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BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, Minnesota 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East
Suite 350
St. Paul, Minnesota 55101-2147

MPUC Docket Nos. G-008/M-21-138; G-004/M-21-235;
G-002/CI-21-610; and G-011/CI-21-611
OAH Docket No. 71-2500-37763

In the Matter of the Petitions for Recovery of Certain Gas Costs

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

In the Matter of the Petition by Great Plains Natural Gas Co. for Approval of Rule Variances to Recover High Natural Gas Costs from February 2021

In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy to Recover February 2021 Natural Gas Costs

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

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DIRECT TESTIMONY AND SCHEDULES OF THE MINNESOTA OFFICE OF THE ATTORNEY GENERAL—RESIDENTIAL UTILITIES DIVISION

WITNESS:

BRIAN LEBENS

December 22, 2021

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I. BACKGROUND AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Brian Lebens. My business address is Suite 1400, 445 Minnesota Street, Saint Paul, Minnesota 55101.

Q. By whom are you employed?

A. I am a Financial Analyst with the Office of the Minnesota Attorney General – Residential Utilities Division ("OAG").

Q. What is your educational and professional background?

A. I hold an MBA from the Carlson School of Management at the University of Minnesota as well as a Bachelor of Science degree in Finance, also from the Carlson School. Additionally, I have eight years of experience in finance with 3M Company and Lockheed Martin. My responsibilities in these positions included financial modeling, cost accounting, audit, discounted cash flow analysis, and project management including cost and schedule analysis. I also provided strategic financial counsel to senior leadership in the areas for which I was responsible.

I started with the OAG in 2015 and I have provided testimony on behalf of the OAG before the Minnesota Public Utilities Commission ("Commission") in several rate cases since then, including Minnesota Energy Resources Corporation's two most recent natural gas rate cases, which were filed in 2015 and 2017 (Docket Nos. G-011/GR-15-736 and G-011/GR-17-563); Dakota Electric Association's most recent electric rate case (Docket No. E-111/GR-19-478); CenterPoint Energy's two most recent natural gas rate case (Docket Nos. G-008/GR-17-285 and G-008/GR-19-524); Minnesota Power's 2016 electric rate case (Docket No. E-015/GR-16-664); Otter Tail Power's two most recent electric rate cases (Docket Nos. E-017/GR-15-1033 and E-017/GR-20-719); Great Plains' most recent gas rate case (Docket No. G-004/GR-19-511); and Xcel Energy's 2015 electric rate case (Docket No. E-002/GR-15-826). Additionally, I analyzed Xcel Energy's petition to acquire the Mankato Energy Center (Docket No. E-002/PA-18-702).

II. TESTIMONY OVERVIEW

Q. What topics do you examine in your testimony?

A. The primary purpose of my testimony is to provide information regarding (1) potential hedges that utilities could have pursued to offset some of the cost of the price spike, and (2) actual market results (from February 2021) for hedges that were available to the utilities. That is, I will explain that there are several types of hedges that the utilities may have been able to pursue, either in the short-term (during February 2021) or longer-term (a year or more ahead of time), which could have mitigated some of the extraordinary costs. Additionally, I discuss hedging budgets, hedging flexibility, practical limitations on selling put options and specific advice that one of the utilities received from a third-party prior to the price spike.

III. INTRODUCTION

Q. What is hedging and why would a company want to engage in it?

A. Hedging can be defined as "a tactical action that an investor takes with the intent of reducing the risk of losing money."[1] A company would want to engage in it to reduce the risk of losing money.

Q. How would hedging benefit a gas utilities' ratepayers?

A. Hedging can mitigate the financial impact of a price spike such as the one that is the subject of this docket.

Q. Are there examples of gas utilities engaging in hedging?

A. Yes, the four utilities in this docket have generally engaged in hedging in one form or another, whether it is physical hedging or financial hedging.

Q. What are some differences between physical hedging and financial hedging?

A. Members of the gas utility industry sometimes use the term "physical hedging" when referring to actions like purchasing natural gas over the summer and physically storing it for later use during the winter. Financial hedging often involves derivatives, such as options and futures contracts.

Q. Will you be discussing physical hedging or financial hedging?

A. I will spend the bulk of my time discussing financial hedging.

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[1] *Investopedia: Hedging Transaction*, investopedia.com/terms/h/hedging-transaction.asp (last visited Dec. 16, 2021).

IV. CLARIFYING "CALL OPTION" TERMINOLOGY.

Q. Is there a consensus in this case regarding a single definition of a call option?

A. No, the four utilities appear to use two different descriptions of call options—and some of the utilities seem to use the two somewhat interchangeably.

Q. What is the first description of a "call option?"

A. The most widely accepted description of a call option includes a specific price at which the buyer of the option can purchase the underlying asset. The following definition specifically references commodities (such as natural gas), but can also be applied to other assets (like shares of a company):

> Call options give the owner the right, but not the obligation, to buy a specific amount of the underlying commodity at a specific price (the option's strike price) for a limited period of time (until the expiration date). The option seller is paid a premium for agreeing to deliver the commodity (or its financial equivalent) under the contract terms. Call options with strike prices below the current market price are "in the money." If the strike price is near or equal to the market price, the options are considered "at the money," and if it is above the market price, they're "out of the money.[2]

Q. Did any of the utilities provide a similar definition of call options?

A. Yes, call options are a widely understood financial concept and at least some of the utilities provided similar explanations in their Initial Filings.[3]

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[2] WAYNE PENELLO & ANDREW P. FURMAN, RISK IS AN ASSET: TURNING COMMODITY PRICE UNCERTAINTY INTO A STRATEGIC ADVANTAGE 118 (ForbesBooks) (Kindle Edition).
[3] Grizzle Direct at Schedule 2, pp. 41-42 of 101; Derrbyberry Direct at Schedule 2, p. 12.

