk-power system to withstand sudden, unexpected disturbances caused by manmade physical or cyber-attacks.

Thermal power plants currently serving Xcel's reliability requirements are retiring, and variable and use-limited resources such as wind, solar, and battery storage are increasing. Xcel stated that "grid operators must ensure that, as the mix of resources on the grid continues to evolve, all the necessary resource attributes that ensure the reliable supply and delivery of electricity to customers remain present."[95]

In 2020, roughly 30 percent of Xcel's generation came from renewable sources, and the Alternate Plan proposes approximately 5,800 MW of additional renewable resources. Xcel's reliability analysis evaluated its ability to support these renewable energy additions. The Company's transition to a chronological hourly dispatch model helped inform this analysis, and EnCompass added approximately 3,000 MW of firm peaking, load-supporting resources to ensure a stable system under all conditions.

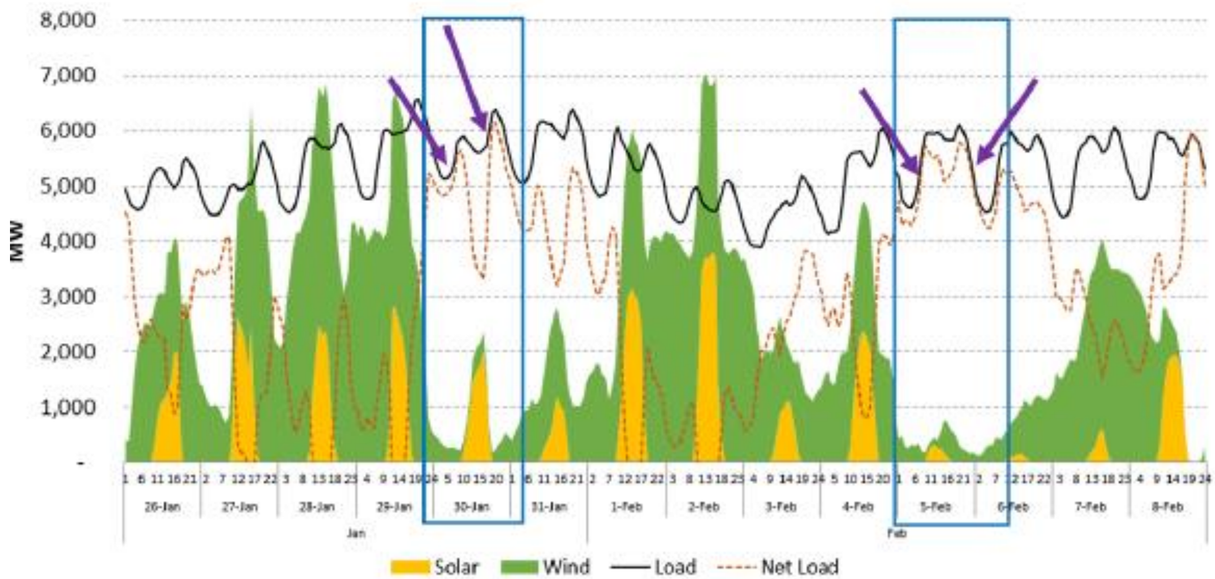
In its discussion of year-round resource adequacy, one factor Xcel emphasized was winter weather emergencies, which are occurring with greater frequency and intensity. Xcel noted that winter storms and polar vortex conditions have affected the region multiple times in recent years, including in 2011, 2014, 2019, and most recently in early-2021. In addition to extreme weather events, variations in weather impact fuel for generation. The IRP proposes to ensure sufficient firm dispatchable capacity to handle unexpected demand spikes or supply shortfalls.

Xcel conducted an analysis based on data from the 2019 polar vortex. During that event, firm dispatchable resources were critical to meeting demand during severe and prolonged cold temperatures. In the three-day time period from January 29-31, 2019, output from wind resources was significantly lower than average output, and actual consumer demand could not have been met without dispatchable resources.

[95] Xcel reply comments, p. 31.

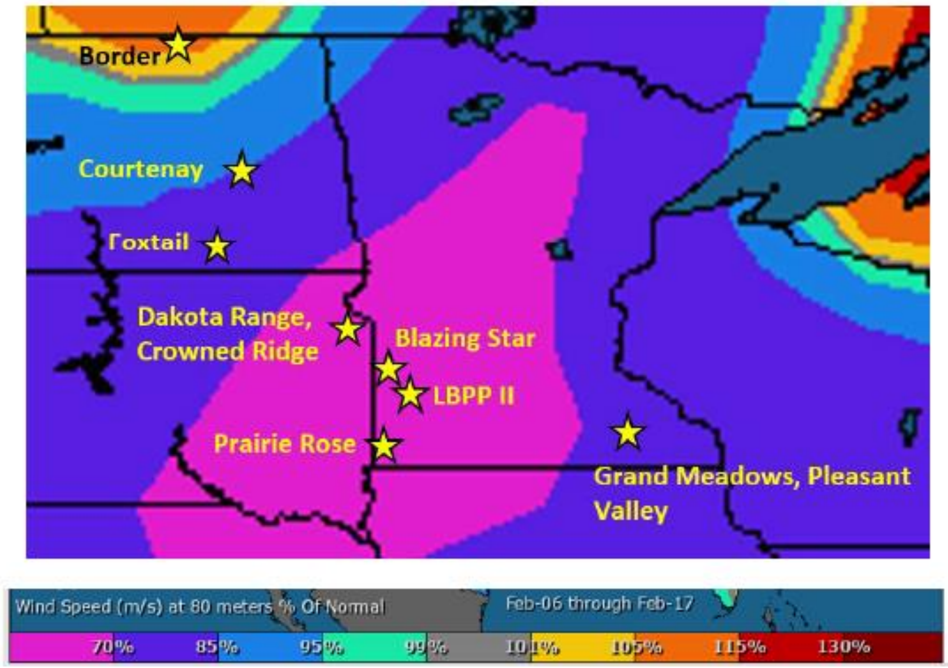
Figure 2-2 below depicts the approximated output for the NSP System during the 2019 polar vortex event. Wind output is shown in green, and solar output is shown in yellow. Xcel stated that even if wind output would have hypothetically doubled, there were at least two periods during the January 30 to February 5 event where wind generation would have had minimal impact on net load. (See that the MW shown by the green and yellow areas are well-below net load.) Xcel stated that adding more renewables alone is not sufficient to mitigate gaps in output caused by low temperatures or low wind speeds.

Figure 2-2: Approximated NSP System Output – 2019 Polar Vortex



Another example was Winter Storm Uri in February 2021. While the impacts to Minnesota's electric system were not nearly as severe as what unfolded in Texas, extreme cold temperatures in Minnesota from Winter Storm Uri were longer in duration than the 2019 polar vortex. Renewable performance during Uri was predictably low throughout the entire cold spell. Figure 2-4 below shows that during Winter Storm Uri the average wind speeds during this timeframe were about 70 to 85 percent below normal levels.

Figure 2-4: Average Wind Speed Departure from Normal at Turbine Height – February 6-17, 2021



However, Xcel's three nuclear units performed extremely well during the storm. In fact, Xcel's nuclear fleet operated at 100 percent capacity factor during recent polar vortex events. Xcel noted that at any given time, nuclear plants have 18 to 24 months of fuel supply and can run when other energy resources are interrupted by extreme weather or other circumstances.

2. Maintaining Stability Along the Sherco Gen-Tie Line

Given the length of the proposed Sherco gen-tie line and the goal of maximizing renewable integration along the line, Xcel studied a variety of renewable and reactive-support additions to identify the conditions under which the line maintained stability. Xcel explained:

> Based on this study, we first concluded that resources to provide inertial and voltage support were needed at the Sherco-end of the line. Specifically, we studied the inclusion of two synchronous condensers at Sherco. Second, to achieve maximum renewable integration along the line, resources to support stability also are needed at the Lyon County end. Specifically, we studied the inclusion of 400 MW of CTs operating as synchronous condensers at the end of the line. With these resources in place, we determined the gen-tie lines could support up to 2,600 MW of transfer capacity at any given time, which closely aligns with the 2,400 MW of interconnection capacity that will be available at Sherco when the coal units retire.[96]

[96] Xcel reply comments, p. 52.

3. Comparison to Alternative Plans

Xcel explained its method for comparing the Alternate Plan to modeling parties plans as follows:

> At a high level, the analysis evaluates each plan's performance across several dimensions related to reliability, including times when both our own capacity and ability to import from MISO is insufficient to cover our load, and high net load ramps. We conducted this analysis under both typical meteorological year (TMY)[97] conditions and actual hourly conditions for 2019 (during which we experienced strained conditions during a polar vortex), in order to examine how a plan might perform under more extreme circumstances than TMY.
>
> …
>
> [T]he Supplement Plan and Alternate Plans are more robust to a variety of reliability concerns than either the CEO or Sierra Club plans. These CEO and Sierra Club plans exhibit higher levels of unserved energy and a higher level of reliance on the availability of MISO than either our Supplement Plan or Alternate Plan. Further, modeling party plans appear particularly susceptible to periods of low output from wind or solar generation, correlated outages of the few remaining gas units in operation, or small but reasonable changes to battery operational assumptions such as the application of a minimal forced outage rate. Plan performance under these tests suggests that the lack of firm dispatchable capacity to supplement large amounts of variable and use-limited resources evidences a higher level of reliability risk than the Company can adopt.[98]

In Table 4-14 below, Xcel displays the summary results of its comparison of the Company's Alternate Plan and Supplement Plan to party alternatives in 2034. Note the number of shortfall events, the number of hours requiring maximum MISO imports, and the size of the peak capacity shortfall across plans.

[97] Typical Meteorological Year (TMY) shapes are planning assumptions for capacity expansion runs in EnCompass. In other words, "typical" or "average" conditions are used to derive the load and intermittent renewable generation profiles that are used for capacity expansion runs in the Company's Resource Planning process. While helpful for optimizing long-term capacity expansion models, TMY shapes are limited in that they do not effectively capture variability on an 8,760-hour basis or extreme weather events that our system may encounter in a given year – such as an extreme heat wave in the summer, or a polar vortex condition in the winter. The reliability analysis uses supplementary production cost runs with additional, more variable sets of 8,760 load and generation resource profiles ("shapes") to allow the Company to compare how various capacity expansion plans react to an increased level of variability.

[98] Xcel reply comments, p. 134.

Table 4-14: Summary Results of Reliability Analysis Between Four Major Plans[99]

Plan	Hourly Conditions in Simulated for Plan Year 2034	Native Capacity Shortfall Events	Shortfall Hours Requiring Maximum MISO Imports	Average Shortfall Intensity (MW)	Longest Shortfall (Hr)	Peak Capacity Shortfall (MW)	Max Net Load Ramp	LOLH	EUE (MWh)
Company Alternate Plan	TMY (Average Year)	0	0	0	0	0	4,484	0	0
	2019 Actual Hourly Load & Generation	1	2	171-205	2	213-239	4,794-4,814	0	0
Company Supplement Plan (Updated Scenario 9)	TMY (Average Year)	0	0	0	0	0	4,081	0	0
	2019 Actual Hourly Load & Generation	1-2	0-3	81-135	2	145-171	5,019-5,178	0	0
CEO Preferred Plan	TMY (Average Year)	0	0	0	2	0	5,637-5,746	0	0
	2019 Actual Hourly Load & Generation	13-17	28-42	390 - 399	5-6	1,238 – 1,531	6,037 – 7,207	0	0
Sierra Club Preferred Plan	TMY (Average Year)	3	0-4	154	2	260	260 7,082	0	0
	2019 Actual Hourly Load & Generation	30-47	28-140	440-484	11	1,818-2,819	7,990-9,521	0-17	0-5,767

Xcel then explained a few takeaways from Table 4-14:

> There are several important takeaways from the results of our reliability analyses. First, the hourly performance of all plans varies – in some cases substantially – between performance under average year ("TMY") conditions versus a recent actual year's hourly load and renewable shape contributions ("2019 Actual Hourly Load and Generation").
>
> The results of this analysis suggest that analyzing multiple sets of assumptions is, indeed, critical to assessing the reliability risks associated with different plans, as the 2019 Actuals analysis reveals a greater quantity and more severe events relative to the TMY analyses. For this same purpose, we also analyze plans along a variety of dimensions, including traditional reliability metrics, such as EUE or LOLH, and others that we believe provide helpful additional information to

[99] CUB did not provide sufficient information to perform this analysis on its preferred plan.

examine the risk associated with each plan (i.e. max net load ramp, or the number of hours the plan assumes it can import from MISO at or near the max transfer limit during hours when we lack enough of our own available capacity).

In combination, we believe that an expansion plan that consistently indicates a high result across several dimensions is more likely to result in risk and reliability concerns. In this case, both Sierra Club's and the CEOs' preferred plans consistently result in worse outcomes than both the Company's Plans, across every measure. Not only do they have a higher frequency of occasions where the generation portfolio would be insufficient to cover its own load ("shortfalls"), but these shortfalls are longer in duration and require more capacity assistance from MISO than shortfalls in either of the Company's plans. The CEOs' and Sierra Club's plans also max out the MISO import capability, exhibit higher levels of shortfalls, show significantly steeper net load ramps and have a higher risk of EUE. Further, as exhibited by the EUE analysis in Table 4-14 above, we would expect these concerns would only grow if we analyzed a year beyond 2034.[100]

4. Battery Storage

Xcel discussed several limitations of battery storage:

- The ability of storage to provide the same attributes as CTs is not yet economically feasible or fully understood in this climate zone. For example, the capabilities of the storage resource predominantly modeled by parties – conventional lithium-ion batteries – are currently limited to four hours. Four-hour batteries are simply not sufficient to meet reliability needs in all cases, particularly when needed in substantial amounts for multi-day contiguous periods. For example, on January 30 and 31, 2019, Xcel's CT fleet dispatched for a period of 45 contiguous hours – a critical time period during the 2019 polar vortex.

- For extreme weather conditions in which the grid is still stable, such as the February 2021 cold spell, batteries providing restoration services would likely be unavailable for providing much-needed energy to the bulk power grid.

- Very little literature and existing operational data from climates similar to the NSP System is domestically available on this topic. For example, neither NREL ATB 2019 or 2020 make explicit assumptions about cold weather parameters or thermal management systems for standalone storage, nor are battery-specific topics yet found in the MISO Winterization Guidelines.

- Batteries provide limited value in system restoration. While some batteries can provide blackstart or system restoration services in certain limited circumstances, the portion of

[100] Xcel reply comments, pp. 135-136.

the battery reserved for this purpose would provide very little, if any, other grid value because it must maintain its charge at all times to be prepared for a restoration event.

- Xcel made relatively optimistic operational and planning assumptions for batteries in our modeling. Batteries are the only resource modeled with a 0 percent Forced Outage Rate and 100 percent capacity accreditation (UCAP) in EnCompass. Furthermore, unlike solar resources, no declining ELCC has been applied to firm capacity ratings, which would be appropriate for the scale of battery resources adopted in some modeling party plans.

B. CEOs Response

1. Resource Attributes

In Figure VI-1 of Xcel's Supplement,[101] the Company maps several resource types by their ability to provide essential reliability services, flexibility, energy availability, and blackstart. CEOs argued that, contrary to Xcel's claims, wind and solar have excellent capability to provide all of the essentially reliability service Xcel maps, with the exception of inertial response. According to CEOs, wind and solar out-perform traditional generator in terms of speed and accuracy of providing reliability service. Wind and solar can also provide frequency response and have fast bidirectional ramping capability.

Also, referring to battery storage as duration-limited is partly incorrect because batteries act like transmission assets called STATCOMs. Battery storage can provide blackstart capability as well, and in the extremely rare circumstance of a blackstart need, it is unlikely that a battery would need to discharge at full capacity for the duration of an extended blackstart scenario.

2. Reliability Metrics

CEOs examined similar reliability metrics as Xcel described in Xcel Tables 4-1 and 4-14 shown in the previous section. Table 17 of EFG's report below – included as Attachment A of CEOs' Initial Comments – shows the reliability summary of the CEOs Preferred Plan (not the CEOs Alternate Plan) compared to the Revised Xcel Preferred Plan.[102] Table 17 shows that the CEOs Preferred Plan and the Revised Xcel Preferred Plan both had 0 hours of native capacity shortfall events and had reported LOLH, LOLE, and EUE of 0.

[101] Xcel Supplement, p. 94.

[102] The Revised Xcel Preferred Plan left alone Xcel's constraint forcing the Sherco CC into the model but adjusted other assumptions CEO determined were unreasonable.

Table 17. Energy and Capacity Adequacy Metrics for Revised Xcel Preferred Plan and CEO Preferred Plan[103]

	Native Capacity Shortfall Events					Flex. RA Metric	Max. Import Metric	Industry Metrics		
Plan	Native Shortfall Events	Ave. Duration of Shortfall Events (hrs)	Ave. Intensity of Events (MW)	Longest Shortfall Event (hrs)	Peak Shortfall Event (MW)	Max 3-hr ramp	Hrs w/ High Imports	LOLH (hours)	LOLE (days)	EUE (MWH
Xcel	0	0	0	0	0	6,512	23	0	0	0
CEO	0	0	0	0	0	7,000	154	0	0	0

The two metrics where the scenarios differ are the Flexible RA (Resource Adequacy) and Maximum Imports metrics; however, the reasons why the CEO plan had a higher maximum ramp and higher imports were due to economics, not reliability events. EFG also noted that these metrics do not mean much as a reflection of Xcel's system alone. EFG stated, "MISO coordinates the delivery of bulk power through Minnesota and beyond, so the LOLE, LOLH, and EUE of its entire system are more meaningful metrics."[104]

3. Unserved Energy

CEOs did not repeat the analysis discussed above for the CEO Alternate Plan, but the EFG report did respond to Xcel's assessment of the reliability of the CEOs Preferred Plan. As shown in Xcel's Table 4-12 of Reply Comments, the CEOs' and Sierra Club's plans had substantially more unserved energy than the Company's Plans. However, these unserved energy periods occur after the 2020-2034 planning period. Note that Xcel Table 4-12 calculate EUE from 2037-2045.

Table 4-12: Comparison of Annual Unserved Energy (EUE) Between Plans

Scenario	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Supplement Plan	--	--	--	--	--	--	--	--	--	0
Alternate Plan	--	--	--	--	--	--	654	--	--	654
CEO Preferred Plan – Corrected Xcel Base Case	6,595	4,852	--	5,839	4,629	--	20,484	13,161	1,822	57,382
CEO Preferred Plan – CEO Base Case	--	--	--	--	1,995	7,605	11,121	22,137	4,317	47,175
Sierra Club Preferred Plan	2,033	2,980	--	7,840	3,551	11,768	20,316	15,485	10,489	74,462

[103] Staff replicated Table 17 for space. EFG's version is on page 32 of Attachment A of CEOs Initial Comments.

[104] EFG report, Attachment A of CEOs' Initial Comments, p. 31.

EFG stated it did not believe that unserved energy is a concern because:

- They are so far out in the planning period that there is significant uncertainty about both which resources will be dispatched and Xcel's generation fleet;
- There are a significant number of resource retirements between 2040 and 2045, including Monticello in 2040; and
- Long-duration storage is not considered in Xcel's or CEOs' plan, but in the post-planning period, storage could help address unserved energy that may materialize.

Tables 8 and 9 of the EFG report shows that there is some unserved energy in 2037 and beyond in the CEO and Xcel Alternate Plans, but they are a very small percentage of annual energy:

Table 8. Unserved Energy (MWH) in CEO Alternate Plan

Year	Unserved Energy (MWH)	Annual Energy (MWH)	Percent of Annual Energy
2037	1,305	56,580,000	.0023%
2038	462	57,143,000	.0008%
2043	13,395	60,200,000	.0223%
2044	1,526	60,975,000	.0025%

Table 9. Unserved Energy in Xcel Alternate Plan Reoptimization

Year	Unserved Energy (MWH)	Annual Energy (MWH)	Percent of Annual Energy
2043	7,318	60,200,000	.0122%

4. Winter Reliability

Xcel pointed to the 2019 polar vortex and the 2021 Winter Storm Uri as examples of recent extreme weather events that demonstrate the importance of having firm dispatchable resources, like nuclear and CT capacity. CEOs responded that Xcel's existing CT fleet did not operate at even close to its full capability during this event. Figure 2 of the EFG report shows the hourly weighted average capacity factor of Xcel's existing CTs during Winter Storm Uri from February 14 – February 18, 2021. During this event, six of the CTs did not operate during any hour of the event.

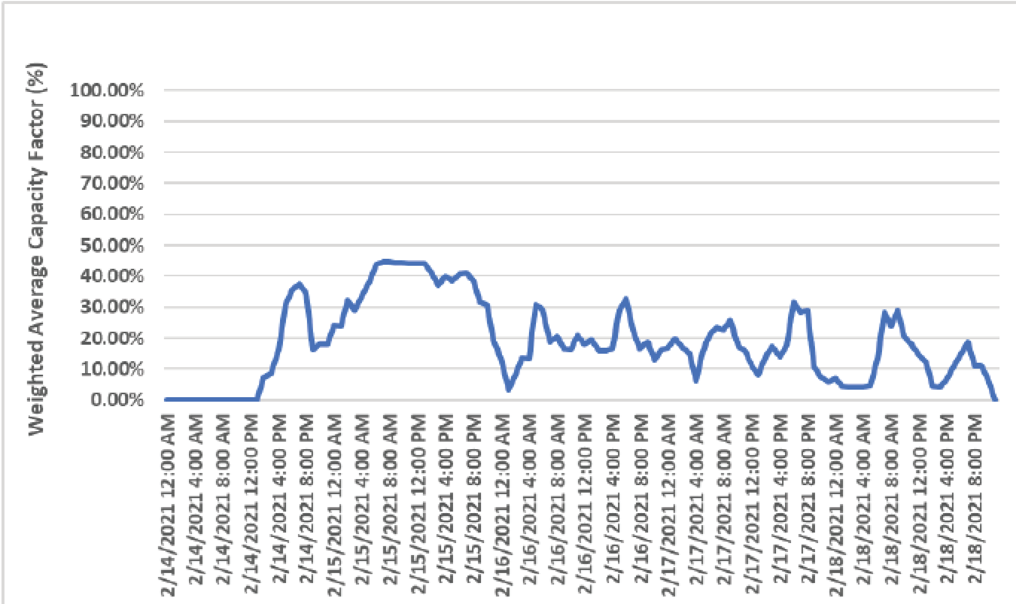


Figure 2. Weighted Average Capacity Factor (%) of Xcel's CTs During Arctic Event

Since Xcel already has a large CT fleet, the in-service dates of 2027 and 2029 for the Fargo and Lyon County CTs are far into the future, and long-duration storage technology is likely to improve, Xcel has not justified the need for committing to investments in new CTs at this time.

5. Lyon County CT

CEOs argued that Xcel failed to demonstrate that the Lyon County CT is needed for stability at the end of the Sherco gen-tie. CEOs retained Telos Energy (Telos) to review the Sherco gen-tie line's stability needs. Telos concluded that Xcel did not establish the proposed CTs are required for adequate stability and further analysis is required. The Telos report stated:

> Xcel's justification for the need for a new gas-fired combustion turbine (CT) to support stability of the proposed Sherco gen-tie line is based on an incomplete analysis. The information provided by Xcel regarding the stability on the Sherco gen-tie line does not demonstrate that the proposed Lyon County CT is the only or best option for providing stability for the interconnection of 2,400 MW of renewable inverter-based resources (IBR) to the Sherco gen-tie line. There are multiple other technologies and design options to determine the most cost-effective approach to stable operation of the Sherco gen-tie line with 2,400 MW of IBRs. For example, spreading the IBR generation out along the tie-line and using grid-forming (GFM) inverter technology is likely to reduce or eliminate the need for series compensation and synchronous condensers, and thus for the proposed Lyon County CT. It would also very likely ease project siting and land-use rights acquisition and reduce the complexity and cost of the project significantly.
>
> …

More detail is needed to evaluate the stability of the proposed project, and then to assess the equipment needs and estimate the costs vs. benefits before assuming a new 400 MW CT is the optimal design choice. Three major open questions include:

- Where along the 140-mile line is the new IBR generation intended to be connected?
- Could grid-forming (GFM) inverters provide significant stability on the line?
- How does the timing of implementing the whole project potentially address stability issues?

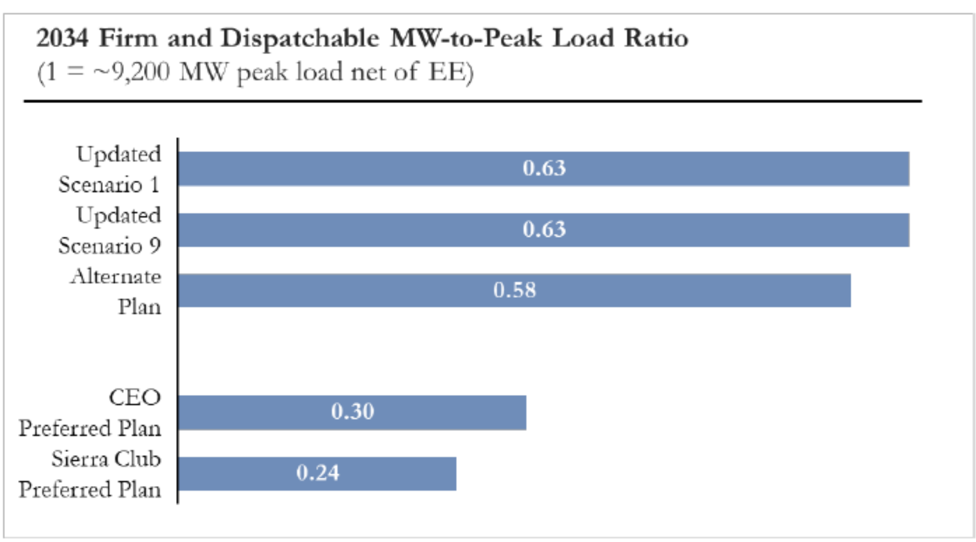
Telos concluded that until more is known about where resources will be located, the line's overall need for stability reinforcement cannot be known. However, siting generation closer to the Sherco interconnection and/or spreading out the generation to different points along the line would significantly reduce stability concerns. GFM inverters, which can enable interconnection of higher levels of renewables with less transmission reinforcements, are a rapidly emerging technology and is now commercially-available for battery energy storage systems. Also, Xcel intends to distribute resources to the line over a period of many years, which mitigates the stability challenge. Since Xcel stated that the wind and CT resources will not come online until 2028-2029, there is sufficient time to study stability needs on the line.

C. Sierra Club Response

1. Xcel's Reliability Metrics

Xcel Figure 4-11 of the Company's Reply Comments[105] compares the Alternate Plan to the CEOs' and Sierra Club's plans by using a firm capacity-to-peak demand ratio, which is the amount of accredited capacity from firm and dispatchable resources relative to system peak demand.

Figure 4-11: Firm and Dispatchable Capacity-to-Peak Load Ratio, 2034

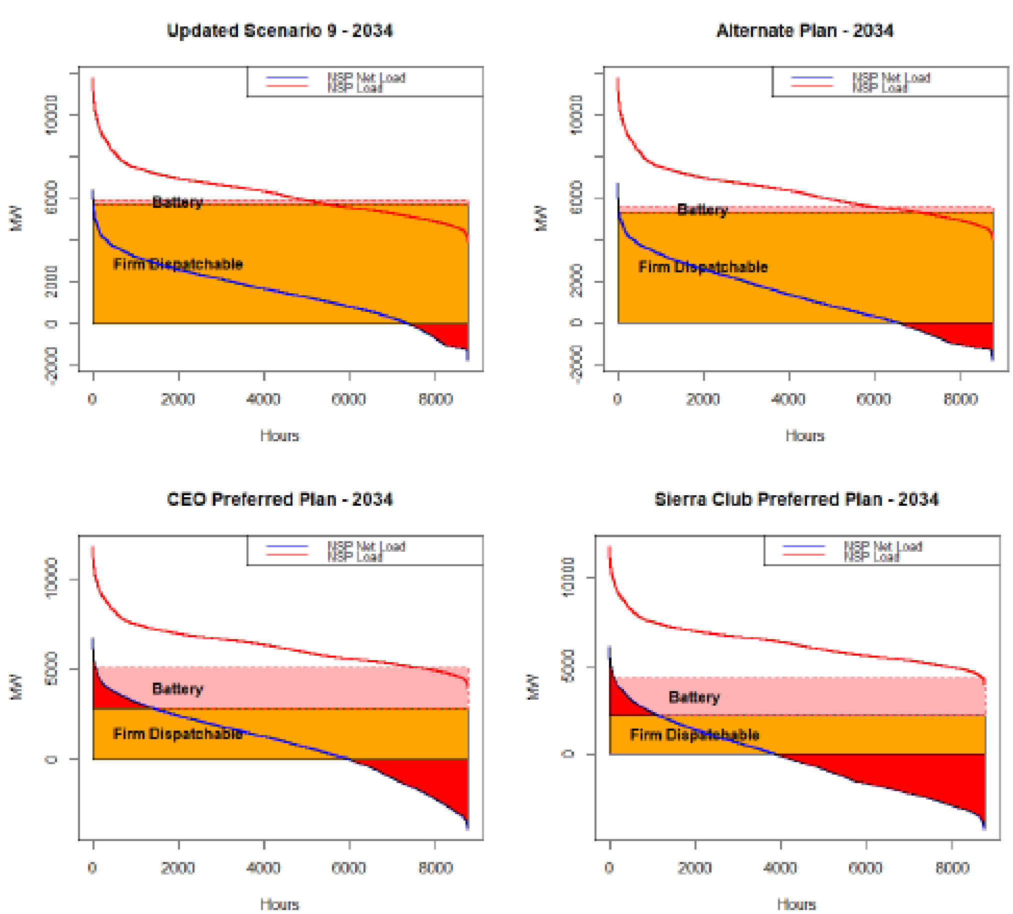


[105] Xcel reply comments, p. 126.

Sierra Club referred to Xcel's firm capacity-to-peak demand ratio as "a simplistic metric," which gives zero credit for the large contributions of resources such as battery storage, DR, and renewables. Sierra Club recommends the Commission disregard this metric, as it does not reflect resources' actual reliability contributions.

To examine exposure to capacity and market risk, Xcel compared how net load[106] interacts with firm and dispatchable generation in 2034 across the Xcel, CEOs, and Sierra Club plans. Xcel's Figure 4-12[107] below shows net load duration curves for the various plans, ranking hours in the year from highest- to lowest-net load. The red curve is NSP Load, and the blue curve is NSP Net Load. The red shaded areas in the charts below indicate where a plan is relying on duration limited resources or the market to either meet net load (on the left end of the chart) or absorb excess renewable generation (on the right end of the chart), relative to net load hours where customer needs are expected to be able to be matched by firm dispatchable capacity.

Figure 4-12: Company and Modeling Party Plans, Net Load and Firm Capacity Across Hours in 2034[45]



[106] Net load refers to the total electric demand in the system for a given hour, minus variable renewable energy production, (i.e. wind and solar) for that hour. It represents the hourly demand that must be met with other firm and/or dispatchable energy resources or imported electricity from the market.

[107] Xcel reply comments, p. 128.

Sierra Club responded that the net load duration curves metric is inferior to sequential hourly modeling in representing the real-world dispatch of resources. Xcel's presentation also misleadingly shows many hours of negative net load under the CEO and Sierra Club plans, ignoring that energy storage will be charging during these hours, which, when considered in conjunction with market sales, will keep net load positive. That said, Xcel's analysis confirms that renewables provide significant capacity value, as indicated by the fact that peak net load is more than 5,000 MW lower than peak load in both the CEO and Sierra Club plans.[108]

Regarding Xcel's modeled generation shortfalls, like CEOs, Sierra Club stated that these shortfalls occur in 2037-2045, which is outside the planning period. Sierra Club focused its analysis on the 2020-2034 planning period and did not attempt to optimize the model to meet reliability needs post-planning period.

