Before the Office of Administrative Hearings
600 North Robert Steet
Saint Paul, Minnesota 55101

For the Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
Saint Paul, Minnesota 55101

IN THE MATTER OF THE PETITIONS FOR RECOVERY OF CERTAIN GAS COSTS	OAH Docket No. 71-2500-37763
IN THE MATTER OF THE PETITION OF CENTERPOINT ENERGY FOR APPROVAL OF A RECOVERY PROCESS FOR COST IMPACTS DUE TO FEBRUARY EXTREME GAS MARKET CONDITIONS	MPUC Docket No. G008/M-21-138
IN THE MATTER OF THE PETITION BY GREAT PLAINS NATURAL GAS CO., A DIVISION OF MONTANA-DAKOTA UTILITIES CO., FOR APPROVAL OF RULE VARIANCES TO RECOVER HIGH NATURAL GAS COSTS FROM FEBRUARY 2021	MPUC Docket No. G004/M-21-235
IN THE MATTER OF A PETITION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY TO RECOVER FEBRUARY 2021 NATURAL GAS COSTS	MPUC Docket No. G002/CI-21-610
IN THE MATTER OF THE PETITION OF MINNESOTA ENERGY RESOURCES CORPORATION FOR APPROVAL OF A RECOVERY PROCESS FOR COST IMPACTS DUE TO FEBRUARY EXTREME GAS MARKET CONDITIONS	MPUC Docket No. G011/CI-21-611

PREFILED DIRECT TESTIMONY
OF BRADLEY CEBULKO
ON BEHALF OF
THE CITIZENS UTILITY BOARD OF MINNESOTA
Exhibit ___(BC-D)

December 22, 2021

Contents

Exhibit List

See exhibit list attachment

PREFILED DIRECT TESTIMONY OF

BRADLEY CEBULKO

ON BEHALF OF THE CITIZENS UTILITY BOARD OF MINNESOTA

I. Introduction

Q1. Please state your name and position.

A1. My name is Bradley Cebulko. I am a Senior Consultant at Strategen Consulting located at 2150 Allston Way Suite 400, Berkeley, California 94704.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of the Citizens Utility Board of Minnesota ("CUB").

Q3. Are you sponsoring any schedules?

A3. Yes. Please see the Exhibit list attached to this testimony, Schedules 1-37.

Q4. Please describe your formal education and professional experience.

A4. I am a Senior Consultant at Strategen Consulting. At Strategen, I work with consumer advocates, non-governmental organizations, and commissions on utility regulatory issues including new regulatory business models and integrated resource planning.

Prior to joining Strategen earlier this year, I worked at the Washington State Utilities and Transportation Commission ("UTC") for 8 years. From 2013-2016, I was an analyst with the UTC Commission Staff focused on integrated resource planning (IRP), electric and natural gas energy efficiency programs, and new program design and implementation. I was the Staff lead for natural gas IRPs. From 2016-2021, I was an Advisor to the Commissioners, where I led the Commissioners' review of major filings and adjudications, natural gas general rate cases, purchase gas adjustments, rulemakings, and natural gas integrated resource plans.

I have a Master's in Public Policy and Governance from the University of Washington and a Bachelor of Arts in Political Science from Colorado State University. My resume is attached as Exhibit ___(BC-D), Schedule 1.

Q5. Have you previously testified before the Public Utility Commission?

A5. No, I have not previously testified before the Minnesota Public Utility Commission, but I have testified before the Washington State Utilities and Transportation Commission. Before the Washington UTC, I filed testimony on service quality and reliability metrics in 2014 and 2015, and in 2016 on a utility's proposed appliance leasing program.[1]

Q6. Do you have any other relevant experience?

A6. Yes, from September 2016 until August 2021, I served as an Advisor to the Washington State Commissioners, where I led the Commissioners' review of dozens of adjudicated cases including electric and natural gas general rate cases, prudence cases, natural gas purchase gas adjustments, utility sales, and worked

[1] UE-140188 & UG-140189, UE-150204 & UG-150205, and UE-151871 & UG-151872

alongside the Administrative Law Judges to write dozens of Commission orders. I also led the Commissioners review of electric and natural gas integrated resource plans.

II. Testimony Overview

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to analyze the specific actions CenterPoint, MERC, and Xcel's took in the lead up to and during the February Event ("the Event").[2] If in my analysis I determine that a utility acted imprudently, I propose a range of disallowances for that issue. My approach is holistic and recognizes the inter-dependencies of each of the utility's decisions. For instance, any assumption I make on how a utility uses its storage will impact how it should optimize its peaking resources.

Q8. How is your testimony organized?

A8. I begin with a timeline of events covering what the utilities knew and when. Then, I analyze four areas that are key to the utilities decision-making during the Event: 1) load forecasting, 2) storage optimization, 3) curtailment, and 4) peaking facilities optimization. For issues that I believe a utility made an imprudent decision, I propose a range of disallowances.

Q9. Please summarize your key conclusions and recommendations.

[2] Strategen did not review the actions of Great Plains in this case.

A9. Based on my analysis, I found that CenterPoint, MERC, and Xcel each made imprudent decisions leading up to and during the Event. Each utility is differently situated and responded differently to the Event, so I will address each individually. However, there are certain facts that were apparent to all the utilities leading up to and during the Event that should have impacted their decision-making.

1. Due to the structure of the natural gas market, the utilities had to procure ratable natural gas on February 12 for the four-day period of February 13-16. As such, the utilities must plan to meet the highest load day (February 14) during the four-day weekend.

   The utilities knew that there was significant market uncertainty and were already experiencing high natural gas prices (greater than $15/Dth) when they developed their supply plans for the four-day weekend (February 13 – 16) on February 11 and 12.
2. On February 16, during the Event, natural gas prices were at unprecedented levels with Demarc and Ventura settling at $133.64 and $188.32, respectively. However, the utilities did not sufficiently modify their plans or actions for supplying gas to customers February 17, even knowing the extent of the storm, the impact to the natural gas market, and the extraordinary, incremental costs they had already incurred and planned to pass onto customers.
3. Reasonably accurate load forecasting was important for avoiding extraordinary index natural gas prices immediately before and during the

Event. MERC and Xcel's overly conservative load forecasts led to the over-procurement of gas that was indexed at the daily price, which forced the two utilities to ramp down storage to a larger degree than would have been necessary with better planning. This resulted in exorbitant costs for customers.

4. All the utilities can curtail their interruptible customers for economic purposes, such as responding to a price spike, and should have utilized that option during the Event.
5. The utilities could have, and should have, dispatched their peaking facilities to respond to the Event.

I also examined each utility's individual actions and came to utility-specific conclusions based on my analysis. Below, I summarize my findings for each utility and identify a range of disallowances.

a. CenterPoint

1. CenterPoint should have curtailed all interruptible load during the entirety of the Event. There was no operational or tariff restriction that would have prevented the utility from curtailing for economic reasons. I estimate that curtailing all interruptible customers would have saved customers $73 million over the five-day Event, and $17.5 million on February 17 alone.
2. CenterPoint had reasonable load forecasting throughout the Event and appears to have optimized its storage. I do not provide a disallowance on this issue.
3. CenterPoint had more than sufficient inventory in its peaking facilities to economically dispatch the LNG and propane facilities to reduce costs to

customers and adequately maintain reliability. I estimate that better use of the peaking facilities could have saved customers between $12.2 million and $122.6 million over the five-day Event, and between $12.2 million and $25 million on February 17 alone.

4. In total, I estimate that CenterPoint could have saved customers between $29.6 million and $196 million if it had better optimized its resource portfolio during the Event.

Table 1: CenterPoint Disallowance Range

CenterPoint Disallowance Estimate Range		
Curtailment	**100% called (95% responsive)**	
2/13 – 2/17	$73,602,994	
2/17 Only	$17,468,247	
Load forecasting and storage optimization	None	
Peaking optimization	**50% LNG, 25% Propane**	**100% LNG, 50% propane**
2/13 – 2/17	$56,809,146	$122,653,731
2/17 Only	$12,214,984	$24,923,313
2/13 – 2/17 Total	**$130,412,140**	**$196,256,724**
2/17 Only Total	**$29,683,231**	**$42,391,560**

b. MERC

1. MERC should have curtailed 50 percent of its interruptible load during the entirety of the Event. There was no operational or tariff restriction that would

have prevented the utility from curtailing for economic reasons. I estimate that curtailing all interruptible customers would have saved customers $4 million over the five-day Event, and $820,000 on February 17.

2. MERC imprudently relied on overly conservative load forecasts for the critical planning days of February 14 and 17. The Company's estimated forecast error on February 14 and 17 are 9.95 percent and 34.32 percent, respectively. The Company subsequently purchased more spot gas and took more call options at unprecedented prices rather than optimizing its existing storage. I estimate that MERC could have saved customers between $8.5 million and $18 million with better load forecasting.
3. MERC does not own or contract with any peaking facilities.
4. I estimate that MERC could have saved customers between $9.3 million and $22.1 million if it had better optimized its resource portfolio during the Event.

Table 2: MERC Disallowance Range

MERC Disallowance Estimate Range		
Curtailment	**50% Interrupted**	
2/13 – 2/17	$4,083,076	
2/17 Only	$820,184	
Load Forecasting Error and Storage Optimization	**5% Forecasting Error**	**10% Forecasting Error**
2/13 – 2/17	$18,028,508	$8,454,945
2/17 Only	$10,202,942	$8,454,945
Peaking Facilities	N/A	N/A

2/13 – 2/17 Total	**$22,111,585**	**$12,538,021**
2/17 Only Total	**$11,023,127**	**$9,275,129**

c. Xcel

1. Xcel curtailed all interruptible customers at the beginning of the Event, which saved customers tens of millions of dollars. However, the Company started releasing interruptible customers on February 17 while prices were still unprecedented. Had Xcel not released some customers on February 17, I estimate that the Company could have saved customers $1.6 million.
2. Xcel imprudently chose to base its supply plans on load forecasts that included interruptible customers, and which did not accurately represent the firm load served by the Company. Had Xcel relied on load forecasts that excluded curtailed customers, the Company's would have been able to see that its supply plan exceeded expected firm load by 11 percent and 9 percent on February 14 and 17, respectively. Had Xcel built its supply plans off more accurate load forecasts, I estimate the Company could have saved customers between $1.5 million and $9.7 million.
3. Xcel does not sufficiently justify that they properly maintained and prepared their LNG facility, Wescott, for use during the 2020-2021 winter season.
4. I estimate that Xcel could have saved customers between $5.7 million and $127 million if it had better optimized its resource portfolio during the Event.

Table 3: Xcel Disallowance Range

Xcel Disallowance Estimate Range						
Curtailment	Additional Curtailment 2/17 (95% responsive)					
2/13 – 2/17	$1,585,125					
2/17 Only	$1,585,125					
Load forecasting and storage optimization	**5% Forecasting Error**			**10% Forecasting Error**		
2/13 – 2/17	$9,734,465			$1,513,382		
2/17 Only	$4,836,909			$1,513,382		
Peaking Facilities	**Propane 50%, only**	**LNG 50%, Propane 25%**	**LNG 100%, Propane 50%**	**Propane 50%, only**	**LNG 50%, Propane 25%**	**LNG 100%, Propane 50%**
2/13 – 2/17	$14,311,286	$57,895,657	$115,791,314	$14,311,286	$57,895,657	$115,791,314
2/17 only	$2,488,873	$10,068,623	$20,137,247	$2,488,873	$10,068,623	$20,137,247
2/13 – 2/17 Total	$25,630,876	$69,215,247	$127,110,904	$15,824,669	$60,994,164	$118,889,821
2/17 Only Total	$8,910,908	$16,490,658	$26,559,281	$5,587,380	$13,167,130	$23,235,754

III. February Event Timeline

a. Conditions Before the February Event

Q10. What is the purpose of this section of your testimony?

A10. The purpose of this section of my testimony is to establish a clear timeline of utility knowledge and actions during the February Event. Key facts discussed in this section include weather forecasts, price changes, gas supply, market conditions, and associated utility actions and decisions informed by these pieces of information.

Q11. How do you define the February Event?

A11. My colleague Ron Nelson and I use the same definition as the Commission defined in its August 30, 2021 Order.[3] The February Event is defined as the 5-day period between February 13 – 17, 2021.

Q12. Did you prepare an Exhibit that details the timeline?

A12. Yes. Please see Exhibit___(BC-D), Schedule 2. This exhibit details the timeline of events specifically relating to weather forecasts, weather conditions, pipeline notices, and natural gas spot prices. Additionally, this includes a timeline of what each utility claimed to know and what actions they took as a result. Unless otherwise indicated, all dates included in the timeline and in this testimony occurred in 2021. Please note that our timeline and review is only considering CenterPoint, MERC, and Xcel. We did not include Great Plains in our review.

Q13. When was the first forecast for extreme cold weather in Minnesota?

[3] Order Granting Variances and Authorizing Modified Cost Recovery Subject to Prudence Review, and Notice of and Order for Hearing, MPUC Docket No. G-999/CI-21-135, p.11 (August 30, 2021).

A13. On January 28, 2021, the Commodity Weather Group (CWG) issued a 16 to 30-day map, covering February 12-26, 2021, and forecasting colder than normal temperatures in Minnesota but normal or above normal temperatures in the southern and south-central United States.[4] At the end of January, the National Weather Service issued a public forecast consistent with that of CWG.[5] By February 5, 2021, Minnesota started to experience unusually cold temperatures, and the National Weather Service's February 5, 2021, 8- to 10-day outlook forecasted the probability of a cold weather event affecting the entire Midwest over the Presidents' Day weekend.[6] By Monday, February 8, predictions emerged that southern producing states, such as Texas and Oklahoma, would also experience extreme cold weather.[7]

Q14. Please describe the weather conditions leading up to the February Event.

A14. On Friday, February 5, Minnesota started to experience unusually cold temperatures. The ten consecutive days following February 5, until February 15, had highs at or below 10F. Ten consecutive days of highs at or below 10F had not occurred since 1999.[8] Additionally, from February 12-15, 2021, the temperatures

[4] Direct Testimony and Schedules of Michael L. Boughner on Behalf of Northern States Power Company, MPUC Docket No. G002/CI-021-610, OAH Docket No. 71-2500-37763, p. 8, lines 13-14 (Oct. 22, 2021) ("Boughner Direct")
[5] Direct Testimony and Schedules of Richard G. Smead on Behalf of Joint Gas Utilities, MPUC Docket No. G002/CI-021-610, MPUC Docket No. G004/M-21-235, MPUC Docket No. G008/CI-21-138, MPUC Docket No. G011/CI-21-611, OAH Docket No. 71-2500-37763, p. 42, linse 1-3 (Oct. 22, 2021) ("Smead Direct")
[6] Direct Testimony and Schedules of Jeffrey T. Toys on Behalf of CenterPoint Energy, MPUC Docket No. G008/CI-021-138/OAH Docket No. 71-2500-37763, p. 25, line 15-17 (Oct. 22, 2021) ("Toys Direct")
[7] Smead Direct, p.42, lines 4-6.
[8] Direct Testimony and Schedules of Allen D. Krug on Behalf of Northern States Power Company, MPUC Docket No. G002/CI-021-610, OAH Docket No. 71-2500-37763, p. 13, line 1-2 (Oct. 22, 2021) ("Krug Direct")

in the Twin Cities stayed below zero for four consecutive days, which had not occurred since 1994.[9]

Q15. When did the pipeline operators begin indicating that their systems were stressed?

A15. On February 4, NNG first called a system overrun limitation (SOL) and continued to call SOLs daily through February 17.[10] An SOL-day is called if the operating integrity of the pipeline system is in jeopardy, which means shippers could incur a higher variance charge if they take more gas than what they have scheduled.[11] On February 11 at 11:46 p.m., NiGas issued a critical day notice for February 13 beginning at 9 a.m., which was anticipated to continue through February 15.[12] On February 12 at 10:10 a.m., NNG posted a critical day notice effective at 9 a.m. on February 13 through 8:59 a.m. on February 14. NNG also posted critical day notices each morning from February 13 - 19.[13] A Critical Day is called when the operating condition of the pipeline system has severely deteriorated, and the integrity of the system is threatened.[14]

Q16. What is the significance of these pipeline operational alerts?

[9] Krug Direct, p.13, lines 2-4.
[10] Direct Testimony and Schedules of Sarah R. Mead on Behalf of Minnesota Energy Resources Corporation, MPUC Docket No. G011/CI-021-611, OAH Docket No. 71-2500-37763, p. 44, lines 9-10 (Oct. 22, 2021) ("Mead Direct")
[11] Northern Natural Gas, NNG Flowing Gas and Invoicing User Manual, p.35 (January 2021), https://www.northernnaturalgas.com/Document%20Postings/Flow_GAS_and_Invoicing_Manual.pdf
[12] Smead Direct, Schedule 6, p. 1-6.
[13] Smead Direct, Schedule 6, p. 1-6.
[14] Mead Direct, p.51, line 9-10.