Q. What is the second description of a "call option" that you mentioned?

A. The utilities also discuss a different type of "call option" that does not specify the price at which the buyer can purchase natural gas. Some of the utilities describe the ability to "call" on gas supply that has been prearranged to be provided on 24 hours' notice at a floating, index-based price (i.e. with no upper limit, or ceiling on the price).

Q. Would you provide an analogy to try to explain that second type of call option that you described?

A. Yes. Think about the long lines and high prices associated with the 1970s gasoline shortages. This type of "call option" essentially gives the utility the contractual right to skip to the front of the line immediately without waiting but is still required to pay the market price—because of the supply/demand imbalance, the price may be exorbitant.

Q. Which of the two descriptions is the more commonly accepted definition?

A. The first description (that includes a specific price) is the one most people familiar with financial markets would think of when they think about a call option.[4]

Q. Is the second description incorrect?

A. Not necessarily, but I will refer to the type of contract with guaranteed supply, but no upper price limit as a "swing" contract, in accordance with utility explanations in their testimony.[5]

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4 *Investopedia: Call Option*, investopedia.com/terms/c/calloption.asp (last visited Dec. 18, 2021).

5 CenterPoint mentions "swing" supply throughout its testimony. *See, e.g.*, Grizzle Direct at Schedule 2 p. 35 of 101.

V. POTENTIAL HEDGES

Q. Are there hedges that the utilities may have been able to pursue which could have mitigated some of the extraordinary cost?

A. There are several, including daily options,[6] weekly options,[7] and short-term[8] options. Schedules BPL-D-1, BPL-D-2, and BPL-D-3 provide CME Group's explanations about the specifications of these options. Additionally, the utilities may have been able to pursue customizable over-the-counter (OTC) contracts that cap the maximum price that they would have paid. Finally, Schedule BPL-D-4 provides an overview of CME Group's Weather Futures and Options, which are tied to temperatures at specific cities around the world, including Minneapolis and Dallas.[9]

Q. Who is CME Group?

A. CME Group explains that:

> As the world's leading and most diverse derivatives exchange, CME Group is where the world comes to manage risk. We help meet uncertainty and volatility with confidence and clarity. Across the trading lifecycle and around the world, we enable market participants to manage risk and capture opportunity.[10]

In other words, CME Group is one of the main places where utilities can manage the risk of a price spike.

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[6] *CME Group: Daily Natural Gas Option-Contract Specs*, cmegroup.com/markets/energy/natural-gas/natural-gas.contractSpecs.options.html#optionProductId=2801 (last visited Dec. 16, 2021).
[7] *CME Group: Natural Gas Weekly Options (American)-Contract Specs*, cmegroup.com/markets/energy/natural-gas/natural-gas.contractSpecs.options html#optionProductId=7508 (last visited Dec. 16, 2021).
[8] *CME Group: Natural Gas Short-Term Option-Contract Specs*, cmegroup.com/markets/energy/natural-gas/natural-gas.contractSpecs.options.html#optionProductId=6213 (last visited Dec. 16, 2021).
[9] *CME Group: Weather Futures and Options*, cmegroup.com/trading/weather/files/weather-fact-card.pdf (attached as Schedule BPL-D-4).
[10] *CME Group: About Us,* cmegroup.com/company/about-us html. (last visited December 19, 2021).

Q. Did the utilities mention "daily options" in testimony?

A. Yes, they repeatedly mentioned daily options and, among other things, said "[t]ypically, daily call options would be purchased prior to the beginning of winter and would only cover the winter season."[11]

Q. Did any of the utilities purchase the type of call option contracts that cap the maximum price that they may pay for gas in the daily market?

A. It appears that they did not—if they did purchase some, it was clearly not enough to mitigate an outlier scenario like the one experienced in February 2021. The price spike would have been mitigated to the extent that they had entered into reasonable and prudent contracts that capped their daily maximum price.

Q. Did some of the utilities purchase call options that cap the maximum price they may pay in the monthly market?

A. Yes. It is important to note that some of the utilities did purchase call options that cap the maximum price in the <u>monthly</u> market. That is, they purchased some options that protect against price spikes for a month-long supply of gas, but do not protect against price spikes for short-term gas supply during the middle of the month. These options may be described as monthly, "first of month" or (FOM) contracts and, again, do not fully hedge against price spikes such as the one that occurred in February 2021.

[11] Grizzle Direct at Schedule 2, p. 35 of 101.

Q. Do you have an example of this?

A. Yes. Xcel explained:

> . . . we use financial hedges to limit longer-term supply cost volatility. Those hedges involve a monthly call option purchased well in advance of the heating season that can be exercised when the price on the first day of the month is higher than the option price.[12]

Q. Were you able to find price data for any of the daily, weekly, or short-term options for each day during February 2021?

A. No.[13] I request that the utilities discuss options like these in their rebuttal testimony, so I can provide further analysis in my surrebuttal testimony. This discussion should include the extent to which they have traded options like the daily, weekly, and short-term options in the last 15 years. It is possible that some of the utilities have traded them in the past, but not during February 2021.

Q. If the utilities had implemented CME Group's daily, weekly, or short-term options, would it have fully offset the price spikes that the utilities experienced?