Furthermore, Xcel made unreasonable assumptions about the cost of unserved energy, which are shown below from Xcel Table 4-13 of Reply Comments:

Table 4-13: Unserved Energy Cost in Party-proposed Plans vs the Company's Plans, 2037-2045

	Supplement Plan	Alternate Plan	CEO Preferred Plans[53]	Sierra Club Preferred Plan
Net present value of EUE Occurring in 2037-2045[54] ($ million)	$0	$4	$297 - $406	$484
Surplus CT Capacity Equivalent	0	7 MW	519-709 MW	869 MW

After reiterating that Sierra Club's modeling was not focused on reliability needs in 2037-2045, Sierra Club noted that Xcel's analysis is misleading because it assumes a $10,000/MWh cost for the unserved energy in the 2037-2045 timeframe. MISO caps generation offers at $2,000/MWh and has a hard price cap of $3,500/MWh, which is MISO's assumed value of lost load.

2. Winter Reliability

Xcel's discussion of winter reliability presents a worst-case analysis under a repeat of 2019 polar vortex conditions. Sierra Club contends that its Clean Energy For All Plan is reliable under the conditions it was optimized to meet, with no loss of load under typical conditions or even under many of the scenarios Xcel used to represent 2019 polar vortex conditions.

Xcel also asserted that increasing levels of renewable energy will be insufficient to ensure energy adequacy in every hour of every day, and the 2019 polar vortex event demonstrates why firm and dispatchable resources are needed. Sierra Club responded that MISO's ELCC methodology already accounts for wind's availability to meet load in all hours of the year. Moreover, the 2019 polar vortex event was "an extremely unusual event, with many locations

[108] Staff notes that the image might be blurry, but Sierra Club is referring to the y-axis showing a 5,000 MW difference between the NSP Load and NSP Net Load curves.

experiencing record or near-record cold temperatures and generators *of* all types experiencing outages and derates."[109] Sierra Club explained:

> Despite such an extreme event, MISO had more than enough generation supply to meet demand throughout the event, and never had to resort to rolling outages.
>
> Moreover, the unexpected wind outage is unlikely to be repeated due to steps MISO and others took following the event. The primary problem during that event was that MISO's wind forecast did not include detailed parameters for the minimum operating temperatures of turbines, so grid operators were caught off guard when wind output fell below what had been expected the day before. MISO notes that it immediately addressed that problem by incorporating plant specific low temperature operating limits into MISO's wind forecast. If MISO ever experiences a similarly severe cold snap, grid operators will be prepared and commit additional generating resources and imports the day before if there is a risk of temperature-related outages.
>
> Said another way, the 2019 event was a grid operating concern and not a grid planning problem.[110]

3. Resource Attributes

As with CEOs' response on resource attributes, Sierra Club responded to pages 94-100 of Xcel's Supplement that mapped resource types' ability to provide:

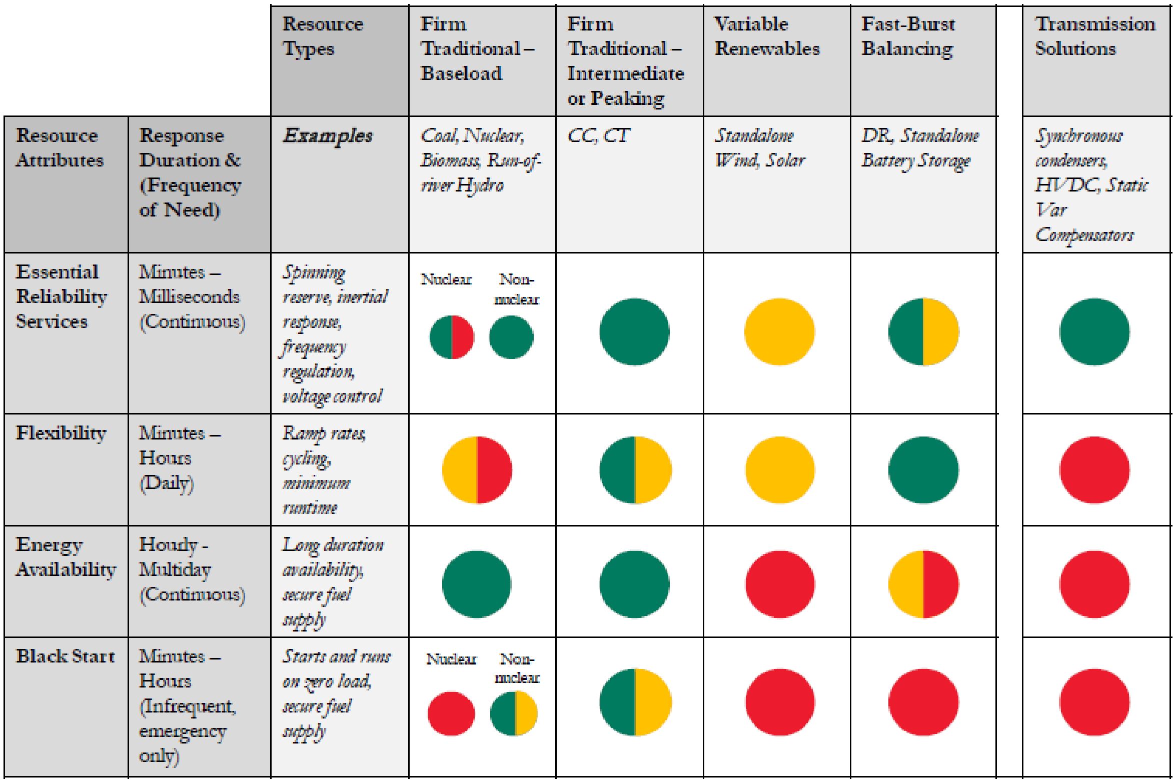
- Essential reliability services – System strength and stability;
- Flexibility;
- Energy availability; and
- Blackstart.

Figure VI-1 of the Supplement maps reliability attributes across resource types.

[109] Sierra Club comments, pp. 60-61.

[110] Sierra Club comments, pp. 61-62.

Figure VI-1: Resource Attributes Mapped to Resource Types



According to Sierra Club, Figure VI-1 overstates the reliability services provided by fossil generators and understates the reliability services capability of renewable and storage resources. Sierra Club stated:

> This chart does not accurately portray the reliability contributions of renewable and storage resources relative to conventional generators. In particular, the Essential Reliability Services capabilities of wind, solar, and storage resources exceed those of conventional generators in many ways. Wind, solar, and battery storage are digitally-controlled inverter-based resources, which allows them to respond to grid disturbances orders of magnitude more quickly than mechanically controlled conventional generators, with a full response in a few seconds or less. This frequency response is fast enough that it can offset the need for inertial response from conventional generators, while also reducing the need for conventional generators' slower frequency response. Wind and solar generators are also highly flexible, with an ability to have their output fully dispatched up or down in seconds, compared to many minutes for conventional generators. Thus, Xcel should not have rated wind and solar as less flexible than conventional generators. Moreover, inverter-based resources are increasingly technically able to provide black start services.[111]

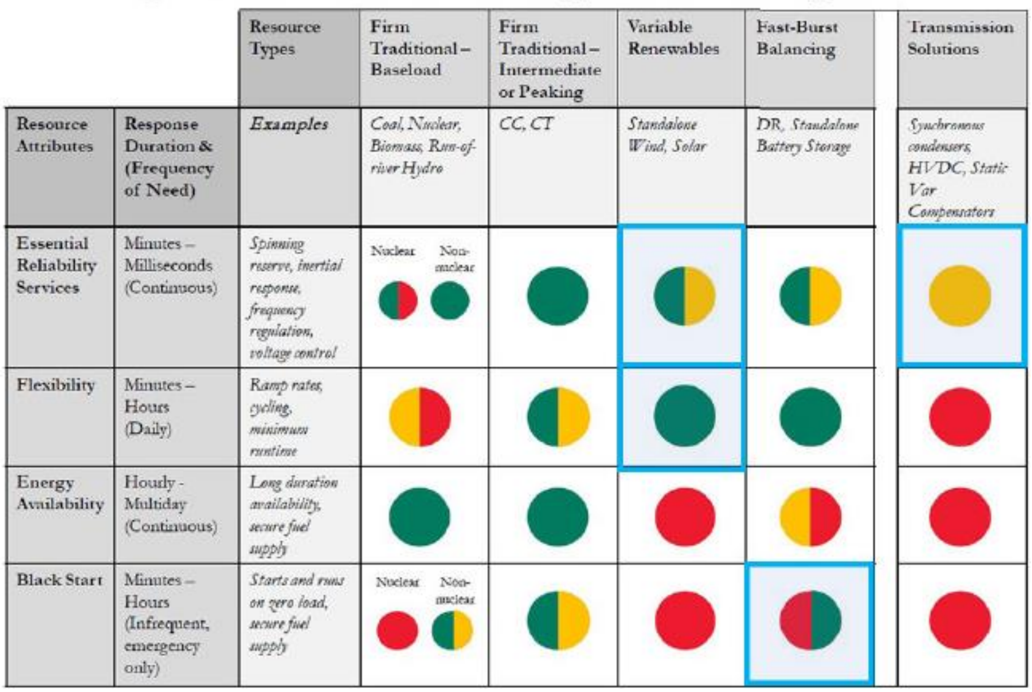
[111] Sierra Club initial comments, p. 79.

Wind and solar generators are highly flexible, with an ability to have their output fully dispatched up or down in seconds, compared to many minutes for conventional generators. Thus, Xcel should not have rated wind and solar as less flexible than conventional generators. Moreover, inverter-based resources are increasingly technically able to provide blackstart services.

The report conducted by Telos in this proceeding (on behalf of Sierra Club and CEOs) also confirms the errors in Xcel's assessment of these capabilities. Telos found Figure VI-1 to be "misleading, outdated or incorrect" in several ways. Telos provided a modified map, as Figure 17 of Sierra Club's Initial Comments, correcting these errors.

Figure 17 Resource Attributes Table As Modified by Telos Energy

Figure VI-1: Resource Attributes Mapped to Resource Types



Sierra Club continued to emphasize that Xcel has not given battery storage sufficient consideration despite it being an increasingly cost-effective peaking capacity option able to provide reliability services. Xcel's modeling lacks the chronological and geographic resolution necessary to capture battery storage's ability to provide reliability services when and where they are needed. Batteries have the unique ability to absorb excess renewable output by charging, which gas and conventional generators cannot do.[112]

4. Lyon County CT

Xcel claimed that without the additional reactive support located at Lyon County, the amount of generation that can be delivered on that line is reduced, which is an argument Sierra Club found to be highly misleading. Sierra Club cited Xcel's response to XLI Information Request No.

[112] Sierra Club initial comments, p. 80.

159, which provided a stability assessment Xcel conducted for the Sherco gen-tie. While Xcel's response was redacted, it supported Sierra Club's conclusion that the CT is not needed for stability on the line, and even if line stability could be an issue, there are other low-cost solutions that could be implemented.

According to Sierra Club, storage and renewables can provide the reliability services Xcel proposes to provide from the Lyon County CT, but Xcel failed to even consider this as an option. For example, in response to Sierra Club Information Request No. 206, Xcel acknowledged that it did not evaluate the potential use of battery storage to absorb curtailed renewable energy or provide reactive power service on the Sherco gen-tie, stating, "While we are open to it, the Company has not yet evaluated the potential for adding battery energy storage resources on the gen-ties specifically." Furthermore, in response to Sierra Club Information Request No. 202, Xcel confirmed that "the Company did not conduct a quantitative evaluation of whether batteries could perform the same technical capabilities as the CT proposed for the Sherco gen-tie."[113]

Sierra Club's recommendation to the Commission on the Lyon County CT states:

> While Xcel should evaluate the transmission options we have highlighted above, the most important action for the Commission to take at this point is to ensure that Xcel does not rush into deploying the 374 MW Lyon County CT that was forced into the Company's modeling and is not needed for nearly a decade. Without more thorough analysis of the claimed need for and alternative sources of reliability services, this CT could become a stranded asset for ratepayers. Relative to battery storage, the CT could also inhibit the Company's transition to a cleaner generation mix, as battery storage can provide comparable reliability services as a CT while also absorbing curtailed renewable generation, something a CT cannot do. At page 52 of its Reply Comments, Xcel itself notes that the proposed "stability investments are intended to be indicative of cost only. Should the Commission approve the Alternate Plan, we would commence further regulatory proceedings related to the line, including specific proposed stability investments." Given that the Lyon County CT is by far the largest of those stability investments, it is premature for that plant to be included in the IRP. As part of the stability investment proceeding and the blackstart docket that Xcel has called for, the Company and the Commission should comprehensively evaluate all reliability services that are needed and evaluate all potential solutions to determine the optimal mix of resources to meet those needs, rather than Xcel's approach of limiting the solution to the single option of building a 374 MW CT.[114]

5. Blackstart and System Restoration

According to Sierra Club, the Sherco CC, King, and Monticello plants are not needed for blackstart, and batteries have an advantage in providing blackstart because of their small

[113] Sierra Club supplemental comments, p. 32.

[114] Sierra Club supplemental comments, p. 37.

modular size and extremely fast response. Despite Xcel's claims to the contrary, commercially-available batteries have a proven ability to provide blackstart, in addition to voltage support, stability, short-circuit current contribution to counteract weak grid issues, and other reliability services. As an example, "a recently announced 185 MW battery project in Hawaii will fully replace the grid services currently provided by a nearby coal plant by providing blackstart, fast frequency response, and grid-forming services."[115]

Xcel's primary argument against the use of batteries for blackstart is that, due to their limited energy duration, the battery capacity must be dedicated to providing blackstart and cannot provide other grid services. However, in response to Sierra Club's Information Request 220, Xcel admitted that "[d]uring normal operation of lithium-ion batteries, the battery charge state would be between 30-70 percent of the battery capacity." Thus, under normal operations, the battery would always have at least 30 percent of its capacity available, and likely much more, to provide blackstart if the grid unexpectedly collapsed. Moreover, as the system is restored, batteries providing blackstart service can be recharged as they help balance generation from nearby resources, including wind and solar plants.

The Commission should also question the claimed benefits of Xcel's proposed zonal restoration approach and consider its potentially significant cost. Xcel discusses the potential for somewhat faster restoration of customer power under the zonal approach. However, it is important to keep the value of this benefit in perspective, given that it is unlikely blackstart restoration will be required during our lifetime. Xcel acknowledged in response to Sierra Club Information Request No. 224 that "blackstart restoration has not been required within Minnesota." Even in past large-scale blackouts, like the 2003 and 1965 outages that affected multiple states in the Northeast, power was mostly restored not from blackstart units but by connecting load and generation to other parts of the Eastern Interconnect that were unaffected.

D. CUB Response

Xcel stated that CUB's Consumers Plan did not provide enough information for the Company to analyze it in the same way as the CEOs and Sierra Club Plans. CUB disputed Xcel's claim, citing several information requests in which CUB included all the necessary code and information to glean the critical inputs and assumptions utilized in the Consumers Plan.

CUB recognized that the WIS:dom model has never been used in a formal IRP proceeding in Minnesota, but its robust, peer-reviewed methodology and software has produced valuable insights into resource options on Xcel's system. All models have limitations, CUB argued, including EnCompass, which is not capable of co-optimizing distributed energy resources. WIS:dom adheres to the same planning requirements as other models, while demonstrating enhanced capabilities around distribution system co-optimization, resource siting, and climate change impacts. WIS:dom ensures that load is met on a five-minute basis throughout every hour of the modeled year.

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[115] Sierra Club supplemental comments, p. 27.

CUB's modeling ensures reliability and resource adequacy by requiring a 7 percent load following reserve at all time while maintaining the NERC-recommended planning reserve margins. The Consumers Plan maintains reliable grid operations even with 78 percent of the installed capacity being variable renewable energy. Also, WIS:dom selects sites with the best capacity factors and correlation to load while accounting for grid impacts when renewable energy output is low or non-existent.

IX. Resource Acquisition Process

Staff provided a summary of the Commission's resource acquisition processes earlier in the briefing paper, so staff will not repeat that discussion here. Below is a summary of party recommendations for the resource acquisition process that should be used to implement the approved IRP.

A. Xcel

Xcel requests the Commission approve the use of the Modified Track 2 process for the following acquisition proceedings:

- Solar, wind, and storage resources that utilize the transmission interconnection at the Sherco site;
- Solar and storage resource that utilize the transmission interconnection at the King site; and
- Any additions of renewable resources, storage, or resources powered by hydrogen or clean fuel alternatives that would be cost-effective, maintain reliability, and aid in achieving compliance with decarbonization policies and that are proposed before Commission approval of the next resource plan.

B. CEOs

CEO recommends the Commission deny Xcel's request to use the Modified Track 2 process to acquire the Lyon County CT (for which Xcel is no longer requesting specific approval) because an abbreviated process cannot be used to acquire new fossil fuel resources not yet shown to be needed or in the public interest. Proposed fossil fuel plants require even greater scrutiny to determine whether they can be in the public interest despite the need for deep decarbonization.

C. City of Minneapolis and Sierra Club

The City of Minneapolis supports using the Commission's Modified Track 2 process for resource procurement; however, what Minneapolis envisions in its comments is an all-source procurement process that is inclusive of DERs, EE, and DR programs to be part of a Clean Energy Portfolio approach. Minneapolis compares this process to all-source bidding in other states, including Xcel's Colorado jurisdiction. Minneapolis also suggests the Commission consider a review of bidding procedures to revisit rules for fairness and objectivity and ensure that utility ownership is not at odds with competitive bidding.

Sierra Club stated that the Commission should consider ordering Xcel to conduct an all-source bidding process to assess hybrid costs and availability in its territory.

D. Department

Pages 91-104 of the Department's Initial Comments provide an extensive discussion of resource acquisition process—how the processes operate, when and why the Commission approved them, and examples of failed processes.

First, the Department recommends that the Commission determine that the Commission approved bidding process applies in all instances where Xcel intends to acquire 100 MW of capacity for a duration longer than five years. This will ensure that the bidding process is limited to instances of significant potential investment and will not interfere in the Company's short-term operations.

Second, the Department recommends that the Commission approve the Track 1 bidding process for resource acquisitions in which Xcel decides to not bid and that the Commission approve the Modified Track 2 bidding process for resource acquisitions in which Xcel decides to bid. When followed correctly, both processes have proven successful in recent dockets and provide significant ratepayer protections and thus warrant permanent approval.

The Department noted that while Xcel used a CT as a proxy for a peaking resource, the Company made it clear throughout this proceeding that the Company is neutral as to the actual technology that would be acquired to fill any future needs for peaking resources. The Department agrees with Xcel on this approach, and therefore the Department recommends that the Commission require that any RFP documents for peaking resources issued by Xcel be technology-neutral.

The Department also discussed problems with all-source bidding. All-source bidding has already failed twice in Minnesota, which is what led to the current, two-track bidding process. An IRP aims to establish the size, type, and timing of resource needs, and there is no reason to believe that a Commission-approved plan will actually be followed with an all-source process. Finally, if an all-source bidding process attracts variety of bids for resources with a different size, type, and timing than the IRP, and if capacity expansion modeling is required to evaluate the bids, the number of combinations will make the modeling process difficult if not impossible.

Finally, the Department recommends that the Commission cap any ROFO offer made by Xcel at net book value and require any RFP to include the option for both PPAs and BOTs unless the Company can demonstrate why either a PPA or BOT proposal is not feasible.

E. Distributed Solar Parties

DSP disputed the Department's comments that an all-resource bidding process, which could consider resources with different sizes, types and timing, would be difficult and unreasonable to use following Xcel's IRP. DSP contends that the Department's position is inconsistent with the experience in other states, such as Michigan and Indiana, where all-source RFPs have been used successfully to inform resource planning around the region. DSP recommends the Commission investigate the benefits and uses of all-source RFPs to inform future IRP.

F. OAG and CUB

The OAG is generally supportive of Xcel's request to use the Modified Track 2 process to acquire new solar and wind, but the Sherco Solar experience demonstrates that approval of the Modified Track 2 process alone does not provide adequate customer protection, and safeguards must be put in place to prevent Xcel from undermining competition.

The OAG recommends that prior to the issuance of an RFP to procure new generation, Xcel shall provide a filing detailing its proposed competitive bidding process including, at minimum, the following components:

- A list of potential independent auditors to oversee the bidding process and evaluate the proposals;
- The criteria that the independent auditor will use to evaluate proposals;
- The proposed text of the request for proposals;
- The proposed timeline for the issuance of the request for proposals, the allowed response time, the date upon which Xcel will submit its self-build proposal (if applicable), and the date upon which the independent auditor will submit its report to the Commission detailing the bid results;
- Confirmation that the request for proposals will be published publicly and open to any interested developer;
- Confirmation that there will be no geographic or ownership limitations on the proposals; and
- A contingency plan in the event of an unsuccessful bidding process.

CUB's recommendations on resource acquisition process mirror the OAGs.

X. Intervenor Comments

This section will provide a summary of comments from parties who filed a Petition to Intervene or are employees of government agencies. These parties include:

- Center of the American Experiment;
- Citizens Utility Board of Minnesota;
- City of Minneapolis;
- Clean Energy Organizations;
- Department of Commerce (Department Staff and Deputy Commissioner Aditya Ranade)
- Distributed Solar Parties;
- International Brotherhood of Electrical Workers Locals 23, 160, and 949;
- Northern Natural Gas;
- Office of the Attorney General – Residential Utilities Division;
- Sierra Club;
- Suburban Rate Authority and Coalition of Local Government Units; and

- Xcel Large Industrials.

A. Center of the American Experiment

Center of the American Experiment (CAE) recommends the Commission approve a modified version of Scenario 15, which:

- Retains Sherco 3 and King through the end of their current retirement dates;
- Extends Monticello and Prairie Island; and
- Does not acquire any solar or wind resources that are not required to meet statutory mandates.

According to CAE's analysis, Xcel's Alternate Plan would cost $47.8 billion through 2050, resulting in charging every Xcel customer $1,100 per year on average through 2050. In addition, the Alternate Plan would expose electricity consumers to spikes in natural gas prices, as well as diminish the reliability of the grid due to the loss of a significant amount of firm, dispatchable capacity.

CAE argued that the energy crisis in Europe should serve as a cautionary tale that the shift away from coal and to an extent nuclear has resulted in an increase in natural gas and renewable energy, which has led Europe to be increasingly vulnerable to natural gas price increases and supply shocks. In addition, Europe recently experienced a "wind drought," with wind output falling by 15 percent, requiring European electric providers to restart coal plants.

CAE explained that high energy costs in Europe have harmed manufacturing. For example, German factories have reported production cost increases, and British manufacturers have warned that they could be forced to shut down due to soaring energy prices. According to CAE, "[t]he energy policies enacted in Europe over the last two decades should be an example of what not to do."

Xcel's Alternate Plan proposes to rely more heavily on natural gas, which will include periods of extreme weather when it could be too cold for wind turbines to operate. Relying more heavily on natural gas instead of coal during events like Winter Storm Uri may result in natural gas price spikes, thus increasing the cost of electricity generation and home heating costs for residential customers.

CAE also questioned whether utilities would have sufficient coal stocks to get through winter months. CAE explained:

> Elevated natural gas prices have increased the burn rate of coal-fired power plants in the [MISO] footprint. According to EIA data, the coal burn was substantially higher in August of 2021 than in August of 2020 . . . While coal demand is rebounding, supplies are not. According to S&P Global, mining companies have not ramped up production to meet the new market conditions.[116]

[116] CARE supplemental comments, p. 9.

CAE warned that relying too heavily on wind is dangerous for reliability and market exposure. During Winter Storm Uri, for example, there were periods when Sherco and King generated more electricity, on average, than all of the wind installed in MISO combined. This was despite the fact that Xcel's coal fleet has an installed capacity of 2,749 MW, while there were 22,040 MW of installed wind capacity in the MISO footprint at the time of the storm. The Commission should therefore consider whether Minnesota will be able to shut down coal and still be able to provide reliable, affordable electricity.

CAE recommends that Xcel build upon its recent Memorandum of Understanding with NuScale Power and plan to gradually replace its existing carbon- emitting facilities with small-modular nuclear reactors (SMRs). Xcel sees the value in SMRs, which is an emerging firm, carbon-free technology, and retaining existing coal and gas plants until SMRs can replace them is the most reliable and affordable bridge to zero emissions.

B. Citizens Utility Board of Minnesota

While the Alternate Plan is significant improvement from Xcel's Supplemental Plan, CUB's primary concern with the Alternate Plan is Xcel's proposal to add approximately 1,100 MW of new capacity in the form of four CT resources, as well as an additional 1,800 MW of new firm dispatchable capacity that will use an unspecified technology. Because Xcel's proposed CTs would run on methane gas and may or may not be able to use hydrogen in the future, they would face the same risk as the Sherco CC of needing to be retired early to meet Xcel's carbon goals and/or comply with future carbon regulations.

Moreover, Xcel has provided no details on the future availability or potential cost of hydrogen that might be used to supply the proposed CTs, or explained what proportion of hydrogen the CTs would be able to accommodate in their fuel streams.

According to CUB, the primary purpose of the four CTs is to provide blackstart capabilities, not to meet energy or capacity needs. Resources built to provide blackstart should play other necessary roles such as meeting peak capacity needs. Xcel states that one of the greenfield CTs will support solar and wind additions on the proposed Sherco gen-tie and provide general energy needs but provides very few details on the other roles that the CTs will play. Moreover, Xcel does not appear to have considered whether other resources could more effectively meet these purported needs; for example, additional battery storage, standalone synchronous condensers, or other technologies could likely be used to support the proposed wind and solar additions on the Sherco gen-tie.

C. City of Minneapolis

The City of Minneapolis (Minneapolis) recommends the Commission approve Xcel's Alternate Plan with modifications. Minneapolis supports removing the Sherco CC from Xcel's Preferred Plan as well as constructing gen-ties at the Sherco and King sites for replacement renewable resources. Minneapolis also supports acquiring renewable resources through the Commission's Modified Track 2 process but recommends allowing DERs to compete against large-scale resources in a competitive resource acquisition process. Minneapolis supports acquiring dispatchable resources but recommends that Xcel utilize energy storage and other carbon-free technologies to meet the need for firm dispatchable resources. Minneapolis agrees with Xcel on maximizing cost-effective DER potential, but Minneapolis believes that Xcel understates the amount of DER that is cost-effective.

While Minneapolis supports a modified version of the Alternate Plan, Minnesota believes there are additional areas Xcel should incorporate into resource planning, such as:

- equity and customer values;
- local generation that could improve energy affordability, build community wealth, and support local renewable energy goals;
- aligning distribution planning with IRP; and
- prioritizing beneficial electrification and grid flexibility as decarbonization strategies.

1. Equity

One way to address equity is by considering how the IRP will impact communities and customers with the highest energy burden. In a report looking at six years of energy burden data in Minneapolis, the top quintile of most burdened tracts in Minneapolis had an energy burden of 5.6 percent in 2019, compared to 1.9 percent in the least burdened tracts.

The map below shows the energy burden in Hennepin County by census tract, which ranges from 1 percent to 13 percent. The darker shade of purple represents census tracts with highest energy burden (closer to 13 percent), and the lighter colors represent neighborhoods with lowest energy burden (3 percent or less).

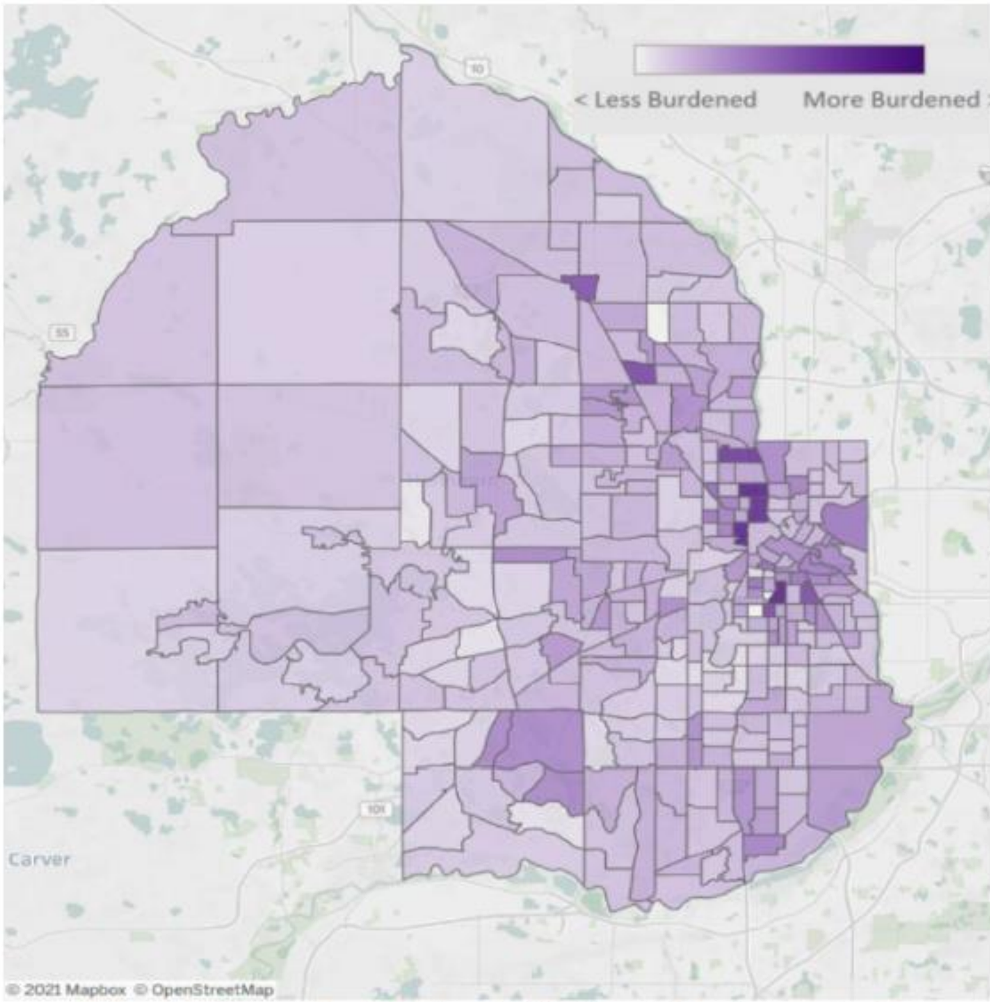


Figure 1- 2019 energy burden for households in Hennepin County, census tract[21]

Minneapolis, Xcel, and the Commission have a collective responsibility to carefully examine how the decisions made in this resource plan will benefit and burden communities, particularly low-income households and communities of color, that are already severely burdened. With the City's Strategic and Racial Equity Action Plan (SREAP), Minneapolis's goal is to prioritize sustainable practices and renewable resources to equitably address climate change while restoring and protecting our soil, water and air. Resource plans should consider ways to mitigate these disparities.

2. Distributed Energy Resources

Minneapolis adopted a goal to reach 100 percent renewable electricity communitywide by 2030 and 10 percent local generation by 2025. More local generation and DER will lead to a more equitable and affordable resource plan as well as helping support renewable energy goals within the state and local jurisdictions. Minneapolis would like to work with Xcel to develop new local renewable resources through special contracts, expanded community solar offerings, and on-site solar incentives.

Minneapolis argued that the Company's distributed solar forecast was too low and does not incorporate local renewable energy goals. In fact, combining the in-boundary renewable goals for the Cities of Minneapolis, Saint Paul, St. Louis Park, Eden Prairie, Northfield, and Red Wing results in 580 MW of local solar, capturing the entire distributed solar capacity estimated by Xcel. Increasing distributed solar is also important to Minneapolis because it is a job creation tool. Xcel can be a job creator with renewables resulting in 2.5 times as many jobs as the fossil fuel industry dollar for dollar.