A16. Minnesota natural gas utilities depend on the pipelines for transporting nearly all of their gas, both market purchases and storage. Declarations of critical days or SOLs indicate tightened flow tolerances and means that the pipeline may limit the ability of the utility to deliver its scheduled volume. Under these types of designations, the risk of penalties increases and the importance of the utility's load forecast during the designated period also increases. NNG's SOL was called just over a week before the onset of the February event giving the utilities time to plan for adequate balancing services prior to the long weekend. In addition to the weather reports, the SOL and critical day notifications are another indication that the weekend market conditions were deteriorating.

Q17. Were there any other notable events in the lead up to the February Event that may have indicated the possibility of supply shortages?

A17. Yes. On February 8, Platts Gas Daily reported that **[BEGIN TRADE SECRET INFORMATION] [END TRADE SECRET INFORMATION]**.[15] Additionally, on February 10 and 11, potential production freeze-offs were being reported by the trade press.[16] For example, the February 11 edition of Gas Daily published on February 10 noted: "The potential for increased local demand and lower production has also helped raise Permian spot gas prices. West Texas is expected to see temperatures fall below freezing in the near term, with the

[15] CenterPoint Energy, Trade Secret Response to CUB IR#2, (Attached as Exhibit___(BC-D), Schedule 3), MPUC Docket No. G999/CI-21-135.
[16] Xcel Energy, Public Response to DOC IR#36 (Attached as Exhibit___(BC-D), Schedule 4), MPUC Docket No. G002/CI-21-610, OAH Docket No. 71-2500-37763.

National Weather Service forecasting a low of 28 degrees Fahrenheit at Midland, Texas on Feb. 11. Further lows are expected through the weekend, with temperatures expected to fall as low as 15 F on Feb. 13, which could prompt wellhead freeze-offs."[17] Likewise, the February 12 edition of Gas Daily published on February 11 noted: "The Midcontinent led the surge in US gas prices in Feb. 11 trading as a sharp rise in heating demand met with regional production freeze-offs, significantly tightening balances across much of the Central US. In morning trading, cash prices at hubs in Kansas, Oklahoma and eastern Arkansas hit levels not seen since 2014, with select locations hitting record highs, Intercontinental Exchange data showed. At One Oak Gas Transmission, Southern Star and Enable Gas, spot prices reached record highs around $85, $45, and $30/MMBtu, respectively. At other hubs, including ANR Oklahoma, Panhandle and NGPL Midcontinent, prices hit their highest in seven years, topping $16, $14, and $12/MMBtu, respectively."[18]

CenterPoint, MERC, and Xcel have indicated that they review Platts Gas Daily-MERC notes prices reported from Gas Daily in Information Requests,[19] CenterPoint refers to Platts Gas Daily Prices in Information Requests[20] and Platts Gas Daily news updates were in the email inboxes of key Xcel employees on the

---

[17] *Ibid.*
[18] *Ibid.*
[19] MERC, Trade Secret Response to CUB IR#21, MPUC Docket No. G011/CI-21-611, OAH Docket No. 71-2500-37763
(Attached as Exhibit___(BC-D), Schedule 5).
[20] CenterPoint Energy, HCTS Response to OAG IR#5, p. 325, MPUC Docket No. G-999/CI-21-135 (Attached as Exhibit___(BC-D), Schedule 6).

mornings of February 11 and 12[21]- and thus should have been aware of this information.

Q18. Please describe natural gas spot prices leading up to the February Event.

A18. There are three key trading hubs that are directly relevant to the Minnesota market: Emerson, Manitoba (Emerson), where TransCanada feeds both Great Lakes and Viking; NNG Field/Market Demarcation (Demarc), the Kansas boundary between NNG's supply-area system and the market system that serves Minnesota; and Ventura, Iowa (Ventura), where Northern Border and NNG boundary between NNG's supply-area system and the market system that intersect.

The 5-year annual average gas price is $2.433/MMBtu for delivery into Emerson, $2.468/MMBtu for Demarc, and $2.543/MMBtu Ventura.[22] On January 27, natural gas spot prices settled at $2.506/MMBtu for delivery into Emerson, $2.651/MMBtu for Demarc, and $2.639/MMBtu Ventura.[23] This was the last day of spot prices published before the final day for monthly spot market purchases, January 28. First of the month (FOM) contract purchases settled slightly above the spot price.

Spot market prices began to noticeably rise by Wednesday, February 10 for gas delivered on February 11. At the end of February 10, spot market prices settled at

[21] Xcel Energy, HCTS Response to OAG IR#5, MPUC Docket No. G002/CI-21-610, OAH Docket No. 71-2500-37763 (Attached as Exhibit___(BC-D), Schedule 7).
[22] Analysis based on S&P Capital IQ Pro data.
[23] S&P Capital IQ Pro Historical Spot Natural Gas Index.

$4.733/MMBtu at Emerson, $6.900/MMBtu at Ventura, and $7.245 at Demarc.[24] These February 10 prices represent a 95 percent (Emerson), 171 percent (Ventura) and 194 percent (Demarc) increase over 5-year annual average prices, respectively.

By the end of February 11, spot prices had more than doubled from the previous day at both Demarc and Ventura settling at $14.109/MMBtu and $15.613/MMBtu, respectively. Prices at Emerson were just under 1.5 times the spot price of the previous day settling at $6.5/MMbtu.[25] These February 11 prices represent a 472 percent (Demarc), 514 percent (Ventura), and 167 percent (Emerson) increase over 5-year annual average prices.

Q19. Will you please put the prices on February 11, as the utilities were preparing to purchase gas for the four-day period of February 13-16, into historical perspective?

A19. In the past 10 years in Minnesota, natural gas spot prices had only exceeded $14/MMBtu during the 2013/2014 Polar Vortex, the TransCanada Pipeline Explosion in 2014, and the extreme cold of New Year's 2017/2018.[26] Prior to making purchases for the long weekend, utilities were well aware of extreme natural gas prices due to the spot market prices from the February 11 gas day, and they were aware that the peak day forecast was not until February 14.

[24] *Ibid.*
[25] *Ibid.*
[26] *Ibid.*

Q20. How do the natural gas spot prices in the lead up to the February Event compare to historical averages?

A20. The spot market prices on February 10 and 11 were in the 98th percentile at Emerson, Demarc, and Ventura, as compared to the past 5 years of natural gas spot prices at each respective trading hub.[27] The unusually high prices prior to the worst of the storm tightened pipeline supply conditions, and a four-day gas buying period should have strongly indicated to the utilities that price volatility would likely continue.

Table 4: Natural gas spot prices ($/MMBtu) in the lead up to the February Event as compared to 5-year averages[28]

Trade Date	Flow Date	Emerson ($/MMBtu)	Demarc ($/MMBtu)	Ventura ($/MMBtu)
2/8/2021	2/9/2021	3.359	3.800	4.052
2/9/2021	2/10/2021	3.158	3.881	4.056
2/10/2021	2/11/2021	4.733	6.900	7.245
2/11/2021	2/12/2021	6.500	14.109	15.613
5-Year Historic Average		2.433	2.468	2.543

Q21. Can the utilities be reasonably expected to have knowledge of the weather, pricing, and market conditions that you just described?

[27] Analysis based on S&P Capital IQ Pro data.
[28] S&P Capital IQ Pro Historical Spot Natural Gas Index.

A21. Yes, the utilities can all be reasonably expected to have knowledge of all the information that I discussed in this subsection. The weather forecasts are publicly available, the NNG and NiGas critical day and SOL notices are publicly available on their websites, and the utilities frequently communicate with gas suppliers and have indicated that they refer to Platt's Gas Daily, so they are aware of forecasted price points.

Going into the long weekend, market prices were already higher than alternative, available resources, such as storage, curtailing interruptible customers, and peaking facilities, and there was no logical scenario where the utilities could have predicted that prices would have decreased over the weekend.

b. Conditions During the February Event

Q22. Please describe the weather conditions during the February Event.

A22. From February 12-15, the temperatures in the Twin Cities stayed below zero for four consecutive days, which had not occurred since 1994.[29] February 14 was the coldest day of the long weekend. Temperatures stayed below 10F during the entirety of the February Event.

Q23. Please describe the natural gas prices during the Event.

A23. During the February Event, natural gas spot prices reached unprecedented levels. Natural gas spot prices for the February Event spiked to $9.055/MMBtu, $155/MMBtu, $178/MMBtu, at Emerson, Demarc, and Ventura, respectively. At

[29] Krug Direct, p.13, lines 2-4.

Emerson and Ventura these price spikes occurred on February 17. At Demarc, this price spike occurred on February 16.[30] These peak prices represent a 272 percent (Emerson), 6,900 percent (Ventura) and 6,180 percent (Demarc) increase over 5-year annual average prices.

Q24. When did the utilities purchase daily spot gas for February 13-16?

A24. Given the volume that CenterPoint needed to procure for the long weekend, tightening of supply on February 10, and "hesitance of suppliers to sell at the Gas Daily Index or at a fixed price due because of price movements on February 10 and where the market was estimating prices would settle for Gas Day February 11," CenterPoint purchased 195,000 of daily spot gas for delivery over the holiday weekend on the morning of February 11.[31] CenterPoint made additional purchases on February 12.[32] Xcel began purchasing gas for the long weekend at 6:40 a.m. on February 12.[33] MERC purchased daily gas on February 11 between 1:45 p.m. and 2:25 p.m.[34]

Q25. What was the price of daily spot natural gas on February 16 when the utilities purchased gas for February 17?

A25. By Tuesday February 16, when the utilities were purchasing gas for Wednesday, February 17, the utilities knew that prices over the four-day period were at

---

[30] S&P Capital IQ Pro Historical Spot Natural Gas Index.
[31] Toys Direct, p.31, lines 8-14.
[32] Toys Direct, p.37, lines 14-16.
[33] Direct Testimony and Schedules of Gordon H. Green on Behalf of Northern States Power Company, MPUC Docket No. G002/CI-021-610, OAH Docket No. 71-2500-37763, p. 13, lines 17-19 (Oct. 22, 2021) ("Green Direct")
[34] Mead Direct, p.46, lines 21-22.

unprecedented levels. Prices settled at $133.64/Dth and $188.32/Dth at Demarc and Ventura, respectively, on February 16. When the utilities purchased gas on February 16 for February 17, the utilities cannot say that they did not know prices would reach unprecedented levels as they just experienced four days of unprecedented prices.

Q26. Has Minnesota ever experienced natural gas price spikes associated with extreme cold weather events?

A26. Yes. In the past 10 years in Minnesota, prices have spiked due to the 2013/2014 Polar Vortex, the TransCanada Pipeline Explosion, the extreme cold of New Year's 2017/2018, and the 2019 Polar Vortex. Price spikes as a result of the 2019 Polar Vortex were less extreme than the other aforementioned events, but prices at Emerson, Demarc, and Ventura still reached at least double the 5-year average price. The utilities have repeated experience navigating extreme cold weather events accompanied by price spikes.

c. Utility Knowledge and Associated Actions

Q27. Let's take each company in turn. Please start with CenterPoint. Will you please describe what knowledge CenterPoint claimed to have in the lead up to and during the Event?

A27. CenterPoint uses a two-day forecast to inform gas purchasing decisions, but on weekends and/or holidays, which require a longer forecast period, 5-day forecast weather data is used.[35] CenterPoint reviews 2-5 day weather data at its Daily Supply Plan review meeting daily at 7AM. CenterPoint also reviews 10-day weather data from a Company-developed model to monitor longer-range forecasts and identify potential weather patterns.[36] Witness Toys testified that entering the month of February, forecasts began to suggest that the month would be a few degrees colder than normal. Witness Toys also refers to the National Weather Service's February 5, 8- to 10-day weather forecast showing the probability of a cold weather event affecting the entire Midwest over the Presidents' Day weekend.[37]

Witness Toys testified that on February 11, CenterPoint was seeing tightening of supply in the market for daily gas and "there were indications on February 11th that the market might rise even higher on February 12th."[38] Further, on the morning of February 11, some suppliers indicated to CenterPoint that they would not sell to the Company so as to not end up short for the long weekend and CenterPoint expressed concern about securing enough gas for the long weekend.[39] In an exchange with a supplier, a CenterPoint representative asked "how are prices this morning" and after a response from the third party responded with "it[']s scary."[40]

[35] Direct Testimony and Schedules of Dr. Adam J. Stepanek on Behalf of CenterPoint Energy, MPUC Docket No. G008/CI-021-138, OAH Docket No. 71-2500-37763, p. 6, lines 8-15 (Oct. 22, 2021) ("Stepanek Direct")
[36] Stepanek Direct, p.6, lines 8-22.
[37] Toys Direct, p.25, lines 15-17.
[38] Toys Direct, p.32, lines 8-10.
[39] Toys Direct, p.32, lines 1-3.
[40] Office of the Attorney General, Docket No. G-999/CI-21-135/21-138/21-235, p. 46 (July 6, 2021).

Q28. Are CenterPoint's claims consistent with what the Company reasonably should have known in the lead up to the February Event?

A28. Yes except for one notable omission. Witness Toys is focused on what the Company knew prior to the four-day gas buying period for February 13-16. CenterPoint does not address what it knew on February 16 for gas day February 17, notably that its service territory was experiencing an unprecedented price spike. CenterPoint failed to address this, and it appears that it did not adjust its actions based on that unmistakable knowledge.

Q29. What decisions did CenterPoint make based on this knowledge?

A29. CenterPoint reported that it updated its load forecast developed 2-5 days prior to each day and reviewed weather data at its Daily Supply Plan review meeting at 7 a.m.[41]

- On February 11 at 9 a.m., CenterPoint purchased 195,000 Dth of daily spot gas for delivery over the long weekend.[42]
- At its Daily Supply Plan meeting on February 12 at 7 a.m., CenterPoint updated its weather forecasts up to February 16, discussed the possibility of curtailing customers, and planned to maximize gas storage on February 14, as this was the

[41] Olsen Direct p.8, lines 5-7; Olsen Direct p.12, lines 12-13.
[42] Toys Direct, p.31, lines 10-12.

highest projected load day.[43] Also on February 12, CenterPoint purchased 540,000 Dth of daily swing supplies.[44]

- On February 13, CenterPoint maximized storage withdrawals, and dispatched 229 Dth of LNG and 1,397 Dth of propane for peak shaving. At the end of the day, the Company decided to dispatch propane from Rum River at 7 a.m.[45]
- On February 14, CenterPoint curtailed 31 customers beginning at 5AM, Rum River was dispatched from 7 a.m. -11 a.m., and CenterPoint's LNG resources ran at 50 percent for the rest of the gas day.[46] Storage withdrawals were once again maximized.[47]
- On February 15 CenterPoint again maximized storage withdrawals and ran its LNG peaking facilities at 50 percent.[48]
- On February 16, storage withdrawals were reduced, and customers were released from curtailment despite continuous price increases and no indications of changing supply conditions.[49]
- On February 17, CenterPoint nominated its full baseload (358,436 Dth) and swing supply (70,000 Dth), nominated its daily maximum storage capacity, and purchased a reduced amount of daily spot gas.[50]

---

[43] Olsen Direct p. 22-23, lines 6-17 and 1-18; Direct Testimony and Schedules of John J. Reed on Behalf of CenterPoint Energy, MPUC Docket No. G008/CI-021-138, OAH Docket No. 71-2500-37763, p. 78, lines 12-13 (Oct. 22, 2021) ("Reed Direct")
[44] Reed Direct, p.79, lines 10-11.
[45] Direct Testimony and Schedules of John W. Heer on Behalf of CenterPoint Energy, MPUC Docket No. G008/CI-021-138, OAH Docket No. 71-2500-37763, p. 35-36, lines 12-13 and 1-2 (Oct. 22, 2021) ("Heer Direct")
[46] Heer Direct, p.36, lines 11-13; Toys Direct, p.47, lines 13-15.
[47] Toys Direct, p.47, lines 7-9.
[48] Toys Direct, p.51, lines 14-19.
[49] Toys Direct, p.55, lines 4-9.
[50] Toys p.55, lines 13-14.

Q30. Will you please describe what knowledge MERC claimed to have in the lead up to and during the February Event?

A30. MERC claimed that it was aware of a cold weather forecast for Minnesota on February 2 and aware of a cold weather forecast for other US states "several days later."[51] Regarding pricing, Witness Eidukas claims that MERC became aware of the price spike late on the morning of February 12.[52]

Q31. Are MERC's claims consistent with what the Company reasonably should have known in the lead up to the February Event and during the Event?