A. Since most, if not all, of CME Group's options are tied to Henry Hub, rather than hubs like Demarc and Ventura, it is not likely that the daily, weekly, or short-term options would have precisely offset all of the cost. But they may have offset more cost relative to the monthly Henry Hub options that I will discuss in Section VI (Actual Hedge Results) below. This is because they are tied to shorter time frames (daily/weekly vs. monthly) and would therefore be more responsive to short-term price spikes.

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[12] Krug Direct at 10.

[13] Much of this data may be available for purchase from places like CME Group and the Intercontinental Exchange (ICE).

Q. What is the difference between Henry Hub, Demarc, and Ventura?

A. As Mr. Smead explained:

> The Henry Hub in Erath, Louisiana was established in 1990 as the reference point for the NYMEX contract, and has since become the primary trading reference point for the industry. Prices at other market points are spoken of in terms of "basis," the difference in price from the Henry Hub price.[14]

Demarc is located in Kansas and Ventura is located in Iowa—these are less popular trading hubs when compared with Henry Hub.

Q. Is it possible for utilities to establish contracts based on the Henry Hub reference point, rather than Demarc or Ventura?

A. Yes, Xcel explained that "NSPM also indexes to a few other locations (e.g., NYMEX Henry Hub, Chicago Citygate, etc.)."[15]

And Xcel explained that:

> Most of NSPM purchases of natural gas are transported to NSPM's gas distribution system using NSPM's contracted transportation on NNG and Viking. NSPM also has some delivered supply deals with suppliers that deliver gas to the NSPM gas distribution system using the suppliers' pipeline capacity (i.e., not using NSPM's contracted transportation on NNG and Viking). These delivered supply deals are typically priced using daily index prices, in which the supplier agrees to deliver the supply at the request of NSPM on a limited number of days of the month.[16]

It may be possible for pricing to be based on a particular trading hub while taking physical delivery at a different location.

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[14] Smead Direct at 10, n.2.
[15] Levine Direct at Schedule 2, p. 25 of 45.
[16] *Id.*

Q. What were the daily prices for gas at Henry Hub during the price spike?

A. While prices were in well in excess of $100 at Demarc and Ventura for the duration of the long weekend, they were only $6 at Henry Hub.[17]

Q. Why would some options provide a more precise hedge than other options?

A. Using this docket as an example, options that are more closely aligned with (1) the timing of a potential price spike (in the short-term gas market) and (2) the trading hubs that the Minnesota utilities have selected as the index for their gas purchases (such as Demarc in Kansas) will more precisely hedge a price spike.

Q. So, if the utilities had negotiated Henry Hub pricing to be the basis for their swing purchases (rather than places like Demarc and Ventura), it may have been easier to hedge against the price spike?

A. Yes exchange-traded options are particularly well suited to hedge at Henry Hub.

Q. Did prices spike above $20 at Henry Hub during the weekend?

A. No, they were only $6 for the weekend, but they almost quadrupled a few days after that.[18]

Q. Are there any exchange-traded hedges that would have fully offset the price spike cost that occurred at places like Demarc and Ventura?

A. I am not currently aware of any such hedges traded in the market during 2021 that would have fully offset the prices above $20 at specific places like Demarc and Ventura. I request that the utilities discuss options specific to trading hubs like Demarc and Ventura in their rebuttal testimony, so I can provide further analysis in my surrebuttal testimony.

[17] Levine Direct at Schedule 2, p. 16 of 45.
[18] *Id.*

This discussion should include the extent to which they have traded options specific to trading hubs like Demarc and Ventura in the last 15 years. It is possible that some of the utilities have traded them in the past, but not during February 2021.

Q. Are there any non-exchange-traded hedges that would have fully offset the price spike costs above $20?

A. Non-exchange-traded investments are not usually available for public viewing. But, building on some of the utilities' daily swing options with individual third parties, it is possible that the utilities could have also pre-negotiated a maximum, or ceiling, price above which they would not have had to pay.

Q. What might a counter-party request in exchange for agreeing to a ceiling price?

A. In order to enter into such an agreement, a potential counter party may request things like (1) an up-front payment (a premium) in exchange for agreeing to a ceiling price or (2) the counter party may also ask the utility to agree to a floor price below which the gas would not be priced. The up-front payment and the floor price would both be intended to compensate the counter party for the chance that the market price would move more than expected.

Q. Is there another name for a floor combined with a ceiling?

A. Yes, a shorthand name for a floor combined with a ceiling is a "collar," which some of the utilities explained in their testimony.[19] As I and utility witnesses have discussed, purchasing a call option creates a ceiling and selling a put option creates a floor.

[19] Grizzle Direct at Schedule 2, p. 42 of 101

Q. Are collars, or other hedges, generally available to all four of the utilities in this case?

A. Yes, the exchange-traded puts and calls used for hedges like collars are available to all market participants. OTC hedges are, almost by definition, often individually negotiated between two specific counterparties, so it is not clear whether they would be available to all four of the utilities.

A. FUTURES CURVES.

Q. Do any of the utilities begin their hedging activities more than one year in advance?

A. Yes. CenterPoint's Gas Procurement Plan explains that it may begin hedging up to three years in advance.[20] The extent to which the other utilities begin hedging more than a year in advance is not clear.

Q. What prices do buyers and sellers in a non-exchange traded transaction (e.g. an OTC transaction) likely consider as they agree on prices several years in advance?

A. Both buyers and sellers likely consider things like the natural gas futures curve, as described by Joint Utility witness Mr. Smead.[21]

Q. Can you provide the futures curves from around the time when the utilities would have been lining up their gas purchases during the three summers preceding February 2021?