If transmission issues delay new utility-scale renewable projects from coming online, Xcel should invest in more distributed solar. The advanced grid improvements Xcel has proposed in the Integrated Distribution Plan (IDP) include advanced meters, communication networks and data processing and management systems that can support safely integrating more DER if vendor and utility systems are coordinated. In order to justify the cost recovery of these investments from customers, there should be a proactive approach to support DER integration and more accuracy in forecasting DER adoption.

3. Aligning Distribution Planning and Resource Planning

Xcel's IRP and IDP processes are not yet integrated. Minneapolis encourages Xcel and the Commission to integrate the IRP and IDP for future planning cycles. Combining distribution grid and resource planning can proactively improve energy equity by decreasing overall system costs and allowing for local economic participation through distribution level resource solutions.

4. Beneficial Electrification

Minneapolis requests the Commission require electrification plans be included in future electrification scenarios. Building and vehicle electrification are strategies to minimize adverse environmental impacts if paired with renewables, but electrification needs to be carefully managed to avoid substantial grid costs. If properly designed, new electrified end-uses can provide considerable grid services to contribute to reliability, renewable integration and enable a more flexible resilient grid.

The current planned scenario does not include building electrification. By Xcel Energy's own estimates, "our current electric system would need to be built out to twice or more its current size to deliver the same amount of energy that our natural gas system delivers on a peak winter day." The State of Minnesota and cities like Minneapolis have GHG reduction goals that require significant building electrification efforts. These goals should be better integrated into the assumptions.

Minneapolis would like to partner with Xcel in designing programs that increase beneficial electrification with a focus on low-income households and communities. Since low-income households have higher energy burdens and often reside in rental properties, providing education and incentives to encourage building owners of low-income properties to pursue electrification technology that may have a higher initial price but result in lower utility bills will be important.

Designing programs to encourage beneficial electrification will benefit the communities Xcel serves. Electrification reduces health impacts from local pollutants such as natural gas in a building or gas automobiles. Black and Hispanic Americans are exposed to 63 percent and 56 percent more pollution than they create. Indoor air pollution from burning fossil fuels in residential and commercial buildings (e.g., for space heating, hot water, cooking) causes more premature deaths (over 28,000 per year) in the U.S. than any other sector.

D. CEOs

1. Sherco CC

A large portion of CEOs Reply Comments addressed the Sherco CC. Since Xcel has since withdrew the Sherco CC from its Preferred Plan, staff will briefly state a few important comments on this matter:

- The 2017 legislation authorizing Xcel to construct the gas plant at Sherco requires Xcel to demonstrate that costs and investments were "reasonable and prudently incurred." Xcel has not even provided final cost estimates for the plant or associated pipeline, but the Commission can rely on ample record evidence submitted by parties showing the Sherco CC is not cost-effective. Thus, Commission should make a finding that the Sherco CC is not in the public interest.

- Under Minn. Stat. § 216B.2422, subd. 4 (Renewable Preference), the Commission cannot approve a nonrenewable resource like the Sherco CC or allow rate recovery unless the utility "has demonstrated that a renewable energy facility is not in the public interest.' As of the Supplement Plan, Xcel locked in the Sherco CC in all of its modeling runs, which CEOs described as a "failure to examine the Sherco CC in its modeling."

- Since the Sherco legislation was passed into law, circumstances have changed such that it is now far riskier to build a large new source of carbon emissions. Updated climate science continues to sound the alarm about the need to drastically cut carbon emissions. Xcel has announced net zero emissions by 2050, and state governors and the federal government have embraced goals for 100% clean electricity. Gas plants like the Sherco CC are inconsistent with the rate of deep decarbonization required to meet climate goals. Moreover, new data about methane leakage from gas extraction and transportation substantially increases the estimated lifecycle climate impact of gas plants.

2. Supplemental Comments After Xcel's Removal of Sherco CC

CEOs supported Xcel's removal of the Sherco CC from the Company's Preferred Plan. Adding to what CEOs stated in Reply Comments, CEOs noted that that locking in long-term carbon emissions would have carried enormous risk; CEOs cited an August 2021 analysis by S&P Global Market Intelligence, which found that 13 percent of the nation's fleet of CC plants is at risk of being stranded just under current policies and market conditions. If existing CC plants are already at risk, the Sherco CC – originally intended to be placed into service in 2027 – would be an even riskier investment.

3. Denying the Lyon County and Fargo CTs

For reasons similar to their opposition to the Sherco CC, CEOs recommend removing the Lyon County and Fargo CTs from Xcel's approved plan. As with the Sherco CC, CEOs argued that Xcel failed to demonstrate that the Lyon County and Fargo CTs meet the threshold required by Minn. Stat. § 216B.2422, subd. 4 that a nonrenewable resource overcomes the State's renewable preference. Moreover, it is premature to approve two new fossil fuel plants years before they are needed, especially considering how fast carbon policy and carbon-free technologies are advancing. For example, the Biden administrating aims to achieve 100% carbon-free electricity by 2035; at that point, Xcel's CTs would be just 6-8 years old.

Moreover, based on CEOs analysis of Xcel's modeling and the CEOs' own optimization, the two new, 400 MW CTs are not optimal economic resources. After EFG's modeling adjustment that allowed EnCompass to select other options, such as standalone storage and solar-battery hybrids, CTs were not selected.

CEOs also responded to Xcel's statement that the Fargo CT reflects the Company's intention to fulfill a regulatory commitment to build a CT in North Dakota. CEO stated that the out-of-state location does not absolve Xcel's requirement to justify it, and the Commission retains the authority to scrutinize it.

E. Department Staff

The Department's explained that its preferred scenario meets all of the decision criteria contained in Minnesota Rules.

All of the scenarios modeled by Department had, as inputs, the current MISO reliability construct. Therefore, each scenario provides the same level of reliability at a minimum. At points in time some scenarios will have some surplus capacity, which implies a slightly higher level of reliability. The Department also explored high and low load contingencies that vary the forecasted demand and energy requirements.

The Department's preferred plan also has the ability to keep the customers' bills and the utility's rates as low as practicable because its recommended scenario consistently ranked among the least-cost scenarios across various contingencies (high/low forecast, high/low gas prices, etc.). The recommended scenario also ranked among the least-cost scenarios when the fundamental modeling changes (nuclear cost and forecast) were removed. The only contingency where the Department's preferred scenario performed poorly and is relevant here is the no externalities or CO_2 regulatory cost contingency and the low regulatory cost contingency. Thus, as long as the assumption that CO_2 regulatory cost will be imposed around 2025 is valid, Department Staff's scenario will keep customers' bills and Xcel's rates as low as practicable.

The third criterion under Minnesota Rules is the ability to minimize adverse socioeconomic effects and adverse effects upon the environment. Adverse effects on the environment are taken into account via the Commission's CO_2 regulatory cost and various externality cost values. Since these are basic inputs to the model, all scenarios directly consider adverse effects upon the environment. The Department's preferred scenario minimizes adverse socioeconomic effects by selecting the normal retirement date for the retirement of Monticello, which provides time for the Monticello area to adapt to the closure of the plant while not burdening other areas served by Xcel with an uneconomic asset for an extended duration. Also, Department's recommended re-study of the preferred retirement date for Prairie Island provides time for additional facts to develop before a final decision is made on Prairie Island. Last, adverse socioeconomic effects and adverse effects upon the environment are typically considered as part of the environmental review phase of site and route permit proceedings associated with Certificate of Need proceedings. The Department recommends that the Commission consider these effects in those proceedings.

The fourth criterion under Minnesota Rules is the ability to enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations. The only near-term actions on supply-side resources required by Department's modeling results are additions of substantial solar resources by 2024. Delaying most additions until after the five-year action plan enables the utility to adapt to changes in financial, social, and technological factors by providing time for these factors develop before irreversible decisions are made.

The fifth criterion under Minnesota Rules is the ability to limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control. The Department's recommended scenario maintains a wide variety of resource types on Xcel's system for at least the next decade while deferring most major additions. Maintaining a variety of resource types mitigates risks by allowing Xcel to use a variety of existing resources if events beyond the Company's control make any one resource unusable. Deferring most additions also mitigates risk because it prevents the Company from locking-in substantial resources that might later be regretted.

F. Deputy Commissioner Ranade

On February 11, 2021, Deputy Commissioner of Commerce, Aditya Ranade, filed a letter asking the Commission consider additional practical and policy concerns that are outside the parameters of the Department's Energy Regulation Planning group analysis. Deputy Commissioner Ranade recommended that the Commission approve the Monticello license extension, contingent upon approval from the NRC. Deputy Commissioner Ranade also raised concerns high methane emissions factor from natural gas production and the significant increase in transmission expenditures required to connect non-dispatchable sources of energy.

G. Distributed Solar Parties

DSP worked closely with the Sierra Club to develop and include the Distributed Generation as a Resource (DGR) model included in Sierra Club's Clean Energy for All Plan.

1. Flawed Modeling of Distributed Solar

DSP discussed several flaws about Xcel's approach to modeling distributed energy resources, in particular customer-sited solar and CSG. Xcel's modeling removed distributed solar from its corporate forecast to model distributed solar as a supply-side resource. However, unlike other resources that are allowed to be optimized by the model, distributed solar and CSG are inputs that are based on two forecasts—a base case and a high adoption scenario. In other words, Xcel fixed two amounts of distributed solar rather than using the costs and benefits of distributed solar to allow it to be a selectable resource option.

When Xcel adjusted its corporate forecast to model load-modifying resources as supply-side resources, the Company examined bundles of EE and DR, but not distributed solar. Instead, Xcel's baseline assumption is that distributed solar abruptly and significantly drops once funding for Solar*Rewards goes away after 2021 (with final installations by 2023) and Made in Minnesota awards end after 2017. New distributed solar is 173 MW in 2020 but only 16 MW in 2025 and then 15 MW annually 2026-2034.

Xcel's High Distributed Solar scenario was limited because it considered only one set of variables instead of a wide range of options. For example, the High Distributed Solar scenario was always paired with assumptions of lower fuel price, lower load, and lower technology costs for other resources. Xcel did not evaluate a range of tax credit options, price assumptions, fuel cost scenarios, or load scenarios.

In addition, DSP disagreed with Xcel's approach to treat the costs of distributed solar as strictly a utility cost because this assumption ignores costs borne voluntarily by individual customers. In effect, assuming customer-owned distributed generation costs are borne fully by the utility means distributed solar is never lower cost than utility-scale solar. However, the "cost" to the utility consists only of the incentives, if any, provided by the utility to the distributed generation owner. In fact, one of the largest benefits to the system from distributed generation is that private investment, rather than the utility and ratepayers, pay the capital costs of the generation.

Regarding CSG costs, DSP explained:

> [T]he purchase price of CSG generation to the utility reflects more than the production capacity and energy value of the solar produced. At either the applicable retail rate or value of solar rate, the cost of the output also reflects avoided distribution system costs, line losses, and environmental costs. See e.g., Minn. Stat. § 216B.164, subd. 10(f). Those costs are not included in Xcel's expansion plan modeling for other resources, so the fully loaded CSG credit is not comparable to model inputs for other resources in Xcel's planning model.[117]

According to DSP, Xcel has a history of under-forecasting CSG growth. Xcel's Supplement Plan forecasts 863 MW of community solar by 2034. Operational community solar capacity was 757

[117] DSP initial comments, p. 9.

MW on December 1, 2020, which means Xcel assumes that by 2034, there will be just 106 MW of additional CSG, or 8 MW per year.

DSP acknowledged several mitigating factors, like declines in the Value of Solar rate and interconnection delays, which could slow CSG development from historic levels. However, it unlikely such factors could slow CSG growth to a level contemplated by Xcel's forecast, including its High Distributed Solar scenario.

2. DSP's Alternative Modeling

DSP includes "Distributed Generation as a Resource" proposal, offers incremental distributed generation (over and above Xcel's base assumption) to Sierra Club's EnCompass modelers. Increments of distributed solar were priced at the utility's cost, which is the incentive, rather than the all-in cost borne by the solar owner, so the model could select additional distributed solar. DSP based this approach on the "Williams price response model," which staff will discuss below. DSP determined the amount of price reduction necessary to produce different increments of distributed generation adoption. The DG Resource concept translates the value of distributed generation to a customer into customer's adoption level.

> To identify the *utility* cost of modeled residential solar adoption, we selected incentive levels (in dollars per MWh) and used the Williams et al., model to identify adoption curves. We selected resource net cost reduction (incentive level) increments ($0, $10, $20, $30, $35 and $40) that were in the range of costs available to the model. It was assumed that other resources would be selected at cost levels above $40/MWh. An incentive level of $0 represents the difference between the Xcel base distributed generation inputs and the distributed generation adoption model.
>
> Non-residential distributed solar was estimated to be 71 percent of residential adoption, based on a national trend of relatively lower non-residential capacity. The 71 percent figure was from Solar Energy Industries Association for the entire country in 2019.
>
> Based on the calculations, we developed a DG Resource model that was offered to EnCompass by the Sierra Club modeling team at each of the five different incentive levels in each year. The quantity of megawatts available in any given year were derived from the Williams et al. model.[118]

For CSGs, DSP explained the Sierra Clubs took the modeling approach of assuming CSGs will be developed at similar rates to historic adoption levels of 140 MW per year, until a cumulative 2,040 MW of CSG is reached in 2029. At this point, CSG reaches a constraint based on the capacity available in the most recent hosting capacity analysis. Also, DSP and Sierra Club modeled incremental CSG additions as zero cost addition. DSP explained:

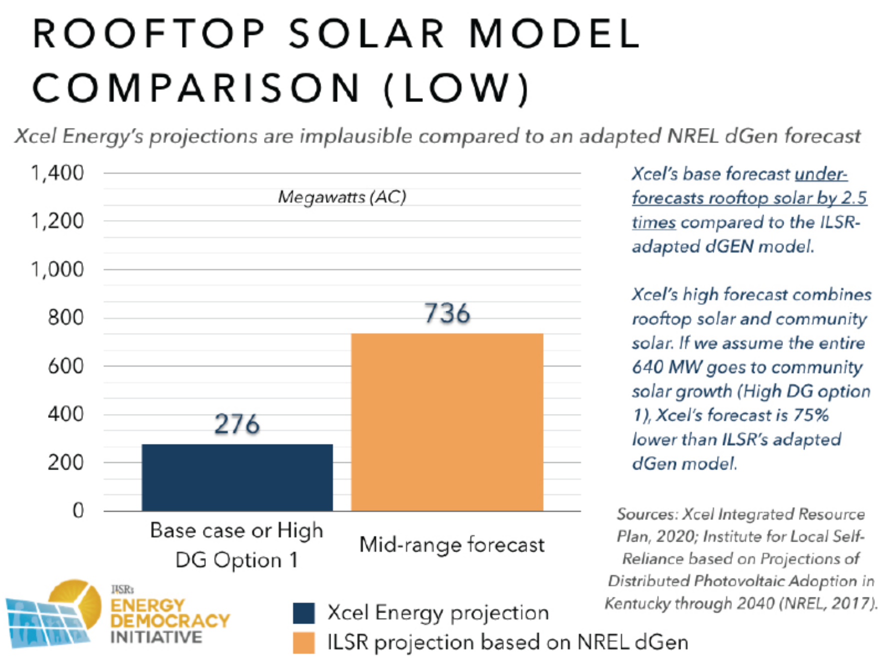
[118] DSP initial comments, p. 31.

> We model incremental CSG additions at zero cost because CSG are a unique resource in the context of integrated resource planning. CSG is a freestanding program whose adoption is driven by customer interest and developer capacity. In that way, the same costs are incurred and resources added without regard to the rest of the utility's resource mix. So long as the costs of non-selectable resources are held constant between scenario runs, the precise level does not affect portfolio selection. Excluding CSG Additions costs from the model for all runs produces the actual difference in costs based on resource choices available.[119]

3. NREL model and Williams Model

ILSR compared Xcel Energy's distributed solar forecasts to alternative forecasts produced with two independent tools. The first an Xcel/Minnesota adaptation of the NREL's dGen model,[120] which predicts individual decision-making by consumers in a population, taking into account economic and behavioral considerations. The other based is on a paper in *Renewable Energy* by Eric Williams, et al., which is based on the relationship of the net present value cost per kilowatt for a customer to install solar and the likelihood of adoption.[121]

The NREL's dGen model of approximately 736 megawatts of rooftop PV in Xcel's Minnesota territory by 2034, compared to Xcel's estimate of only 276 MW.



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[119] DSP initial comments, p. 33.

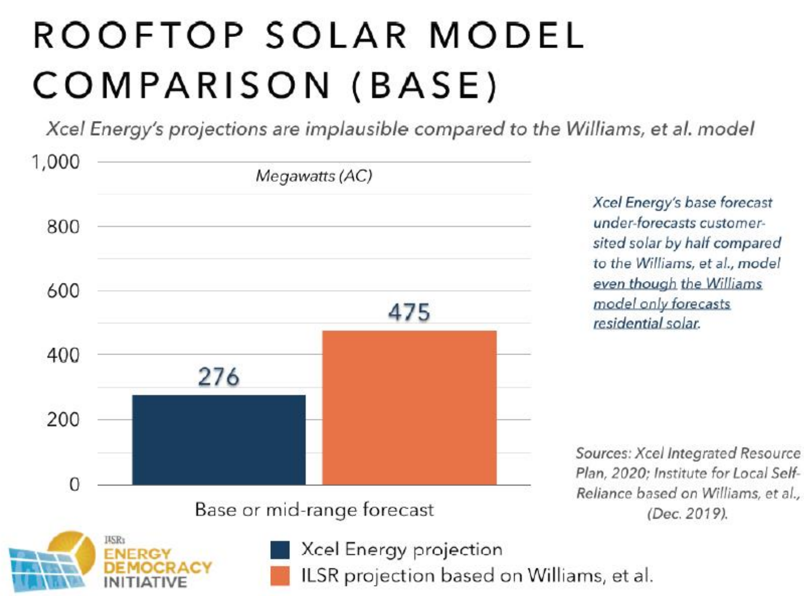
[120] The Distributed Generation Market Demand (dGen™) model simulates customer adoption of distributed energy resources for residential, commercial, and industrial entities.

[121] According to ILSR, the Williams model has a good fit with actual adoption in several markets, including three U.S. states and two non-U.S. countries. ILSR built a Minnesota-specific version of the Williams model. Assumptions are shown in the Appendix (page 31) of the ILSR report in DSP's Initial Comments.

Using the Williams model, ILSR estimated that *residential* rooftop solar should produce 475 MW of additional residential rooftop solar by 2034. Xcel forecasts only 276 MW on *residential and commercial* rooftops. DSP explained the Williams model approach as follows:

> Essentially, it uses inputs of existing, available residential rate structures and then uses a best fit model to several existing domestic and international PV markets to link net present value to megawatt adoption. By reducing the NPV to the population of eligible customers (e.g., through an incentive) the utility can produce a predictable increase in distributed generation adoption.
>
> Utilizing the Williams et al. empirical model we determined the amount of price reduction necessary to produce different increments of distributed generation adoption. The DG Resource concept translates the value of distributed generation to a customer into customer's adoption level.
>
> While those price reductions could occur naturally as further technology advances and economies of scale reduce the cost of distributed generation to a greater degree than assumed, the utility can also accomplish them and produce the corresponding customer price response by providing an incentive to lower the net cost to the level that will induce the desired level of customer distributed generation adoption.[122]

ILSR built a Minnesota-specific version of the Williams model using several assumptions, including a 4 kW system size, \$3.50/Watt, \$14,000 capital cost, 5,000 kWh annual production, and a retail price of \$0.12/kWh. In addition, ILSR added, among other parameters, a baseline of 667,980 single-family, detached homes in the Twin Cities Metro area and a solar cost declination of 5 percent per year. ILSR's projection was about 200 MW higher than Xcel's.



[122] DSP initial comments, p. 30.

4. Rakon Energy Report

DSP commissioned Rakon Energy to evaluate several considerations for high penetration distributed generation impacts on the Company's system, including identifying opportunities within the MISO market, addressing challenges, and leveraging opportunities. Rakon provided five conclusions:

1. Xcel should improve its planning to include additional distributed resources and treat them as a "central element to the utility's optimized plan." Planning for greater distributed resource penetration now allows efficient optimization rather than inefficient after-the-fact adjustments to the Company's resource plans.
2. Distributed resources interconnected to Xcel's distribution system avoid the MISO queue process that is currently backed up by more than a few years and which neither the Commission nor Xcel can control. This allows Xcel to integrate higher levels of renewable resources than by focusing on utility scale, transmission-interconnected, generation that must navigate the MISO interconnection queue.
3. MISO is currently modeling more than 3,000 MWs of distributed solar in 2021 transmission planning models. Those model runs demonstrate that a much higher level of distributed solar can be economically added to the system than Xcel is currently planning. That further confirms that the Company should revise and extend its assumptions beyond the level of distributed generation in its HDS sensitivity to determine transmission and distribution needs now.
4. Distributed solar, especially within the Twin Cities Metro Area, should have a higher ELCC than utility-scale solar connected at transmission to remote nodes. Differences in the ELCC of the same resource has been shown to vary by interconnection node.
5. Distribution connected solar avoids distribution and transmission system costs in addition to providing resource benefits. Aligning distribution, transmission, and resource planning will reveal currently unrealized value.

5. Alignment of Resource Plan and Distribution Planning

According to DSP, there must be more alignment between IRP and distribution planning:

> [S]ome of the traditional separations between the Company's distribution and resource planning functions must change - and change quickly, in order for Xcel to rapidly expand DER deployment over the forecast period. In other words, alignment between resource and distribution planning must lead - not lag - increasing DER penetration. This is because a highly distributed resource portfolio can deliver cost savings to Xcel's customers if those distributed energy resources are co-optimized with Xcel's bulk system resources.[123]

As an initial step, Xcel should take the following actions as a part of its resource and distribution planning processes:

[123] DSP initial comments, p. 42.

- Set DER deployment targets consistent with approved IRP.
- Conduct advanced forecasting to better project the levels of DER deployment at a feeder level, using Xcel's advanced planning tool.
- Proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with DER deployment targets.
- Improve Non-wires Alternative analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of DERs to address discrete distribution system costs.
- Plan for aggregated DERs to provide system value including energy/capacity during peak hours.

6. Equity

The IRP process can move toward equity by evaluating future energy sources in ways that prioritize building wealth, health, and opportunity for low-income communities and communities of color. Distributed generation allows energy users to own and control the long-term revenue from future energy sources, allowing individuals and families to share in wealth that historically has been limited to utility investors. Customer-owned or sponsored distributed generation provides increased value by distributing the profits from renewable generation as direct customer bill savings. Also, job creation and local business development opportunities are inherently greater for community-based renewable energy than for large, centralized energy systems.

H. IBEW Locals 23, 160, and 949

The International Brotherhood of Electrical Workers Locals 23, 160, and 949 (IBEW Locals) urge the Commission to recognize the impact of Xcel's energy transition – which IBEW Locals generally supports – on Xcel's union workforce.

Local 23 is headquartered in Saint Paul and has bargained with Xcel on behalf of workers in Minnesota since May 1940. Local 23 represents approximately 454 Xcel workers, with all working in Minnesota and approximately 80 percent of them residing in Minnesota. Their workers are employed in all facets of Xcel's operations, from generation to transmission and delivery, which includes but is not limited to employees working at the King plant.

Local 160 is headquartered in St. Anthony and has bargained with Xcel since 1939. Local 160 represents approximately 989 Xcel workers, with approximately 97 percent in Minnesota. Like Local 23, Local 160's workers are also employed in all facets of Xcel's operations. This includes employees currently working at the Sherco and Monticello plants.

Local 949 is headquartered in Burnsville and has bargained with Xcel since July 1946. Local 949 represents approximately 470 Xcel workers, with approximately 400 of them working and residing in Minnesota. Local 949's workers are employed in all facets of Xcel's operations as well, including the Prairie Island plant and the Wilmarth and Red Wing Refuse-Derived Fuel (RDF) plants.

IBEW Locals are participating because this IRP affects Xcel's workers, particularly those whose positions will be eliminated by the planned coal plant closures and the workers who will be employed in the future to construct, operate, and maintain Xcel's new clean energy facilities. IBEW Locals encourage a just transition that minimizes adverse impacts on workers; therefore, IBEW Locals support the construction of the Becker gas plant and Monticello nuclear plant extension. Construction of the Sherco CC could act as a source of quality jobs for over 300 IBEW workers who will be displaced by the closure of Sherco and King. The extension of Monticello will provide a source of skill-appropriate work for Xcel's highly-experienced nuclear workers.

IBEW Locals encourage the Commission and Xcel to implement the following measures as part of a workforce transition plan: fully-funded apprenticeship and training programs; relocation assistance; retention bonuses for staying through coal plant closures; early retirement; in-house decommissioning work; flexible retraining options; creation and funding of local transition centers; support for union labor to build and operate new generation resources; and creation of an ongoing labor management task force.

I. Northern Natural Gas

Northern Natural Gas (Northern) filed Initial Comments and Reply Comments but did not file Supplemental Comments once Xcel withdrew the Sherco CC from the Preferred Plan.

The focus of Northern's comments was that the modeled pipeline is hundreds of millions of dollars more expensive to build than alternatives Northern has presented to Xcel. The options Northern presented to Xcel for service to Sherco would require construction of a new 16.6-mile greenfield lateral pipeline originating from Northern's existing facilities near Buffalo, Minnesota, with other necessary system enhancements to be installed parallel to existing facilities, largely in existing right-of-way and previously disturbed areas. This represents eight times less new greenfield right-of-way than that required for Xcel's assumed pipeline.

Xcel and Northern have discussed several scenarios under which Northern would provide service to the Sherco plant throughout its useful life. In those discussions, Northern has consistently committed to be Xcel's lowest-cost and highest quality alternative for firm natural gas transportation service to Sherco. To date, however, the parties have not reached an agreement. Xcel recently issued a solicitation of interest seeking proposals from natural gas pipelines to provide the Sherco plant with natural gas transportation service. Northern responded to the solicitation by proposing no less than six separate service options, in each case providing fixed-price annual firm demand costs and assuming no upfront costs to Xcel, thereby eliminating substantial pricing risk for Xcel and its customers.

For Xcel's IRP modeling, Xcel assumed that its least-cost option to serve the Sherco CC is a 135-mile, greenfield pipeline interconnecting with the Northern Border Pipeline Company's interstate pipeline in south central Minnesota near Trimont, Minnesota. According to

Northern, Xcel's pipeline cost assumptions underestimate Northern's options, which cost less, are more reliable, and have significantly less environmental impact. The table below highlights some of the major differences in impacts between the two options.

Environmental Feature of Greenfield Pipeline	Unit	Northern Greenfield Lateral	Xcel Assumed Pipeline
Greenfield pipeline	Miles	16.6	134.5
Total Construction ROW[14]	Acres	201.3	1629.8
Wetlands Crossed[15]	Miles	1.4	6.7
Waterbodies Crossed[16]	Number	9	87
Minnesota Department of Natural Resources sites impacted	Number	9	63
Regionally Significant Ecological Areas (1 and 2)	Number	5	13
FEMA Floodplains crossed (Zones A and AE)	Number	3	9

Prior to adjusting for known risks, Northern's analysis shows that Xcel's assumed pipeline, depending on ultimate design parameters, will cost between $450 million and $550 million in 2026 dollars. Northern's analysis, however, is extremely conservative. The capital costs estimated in the analysis do not incorporate, for instance, the likely and significant increased costs caused by permitting opposition and the often-associated cost overruns. And while the analysis examines the risks a new pipeline would likely encounter in market variability, increased costs tied to rock installation and related pipe design factors, complications associated with the large amount of horizontal directional drilling required, increased pipeline length, and the significant right-of-way acquisition cost risks, it is important to note that Northern's cost analysis purposely excluded much of the impact of these risks. If realized, however, these risks would undoubtedly increase the cost of the Xcel assumed pipeline option by another $98 million to $136 million. On average, the alternatives identified by Xcel are approximately $300 million more than the Northern options.

Another reason Northern's cost analysis of Xcel's pipeline option is conservative is because it assumed there would be no increased costs caused by delays in the permitting process. While permitting delays are not the only reason for project cost overruns, they undoubtedly have played a significant role in overruns experienced by recent pipeline projects throughout the country. Northern's interstate alternative would be subject to review by FERC, so there are many reasons why Northern would be much more likely to obtain all necessary permits.

In summary, Northern explained that the legislature has authorized construction of the Sherco CC, subject to the Commission's confirmation of Xcel's IRP. Xcel has assumed the cost of a 135+ mile greenfield pipeline originating from a single point of interconnection near Trimont, Minnesota. However, Northern has presented to Xcel a pipeline that is hundreds of millions of dollars less expensive, more reliable, and have significantly less environmental impact.

J. OAG

The OAG did not submit an alternative plan, but based on the OAG's review of Xcel's modeling – which the OAG characterized as "biased," "misleading," and "flawed" – the OAG concluded that Xcel's Alternate Plan is not in the public interest. A primary concern the OAG has with the Alternate Plan is that Xcel circumvents competition by proposing Xcel-owned renewables along Xcel-owned transmission lines, which are exceedingly costly.

The proposed Sherco gen-tie line would likely be more expensive than procuring new renewables through an open, competitive bidding process and would subject Xcel's customers to unnecessary risks. The proposed gen-ties require Xcel-ownership of nearly all of the generation added in the 2020s, and the path of the lines would restrict the location of potential new resources. Consistent with arguments the OAG made in the Sherco Solar docket, avoiding competition by restricting bids to ownership and geographic results in exorbitant costs. Instead of the Sherco gen-tie, the OAG recommends the Commission require Xcel to complete a competitive bidding process to procure solar-plus-storage projects.

1. Sherco Gen-tie

The OAG determined that the Sherco gen-tie was only justified because of systematically biased, flawed modeling from the Company. Xcel claimed that the cost of its proposed Sherco gen-tie would be lower, on a per kW basis, than the interconnection costs for other new wind or solar projects in the region, but Xcel both understated the cost of the Sherco gen-tie and overstated the interconnection costs for new wind and solar projects. The OAG explained:

> Xcel's Sherco gen-tie cost estimate understates costs in at least two ways. First, the per-kW gen-tie cost stated by Xcel includes the replacement generation for all three Sherco units, which is inappropriate considering the gen-tie will only be used for replacement generation for the Sherco 1 and 3 retirements. When only the Sherco 1 and 3 replacement generation is included, the Sherco gen-tie's capital cost would be roughly $170 per kW. Second, in order to arrive at its per-kW cost estimate, Xcel assumes an unrealistic amount of new generation will be allowed to utilize the line. Sherco 1 and 3's combined interconnection rights are under 1,300 MW, yet Xcel's modeling included over 3,100 MW of replacement generation on the Sherco gen-tie, including 1,600 MW of generic wind in the 2030s. It is highly speculative to claim that this much new generation will be able to be added to the line, and even if it is technically possible, it will likely result in significant curtailments and/or capacity accreditation derates. If this 1,600 MW of generic wind is unable to be interconnected on the gen-tie, the per-kW cost of the Sherco gen-tie would increase to nearly $350.[124]

Xcel's interconnection cost assumption of $500 per kW for new wind projects and $200 per kW for solar projects is inflated because Xcel's own analysis of the interconnection costs of the

[124] OAG supplemental comments, p. 3.

most recently completed MISO West renewable projects found interconnection costs of just $157 per kW for wind projects and $97 per kW for solar.

Since Xcel proposes to own the gen-tie line, customers would have to repay not just the initial capital costs, but also Xcel's rate of return, ongoing O&M expenses, and new capital spending throughout the life of the project. By contrast, when developers bear interconnection costs, they are able to utilize lower-cost capital, and customers do not bear the risk of higher than projected O&M expenses and ongoing capital spending.