A31. Not all of MERC's claims are consistent with what the Company reasonably should have known in the lead up to the February Event. MERC's knowledge of weather prior to the February Event is consistent with what the company could have been reasonably expected to know, but Witness Eidukas' claim that MERC only became aware of price spikes the morning of February 12 is unreasonable. As discussed earlier in my testimony, both the February 10 and 11 spot market prices were in the 98th percentile at Emerson, Demarc, and Ventura, as compared to the past 5 years of natural gas spot prices at each respective trading hub. The spot prices seen in the lead up to the Event were significantly higher than average natural gas spot prices in Minnesota, which should have caught the attention of all

---

[51] Direct Testimony and Schedules of Theodore T. Eidukas on Behalf of Minnesota Energy Resources Corporation, MPUC Docket No. G011/CI-021-611, OAH Docket No. 71-2500-37763, p. 24, line 14-17 (Oct. 22, 2021) ("Eidukas Direct").

[52] Eidukas Direct, p.26, lines 6-10.

the utilities especially considering awareness of tightened supply conditions and deliverability concerns due to the pipeline warnings.

Further, by Tuesday, February 16, extreme prices were well known, but MERC failed to acknowledge this available information and did not adjust its actions to benefit customers.

Q32. What decisions did MERC make based on this knowledge?

A32. MERC began planning for the long weekend in the afternoon of February 11.[53]

- On February 11 between 1:45 p.m. and 2:25 p.m., MERC purchased daily gas for the long weekend.[54]
- On February 14 at 7 a.m., MERC significantly reduced its forecast of gas load from 456,675 Dth to 379,990 Dth and reduced transport volumes from 187,765 Dth to 137,765 Dth.[55] MERC also reduced storage withdrawals by 33,675 Dth.[56]
- On February 15, MERC began planning for the purchasing gas for February 17.[57]
- On February 16 at 7:30 a.m., MERC purchased gas for February 17.[58]
- On February 17 at 7 a.m., MERC reduced its forecast of gas load from 391,379 Dth to 318,603 Dth and increased transport customers' estimated volumes by a few hundred Dth.[59]

[53] Mead Direct, p.46, line 19.
[54] Mead Direct, p.46, lines 20-22.
[55] Mead Direct, p.48, lines 6-9.
[56] Mead Direct, p.48, lines 9-10.
[57] Mead Direct, p.48, lines 16-17.
[58] Mead Direct, p.48, lines 17-22.
[59] Mead Direct, p.50, lines 1-3.

Q33. Should MERC have begun planning for the long weekend prior to February 11?

A33. Yes. As a result of the 2019 Polar Vortex, MERC "proposed that when severe cold weather is forecasted, the Company would establish a meeting schedule with key employees from operations, engineering, and gas supply to provide updates and to regularly monitor and respond to any service-related issues."[60] MERC continued on to say that, "In the last severe cold weather event, MERC began a meeting schedule after the event had begun. MERC believes being proactive will allow MERC personnel to be better prepared." [61] As a result of the 2019 Polar Vortex, MERC recognized the need to proactively plan, but did not apply this lesson learned during the February Event. Forecasts indicating severe cold weather were publicly available by February 5, so MERC should have begun its planning process then. The company provided no evidence that it began acting sooner than February 11.

Q34. Lastly, will you please describe what knowledge Xcel claimed to have in the lead up to the February Event?

A34. Xcel's January 28 weather map for February 12-16 projected colder than normal temperatures in Minnesota, but normal or above normal temperatures in the southern and south-central United States.[62] Xcel's February 2 weather map

[60] Compliance Filing of Minnesota Energy Resources Corporation, MPUC Docket No. E,G-999/CI-19-160, p.1 (November 1, 2019).
[61] *Ibid.*
[62] Boughner Direct, p.7, lines 22-25.

forecast colder than average weather for the southern and south-central states. The Company's February 8 weather map illustrated extreme cold across the United States.[63] On February 11, Xcel's gas traders noted price increases in the market.[64]

Q35. Are Xcel's claims consistent with what the Company reasonably should have known in the lead up to the Event?

A35. Not all of Xcel's claims are consistent with what the Company reasonably should have known in the lead up to the February Event. Xcel's knowledge of weather prior to the February Event is consistent with what the Company could have been reasonably expected to know, but Xcel repeatedly claims a lack of knowledge of the extreme prices. While it is true that the utility could not have reasonably foreseen the extent of the price spikes, prices were already spiking on February 10 and 11, and price spikes should have been expected to continue as experienced in all of Minnesota's extreme cold weather events in the past 10 years. Additionally, by Tuesday, February 16, extreme prices were well known, but Xcel did not take all reasonable actions that it could have taken to benefit customers.

Q36. Prior to the February Event, were there any important dates that are relevant and should have informed Xcel's decision-making during the Event?

A36. Yes. As will be discussed in greater detail later in my testimony, during vaporization testing on the Wescott plan on December 31st, 2020, there was a malfunction on vaporization equipment and natural gas was released into the

[63] Boughner Direct p.11, lines 6-7.
[64] Krug Direct, p.25, lines 18-19.

atmosphere. The same occurrence happened during a January 3, 2021, test as well. After investigating into two propane facilities, Xcel also shut down its Sibley and Maplewood plants, and the Wescott LNG facility. All three of the utility's peaking facilities would remain offline through the winter season and into today. The Company procured additional firm pipeline capacity to ensure it had sufficient capacity for the season.

Q37. What decisions did Xcel make based on the information it was receiving the week prior to the Event?

A37. Xcel made the following decisions based on the information it was receiving the week prior to the Event:

- On February 4, Xcel released an internal extreme cold weather alert and began planning for the upcoming extreme cold weather. Additionally, on February 4, Xcel initiated discussions with all gas teams, increased staffing to monitor the gas system, opened redundant supply paths, made compressed natural gas mobile units available, planned to maximize storage withdrawals, and encouraged conservation efforts.[65]
- On February 5, Xcel curtailed all of its interruptible firm and transport customers. These curtailments continued until February 18 for firm customers and February 22 for transportation customers.[66]
- On February 10, Xcel purchased 354,912 Dth for $6.04/Dth.[67]

[65] Krug Direct, p. 20-21, lines 10-4.
[66] Krug Direct, p.21, lines 7-18.
[67] Green Direct, p.12, lines 14-15.

- On February 11, Xcel purchased 354,825 Dth for $13.6/Dth.[68]
- On February 12 at 11 a.m., Xcel again curtailed interruptible gas customers.[69]
- On February 13, Xcel purchased 14,000 Dth at $95/Dth.[70]
- On February 15, Xcel purchased 8,280 Dth at $157/Dth.[71]
- On February 16, Xcel purchased 272,953 Dth at $127.19/Dth.[72]
- On February 17 at 6 p.m., most gas customers were released from curtailment.[73]
- On February 18 at 9 a.m., the remainder of Xcel's interruptible gas customers were released from curtailment.[74]

IV. Load Forecasting and Supply Planning

Q38. What is the purpose of this section of your testimony?

A38. The purpose of the section is to analyze whether the utilities load forecasting was prudent and informed prudent decision making before, during, and after the Event.

Q39. Why are load forecast important and how do they relate to supply procurement for customers?

[68] Green Direct, p.12, lines 19-20.
[69] Krug Direct, p.21, lines 11-13.
[70] Green Direct, p.19, lines 23-24.
[71] Green Direct, p.20, lines 26-27.
[72] Green Direct, p.19, lines 10-11.
[73] Krug Direct, p.21, lines 13-15.
[74] *Ibid.*

A39. Load forecasting is important because it is the basis for understanding how much supply is necessary to meet the forecasted load. From there, the Company can determine the optimal strategy for delivering supply to load that maintains reliability at the lowest reasonable cost. Forecasting errors, to some degree, are inevitable and expected, and the utilities have options to balance the system within the day. However, unreasonable forecasting errors can be enormously expensive and at worst, cause a reliability issue.

Q40. In regard to their load forecasts, what did the utilities include in their testimonies? What did they not include?

A40. By and large, the utilities provided timelines of their load forecasts and subsequent supply decisions, but they did not provide analysis or explanation as to the reasonableness of their load forecasts. Questions that I would have expected the utilities to answer include, but are not limited to: What was the load forecasting error for each day during the Event? What is an acceptable level of load forecasting error? Is there any industry benchmark? Does the utility modify its methodology or approach when it is forecasting for a long weekend or for an extreme cold weather event, or if the pipelines have issued an operational flow order or other critical designation?

Q41. Did the utilities face any constraints in planning to meet load prior to or during the event?

A41. Yes. As detailed in the timeline I developed, attached as Exhibit___(BC-D), Schedule 2, the worst of the storm was predicted to occur over President's Day weekend. Due to the holiday and the structure of the natural gas market, the utilities would need to plan how they would meet expected demand for February 13-16 on Friday, February 12, the last day for purchasing gas on the market. The daily spot purchases and call options over the long weekend (February 13-16, 2021) must be "ratable," meaning that each day must be equivalent in volume. To ensure sufficient daily supply, the utilities focused their planning on meeting load on February 14, which was forecast to have the coldest temperature and highest load over the four-day weekend. Although suppliers occasionally offer non-ratable spot purchases at a premium, CenterPoint and MERC reported that they did not receive any offers for non-ratable gas over the long weekend.[75]

In addition, NNG issued a System Overrun Limitation (SOL) on February 4th lasting through the remainder of the Event. During a SOL, the pipeline restricts the utility's ability to use the pipeline's balancing service (called System Management Service) and also applies stiff penalties to the utility if it pulls more or less gas than it scheduled.[76]

Q42. How have the utilities argued that these constraints limited their ability to minimize costs during the event?

A42. Each utility has argued that the requirement to purchase ratable gas over the long weekend essentially forced them to over-procure daily spot purchases, and in the

[75] CenterPoint Energy, Public Response to CUB IR # 35a, MPUC Docket No. G-008/M-21-138/OAH Docket No. 71-2500-37763 (Attached as Exhibit___(BC-D), Schedule 9).; Minnesota Energy Resources Corporation, Public Response to CUB IR #33a, MPUC Docket No. 21-611/ OAH Docket No. 71-2500-37763 (Attached as Exhibit___(BC-D), Schedule 10).

[76] CenterPoint Energy, HCTS Response to CUB IR #39, MPUC Docket No. G-008/M-21-138/OAH Docket No. 71-2500-37763 (Attached as Exhibit___(BC-D), Schedule 11).

case of CenterPoint and MERC, call options, during the three days in which load was not expected to peak. To ensure adequate supply on the peak date of February 14, while also meeting the requirement for ratable spot purchases, the utilities were left with no choice, in their account, but to purchase excess gas during the non-peak dates while ramping down storage in order to balance the system and avoid paying steep penalties for excess supply.[77]

Q43. Do you agree with this conclusion reached by each utility?

A43. Partially, but I also disagree with some aspects of these conclusions. The requirement for ratable gas purchases over the long weekend undoubtedly presented a constraint: the utilities must balance the need to provide reliable supply on February 14 against the obligation to minimize the cost of over-procurement of daily spot and swing purchases on the three days expected to have non-peak load. Given the essential need to ensure reliability and the state of the natural gas market, it is reasonable for the utility to plan for the peak day and to anticipate some level of over-procurement of daily spot and swing gas during the non-peak days.

However, I disagree with aspects of the utilities' conclusions for two reasons. First, the scale by which Xcel and MERC over-forecasted their customers' demand was unreasonably conservative, as I will discuss in greater detail shortly. Second, Xcel and MERC appear to be emphasizing the requirement for ratable

[77] Toys Direct, p.39, lines 12-19, p. 40, lines 1-5, p. 44, lines 9-17, p. 56, lines 11–13, p. 57, lines 1-4, p. 63, lines 14-15; Mead Direct, p. 57, lines 7-17; Green Direct, p. 8, lines 4-8; Levine Direct, Schedule 2, Review of NSPM's Natural Gas Procurement for Retail Natural Gas Customers, spp. 42-43, paragraph 64.

purchases while downplaying their own role in managing costs to suggest that an unnecessary level of over-procurement of daily spot gas was inevitable and unavoidable. Had MERC and Xcel produced better load forecasts and reacted to volatile prices by planning supply in a manner that more reasonably balanced cost and risk, they could have substantially reduced costs for their customers – even though ratable purchases were required. As my colleague Ron Nelson and I testify, the utilities chose to prioritize minimizing risks to the utility, shareholders, and non-firm customers over balancing costs and risk for all ratepayers.

Q44. Have the constraints faced by the utilities informed your analysis and recommended range for disallowances?

A44. Yes. It would not be reasonable to penalize utilities solely for making ratable purchases over the long weekend. Given that they did not appear to have a reasonable option to purchase non-ratable gas immediately prior to the long weekend, the utilities could not have reasonably addressed this constraint. My analysis instead assesses the reasonableness and impact of the utilities' efforts to plan for February 14, the date when peak load was expected over the long weekend, as well as February 17, when (i) non-ratable purchases were available, (ii) the utilities knew the extent of the storm, and (iii) prices had already reached unprecedented heights.

Q45. Do you have concerns regarding the reasonableness of each utility's load forecast prior to and during the event?

A45. Yes. Although CenterPoint produced relatively accurate load forecasts, I am concerned about MERC and Xcel's load forecasting. MERC substantially over-projected load for MERC NNG on February 14 and 17. Unfortunately, the utility did not testify as to the reasonableness of its forecast. I am also concerned that Xcel chose to base its supply plans on a forecast that included delivery to interruptible customers. Given that Xcel interrupted a substantial amount of non-firm load, the load forecast served as an inaccurate tool for informing supply decisions.[78] I am particularly concerned that MERC and Xcel's approaches were the most conservative when planning for February 17, after daily spot prices had reached unprecedented heights.

Q46. Was CenterPoint's load forecast prior to and through the Event reasonable?

A46. CenterPoint appears to have forecasted load with a moderate to high degree of accuracy. In assessing the accuracy of each utility's forecasts, it is important to note that Xcel's and CenterPoint's forecasts included non-firm load while actuals omitted interrupted customers – a fact shielded by the comparison of forecasts to actuals provided by each utility. [79] In order to facilitate an apples-to-apples comparison, I have subtracted estimated interruptions from CenterPoint's load forecasts to estimate that the Company's forecast came within approximately 5

[78] Xcel Energy, Response to CUB IR #60a, MPUC Docket No. G011/CI-21-611/OAH Docket No. 71-2500-37763 (Attached as Exhibit___(BC-D), Schedule 13).
[79] CenterPoint Energy, Public Response to DOC IR #4a, MPUC Docket No. G-008/M-21-138/OAH Docket No. 71-2500-37763 (Attached as Exhibit___(BC-D), Schedule 14).; Xcel Energy, Public Response to CUB IR #60, MPUC Docket No. G011/CI-21-611/OAH Docket No. 71-2500-37763 (Attached as Exhibit___(BC-D), Schedule 13).; CenterPoint Energy, HCTS Response to CUB IR # 47, MPUC Docket No. G-008/M-21-138/OAH Docket No. 71-2500-37763 (Attached as Exhibit___(BC-D), Schedule 15).

percent and 3 percent of delivered load on February 14 and 17, respectively, as indicated in my workpapers.[80] The Company planned a relatively modest supply margin of less than 2 percent on both dates.[81] Given the relative accuracy of CenterPoint's forecast, I believe that it provides evidence that it was possible to forecast load with a moderate to high degree of accuracy on the key dates of February 14 and 17.

I am concerned, however, that CenterPoint chose not to maximize curtailments throughout the Event.[82] I will discuss this issue in greater detail later in my testimony.

Table 5: CenterPoint Load Forecast During the Event

	Formula	**2/14/2021**	**2/17/2021**
A. Load Forecast as of Supply Meeting[83]		1,223,099	959,549
B. Estimated Interrupted Load[84]		(57,000)	(4,400)
C. Estimated Forecast for Non-Interrupted Load	A - B	1,166,099	955,149
D. Actual Load[85]		1,228,842	979,923
E. Forecast Error	(C-D)/D	-5.11%	-2.53%

[80] CenterPoint Energy, Public Response to OAG IR # 118d (Attached as Exhibit___(BC-D), Schedule 16), MPUC Docket No. G-999/CI-21-135; Toys Direct, p. 34, Table 9 and p. 57, line 18
[81] Toys Direct, p. 34, Table 9; p. 55, lines 13-16; p. 57, line 18; p. 25, Table 25; CenterPoint Energy, HCTS Response to CUB IR #6 (Attached as Exhibit___(BC-D), Schedule 17).
[82] CenterPoint Energy, Responses to OAG IR # 118a and 118d (Attached as Exhibit___(BC-D), Schedule 16), MPUC Docket No. G-999/CI-21-135.
[83] Toys Direct, p. 34, Table 9, p. 57, line 18.
[84] CenterPoint Energy, Public Response to OAG IR #118d (Attached as Exhibit___(BC-D), Schedule 16), MPUC Docket No. G-999/CI-21-135.
[85] CenterPoint Energy, Public Response to DOC #16f (Attached as Exhibit___(BC-D), Schedule 19), MPUC Docket No. G-999/CI-21-135

Q47. Do you have concerns regarding the reasonableness of MERC's load forecast prior to and during the event?

A47. Yes. MERC appears to have produced relatively accurate load forecasts for MERC Consolidated, yet MERC NNG's forecasts were quite inaccurate on the critical dates of February 14 and 17. MERC's NNG area experienced extraordinary prices during the Event, while MERC's Consolidated area did not experience a similar price spike.