A. Yes, please see Schedule BPL-D-5. There I provide the futures curves as of July 31, 2018, 2019, and 2020 in red, blue, and green respectively.

[20] Grizzle Direct at Schedule 2, p. 7 of 101
[21] Smead Direct at 9-10.

Q. Are any of these futures curves anywhere near the $20 threshold being used in this docket?

A. No, setting aside the prices that occurred this summer and fall (outside the time frame in this docket), the futures curves are all well under $4.[22]

Q. What does this suggest?

A. This suggests that both buyers and sellers of natural gas likely would have entered into transactions to trade Henry Hub natural gas well under the $20 threshold used in this docket. But the exact price differentials between Henry Hub and hubs like Demarc and Ventura are not clear. But it is safe to say that, as of the injection seasons of 2018, 2019, and 2020, these differentials would likely not have brought the total cost over the $20 threshold being used by the Commission in this case.

B. WEATHER DERIVATIVES.

[HIGHLY CONFIDENTIAL TRADE SECRET INFORMATION BEGINS]

[HIGHLY CONFIDENTIAL TRADE SECRET INFORMATION ENDS]

[22] Source: Enverus.

[23] BPL-D-6, DOC Information Request 5(a), Risk Policy.

Q. How did weather derivatives perform during winter 2020/2021?

A. I could not find detailed information on Minneapolis weather derivatives, but the Dallas weather derivatives performed well. The price per contract increased as much as 66 percent during February 2021.[24] This suggests that the utilities could have mitigated some price spike costs by using weather derivatives in addition to the other specific hedging methods that I explained earlier in this Section and in the next two Sections of this testimony. Both futures and options are available, so utilities may have been able to implement costless collars on weather derivatives—but it is not clear whether the utilities have requested Commission approval to use weather derivatives.[25]

[24] February 2021 weather derivatives data is attached as Schedule BPL-D-7. Source: Enverus.
[25] *CME Group: Weather Futures and Options*, cmegroup.com/trading/weather/files/weather-fact-card.pdf (attached as Schedule BPL-D-4).

VI. ACTUAL HEDGE RESULTS

Q. Were you able to find any market information from February 2021 showing the actual results of specific natural gas hedges that were available to the utilities?

A. Yes, the current monthly call options at the time of the event during February 2021 mimicked what one would expect during a price spike.

Q. How did these hedges perform?

A. They also spiked, but not quite as much as a perfect hedge would have spiked. In the context of Xcel's high-level 100x quantification that "during the February Event, the price for natural gas suddenly jumped to trading at over 100 times that price,"[26] the hedges increased in value by approximately 20x to 30x.[27]

Q. What is an example of a 100x increase?

A. A $3 price moving up to $300 is a 100x increase.

Q. What proportion of a 100x increase would a 20x increase offset?

A. A 20x increase in the value of a hedge would offset 1/5, or 20%, of a 100x underlying price increase.

Q. What percentage of a 125x increase would a 20x increase offset?

A. 16 percent.[28]

Q. What percentage of an 80x increase would a 20x increase offset?

A. 25 percent.[29]

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[26] Krug Direct at 2.
[27] The specific options are those that were the current "monthly" call options at the time of the event with a 4.00 strike price. *See* Schedule BPL-D-8. Source: Enverus.
[28] 16% = 20/125.
[29] 25% = 20/80.

Q. How does that compare with the roughly $600 million of expenses at issue across the four utilities in this proceeding?

A. If we again use 100x as a rough estimate of the price spike, and make a simplifying assumption that the total at issue in this case is exactly $600 million, a 20x hedge would have offset approximately $120 million of cost across the four utilities.[30]

Q. Would you specifically quantify how you estimated the 20x increase?

A. Yes, the market price of each call option increased from $30 to $650.[31] So, I divided 650 by 30, and rounded the result of 21.67 down to 20.

Q. If a company were to invest $6.5 million at a price of $30 and sell at price of $650, how much profit would it have?

A. The $6.5 million initially invested would increase in value to approximately $141 million for a net profit of approximately $134 million.[32]

Q. Are the $30 and $650 prices theoretical or hypothetical prices for illustrative purposes?

A. No, they are the actual prices that occurred in the market during February 2021.[33]

Q. When were the call options priced at $30 each?

A. Please see the chart in Schedule BPL-D-8. It shows that the last traded price was $30 from the morning of February 8, 2021 until early afternoon of February 10, 2021.[34]

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[30] $120 million = $600 million * 20%.

[31] Source: Enverus. This $30 and $650 are $0.003 and $0.065 per MMBtu respectively—the standardized contract size for these options is 10,000 MMBtu.

[32] $134 million = $6.5 million * (650/30) - $6.5 million.

[33] Source: Enverus.

[34] Source: Enverus.

Q. When were the call options priced at $650 each?

A. They were valued at $650 during the night of Wednesday February 17th, from approximately six p.m. until midnight.[35,36]

Q. Do you believe the utilities would have been able to close the hedge at the highest price of $650 during the night of the 17th?

A. No. The Commission must use hindsight to some extent (to establish basic facts like the actual price paid for gas), but it should focus as much as possible on evaluating the decisions that would have been prudent based on the information available at the time when those decisions were made.[37] The utilities were faced with a continuous stream of new information, including the warming weather forecasts, the status of the Texas freeze-offs, and pipeline restrictions being lifted. It is not likely that the utilities would have closed these specific hedges at exactly $650.

Q. What is the value of looking at the price action that occurred for actual hedges during February 2021, given that the utilities would not likely have closed these hedges at exactly $650?