The Sherco gen-tie also exposes customers to significant financial risk; for example, Xcel acknowledged that the length of the line may need to be increased, which could increase the cost of the line by over twenty percent, and there may be a need for additional VAR support. The OAG also noted that if Xcel's resource need is overstated, customers are even more worse off because the cost of the line will be roughly the same regardless of the amount of generation that is added along it.

Finally, as discussed in a previous section, the OAG argued that Xcel misleadingly compared the cost of Sherco gen-tie solar to generic solar because it did not account for incremental transmission costs. The OAG therefore requested this information in OAG Information Request No. 16, and based on Xcel's response, the OAG stated:

> Xcel itself acknowledges that Xcel-owned solar will be significantly more expensive than third-party-owned solar. In its Reply Comment modeling, Xcel developed separate cost forecasts for utility-scale solar that would be interconnected to the Sherco and King gen-tie lines, one for generic—i.e., non-Xcel-owned—solar and one for Xcel-owned solar. Importantly, the projected cost of Xcel-owned solar was at least [TRADE SECRET DATA BEGINS … … TRADE SECRET DATA ENDS] higher than generic solar in each year of the planning period, and it was as much as [TRADE SECRET DATA BEGINS … … TRADE SECRET DATA ENDS] higher in some years.[125]

2. Sherco Solar

Xcel's petition for approval of Sherco Solar is currently awaiting Reply Comments in Docket No. 20-891. The OAG is an intervenor in that proceeding and currently recommends denying the project due to the project's costs, which the OAG ascribes to a failed bidding process. The OAG stated that Sherco Solar has a levelized cost that is dramatically higher than recent utility-scale solar projects in the region.

Xcel acknowledges that Xcel-owned solar will be significantly more expensive than third-party-owned solar. In its Reply Comment modeling, Xcel developed separate cost forecasts for utility-scale solar that would be interconnected to the Sherco and King gen-tie lines, one for generic solar and one for Xcel-owned solar. The projected cost of Xcel-owned solar was higher than generic solar in each year of the planning period.

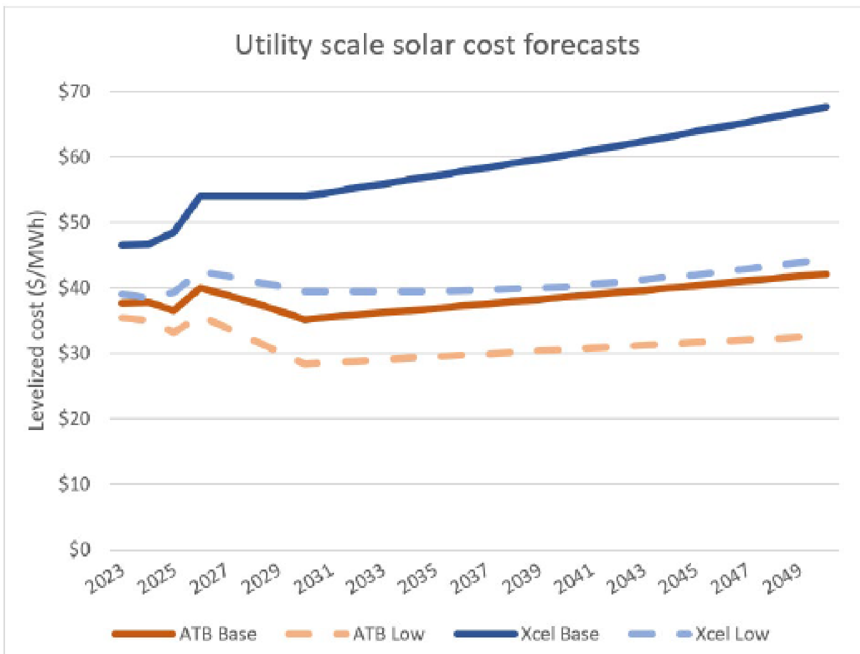
[125] OAG supplemental comments, p. 6.

The Sherco Solar project is just 460 MW of Xcel's proposed 2,400 MW of new Company-owned renewables in the 2020s. Sherco Solar alone would cost customers hundreds of millions more than a generic solar project, but if the full 2,400 MW is to be Company-owned, the resulting rate increases would be severe.

3. Additional Modeling Flaws

According to the OAG, "Xcel's solar forecasts are so significantly flawed that even the lowest solar cost sensitivity overestimates solar costs." Xcel continued to rely on solar price assumptions from the NREL 2019 ATB – which is now two years out of date – but Xcel modified it to use an unreasonably low capacity factor and interconnection costs that are unreasonably high. Figure 1 compares the solar cost inputs used in Xcel's modeling to what the inputs would be had Xcel utilized the updated ATB forecast without modification:

Figure 1. Xcel IRP and 2021 ATB solar cost forecasts



Since Xcel's Low solar cost forecast is higher than the ATB's Base forecast, Xcel's argument that is used a sensitivity analyses to examine the impact of lower-than-forecasted solar costs is invalid.

Xcel's battery storage cost forecasts are similarly flawed. Xcel's Base forecast for standalone four-hour battery storage with a 2022 COD is $18.82/kW-month. For comparison, Xcel Colorado's 2017 all-source bidding solicitation received bids from multiple developers for four-hour battery storage at under $10/kW-month, with the low bid coming in at $8.61/kW-month, or less than half of Xcel's Base battery forecast.

The OAG also agreed with the Department's analysis finding that Xcel's resource needs are likely overstated. And contrary to Xcel's claim that its "updated analysis generally results in variances within the Department's ±5 percent band," the average forecast variance far exceeds the Department's band for a significant portion of the planning period.

K. Sierra Club

In addition to the modeling and reliability analysis previously discussed, Sierra Club's comments also emphasized the importance of considering equity as part of resource planning. Sierra Club explained:

> While Xcel has taken the critical first step of discussing equity considerations in its IRP and publicly stating its commitment to racial equity, certain key elements of its proposed Alternate Plan continue to create a barrier to achieving the outcome the utility has expressed it desires.

Sierra Club stated that the construction of two new gas plants is inconsistent with this commitment because the impacts of climate change will be borne disproportionately by Black, Indigenous, and People of Color (BIPOC) communities in Minnesota. The gas plants are also more expensive than clean energy alternatives and could saddle customers with stranded costs, an economic burden that would most harm our most vulnerable communities.

Strong deployment of distributed and community solar will result in job creation and community investment, both keys to Minnesota's sound economic future. Programs are also needed to ensure that the customers who most need the benefits of clean energy – BIPOC and low-income Minnesotans, as well as renters – have access to community solar, distributed generation, and EE programs. The Commission should further encourage Xcel to work with stakeholders to expand opportunities for low-income customers to access solar and energy efficiency and develop dedicated marketing plans for these programs.

Sierra Club recommends the Commission order Xcel to bring forward a proposal in 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. Xcel's own forecasting in its High Distributed Solar Adoption forecast shows that a 10 percent cost reduction incentive is able to stimulate significantly more customer investment in distributed generation.

Sierra Club also recommends the Commission to order Xcel to commit to ending its contract with the Hennepin County Recovery Center (HERC) when it expires in 2024, and to explore ways to exit that contract as soon as possible. The HERC incinerator is a major source of air pollution and directly impacts Minneapolis environmental justice communities.

L. Suburban Rate Authority and Coalition of Local Government Units

A coalition of 38 Minnesota local governments within Xcel's service territory, which includes the Suburban Rate Authority – a 32-member city joint powers association – filed a letter expressing the shared goal of decarbonizing the electricity system for the public good. The letter provided a table showing local governments' energy and carbon reduction goals:

Local Government	Carbon Reduction Goal	Energy Goal
Bloomington	75% by 2035	95% reduction in city-wide electricity-related ghg emissions
Eden Prairie	100% carbon neutral by 2050	10% in-boundary renewable electricity (51 MW)
Edina	30% by 2025, 80% by 2050	
Hennepin County	30% by 2025, 80% by 2050	3% annual operational energy reduction, proposed 5% renewable energy goal regionally
Mahtomedi	30% by 2030, 100% (carbon neutral) by 2050	1.4% annual energy savings, 19% reduction by 2030 (from 2016 baseline)
Northfield	Carbon-free electricity by 2030, 100% by 2040 (economy-wide)	10% in-boundary renewable electricity (20 MW)
Ramsey County*	30% by 2025, 80% by 2050	Energy use reduction: 30% by 2025, 80% by 2050
St. Louis Park	100% carbon neutral by 2040	100% by 2030, 10% in-boundary (37 MW)
Saint Paul	100% carbon neutral by 2050	10% in-boundary renewable electricity (200 MW)
Washington County	30% by 2025, 80% by 2050	

**- Goal for local government operations*

The coalition applauds the actions Xcel proposes to support clean energy and decarbonization that are generally in line with the signees' goals, in particular Xcel's decisions to:

- Retire all coal plants by 2030,
- Retire the Cottage Grove and Black Dog 5 gas plants,
- Increase solar and wind generation, and
- Increase energy efficiency and demand response.

However, the coalition believes Xcel can do more to reduce carbon emissions and support underserved communities. Minnesota local governments have priorities to address racial inequities. Minimizing adverse socioeconomic effects of utility decisions means protecting communities from the impact of harmful energy production processes and addressing the historic impact such processes have had on low-income communities and people of color, while providing equitable access to the clean energy economy.

Also, the above-noted local governments have goals to add over 300 MW of local/in-boundary renewable generation, and the coalition recommends that the IRP consider local clean energy goals. The coalition also asks that Xcel coordinate resource and distribution planning; local governments are doing infrastructure and asset planning on a local scale, which presents a great opportunity for coordination to maximize efficiency and ensure cost-effectiveness. Xcel should also include beneficial building electrification in the load forecast. Finally, Xcel made a commitment to carbon neutrality by 2050; the coalition requests more details on the subsequent 15-year period (2035-2050) in order to have confidence in Xcel's plans to achieve that goal.

M. Xcel Large Industrials

Xcel Large Industrials (XLI) recommend the Commission approve Xcel's Scenario 15 (minus the Sherco CC), which is Xcel's "Extend All Nuclear" scenario from the Company's Supplement. Under Scenario 15, both Monticello and Prairie Island are extended for 10 years, but the retirement dates for King and Sherco 3 are unchanged. (Staff notes that Xcel did not re-run Scenario 15 as part of its Reply Comment modeling.) XLI recommends the Commission reject the Alternate Plan because it does not meet the Commission's criteria for a resource plan due to its lack of detail and uncertainty.

XLI's comments emphasized affordability, reliability, and flexibility, and XLI urges the Commission to consider customers' exposure to the risks associated with the Alternate Plan:

> Consistent with Minn. R. 7843.0500, subp. 3, which contains the factors the Commission must consider when evaluating an IRP, XLI has continually approached each iteration of this IRP with a focus on the following factors: (1) cost and affordability, in light of Xcel's increasing industrial rates; (2) reliability, as the electric generation sector retires traditional dispatchable units; and (3) flexibility, in transitioning to an untested carbon-free future. XLI has also drawn the Commission's attention to Minn. Stat. § 216C.05, subd. 2(4), which is a new energy policy goal added in the year 2017 to have "retail electricity rates for each customer class be at least five percent below the national average."[126]

1. Scenario 15

XLI argued that an approach which extends existing nuclear assets and allows the coal plants to reach the end of their economic lives, as contemplated by Scenario 15, strikes a reasonable, cost-effective balance between maintaining flexibility and decarbonizing Xcel's system. XLI noted that all 15 baseload scenarios from Xcel's Supplement exceed Minnesota's existing goal of a 30 percent emissions reduction by 2025 and 80 percent reduction by 2050, and all 15 plans achieve reductions of at least 70 percent by 2030.[127] Moreover, Scenario 15 still allows Xcel to reach its internal goal of 80 percent carbon-free by 2030. The added benefit is that Scenario 15 allows the Commission time to review retirement dates in the next IRP. Xcel could also operate remaining coal plants at reduced capacity factors, which could further reduce their carbon emissions relative to how the plants operate today.

In Figure 3 below, which is included in a report from XLI's expert, Kennedy and Associates, shows that there were six plans in Xcel's Supplement that were lower cost, under the PVRR measure, than Xcel's (formerly) Preferred Plan, Scenario 9. Scenario 15, Extend Nuclear, was the second least-cost plan (with Extend Prairie Island only being the least-cost scenario).

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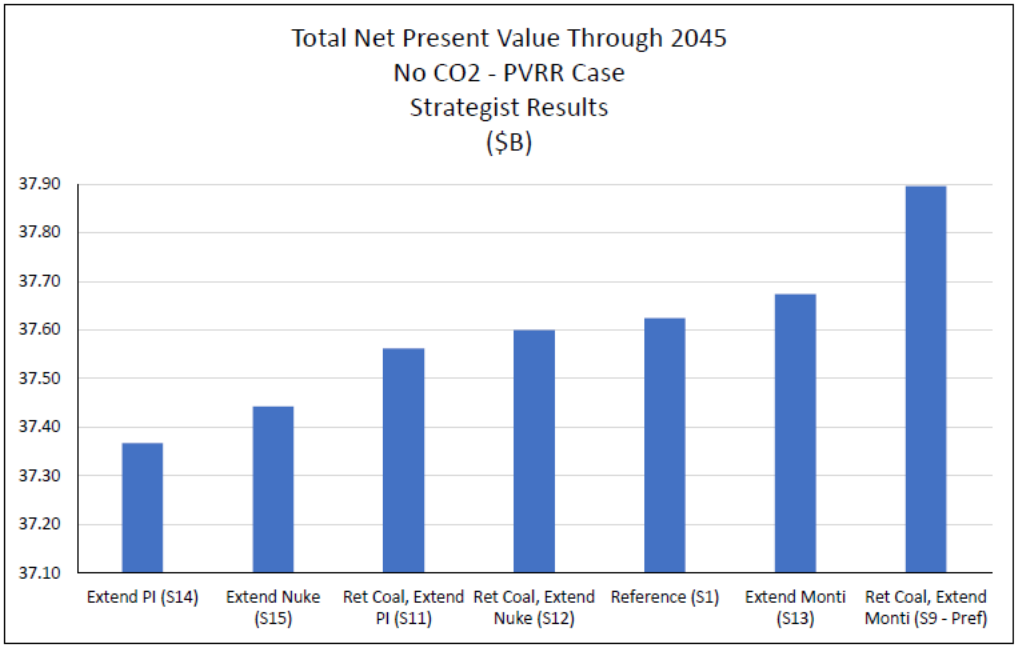
[126] XLI supplemental comments, pp. 2-3.

[127] XLI reply comments, p. 3

Figure 3



XLI emphasized that its recommendation to defer a decision on coal plant retirement dates is not so the coal units can operate longer. Rather, XLI's position is that it is unnecessary to commit to retiring King and Sherco 3 at this time, and additional analysis is required to ensure the plants can be removed from Xcel's system without risking grid stability and reliability. By the next IRP, XLI expects that more will be known about upgrades that are needed to the transmission system and other carbon-free technologies.

Kennedy and Associates cited NERC's 2020 Long-Term Reliability Assessment, which stated that with system-wide penetrations of renewable resources growing quickly, reliability risk is becoming less concentrated at traditional peak hours, and more distributed throughout the year. Moreover, the MISO system could have a shortfall of 1,161 MWs in 2025 in meeting its target reserve margin.[128] Kennedy and Associates concluded:

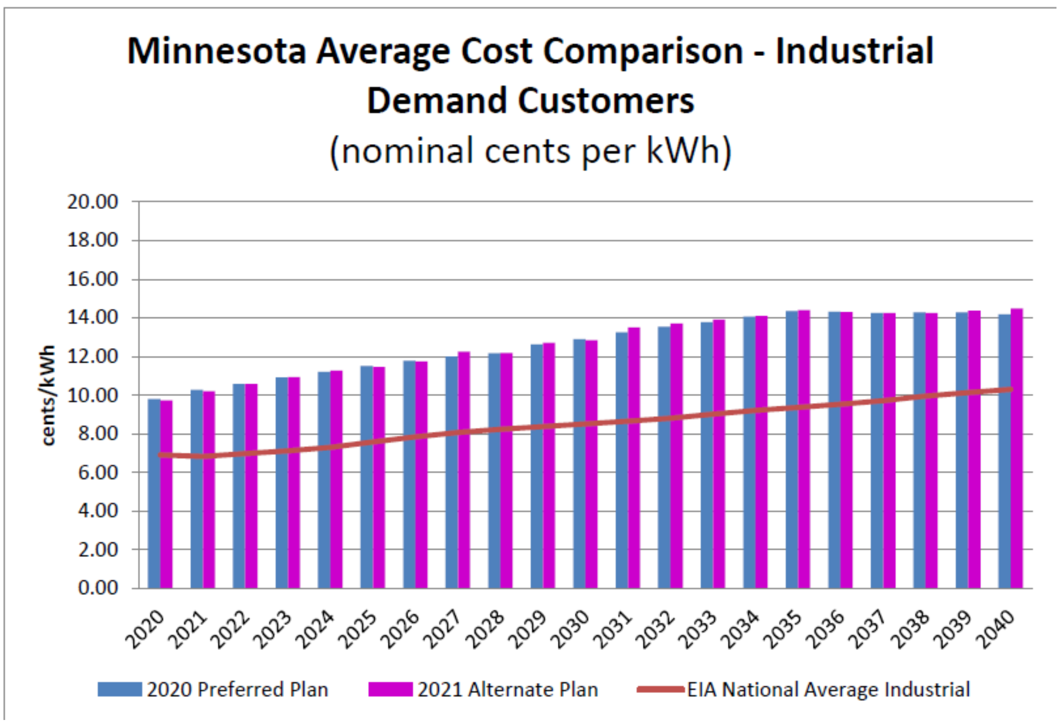
> In order for the Company to flexibly navigate the coming energy transition to more renewable resources and provide clean, affordable, and reliable electricity to ratepayers, the Commission should emphasize flexibility and affordability. The simplest way to do this, in our opinion, is to not assume the nuclear units would be retired, not commit to early retirement dates for coal units, and not prejudge the resources that should be considered in the blackstart proceeding.
>
> Although the Company's Alternate Plan promises cost savings on the surface, these savings are based on simplistic analyses that are exposed to cost overruns and operational risks. Further, because the Company did not consider the costs of

[128] XLI supplemental comments, Exhibit C, Kennedy and Associates report, p. 9.

other Alternate Scenarios, it withheld an apples-to-apples comparison of the costs and benefits of this new directional approach.[129]

2. Rate Impacts

XLI does not believe Xcel and other stakeholders have sufficiently considered cost and affordability in their respective proposals, which is required under the Commission's IRP rules and Minnesota law. XLI stated that the average delivered cost of energy for Xcel's industrial customers was $0.0802/kWh in 2019, which was roughly 17.8 percent above the national average in 2019 for industrial customers. Xcel's projected rates for industrial customers will not improve under either the Updated Supplement or Alternate Plan. The figure below, which Xcel produced in response to XLI Information Request No. 154, shows that the average cost for Minnesota industrial customers will remain higher than the national average (using EIA National Average data):



XLI applauded Xcel's ambitious carbon goals; however, XLI cautioned that goals can come at the cost of rates and flexibility, and Xcel's decarbonization is not necessarily in the interests of its ratepayers. Kennedy and Associates stated:

> [I]t should not be ignored that the Company stands to receive significant financial benefits if its coal units are retired early and it builds new replacement resources. The Company will do this by seeking to recover all of the remaining undepreciated

[129] XLI supplemental comments, Exhibit C, Kennedy and Associates report, p. 13.

costs of the retired assets and by increasing its rate base for all of the newly constructed Company-owned resources.[130]

3. Zonal System Restoration

XLI raised concerns that Xcel's zonal blackstart proposal is not a fully-fledged plan, and the new approach to system reliability, which was not introduced until Reply Comments, has not been sufficiently vetted by stakeholders. XLI noted that the zonal blackstart approach will require the involvement of other utilities in Minnesota, with uncertain results. XLI stated that while the Alternate Plan proposed interesting ideas, "the record upon which it is being proposed is exceedingly thin."

In fact, XLI believes that the Alternate Plan does not meet even the most basic definition of a resource plan, which is "a set of resource options that a utility could use to meet the service needs of its customers over a forecast period." According to XLI, the proposed zonal blackstart approach is merely theoretical, and any resource plan proposed to the Commission must show that it can meet the service needs of its customers before it can be approved. By offering a future proceeding dedicated to blackstart, the purpose of which will be to address the location and type of resources needed, Xcel concedes that Alternate Plan is undeveloped. Basic questions such as how Xcel would handle a blackout that occurs at night, to what extent will solar and wind be part of a blackstart plan, or how might power outage times may change under a zonal approach versus a centralized approach, remain unanswered.

In addition to failing to meet reliability standards, the Alternate Plan takes excessive risks; one is that a zonal approach will require near-term investment that would lock Xcel into the zonal blackstart approach, or at least make reversal costly. Until ratepayers can be reasonably sure of the costs, benefits, and risks, the Commission should not approve the zonal blackstart plan. XLI therefore recommends that the Commission reject the Alternate Plan because it fails to comply with the evidentiary and legal requirements applicable to resource plans.

4. Transmission Lines

XLI supports Xcel's plans to use existing interconnection capacity at the King and Sherco sites. However, XLI is concerned about the costs. For instance, Xcel's cost analysis is limited, and Xcel made significant assumptions within its modeling that are highly uncertain. For example, Xcel tested a transmission cost sensitivity that increased the line mileage of the Sherco gen-tie from 140 miles to 175 miles. This assumption alone increased the modeled cost of the Sherco gen-tie from $578 million to $713 million, and in the production cost modeling, customer savings relative to the Supplement Plan were reduced approximately $132 million, which eroded nearly all projected savings on a PVRR basis. Kennedy and Associates stated:

> [T]he Company's transmission analysis for the AS King and Sherco gen-tie upgrades has only been investigated at a high level and will need to be significantly expanded and scrutinized before being considered for Commission approval.

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[130] Kennedy and Associates report, Exhibit A of XLI Initial Comments, p. 15.

> These shortcomings do nothing to abate our existing concerns about upcoming resource adequacy challenges in MISO, the timing of elements included in the plan, and the lack of apples-to-apples comparisons with other resource plans that the Company previously evaluated, including XLI's preferred Scenario 15.[131]

5. Recommendations

XLI supports Xcel's Scenario 15 without the Sherco CC and believes more analysis is required before the Company transitions from a centralized system restoration approach to a zonal approach. Scenario 15 allows flexibility by not committing to early retirements of existing resources that may be considered further in a zonal blackstart proceeding. However, if the Commission does not prefer Scenario 15, it could adopt a hybrid approach that would approve common elements of Scenario 15 and proposals in modeling parties' plans, such as:

- 0.6 GW of distributed solar;
- 2.0 GW of energy efficiency;
- 0.5 GW of demand reduction;
- 0.8 GW of wind; and
- 2.7 GW of solar.

Since Xcel has not demonstrated that the transmission expenses, reliability risks, or the need for gas-fired CTs have been adequately addressed, XLI recommends the Commission order an investigatory docket that would address:

- Whether a zonal blackstart approach can provide a cost-effective (from both a rate and bill impact perspective) and reliable alternative to centralized blackstart;
- The resources that would best support zonal blackstart to provide reliable and cost-effective capacity and energy to consumers; and
- Whether prolonged economic dispatch of existing resources can avoid significant capital investments in interim natural gas resources, thereby ultimately accelerating the transition to a carbon-free future.

XI. Public Comments

<u>2019 Public Meetings</u>

Soon after the filing of Xcel's initial filing on July 1, 2019, the Commission asked the Office of Administrative Hearings (OAH) to hold public meetings in Xcel's service area. The OAH conducted five in-person public meetings in October 2019. Collectively, 323 individuals signed-in at the meetings, 104 people spoke, and the ALJ collected 47 written comments.

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[131] XLI supplemental comments, Attachment C, J. Kennedy and Associates, Inc., p. 6.

Table 8: Public Meeting Participation

Mon, Oct. 21, 2019, 2pm	Sabathani Community Center Minneapolis	27 participants 12 speakers 4 written comments
Mon, Oct. 21, 2019 7pm	Sabathani Community Center Minneapolis	101 participants 30 speakers 15 written comments
Wed, Oct. 23, 2019 7pm	Holiday Inn St. Cloud	75 participants 21 speakers 7 written comments
Mon, Oct. 28, 2019 7pm	Dayton's Bluff Recreation Center St. Paul	86 participants 29 speakers 14 written Comments
Wed, Oct. 30, 2019 7pm	Mankato Civic Center Mankato	31 participants 12 speakers 7 written comments

On December 28, 2019, the ALJ filed a written summary of the public comments. Transcripts of each public meeting are also available in eDockets. Below, staff excerpts major points from the ALJ's summary.[132]

- Across all of the public meetings, numerous commenters expressed concerns about climate change, asserting that a climate crisis exists and requires action. These commenters generally asserted that Xcel's IRP is not aggressive enough to address this issue.
- Xcel's plan to extend the life of the Monticello nuclear plant received positive and negative comments.
- Many commenters expressed concerns about Xcel's plan to build a fracked gas plant in Becker, Minnesota. The gas plant also received support from some commenters.
- Many commenters at the meetings expressed that Xcel should do more to foster and integrate community and rooftop solar, as well as battery storage, and put ownership of energy infrastructure into the hands of Minnesotans.
- Several commenters expressed generally favorable views about Xcel related to matters other than the IRP.

General Comments

In addition to the public hearing comments, the Commission directly received a large number of written public comments. There are approximately 225 entries in eDocekts under "public comments," but some of those are for batched entries that contain more than one separate comment. Comments from a number of non-intervenor groups are summarized specifically in the sections below. While it is difficult to summarize all the individual comments, in general they tend to fall into the following categories:

[132] Report Summarizing Public Meetings.

- Xcel's plan is heading in the right direction, but should move more quickly to renewables.
- Many commenters specifically opposed the proposed 800 MW Sherco CC.
- Xcel should prioritize communities, workers, consumers, and renewable energy to reduce emissions as quickly and steeply as possible.
- The Commission should reject the plan because it is too expensive.
- Xcel should not shut down coal plants early and risk reliability.

The majority of the comments fell under the general views summarized in the first three bullet points above.

Local Governments and Tribal Nations

A. Prairie Island Indian Community

The Prairie Island Indian Community (PIIC) raised several concerns about the continued operation and possible license extension for Prairie Island Units 1 and 2. PIIC has been a constant source of concern since the plant was placed into service. PIIC had no role in siting the plant, received no benefit from the plant's construction or continued operation, and is experiencing negative impacts as a result of the plant's construction.

While Xcel did not propose a license extension in this IRP, PIIC remains concerned about the risks associated with ongoing operation, as well as the indefinite storage of spent nuclear fuel. In the next IRP, PIIC recommends that Xcel provide sufficient data and operating experience that could provide insight into any technical issues or concerns related to subsequent renewals. For example, Xcel should be required to provide general information needed on subsequent license renewals, such as:

- Planned investments at the Prairie Island nuclear plant.
- Any aging management issues that may arise from continued operation.
- Expectations regarding the future nuclear workforce.
- Cyber-security issues or concerns, as plants move from analog to digital systems.
- True comprehensive cost-benefit analysis, which includes potential environmental and economic impacts to the PIIC and Treasure Island.
- Additional spent nuclear fuel generated over a 10- or 20-year period.
- How fuel stored on-site will be removed.
- Additional State permits, Certificates of Need, or federal licenses that will be required.

B. City of Becker

The City of Becker filed comments on February 9, 2021, before Xcel withdrew the Sherco CC. However, the City of Becker expressed support for the Sherco CC as well as license extensions for the Monticello and Prairie Island plants. The City of Becker also supported Xcel's goals for carbon reduction and hopes to continue working with regulators, policymakers, and stakeholders to mitigate the impacts of coal plant closures on host communities.

C. Becker Township

After Xcel withdrew the Sherco CC from its Preferred Plan, Becker Township filed comments emphasizing the devastating impact such a decision would have on the socioeconomic future of the City of Becker and the surrounding region, including Becker Township. The entire Becker community has hosted a central power station since the 1970s, and Becker Township supported the Sherco CC because it viewed the replacement power plant as an effort to mitigate the adverse socioeconomic impacts of retiring all three Sherco coal units. Becker Township requested the following:

> if the Sherco combined cycle plant is not included in the final, approved plan, it is now more essential than ever that all stakeholders, including the Commission, Xcel Energy, and numerous other participants in this docket, use every tool at your disposal to support communities like Becker, both the City and Township.

Becker Township supports the extension of the Monticello Nuclear Plant and requests the Commission consider the same socioeconomic impacts to the City of Monticello.

D. City of Burnsville

The City of Burnsville (Burnsville) filed comments on December 10, 2020. Burnsville supported Xcel's plan to retire or repurpose its coal plants, which the Company has successfully done in Burnsville at the Black Dog plant. Burnsville supports the expansion of wind and solar energy, continued operation of the nuclear plants, and the Sherco CC.

Burnsville also noted that it is successfully achieving its goals set forth in the city's Sustainability Plan and is on track to meet its goal of a 30 percent greenhouse gas reduction by 2025. However, Burnsville understands that reliability is important; for example, there is a need for natural gas backup to pump and process drinking water and keep its buildings operational by maintaining a reliable power source.

E. Burnsville Chamber of Commerce

The Burnsville Chamber of Commerce filed comments supporting Xcel's IRP and Xcel's commitment to energy, reliability, and affordability while reducing carbon emissions.

F. City of Monticello and City of Monticello Industrial Economic Development Committee

The City of Monticello (Monticello) is a community of approximately 13,900 residents located in Wright County. Monticello supports Xcel's proposed extension of the Monticello nuclear plant through 2040. In addition, Monticello supports the Sherco CC and continued operation of the Prairie Island nuclear plant.

The proposed license extension at Monticello provides valuable time to prepare a transition for the community, and an impact as significant as replacing the economic benefits of the nuclear plant will require as much time as possible. In preparing a transition plan, Monticello seeks collaboration with Xcel and other stakeholders.

The City of Monticello Industrial Economic Development Committee also filed comments supporting the proposed extension of the Monticello plant and also emphasized the importance of having sufficient time to prepare a long-term transition plan.

G. City of Red Wing

The City of Red Wing (Red Wing) discussed how the Prairie Island nuclear plant is "deeply intertwined" with the community's economic well-being, and the plant is, and will hopefully remain, a boon to the regional economy while providing carbon-free energy.

Red Wing also expressed disappointment that this resource planning process has lasted more than two years, which inhibits the City's efforts to be able to plan according to the Commission's decision. While Xcel had stated in 2019 that the future of Prairie Island would be a part of the Company's next IRP process, given the amount of time that has passed since the process began, Red Wing asks the Commission to consider an adjusted forecast period and use the evidence presented in this record to determine that an extension of Prairie Island is in the public interest. In the alternative, Red Wing requests the Commission require that Xcel begin Prairie Island stakeholder discussions and make additional filings immediately.

The table below is an excerpt from the host community study facilities by the Center for Energy and Environment, entitled "Minnesota's Power Plant Communities: An Uncertain Future," which shows some of the socioeconomic benefits Prairie Island provides to the community. Red Wing noted that over half of Red Wing's tax base is derived from the plant or related property, and over half of the more than 600 plant employees earn roughly $109,023 on average. In addition, many plant employees reside within Red Wing and Goodhue County.

Table 6: Prairie Island Nuclear Generating Station Quick Facts

Power Plant Information	
Power plant fuel type	Nuclear
Projected closure date (unit respective)	2033, 2034
Generation capacity	1,100 megawatts
Plant employees	600
Average annual plant employee income[38]	$109,023
City Information	
City population	16,500
% of plant workers residing in city	31%
% of city's tax base from power plant	54%
County Information	
Goodhue County population	46,304
% of plant workers residing in county	39%
% of county's tax base from power plant	22%
School District Information	
% of school district's tax base from power plant	40%

Red Wing requires the ability to develop near-term city budgets and long-term planning; Red Wing stated "we owe it to our residents and businesses to be planning for the day when [the Prairie Island plant] retires." Not knowing when or if the plant will retire in the 2030s impedes Red Wing's ability to make that transition.