As explained in the testimonies of Witnesses Mead and Sexton, MERC NNG is responsible for procuring gas for the Company's Sales customers, but also distributes gas to Transportation customers who procure and deliver their own supply on MERC's distribution system. MERC does not have direct insight into the Company's Transportation customer contracts and must thus rely on information from Transportation customers when forecasting load.[86] I have estimated actual load for MERC NNG's Sales customers by subtracting scheduled Transportation from the combined load actuals for both Sales and Transportation customers. As depicted in my workpapers, the estimated forecast error on February 14 and 17 are 9.95 percent and 34.32 percent, respectively.

Table 6: MERC's Load Forecast During the Event

	Formula	**2/14/2021**	**2/17/2021**
A. Load Forecast for All Customers as of Supply Meeting[87]		456,675	391,379

[86] Mead Direct, p. 8, lines 13-17; Direct Testimony and Schedules of Timothy C. Sexton on Behalf of Minnesota Energy Resources Corporation, MPUC Docket No G011/CI-21-611/OAH Docket No. 71-2500-37763, (Oct. 22, 2021) ("Sexton Direct"), p. 25, lines 11-20.
[87] Mead Direct, Exhibit____(SRM-D), Schedule 7

B. Load Forecast for Transportation Customers as of Supply Meeting[88]		(187,789)	(138,405)
C. Load Forecast for Sales Customers as of Supply Meeting[89]		268,886	252,974
D. Actual Load for All Customers[90]		391,447	325,439
E. Scheduled Transportation[91]		(146,905)	(137,100)
F. Estimated Load Actuals for Sales Customers	D-E	244,542	188,339
G. Forecast Error, All Customers	(A-D)/D	16.66%	20.26%
H. Estimated Forecast Error, Sales Customers	(C-F)/F	9.95%	34.32%

Unfortunately, we do not know why MERC's forecasting error was off, because the Company did not sufficiently address this issue in its testimony. In response to Information Requests, MERC has claimed that its substantial error on February 17 was due to the weather turning out warmer than expected.[92] However, because MERC has claimed that the Company "does not generally retain historical records of daily load forecasts used to make gas procurement decisions,"[93] the Company has not provided the transparency necessary to quantify whether the scale of its forecasting miss was consistent with other days with imprecise weather forecasts. MERC also claimed that the percentage impact of its forecasting miss on February 17 was large because the Company over-projected a relatively small

[88] *Ibid.*
[89] *Ibid.*
[90] Minnesota Energy Resource Corporation, Response to DOC IR #55a (Attached as Exhibit___(BC-D), Schedule 20), MPUC Docket No. G011/CI-21-611/OAH Docket No. 71-2500-37763
[91] *Ibid.*
[92] Minnesota Energy Resources Corporation, Public Response to DOC IR #52b (Attached as Exhibit___(BC-D), Schedule 21), MPUC Docket No. G011/CI-21-611/OAH Docket No. 71-2500-37763; Minnesota Energy Resource Corporation, Response to DOC IR #55d (Attached as Exhibit___(BC-D), Schedule 20), MPUC Docket No. G011/CI-21-611/OAH Docket No. 71-2500-37763
[93] Minnesota Energy Resources Corporation, Response to DOC IR #55d (Attached as Exhibit___(BC-D), Schedule 20), MPUC Docket No. G011/CI-21-611/OAH Docket No. 71-2500-37763

amount of load.[94] However, this merely describes rather than explains the scale of MERC's forecasting miss on a date when the Company anticipated a relatively small amount of load. MERC NNG did not plan to interrupt any load during the Event, nor did the Company do so in practice. As stated previously, I am particularly concerned that MERC's forecasting errors were largest on the key planning date of February 17, and after prices had reached substantially escalated levels.

Q48. Do you have concerns regarding the reasonableness of Xcel's load forecast prior to and during the event?

A48. Yes. If we again subtract interrupted load estimates from load forecasts to create an apples-to-apples comparison, Xcel's estimated load forecasts for non-interrupted customers were within 2 percent of actual load on February 14, and 5 percent of actual load on February 17. However, Xcel chose to base its supply plans on load forecasts that included interruptible customers, and which thus did not accurately represent the load served by the Company.[95] The Company continued this approach of procuring duplicative supply for curtailed customers even when planning for February 17, when it knew that prices were at

[94] Minnesota Energy Resources Corporation, Public Response to DOC IR #52b (Attached as Exhibit___(BC-D), Schedule 21), MPUC Docket No. G011/CI-21-611/OAH Docket No. 71-2500-37763; Minnesota Energy Resource Corporation, Response to DOC IR #55d (Attached as Exhibit___(BC-D), Schedule 20), MPUC Docket No. G011/CI-21-611/OAH Docket No. 71-2500-37763

[95] Xcel Energy, Response to CUB IR #60a (Attached as Exhibit___(BC-D), Schedule 13), MPUC Docket No. G002/CI-21-610/OAH Docket No. 71-2500-37763; Xcel Energy, Public Response to DOC IR#14 (Attached as Exhibit___(BC-D), Schedule 22), MPUC Docket No. G-999/CI-21-135; Direct Testimony and Schedules of Richard L. Derryberry on Behalf of Northern States Power Company, MPUC Docket No. G002/CI-21-610/OAH Docket No. 71-2500-37763, (Oct. 22, 2021) ("Derryberry Direct"), Schedule 2, Xcel Energy Minnesota Gas Supply White Paper, p. 26, Table 3.

unprecedented levels. For this reason, the Company over-procured spot gas during the February Event despite maximizing curtailment. The load forecasts that Xcel actually used, which included forecasts for all (firm and non-firm) customers, exceeded actual load by 6.26 percent on February 14 and by 12.28 percent on February 17.[96]

Although it might not seem substantial that Xcel's load forecast exceeded actuals by 6 percent on February 14, it is worth highlighting the full implications of the Company's approach to supply planning. According to the Schedules provided by Xcel, the Company planned to procure a small reserve margin (less than 2 percent) above forecast load in order to ensure sufficient supply should actual load be higher than anticipated.[97] While this may sound reasonable at first glance, Xcel maximized curtailments on February 14, while still planning a reserve margin based on an escalated load forecast that *included these curtailments*.[98] Had Xcel based its supply planning off of a forecast for non-interrupted customers only, the Company would have seen that it was planning to exceed this forecast by 11 percent on what was expected to be the peak day of the Event, thus increasing the need to over-procure on each day of the long weekend in order to meet the requirement that purchases be ratable. This highly conservative approach can hardly be considered a reasonable balance between minimizing risk and cost.

[96] Xcel Energy, Public Response to DOC IR#14 (Attached as Exhibit___(BC-D), Schedule 22), MPUC Docket No. G-999/CI-21-135
[97] Derryberry Direct, Schedule 2, Xcel Energy Minnesota Gas Supply White Paper, p. 26.
[98] *Ibid*.; Xcel Energy, Response to CUB IR #60a (Attached as Exhibit___(BC-D), Schedule 13), MPUC Docket No. G002/CI-21-610/OAH Docket No. 71-2500-37763; Xcel Energy, Response to OAG IR#118 (Attached as Exhibit___(BC-D), Schedule 23), MPUC Docket No. G-999/CI-21-135

Xcel did not address this aspect of its load forecasting in its testimony or explain why it was a reasonable approach.

Table 7: Xcel's Load Forecast During the Event

	Formula	2/14/2021	2/17/2021
A. Load Forecast as of Supply Meeting[99]		754,477	644,628
B. Estimated Interrupted Load[100]		(61,806)	(43,095)
C. Estimated Forecast for Non-Interrupted Load	A - B	692,671	601,533
D. Actual Load[101]		710,041	574,135
E. Error, Estimated Forecast of Non-Interrupted Load	(C-D)/D	(2.45%)	4.77%
G. Error, Forecast Used to Inform Planning	(A-D)/D	6.26%	12.28%
F. Planned Supply as of Supply Meeting[102]		766,354	655,946
G. Planned Over-Supply for Non-Interrupted Load	(F-C)/C	10.64%	9.05%

Q49. What was the consequence of MERC and Xcel's conservative approach to load forecasting on February 14 and 17?

A49. MERC and Xcel's conservative approach to forecasting on the key dates of February 14 and 17 led to the over-procurement of daily spot gas for each day of the long weekend (February 13-16) and on February 17. Due to the utilities' own conservative planning, they were forced to ramp down storage to avoid delivering excess supply. As calculated in Q70 and Q71, the result was substantially escalated costs for customers.

[99] Derryberry Direct, Schedule 2, Xcel Energy Minnesota Gas Supply White Paper, p. 26.
[100] Northern States Power Company, Response to OAG IR#118 (Attached as Exhibit___(BC-D), Schedule 23), MPUC Docket No. G-999/CI-21-135.
[101] Derryberry Direct, Schedule 2, Xcel Energy Minnesota Gas Supply White Paper, p. 26.
[102] *Ibid.*

Q50. Did MERC or Xcel provide testimony that explains their load forecasting approach or describes a reasonable benchmark for preventing over-procurement?

A50. No, neither Company provided any justification or support for the accuracy of their load forecasting. Xcel has stated only that the Company's metrics for "ensuring that the level of supply is reliable, avoids over procurement, and is the lowest reasonable cost for customers" is to ensure 100% reliability for firm customers and rely on adjusting storage to avoid over-procurement – a strategy that in reality only ensures that Xcel avoids over-delivering rather than over-procuring.[103]

Q51. Have you analyzed the impact of MERC and Xcel's conservative approach to load forecasting on February 14 and 17?

A51. Yes. I analyzed a range of scenarios through which the utilities could have reduced costs for ratepayers through better planning, including through less conservative load forecasting. In order to contextualize MERC and Xcel's historical forecasting errors, I requested historical information on January-February load forecasts and actuals from each utility. MERC NNG provided its historical forecasts and actuals for the Company's combined Sales and Transportation customers over January and February of 2018-2020. Over this time, MERC NNG's forecast errors have exceeded 10 percent on only 15 of 278

[103] Xcel Energy, Public Response to CUB IR #68 (Attached as Exhibit___(BC-D), Schedule 24), MPUC Docket No. G002/CI-21-610, OAH Docket No. 71-2500-37763.

days, or 8 percent of the time. Errors have exceeded 15 percent only 3 percent of the time, and there was not a single date over the period analyzed in which error rates reached 20 percent or more.[104] Moreover, MERC NNG's forecasting errors of over 5 percent or more during these winter dates have almost always been under-projections: MERC over-projected load by over 5 percent on only 6 dates (or 3.37 percent of the time), only one of which had an error of over 10 percent, and none of which exceeded 12 percent.

It is worth noting that interrupted volumes have not been subtracted from these forecasts, given that MERC has stated that it does not have historic information on interrupted volumes.[105] I do not expect this fact to substantially impact these calculations, given the relatively small number of curtailments that were made over the dates analyzed. These numbers reflect error rates for MERC's Sales and Transportation customers combined; as noted previously, when asked to separate figures for Sales customers, MERC stated that it has not retained this historical information.[106]

Xcel has similarly claimed that "[t]he Company does not have historical forecast data that it can reliably verify was relied upon in the days in question."[107]

[104] Minnesota Energy Resources Corporation, Response to CUB IR#31 (Attached as Exhibit___(BC-D), Schedule 25), MPUC Docket No. G002/CI-21-610/OAH Docket No. 71-2500-37763
[105] Minnesota Energy Resources Corporation, Response to OAG #119 (Attached as Exhibit___(BC-D), Schedule 26), MPUC Docket No. G-999/CI-21-135
[106] Minnesota Energy Resources Corporation, Response to DOC IR #55d (Attached as Exhibit___(BC-D), Schedule 20), MPUC Docket No. G011/CI-21-611/OAH Docket No. 71-2500-37763
[107] Xcel Energy, Response to CUB IR #52f (Attached as Exhibit___(BC-D), Schedule 27), MPUC Docket No. G002/CI-21-610/OAH Docket No. 71-2500-37763

Based on the information that MERC has provided for Sales and Transportation customers in MERC NNG – which is the only historic information on load forecasts provided by either utility – I have quantified the impact of a 5 percent and 10 percent over-forecast for each utility which, according to the information provided by MERC, would be a historic anomaly.

Q52. Are you proposing a disallowance for MERC and Xcel's failure to justify their load forecasts during the Event?

A52. Yes, however, I will present my recommended cost disallowances in the subsequent section of this testimony discussing storage optimization, as I assume that avoided spot and swing purchases due to better load forecasting would be offset by storage.

Q53. Are you relying on hindsight to argue that, despite the utilities' reasonable efforts, their forecasts turned out to be inaccurate and costs turned out to be higher than anticipated for reasons that could not have been foreseen given what was known and reasonably knowable at the time?

A53. No. As stated, MERC has not provided the information needed to calculate the historic forecasting error for Sales customers only. However, even when the Company's combined forecast error for Sales and Transportation customers on February 17 is compared with historic errors, MERC's error of 20.26 percent on this date is still a larger over-projection than on any other day in January or

February of 2018-2020.[108] Although it would be unreasonable to expect a utility to perfectly forecast load, it would also be unreasonable to conclude that this highly unusual and significant forecasting error was due to pure happenstance. As stated, MERC has not explained why the Company was unable to accurately forecast load on these dates.

Xcel, on the other hand, chose to procure daily spot gas on behalf of the customers that it would later curtail. The forecasting failures of both utilities could have been avoided with better planning and better recognition that a utility must find the balance between risk and cost.

Although my assessment relies on load actuals that were not known at the time, this is inherent in any assessment of accuracy. It would be unreasonable to claim that accuracy cannot be examined, or that utilities have no obligation to care about the accuracy of their forecasts, simply because assessing accuracy requires comparing forecasts to actuals. Moreover, the utilities had actuals during the Event when they forecasted load for February 17 on February 16.

Finally, the fact that prices turned out to be higher than anticipated when supply decisions were made for the long weekend is not the subject of this prudence review, given that utilities knew of significantly escalated prices when making these decisions. The fact that prices turned out to be higher than anticipated does not mean that utilities had no obligation to react to market conditions; it simply means that the cost of failing to do so was substantially greater. As previously

[108] See Cebulko Workpapers

stated, even when MERC and Xcel knew of unprecedented prices on February 16, their planning became even more conservative and costly to ratepayers.

Q54. Is it the intervenor's responsibility to demonstrate that each utility's load forecast was imprudent?

A54. No. As summarized in the testimony of Witness Nelson, Minnesota law and precedent place the burden of proof on the utilities to demonstrate the prudence of their costs and requires that any doubt is resolved in favor of the ratepayer. As summarized by Witness Nelson, although it may be challenging to precisely quantify what constitutes "unreasonable" over-procurement, this does not dismiss utilities or regulators from their obligation to ensure that procurement levels are consistent with providing just and reasonable rates. To the extent that utilities do not provide the "transparency necessary to quantify the prudence of final costs,"[109] the Minnesota Public Utilities Commission (MPUC) has significant latitude in determining cost disallowances.

Q55. Have the utilities explained why their approaches to forecasting were reasonable?

A55. No. MERC has not explained why, despite the Company's historic ability to provide accurate forecasts, MERC's forecasting errors on February 14 and 17 were reasonable. As stated previously, MERC has not provided the transparency

[109] Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes, MPUC Docket No. E-002/CI-13-754 In the Matter of a Commission Investigation into Xcel Energy's Monticello Life-Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost (May 8, 2015).

necessary to quantify where the scale of its forecasting errors were reasonable. On the contrary, MERC's explanations during testimony have been misleading: Although MERC's Witnesses have claimed that the Company pursued only a "minimal" reserve margin of less than 2 percent on February 14,[110] a less than 2 percent reserve margin is hardly minimal when load is over-projected by 34 percent. Any mention of this more pertinent over-projection, or of MERC's actual load, is conspicuously absent in MERC's testimony.

Although Xcel also planned a reserve margin of less than 2 percent on both dates, the Xcel's claim that this was a "slight" reserve margin is similarly misleading when one considers the full context of Xcel's conservative approach to supply planning.[111] Because Xcel claims that it "does not have historical forecast data that it can reliably verify was relied upon"[112] during previous winters, it is not possible to contextualize the Company's approach to forecasting during the Event. In addition, Xcel has not explained why maximizing curtailment while simultaneously procuring supply for curtailed customers was reasonable, given that it could have separated these two customer classes in its load forecasts – just as all three utilities do when planning to meet capacity requirements.[113]

Q56. Please summarize your conclusions on load forecasting and why it is pertinent to this case?

---

[110] Mead Direct, Exhibit____(SRM-D), Schedule 7.
[111] Krug Direct, p. 34, line 8.
[112] Xcel Energy, Response to CUB IR#52f (Attached as Exhibit___(BC-D), Schedule 27), MPUC Docket No. G002/CI-21-610/OAH Docket No. 71-2500-37763
[113] Heer Direct, p. 10, line 17; Mead Direct, p. 19, lines 17-19; Derryberry Direct, p. 10, lines 6-11; Derryberry Direct, Schedule 2, Xcel Energy Minnesota Gas Supply White Paper, p. 3.