A. It is valuable largely because it mimics how the daily, weekly, and short-term hedges that I discussed in Section V would have performed, and because it mimics how hedged swing contracts would have performed if they had been in place. I will discuss hedged swing contracts in Section VII below. But hedged swing contracts would essentially be "sold at the top," fully maximizing the potential value of the hedge, with no specific

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[35] This market is closed on weekends and holidays, but is otherwise open 23 hours per day, with a break from 4 p.m. to 5 p m. CST each business day.
[36] Schedule BPL-D-8; Source: Enverus.
[37] Honorable Direct.

decisions required, other than the utilities planning ahead by putting hedged swing contracts in place in advance.

Q. What do you recommend to the Commission regarding the 21.67x increase?

A. On the basis of the specific hedges that increased from $30 to $650, the Commission should treat that 21.67x increase as the maximum amount that it could disallow—I discuss the basis for other disallowances separately. In other words, that is the highest level of savings the utilities could have achieved given perfect hindsight using <u>monthly</u> options. But, daily, weekly, short-term and other more targeted hedges may have performed better, as I explained in Section V above.

Q. Would a reasonable and prudent utility have added a hedge during the week prior to the price spike?

A. Yes, there were a number of reasons to add hedges such as call options or costless collars, including:

- the particularly cold weather forecast in Texas from both utility and third-party meteorologists.[38]
- Reports of "the possibility of freeze-offs starting February 8th and stronger competition from traders in different regions for gas supplies."[39] That February 8, 2021 report (the Monday before the event) mentions "freeze-offs" **[TRADE SECRET BEGINS]** **[TRADE SECRET ENDS]** times.
- "supply loss[es that] began as early as February 7, 2021."[40,41]

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[38] Boughner Direct at 11–12, Figures 5-7.
[39] Reed Direct at 69 (citing S&P Global Platts Gas Daily, February 8, 2021). Attached in full as Schedule BPL-D-9.
[40] *See* Schedule BPL-D-10 (Joint Gas Utilities' response to DOC Information Request 29).
[41] *See also* Smead Direct at Schedule 5, p. 2.

- SOL notices from the pipelines.[42]

I will provide excerpts from a recently published book in Section XI below that further explains utility hedging in this context.

Q. Is there any specific information from inside the utilities that would have supported a hedge prior to the spike?

A. Yes. One utility's Director of Gas Supply explained, in an internal email on Friday February 12, 2021 at 10:24am, that "Gas Prices are currently trading across our LDC's between [DATA EXCISED] More information will be available later today, however <u>I do not think these are as high as we might see</u>."[43]

Q. At what prices would the utilities have been able to purchase a hedge?

A. If the utilities had acted early in the week when things started looking concerning, they may have been able to open the hedge for approximately $30 to $35 on February 8-9, 2021. If they had waited until later in the week, they may have been able to open it for around $45 on February 11, 2021. In fact, the weighted average price during the week prior to the event was approximately $46, including the relatively high prices paid during the afternoon of Friday, February 12, 2021.[44]

Q. What would be the weighted average price if the high prices paid during the afternoon of the 12th were excluded?

A. Excluding the relatively high prices paid during the afternoon of Friday, February 12, the weighted average price paid during that week was approximately $44.[45]

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[42] Mead Direct at 44; Levine Direct at Schedule 2, pp. 14–15 of 45.
[43] Schedule BPL-D-14 (internal MERC email from February 12, 2021). *Emphasis added.*
[44] Source: Enverus.
[45] Source: Enverus.

Q. At what prices would the utilities have been likely to purchase a hedge?

A. Given the information above, I believe a range between approximately $35 and $45 is a reasonable estimate, but it could have been as low as $10.

Q. Would the utilities have had to essentially "gamble" ratepayer money while pursuing a hedge that may not eventually prove useful?

A. No. They could have used costless collar hedge structures,[46] which by definition do not cost anything, but they do hedge against outlier scenarios like this one. I explain costless collars in Section VIII.[47]

Q. Given that the utilities would not likely have closed their hedges at the exact top of $650 in this example, at what price to you believe the utilities may have closed?

A. This is much more difficult to assess than assessing the price at which they would likely have initiated the hedge. A range from $400 to $500 is a reasonable estimate of the price at which the utilities may have closed their hedges if they had been prudently managing their hedges based on incoming information. This range is based on looking at the price chart from February 2021[48] in combination with considering the timing of the information available to the utilities in the days after President's Day weekend, including things like warming weather forecasts—likely only a subset of each utilities' information has been presented to the Commission in this docket. Additionally, $500 is a reasonable estimate because it is more than 20 percent below the $650 peak.[49] Also, as I said earlier and will explain further in Section VII, if the utilities had prudently built hedges into their

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[46] *See infra* Section X (Practical Limitations On Selling Puts).
[47] *See* Grizzle Direct at Schedule 2, pp. 42–45 of 101.
[48] Schedule BPL-D-8. Source: Enverus.
[49] 500/650-1=23.1%.

swing contracts ahead of time, they would have essentially been able to "sell at the exact $650 top," capturing the full potential of such hedges without any additional decision-making.

Q. What proportion of the move from $30 to $650 would have been captured if the utilities had purchased at $35 instead of $30 and sold at $500 instead of $650?

A. Approximately two-thirds.[50]

Q. What portion of the move from $30 to $650 would have been captured if the utilities had purchased at $45 instead of $30 and sold at $500 instead of $650?