Finally, the uncertain fate of Prairie Island impacts Red Wing's ability to access external resources to support transition planning because eligibility for those programs sometimes exclude communities where the retirement status is uncertain. For example, the Energy Transition Grant Program was created in 2020 to provide grants to power plant host communities, and Red Wing was the only community hosting an Xcel power plant that was excluded from receiving an award.

H. City of Saint Paul

The City of Saint Paul (Saint Paul) supported the Company's decision to withdraw the Sherco CC and accelerate renewable energy and storage. However, Xcel's Alternate Plan insufficiently addresses equity and economic outcomes for Saint Paul's BIPOC and under-resourced residents. Xcel is one of the larger employers in Minnesota, so it is critical that Xcel bolster its efforts in workforce development and training to intentionally create pathways to careers at Xcel for BIPOC and low-wealth/low income Minnesotans.

In addition, Xcel's IRP fails to adequately capture distributed solar. Saint Paul has a goal of 200 MW of distributed solar by 2030, yet Xcel's IRP forecasts very little distributed solar. In addition, Saint Paul also has aggressive energy efficiency goals, which prioritizes improved efficiency in the homes of energy-burdened residents. Xcel should also perform additional analysis accounting for faster beneficial electrification so that Xcel's infrastructure is not a limiting factor. Finally, Saint Paul supports a just transition in Becker and Sherburne County to assure that the loss of jobs and local revenues associated with this IRP are mitigated.

I. City of St. Louis Park

The City of St. Louis Park (St. Louis Park) has a Climate Action Plan, which aims to achieve a net zero carbon footprint by 2040 and has an interim goal that includes achieving 100 percent renewable electricity by 2030. St. Louis Park supports Xcel's goal to reach 80 percent carbon reductions by 2030 but encourages Xcel to explore a transition away from natural gas to 100 percent renewable energy. St. Louis Park noted that methane leaks occur during the extraction and transportation of natural gas, which has a Global Warming Potential many times greater than that of CO_2.

St. Louis Park recognized that nuclear energy *may* play a role in reducing greenhouse gas emissions in the short-term, but with the risks inherent in nuclear power, St. Louis Park encourages Xcel to plan for a future without nuclear power.

J. Goodhue County Board of Commissioners

The Goodhue County Board of Commissioners adopted and filed a resolution supporting Xcel's IRP. The resolution stated:

- Xcel is a critical piece of the economy in Goodhue County, the largest taxpayer, and one of the largest employers;
- Goodhue County supports activities that sustain the large tax base and workforce that Xcel provides within Goodhue County;

- Goodhue County supports reducing carbon emissions and investing in clean energy;
- Goodhue County values reliable electricity; and
- Goodhue County supports Xcel's plan to retire its coal plants in the Upper Midwest and build a natural gas plant in Becker.

K. Wright County Board of Commissioners

The Wright County Board of Commissioners also adopted and filed a resolution supporting Xcel's IRP. The resolution supported Xcel's plan to reduce emissions, invest in renewable energy, retire its coal plant, and build a natural gas plant in Becker to ensure reliability.

L. Wright County Economic Development Partnership

Wright County Economic Development Partnership is a not-for-profit member organization focused on enhancing the economic vitality of the region. Its membership includes all the cities and many large and small businesses within Wright County. The Partnership supported Xcel's plan to retire its coal plants, expand wind and solar energy, continue operating its carbon-free nuclear plants, and build the Sherco CC. The Partnership expressed support for reducing carbon emissions and expanding clean energy, while maintaining reliability of service.

<u>Organizations</u>

M. Clean Energy Economy Minnesota

Clean Energy Economy Minnesota (CEEM) encouraged Xcel to achieve 100 percent carbon-free electricity by 2050 and avoid replacing thermal power plants with resources that could potentially leave ratepayers with stranded costs. As Xcel considers how to meet its firm dispatchable resource needs, CEEM argued that solar-plus-storage, standalone storage, and DR are superior alternatives. CEEM expressed support for the Sherco Solar project, and in the future, Xcel should pursue additional solar-plus-storage projects, which are already competitive against new gas peaking plants.

CEEM discussed several benefits of DR, and CEEM argued DR should play an even bigger role to offset any decreases in system performance when integrating variable resources. Xcel should focus on offering more DR options to its customers, including allowing customers to work with third-party aggregators. In its IRP, Xcel expressed concern that its DR capacity accreditation could be reduced by MISO because it is considering more stringent testing requirements, which could yield lower benefits in future years. However, since Xcel's filing, FERC approved MISO's proposal to enhance its capacity accreditation requirements that apply to DR to reduce the disparity between resources that cleared and resources that responded to calls for deployment.

CEEM discussed how distributed solar, distributed storage, dispatchable and non-dispatchable DR, energy efficiency, and smart charging of EVs can all work together to help Xcel realize a carbon-free future. To do this, Xcel's Integrated Distribution Plan (IDP) should be considered in conjunction with its IRP.

CEEM encourages Xcel and the Commission to emphasize equitable paths to a carbon-free future and prioritize where clean energy delivers the most public benefits. Xcel's IRP should deliver benefits including but not limited to disadvantaged, vulnerable, and low-income communities; black, indigenous, and peoples of color; communities that will be impacted by retirements; and landowners as land use changes to accommodate clean energy resources.

N. Coalition of Utility Cities

The Coalition of Utility Cities (CUC) is an organization of eight member cities that host Minnesota's largest power plants. The organization's membership includes Becker, Granite Falls, Monticello, Oak Park Heights, and Red Wing.

The CUC expressed disappointment that Xcel withdrew the Sherco CC from its Preferred Plan, since the City of Becker will be deeply impacted by the closure of the Sherco coal plants. Constructing and operating the Sherco CC would create jobs and provide tax base in the region.

The CUC also supported the extension of the Monticello nuclear plant. CUC explained that the Monticello plant is beneficial to the community and its residents, and if the plant is not extended, the simultaneous retirement of Sherco and Monticello would have devastating effects on the region.

Regarding the Prairie Island nuclear plant, CUC believes waiting until the next IRP to make a decision on the Prairie Island plant has serious negative consequences on the city. It is essential for any community facing the possibility of plant retirement to have ample time to prepare for the outcome of either extension or retirement. The City of Red Wing is working to plan for any scenario, but the uncertainty surrounding the fate of the plant inhibits their ability to make and finance strategic investments.

In addition, the plant's uncertain future puts the city in limbo when it comes to outside resources for transition planning. This was already seen when Red Wing was unable to take advantage of the Community Energy Transition Grant Program created by the Minnesota Legislature in 2020 because the plant is not addressed by this resource plan. Other cities including Red Wing's nuclear host community peers in Monticello received grants of up to $500,000 to support planning, economic development, and transition work in advance of potential plant retirements.

Finally, the CUC discussed the creation of the Energy Transition Office, which is intended to ensure a successful transition for communities and workers that will be impacted by the retirement of power plants. The CUC strongly urges the Commission to participate actively in this process, and the Commission should do its part to support host communities and workers.

O. Community Energy Justice Commenters

The Community Energy Justice Commenters consists of community-based organizations who met regularly to collectively evaluate Xcel's IRP. The community commenters applauded Xcel's removal of the Sherco CC but remain concerned that Xcel supplemented the plan with additional fossil fuel plants. The community commenters outlined its top three priorities:

- Prioritize local, distributed renewables, efficiency, and energy storage to equitably build community wealth, deepen energy affordability, and alleviate health burdens;
- No perpetuation of dirty energy, which disproportionately pollutes and extracts wealth from working class communities and communities of color both in Minnesota and the national and international sites of fuel extraction; and
- Create clear mechanisms and metrics for accountability to ensure the public interest is protected, and that benefits equitably accrue to local communities from our energy system.

The community commenters' specific directives for the IRP include:

- Withdraw plans for the Sherco CC;
- Do not extend the Monticello or Prairie Island nuclear plants;
- Shut down Sherco units 1-3 and King by 2025;
- No ownership or contract for purchase of energy from trash burners and commit to cutting contracts with the HERC incinerator;
- Solicit local community energy plans and climate action plans from the communities that Xcel serves;
- Reparation and remediation for harm done in the following host plant communities; and
- Create clear workforce goals and benchmarks for Xcel's internal and external workforce.

P. Energy Efficiency for All Partners

Energy Efficiency for All Partners (EEFA) is comprised of Fresh Energy, Community Stabilization Project, Green & Healthy Homes Initiative, Inquilinxs Unidxs Por Justicia, Minnesota Housing Partnership, National Housing Trust, and Natural Resources Defense Council. EEFA recommends the Commission:

- Direct Xcel to adopt practices in furtherance of procedural justice, including: deeper engagement with renters, affordable rental property owners, BIPOC communities, and under-resourced individuals, providing resources for engagement and participation, and providing financial support for impacted individuals to participate in dockets and decision-making processes;
- Direct Xcel to support the formation of an environmental justice accountability board, which would develop environmental justice-focused initiatives to be incorporated throughout the utility;
- Direct Xcel to develop and report on (or more regularly report on, if already developed) comprehensive recruitment, hiring, retention, and advancement goals and strategies for staff and board, as well as deepening its supplier and vendor diversity efforts; and
- Modify the Company's IRP to remove the proposed gas plant, which will disproportionately harm Minnesota BIPOC and under-resourced communities, and direct Xcel to instead focus on equitable energy efficiency and renewable energy investments.

EFFA's imperatives were summarized as follows:

> Fundamental to our Energy Efficiency for All (EEFA) work are the imperatives of racial equity and environmental justice. Fresh Energy, for example, has defined equity as "the elimination of barriers to full participation in the *process*, and access to the full benefits of the *outcome*." This intentionally broad definition is designed to reflect the unique needs of any given individual, group, or community, and acknowledge that fully realizing this definition of equity in practice will inherently require different levels of investment (such as time, outreach and education, or financial support) for certain groups, especially those who have been historically under-resourced or marginalized.

While Xcel's equity-related commitments to-date positive show signs of equitable *outcomes*, EEFA believes there is an equivalent need to focus intentional action on equitable *process* in the Company's IRP and future processes.

EEFA recommended improvements in diversity and inclusion. In Xcel's Supplement, the Company states that "[a]t the end of 2019, Xcel Energy's female representation was 23 percent of the workforce and minority representation was 15.4 percent of the workforce…Xcel's female representation of leaders was 20.7 percent and minority representation of leaders was 9.8 percent." The Company also states that it "aims to increase these numbers" in its workforce diversity, but Xcel should state clear goals for diversity in its workforce and leadership, based on clear and tangible metrics suggest that regular reporting could take place in the Commission's Energy Utility Diversity Group (EUDG) docket,[133] and strategies could be included in future IRPs.

Xcel should also consider its role in the broader Minnesota clean energy workforce. Energy efficiency jobs are the largest clean energy employer in the state, and the Company should prioritize contracting and working with diverse entities. The Company should explore and discuss best practices and opportunities to increase vendor and supplier diversity with interested parties and community partners.

EEFA also opposed the Sherco CC. Natural gas facilities are inequitable for BIPOC and under-resourced communities. New carbon-emitting electric generation would put Minnesotans at risk of continued pollution, including BIPOC communities who are already suffering disproportionately. Further, BIPOC and under-resourced communities are most at risk of impacts to ratepayers due to stranded assets and uneconomic operations

Q. Energy We Can't Afford

Forty-one Energy We Can't Afford supporters, who are also Xcel customers, filed letters opposing any plan that would contain new natural gas plants.

R. Generation Atomic

Generation Atomic supported continued operation of Xcel's nuclear plants and encourages the Commission to extend the life of both plants to 80 years. Generation Atomic stated the Prairie

[133] Docket No. 19-336

Island plant has been less expensive, on a levelized cost basis, than new wind resources, after accounting for transmission costs. Generation Atomic cited Germany's decision to phase out nuclear power, which has resulted in delaying their ability to phase out coal units.

Since nuclear plants are dispatchable sources of power, replacing them with weather-dependent renewable resources will require the continued use of gas and coal plants or the installation of unproven grid-scale storage technologies. In addition, Generation Atomic believes the risk around the storage of spent nuclear fuel is overstated.

S. ILSR et al.

Institute for Local Self Reliance (ILSR), Native Sun, Solar Bear, Minnesota Interfaith Power and Light, MN350, Community Power, St. Paul 350, Izaak Walton League – Minnesota Division, Union of Concerned Scientists, Sierra Club, Land Stewardship Project, Honor the Earth, Minnesota Environmental Partnership, and Clean Up the River Environment (CURE) submitted a joint letter urging the Commission not to approve Xcel's proposed CTs. Instead, the organizations urged the Commission to delay consideration so it could examine alternatives such as a combination of renewable energy and energy storage to meet the need instead.

T. Investors (As You Sow, Boston Common Asset Management, Seventh Generation Interfaith Coalition for Response Investment)

As You Sow, Boston Common Asset Management, and Seventh Generation Interfaith Coalition for Responsible Investment (Investors) are engagement service providers representing institutional investors of large publicly-traded companies, including Xcel. The Investors have a fiduciary duty to assess companies' climate transition plans and make investments that support a resilient and thriving economy. The Investors voiced concerns over Xcel's proposal to build the Sherco CC, as it undermines the achievement of a clean energy transition and poses significant risk to both investors and ratepayers.

More businesses would invest in clean energy in Minnesota if there is an opportunity to do so. Clean energy, including DER, allows businesses with significant energy demand to source less of their electricity load from the power grid and reduce peak demand.

Finally, the Investors support equity and energy justice for all Minnesota ratepayers, particularly for historically-marginalized communities. Xcel should strive to broaden participation in resource planning processes, especially to include those in historically-marginalized communities who are often most impacted by these decisions.

U. IUOE Local 49

International Union of Operating Engineers, Local 49 (IUOE 49) represents over 14,000 heavy equipment operating engineers across Minnesota, North Dakota, and South Dakota. IUOE 49 supported Xcel's commitment to utilizing local union labor for the construction of its renewable energy projects and for the Company's strong history of utilizing local contractors and union labor at legacy facilities.

IUOE 49 also supported Xcel's path transitioning away from fossil fuels while maintaining reasonable costs and a dependable energy supply for its ratepayers. IUOE 49 noted that many of its members are also Xcel ratepayers. IUOE 49 is therefore supportive of extensive renewable additions, firm generation peaking facilities, and the extension of licensed use of nuclear facilities. IUOE 49 noted:

> The proposed extension will allow the highly skilled men and women that work at and maintain the Monticello Nuclear Plant to continue that work at least through 2040. This extra decade of operation will create substantive employment opportunities. From January 1st, 2018 through April 30th, 2021 20 Local 49 members and 4 Operating Engineers from other locals have worked a cumulative 14,415 hours. This equated to over $640,000 paid to IUOE members. Based on the historic frequency that this facility conducts major maintenance projects the additional decade of facility usage would conservatively provide our members with over 36,000 hours of work translating into over $1.6 million in compensation.

Xcel's IRP Attachment C discusses the Company's plans for an inclusive and diverse workforce, as well as how they plan to ensure an equitable workforce transition. IUOE 49 stated that Xcel's commitment to utilizing local union labor to build, staff, and maintain their facilities advances this strategy. IUOE 49 Local 49 is also committed to diversity efforts, and their comments discuss several initiatives to become more inclusive and equitable in the energy construction sector.

V. LIUNA Minnesota and North Dakota

LIUNA supports Xcel's original IRP, which includes the Sherco CC. LIUNA stated that the Minnesota Legislature recognized the economic significance of the natural gas plant when it voted in 2017 to authorize Xcel to build the facility. LIUNA urged the Commission to recognize in the legislature's action a state policy that explicitly favors resource decisions designed to mitigate the impact of the Sherco coal unit retirements on area workers and communities.

The Sherco CC was expected to create 400-500 construction jobs and additional operations jobs, so not moving forward with the gas plant will have significant consequences for area members of LIUNA and fellow building trades, utility workers, and surrounding communities. In addition, LIUNA believes Xcel's system is more vulnerable to intermittent renewable energy, which exposes Xcel's customers to increasingly volatile energy markets.

If the Commission prefers Xcel's Alternate Plan, LIUNA supports Xcel's two proposed natural gas plants in Fargo and Lyon County. This will provide some assurance that the system will continue to function in extreme weather conditions. LIUNA disagrees with proponents of battery storage as a viable alternative to the Sherco CC. As recent experiences in California and elsewhere have demonstrated, battery storage is not a sufficiently reliable resource, and according to LIUNA, natural gas CTs are clearly superior resources to meet Xcel's peak and blackstart needs.

Also, if the Commission does not approve the Sherco CC, the Commission should approve Xcel's plan to reuse existing interconnection rights, including the construction of a gen-tie line to facilitate development of renewable resources. Transmission is a major constraint to renewable energy development in the region, and Xcel's gen-tie proposal offers a way forward.

W. MN Sustainable Growth Coalition

The MN Sustainable Growth Coalition is comprised of numerous large commercial and industrial customers of Xcel. The Coalition supported Xcel's preferred plan as it focused on a reduction in carbon emissions while preserving reliability. It also recommended focusing on several additional issues, including clean energy and regional prosperity, transmission build out, and community and equity. For example, it recommended increasing investment in workforce development that prioritize low-income community members, BIPOC, women, and displaced workers.

X. Monticello Labor Coalition

The Monticello Labor Coalition consists of the Minnesota Building & Construction Trades Council, Pipefitters Local 539, and Construction & General Laborers Local 563. The Monticello Labor Coalition's comments explain its support for the Monticello nuclear plant extension.

The Monticello Labor Coalition argues the Monticello plan is essential to Xcel's and the State's decarbonization goals. In fact, at 671 MW operating at 95 percent or more capacity factor, it is the only significant carbon-free, non-intermittent generating resource on Xcel's system on the Prairie Island units. Monticello is made even more valuable generating resource as a result of Xcel's removal of the Sherco CC from its Preferred Plan.

According to the coalition, declining to approve the Monticello extension as part of Xcel's IRP would have adverse consequences to Minnesota energy consumers and result in unacceptably high risk. Specifically, declining to approve the extension would pose the following risks:

- Decarbonization goals would be more challenging because carbon-emitting generation resources may replace the baseload contribution from Monticello;
- Monticello provides around-the-clock reliability, system resiliency, and insulation from extreme weather and gas commodity price spikes, which no alternative can provide;
- Xcel's modeling indicated that the least-cost scenarios included extensions of Monticello and Prairie Island. Thus, Monticello allows Xcel to control costs and ensure affordable service.
- The Monticello Plant provides economic security for employees and tax revenues for local communities. Extension of the Monticello license would extend those benefits.

In response to Xcel's proposed Alternate Plan, the Monticello Labor Coalition stated that the removal of the initially proposed Sherco CC increases the importance of extending the Monticello facility.

Y. Litty Solar

Litty Solar recommended that Xcel incorporate more DR and point-of-use solar. Litty Solar noted that capital projects such as grid-scale solar, combined cycle, and firm dispatchable technologies are not necessarily the most reliable, affordable, equitable, least-risky solutions because major capital projects are inherently risky and expensive. Responsibility for capital investment and O&M cost on behind-the-meter DR and distributed solar rests solely on individual owners and can therefore reduce risk and cost to the public.

Litty Solar explained that for Xcel to build 4,000 MW of grid-scale solar, they will need to secure over 20,000 acres, likely through eminent domain processes, of previously undeveloped land as well as building roads, feeder lines, and expanded substation capabilities. Distributed solar and DR, on the other hand, make use entirely of already developed areas and infrastructure that is generally adequate to support energy improvements.

Z. St. Paul 350

St. Paul 350 filed Initial, Reply, and Supplemental comments, along with letters of support from 12 of St. Paul's district councils and over 1,300 St. Paul residents. They noted the importance of reducing carbon emissions to avoid the worst impact of climate change. St. Paul 350 supported Xcel's plans to retire their coal plants early, increase utility-scale solar, and increase DSM. St. Paul 350 noted Xcel's lack of inclusion of city-specific energy goals—for example, the City of St. Paul's goal of 200 MW of in boundary renewable energy by 2030. St. Paul 350 recommended a more robust inclusion of distributed solar resources in future IRPs. St. Paul 350 opposed Xcel's new proposal for CTs, stating there had not been enough time to evaluate what it considered an entirely new IRP. Therefore, it recommended denying Xcel's request to add 1,200 MW of new CT capacity additions and defer the decision to a future IRP.

Tim Wulling, a volunteer at St. Paul 350, filed an individual public comment. Tim Wulling stated that because greenhouse gas emissions have continued to increase in spite of global commitments to reduce CO_2, there is less time to act; therefore, carbon-free deadlines must be advanced. The Commission must deny fossil fuel generation like natural gas CTs. Moreover, before approving new or repowered gas CT, the Commission should direct, Xcel to provide more detail on its plans for operating with hydrogen as a fuel source. In addition, DSM must become a major component in light of an increasingly renewable grid. Finally, Xcel's IRP did not adequately address how Advanced Metering Infrastructure (AMI) could be implemented .

AA. St. Paul Area Chamber

The St. Paul Area Chamber supported Xcel's IRP because it would advance sustainability while allowing for economic growth to continue. The St. Paul Area Chamber stated it "supports an innovative energy system that balances cost-effectiveness and reliability, while integrating renewables and new technologies that customers and the market require," which Xcel's IRP achieves.

BB. U.S. Representative Tom Emmer

U.S. Representative Tom Emmer, representing Minnesota's Sixth Congressional District, submitted comments conveying the concerns of constituents regarding, in particular, Xcel's decision to remove the Sherco CC from its Preferred Plan. Representative Emmer stated that the Alternate Plan is less reliable than Xcel's 2019 proposal. While Xcel stated in its Reply Comments that many parties opposed the Sherco CC, the Company's decision ignored supporters of the Sherco CC. Additionally, Xcel ignored the jobs and economic opportunities that would be created by the Sherco CC, and Xcel's promise to work with employees to ensure a smooth transition away from coal is vague.

CC. U.S. Solar

U.S. Solar supported CUB's Consumers Plan and specifically the use of the WIS:dom model, which treats distribution-interconnected DERs as a variable that can be dynamically scaled up or down during the course of model runs. Significant ratepayer savings can be found when an IRP model is able co-optimize for distribution-level resources, and for the first time, an IRP model can dynamically calculate these savings. cumulative Minnesota ratepayer costs by "$6.45 billion by 2040" by implementing CUB's proposed Consumers Plan, which achieves this modeled cost reduction by selecting, among other resources, "1,900 MW of distributed solar PV" and "1,300 MW of 8-hour battery storage" over the next 15 years. With this level of DER capacity, VCE found that by 2035, "the Consumers Plan is 2.15 ¢/kWh cheaper than [Xcel's] Preferred Plan." US Solar recommends the Commission modify Xcel's IRP to use the cost optimal DER capacity increments found CUB's Consumers Plan.

XII. Staff Discussion

A. "Hard-coded" Resources

As a preliminary matter, as staff reviewed the rounds of modeling and analysis by Xcel and the parties, it was frustrating to see repeated arguments over "hard-coded" large natural gas units—meaning EnCompass is forced to accept certain expansion units that were not approved by the Commission. Presumably, if resources are in the public interest, then that would be a robust result in the selection of an optimized portfolio.

The discussion over Xcel hard-coding large natural gas units into its model dates back to pre-filing stakeholder workshops. Staff attended at least one stakeholder meeting where it was suggested to Xcel not to model the Mankato Energy Center (MEC) solely as an acquired asset because the Commission had not yet approved it. Xcel chose to model MEC as an acquisition, and after the Commission denied it, Xcel needed to supplement the modeling accordingly.

Similarly, the Sherco CC was a hard-coded resource in Xcel's initial filing and Supplement. This required other modeling experts to fix the constraint and reoptimize the model to identify a least-cost plan. EFG (on behalf of CEOs) explained:

1.1.5 Allowing the Model to Choose the Sherco CC

All EnCompass modeling runs discussed by Xcel in its Supplemental IRP filing included the Sherco combined cycle ("CC") as a hardcoded resource. Since Xcel did not present any runs without the Sherco CC, it was not possible to ascertain if the Sherco CC was indeed an optimal choice. Xcel did provide a scenario in its EnCompass database that was set up with a constraint to prevent the model from adding the Sherco CC but the results of that run were not provided nor discussed in the IRP. For these reasons, we set up an initial run in which we removed Xcel's constraint forcing in the Sherco CC and allowed EnCompass to choose the resource (or not) as part of its optimal plan. When the constraint was removed, the Sherco CC is not selected by EnCompass. Because EnCompass did not view the Sherco CC as "optimal", the constraint forcing the addition of the Sherco CC was removed for all CEO modeling runs, with the exception of the "Revised Xcel Preferred Plan". We left the Sherco CC as a fixed resource in our "Revised Xcel Preferred Plan" capacity expansion resource portfolio (explained below), so that a resource portfolio with the Sherco CC could be compared directly with the "CEO Preferred Plan" capacity expansion resource portfolio (also explained below in Section 3.1).

Once again, in Supplemental Comments, Sierra Club objected to Xcel's choice to hard-code the greenfield CTs in Fargo and Lyon County into the Alternate Plan. Sierra Club explained:

> Xcel hard-wired the CT additions into its EnCompass resource baseline, circumventing the point of conducting capacity expansion modeling: developing the optimal least-cost portfolio. Existing units should be allowed to retire and new resources should be selected on an economic basis to ensure a least-cost plan. It is a common technique in modeling to justify a resource decision by comparing it to the next best alternative—i.e., by allowing for the model to choose optimal resource additions. Yet the Company has <u>only</u> modeled portfolios for its Alternate Plan that include the CT resource additions rather than let the model determine an optimal resource. Even if one agreed with all of the Company's other assumptions and methodology (which we do not), Xcel has provided no evidence in its Reply Comments and Alternate Plan that the newly proposed greenfield CTs are optimal resource additions because Xcel baked them into all of its model runs.[134]

If in fact Xcel "hard-wired the CT additions into its EnCompass resource baseline," as Sierra Club stated, then this would be contrary to Xcel's statement in Reply Comments that "the Company has only included projects in our baseline that were approved as of June 1, 2021."[135]

Since staff did not perform capacity expansion modeling, perhaps Xcel can clarify this issue and justify why it hard-coded natural gas resources. After all, hard-coding units is not new; utilities have locked-in wind and solar units needed to comply with the RES/SES, but clearly, natural gas resources do not have a statutory mandate. At a minimum, hard-coding large, carbon-emitting units seems to create additional, unnecessary work for intervenors who already have limited

[134] Sierra Club supplemental comments, pp. 5-6.

[135] Xcel reply comments, p. 90.

time and resources, and it makes reviewing various plans needlessly complicated, especially without clear explanation from Xcel about why constraints are in place to begin with. Staff defers to the modeling parties on whether the Commission needs to address this issue, but staff's hope is that intervening parties do not have to keep repeating this same concern in future proceedings.

B. Justifications for Approving the Alternate Plan

One justification for approving Xcel's Alternate Plan is the plan's performance across a broad range of sensitivities under both the PVRR and PVSC metrics. Table 4-16 of Xcel's Reply Comments, also on page 45 of the briefing papers, shows that the Alternate Plan results in savings relative to the Reference Case under all but one sensitivity run. Also, sensitivities J, K, and L – the environmental externalities sensitivities – show that customer savings increase as environmental externality costs are increased.

A second justification for approving the Alternate Plan is that it insulates customers from risk. According to Xcel's sensitivity analysis, the Company explained that the upside potential of the Alternate Plan is much greater than the downside potential.

> As shown in [Table 4-16], both the Supplement Plan and the Alternate Plan show benefits under a broad range of sensitivities and futures, and a much larger range of upside (savings) potential than cost potential. Specifically, the range of outcomes above show that we could expect the Supplement Plan to achieve anywhere from $1 billion of savings to $124 million of cost, as compared to the Reference Case. But there are far more cases in which the Supplement Plan shows savings than costs, and the median sensitivity indicates expected savings of approximately $200 million. **For the Alternate Plan, the upside potential is even higher, while the downside potential is lower**, with a range of just over $2 billion of potential savings and the highest potential cost would be $16 million.[136] *(Emphasis added by staff.)*

Third, the Alternate Plan performs well across several reliability metrics while providing a path for deep decarbonization. Table 4-1 below shows reliability metrics Xcel used to evaluate its plan, the range of costs deltas relative to the Reference Case, and an estimated carbon reduction of 86 percent relative to 2005 levels.

[136] Xcel reply comments, pp. 140-141.

Table 4-1: Company Plan Performance Across Selected Key Planning Metrics

	Plan	Updated Scenario 9	Alternate Plan
Cost	PVSC delta ($ million, cost/(savings) relative to Reference Case)	($234)	($606)
	PVRR delta ($ million, cost/(savings) relative to Reference Case)	$96	($46)
Environment	Carbon reduction by 2030 (percent, from 2005 levels)	80%	86%
	Total carbon-free generation, 2034 (percent of total generation)	73%	82%
Risk and Reliability	Firm capacity-to-peak demand ratio	0.63	0.58
	Sensitivities - range of cost deltas relative to Reference Case	(1,090) – 124 *Median: (202)*	(2,163)-16 *Median: (544)*
	2034 Native capacity shortfall events	0	0
	2034 expected unserved energy (EUE)	0	0
	Loss of Load Hours (LOLH)	0	0
	2034 maximum 3-hour net load ramp under base assumptions (MW)	4,081	4,484

Under the Commission's IRP Rules, resource plans must be evaluated on their ability to maintain or improve reliability of service; keep customers' bills and the utility's rates as low as practicable; minimize adverse socioeconomic effects and adverse effects upon the environment; and effectively manage risk to the utility and to its customers. As shown in Table 4-1, the Alternate Plan meets all five factors the Commission must consider.

In response to the argument that approving a gat CT would be in violation of the Renewable Preference Statute, system reliability is a core element of resource planning. If parties' alternative plans present greater reliability risks than Xcel's Alternate Plan, then these plans may not be in the public interest. However, if the Commission finds that modeling parties' alternative plans are not inferior to Xcel's Alternate Plan from a reliability perspective, then staff would agree the Renewable Preference Statute may prohibit approval of a gas CT at this time.

C. Firm Dispatchable Resources

Xcel requests that the Commission find there is a need for approximately 800 MW of generic firm dispatchable resources to be acquired through the Modified Track 2 resource acquisition process. It is imperative that there be a clear understanding what "generic firm dispatchable" means. And, staff believes it is insufficient to simply state a technology can at some point in the future operate on hydrogen, when no assessment of the costs or risks were presented.

Xcel defines firm dispatchable resources as "resources that are guaranteed available at and for a given time ("firm") and can be dispatched within a designated amount of time at the request of grid operators."[137] Xcel also describes wind and solar as "variable," batteries as "use-limited," and Xcel believes "hybrid renewables-plus-storage resources are not expected to be a cost-effective alternative to standalone renewables."[138] By process of elimination, it is unclear what resource(s), from Xcel's perspective, could add up to 800 MW of generic firm dispatchable resources except a gas CT. Also, staff presumes Xcel is referring to 800 MW of installed capacity, not UCAP MW, but staff notes that Xcel defines its net obligation in terms of UCAP, and Xcel uses different assumptions for capacity accreditation across resource types.

Clarification is also needed because under the Modified Track 2 process, into which Xcel would presumably bid the Lyon County CT, it should be clear how Xcel will define firm dispatchable generation when issuing an RFP, so prospective bidders understand the definition.

Unlike the Track 2 process that is overseen by an ALJ, the Modified Track 2 process allows Xcel greater control in terms of the selection and evaluation of projects. Xcel would take the following steps under the Modified Track 2 process (assuming it bids the Lyon County CT):

1. Xcel would issue an RFP for firm dispatchable resource proposals.

2. The day before Xcel receives responses to that RFP, Xcel submits its own (e.g. Lyon County CT) petition. This petition will contain an estimate of final costs for the project and other project details necessary to evaluate its proposal in accordance with the factors identified above.