A56. Accurate load forecasts are important because the forecast is the basis for understanding how much supply is necessary to meet load. From there, the Company can determine the optimal strategy for delivering supply to load that maintains reliability at the lowest reasonable cost. Our analysis found that MERC and Xcel made unreasonably conservative load forecasts which made it appear that the utilities needed more supply than they actually did. This led to excessive over-procurement of daily spot purchases rather than utilization of more cost-effective alternatives, like storage or peaking facilities.

V. Storage Optimization

Q57. What is the purpose of this section of your testimony?

A57. The purpose of this section is to analyze whether the utilities' use of storage during the event was prudent, including how the utilities could have increased their utilization of storage with better planning.

Q58. Why is storage important, and how does it relate to providing reliable and affordable supply to customers?

A58. There are three main types of natural gas storage: underground, LNG, and pipeline, also called line packing. The most common type of storage is underground.[114] The utilities can either own or contract for storage, but the mechanics and benefits are the same. Storage operators typically inject, or fill the facility, when prices are cheap during the summer and withdraw in the winter

[114] U.S. Energy Information Administration, The Basics of Underground Natural Gas Storage, https://www.eia.gov/naturalgas/storage/basics/

when prices and demand are high. Storage is both an economic and physical hedge. It is an economic hedge because it can be dispatched when prices are high rather than relying on spot or call options. It is a physical hedge because the gas is already owned and contractually within the possession of the utility and is another geographical supplier that can be called upon should a different source be unavailable.

Finally, storage is also used for intra-day balancing. As CenterPoint Witness Grizzle testified, the utility uses storage to balance its gas supply to varying levels of daily demands.[115] That is, the utility can call upon it if demand is more than the utility originally anticipated.

a. CenterPoint

Q59. Did CenterPoint optimize its use of storage during the Event?

A59. Of the three utilities, CenterPoint appears to have the highest performance in maximizing available storage resources. As discussed in the load forecasting section of my testimony, given that CenterPoint's load forecasts on February 14 and 17 were relatively accurate, the utility was better able to maximize available storage on these dates. However, although ramping down some amount of storage during the non-peak dates of the long weekend was inevitable, this need could have been reduced had the Company planned to call curtailments, or use more of its peaking facilities, on February 14.

[115] Grizzle Direct, p. 8, lines 13-15.

Q60. Please discuss the relationship between storage, daily spot gas purchases and peaking facilities as part of the utility's supply plan.

A60. CenterPoint uses its storage to help balance its system. When purchasing supplies on February 12 to meet load on the anticipated peak date of February 14, CenterPoint planned to nominate all available storage.[116] CenterPoint was able to slightly surpass these plans because operating conditions at the Company-owned Medford/Waterville facility enabled the utility to withdraw more gas than could reasonably be anticipated.[117] Although CenterPoint did not maximize withdrawals on February 13 or 16, the Company claims that this was due to the requirement that purchases be ratable for each day of the long weekend as described in Q41. The utility claims that it was thus forced to ramp down storage on the non-peak dates in order to balance the system.[118]

Had CenterPoint's supply plan for the four-day weekend increased its use of peaking plant dispatch or curtailment on February 14, the utility could have purchased less spot gas on each date of the long weekend and thus reduced the need to ramp down storage on these dates. Had CenterPoint maximized peaking plants and curtailment on *every* day of the long weekend, rather than just the peak date, the Company would have been able to offset spot and call option purchases while keeping storage withdrawals at levels like those witnessed during the Event.

[116] Toys Direct, p. 40, Table 13, p. 48, Table 18.
[117] CenterPoint Energy, Response to CUB IR #18b (Attached as Exhibit___(BC-D), Schedule 28), MPUC Docket No. G-999/CI-21-135.
[118] CenterPoint Energy, HCTS Response to CUB IR #6b, MPUC Docket No. G-999/CI-21-135 (Attached as Exhibit___(BC-D), Schedule 17); CenterPoint Energy, Responses to CUB IR #18a and #18c (Attached as Exhibit___(BC-D), Schedule 28), MPUC Docket No. G-999/CI-21-135

In other words, there were a variety of options available to the Company to reduce spot purchases over the long weekend. In my cost disallowances, I have assumed that CenterPoint maximized curtailments on each day of the event while keeping storage withdrawals constant.

Q61. Please describe CenterPoint's use of storage on February 17.

A61. Although CenterPoint maximized available storage on February 14, storage utilization dropped significantly from **[BEGIN HIGHLY CONFIDENTIAL TRADE SECRET] [END HIGHLY CONFIDENTIAL TRADE SECRET]** on February 17.[119] CenterPoint explained that this reduced figure was the maximum amount of storage available on February 17.[120] The decrease in available storage was due primarily to the automatic decrease of BP Canada daily withdrawal allowances after CenterPoint had fully utilized available seasonal swing volumes at the Ventura facility.[121] The fact that operating conditions no longer permitted withdrawals to exceed the typical daily maximum at the Company-owned Medford/Waterville facility also played a minor role.[122]

Q62. Is CenterPoint's explanation on its use of storage on February 17 satisfactory to you?

[119] CenterPoint Energy, HCTS Response to CUB IR #6 (Attached as Exhibit___(BC-D), Schedule 17), MPUC Docket No. G-999/CI-21-135.
[120] CenterPoint Energy, Response to CUB IR #13 (Attached as Exhibit___(BC-D), Schedule 29), MPUC Docket No. G-008/M-21-138/OAH Docket No. 71-2500; Toys Direct, p. 60-61.
[121] *Ibid.*
[122] CenterPoint Energy, HCTS Response to CUB IR #6 (Attached as Exhibit___(BC-D), Schedule 17), MPUC Docket No. G-999/CI-21-135; CenterPoint Energy, Response to CUB #18b (Attached as Exhibit___(BC-D), Schedule 28), MPUC Docket No. G-999/CI-21-135.

A62. Yes.

b. MERC

Q63. Did MERC optimize its use of storage during the event?

A63. No. Because MERC over-projected MERC NNG load by 10 percent and 34 percent on February 14 and 17, respectively, the utility was forced to ramp down storage withdrawals by 17 percent on February 14, and by 49 percent on February 17 to match supply with demand. Since MERC forecasting errors for MERC NNG led to the over-procurement of spot gas purchases for each day of the long weekend, the need to reduce storage over these dates was higher than necessary and reached a maximum reduction of 49 percent.

c. Xcel

Q64. Did Xcel optimize its use of storage during the event?

A64. No. Because Xcel chose to base its supply plans on load forecasts that included substantial load that would later be curtailed, the Company's planned supplies exceeded actual load by 8 percent on February 14, and by 14 percent on February 17. Xcel was thus forced to reduce storage withdrawals by 18 percent on February 14, and by 22 percent on February 17 to balance the system. Moreover, since Xcel's duplicative supply planning led to over-procurement of spot gas for every day of the long weekend, the need to reduce storage withdrawals over each day of the weekend was high and reached a maximum of 38 percent in storage withdrawal reductions on February 16. Although Xcel's decision to procure supplies for curtailed customers was a significant source of the problem, had Xcel been able to maximize its peaking plants on February 14, this would have further minimized the need to reduce storage.

Q65. Have the utilities explained why, despite failing to optimize storage during the event, their use of storage during the event was prudent?

A65. No. The explanations provided by the utilities are misleading. The three utilities have framed their reduction of storage as an action needed to balance the system and which saved ratepayers money given the penalties for oversupplying.[123] Storage is certainly used for balancing the system, however, this "need" to balance was due to the utilities' own overly conservative forecasts, or decision to not maximize curtailment and peaking resources, that resulted in the excessive reliance on daily spot and swing purchases to meet demand.

Although CenterPoint's storage utilization was the highest among the three utilities, CenterPoint has not explained why, when faced with spot gas prices that were already at least five times the prevailing price, it was prudent to avoid maximizing peaking plant dispatch on February 14 and thereby minimize the need to reduce storage on the non-peak dates of the long weekend. I will address peaking plant dispatch in Section VII of my testimony. I will note that CenterPoint's claim that customers would have been subjected to $100 million or more in imbalance penalties had they not reduced storage masks the fact that the

[123] CenterPoint Energy, Response to CUB #6b (Attached as Exhibit___(BC-D), Schedule 17), MPUC Docket No. G-999/CI-21-135; Derryberry Direct, Schedule 2, Xcel Energy Minnesota Gas Supply White Paper, pp. 32-34; Mead Direct, p. 57, lines 7-12.

need to reduce storage would have been minimized had CenterPoint curtailed all its interruptible customers and dispatched their peaking facilities to decrease demand on February 14.[124]

Xcel and MERC have failed to acknowledge that their storage utilization was sub-optimal and have offered explanations that are misleading and illogical. Even though Xcel could have utilized more storage with better planning, Xcel's Witness Steven H. Levine claims that the Company, "maximized its use of storage, to the benefit of its customers" during the Event.[125] Witness Levine reasons that because Xcel "nominated its maximum amount of storage capability and these maximum storage amounts were reflected in the daily purchase decisions NSPM [Xcel] made," the Company also maximized storage withdrawals.[126] MERC Witness Timothy C. Sexton makes a very similar argument that "storage nominations were at maximum levels and as a result, MERC maximized the use of its storage capacity during the February Event."[127] Maximizing storage nominations does not necessarily mean that withdrawals were also maximized. According to this logic, Xcel and MERC could over-project load by two or three or ten-fold, fail to withdraw any storage, but still claim optimal storage utilization because the utilities maximized storage nominations

[124] CenterPoint Energy, HCTS Response to CUB IR #6b (Attached as Exhibit___(BC-D), Schedule 17), MPUC Docket No. G-999/CI-21-135.
[125] Direct Testimony and Schedules of Steven H. Levine on Behalf of Northern States Power Company, MPUC Docket No. G002/CI-021-610/OAH Docket No. 71-2500-37763, (Oct. 22, 2021) ("Levine Direct"), Schedule 2, Review of NSPM's Natural Gas Procurement for Retail Natural Gas Customers, p. 37, paragraph 51.
[126] Levine Direct, Schedule 2, Review of NSPM's Natural Gas Procurement for Retail Natural Gas Customers, p. 42, paragraph 64.
[127] Sexton Direct, p. 32, lines 12-14.

during the planning process. At issue in this prudence review is not whether Xcel and MERC maximized storage nominations, but rather storage utilization. Unfortunately for ratepayers, because Xcel and MERC significantly over-procured gas, the companies were not able to maximize storage withdrawals. Due to the misleading and incomplete nature of these explanations, MERC and Xcel have not met their burden of proof to demonstrate that the failure to maximize storage – despite having the ability to do so with better planning– was prudent.

d. Load Forecasting and Storage Disallowance Recommendations

Q66. Are you proposing a specific disallowance for each utility?

A66. No, I am not. For each of the core issues in my testimony, I am providing a range of disallowances for each utility.

Q67. Why are you providing a range of disallowances?

A67. In my experience, it is helpful for a Commission to see multiple scenarios to understand the impact, or magnitude, of a utility's decision. As such, I will make a range of recommendations on each narrow issue. Built off my analysis, my colleague Ron Nelson proposes a specific disallowance for each utility that considers our assumptions across utilities and the reasonableness of the total proposed disallowance.

I am also showing disallowances for the two key planning periods during the Event, February 13-16 and February 17. The facts of what the utilities knew when they made their decisions were different on those two days and therefore, I list the two periods separately.

Q68. You said earlier that your approach is holistic and recognizes the inter-dependencies of each of the utility's various decisions. Can you explain the how that impacts your analysis?

A68. Yes, I account for the interdependencies of the available resources. For instance, if a scenario includes the utility maximizing its curtailments, then that would likely impact the amount of storage or peaking resources it uses. Therefore, the recommendations from each section can be added together to a total disallowance recommendation for each utility.

Q69. Have you documented how you arrived at your disallowance calculations?

A69. Yes. I am filing my workpapers, which provide all documentation for my calculations for each utility. My calculations apply a small number of inputs that I am in the process of confirming through pending Information Requests. For example, CenterPoint and Xcel have not yet distinguished between the spot and swing prices of gas over each day of the event. My current calculations are based on averages reported by the utilities and will be updated in subsequent phases of this proceeding upon receiving confirmed data for a small number of inputs.

Q70. What is your range of disallowance for CenterPoint on the issue of maximizing storage?

A70. I am not proposing a disallowance for CenterPoint on this issue as the Company appears to have accurately forecasted load for the Event.

Q71. What is your range of disallowance for MERC on the issue of maximizing storage?

A71. As indicated in Table 8 below, I recommend between $8.5 million and $18 million in disallowances for MERC NNG due to the utility's unreasonably conservative load forecasting and subsequent failure to maximize storage on the key planning dates of February 14 and 17. Had MERC NNG's over-projections fallen within the Company's historical limits of 5 to 10 percent, the Company could have substantially reduced costs: A 5 percent forecasting error would have saved $10.2 million on February 17 alone given the scale of the utility's aberrant and unexplained 34 percent over-projection on this date. The remaining $7.8 million in savings can be attributed to the reduced need for spot purchases over each day of the long weekend. Because MERC's forecasting error for MERC NNG on February 14 was 9.95 percent –under the 10 percent threshold – a 10 percent forecasting error would have saved customers $8.5M on February 17 only.

Table 8:Proposed MERC Disallowance due to Conservative Load Forecasting and Failure to Maximize Storage

	5% Forecasting Error on February 14 and 17	**10% Forecasting Error on February 17**
Full Event (2/13-2/17) Total	$18,028,508.47	$8,454,944.63
2/17 Only	$10,202,942.71	$8,454,944.63

Q72. What is your range of disallowance for Xcel on the issue of maximizing storage?

A72. Had Xcel chosen to avoid procuring supply for the same customers that the Company curtailed, the utility could have saved between $1.5 million and $9.7 million. Like MERC, Xcel's approach was the most conservative on February 17. A 5 percent forecast error would thus have saved $4.8 million on February 17 alone. Containing the forecasting error to 10% would have saved $1.5 million on February 17 only.

Table 9. Proposed Xcel Disallowance due to Conservative Load Forecasting and Failure to Maximize Storage

	5% Forecasting Error on February 14 and 17	**10% Forecasting Error on February 17**
Full Event (2/13-2-17) Total	$9,734,465.31	$1,513,382.56
2/17 Only	$4,836,909.89	$1,513,382.56

VI. Interruptible Customer Curtailment

Q73. What is an interruptible tariff?

A73. An interruptible tariff is a utility program that offers certain customers a lower rate in exchange for agreeing to be curtailed during times of shortage or high demand.[128]

[128] Harunuzzaman, M., Koundinua, S. Cost Allocation and Rate design for Unbundled Gas Services, National Regulatory Research Institute, The Ohio State University, page 98 (May 2000).

Q74. Which type of customers use interruptible tariffs?

A74. For the most part, utilities across the country offer these programs to large commercial and industrial (C&I) customers. From there, we can split interruptible C&I customers into transportation customers and firm system sales customers. Interruptible transportation customers are responsible for procuring their own natural gas but rely on the utility to deliver the gas. Interruptible system sales customers rely on the utility to purchase and deliver natural gas but are served at a reduced rate in exchange for the curtailment option.

Q75. What is the value of an interruptible program for ratepayers?

A75. In exchange for a lower rate, interruptible customers agree to be curtailed at the request of the utility. By-and-large, the concept of these programs is to reduce the amount of capacity a utility needs to procure on behalf of its customers. Utilities design their systems to meet the design day needs of its customers, and if the utility can reduce peak need by planning not to provide firm service for interruptible customers during peak events, costs are reduced for all ratepayers. If priced correctly, then an interruptible program should be to the benefit of all customers.

Q76. What reasons could a utility call for an interruption?

A76. This depends on the utility's tariffs. Some tariffs are specific and will provide specific reasons that the utility could curtail its customers. Others, like the tariffs of CenterPoint, MERC, and Xcel, are non-specific.

Q77. Could a utility ask an interruptible customer to curtail to meet a local reliability constraint?

A77. Yes, if the tariff allows for those types of interruptions.

Q78. Could a utility ask an interruptible customer to curtail for economic reasons, that is, if the price of natural gas is extraordinary?

A78. Yes, if the tariff allows for those types of interruptions.

Q79. Did CenterPoint, MERC and Xcel curtail customers during the Event?

A79. Each utility took a different action.

- CenterPoint curtailed 31 customers comprising about 23 percent of its available interruptible load,
- MERC did not curtail any customers, and
- Xcel curtailed all interruptible transportation and system sales customers.

a. CenterPoint

Q80. Let's take each company in turn. Please start with CenterPoint. Will you please describe the Company's interruptible tariffs?