A. Approximately one-half.[51]

Q. For a hypothetical utility that suffered from a 100x increase in prices (e.g. from $3 to $300), what percentage of that 100x increase would be offset by a hedge that captured two-thirds of the $30 to $650 move that you just described?

A. Since two-thirds of the 21.67x move is 14.29x, it would have offset 14.29 percent of the cost.

Q. Did any of the four utilities in this proceeding suffer from price increases of precisely 100 times the previous prices (e.g. $3 to $300)?

A. I do not believe so, some of them may have been higher than that and some of them may have been lower than that. I request that each utility provide its best estimate in rebuttal testimony for the Commission's reference.

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[50] 500/35 = 14.29. This 14.29x move is approximately 65.9 percent of the full 21.67x move. 14.29/21.67 = 0.659.
[51] 500/45 = 11.11. This 11.11x move is approximately 51.3 percent of the full 21.67x move. 11.11/21.67 = 0.513.

Q. How should the Commission consider the information you are requesting from the utilities?

A. The 14.29 percent disallowance based on the actual February hedge would need to be scaled differently depending on the extent to which each utility was impacted by the price spike. For example, if a utility experienced a 125x price spike, rather than 100x, the disallowance would be 11.43 percent of the cost associated with prices above $20, instead of 14.29 percent.[52]

Q. Why does a larger price spike result in a smaller disallowance?

A. A disallowance on this basis (setting aside the basis for multiple other disallowances I explain in this testimony) is based on the performance of a specific hedge that was available in the market during February 2021. A reasonable estimate of the hedge's performance is 14.29x. That 14.29x becomes a smaller percentage as the overall spike becomes larger—e.g. the 14.29x hedge would only be one percent of a 1,429x price spike.

Q. What is 14 percent of each utility's cost at issue in this docket?

- 14 percent of Great Plains' $8.8 million of extraordinary cost is approximately $1.2 million;
- 14 percent of MERC's $65 million of extraordinary cost is approximately $9 million;
- 14 percent of Xcel's $179 million is approximately $25 million;
- 14 percent of CenterPoint's $409 million is approximately $57 million.

This totals approximately $92 million across the four utilities.

[52] 11.43% = 125/14.29
14.29% = 100/14.29

Q. What would be the disallowance on this basis if the utilities had only captured half of the move from $30 to $650?

A. Applying similar calculations, the disallowance would be approximately $71.4 million.[53]

Q. If utilities had entered into hedged swing contracts prior to the event, would they have captured more than two-thirds of the value of the hedge?

A. I will discuss hedged swing contracts in Section VII, but yes, hedged swing contracts likely would have captured more than two-thirds of the value of the hedge.

Q. Would they have captured 100 percent of the hedge?

A. There would have likely been a gap between the expected market price of natural gas and the strike price of the call (i.e., the ceiling price) at the time the hedges were put on. But as I explained in Section V(b), the strike prices would have likely been less than $20, so to the extent that hedged swing contracts were in place (rather than unhedged swing contracts) the utilities would have avoided all cost above this docket's $20 price threshold.

Q. Do you believe a disallowance in the range of $71 million to $92 million would be reasonable based on a price spike of 100x and the other facts of this case?

A. Yes, those amounts are reasonable because (1) a $71 million to $92 million disallowance is essentially equivalent to a relatively small subset of a full $600+ million disallowance based on hedged swing contracts and (2) the $71 million to $92 million is based on only capturing ½ to ⅔ of actual hedges that were available in the market during February 2021. That is, because such a disallowance would mimic how a relatively small number of hedged swing contracts would have performed had they been in place, those dollar

[53] 21.67/2 = 10.8. 10.8% of $661 million is $71.4 million.

amounts would be reasonable. But, again, the specific disallowance for each utility would need to be adjusted to reflect the extent to which prices spiked for each utility rather than assuming it was exactly 100x across the board.

Q. Would you further explain hedged swing contracts?

A. Yes, I will further explain hedged swing contracts in the next Section.

VII. HEDGES ON SWING CONTRACTS

Q. Are there other hedges that could have performed better than if the utilities had fully captured the move up to $650?

A. Yes, as I alluded to earlier, if the utilities had a hedge in place that was appropriately tailored to the time and location where the gas supply was priced, they likely would have offset a greater portion of the cost than if they were able to sell at the $650 from the earlier example.

Q. Can you expand on that?

A. Yes. If the utilities had negotiated collars into their swing contracts, all related costs for prices above $20 would have likely been mitigated—that is accurate for the purchases related to their swing contracts, but not necessarily for spot purchases exposed to index-based pricing. It largely depends on the strike price of the implied call option that a third-party swing gas supplier would have agreed to prior to winter 2020-2021—based on the futures contracts explained in Section V(a) and provided in Schedule BPL-D-5, it appears likely that the strike prices would have been $20 or less and therefore would have fully avoided all cost related to prices over $20 for those hedged swing contracts.

Q. If the Commission finds that it would have been prudent for the utilities to have negotiated collars into their swing contracts ahead of time, how much should it disallow on that basis?

A. In that situation, the total disallowance for the four utilities could approach the full $600+ million. But the Commission should carefully study all information available to it and determine how much gas, if any, should have still been fully exposed to spot market pricing risks (and therefore not protected by the hedges embedded in the swing contracts.) This partly depends on other factors that are outside the scope of my testimony, such as peaking resources, conservation appeals, curtailment, and weekend gas sales, etc. If the Commission finds that it was reasonable and prudent for the utilities to remain exposed to some unhedged gas in the spot market, the Commission should reduce its disallowance below the full $661 million accordingly.