3. After receiving bids in response to Xcel's RFP, the Company will evaluate the bids and select projects for contract negotiation that are in the best interest of its customers. Xcel will evaluate the bids using a number of factors, such as:
    a. Levelized cost;
    b. Financial capability;
    c. Project schedule;
    d. Project design;
    e. Project risks;
    f. MISO queue position status;
    g. Interconnection and network upgrades;
    h. Energy production profile;
    i. Site control;
    j. Project output delivery plan;
    k. Expected turbine availability;
    l. Pricing options;
    m. Project development milestones;
    n. Exceptions to standard contract terms and conditions; and
    o. Other relevant factors

[137] Xcel response to PUC Information Request No. 16.

[138] Xcel supplement, p. 53.

4. Xcel will then make a filing to the Commission that will include the contracts for projects selected from the RFP, as well as a comparison between those projects and Xcel's proposal. Xcel will include a ranking and bid data for all bids received in response to the RFP and an analysis of the factors identified above for all projects for which the Company conducts due diligence. Additionally, Xcel will provide an independent third-party auditor report of its RFP process, which will review Xcel's evaluation of proposals and due diligence, as well as tis selection of proposals for contract negotiation.

D. Xcel's Five-Year Action Plan

Xcel's five-year action plan, which is required under Minn. R. 7843.0400, subp. 3(c), is essentially a description of the resources a utility plans to acquire and the regulatory filings a utility intends to make over the first five years of its resource plan.[139] Xcel describes its five-year action plan on pages 23-26 of the Company's Reply Comments.

In total, the Alternate Plan adds over 9,000 MW of new resources by 2034, incremental to the Company's existing baseline, and not including the extension of Monticello. However, since resource planning is an iterative process, and expansion plans change – often quite dramatically – from one resource plan to the next, the Commission often limits the acquisition process to roughly the five-year action plan, although the Commission can certainly address years beyond the action plan. The table below[140] displays additions by resource type and over three groups of time: the full planning period, 2024-2026, and the 2027-2029 timeframe.

Table 9. Total Resources Added, in MW, 2020-2034

Type	Total, 2020-'34	Total in 2024-'26	Total in 2027-'29
Storage	250	0	0
Wind	2,650	0	400
Solar	3,150	1,300	1,150
Firm Dispatchable	2,937	319	748

Staff chose these groups of time because 2024-2026 is the Sherco 2 replacement window, and 2027-2029 is the Sherco 1 replacement window. The Commission may choose to address the two replacement windows differently, either by establishing different resource acquisition processes or deferring action on the second group to the next IRP.

There is general consensus that Xcel should add a substantial amount of solar in 2024-2026, although there is not agreement that Xcel should construct transmission lines and own the solar. (Note that the CUB and Sierra Club plans both add substantial amounts of wind in this timeframe as well.) Also, not all resources in the table above will go through Minnesota

[139] Since the initial filing was in 2019, but the Alternate Plan was proposed in 2021, Xcel extended the end date of the five-year action plan from 2024 to 2025.
[140] The table is based on Table 4-10 of Xcel's Reply Comments.

regulatory process. Below, staff will discuss what the Commission can expect to see prior to Xcel's next IRP filing. This may help the Commission decide how to view different groups of time over the planning period.

Out-of-State and Blackstart Resources. The Fargo CT and the Wisconsin blackstart unit will move forward through North Dakota and Wisconsin regulatory proceedings, respectively. The Minnesota-located blackstart unit will be a repowering project, which Xcel argues does not require a separate regulatory proceeding for a Certificate of Need, as it falls under an exemption.[141] These units represent three out of the four nonrenewable resources proposed in the 2020s (the fourth being the Lyon County CT).

Transmission Lines. According to Xcel, the two high voltage transmission lines – the 140-mile 345-kV line going south from Sherco to Lyon County in southern Minnesota and the 15-mile 345-kV line going east from King into Wisconsin – will take approximately five years to permit and build.[142] Thus, staff expects regulatory proceedings for both transmission lines will begin soon after the IRP is approved.

Replacement Resources. Similarly, staff expects Xcel will begin filing replacement resource petitions once the IRP is approved. At the October 7, 2021 Commission meeting – when the Commission took up Xcel's Motion to Strike the OAG's Reply Comments – Xcel notified the Commission that the Company will issue a solar RFP following the IRP decision, so staff expects the solar acquisition process to begin in 2022.[143] Xcel's Reply Comments did not specify if resource replacement filings will include combinations of resources (similar to Minnesota Power's Energy***Forward*** Portfolio), or if they would be staggered. Xcel's Reply Comments did state that solar, the Lyon County CT, and possibly wind acquisition proceedings will begin in the five-year action plan.

Also, staff notes that EnCompass chooses a higher level of solar (on an installed capacity basis) than the interconnection rights, due to expected generation patterns and accreditation levels for renewables.[144,145] Thus, the years in which EnCompass selects solar does not exactly match the three-year windows allowed for replacement resources at Sherco 2, Sherco 1, and King, as shown in the two tables below.

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[141] Specifically, Xcel argues the repowering qualifies under Minn. Stat. § 216B.243, Subd. 8(a)(6), which applies to "the modification of an existing electric generating plant to increase efficiency, as long as the capacity of the plant is not increased more than ten percent or more than 100 megawatts, whichever is greater."

[142] Xcel reply comments, p. 26.

[143] Commission meeting webcast, at 46:36, https://minnesotapuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=1552

[144] Xcel response to OAG Information Request No. 14.

[145] Note that Encompass limits the hourly MW flow of all replacement resources to not exceed 720 MW from 2024-2026; 1,430 MW 2027-2029 and 1,996 MW 2030-onward, but does not limit the model on an installed capacity basis.

Resource replacements (MW ICAP)			
	Xcel-owned	Generic	Year(s)
Sherco 1			
Solar	850 MW		2024-2025
Wind			
Sherco 2			
Solar	600 MW		2027
Wind	400 MW		2028-2029
CT		374 MW	2029
Sherco 3			
Solar			
Wind	150 MW	1,600 MW	2030-2032
King			
Solar	600 MW	50 MW	2028-2030
Wind			

Year	Amount of Solar Added in EnCompass (MW)
2024	700
2025	600
2026	-
2027	600
2028	150
2029	400
2030	100

Lyon County CT. Some parties recommend the Commission take no action or defer a decision on the Lyon County CT because the in-service date for the Lyon County CT is not until 2029. As staff will explain in the Resource Acquisition section, staff believes the most appropriate course of action is to not approve the Lyon County CT in this IRP and require that it be competitively bid into a separate process that allows other resource types.

Future Solar Acquisition Filings. The Alternate Plan proposes extensive new capital investments in the near-term. Staff shares the OAG's and XLI's concerns about the cost of the gen-ties and the Department's modeling finding that a mere $5/MWh increase in solar pricing eliminated solar from the five-year action. (Staff also shares the Department's perspective that "one of the few realistic paths in the near term for adding substantial, cost-effective capacity of any type is through Company ownership of Sherco and King gen-tie lines and re-use of the existing interconnection rights.")

Staff expects Xcel will file a petition for approval of one or more solar resources shortly after the IRP decision, which, given the amount of solar selected in the model, may resemble Xcel's 1,550 MW wind portfolio petition in 2016 (the Alternate Plan includes 1,300 MW of solar in

2024-2025).[146] In that petition, Xcel evaluated proposed projects both on an individual basis and as a total portfolio to provide transparency around the projected benefits of each individual project.[147] For future solar acquisition petitions, staff recommends the Commission require Xcel to include updated capacity expansion modeling, with forecasted rate impacts. For solar acquisition petitions that include more than one project, staff recommends that projects be modeled on an individual basis and as a total portfolio. Also, while not a decision option, the Commission could contemplate a general finding consistent with the Department's language that "small increases [in solar prices] are significant and should be taken into account in the subsequent resource acquisition proceeding."

E. Resource Need

The IRP process is intended to ensure there are sufficient resources to reliably serve a utility's customers over a 15-year planning period. In capacity expansion modeling terms, Xcel explained:

> [O]ur capacity expansion modeling is solving to add resources that provide enough **accredited capacity** to meet our full Planning Reserve Margin Requirement (PRMR) obligations at MISO, **informed by our load** for our entire upper Midwest service area (including NSP-W), our effective planning reserve margin, and the existing and approved resources we have on the system.[148] *(Emphasis added by staff.)*

When EnCompass is "solving to add resources," the load forecast informs the size, type, and timing of resources that will be needed. Next, assumptions must be made about how much MISO-accredited capacity will be provided by existing and future resources. Certain modeling choices also influence the resource need, such as allowing all existing contracts to expire and removing existing resources from the system at the end of their economic lives.

1. Load Forecasting

A utility's load forecast is the foundation of an IRP, which makes the Department's conclusion that Xcel's forecast is "systematically biased" quite concerning. Generally, resource planning assesses range estimates as opposed to point estimates, so Xcel was correct in its response that a sensitivity analysis can usually account for uncertainty. However, the Department's argument is that there is bias, not error, and Xcel has overstated its need by more than the sensitivity range. A fundamental element of resource planning is to assess risk, and the risk of over-forecasting could mean ratepayers having to pay for unnecessary resources.

Staff's earlier summary of the Department's comments showed a table of Xcel's forecast error in terms of percent error. Portrayed another way, the table below shows the average error in terms of MW (again from October 2008 to 2018). If beginning just with year 2014, the forecast

[146] Docket No. 16-777.

[147] Docket No. 16-777, Xcel Petition, p. 44.

[148] Xcel reply comments, p. 91.

error not only always overstates the need at every data point, but the size of the error equates to about the size of one or two CTs in within about the second or third year of the forecast.

Table 3b: Xcel's Demand Forecast Error, October 2008 to Present (MW)

Forecast Vintage	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Oct-08					873	1,053	612	196	451	504	1,279	1,606	1,322	1,866	1,550
Apr-09						790	280	(167)	31	38	762	1,044	725	1,238	882
Oct-09						6	149	(232)	29	26	744	1,009	672	1,165	796
Apr-10							16	(293)	31	140	973	1,330	1,079	1,653	1,370
Jul-10							55	(266)	41	99	891	1,205	912	1,442	1,114
Apr-11								(483)	(230)	(231)	567	909	629	1,179	862
Sep-11								169	(262)	(311)	453	776	487	1,027	716
Mar-12									(508)	(510)	241	553	261	809	504
Jul-12									3	(309)	432	749	438	971	641
Mar-13										(350)	355	643	324	855	529
Jul-13										(228)	507	813	494	1,006	654
Sep-13										(352)	364	620	313	854	531
Mar-14											440	703	394	918	587
Aug-14											-	680	407	932	604
Mar-15												622	357	900	558
Jul-15												570	325	857	515
Mar-16													140	689	326
Aug-16													116	636	266
Nov-16														633	262
Mar-17														641	254
Jul-17														590	260
Mar-18															112
Jul-18															181

Xcel explained that the variances were attributable to factors outside of Xcel's control, such as weather, changes in wholesale load, changes in large customer load, CHP operations, and energy efficiency. Importantly, though, the Department countered that even after accounting for these five factors – which the Department did not thoroughly examine due to limited time – "about 90 percent of the demand forecast variances are still too high."[149]

To provide additional historical context, the table below shows historical peak demand and energy use since 2008.[150] Note that 2020 actuals are lower than 2008 actuals.[151]

149 Department supplemental comments, p. 11.

150 Xcel response to OAG Information Request No. 13.

151 This historical data is not weather normalized and is net of distributed solar impacts. The forecast presented in the IRP assumes normal weather and does not include the impacts of distributed solar.

Historical Peak Demand and Energy		
	Peak Demand (MW)	Energy (GWh)
2008	8,694	47,166
2009	8,609	45,224
2010	9,131	46,422
2011	9,623	46,286
2012	9,475	45,659
2013	9,524	45,154
2014	8,848	45,039
2015	8,621	44,290
2016	9,002	44,733
2017	8,546	43,709
2018	8,948	44,987
2019	8,774	43,779
2020	8,571	42,738

In the latest corporate forecast provided in the Supplement, Xcel estimated 0.7 annual demand growth and 0.2 percent annual energy growth, which was lower than the forecast used in the initial filing, and both forecasts were lower than the forecast used for the 2015 IRP. Considering these trends in over-forecasting and declining sales, staff believes the Department's forecast adjustment was reasonable. If the Commission agrees, this could be factored into the Commission's decision in two main ways.

One way is to adopt the Department's recommendation from Initial Comments for Xcel to use a forecast from an independent consultant in any future regulatory proceedings until Xcel has identified the source(s) of the bias in Company-prepared forecasts. The Department withdrew this recommendation in Supplemental Comments (therefore it is not in the Decision Options), but not because the Department decided Xcel's forecast is of high quality. An independent consultant could be useful to either confirm that Xcel's forecasting is reliable or confirm the Department's conclusion that there is systematic bias, which may have value either way.

A second way to address an overstated resource need would be to adopt the Department's recommended DOC Scenario 11, perhaps with some modifications. Notably, the Department was the only modeling party that made adjustments to Xcel's forecast; as a result, alternative plans may arguably overstate Xcel's resource need as well.

The EnCompass outputs of DOC Scenario 11 are shown below, which applied a forecast adjustment in the base case. Note that the base case and sensitivity/contingency analysis generally shows a range of:

- 900-1,900 MW of large solar between 2020-2029 (higher levels of distributed solar may change this amount);
- 0-300 MW of wind in 2025-2029, but usually no wind; and
- One or two peaking units in 2025-2029.

Docket No. E002/RP-19-368

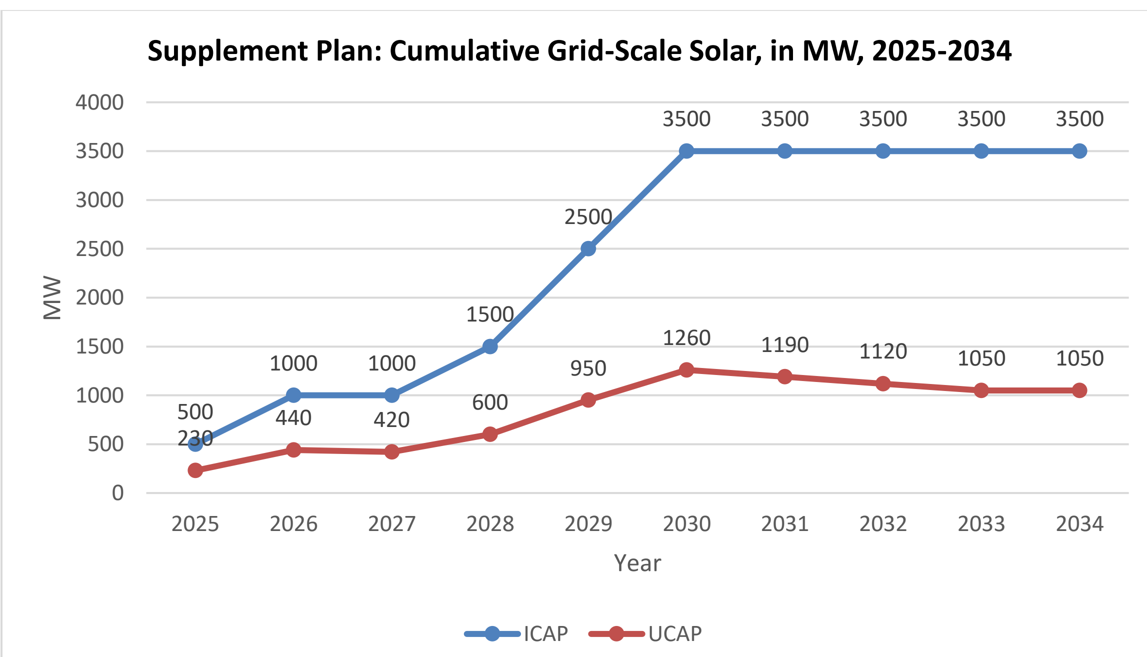
Department Attachment 3

Select EnCompass Outputs--Standard Assumptions

Scenario 11	PVSC System ($ Million)	CO2 Emissions 2020-'34 (Million tons)	Wind MW 2020-'24	Wind MW 2025-'29	Wind MW 2030-'34	Solar MW 2020-'24	Solar MW 2025-'29	Solar MW 2030-'34	CT MW 2020-'24	CT MW 2025-'29	CT MW 2030-'34
Base Case	$ 36,479	122,239	-	-	2,050	700	1,000	700	-	374	1,496
B–Low Gas, Market	$ 36,432	120,597	-	-	1,550	750	950	500	-	374	1,870
C–High Gas, Market	$ 36,186	119,982	-	200	2,500	700	1,200	1,250	-	374	374
D–Low Load	$ 35,603	116,284	-	50	2,000	700	950	650	-	-	1,496
E–High Load	$ 37,307	128,099	-	-	2,100	700	1,150	650	-	748	1,496
H–High Ext, High Reg	$ 37,841	119,154	-	150	1,900	700	1,150	550	-	374	1,496
I–Low Externality	$ 35,975	136,196	-	-	1,850	700	200	900	-	748	1,496
J–Low Ext, Low Reg	$ 35,091	131,647	-	-	1,950	700	200	750	-	748	1,496
K2–Mid Externality	$ 38,745	136,196	-	-	1,850	700	200	900	-	748	1,496
L–High Externality	$ 41,672	136,196	-	-	1,850	700	200	900	-	748	1,496
M–No Externality	$ 34,056	136,196	-	-	1,850	700	200	900	-	748	1,496
W–Low Wind	$ 36,142	120,590	-	300	1,900	700	850	850	-	374	1,496
X–High Wind	$ 36,688	122,643	-	-	1,850	700	1,000	950	-	374	1,496
Y–Low Solar	$ 36,197	121,012	-	-	2,000	750	1,050	900	-	374	1,496
Z–High Solar	$ 36,718	125,316	-	-	2,150	-	900	600	-	748	1,496

2. Accredited Capacity for Solar Resources

Xcel's assumptions for MISO-accredited capacity for renewable resources can have a significant impact on Xcel's resource need. For wind, Xcel assumed an ELCC of 16.7 percent. For solar, Xcel assumed an ELCC of 50 percent through 2023, declining 2 percent annually to 30 percent by 2033. Given the amount of solar in Xcel's IRP, the declining solar capacity accreditation is significant. The table below shows the cumulative installed capacity (ICAP) of solar additions, in blue, compared to the cumulative MISO accredited solar capacity (UCAP), in orange.



To be clear, staff does not believe it was unreasonable for Xcel to assume a declining ELCC or a Year 1 capacity accreditation of 50 percent because that is reflective of the MISO process. Also, parties agreed that as the grid incorporates more variable resources, the ELCC can be expected to decline. However, staff's concern is that a 50 percent capacity credit over a solar unit's lifetime could be too low, and the capacity credit declination of 2 percent annually could be too fast. Staff notes that Xcel stated this assumption was aligned with accreditation assumptions from MISO's 2019 Transmission Expansion Plan (MTEP) study assumptions; Sierra Club responded that "MTEP provides no documentation or analytical foundation for the assumption," and MTEP's assumption "is not grounded in an analytical foundation."[152]

The accredited capacity assumption for solar resources is important not only because Xcel plans to add 3,150 MW of utility-scale solar and 575 MW of distributed solar, but because the solar ELCC assumption (a) affects Xcel's optimal expansion plan, and (b) does not resemble the accredited capacity that Xcel's existing solar resources receive.

To explain how this could affect the IRP, staff notes that in the Supplement, Xcel ran a sensitivity where it maintained the 50 percent solar ELCC. The results found:

- A higher solar capacity accreditation value results in the model selecting more solar at an overall lower portfolio cost;[153] and
- A fixed 50 percent capacity credit for solar significantly increases incremental solar additions and reduces firm peaking capacity selected but results in approximately the same amount of storage.[154]

Appendix N7 on page 22 of the initial filing (the 2019 Annual SES Report) shows capacity accreditation for existing solar, which includes a table showing the percent capacity accreditation for the Aurora,[155] Marshall, and North Star solar facilities.[156] Note that these values are based on actual performance, rather than the Year 1 MISO-prescribed 50 percent solar capacity credit.[157] (Staff does not provide actual capacity credit values here because Xcel designated them as non-public information.) Based on these values, the assumption that future or existing resources will receive 50 capacity accreditation is inconsistent with Appendix N7.[158] Also note that CSG is reported to have a 60 percent capacity accreditation.

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[152] Sierra Club initial comments, p. 64.

[153] Xcel Supplement, Attachment A, p. 136.

[154] Xcel Supplement, p. 57.

[155] Docket No. 20-464.

[156] Capacity accreditation for Aurora Distributed Solar represents contractual agreement value. Capacity accreditation for other resources represent MISO first year of operation value.

[157] Per MISO Solar Accreditation practices in the Business Practice Manual, for Year 1, solar resource accreditation will be 50% of nameplate rating; in subsequent years the accreditation is calculated based on historic operation data.

[158] Staff also notes that in Xcel's 2020 SES report in Docket No. 20-464, concerning the 2019 reporting year, Aurora, Marshall, and North Star had similar percent capacity accreditation values as in the 2019 SES report.

	Minnesota Public Utilities Commission		
INFORMATION DOCKET E999/M-19-276		**Reporting Period:**	**January 1, 2018 - December 31, 2018**
Solar Energy Standard Annual Report		**Utility:**	**Xcel Energy**
Report Year:	2018	Date Submitted:	May 31, 2019

Additional information supporting assumed capacity factor, effective load carrying capability, and MISO capacity

Docket Nos. E999/CI-13-542, E999/M-14-321, Commission Order (October 23, 2014), Order Points 2.b & 2.d

Solar Project	Nameplate (MW)	Capacity Factor	Capacity Accreditation[1]	Project Status
		[PROTECTED DATA BEGINS		
Aurora Distributed Solar, LLC [2,6]	100 MW			existing
North Star Solar PV, LLC [2,7]	100 MW			existing
Marshall Solar, LLC [2,7]	62.25 MW			existing
			PROTECTED DATA ENDS]	
Community Solar Garden installations [2, 4, 5,8]	various	15-20%	60%	planned
Small Solar - RDF Projects	various	15-18%	58%	planned
Small Solar (<=40 kW)[8]	various	10-18%	BTMG[6]	planned

Xcel (along with other utilities) files annual OMS/MISO Resource Adequacy Surveys, which are voluntary surveys to assess available resource capacity to serve projected load in MISO over the next five years. Xcel filed its most recent survey in this docket on May 24, 2021. Notably, Xcel's reported 2020 UCAP MW for existing solar in the survey[159] is much different than the UCAP MW assumed in the IRP model for the same resources in the same year.[160]

According to MISO's Business Practices Manual (Resource Adequacy section) – effective October 31, 2021 – solar resources "have their annual Total UCAP value determined based on the three (3) year historical average output…", which explains why Xcel's OMS-MISO survey shows different values than the IRP. Further, MISO released its Planning Year 2022-2023 Wind and Solar Capacity Credit in January 2022, which stated, "New solar resources will continue to receive the class average capacity credit of 50 [percent] for their first year in operation while existing solar resources will continue to be accredited based on historical summer performance."[161]

There are different ways to assume accredited capacity for solar resources. Xcel aligned its assumptions with assumptions used in MISO MTEP 2019 modeling. Another way could be to use past operating performance. Xcel noted that the California Public Utilities Commission has begun to use monthly average ELCC values to determine variable renewable resources' qualifying capacity.[162] Staff does not believe there is a right answer; staff raises this issue because it is an important consideration due to its impact on the expansion plan.

3. Distributed Solar and CSG

Xcel forecasts that about 14-16 MW of non-CSG customer-sited solar per year will be added to its system during the planning period, which staff believes is an unreasonable forecast. As described in its Supplement, Xcel uses Solar*Rewards funding and historic net metering adoption rates to determine future levels of customer-sited solar, which assumes no year-over-

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159 Xcel compliance filing, MISO/OMS Resource Adequacy Survey, May 24, 2021.

160 Xcel response to PUC Information Request No. 11.

161 https://cdn.misoenergy.org/2022%20Wind%20and%20Solar%20Capacity%20Credit%20Report618340.pdf

162 Xcel supplement, Attachment A, p. 110.

year growth after 2020. Staff believes this approach is flawed for a number of reasons. First, customers in Xcel's service territory have installed more solar than the year before almost every year since 2013.[163] Preliminary estimates for 2021 indicate nearly 30 MW of customer-sited solar facilities achieved interconnection, with an additional 37 MW of pending applications.[164] Second, while historically the amount of under 40kW customer-sited solar has closely tracked Solar*Rewards funding, in 2021, Solar*Rewards funding ran out on April 14, yet Xcel received over 7 MW of applications for non-incentive solar under 40kW throughout 2021, according to Xcel's January 1, 2022 public queue report. This points to a change from the historical trend where the amount of distributed solar closely correlated with the amount of Solar*Rewards funding available. Finally, as several parties and commenters pointed out, Xcel does not appear to have included city-specific distributed solar goals as a consideration in its base forecasts. As described by Minneapolis in its Initial Comments, "combining the in-boundary renewable goals for the Cities of Minneapolis, Saint Paul, St. Louis Park, Eden Prairie, Northfield, and Red Wing results in 580 MW of local solar, capturing the entire distributed solar capacity estimated by Xcel," which also includes Xcel's CSG forecast.[165] Based on these points, staff believes Xcel's customer-sited distributed solar forecast is a significant underestimate, and needs to be corrected in future IRPs.

Xcel forecasts a single MW of CSG adoption per year starting in 2025 onward, which staff also believes is an unreasonable forecast.[166] From 2021-2024, Xcel assumes CSG grows from 714 MW to 852, or 138 MW of incremental CSG. However, as of January 1, 2022, interconnected CSGs on Xcel's system already reached 825 MW, which Xcel's forecast did not predict it reaching until 2023. Additionally, as of January 1, 2022, the current number of active CSG applications in the Company's queue was 428 MW. While not every CSG in Xcel's queue will achieve interconnection, it is unreasonable to forecast less CSG adoption than there are pending applications.

It is difficult to ascertain from Xcel's modeling what impact, exactly, higher-than-assumed distributed solar and CSG growth has on the model. This is because Xcel's High DG Future assumes "special case parameters," which means the High DG Future also assumed low resource costs, low fuel prices, and higher EE. This is shown in Table 4-17 of Xcel's Reply Comments. Note that one assumption is including 4.7 GW of EE, which is 2.7 GW more EE than in the Alternate Plan.

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[163] Xcel Annual Interconnection Report, Docket 21-10. Note: 2019 saw a decline in interconnections due to issues with Xcel's implementation of the new interconnection standard, however the number of applications surpassed previous years.

[164] Xcel Public Queue, January 1, 2022 (https://mn.my.xcelenergy.com/s/renewable/developers/interconnection) and Xcel Q2 Compliance Filing, Docket 16-521.

[165] Minneapolis, Initial Comments, p. 23

[166] Xcel reply comments, Appendix A, Table 15, p. 18.

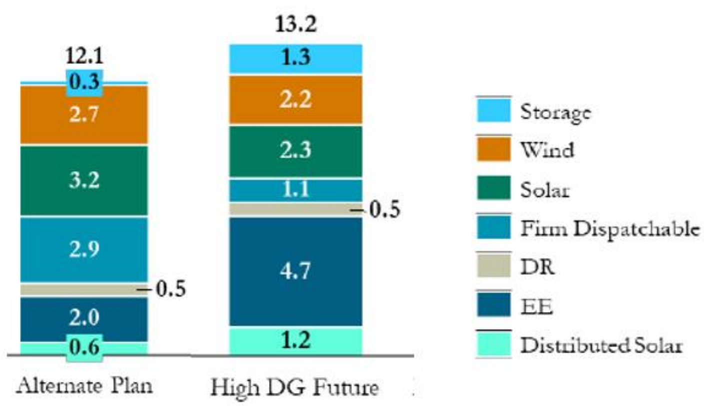
Table 4-17: Special Case Parameters

Special Scenarios	Description	Gas/Coal/Market Prices	Load Forecast	Carbon & Externality Costs	New Resource Costs
P. High DG Adoption and Low Technology Cost Future	Similar to MISO MTEP Limited Fleet Change Scenario	Low	High DG Solar Forecast, Higher EE Levels	High/High	Low

An excerpt of Figure 4-13 of Xcel's Reply Comments below indicates that the High DG Future may result in the addition of more storage and less firm dispatchable capacity, but this may be due to the Low New Resource Cost assumption. What can be gleaned is that High DG leads to much less firm dispatchable capacity.

Figure 4-13: 2020-2034 Cumulative Resource Additions Under Special Case Assumptions

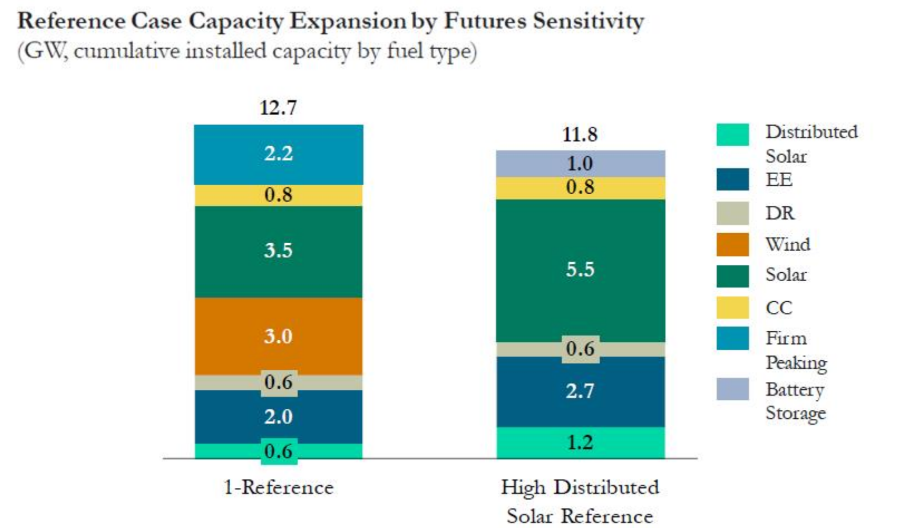
Alternate Plan Total Capacity Additions Under Special Case Assumptions, 2020-2034 (GW, UCAP)



Xcel's Supplement presented slightly different results. Xcel stated, "In the High Distributed Solar future – because load is lower overall – the model selects less capacity overall, and additions are primarily solar, alongside battery storage, with no wind or CTs."[167] Figure 2-14 below shows the Reference Case expansion plan and the High Distributed Solar Reference Case.

[167] Xcel Supplement, p. 38.

Figure 2-14: Reference Case Results by Futures Sensitivity



Importantly, though, in the Supplement (but not in Reply Comments) Xcel analyzed the High Distributed Solar Future across previously discussed reliability metrics. According to Table 2-10 of the Supplement, the High DG Future encountered 14 native capacity shortfall events and had significant exposure to market risk.

Table 2-10: Summary of Reliability Metrics Analyzed, by Test

	Native Capacity Shortfall Metrics		Flexible Resource Adequacy Metric	Maximum Import Metric
Expansion Plan Tested *(Test Load and Resource Shapes)*	Number of Native Capacity Shortfall Events	Longest Shortfall Event (hours)	Maximum 3 – Hour Upward Ramp and Occurrence Month (MW)	Hours >95 Percent of 2,300 MW Import Limit
Baseline – Scenario 9 *(Default)*	0	0	4,760 (February)	9
Scenario 9 – High Distributed Solar Future *(2019)*	14	5	7,221 (June)	157

4. Electrification

Xcel's fall 2019 forecast shows a decline in system net demand relative to the fall 2018 forecast, and both forecasts are lower than the 2015 IRP forecast—that is, until the later years of the planning period when there is an uptick due to increased EV adoption. Xcel also ran a High

Electrification Future, which added substantially more resources than the Alternate Plan and created several native capacity shortfall events.[168]

With respect to transportation electrification, EVs are undoubtedly a source of uncertainty in Xcel's load forecasting, and staff believes that EVs and electrification more broadly will eventually play a key role in shaping the need for new resources. However, Xcel expects increased EV adoption to mostly affect the later years of the planning period, and it is not clear that EVs will necessarily change Xcel's five-year action plan. Other factors, such as declining sales, increasing energy efficiency, ongoing development of Xcel's load flexibility programs, and higher-than-assumed distributed solar may compensate for possibly unaccounted for electrification in the first few years of Xcel's baseline forecast.