A80. CenterPoint has several rate schedules that include interruptible service, such as the Small Volume Dual Fuel Sales Service, the Small Volume Firm/Interruptible Sales Service, the Large Volume Dual Fuel Sales Service, the Large Volume Firm/Interruptible Sales Service, the Small Volume Dual Fuel Transportation Service, the Small Volume Firm/Interruptible Transportation Service, the Large Volume Dual Fuel Transportation Service, and the Large Volume

Firm/Interruptible Transportation Service. CenterPoint also has the Process Interruptible Sales Service Rider which makes the Dual Fuel Sales Service available to certain customers who have no alternative fuel facilities.[129]

While the Company has an array of interruptible tariffs, these options all share common terms and conditions. All customers on these tariffs are required to "curtail the use of gas on one (1) hour's notice when requested by CenterPoint Energy."[130] Further, "CenterPoint Energy can interrupt End User if capacity constraints require or for other appropriate reasons."[131]

Q81. Does CenterPoint agree that it can curtail customers for economic reasons?

A81. CenterPoint agrees that there are no legal, tariff, or contractual provisions that preclude interruptible customer curtailment based on economic reasons.[132]

Q82. Earlier you said that the CenterPoint only curtailed 31 customers during the Event. Can you elaborate on CenterPoint's curtailment actions?

A82. In an April 2021 report to the Commission, CenterPoint noted that as the 4-day weekend approached, the Company planned on February 12, 2021, to curtail 31 customers from February 12- February 16, with such curtailment representing "approximately 30-40 percent of interruptible load."[133] However, based on our

[129] See CenterPoint Energy Gas Rate Book at https://www.centerpointenergy.com/en-us/Documents/RatesandTariffs/Minnesota/CPE-MN-Tariff-Book.pdf.
[130] *Ibid.* at Section V p. 4, p.5, p.6, p.7, p.19.a, Section VII p. 1.a, p. 2.a, p. 3.a, p. 5.a, p. 10.b.
[131] *Ibid*. at Section VII page 10.b.
[132] CenterPoint Energy, Response to OAG IR #108 (Attached as Exhibit___(BC-D), Schedule 30), MPUC Docket No. G-999/CI-21-135.
[133] CenterPoint, In the Matter of a Commission Investigation into the Impact of Severe Weather in February 2021 on Impacted Minnesota Natural Gas Utilities and Customers Docket No. G-999/CI-21-135/21-138.

calculations, the Company called only 23 percent of available interruptible load during the Event from February 13 – 17.[134]

Q83. Can you please explain why the CenterPoint only curtailed a limited number of customers and available interruptible load?

A83. CenterPoint reported that it maintained reliable natural gas service to all firm customers, except for certain sections that were forecasted to have system deliverability constraints. Witness Olsen testified that CenterPoint identified 8 different sections of the distribution system where deliverability was expected to be limited.[135] Thus, on Friday, February 12, the Company decided to curtail only 31 customers from February 13 - 16 when demand was expected to decline.[136]

Q84. How did CenterPoint decide who to curtail?

A84. CenterPoint stated that the determination is based on rate margin, that is, the largest customers were called upon first.[137]

Q85. Why did CenterPoint choose not to curtail based on price?

A85. Witness Olsen testified that he was unaware of any circumstance in which CenterPoint has curtailed based on price alone.[138] Witness Olsen continued that CenterPoint was required to purchase gas for the 4-day period on Friday,

[134] See Cebulko Workpapers
[135] Olsen Direct, p. 29, lines 8-9.
[136] CenterPoint Energy, Report on Gas Cost Investigation, Docket No. G-999/CI-21-135/21-138, page 10 (April 9, 2021).
[137] Olsen Direct, p. 19, lines 13-15.
[138] Olsen Direct, p.32, lines 15-16.

February 12, thus there were no apparent threats to physical supplies nor could the utility have anticipated unprecedented prices.[139]

Q86. Do you find that argument convincing?

A86. No. The statement that a Company has not taken an action in the past is not a convincing argument that it cannot in the future especially if the action is in the public interest. As described earlier in my testimony, by the time CenterPoint was procuring gas for February 13-16, it understood prices were already at the 98th percentile and the worst of the storm was yet to occur. Pipelines had issued SOLs and critical day designations, signaling that they were capacity constrained. The peak day was expected to be on February 14 during the middle of the 4-day period. As Witness Nelson explains, we do not expect the Company to predict ~$180/Dth gas, but gas purchased on February 11 for gas on February 12 had already reached $15.42/Dth and $15.68/Dth at Ventura and Demarc respectively. There is no logical scenario where the price over the weekend would decrease.

By Thursday, February 11, a reasonable utility would have recognized the significant uncertainty and managed its risk by interrupting all eligible customers, a resource that customers have been paying for. Yet CenterPoint chose not to call its known, relatively inexpensive resource, and instead chose to rely mostly on spot purchases.

Moreover, even if the Company could claim ignorance to the unprecedented prices when it procured gas for the four-day period on February 12, it has

[139] Olsen Direct, p. 32, lines 19-21, p. 33, lines 1-3.

absolutely no justification that it did not know where prices would be on February 16 when it purchased gas for February 17.

Q87. Does CenterPoint explain why it only called a minimal amount of curtailment for February 17?

A87. No. On February 16, the Company knew that gas prices had reached unprecedented levels, it should have known or been able to see that it had a 98 percent compliance with customer curtailment, and it would have known that the daily spot market prices were still extraordinary. Yet, the Company chose to call only 4,440 Dth of interruption, or 4 percent of its interruptible load, and to continue to subject its customers to gas prices that had settled at $192/Dth the day before.

Q88. Do you any final thoughts on CenterPoint's unwillingness to call all its interruptible customers?

A88. Yes. CenterPoint's only explanation for not curtailing more customers is that it had never previously curtailed for economic reasons. In my view, this is not a prudent decision. Even if the utility had never called on non-firm customers to curtail for economic reasons, a reasonable utility with full knowledge of price of natural gas, both on February 12 and 16, should have done all that they could do to avoid purchasing gas at those high costs to save their customers tens of millions of dollars.

b. MERC

Q89. Let's turn to the next utility. Will you please describe MERC's interruptible tariffs?

A89. Customers taking service under NNG Interruptible Service, NNG Agricultural Grain Dryer Service, NNG Electric Generation Service, NNG Firm/Interruptible Service, Consolidated Interruptible Service, Consolidated Agricultural Grain Dryer Service, Consolidated Electric Generation Service "may be interrupted, curtailed or discontinued at any time at the option of the Company."[140] Within its Rate Book General Rules, Regulations, Terms, and Conditions, MERC provides an order of priority for "when in the opinion of the Company it becomes necessary to curtail or interrupt service to any of the Company's customers."[141] All interruptible customers must either (1) have and maintain adequate standby facilities and have available sufficient fuel supplies to maintain operations during periods of curtailment or (2) have the ability to fully and completely suspend the use of interruptible gas on one hour's notice when requested to do so by the Company.[142]

Q90. Did MERC call on any interruptible customers during the Event?

A90. No.

Q91. Why did MERC not curtail its interruptible customers?

[140] See MERC Tariff and Rate Book, General Rules, Regulations, Terms and Conditions ("MERC Rules and Regulations") at https://www.minnesotaenergyresources.com/company/tariffs/rules.pdf.
[141] *Ibid.* at 8.01.
[142] *Ibid.* at 8.01.

A91. Witness Theodore Eidukas testified that the Company's tariffs do not provide for price-based curtailment and can only curtail when there is a distribution system constraint, operational issue, or pipeline capacity limitation.[143] Eidukas continues that there were no constraints on its systems. Further, Witness Eidukas testified that even if MERC was permitted to curtail, it would have had to curtail by 8:00 a.m. Friday, February 12 for each of the following four days and the Company had no reason to expect prices to reach unprecedented levels.[144]

Q92. Do you agree with Witness Eidukas' interpretation of the tariffs?

A92. No. the plain reading of the tariffs does not restrict the reasons for which the Company calls a curtailment. The General Rules, Regulations, Terms and Conditions states that for interruptible service, "[c]ustomers taking natural gas service which may be interrupted, curtailed or discontinued at any time at the option of the Company in accordance with the provisions herein."[145]

In response to an information request inquiring whether MERC has any legal, tariff, or contractual provisions preventing economic curtailment of customers, MERC claims that it cannot curtail customers based on pricing and references MERC Tariff Sheet No. 8.40-8.41a which states that, "[t]he following priorities will be followed when operational and supply conditions require service interruptions with highest priorities listed first."[146] While MERC claims that this

[143] Eidukas Direct, p. 28, lines 8-10.
[144] Eidukas Direct, p. 29, lines 4-5.
[145] MERC Rules and Regulations at 8.01.
[146] MERC Rules and Regulations at 8.40-8.41a.

means that curtailments may only be triggered by available pipeline capacity and supply, this is not true.

The term “supply conditions” is not explicitly defined by MERC in its tariffs. The tariffs do state that “[MERC] does not employ any technical or special terms which are unique to the application of any of its rate schedules, rules or regulations. All terms used by the Company are common terms in the industry. For clarification purposes such terms are defined in Rules and Regulations.”[147] As “supply conditions” is not a term defined in MERC’s Rules and Regulations, this term is left up to interpretation based on common industry definitions. Supply conditions are reasonably interpreted to include pricing, quantity, and weather, among others. Moreover, as I stated at the beginning of this question, the plain language in the tariff provides MERC authority to interrupt at any time, stating that customers "may be interrupted, curtailed or discontinued at any time at the option of the Company."[148]

Q93. Did MERC investigate its tariffs to determine if economic curtailment was permissible?

A93. Based on what MERC has filed and produced in discovery, it does not appear that the Company put in any effort to determine if they could curtail based on price. On February 12 at 4:40 p.m., a MERC employee asked colleagues, “If marketers are shedding customers due to high priced gas, are we paying through the nose for

[147] See MERC Technical Terms and Abbreviations at https://www.minnesotaenergyresources.com/company/tariffs/terms.pdf.
[148] MERC Rules and Regulations at 8.01.

gas and is it smart to curtail for economic reasons? I think the customer pays what we pay…but it is killing us on costs." A colleague responded that they asked Sarah[149] that question and "she indicated that our tariff does not allow us to curtail for economic reasons. So whatever we are purchasing, will go through the AAA and be passed on to all customers." Witness Sarah Mead added to the conversation that "Regulatory" should weigh in, but it was her interpretation that MERC could not curtail unless there is a pipeline issue.[150]

Q94. Did the regulatory or legal department ever weigh in on the interpretation of the tariff?

A94. I do not know. The Company does not provide any evidence that there was any discussion prior to purchasing gas on February 12, during the four-day period, or on February 16 when procuring gas for February 17. The idea appears to have been raised and dismissed on Friday February 12 as MERC watched natural gas trading prices climb to historic highs. Witness Mead did send assurances to her colleagues that the extraordinary costs would be collected from customers, writing that, "the increased prices are expected to be recovered through normal regulatory treatment from our LDC customers, however might be delayed for review at the Commissions."[151]

[149] Witness Sarah Mead
[150] MERC, Public Response to CUB IR#21, MPUC Docket No. G011/CI-21-611, OAH Docket No. 71-2500-37763 (Attached as Exhibit___(BC-D), Schedule 5).
[151] MERC, Public Response to CUB IR#21, p. 45, MPUC Docket No. G011/CI-21-611, OAH Docket No. 71-2500-37763 (Attached as Exhibit___(BC-D), Schedule 5).

Q95. Witness Eidukas testified that even if MERC was permitted to curtail, it would have had to curtail by 8:00 a.m. Friday, February 12 for each of the following four days and the Company had no reason to expect prices to reach unprecedented levels. Why would it have mattered if the Company curtailed for economic reasons?

A95. There are numerous reasons. I will focus on four key reasons. First, a reasonable utility would not have uncertainty about the terms of its tariffs. The gas procurement and senior management team should have absolute clarity on the issue. It appears there was uncertainty amongst MERC employees on if MERC could curtail for economic purposes. This lack of clarity on tariff terms is inexcusable and unreasonable.

Second, by Thursday, February 11, MERC knew that prices were in the 98th percentile, and the worst of the storm had yet to occur. They knew that pipelines had issued warnings which suggests that the market was tightening and there could be reliability issues (even if, with hindsight, we know MERC did not have reliability challenges).

Third, going into a four-day gas buying period with great uncertainty, a reasonable utility would have locked in the benefit to the system and customers by curtailing interruptible customers. It is a resource that has already been paid for by customers, the price is known, it reduces the customers exposure, and the utility can make a reasonable estimate of the level of compliance with its call.

Finally, Witness Eidukas omits that MERC knew the unprecedented gas prices on February 16 when it procured gas for February 17 yet continued to choose not to curtail customers.

Q96. What did MERC know on February 16 when it procured gas for February 17?

A96. Like CenterPoint, MERC's testimony is focused on what it knew leading into the four-day weekend and ignored it actions on Tuesday, February 16 for delivering gas on Wednesday, February 17. By February 16, the Company knew that its load forecasts were consistently off and that the settled price of natural gas was greater than $150/Dth on NNG. Yet given all that information, the Company continued to significantly over procure spot gas, not curtail interruptible customers, and not fully maximizing its storage. These decisions display clear indifference for customer costs.

c. Xcel

Q97. Finally, let's turn to Xcel. Will you please describe Xcel's interruptible tariffs?

A97. Xcel offers two interruptible rate schedules – Interruptible Service and Interruptible Transportation Service. Customers accepting service under these rate schedules agree to the following terms:[152]

1. To curtail use within one hour after Company notification,

[152] See Xcel Energy Minnesota Gas Rate Book at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Mg_Section_5.pdf.

2. To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3. To have access to sufficient standby alternate fuel for periods of curtailment of the delivery of gas sold hereunder.

Each of these rate schedules also include the following statement: "Delivery of gas hereunder shall be subject to curtailment whenever requested by Company."[153]

Q98. Did Xcel curtail its interruptible customers?

A98. Yes, according to Witness Krug, Xcel curtailed approximately 325 non-firm customers twice, first from February 5 – 9 and again on Friday, February 12 at 11:00 a.m. through Thursday, February 18. The Company started releasing customers Wednesday, February 17. Krug also reports that the Company curtailed all 15 of its non-firm transportation customers.[154] Witness Krug estimates that curtailing customers saved an estimated $41 million.[155]

Q99. Why did Xcel curtail its interruptible customers?

A99. Witness Derryberry testified that Xcel curtailed its interruptible customers to ensure continued service to firm customers rather than for economic reasons.[156]

Q100. Does Xcel dispute that it could have curtailed customers for economic reasons?

---

[153] *Ibid.* at Section No. 5 Sheet No. 10.
[154] Krug Direct, p. 21, lines 7-20.
[155] Krug, p. 34, lines 25-26.
[156] Derryberry Direct, Exhibit___(RLD-1), Schedule 2, p.37.

A100. No, rather Xcel confirms that it is within the bounds of its authority to curtail customers for economic reasons. In response to an information request, Xcel confirmed that it does not have any legal, tariff, or contractual provisions that would have precluded interruptible-customer curtailment based on economic reasons (i.e., high market prices) during February 12–22.[157]

Q101. When did Xcel start releasing interruptible customers?

A101. Xcel started supplying some interruptible customers in the evening of February 17.[158]

Q102. Was Xcel's release of interruptible customers on February 17 reasonable?

A102. No. Xcel was only able to release customers on February 17 because the Company over-procured spot gas due to their own poor load forecasting. As described earlier in my section on load forecasting, had Xcel not decided to procure gas for customers that they would interrupt then the Company could have procured less spot gas and continued to curtail all customers until prices receded.

d. Interruption Disallowance Recommendations

Q103. Are you proposing a specific disallowance for each utility on the issue of interruptions?

A103. No, I am not. As explained in Q6, I am proposing a range of disallowances on each issue for each utility.

[157] Xcel Energy, Response to OAG IR#108 (Attached as Exhibit___(BC-D), Schedule 31), MPUC Docket No. G-999/CI-21-135.
[158] Krug Direct, p. 21, lines 13-15.

Q104. What is your range of disallowances for CenterPoint on the issue of curtailing interruptible load?

A104. My recommended range of disallowance for the issue of curtailment begins at $17,468,247. This is the amount of money that CenterPoint could have saved customers had they called maximum curtailment for gas day February 17. The high end of my range is $73,602,993, which is the cumulative savings for customers had CenterPoint called for maximum curtailment for all five days of the February Event.

Table 10: CenterPoint Proposed Range of Disallowances for Curtailment

Date	**Curtailment Available[159] (Dth)**	**CP Curtailment Called (Dth)**	**Additional Curtailment (Dth)**	**Spot & Swing Rate ($/Dth)**	**Curtailment Difference ($)**
2/13/21	103,550	19,000	84,550	$191.53	$16,193,861
2/14/21	103,550	57,000	46,550	$190.60	$8,855,672
2/15/21	103,550	39,400	61,150	$189.71	$12,121,784
2/16/21	103,550	4,400	99,150	$192.84	$18,963,429
4-day total					**$56,134,746**
2/17/21	103,550	4,400	99,150	$176.15	$17,468,247
Total					**$73,602,993**

[159] CenterPoint had 109,000 Dth of curtailment available each day. However, I assumed 5% non-compliance with the interruption call, which brings the daily total down to 103,550. 5 percent is based off actual compliance during the Event for Xcel and CenterPoint.