VIII. HEDGING BUDGETS

Q. Do any of the utilities have specific budgets that apply to the cost of hedging that they can recover through the Purchased Gas Adjustment?

A. Yes. CenterPoint's annual hedging expenses have been limited to $6.5 million.

Q. Did CenterPoint spend the entire $6.5 million?

A. No. CenterPoint admitted that it "does not usually engage in financial hedging of the sort subject to the $6.5M limitation."[54] And, in a follow up answer, CenterPoint admitted that it "has not used financial hedges in any recent year, and therefore was not near the $6.5M limit for the 2020/2021 heating season."[55]

Q. Did the utilities discuss the concept of "costless collars?"

A. Yes. The utilities mention collars throughout their testimony, but CenterPoint may have provided the most detail on costless collars in its Gas Procurement Plan.[56] CenterPoint's explanation is relatively generic and would apply to all four utilities.

Figure 1 below is from CenterPoint's Gas Procurement Plan.[57] It illustrates that costless collars protect against all price spikes above the strike price of the call—in CenterPoint's example below, the call option has a strike price of $4.00. The horizontal portion of the red line at $4.00 illustrates that price spikes above $4.00 would be neutralized by the hedge—for example, if the price for gas would have otherwise been $8 (or $300), the hedge would offset the cost such that the net price is limited to only $4.00.

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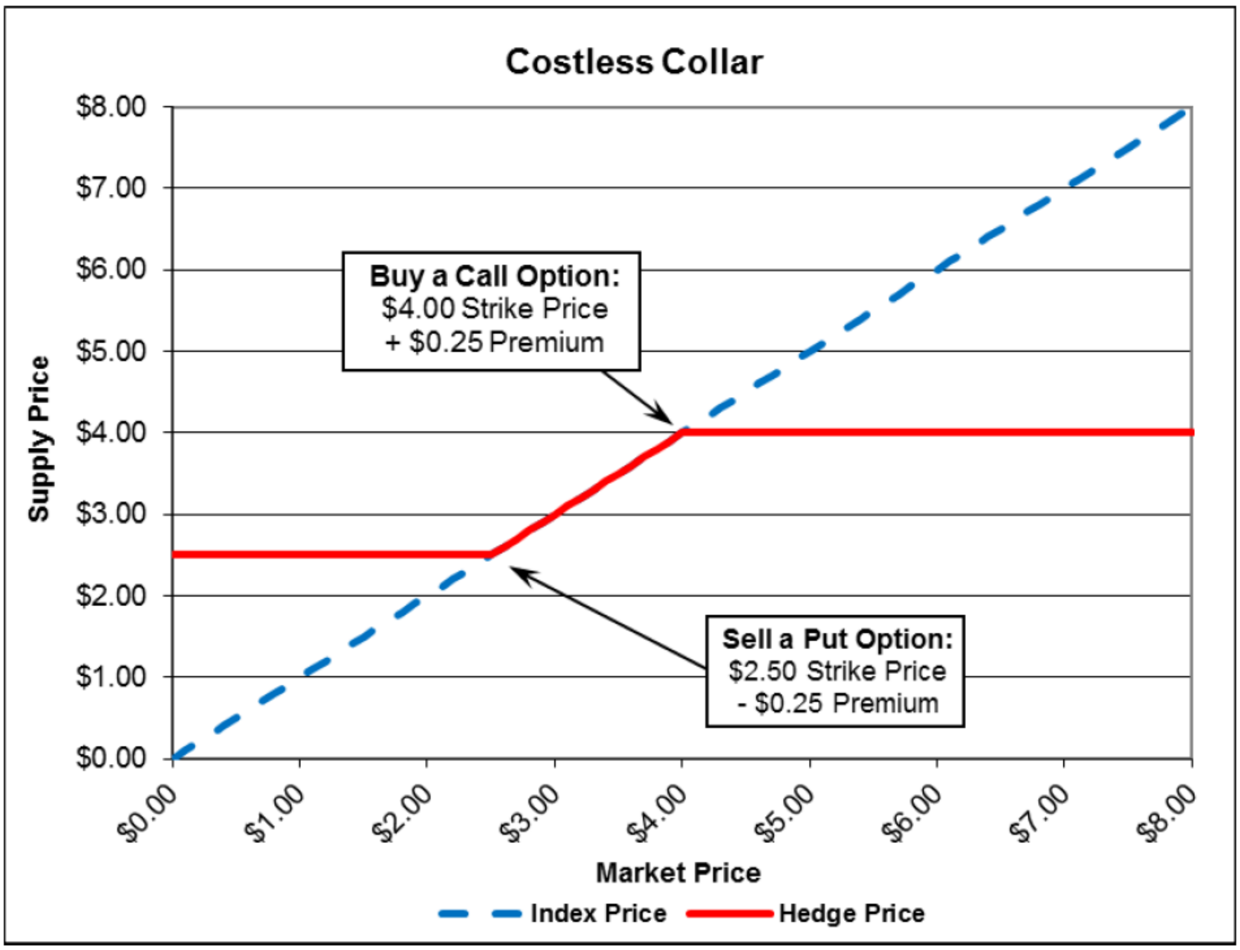
[54] CenterPoint Response to OAG Information Request 008 (attached as Schedule BPL-D-11).
[55] CenterPoint Response to OAG Information Request 008A (attached as Schedule BPL-D-12).
[56] Grizzle Direct at Schedule 2, pp. 42–45 of 101.
[57] Grizzle Direct at Schedule 2, p. 43 of 101.