In addition, EV load has the ability to be flexible in when it occurs on the grid. Managed charging programs should be able to shift demand to lower use times of the day and increase the utilization of existing resources, alleviating the need for additional peaking capacity. (Xcel's High Electrification Future added fewer firm dispatchable units relative to the Alternate Plan but a substantial amount of wind.) When considering whether firm dispatchable resources are needed as a result of higher transportation electrification, the Commission should also consider whether Xcel has made sufficient efforts to enroll EVs in off-peak charging programs.

Other forms of electrification such as space and water heating are currently at more nascent stages in Minnesota, but in the long-run have greater impact on peak demand and energy needs than EV adoption, especially as winter heating load is not as flexible as EV charging. At this stage, it is unclear when that load will materialize. For these reasons, staff does not believe electrification should be a driving force for resource acquisition decisions in this IRP cycle, although staff does believe electrification will be a critical IRP issue in subsequent planning cycles; therefore, staff will discuss electrification in the Issues for the Next IRP section of the briefing papers.

F. Reliability Needs

1. Removal of the Sherco CC

As noted previously, in the Supplement Plan the Sherco CC represented 835 MW of firm dispatchable capacity that operated at an approximately 80 percent capacity factor. With that capacity and associated energy removed, Xcel and parties have proposed various mixes of replacement resources, generally in the 2027-2029 timeframe. While the technologies differ, the plans agree that solar alone is an insufficient replacement.

Some parties recommended deferring a decision on Xcel's proposed CTs to a blackstart proceeding or the next IRP, but staff notes that Xcel is not proposing the CTs solely for blackstart purposes. Xcel explained that, without the Sherco CC, CTs are needed for periods of time when variable resources are unavailable and/or during extreme weather events:

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[168] Xcel supplement, Table 2-10, p. 58.

> The replacement firm dispatchable generation included in the Alternate Plan serves an important role for system stability and blackstart needs, and can support capacity and energy needs when variable renewables are not available (such as the polar vortex of 2019 or the cold weather event our region experienced earlier this year).
>
> . . .
>
> They are, in essence, a necessary insurance policy that enables us to pursue deep carbon reduction and higher and higher levels of renewable penetration while ensuring that our customers will receive reliable and affordable service during the hottest and coldest days of the year, even when renewable generation is limited or non-existent.[169]

A threshold matter is whether Xcel can rely on its existing dispatchable portfolio after retiring 2,400 MW of baseload from 2023-2030. For example, Xcel stated, "Operational reality calls for sufficient firm dispatchable capability to cover the inherent intermittence of renewable energy." The CEOs countered that Xcel has been able to manage even extreme weather events by relying on existing CT capacity, and Xcel's peaking units "did not operate at even close to its full capability" during Winter Storm Uri.[170] However, both Xcel's and the CEOs' analysis lead to the conclusion that new, dispatchable resources are needed; the disagreement is mostly about resource capability, as presented by Xcel's version and the Telos version of Figure VI-1 on page 94 of the Supplement (the map with red, yellow, and green circles). CEOs framed this issue well in Supplemental Comments:

> Xcel's Reply Comments also make general claims about the continued need for firm dispatchable resources in the future, particularly to deal with periods of extreme weather. CEOs agree that developing a portfolio of system flexibility, including dispatchable generation resources, both short- and long-duration storage, load-flexibility through rates and demand response, DERs, and increased transmission deployment, is critically important to achieving a carbon-free electric system. CEOs' modeling chose new battery storage (either standalone or hybrid) to provide this flexibility and reliability, especially in the near-term.[171]

Staff believes the record indicates that system reliability needs to be addressed absent the Sherco CC, and a resource acquisition process to cover resources in the 2027-2029 timeframe – which to be clear should be a separate resource acquisition process than Xcel's likely solar acquisition filing – is a reasonable means to address this reliability need.

2. Fargo CT

Because Xcel has a regulatory commitment to construct generation in North Dakota, staff assumes Xcel will construct the Fargo CT regardless of the Commission's decision in this case; in

[169] Xcel reply comments, p. 11.

[170] CEO supplemental comments, Attachment A (EFG Report), p. 13.

[171] CEOs supplemental comments, p. 18.

other words, staff assumes there will be roughly 400 MW of incremental, dispatchable natural gas capacity on Xcel's system in the 2025-2027 timeframe.[172] However, given ongoing issues regarding costs for certain resources (e.g., CSG, biomass) not being recovered using traditional jurisdictional allocators, as well as Xcel's pending request to recover costs for the Sherco Solar project entirely from Minnesota customers, the Fargo CT is arguably as much of a financial issue as a resource planning issue. Therefore, staff recommends the Commission make no specific decision on the Fargo CT in this IRP. If Xcel proceeds to build the facility, the Commission can address prudence and cost recovery in a future rate case or other cost recovery proceeding.

Staff also clarifies that the Fargo CT is not replacement for the Sherco CC; it was introduced into the Alternate Plan due to the passage of time. In fact, Xcel proposed the Fargo CT in the Company's 2015 IRP, but the Commission modified the unit to a generic resource. Xcel's initial filing in the 2019 IRP stated "the Commission will not find specific mention of a North Dakota natural gas CT addition in the current short-term Action Plan; rather, proposed resource additions in 2025 will be within the Action Plan developed in the next Resource Planning cycle and addressed directly in that filing."[173]

The Commission might wish to ask Xcel when it plans to file an Advance Determination of Prudence with the North Dakota Public Service Commission (ND PSC), as this could affect the Commission's finding of need. As staff understands it, Xcel's regulatory commitment to build North Dakota generation is by 2025. The initial filing referenced in the previous paragraph also mentions 2025. Also, in the 10-year North Dakota Plan filed with the ND PSC – included as Appendix N2 of this IRP –the Fargo CT is in-service by 2025. With a 2025 in-service date, Xcel could file an ADP with the ND PSC fairly soon.

3. Lyon County CT

No intervening party who filed Supplemental Comments (the comment period when the Lyon County CT was proposed) recommended the Commission approve the Lyon County CT; instead, recommendations included approving an alternative resource plan, denying the CT, modifying the CT to a different resource type, or taking no action and defer the decision to a blackstart proceeding or the next IRP.

In Xcel's January 12, 2022 Joint Decision Options filing, Xcel withdrew its request for specific approval of the Lyon County CT in this IRP. Xcel now requests that the Commission find that it is more likely than not that there will be a need for approximately 800 MW of generic firm dispatchable resources between 2027 and 2029.

Staff has at least three concerns about making a general finding about a need for a specific amount of firm dispatchable resources:

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[172] Pursuant to a settlement in ND PSC Case No. PU-12-813, the Company agreed to take steps to locate a system natural gas CT in North Dakota by December 31, 2025.

[173] Xcel initial filing, p. 87.

First, as discussed is Part C of the Staff Discussion, staff believes the phrase "generic firm dispatchable resources" requires clarification and specificity (as does 800 MW).

Second, to the extent Xcel has a near-term need for dispatchable resources at all – that is, there are several reasons to doubt that Xcel needs 800 MW to meet a PRM requirement – the finding does little to address *why* there is a need for dispatchable resources. For example, Xcel raises several important points in the Reliability section of its Reply Comments, none of which are addressed clearly by the proposed finding. For example, staff believes a critical point Xcel discussed was that a reason Xcel proposed the Lyon County CT was to "achieve maximum renewable integration along the [Sherco] line."[174] Further, Xcel stated that with the 400 MW of CTs at the Lyon County end, "the gen-tie lines could support up to 2,600 MW of transfer capacity at any given time, which closely aligns with the 2,400 MW of interconnection capacity that will be available at Sherco when the coal units retire."[175] If achieving maximum renewable integration and transfer capacity can be accomplished without a 400 MW firm dispatchable resource, then more clarification is needed on this finding, or the finding should be modified to address renewable integration and transfer capacity.

Third, Section 2.2 of the Telos report, "Open Questions on the Need for CTs to Stabilize the Sherco Gen-Tie Line," attached to CEOs' Supplement Comments, raised a number of key questions that require answers before the Lyon Count CT can be approved. Presupposing that Xcel needs 800 MW of firm dispatchable generation, some of which is located in North Dakota, sidesteps the Telos report.

4. Nuclear Plant Considerations

a. Prairie Island Nuclear Generating Station

Some parties recommend the Commission approve a license extension of Prairie Island in this proceeding. For instance, Xcel's filings essentially make the economic and environmental case for extending Prairie Island without ultimately requesting a license extension; XLI recommends the Commission approve Scenario 15, which includes the extension of both Prairie Island and Monticello; CUB's Consumers Plan operates Monticello and Prairie Island through 2040; and the City of Red Wing recommends that, given the passage of time, the Commission should shift the 15-year planning period forward to include Prairie Island and approve a license extension.

In staff's view, there is neither sufficient evidence nor any plan for spent fuel that would justify a decision involving Prairie Island. Additionally, Xcel has made a commitment to PIIC and the City of Red Wing to continue outreach efforts before making a proposal. Consider, for example, Xcel's response to Department Information Request No. 34, in which the Department requested all expenditures for license extensions at one or both of the Prairie Island units:

> Given that our operating licenses for Prairie Island run until 2033 and 2034, we believe there is sufficient time to address the future of that plant in upcoming

[174] Xcel reply comments, p. 52.

[175] Xcel reply comments, p. 52.

> resource plans. Additionally, we believe there is a need for additional outreach and discussions with the Prairie Island Indian Community and Red Wing before we determine the future for Prairie Island beyond 2034. We, therefore, have not conducted any detailed analyses of costs associated with a license extension of one or both units at Prairie Island.

On pages 122 and 123 of the Company's Supplement, Xcel provided a spent fuel update. This discussion addresses the transportation and storage of spent fuel, but the solutions are only hypothetical, and these hypothetical options paint a picture of significant opposition. Additionally, the Global Report indicates that there is little reason, if any, to assume there will be an option for off-site spent fuel storage:

> The future of off-site spent fuel storage is not at all clear at this point. There are a number of industry initiatives being evaluated but no firm decisions have been made. How long any one of these initiatives might take to deploy is also unknown.[176]

As discussed previously, on January 15, 2021, PIIC filed public comments stating that PIIC plans to be involved in all Commission proceedings involving decision-making at the Prairie Island plant. PIIC posed several questions, such as: are there planned major investments; have aging management issues been identified; are there cyber-security concerns; how much spent fuel will be generated; will spent fuel stored on-site be removed; and so on. Neither Xcel nor parties who recommend approving a license extension have provided answers to these questions, which staff believes is necessary prior to a decision on the future of Prairie Island.

b. Monticello Extension

While staff agrees with Xcel that a decision on Prairie Island should wait until the next IRP, the path forward for Monticello is less clear. Overall, staff believes there are legitimate concerns about the economics of the extension, the age of the plant, and the lack of options for off-site storage of spent fuel. However, on balance, taking into consideration (1) Xcel's carbon reduction goals; (2) Monticello's reliability attributes, in particular the plant's performance during extreme weather events; (3) the fact that 2,400 MW of baseload is being removed from Xcel's system over the next eight years with no combined cycle plant replacing it; and (4) the socioeconomic benefits, as indicated by several letters of support from the City of Monticello and other organizations in the region, staff believes the record supports approving the license extension. The remainder of this section will discuss why staff believes there are reasonable arguments on both sides of this issue.

First, the Department recommends that no Commission determination be made on Monticello because Xcel has already filed a Certification of Need, which makes sense from a practical perspective. However, given the role Monticello plays on Xcel's system – for capacity, energy,

[176] Global report, p. 11.

and system reliability – as well as socioeconomic impacts and decarbonization, it would seem central to any planning exercise to address the merits of a critical resource.[177]

Second, Monticello had mixed results in the EnCompass modeling. The unit performed poorly in the Department's and Sierra Club's analysis, and the Department's analysis indicated that extending the Monticello plant is generally not cost-effective with or without a nuclear cost adjustment. Also, while Xcel argued that in scenarios when Monticello was retired it would be replaced by gas CTs, Xcel consistently stated that gas CTs in the later years of the planning period are technology-neutral and could be carbon-free resources. However, in the Company's analysis, Xcel tested a scenario (Scenario 4) that included early coal retirement but retired Monticello in 2030, and Scenario 4 resulted in customer savings under both the PVRR and PVSC measures.[178] Also, Scenario 4 had lower carbon emissions than the Reference Case, and incremental firm dispatchable resources were required for reliability. But beyond these competing EnCompass results, from staff's perspective, Xcel's discussion of the reliability benefits of its nuclear plants, in particular their ability to withstand extreme weather and their operation at 100 percent capacity factor during recent polar vortex events, should be taken into account. Depending on the scenario, and depending on the modeling party, an economic case could be made either way, but it is also important to consider overall system benefits, reliability, and diversity that comes from the plant.

Third, the Global report could likewise be viewed in different ways. For instance, Global concluded that Xcel's O&M forecasts were aggressive but attainable, and the capital costs were within reason, but Global was concerned with Xcel's use of contingencies in the capital forecast. This could be viewed as an *extremely* optimistic view of Monticello's future that gives little attention given to the associated risks, or one could read the plain language of the Global report to mean that Xcel's analysis is acceptable for planning purposes.

Fourth, uncertainty with regarding to Xcel's load forecast – in both directions – complicates what to do with Monticello. For instance, in the Department's analysis, Monticello performed very poorly when the forecast was adjusted, but it performed better (but not highly ranked) in the No Forecast Adjustment runs. Also, as discussed in the Supplement, the Extend Monticello scenario was uneconomic in Xcel's High Distributed Solar Future (when there is less load). In the other direction, under the High Electrification scenario (when there is higher load), the Extend Monticello scenario produced more savings. This is demonstrated in an excerpt of Table 2-4 of Xcel's Supplement below.[179] Staff notes that a similar relationship exists between the PVRR and PVSC; when CO_2 costs are introduced, extending Monticello is economic but under the PVRR, it is about breakeven.

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[177] Staff believes the Prairie Island situation is different because the Monticello license expiration occurs sooner; Xcel provided detailed forecasted expenditures for continued operation of Monticello; and Xcel has made promises to PIIC that it would continue discussions and not request approval of Prairie Island in this IRP.

[178] Xcel reply comments, Table 4-18, p. 145.

[179] Xcel Supplement, p. 40. Staff notes that is a recreated version of Table 2-4; the full table includes all 15 baseload scenarios.

Table 2-4: Futures Sensitivities Results Deltas by Baseload Scenario

Baseload Scenario *(all values $2020 millions)*	Base PVSC	Base PVRR	High Distributed Solar Future PVSC	High Electrification Future PVSC
1 - Reference	--	--	--	--
13 – Extend Monti	($30)	$1	$69	($54)

G. Resource Acquisition

The Commission has range of decisions depending on the level of specificity the Commission wishes to include in its Order, such as:

- How far into the planning period should the Commission approve resources (e.g., five-year action plan, through 2029, etc.)?
- What type(s) of resource should be approved (e.g., peaking, firm dispatchable, solar)?
- Should the Commission approve resources by gen-tie or approve generic resources?
- What procurement process should Xcel be required to use to procure resources?

The OAG recommended the Commission authorize a Modified Track 2 process and require Xcel, prior to issuing an RFP, to provide a filing detailing its proposed competitive bidding process with several components.[180] Staff supports the concept of this recommendation because it keys in the parameters needed to ensure there is a fair and level process. (As staff will discuss later, the Commission could use a Track 2 process, which is a contested case.) The Commission may not agree with every component of the OAG's recommendation, but a procedural filing prior to beginning the process would allow the Commission an opportunity for oversight and methods to ensure the procurement process is followed. Thus, if the Commission does not adopt the OAG's recommendation in full, staff believes a modified version of it is reasonable.

1. Modified Track 2 Process

Xcel requests the Commission approve the continued use of the Modified Track 2 process for the following acquisition proceedings:

a. Solar, wind, and storage resources that utilize the transmission interconnection at the Sherco site;
b. Solar and storage resources that utilize the transmission interconnection at the King site; and
c. Any additions of renewable resources, storage, or resources powered by hydrogen or clean fuel alternatives that would be cost-effective, maintain reliability, and aid in achieving compliance with decarbonization policies and that are proposed before Commission approval of the next resource plan.

[180] See OAG supplemental comments, pp. 9-10.

In general, staff supports continued use of the Modified Track 2 process to acquire solar, wind, and storage resources. However, in this case, which resource acquisition process to use is complicated by the proposed ownership and geographically-constrained nature of Xcel's proposal. Moreover, more clarification is needed to support letter c. above because the Modified Track 2 process was not envisioned for nonrenewable resources (i.e., the Fargo and Lyon County CTs).

It is important that the discussion of the Modified Track 2 be placed into context. In its January 11, 2017 IRP Order, the Commission approved a resource plan that contained at least 1,000 MW of new wind by 2019. During the IRP proceeding, Xcel argued that a modified version of a Commission-approved acquisition process that was more flexible than previous procurement processes would be appropriate to ensure the timely and cost-effective acquisition of wind resources, and it could also reduce the burden on wind developers.[181] It was argued that due to the apples-to-apples nature of wind and solar bids and proposals, it would be easy to compare each bid against each other and against Xcel's proposals. The additional rigor of the Track 2 process, which largely uses certificate-of-need criteria to compare differing resources, was not needed for the simple procurement of wind resources.

The Commission agreed, and the Order stated that a new process was appropriate due to "the need for prompt action" to acquire new wind and solar resources in the five-year action plan:

> The Commission will therefore approve the bidding process described by Xcel for the limited purpose of acquiring wind and solar resources in the 2016–2021 timeframe. The Commission declines to approve the proposed acquisition process without limitation because the two-track process has provided needed certainty and transparency for participants and regulators. But in this case, given the scope and nature of the needed acquisitions, and the need for prompt action, the Commission agrees that the proposed modified process is reasonable and appropriate.[182]

In this case, there is no "need for prompt action," and the Alternate Plan includes nonrenewable resources that may require more rigorous analysis, which the CEOs discuss at length in Supplemental Comments. For example, CEOs stated:

> Given the absence of the necessary public interest showing, the Commission must also reject Xcel's unprecedented request to use the Modified Track 2 bidding process to acquire the Lyon County CT.[183]

Xcel is no longer requesting specific approval of the Lyon County CT *as part of the IRP*, but Xcel could bid the Lyon County CT into a competitive procurement process (although letter c. above is quite vague). Nonetheless, is unclear whether Xcel now aims to move the resource planning

[181] Commission Order, p. 7.

[182] Commission Order, p. 8.

[183] CEOs supplemental comments, p. 1.

analysis into a competitive bidding process, but it seems the intent is to stay silent on resource type for now and let a Modified Track 2 process decide which resource type is in the public interest.

Second, the Commission's January 11, 2017 IRP Order recognized that Xcel planned to solicit bids "using both competitive bidding and a competing Company-owned resource proposal."[184] The Alternate Plan proposes the first 2,600 MW of renewable energy to be Xcel-owned and located at or near two existing interconnections. The OAG characterized the Sherco Solar proceeding, which Xcel claims used a Modified Track 2 process, as "a cautionary tale" because Xcel's RFP for solar at the Sherco site received just two competing bids – neither of which could meet the parameters of the RFP – leaving only Xcel's bid able to pass beyond the threshold review. Xcel even acknowledged that "the ownership and geographical scope of the resources acquired to utilize the interconnection rights at King or Sherco will necessarily be limited."[185] If the Commission believes the resource acquisition process should consider bids that interconnect at Sherco and King *but also* bids that do not, then the Commission would need to clarify in its decision that the bids must not have ownership or geographical restrictions.

2. Track 2 Process

There were a substantial number of disagreements between Xcel and modeling parties about price assumptions, interconnection cost assumptions, the capabilities or limitations of storage, and so on. Under Track 2, the Commission could review actual bids, receive expert testimony on the attributes of resource options, more closely examine Xcel's load forecast, and have an ALJ report instead of relying on Xcel's evaluation of bids.[186] If the Commission prefers not to go the contested case route, staff recommends adopting the Department's recommendation to use the Modified Track 2 process, provided terms such as "technology-neutral" or "firm dispatchable" are clear.

Staff suggests Track 2 because, first, Track 2 is used to acquire resources when Xcel proposes a nonrenewable project, which would apply to natural gas bids. If the Commission follows the Track 2 path, the IRP order should establish a need for a specific amount and specific type of capacity in the 2027-2029 timeframe. Due to staff's concerns on resource need, staff suggests using a range with an amount lower than 800 MW.

3. Wind Acquisition

Staff does not believe the Commission needs to require Xcel to issue a wind RFP prior to the next IRP. First, under DOC Scenario 11, there is no new wind in the base case through 2029. Second, staff agrees with Xcel that given ongoing transmission constraints in the MISO region, along with the current status of the MISO queue, incremental greenfield wind will face significant barriers in the near-term.

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[184] Commission's January 11, 2017 Order, p. 6.

[185] Xcel reply comments, p. 28.

[186] Track 2 was most recently used in Docket No. 12-1240, in which the Commission approved Xcel's Black Dog Unit 6, Geronimo's Aurora Solar, and Calpine's Mankato II PPA bids.

However, CUB's Consumers Plan added approximately 3,000 MW by 2025, and Sierra Club's plan adds 480 MW of wind in 2026 and another 480 MW of wind in 2027. In addition, in DOC Scenario 11, 300 MW of wind was added by 2029 under the low wind price contingency, and DOC Scenario 11 includes 150 MW of wind by 2029 under the high externality/high regulatory cost sensitivity (which Xcel argued is more reasonable to use as a base case assumption). Finally, Xcel's High Electrification scenario added 4.6 GW of wind over the planning period. Thus, staff believes there are areas of the record that would support a Commission requirement for Xcel to acquire new wind.

H. Blackstart Proceeding and Zonal System Restoration Approach

In Reply Comments, Xcel requested the Commission approve the transition to a zonal system restoration approach. However, in Xcel's January 12, 2021 Joint Decision Options filing, Xcel withdrew a request for approval of the zonal approach and instead recommended the issue to be discussed at future planning meetings.

For now, staff sees the need for new blackstart resources and the transition to a zonal system restoration approach as separate issues. Xcel's proposed zonal was introduced in Reply Comments, whereas Xcel's position on its blackstart need has been consistent throughout the proceeding. The changes are because as this proceeding has moved along, Xcel's blackstart need has become more refined. For example, Xcel has stated the following in various filings:

- Xcel's initial filing stated, "as discussed in our last Resource Plan, system retirements will impact our current blackstart plans and we are currently analyzing our blackstart path to determine the best fit for our system needs. While we do not propose any action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so."
- Xcel's Supplement stated, "our Supplement Preferred Plan includes cost assumptions that reflect an estimate of the amount of investment required to extend the lives of our existing black start generating facilities beyond their existing planned retirement dates to 2030."
- In Reply Comments, Xcel requested Commission approval of a near-term blackstart plan to be followed by a blackstart proceeding that looks more broadly at blackstart needs for Minnesota and the Upper Midwest area.

Staff supports the approval of the portion of the Alternate Plan that includes the two brownfield repowerings to be used for blackstart, but staff believes approving those two units can be done without approving the shift to a zonal approach. Staff believes XLI and Sierra Club raised important concerns that the transition from a centralized approach to a zonal approach has significant cost uncertainty and warrants closer examination. Also, Xcel stated that the transition to a zonal system restoration approach will evolve over the next ten years, so staff believes there is no need to approve a zonal approach now without additional analysis.

I. HERC PPA

Sierra Club recommended the Commission to order Xcel in its next IRP to include a discussion of potential options for exiting its contract with the HERC incinerator, as well as the costs and benefits of declining to renew its contract with the incinerator. Staff recommends the Commission take no action on this issue.

To provide background, on June 30, 2017, in Docket No. 17-532, Xcel filed a petition requesting that the Commission approve an amendment to extend the HERC PPA by seven years, through 2024, at a lower price, and to approve continued cost recovery through the fuel clause adjustment.[187] In a December 28, 2017 Order, the Commission rejected Xcel's request, determining that the PPA amendment did not reflect a reasonable approximation of the current fair market value of HERC's electrical output. The Commission also found that "none of HERC's alleged unique characteristics provide a basis for charging Xcel's ratepayers substantially more than the market rate for electricity." Since exercised its option to extend the PPA – which Xcel could do nothing about – Xcel stated it would use market-based pricing for energy sold to the Company on an interim basis after December 31, 2017 at the day-ahead MISO locational marginal price (LMP). To staff's knowledge, Xcel never filed, nor received approval for, a revised PPA to reflect the fair market value of HERC's output.

The Alternate Plan assumes the HERC PPA will expire at the end of 2024, so renewing the HERC PPA would be inconsistent with the resource plan. If Xcel seeks renewal of the PPA, the Company will need to first establish the need for the facility and then demonstrate that it is in the public interest. For now, the PPA is a Commission-approved contract.

J. Distributed Solar Incentives

Staff considered parties' distributed solar comments with the following areas of the record in mind:

- Sierra Club requested that the Commission order Xcel to bring forward a proposal in 2022 for programs that could incentivize the growth of solar distributed generation.
- DSP stated, "By reducing the [net present value] to the population of eligible customers (e.g., through an incentive) the utility can produce a predictable increase in distributed generation adoption."[188]
- In Xcel's High Distributed Solar adoption scenario, the Company's Payback adoption model assumes a 10 percent reduction to the to the solar installation cost curve, which resulted in 639 MW of incremental distributed solar by 2034.

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[187] On July 29, 1986, the Commission approved an Electric Sale Agreement in Docket No. 86-176. The HERC PPA originally had a termination date of December 31, 2017. However, the PPA included a seven-year extension at HERC's option. HERC exercised the option, which prompted a new negotiated price at fair market value. The PPA provides that "[i]f Seller decides to continue to operate the plant after the first 28 years, [Xcel] will purchase the electrical output . . . at its fair market value to [Xcel] at the time it is offered, for up to an additional seven years."

[188] DSP initial comments, p. 30.

- CUB stated, "Through innovative ratemaking, incentives, and appropriate valuation of distributed energy services, Xcel can leverage large amounts of private investment in small-scale solar."[189]
- ILSR create two separate forecasts using NREL's dGen model and the Williams model to show that Xcel was significantly underestimating rooftop solar growth.
- Minneapolis stated that Xcel ignored local community goals for renewable energy, and renewable energy goals for just six communities alone captures Xcel's entire distributed solar forecast.

While staff does not believe the Commission should necessarily approve a significantly higher amount of distributed solar – although the Commission could address this indirectly as part of a determination of need – one of staff's takeaways from the parties' comments was that there appears to be significant distributed solar potential, and if Xcel's customers are incentivized to make private investments in solar, it is likely they will do so. While ordering a new solar program to be filed in 2022 might be premature, a modified version of the Sierra Club's recommendation that taps into the distributed solar potential could be explored; the Commission may even wish to discuss with Xcel and parties during Oral Argument how the Company can develop incentive-based programs or pilots.

K. Issues for Xcel's Next Resource Plan

1. Modeling Distributed Solar as a Resource

Xcel accounts for distributed solar, including CSG resources, as a supply-side resource with assumed adoption levels, which is method opposed by DSP and Sierra Club, who proposed the Distributed Generation as a Resource model. In Reply Comments, Xcel explained its "significant concerns" with this approach, arguing that modeling only the cost of the incentive ignores all system costs associated with treating distributed solar as a resource. In order to be "bundled" like EE/DR, as DSP suggests, "either the full cost of that resource must be evaluated through modeling, or the bundles of distributed solar would need to be assessed through an alternative cost-effectiveness test and reflect achievable potential levels."[190]

Staff does not dispute Xcel's position that the full cost of resource should be taken into account; however, the full cost of the resources *to Xcel and its ratepayers* is different than the full cost of the resource to the customer installing solar on their rooftop. Xcel uses the LCOE from the 2019 NREL ATB as its "total utility cost." However, in the 2021 ATB, NREL states:

> Currently, CAPEX—not LCOE—is the most common metric for PV cost. Because of different assumptions in long-term incentives, system location and production characteristics, and cost of capital, LCOE can be confusing and often incomparable for different estimates.[191]

[189] CUB initial comments, p. 17.

[190] Xcel reply comments, p. 155.

[191] https://atb.nrel.gov/electricity/2021/residential_pv

As DSP noted, the cap-ex costs of distributed solar are not borne by the utility, they are borne by the customer. Staff concludes that trying to determine the "total utility cost" of distributed solar that can be compared on an apples-to-apples basis to other resource selections in an IRP model would likely need further development.

Alternatively, if Xcel is open to the idea of creating distributed solar bundles for use in the Company's next IRP, staff supports Xcel working collaboratively with stakeholders to evaluate cost-effectiveness tests that could allow bundles of distributed solar to be modeled as part of Xcel's next IRP. Staff believes this can be done in a similar fashion as the Company's DR stakeholder process that followed Xcel's previous IRP.

2. Electrification

As noted in the resource need section above, electrification will be an important component of future IRPs, both in how Xcel forecasts its load and in the availability of new load flexibility and demand response potential. In this IRP, Xcel used a high electrification scenario to test the robustness of its plan against a future where there is widespread adoption of EVs, heat pumps, and other electric end uses currently served by fossil fuels. This is a reasonable way to "stress test" Xcel's plan given uncertainty about the adoption of electrification, however staff thinks it is also reasonable to include a more robust forecast of expect electrification in Xcel's base case, and not just as a scenario, especially given Xcel has alluded to increased electrification as an explanation for load growth in the out years of its plan.

Therefore, for its next IRP, staff suggest Xcel develop forecasts of electrification technology adoption for space and water heating to include in its base case, in addition to its forecasts for EV adoption. Specifically, staff believes it is reasonable for Xcel to develop base case adoption forecasts for the follow types of electrified technologies:

- Light, medium, and heavy duty EVs
- Electrified space heating
- Electrified water heating
- Electrification of other sectors

In addition, Xcel should describe how the increase in electrified load would impact the potential for demand response and load flexibility.

3. Resource Planning and Distribution Planning

Multiple organizations recommended aligning resource planning and distribution system planning processes.[192] While most parties did not outline specific details on how to align the processes, DSP offered five suggestions to align the processes:

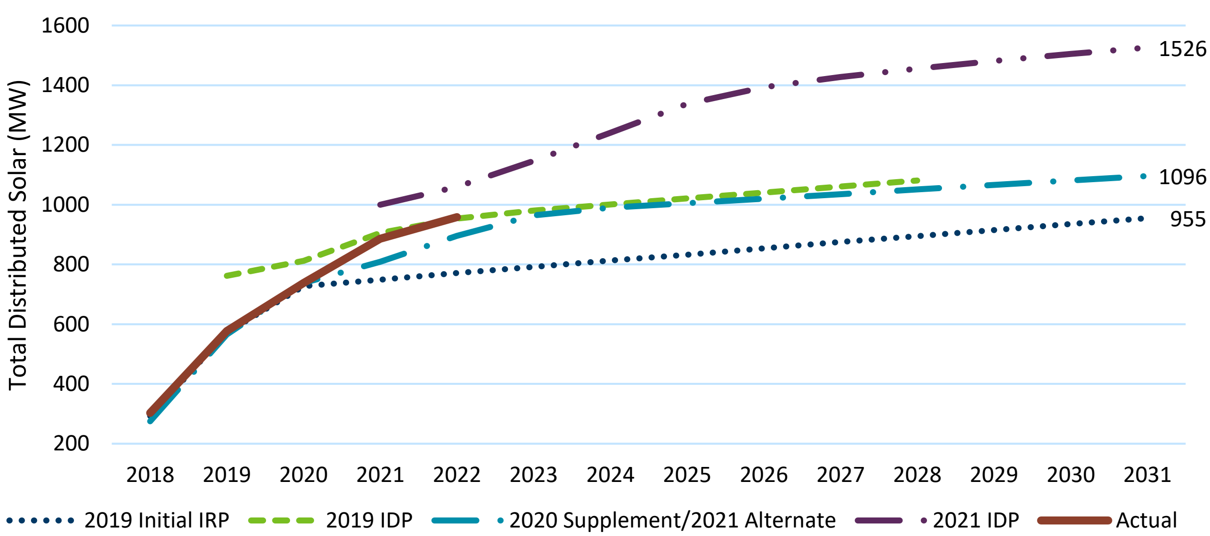
1. Set DER deployment targets in the IDP to be consistent with an approved IRP.
2. Conduct advanced forecasting to better project the levels of DER deployment at a feeder level, using Xcel's advanced planning tool.