Q105. Please describe your considerations when proposing a range of disallowances for MERC on the issue of curtailment.

A105. I recommend that MERC should have only been expected to call 50 percent of its interruptible load. Each utility reasonably needs the capability to increase supply or shed load to help balance the system, and because MERC, unlike CenterPoint and Xcel, does not have peaking resources, it is reasonable for MERC to curtail fewer customers than the other two utilities in this scenario.

Because the maximum available interruptible load was different over each day of the long weekend, I assumed that MERC curtailed 50% of the interruptible load available on February 16 over each day of the weekend to comply with the requirement for ratable spot purchases, which I assumed would be offset by curtailments. Over the long weekend, February 16 was the date with the most interruptible load available.

Q106. What is your range of disallowances for MERC on the issue of curtailing interruptible load?

A106. My recommended range of disallowance for the issue of curtailment begins at $820,185 which is the recommended disallowance based on MERC not curtailing 50 percent of its interruptible load on February 17. The top of my range is $4,083,076, which is the cumulative savings for customers had MERC called for curtailment for all five days of the storm.

Table 11: MERC Disallowance for Curtailment 5 percent load forecasting error

Date	**Curtailment Available[160] (Dth)**	**MERC Curtailment Called (Dth)**	**Additional Curtailment (Dth)**	**Spot & (Swing) Rate ($/Dth)**	**Avoided Costs due to Curtailment**
2/13/21	5,136	-	5,136	$159.69	$820,191.35
2/14/21	5,136	-	5,136	$159.69	$820,191.35
2/15/21	5,136	-	5,136	$156.84	$805,553.33
2/16/21	5,136	-	5,136	$159.06	$816,955.58
4-day total					**$3,262,891**
2/17/21	4,355	-	4,355	$188.35 (Swing)	**$820,185**
Total					**$4,083,076**

Q107. Are you proposing a disallowance for Xcel on the issue of curtailing interruptible load?

A107. Yes. I recommend a disallowance of $1,585,125 for not maximizing curtailments on February 17.

Table 12: Xcel Disallowance for Curtailment

Date	**Curtailment Available[161] (Dth)**	**Xcel Curtailment Called (Dth)**	**Additional Curtailment (Dth)**	**Spot & (Swing) Rate ($/Dth)**	**Avoided Costs due to Curtailment**
2/13/21	61,858	58,545	-	$139	-
2/14/21	64,894	61,806	-	$137.45	-
2/15/21	67,931	64,555	-	$133.64	-
2/16/21	62,926	59,200	-	$137.17	-
4-day total					**-**
2/17/21	59,797	56,807	13,712	$115.60	**$1,585,125**
Total					**$1,585,125**

[160] MERC Response to CUB IR #040 (Attached as Exhibit___(BC-D), Schedule 32), MPUC Docket No. G011/CI-21-611, OAH Docket No. 71-2500-37763. On February 16, MERC had 10,272 Dth of curtailment available on the MERC NNG system. 5,136 is half of 10,272.

[161] *Ibid.*

Q108. How is curtailing interruptible load a different resource than storage or peaking facilities?

A108. Curtailment is a demand-side management resource, and the utility can "dispatch" this resource, to some degree, by incrementally calling customers to curtail as the resource is needed, but the utility does not have the same control over curtailment as it does storage or peaking. A reasonable utility in the face of a severe storm, knowing that the pipelines had already issued warnings, amidst significant natural gas market volatility and uncertainty over a four-day gas period, would optimize its demand-side and supply-side resources by first calling all its available interruptible load, and then dispatching its supply-side load in a least cost, least risk approach.

There isn't a good reason to limit curtailment so that it can be "dispatched" later to meet unforeseen load; that is why a utility has peaking facilities and storage. The exception to this statement is MERC, who does not have peaking facilities and needed some bandwidth to shed load on February 14 as the alternative resource was more gas procured at the daily spot price.

Q109. Why does the bottom end of your range start with your recommended disallowance for February 17?

A109. As my colleague Witness Nelson and I state throughout our testimony, the facts that the utilities knew on Tuesday, February 16 when procuring gas to meet demand on February 17 are different than the facts the utilities knew prior to the four-day weekend. The utilities cannot argue that they were unaware of the unprecedented prices for Wednesday, February 17 when scheduling supply on Tuesday February 16, because they had just experienced a four-day period with extraordinary costs and the extent of the freeze-offs in Texas and Oklahoma and the impact of this extreme weather on the natural gas market was well known. The utilities failure to act upon their knowledge on February 16 is especially egregious.

Q110. Are you suggesting that the CenterPoint and MERC's curtailment actions from February 13-16 were prudent?

A110. Absolutely not.

VII. Peaker Plant Dispatch

Q111. What are natural gas peaking facilities?

A111. Natural gas peaking facilities are supply-side resources that use liquified natural gas (LNG), compressed natural gas (CNG), or propane to meet customer demand. Peaking facilities come in a variety of sizes and have different use cases. Some LNG facilities can hold millions of Dth of gas, while some CNG facilities hold as little as 100 Dth.[162] In general, large, or small, peaking facilities are relatively expensive and are one of the last resources to be dispatched. Utilities often refer

[162] For instance, mobile CNG trucks hold about 100Dth of gas and can be dispatched to directly inject gas into a segment of the distribution system that has low pressure. See Northwest Natural Gas Integrated Resource Plan, page. 6.44.

to these plants as "peak shaving" facilities as they are often built as a substitute for procuring additional pipeline capacity.

Q112. What are the uses of peaking facilities?

A112. There are four primary uses of peaking facilities. First, peaking facilities supply fuel to customers as a supplement to pipeline capacity as the utility approaches design day conditions. A utility's peak demand is generally a relatively short period of time (often just a few hours) during the year. Rather than building, or buying, incremental distribution or transportation pipeline capacity, the utility can build or contract with peaking facilities to meet its peak needs, thus ensuring that the utility has planned for sufficient capacity to meet peak demand.

The second use is to quickly balance the distribution system if supply and demand are out of sync. Unlike the electric industry in which the fuel (electrons) moves at the speed of light, natural gas is transported relatively slowly. If gas demand is higher than anticipated during the day, a utility could dispatch a storage or a peaking facility to meet that need, depending on the circumstances.

Third, peaking facilities are used to meet local reliability needs. Utilities will often site their peaking facilities to meet a reliability need in part of their distribution system in lieu of building additional pipeline capacity to the area. As CenterPoint Witness Heer testifies, a utility may dispatch a propane peaking facility to maintain pressure in an area of its distribution system even if it does not need the gas.[163]

[163] Heer Direct, p. 6, line 10-11.

Finally, peaking facilities can be economically dispatched during periods of high prices.

Q113. Xcel and CenterPoint testify that peaking resources are used for reliability and capacity purposes only, and that they do not dispatch based on price. Why do you say that a peaking facility can be dispatched for economic reasons?

A113. There is no legal obstacle for using a peaking facility to reduce costs to customers, and it certainly is technically possible. Utilities build and operate LNG and propane facilities as a resource to supply system load, and other utilities will dispatch peaking facilities when the cost of natural gas is high.[164] Although a peaking facility has a relatively high cost of gas, this is a known price, unlike daily spot purchases, which is especially important during periods of uncertainty. By February 15, CenterPoint was already forecasting incremental costs of nearly $500 million for Minnesota.[165] Even if CenterPoint had never used peaking facilities (or curtailment, for that matter) to respond to pricing events, there is no better time than when CenterPoint is forecasting that it will incur an additional $480 million amidst a global pandemic to call upon its peaking resources for gas day February 17.

[164] Watson, Aurora, STAFF REPORT ON THE BALTIMORE GAS AND ELECTRIC COMPANY'S LNG AND PROPANE FACILITIES, Maryland Public Service Commission. October 2, 2000.; MERC provided this reference to support this reference to support a position in Docket G011/GP-15-895, In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project Docket No.; and https://www.mass.gov/doc/hopkington-lng-corp-dba-eversource-energy-v-board-of-assessors-of-the-town-of-hopkington-june-21-2021/download

[165] CenterPoint Energy, HCTS Response to CUB IR #19, p. 183 (attached as Exhibit___(BC-D), Schedule 33), MPUC Docket No. G008/M-21-138, OAH Docket No. 71-2500-37763.

Q114. Do CenterPoint, MERC, and Xcel have peaking facilities?

A114. MERC does not have peaking facilities. CenterPoint and Xcel have peaking facilities, however, Xcel's plants were offline at the time of the Event.

a. CenterPoint

Q115. Please describe CenterPoint's peaking facilities.

A115. CenterPoint has one LNG plant and eight air propane plants.[166] CenterPoint's LNG facility has a storage capacity of 1,000,000 Dth, a liquefaction (injection) rate of 5,000 Dth/day, and vaporization (dispatch) rate of 72,000 Dth/day. The eight propane facilities collectively hold 980,000 Dth of gas and can dispatch 149,000 Dth/day.[167]

Q116. Did CenterPoint dispatch its peaking facilities during the Event?

A116. CenterPoint minimally dispatched its peaking facilities during the Event. Witness Heer testified that the Company only dispatched its peaking facilities to ensure reliability and not to reduce the costs of the natural gas to customers.[168]

Q117. Witness Heer testifies that peaking facilities are not designed to address market pricing events.[169] Do you agree?

A117. Witness Heer is over-simplifying the issue and suggesting that the plants are incapable of being dispatched during a pricing event.[170] Witness Heer testified

[166] Heer Direct, p.20-21, lines 11-6.
[167] Heer Direct p. 23, lines 2-6.
[168] Heer Direct, p. 33, lines 13-17.
[169] Heer Direct, p.33, lines 13-14.
[170] Heer Direct p. 33, lines 13-23.

that the peak shaving plants have not been designed or planned for pricing events, but rather are located to ensure reliability and flexibility. Witness Heer portrays the situation as if maintaining reliability and responding to price signals are always two mutually exclusive actions.

A utility should be sufficiently competent to keep multiple objectives in mind when optimizing the resources it has available to meet the circumstances of an event – particularly when optimizing these resources is in the interest of ratepayers who have paid for them. Just because a resource was built with one primary purpose in mind does not mean that it cannot be deployed for other purposes if the circumstances are warranted. There are costs to using a peaking facility (e.g., fuel, fixed O&M, variable O&M), and the utility should be cognizant of those costs and make informed decisions about when to deploy the resources, but not dispatching a natural gas peaking facility that could save customers millions of dollars because "the peak shaving plants have not been designed or planned to address pricing events"[171] is unreasonable and demonstrates an indifference to customer impacts.

Furthermore, Heer does not support the argument that the peaking facilities cannot be dispatched to address pricing events. The Witness does not explain why the utility could or should not use a peaking facility for economic dispatch. Witness Heer simply states it as a fact and moves on.[172]

[171]Heer Direct, p. 33, lines 13-14.
[172] Heer Direct, p. 33, lines 13-23.

Q118. Are Witness Heer's comments consistent with CenterPoint's earlier comments on the benefit of peaking facilities to a diversified portfolio?

A118. No. In its April 9, 2021, comments to the Commission, CenterPoint wrote that "the Company uses a diversified gas supply portfolio consisting of a combination of baseload supplies, call options, daily spot market purchases, storage, and peaking supplies which are designed to maintain reliability, while balancing price protection, stability of gas supply costs billed to customers, and reasonable prices."[173] Witness Heer is only focusing on the peaking facilities role in maintaining reliability and not recognizing that the peaking facilities, as part of a portfolio, also help balance price protection during a price spike where prices greatly exceeded the cost of the peaking dispatch. Again, CenterPoint knew that prices were at $15/Dth when it developed its supply plan for the weekend, that the cost of index gas already far exceeded the cost of its peaking facilities, and that the worst of the storm had yet to occur. There was no logical scenario where the price of index gas would have gone down over the weekend.

Q119. When developing its supply plan for the weekend on February 12, did the Company investigate meeting demand with its peaking facilities?

A119. Yes. In a February 12 exchange with a third party, a CenterPoint representative appears to have refused a gas supply purchase, reasoning that the Company was going to "look at LNG and propane."[174]

---

[173] CenterPoint Energy, Report on Gas Cost Investigation, Docket No. G-999/CI-21-135/21-138, p. 3 (April 9, 2021).
[174] Office of the Attorney General, Docket No. G-999/CI-21-135/21-138/21-235, p. 46 (July 6, 2021).

Q120. Witness Heer testified that the utility must reserve peak shaving supply to address the possibility of severe cold lack of sufficient supply in the future. Do you agree?

A120. Conceptually, yes, but CenterPoint had near full capacity inventory going into the storm. In fact, I am unaware of any winter in which the Company has come even remotely close to depleting its peaking resources. Of course, it would be imprudent for a utility to completely deplete their peaking resources in responding to the Event, however, that was not the circumstance that CenterPoint was facing. As of Friday, February 12, CenterPoint had an LNG peaking inventory of 948,700 Dth and a propane peaking inventory of 751,200 Dth, or 95 percent and 70 percent of annual capacity, respectively.[175] Even if the utility had dispatched the maximum daily throughput of 72,000 Dth/day from its LNG facility throughout the duration of the Event, the Company would still have been left with 516,700 Dth, or 52 percent of its maximum capacity.

On the other hand, had CenterPoint fully dispatched its 8 propane facilities at its maximum daily throughput of 149,000 Dth then it would have depleted its propane position entirely by Tuesday, February 16. That would not have been a reasonable course of action, but CenterPoint could have dispatched a reasonable amount of propane that could have made a material difference to customers. The Company's refusal to dispatch any of its peaking facilities to reduce costs for customers was unreasonable.

---

[175] CenterPoint Energy, Public Response to DOC IR #006 (attached as Exhibit___(BC-D), Schedule 35), MPUC Docket No. G-999/CI-21-135.

Fundamentally, I disagree with Mr. Heer's insinuation that dispatching some amount of the peaking facilities to reduce costs to customers would put CenterPoint in a position of being unable to meet intraday requirements throughout the rest of the heating season.

Q121. Did the Department of Commerce provide analysis on the likelihood of design day conditions occurring after President's Day weekend? If yes, what were the results?

A121. In its May 10 comments before the Commission, the Department wrote that, in a typical year, the President's Day weekend represents the last time that near design-day conditions are likely to occur within the winter planning year.[176] In its review of historical data over the period of the last half of February, March, and April from 1900 to 2021, Commerce had found only 144 instances of daily average temperatures at or below 0F, or 65 HDD, which translates into approximately 1.3 percent of all days. Sixty-five of those days occurred before February 19, meaning there have only been 79 instances from mid- February through April over the past 121 years that have been below 0F.

Q122. You mentioned that CenterPoint has not come close to depleting its peaking facilities during the course of a winter. Can you expand upon your evidence?

[176] Department of Commerce Comments, Docket No. G-999/CI-21-135/21-138, p.28, (May 10, 2021).

A122. Yes. Through discovery, CenterPoint provided data that show how often it has dispatched its LNG and propane facilities since 2010.[177] In short, CenterPoint seldomly uses its LNG and propane facilities, and rarely at all after March 1. Since 2010, CenterPoint's maximum annual dispatch was 237,000 Dth in 2014, which is less than one quarter the LNG's annual capacity of 1,000,000 Dth.[178] Since 2010, CenterPoint had only called upon its LNG facility 9 times after February 14, and 5 times after March 1.

Regarding its propane facilities, CenterPoint's highest utilization in a year since 2010 was 65,309 Dth, or less than 7 percent of its annual inventory.[179] The Company had only dispatched 11,000 Dth of gas from its propane facilities after February 14 and 6,500 Dth after March 1.

Simply put, CenterPoint's peaking facilities are seldomly used and the Company was in no danger of exhausting its peaking supply during the Event if it made appropriate dispatch decisions to reduce cost to customers.

Moreover, CenterPoint did not include any analysis on how it determined the appropriate amount of peaking storage available temporally throughout the winter season, which is critical to determining the reasonableness of this asset's utilization.

---

[177] CenterPoint Energy, Response to CUB IR #25 (attached as Exhibit___(BC-D), Schedule 36), MPUC Docket No. G008/M-21-138, OAH Docket No. 71-2500-37763.
[178] *Ibid.*
[179] *Ibid.*

Q123. How much gas did CenterPoint dispatch from its LNG and propane facilities during the Event?