[192] See, for example, Mpls – Initial, p. 23; CUB – Initial, p. 18; DSP – Initial, p. 41

3. Proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with DER deployment targets.
4. Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of DERs to address discrete distribution system costs.
5. Plan for aggregated DERs to provide system value including energy/capacity during peak hours.[193]

Staff notes one key area where Xcel can align its IDPs and IRPs is in the forecasting of demand side resources such as EVs, distributed solar, and energy efficiency. Historically, Xcel's forecasts have not lined up across these different planning processes. For example, comparing Xcel's IRP and IDP distributed solar[194] forecasts over the past two and a half years (See figure X), there are significant differences in forecasted adoption levels for planning processes that were initiated in the same year.

Figure 1: Comparison of Xcel IRP and IDP Distributed Solar Forecasts[195,196,197,198,199]



In its June 30, 2020 IRP Supplement, Xcel says its projections are "consistent with those included in our 2019 IDP"[200] however, while the numbers are not drastically different, they are not "consistent" with each other. In its 2021 IDP, Xcel forecast 1,520 MW of total (CSG + customer sited) distributed solar adoption by 2031 - over 424 MW more of solar then its 2021

[193] DSP, Initial, pp. 42-43
[194] Community Solar Gardens and Customer Site Solar
[195] Xcel, Initial Filing, Appendix F2 p. 17
[196] Xcel, Initial Filing, 2019 IDP, Docket 19-666, p. 196/PDF p. 232
[197] June 30, 2020 Supplement, Attachment A, p. 64; Xcel, June 25, 2021 Reply Comments, Appendix A, p. 18
[198] Xcel, Initial Filing, 2021 IDP, Docket 21-694, Appendix E2 p. 12
[199] Xcel Annual Report, Docket 21-10; Xcel Public Queue Report, January 1, 2022 (https://mn.my.xcelenergy.com/s/renewable/developers/interconnection); Xcel Q2 Compliance Filing, Docket 16-521. Note: for its forecasts, Staff believes Xcel uses the forecasted amount at the beginning of the calendar year, therefore actual adoption is at the start of the calendar year rather then the end.
[200] Xcel, June 30, 2020 Supplement, p. 37

Reply Comment Alternate IRP forecast. Staff points out these inconsistencies to encourage better integration of IDP forecasts in Xcel's IRP. Using the IDP process to develop and vet not only Xcel's distributed solar forecast, but other demand side resources, could reduce disagreements in the IRP by resolving modeling inputs before they are disputed. Additionally, the IDP (and associated Hosting Capacity Report) is the appropriate place to look at where on the distribution system DERs can locate, as the IRP looks more at size/type/timing rather than specific locations, especially on the distribution level. Put another way, the IDP can determine where to place DERs, and maximum adoption levels, while the IRP can determine what levels of DERs are economic.

Staff notes that while the IDP would be the preferred place develop better forecasts of demand side resources and technologies, the timing to do so before Xcel's next IRP is not ideal, as the current IDP is already underway, and the next IDP will not be filed until November 1, 2023. After this next cycle of IDP/IRP, staff recommends moving development of demand side forecasts to Xcel's IDP process, which can then be used in its IRP.

In January 2021, Xcel Energy reported to the Commission's IDP Stakeholder group that the Company currently uses LoadSEER to allocate the corporate load (including DER) forecast to locations on the distribution grid. Xcel Energy said load forecasts in Integrated Resource Plan and IDP are developed in the same manner; however, due to timing of the filings, the vintage of data may have different results which they account for and describe. Xcel Energy explained LoadSEER allows for cluster parameters, but the company is currently using uniform application and experimenting with other options (e.g. probabilistic). Over time, Xcel Energy expects to use LoadSEER for further granular, locational forecasting. LoadSEER does not feed back into the corporate load forecast.[201]

In addition, Staff provided the following summary of IDP/IRP overlap from the January 8, 2021 IDP Stakeholder Discussion:

> Fresh Energy described moving from capacity expansion based on a sample of days to more days or hourly (8760) modeling and the connection between the hourly DER and distribution system load forecasts … Xcel Energy said the new IRP modeling tool, Encompass, will over time get closer to what Fresh Energy describes; especially when paired with LoadSEER. Currently, Xcel is still planning to feeder or system peak. Xcel Energy noted that IRP is not a stacked value/compensation analysis, but as an economic model that models DER as a supply-side resource competing against other generation types on a cost comparison. Xcel noted there are distinct, and complicated, issues to coordinate when attempting to bridge the top-down and bottom-up analyses, as there are two types of value attributed to energy efficiency and demand response (i.e. overall system value and specific distribution system value).[202]

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[201] PUC Staff Summary of January 8, 2021 IDP Stakeholder Meeting (January 15, 2021), Docket No. E002/M-19-666, p. 2

[202] *Id.*, p. 4

Staff also notes the Commission has received a Department of Energy Grant for technical assistance on better alignment of DER forecasting across IRP and IDP. Staff stresses to Commissioners and parties that IRP and IDP alignment (and an increase in visibility, modeling, and planning on the distribution-system) will be a critical area and area for improvement in the coming years both for IRP and IDP. With the increase in customer-sited/purchased demand side resources, advanced in technology, and changes in FERC Orders and policies, (Order 841 and 2222) improvements to IDP/IRP integration and distribution level forecasts and planning will ensure the Commission is getting the maximum value from both planned and organically procured investments. Staff encourages parties interested in the overlap of IRP and IDP to also participate Xcel's current IDP in Docket 21-694.

4. Xcel's Proposed Process Improvements for Future Resource Plans

In Reply Comments, Xcel proposed recommendations for process improvements for the next IRP, such as minimum information requirements for parties submitting alternative plans. Staff recommends the Commission reject Xcel's recommendations. The requirements for alternative plans are set forth in Minn. R. 7843, subp. 11:

> Subp. 11. **Proposed alternative resource plans.** Parties and other interested persons may express support for the proposed resource plan filed by a utility. Alternatively, parties and other interested persons may file proposed resource plans different from the plan proposed by the utility. When a plan differs from that submitted by the utility, the plan must be accompanied by a narrative and quantitative discussion of why the proposed changes would be in the public interest, considering the factors listed in part 7843.0500, subpart 3.

Since Xcel is most critical of CUB's Consumers Plan, staff notes that CUB's Initial Comments included a narrative and quantitative discussion to explain why its plan is in the public interest. Also, CUB's Reply Comments are actually constructed to explain each factor to consider under 7843.0500, subp. 3. Other parties who submitted alternative plans also meet the requirements of an alternative plan.

One area where staff agrees with Xcel is that alternative plans developed with capacity expansion modeling should include all of Xcel's load and system resources. Xcel stated that CUB "did not attempt to fully model our five-state integrated system's full load, nor all the resources with which we serve that load."[203] In response, CUB stated VCE modeled "the entire MISO footprint, including the entirety of the NSP system."[204] Staff noticed from VCE's report that "[t]he portion of electricity coming from wind generation goes from 8.7% in 2020 to 41% in 2040,"[205] which is much lower than the 21 percent of total generation from wind that the Company reported in Reply Comments. The difference could be that CUB's analysis used 2018

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[203] Xcel reply comments, p. 87.

[204] CUB supplemental comments, p. 6.

[205] VCE report, Attachment 1 of CUB Initial Comments, p. 25.

generation and transmission datasets, and if so, some of CUB's recommended amount of new wind could have already been approved by the Commission.

Presumably CUB can clarify this issue, but it makes no difference to staff's position that additional requirements should not be imposed onto intervening parties. The Commission can decide how to weigh evidence submitted by the parties and contemplate the strengths and weaknesses of alternative plans.

XIII. Decision Options

A. Resource Plan Preferences

<u>Joint Decision Options (Xcel, CEOs, LIUNA, IUOE Local 49, and the North Central States Regional Council of Carpenters) *January 12, 2022 Filing*</u>

1. Approve the Alternate Plan as detailed in Xcel's June 25, 2021 Reply Comments, including but not limited to the following elements:

    a. Approve plan to retire Allen S. King plant in 2028 and Sherco Unit 3 in 2030.
    b. Approve Xcel ownership of Sherco and King gen-tie lines plus renewable resources added on the lines up to the Company's current interconnection rights.
    c. Approve plan to continue pursuing a 10-year extension for the Monticello Nuclear plant.
    d. But not including specific approval of the Lyon County Combustion Turbine (CT) and Fargo CT.

2. Find that it is more likely than not that there will be a need for approximately 800 MW of generic firm dispatchable resources between 2027 and 2029, some of which could be located in North Dakota, and requires that the Company include renewable resources and storage as potential options to meet this need in any applicable resource acquisition proceeding.

<u>Xcel Energy *(June 25, 2021 Reply Comments, alternative to Joint Decision Options)*</u>

3. Approve the Alternate Plan as detailed in Xcel's June 25, 2021 Reply Comments and highlighted below:

    a. Approve Xcel ownership of Sherco and King gen-tie lines plus renewable resources added on the lines.
    b. Approve 400 MW of natural gas combustion turbines in Lyon County, Minnesota and 400 MW natural gas combustion turbines in Fargo, North Dakota.
    c. Approve plan to continue pursuing a 10-year extension for our Monticello Nuclear plant.
    d. Approve the proposed blackstart shift to zonal approach and need for blackstart resources in each zone which includes:
        i. Two specific blackstart additions in Minnesota and Wisconsin by 2026.

Center of the American Experiment (CAE)

4. Approve a modified Scenario 15, where Xcel's coal facilities are operated until the end of their useful lives, both nuclear facilities are extended, and no new wind and solar is built that isn't required by state mandates.

Citizens Utility Board of Minnesota (CUB)

5. Approve CUB's Consumers Plan as described in CUB's Initial Comments and highlighted below:
    a. Retire 2,683 MW of coal plants and 745 MW gas combustion turbines.
    b. Approve a total of 4,522 MW of wind, 940 MW of utility-scale PV, 1,965 MW of distributed PV (including projects up to 40 MW connected to the distribution system), and 259 MW of battery storage.
    c. By 2025, approve 3,000 MW of wind, as well as 333 MW of distributed PV and 1,400 MW of utility-scale PV

6. Require Xcel to retire its remaining coal plants in the next five years and to move to economic commitment of all units as quickly as possible.

7. Require Xcel to retire or allow the expiration of PPAs for at least 550 MW of gas combustion turbine power plants in the next five years.

8. Approve Xcel's proposal to operate the Monticello nuclear unit through 2040, including initiating a Certificate of Need proceeding in Minnesota and a Supplemental License Renewal process with the Nuclear Regulatory Commission in the next five years.

9. Approve Xcel's proposal to achieve 780 GWh/year savings from energy efficiency programs through 2034.

10. Advise Xcel that it will not be permitted to recover any undepreciated costs of the Sherco CC if and when the plant is no longer used and useful, any costs due to oversizing the plant, nor any future costs of retrofitting the plant to reduce emissions.

11. Deny Xcel's proposed CTs.

City of Minneapolis

12. Approve Xcel's decision to not pursue and new combined cycle gas plant at the Sherco site.

13. Approve Xcel's proposed reutilization of interconnections at Sherco and King sites and the proposed renewable resources added on the lines if determined to be in the public interest and does not stifle market competition.

14. Reject the construction of 800 MW of new gas CTs in Lyon County and Fargo.

15. Xcel shall retire the King and Sherco 3 coal plants earlier than 2028 and 2030, consistent with the Citizens Utilities Board "Consumers Plan."

16. Xcel shall deploy the 250 MW of planned energy storage resources from Xcel's Alternate Plan sooner than proposed to field test the capabilities of this resource for meeting future.

<u>Clean Energy Organizations *(Oct 15, 2021 Supplemental Comments, alternative to Joint Decision Options)*</u>

17. Approve Xcel's Alternate Plan but modify it by declining to approve the Lyon County CT and Fargo CT, and either:

    a. Replace them with 450 MW of solar hybrid, 400 MW of battery storage hybrid, 116 MW of standalone storage, and 100 MW of wind in 2027-2029, consistent with the CEOs' Alternate Plan.

    <u>OR</u>

    b. Designate the 800 MW of proposed CTs in 2027 and 2029 in Xcel's Alternate Plan as "generic firm peaking," consistent with Xcel's treatment of the additional CT capacity in its Alternate Plan.

18. Require that Xcel consider and pursue opportunities to deploy renewable resources and storage technologies on a schedule faster than in its Alternative Plan, if such deployment would be cost-effective, maintain reliability, and aid in achieving compliance with decarbonization policies.

<u>Department Staff</u>

19. Adopt Department Staff Scenario 11, as outlined in the Department Staff's October 15, 2021 comments.

<u>OR</u>

20. Require Xcel to:
    a. retire King by the early date, 2028.
    b. retire Sherco unit 3 by the early date, 203.
    c. proceed assuming no Commission determination is made regarding the requested approval to continue pursuing a 10-year extension for Monticello because the Company has since filed a Certificate of Need petition.[206]
    d. proceed assuming Prairie Island will undergo a 10-year license extension and re-study the retirement date in the next resource plan.
    e. acquire a total of approximately 1,125 MW of solar capacity, both distributed and central station, by 2024, contingent upon prices being reasonable.
    f. proceed assuming Xcel will not add wind resources during the action plan period;
    g. proceed assuming Xcel will not add capacity resources during the action plan.

21. Take no action regarding:
    a. the Company's proposed level of energy efficiency resources;
    b. approval of 400 MW of CTs in Lyon County, Minnesota;
    c. approval of 400 MW of CTs in Fargo, North Dakota; and

[206] This leaves Monticello's retirement date at the current license life of 2030.

d. on the request for "flexibility to evaluate and pursue the required incremental DR."

22. Approve Xcel ownership of Sherco and King gen-tie lines plus renewable resources added on the lines.

<u>Deputy Commissioner of Commerce</u>

23. Approve an extension of the Monticello Nuclear Power Plant.

<u>and</u>

24. Review lifecycle emissions associated with natural gas power generation.

<u>Distributed Solar Parties</u>

25. Require Xcel to include the distributed solar resources proposed by the DSP and modeled by Sierra Club in the Company's approved plan.

<u>Sierra Club</u>

26. Approve Xcel's proposed retirement dates for Sherco Unit 3 by no later than 2030 and A.S. King by no later than 2028, with instructions that Xcel should evaluate whether those units should be retired earlier in its next IRP; and approve moving Sherco 2 to seasonal dispatch and King to seasonal dispatch until 2023 and economic commitment thereafter.

27. Do not approve the need for the Sherco CC in 2027.

28. Do not approve the need for the two newly proposed greenfield CTs in 2027 and 2029 or, alternatively, defer a decision on the CTs to another docket so that it can fully consider all the implications, including cost, reliability, and life-cycle climate change impacts associated with this request, and determine if other solutions can meet the need for reliability services at lower cost.

29. Approve the need for 1,350 MW of utility scale solar and 4,320 MW of new wind beginning in years 2027 and 2026, respectively, as well as an additional 4,070 MW of utility scale solar paired with 1,080 MW of battery storage starting in 2031, and 1,200 MW of standalone battery storage beginning in 2027.

30. Approve Xcel's proposal to achieve 780 GWh/year savings from energy efficiency programs through 2034 and 400 MW of new demand response by 2023.

31. Approve the need for 2,050 MW of community solar and 1,851 MW of distributed generation solar, and require Xcel to bring forward a proposal in 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.

32. Do not approve the need for the Monticello license extension through 2040.

<u>Xcel Large Industrials</u>

33. Approve Xcel's Scenario 15, minus the Sherco CC.

34. Reject Xcel's Alternate Plan due to a lack of record support. In recognition of the need for certain resources common in various plans submitted by Xcel and supported by intervenors in this proceeding, approve Xcel's proposed additions of:
    a. 0.6 GW of Distributed Solar.
    b. 2.0 GW of Energy Efficiency.
    c. 0.5 GW of Demand Reduction.
    d. 0.8 GW of Wind.
    e. 2.7 GW of Solar.

B. Resource Acquisition

<u>Joint Decision Options (Xcel, CEOs, LIUNA, IUOE Local 49, and the North Central States Regional Council of Carpenters)</u>

1. Require that Xcel consider and pursue opportunities to deploy renewable resources, storage technologies, and resources powered by hydrogen or clean fuel alternatives on a schedule faster than in its Alternate Plan, if such deployment would be cost-effective, maintain reliability, and aid in achieving compliance with decarbonization policies.

<u>Xcel Energy *(June 25, 2021 Reply Comments, alternative to Joint Decision Options)*</u>

2. Approve the use of the Modified Track 2 process for the following acquisition proceedings:
    a. Solar, wind, and storage resources that utilize the transmission interconnection at the Sherco site.
    b. Solar and storage resource that utilize the transmission interconnection at the King site.
    c. Any additions of renewable resources, storage, or resources powered by hydrogen or clean fuel alternatives that would be cost-effective, maintain reliability, and aid in achieving compliance with decarbonization policies and that are proposed before Commission approval of the next resource plan.

3. Approve the use of the Modified Track 2 process for the following acquisition proceedings:
    a. Solar and wind resources that utilize the transmission interconnection at the Sherco site.
    b. Solar resource that utilize the transmission interconnection at the King site.
    c. Approximately 400 MWs of CTs in Lyon County to connect to the transmission interconnection at the Sherco site.
    d. Any wind or solar additions needed before the next resource plan.

<u>Citizens Utility Board of Minnesota (CUB)</u>

4. Require Xcel to issue one or more RFPs for approximately 3,000 MW of new wind capacity and 1,400 MW of new solar capacity in the next five years. To ensure such processes are competitive, robust, and transparent, require future wind procurement RFP processes to meet, at a minimum, the following conditions:

a. The competitive-bidding process should be administered by an independent third-party.
b. The competitive-bidding process should include a request for proposals that is posted publicly and open to any interested developer.
c. The request for proposals should not include geographic limitations.
d. The request for proposals should be open to power purchase agreements, build-transfer proposals, and utility self-build projects.
e. Xcel's proposed bidding process, timeline, evaluation criteria, and request for proposals language should be filed with the Commission at least one month prior to the issuance of the request for proposals. This filing should also include a contingency plan describing the subsequent process should the bidding process fail to elicit a meaningful number of bids.

5. Require Xcel to enable the adoption of approximately 300 MW of new distributed solar -- including rooftop, community, and larger-sized, distribution system-tied developments -- and 600 MW of new battery storage in the next five years.

<u>City of Minneapolis</u>

6. Approve Xcel's requested use of Modified Track 2 process for solar and wind additions needed before the next IRP, ensuring a competitive bidding process. Minneapolis recommends that this process includes the opportunity for DERs to compete.

7. Require a Clean Energy Portfolio approach if new capacity is needed, as part of a competitive bidding process

<u>Department Staff</u>

8. Regarding resource acquisition, Department Staff recommends that the Commission:

   a. Approve the Track 1 and Modified Track 2 bidding processes, as outlined in Department Staff's February 11, 2021 comments.
   b. Require that any RFP documents for peaking resources issued by Xcel be technology neutral.
   c. Determine that the Commission-approved Track 1/Modified Track 2 bidding process applies in all instances where Xcel intends to acquire 100 MW of capacity for a duration longer than five years.
   d. Cap any ROFO offer made by Xcel at net book value.
   e. Require any RFP issued by Xcel to include the option for both PPAs and BOTs unless the Company can demonstrate why either a PPA or BOT proposal is not feasible.

<u>Distributed Solar Parties</u>

9. Initiate an investigation into the benefits and uses of all-source RFPs to inform future resource plans. *(DSP)*

<u>OAG</u>

10. Require Xcel to complete a competitive bidding process to procure solar-plus-storage projects.

11. Require Xcel to provide a filing, prior to issuing an RFP, detailing its proposed competitive bidding process including, at minimum, the following components:

    a. A list of potential independent auditors to oversee the bidding process and evaluate the proposals.
    b. The criteria that the independent auditor will use to evaluate proposals.
    c. The proposed text of the request for proposals.
    d. The proposed timeline for the issuance of the request for proposals, the allowed response time, the date upon which Xcel will submit its self-build proposal (if applicable), and the date upon which the independent auditor will submit its report to the Commission detailing the bid results.
    e. Confirmation that the request for proposals will be published publicly and open to any interested developer.
    f. Confirmation that there will be no geographic or ownership limitations on the proposals.
    g. A contingency plan in the event of an unsuccessful bidding process.

<u>Commission Staff</u>

12. For future solar acquisition petition, Xcel shall include updated capacity expansion modeling, with forecasted rate impacts. For solar acquisition petitions that include more than one project, projects shall be modeled on an individual basis and as a total portfolio.

C. Blackstart

1. Review Xcel's future blackstart needs in a future planning meeting or set of planning meetings. *(Xcel, CEOs, LIUNA, IUOE Local 49, and the North Central States Regional Council of Carpenters)*

2. Initiate a new regulatory docket to discuss broader blackstart issues that would include the consideration of other blackstart additions in other zones in the later years of the 2020-2034 planning period. *(Xcel, June 25 2022, Comments, alternative to Join Decision Options)*

3. Open a separate proceeding to examine blackstart issues that will inform Xcel's next IRP. *(CUB)*

4. Xcel shall analyze black start options that do not require natural gas and share this analysis prior to the next RFP for new generation or IRP planning cycle. *(Mpls)*

5. Take up Xcel's future blackstart needs in a future proceeding. *(CEO)*

6. Require an investigatory docket to include all Minnesota utilities to address a zonal blackstart approach in Minnesota and the resources that would support such an approach. The proceeding should address:

   a. Whether a zonal blackstart approach can provide a cost-effective (from both a rate and bill impact perspective) and reliable alternative to centralized blackstart.
   b. The resources that would best support zonal blackstart to provide reliable and cost-effective capacity and energy to consumers.
   c. Whether prolonged economic dispatch of existing resources can avoid significant capital investments in interim natural gas resources, thereby ultimately accelerating the transition to a carbon-free future. *(XLI)*

D. Next IRP

<u>Filing Date for Next IRP</u>

1. Require Xcel to submit its next IRP by June 30, 2023. *(Xcel, CEOs, LIUNA, IUOE Local 49, and the North Central States Regional Council of Carpenters, Department)*

2. Require that Xcel submit its next IRP two years from the date of the Commission Order. *(CEO, Oct 15, 2021 Supplemental Comments, alternative to Joint Decision Options))*

<u>Treatment of DSM/DERs</u>

3. Require Xcel to work with stakeholders to develop a modeling construct that enables identification of economic distributed solar additions as part of the Company's next resource plan. Require that Xcel include improved load flexibility and demand response modeling methodologies going forward and in its next resource plan. *(Xcel, CEOs, LIUNA, IUOE Local 49, and the North Central States Regional Council of Carpenters)*

4. Require Xcel to consider distributed generation as a resource in its next IRP, including a quantification of distribution system benefits of distributed generation. *(DSP)*

5. Require Xcel to initiate a pilot program to test the distributed generation adoption model as proposed in DSP's Initial Comments. *(DSP)*

6. Require Xcel to take local clean energy goals, in addition to state policy and existing incentives, into consideration in forecasting and modeling for the IRP. *(SRA)*

7. Require Xcel to include more local generation and distributed energy resources in the next IRP:
   a. Work with customers with local distributed solar goals to develop programs that can support their community, with an emphasis on low-income customers.
   b. Develop new local renewable resources for municipal loads and our community through special contracts, expanded community solar offerings, and on-site solar incentives. *(Mpls, DSP)*

8. Require Xcel to model demand side resources at a more granular level in the next IRP filing and to develop a more sophisticated approach to optimize demand size resources, include energy efficiency and demand response, in the next IRP modeling process, by using a consistent societal discount rate to analyze both energy efficiency and demand response resources in this and future IRPs. *(Mpls)*

9. Require Xcel to assign value to equity impacts and non-energy benefits of DSM programs. *(Mpls)*

10. Require Xcel to model demand flexibility programs separately from traditional demand response programs. *(Mpls)*

Forecast

11. Require Xcel to account for anticipated effects of advanced rate design, demand response, and any other efforts to shift customer demand in its next IRP. *(CUB)*

12. Require Xcel to include beneficial building electrification in the load growth forecast and increased grid flexibility with a more sophisticated modeling software. *(SRA)*

13. Require Xcel to develop and/or improve base case adoption forecasts of the following technologies to include in its overall demand forecast for its next IRP filing, either through its Integrated Distribution System Plan proceedings, or through another stakeholder process.

    a. Light, medium, and heavy duty electric vehicle adoption
    b. Electric space heating adoption
    c. Electric water heating adoption
    d. Electrification of other end uses
    e. Increased potential for demand response and load flexibility from an increase in electrification of the technologies in a – d
    f. Distributed solar adoption, including customer sited, community solar gardens, and non-customer sited/non-CSG distributed solar

Other Resource Adjustments

14. Require that Xcel's next IRP include a deeper analysis of storage options, including making solar-battery hybrids a resource option, and also a deeper analysis of the role of hydrogen and clean fuel alternatives in Xcel's resource mix. *(Xcel, CEOs, LIUNA, IUOE Local 49, and the North Central States Regional Council of Carpenters)*

15. Require Xcel to pursue robust in-state and intrastate transmission expansion. Require Xcel to report on activities and progress to expand intrastate transmission capacity in its next IRP. *(CUB)*

16. Require Xcel in its next IRP to include a discussion of potential options for exiting its contract with the HERC incinerator, as well as the costs and benefits of declining to renew its contract with the incinerator. *(Sierra Club)*

17. Re-evaluate the Monticello nuclear plant extension in the next IRP cycle. *(Mpls)*

18. Require Xcel to file a report in its next IRP explaining:
    a. Planned investments at the Prairie Island Nuclear Generation Plant.
    b. Any aging management issues that may arise from continued operation.
    c. Expectations regarding future nuclear workforce.
    d. Cyber-security issues or concerns, as plants move from analog to digital systems.

   e. True comprehensive cost-benefit analysis, which includes potential environmental and economic impacts to the PIIC and Treasure Island.
   f. Additional spent nuclear fuel generated over a 10- or 20-year period.
   g. How fuel stored on-site will be removed during the next IRP period
   h. Additional State permits, Certificates of Need, or federal licenses will be required. *(Prairie Island Indian Community)*

19. Require Xcel to begin stakeholder discussions about the future of Prairie Island Nuclear Generation Plant (PINGP) immediately, and require Xcel to address the future of PINGP in its next resource plan. *(City of Red Wing)*

Process Changes

20. Require Xcel to conduct a comprehensive planning process to advance a just and equitable clean energy transition as part of the next IRP planning cycle, including a collaborative, participatory planning process through stakeholder workshops as an alternative to the limited information requirements that Xcel proposed in the Alternate Plan, which will be more time efficient while allowing for more community input. *(Mpls)*

21. For future resource plans, for parties submitting alternative plans, parties must include:
   a. A load and resources table that reflects the Company's load plus MISO reserve margin requirements, the Company's full set of existing resources, and the modeling party's proposed expansion plan, on an annual basis.
   b. An evaluation of the proposed alternative plan's Present Value Revenue Requirements and Present Value Societal Costs (PVSC). The modeling parties shall provide PVSC values under the same externality/regulatory cost of carbon sensitivity that the Company presents in its primary plan.
   c. A quantitative bill and/or rate impact analysis of the proposed plan, including whether the plan results in significant differential bill impacts to different customers within a customer class (i.e. participating and non-participating customers).
   d. An analysis of whether the proposed plan results in unserved energy or other significant reliability concerns within the modeled construct.
   e. A reasonably comprehensive documentation of input assumptions, to the extent they are different than the Company's inputs.
   f. Discussion of how its proposed alternative plan achieves the Commission's public interest analysis requirements for approving a resource plan, as outlined in Minn. R. 7843.0500, subp. 3. *(Xcel)*

22. Reject Xcel's suggestion that additional limitations be placed on parties wishing to intervene in future IRP proceedings. *(CUB, DSP)*

E. Miscellaneous

IDP/IRP

1. Require Xcel to explain, in its next Integrated Distribution Plan (IDP), how its distribution plan will put the Company on track to meet the level of distributed energy resource (DER) deployment in its approved IRP. *(CUB)*

2. Require Xcel to align integrated distribution system planning and integrated resource planning processes. *(Mpls)*

3. Require Xcel to take the following steps recommended in DSP's Initial Comments to better align distribution and resource planning, including:
    a. Set DER deployment targets consistent with approved IRP.
    b. Conduct advanced forecasting to better project the levels of DER deployment at a feeder level, using Xcel's advanced planning tool.
    c. Proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with DER deployment targets.
    d. Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of DERs to address discrete distribution system costs.
    e. Plan for aggregated DERs to provide system value including energy/capacity during peak hours. *(DSP)*

<u>Other Commission Processes</u>

4. Require Xcel to proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle (and, CUB would add, additional beneficial electrification) additions consistent with DER deployment targets. *(CUB)*

5. Require Xcel to plan for aggregated DERs to provide system value including energy/capacity during peak hours. *(CUB)*

6. Require Xcel to propose programs for beneficial electrification, including programs for efficient fuel switching under the new Energy Conservation and Optimization Act. *(CUB)*

7. Require Xcel to consider beneficial electrification and grid flexibility as decarbonization strategies by:
    a. Ensuring new electric loads through vehicle electrification or fuel switching can be designed to be grid assets.
    b. Ensuring electrification plans are built into any future high electrification scenario. *(Mpls)*

<u>Equity</u>

8. Require Xcel to center equity in Xcel resource decisions by:
    a. Designing for the equitable delivery of electricity services and programs for energy burdened customers in this IRP.
    b. Creating new options to improve customer access to energy efficiency and renewable energy.
    c. Submitting a plan in 2022 to bring its workforce's racial and gender diversity in line with the population it serves and with the utility's stated goals.
    d. Working closely with the Prairie Island Indian Community, a sovereign nation, in planning for whether to renew the operating licenses for the Prairie Island Nuclear Plant. *(Mpls)*

9. Require Xcel to design DG Resource incentive programs that ensure distributed generation programs provide equitable access to low income and Black, indigenous, and communities of color that have disproportionately borne costs of unjust and inequitable energy decisions *(DSP)*

10. Require Xcel to adopt practices in furtherance of procedural justice, including deeper engagement with renters, affordable rental property owners, BIPOC communities, and under-resourced individuals, providing resources for engagement and participation, and providing financial support for impacted individuals to participate in dockets and decision-making processes. *(EEAP, DSP)*

11. Require Xcel to support the formation of an environmental justice accountability board, which would develop environmental justice-focused initiatives to be incorporated throughout the utility. *(EEAP, DSP)*

12. Require Xcel to develop and report on (or more regularly report on, if already developed) comprehensive recruitment, hiring, retention, and advancement goals and strategies for staff and board, as well as deepening its supplier and vendor diversity efforts. *(EEAP, DSP)*

13. Require Xcel to implement measures that could ease the path of Xcel workers who are displaced from jobs as described in IBEW's initial letter *(IBEW Locals 23, 260, 949)*