A123. Very little. As stated earlier, as of February 12, CenterPoint's propane peaking facilities had a combined inventory of 751,000 Dth and the LNG facility had 946,981 Dth in storage. CenterPoint dispatched only 48,979 Dth of LNG and 8,478 Dth of propane over the five-day Event.[180]

Table 13: CenterPoint's Peaking Facilities Use During the Event

Date	**LNG inventory (Dth)**	**LNG called (Dth)**	**Propane Inventory (Dth)**	**Propane Called (Dth)**
Max Daily		72,000		149,000
2/13/2021	946,752	229	748,864	1,397
2/14/2021	905,141	41,611	741,863	7,001
2/15/2021	898,783	6,358	741,863	0
2/16/2021	898,350	433	741,863	0
Sub-total		**48,631**		**8,398**
2/17/2021	898,002	348	741,783	80
Total		**48,979**		**8,478**

Q124. Are you suggesting that CenterPoint should have dispatched all of its peaking facilities during the Event?

A124. No. Just because design day conditions don't often occur after President's Day weekend, that does not mean that this is impossible. The utility must be prepared

[180] See page 82 of my testimony.

to respond to events into March, as well as other reliability issues. The propane facilities can be used for maintaining system pressure even if the supply is not necessarily needed, as Witness Heer testified.[181] It wouldn't be appropriate to deplete the propane facilities to a point that the utility loses these crucial resources.

However, the Company has not demonstrated that it was in any danger of completely depleting its peaking facilities or that it could not have made modest to aggressive dispatches from its facilities to relieve some costs to customers. CenterPoint should have been trying to balance its two objectives, risk and cost, but unreasonably held back on dispatching its peaking facilities thus exposing ratepayers to exorbitant costs.

b. Xcel

Q125. Let's turn now to Xcel. Please describe Xcel's peaking facilities.

A125. As described by Witness Yehle, Xcel has three peaking plants: one LNG facility and two propane air plants.[182] The Wescott LNG plant has a maximum storage capacity of 2,145,00 Dth and a maximum daily withdrawal of 156,00 Dth. The Sibley and Maplewood propane facilities have maximum storage capacity of 114,000 Dth and 124,000 Dth, respectively, and daily withdrawal capacities of 46,000 and 44,000 Dth, respectively.

[181] Heer Direct, p.34, lines 8-9.
[182] Yehle Direct, p. 3, lines 1-3.

Q126. You said that Xcel's peaking facilities were offline during the Event. Can you please describe why?

A126. Witness Yehle's testimony provides a longer description of this issue which I will briefly recap here. Witness Yehle testified that in either November or December 2020 the Company began "testing certain components of the vaporization equipment at Wescott in preparation for winter operations."[183] On December 31, 2020, as Xcel began testing the vaporization process, some vaporization equipment exceeded design pressure, causing an unplanned release of gas. The same event happened again on January 4, 2021. After the unplanned release at Wescott, Yehle testified that the Company then tested the vaporization processes at the propane facilities. A root cause analysis determined that the Company needed to make additional investments at each of the facilities. The Company shut the units down and purchased additional upstream transportation capacity to ensure the utility had adequate supply.

Q127. Are you challenging Xcel's procurement of additional upstream transportation capacity for the winter season?

A127. I did not perform a review of the utility's upstream procurement; however, it makes sense that Xcel immediately replaced its lost capacity.

Q128. Are the plants back in service?

A128. To the best of my knowledge the plants are still not back in service.

[183] Yehle Direct, p. 15, lines 16-18.

Q129. According to Xcel, what impact did the loss of the three peaking plants have on the Event?

A129. Xcel's position is that peaking resources are capacity-only resources and their unavailability did not have an impact on customers.[184]

Q130. Do you agree with Xcel's assessment that the unavailability of its peakers did not have an impact on customers?

A130. No. My reasoning is the same as I stated in regard to CenterPoint's use of peaking facilities. There are no legal or technical obstacles to using peaking resources for meeting customer demand. The price of a peaking facility, although relatively high, is known, unlike the daily spot price. This can be an advantage during a period of uncertainty. This is especially advantageous when price of a peaking facility is below the prevailing spot market price, as it was beginning on February 12 and continuing through the rest of the Event. A utility should be sufficiently competent to hold multiple objectives when optimizing the resources it has at its availability to meet the circumstances of an event. Although a peaking facility may have been built primarily to displace additional pipeline, that does not preclude it from being used to reduce costs to customers during pricing events. To testify that the unavailability of the peaking facilities had no impact on customers simply ignores that the plants, if utilized appropriately, could have reduced costs to customers by tens of millions of dollars.

[184] Krug Direct, p. 7, lines 14-18.

Q131. Does Xcel usually wait until December 31 to test the vaporization equipment at its peaking facilities?

A131. No. According to Xcel, it typically begins testing in Mid-September and will perform test vaporization runs by Mid-November.[185] In a discovery response, the Company reported that vaporization testing requires temperatures under 40 degrees.[186] However, Xcel did not provide an explanation as to why it delayed its testing until the last day of the year, nor does it say that temperatures played a role in that delay. By not providing that information in its Direct Testimony, Xcel does not meet its burden of demonstrating its actions were prudent.

Q132. Had Xcel started the testing the LNG facility in Mid-September, rather than either November or December, and conducted its vaporization tests in Mid-November, would the plants have been online to be used during the Event?

A132. With hindsight we now know that the LNG facility is still offline, which implies that it would not have made a difference as to its availability.

Q133. Has Xcel demonstrated that it acted prudently in maintaining its LNG and propane facilities prior to pulling them offline at the beginning of January 2021?

A133. No, it has not. Witness Yehle implies that the facilities were adequately maintained because the plants are subject to regulations by state and federal agencies, and the Company made $3.9 million in capital additions in the past

[185] Xcel Energy, Response to CUB IR #17 (attached as Exhibit___(BC-D), Schedule 37), MPUC Docket No. G002/CI-21-610, OAH Docket No. 7-2500-37763.
[186] *Ibid.*

three years.[187] First, the utility is responsible for prudently maintaining its peaking facilities – not a government oversight agency. Further, even if a governmental agency has not found a violation of one of its rules during an inspection, this is not the same as a finding that the utility has properly maintained its facility for use during the winter. Moreover, the Company has been fined as recently as 2019 for failing inspections at all three facilities.[188] Ultimately, Xcel is responsible for demonstrating that the LNG plant's unavailability due to a safety issue was outside of its control, and it has not done so in this docket.

Second, that Xcel has made $3.9 million in capital additions in recent years is also not sufficient support that the Company has adequately maintained its facilities. The Company should have provided context for the additions at the plants. For example, useful information would have included records for schedule for seasonal, annual, and major maintenance project as well as estimated costs, or a past Company study that identified necessary projects and estimated budgets. Given that the peaking facilities were pulled offline at the beginning of the winter season, the level of scrutiny should be relatively high. Yet the Company has not provided any demonstration that its $3.9 million in capital additions were sufficient.

Finally, Witness Yehle glosses over the fact that Xcel voluntarily took the propane facilities offline.

[187] Yehle Direct, p. 8, lines 12-25, p. 9-12.
[188] Yehle Direct, p. 14, lines 4-10.

Q134. Why did Xcel take the propane facilities, Sibley and Maplewood, offline as well?

A134. Witness Yehle's testimony is unclear. Yehle testifies that after the releases at Wescott, and instead of continuing to prepare the plants for the season, Xcel investigated Sibley and Maplewood as well. Through its investigation, Xcel discovered that "additional investments need to be made at Sibley and Maplewood, which also were nearing the end of their life expectancies, so we can safely operate them for many more years."[189] Yehle did not testify what additional investments needed to be made nor did Yehle explain why the Company did not make those investments in the past.

Q135. Why were Sibley and Maplewood not able to be available to customers?

A135. I do not know. Xcel did not provide additional information in its testimony. The Company did not provide any discussion or analysis as to what additional investments needed to be made, if the plants or personnel were at risk when it made its decision, an estimate for the time to repair, a cost estimate, a cost-benefit analysis of alternative resources to replace the facilities, or any other critical information that is needed to determine if the Company took prudent actions.

Q136. In regards to its peaking facilities, were Xcel's actions prudent?

A136. With regards to the LNG facility, I am uncertain as to whether Xcel's actions were prudent. I am not questioning whether it was prudent to take the LNG

[189] Yehle Direct, p. 18-19, lines 9-2.

facility offline once the incidents occurred on December 31, 2020, and January 4, 2021, but it is true that this plant was offline during the Event and could have been used to mitigate the extraordinary costs to customers. Xcel needs to make a convincing case that it had properly maintained the facility and took all reasonable actions to ensure that the facility was available for customers. Based on the information presented in Direct testimony, Xcel's has not made the case that its maintenance was regular and up-to-date and that the timing of its testing was reasonable and prudent.

I am confident that Xcel has not made a convincing case as to why it pulled its propane facilities offline at the same time as the LNG facility. The Company's testimony is inadequate. Xcel does not even present the most basic information, such as, what were the "additional investments" that the Company needed to make at Sibley and Maplewood, much less cost estimates or alternatives considered.[190] Xcel does not even indicate if the additional investments were necessary to keep the plants safe.

In short, Xcel has not met its burden of proof that it properly managed and maintained its peaking facilities.

c. Peaker Dispatch Disallowance Range Recommendations

Q137. How would have a reasonable utility have utilized its peaking facilities?

[190] Yehle Direct, p. 18-19, lines 23-2.

A137. As my colleague Witness Nelson and I have repeatedly testified, a reasonable utility balances the risks and cost to customers. The specific amount the utility should have dispatched from its facilities are specific to that utility's particular situation. Thus, the utility should be considering its relative position. Pertinent questions include the inventory level of its facilities, the probability of a design day event past President's Day weekend, the specific geographic needs of its service territory, and a forecast of how long it may need to mitigate costs. Undoubtedly, there are other considerations as well.

What I can firmly say is that a utility should absolutely be considering the economic dispatch of all its supply-side resource when it is to the benefit of customers and can be done so while maintaining reliability. CenterPoint and Xcel's non-consideration of economic dispatch is imprudent. Furthermore, Xcel has not sufficiently demonstrated that it properly maintained its LNG facilities or adequately explained why it voluntarily pulled its propane facilities offline.

Q138. How did you develop a recommended range for disallowances?

A138. For both utilities, I create multiple, reasonable, counterfactual scenarios. I can imagine an argument for a relatively conservative approach, as well as an aggressive set of actions, each of which could be deemed prudent by the Commission. As such, I tried to outline what I thought fell within the bounds of reason.

For the LNG facilities, because of their size and location along the transportation pipeline, I recommend that the utilities should have been expected to run these facilities at or near their maximum daily capacity as there is no indication in the weather forecasts that the utilities would have had to rely on their LNG plants for a period that could have come close to depleting the resource.

I would recommend a more conservative approach for the propane facilities. These facilities are considerably smaller with a higher maximum daily vaporization relative to the total inventory. It is conceivable that running those plants at maximum daily levels would quickly exhaust their supply. Furthermore, propane facilities are usually located in the distribution system and may be necessary to maintain pressure in certain locales. For Xcel, I also created a counterfactual where just the propane facilities were available to the Company.

Q139. Please describe your considerations when proposing a range of disallowances for CenterPoint on the issue of utilizing its peaking resources.

A139. I created two counterfactuals; a relatively conservative approach that assumed the LNG facility dispatched at 50 percent of maximum daily throughput and the propane facilities dispatched at 25 percent. I also created more aggressive approach that assumed the LNG facility dispatched at 100 percent of maximum daily throughout and 50 percent for the propane facilities. Both scenarios would have left the utility with more than sufficient inventory to respond to intra-day gas needs and deliver during future events later in the winter.

The development of the parameters for the counterfactual were necessary due to CenterPoint not providing sufficient information in direct testimony regarding how peaking facilities can be reasonably operated.

Q140. What is your recommended range of disallowance for CenterPoint on the issue of utilizing its peaking facilities?

A140. For the utilization of peaking facilities, I am recommending a range of $12.2 million to $122.6 million for CenterPoint. The bottom of my range begins with the disallowance for February 17 if CenterPoint had dispatched its LNG and propane facilities at 50 and 25 percent, respectively. The top of my range is the disallowance based on CenterPoint dispatching its LNG and propane facilities at 100 and 50 percent, respectively, for the entirety of the Event.

[BEGIN HIGHLY CONFIDENTIAL TRADE SECRET]

Table 14: CenterPoint Peaking Disallowance Recommendation, LNG 50% and Propane 25%

	Date					**Total**
	2/13/2021	2/14/2021	2/15/2021	2/16/2021	2/17/2021	
Avoided Spot Purchases Due to LNG						
Savings Due to Avoided Spot Purchases						
Avoided Call Options Due to LNG						
Savings Due to Avoided Call Options						
Total LNG Savings						

Cost of LNG						
Net Savings Due to LNG						
Avoided Spot Purchases Due to Propane						
Savings Due to Avoided Spot Purchases						
Avoided Call Options Due to Propane						
Savings Due to Avoided Call Options						
Total Propane Savings						
Cost of Propane						
Net Savings Due to Propane						
Total Savings Due to LNG and Propane					**$12,214,984**	**$56,809,146**

Table 15: CenterPoint Peaking Disallowance Range: LNG 100% and Propane 50%

	Date					**Total**
	2/13/2021	2/14/2021	2/15/2021	2/16/2021	2/17/2021	

Avoided Spot Purchases Due to LNG						
Savings Due to Avoided Spot Purchases						
Avoided Call Options Due to LNG						
Savings Due to Avoided Call Options						
Total LNG Savings						
Cost of LNG						
Net Savings Due to LNG						
Avoided Spot Purchases Due to Propane						
Savings Due to Avoided Spot Purchases						
Avoided Call Options Due to Propane						
Savings Due to Avoided						

Call Options						
Total Propane Savings						
Cost of Propane						
Net Savings Due to Propane						
Total Savings Due to LNG and Propane					**$24,923,313**	**$122,653,731**

[END HIGHLY CONFIDENTIAL TRADE SECRET]

Q141. Please describe your considerations when proposing a range of disallowances for Xcel on the issue of utilizing its peaking resources.

A141. I created three counterfactuals.

1. A relatively conservative approach that assumed the LNG facility dispatched at 50 percent of maximum daily throughput and the propane facilities dispatched at 25 percent.
2. A more aggressive approach that assumed the LNG facility dispatched at 100 percent of maximum daily throughput and 50 percent for the propane facilities.
3. An approach in which the propane facilities were available, and the utility used 50 percent of their daily maximum, but the LNG facility was not available.

These scenarios would have left the utility with sufficient inventory to respond to intra-day gas needs and deliver during future events later in the winter.

Q142. What is your recommended range of disallowance for Xcel on the issue of utilizing its peaking facilities?

For the utilization of peaking facilities, I am recommending a range of $2.5 million to $115.8 million for Xcel. The bottom of my range begins with the disallowance for February 17 if Xcel had only its propane facilities online and injected 50 percent of its daily maximum on that day. The top of my range is the disallowance based on Xcel dispatching its LNG and propane facilities at 100 and

50 percent, respectively, for the entirety of the Event. As with CenterPoint, the development of the parameters for the counterfactual were necessary due to the Company not providing sufficient information in direct testimony on how peaking facilities can be reasonably operated.

[BEGIN HIGHLY CONFIDENTIAL TRADE SECRET]

Table 16: Xcel Peaking Disallowance, Counterfactual Propane only at 50 percent

Date	Avoided Spot Purchases Due to Peaking Plant Dispatch	Savings Due to Avoided Spot Purchases	Cost of LNG	Net Savings Due to LNG	Avoided Spot Purchases Due to Propane	Savings Due to Avoided Spot Purchases	Cost of Propane	Net Savings Due to Propane	Total Savings Due to LNG and Propane
2/13/21									
2/14/21									
2/15/21									
2/16/21									
2/17/21									**$2,488,873**
Total									**$14,311,286**

Table 17: Xcel Peaking Disallowance, Counterfactual LNG at 50% and Propane at 25%

Date	Avoided Spot Purchases	Savings Due to Avoided	Cost of LNG	Net Savings	Avoided Spot Purchases	Savings Due to Avoided	Cost of Propane	Net Savings	Total Savings Due to

	Due to Peaking Plant Dispatch	**Spot Purchases**		**Due to LNG**	**Due to Propane**	**Spot Purchases**		**Due to Propane**	**LNG and Propane**
2/13/21									
2/14/21									
2/15/21									
2/16/21									
2/17/21									**$10,068,623**
Total									**$57,895,657**

Table 18: Xcel Disallowance, Counterfactual LNG at 100% and Propane at 50%

Date	**Avoided Spot Purchases Due to Peaking Plant Dispatch**	**Savings Due to Avoided Spot Purchases**	**Cost of LNG**	**Net Savings Due to LNG**	**Avoided Spot Purchases Due to Propane**	**Savings Due to Avoided Spot Purchases**	**Cost of Propane**	**Net Savings Due to Propane**	**Total Savings Due to LNG and Propane**
2/13/21									
2/14/21									

2/15/21									
2/16/21									
2/17/21									**$20,137,247**
Total									**$115,791,314**

[END HIGHLY CONFIDENTIAL TRADE SECRET]

Q143. Does this conclude your testimony?

A142. Yes.