Q. What does the diagonal portion of the red line illustrate?

A. The diagonal portion of the red line illustrates that the price movements would be unaffected by the hedge between $2.50 and $4.00—that is, if the market price moves up somewhat (from $3.00 to $4.00 for example,) the net price would also move up by the same amount (up to a maximum of $4.00):

Figure 1: Costless Collar



Q. How should costless collars be compared with a specific dollar budget, such as $6.5 million?

A. It is not clear because costless collars, by definition, do not cost anything. In CenterPoint's hypothetical (in Figure 1 above,) the $0.25 Premiums offset each other resulting in zero net cost.[58] In fact, instead of paying money, if a utility were to agree to a high enough floor price (i.e. selling a put) combined with a high enough ceiling price (i.e. buying a call), the utility could actually <u>collect</u> money by selling the put for more than the cost of buying the call.[59] It may seem somewhat counter-intuitive, but that could be described as a "negative-cost collar," rather than a "costless collar."

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[58] *See* Grizzle Direct at Schedule 2, pp. 42–43 of 101.

[59] If a utility were to sell one put option for $0.25, it could purchase up to 25 call options for $0.01 each and it would still be a "costless" situation. *See* Grizzle Direct at Schedule 2, pp. 42–45 of 101.

IX. ADJUSTING HEDGES

Q. Do the utilities discuss the possibility that hedges can be adjusted or change over time?

A. Yes. CenterPoint's Gas Procurement Plan states that:

> The mix of hedge products will change over time as our market view changes and as price of the available hedge products change. The products to be used for hedging will be determined at various times throughout the year and may include, but will not be limited to, the risk management tools described above.[60]

And concludes that:

> It is anticipated that over time, as the hedging strategy is executed and administered, CenterPoint Energy's market view may change due to changing energy environment and updated market information. Therefore, CenterPoint Energy's management may decide upon a different mix of hedging levels and products to mitigate price volatility.[61]

Xcel said:

> As winter months approach, the plans will be adjusted to reflect long-term and near-term weather forecasts, storage inventory levels, historical demand experienced for a given month, and current market conditions. In Minnesota, particular consideration is given to the wide swings in demand that can occur month-by-month and even day-by-day, mirroring the extreme swings in winter weather the State can experience. After this full consideration, the Company works to secure and dispatch an economic mix of long- and short-term firm natural gas supplies using [resources including] financial hedges[62]

[60] Grizzle Direct at Schedule 2, p. 35 of 101.
[61] Grizzle Direct at Schedule 2, p. 59 of 101.
[62] Derryberry Direct at Schedule 2, p. 6.

Q. Who would likely adjust the hedges?

A. CenterPoint explains that:

> Two methods are available to CenterPoint Energy for setting hedges: (a) buy financial products through CenterPoint Energy's financial trading desk, or (b) request competitive bids from physical gas suppliers for hedged price gas. Both methods provide the same result; however, CenterPoint Energy has relied exclusively on physical price hedge products in recent years and does not plan on entering into any financial hedges this Plan year.[63]

Q. Do the other utilities likely have access to a "financial trading desk" similar to CenterPoint's?

A. Yes. The other utilities likely have access to a "financial trading desk" similar to CenterPoint's.

Q. What is the "hedged price gas" that CenterPoint mentions?

A. It is not entirely clear, but it may be similar to the hedged swing gas that I discussed earlier in Section VII.

[63] Grizzle Direct at Schedule 2, p. 40 of 101.

X. PRACTICAL LIMITATIONS ON SELLING PUTS

Q. Are there any practical limitations on selling put options (as part of a costless collar, for example)?

A. Yes. Utilities should avoid selling a greater number of puts than their demand would justify. That is, utilities should avoid selling more put contracts (generally at 10,000 MMBtus each)[64] than the amount of gas that will pass through to their customers during a given time frame (excluding transportation customers since they manage their own cost of gas).[65]

Q. Why is this the case?

A. Primarily because option sellers take on an obligation that remains until they choose to close the contract—in the case of natural gas put sellers, they take on an obligation to buy a certain amount of gas that remains as long as they choose to keep the contract open (usually 10,000 MMBtus per contract).[66]

Q. Does this mean that put sellers can choose to close the contract before it would otherwise expire?

A. Yes. Either the seller or the buyer can close their position at the current market price any time the market is open—the ability to close the position at the market price is similar to the ability to buy or sell shares of Tesla or Amazon at any time. That is, it is not necessary to sell it back to the same person that you bought it from. Likewise, it is not necessary to buy it back from the same person that you sold it to.

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[64] 10,000 MMBtu is approximately equal to 10,000 Dth or 100,000 therms.
[65] This is somewhat analogous to the inverse of a "covered call."
[66] Because either the buyer or the seller can enter into an offsetting position, pipeline imbalance penalties are not a factor in this situation. Additionally, some options are only settled financially and therefore could not result in physical delivery or pipeline imbalance penalties.

Q. Do the limitations you described on the quantity of put options apply to all of your recommendations throughout this testimony?

A. Yes. My recommendations throughout this testimony are somewhat general so it is important to point out that any specific application of my general recommendations should not violate this principle limiting the quantity of puts that a utility can sell. Gas utilities are almost continuously buying natural gas, so it is somewhat natural for them to be selling puts—that is, they essentially have a built-in hedge when selling puts. But they should avoid selling a quantity of puts that would negate that built-in hedge.[67]

Q. Are there similar limits on the number of call options that a utility could purchase?

A. No, buyers of call options do not have an <u>obligation</u> to buy any quantity of gas, only the <u>right</u> to buy. Additionally, the vast majority of options are closed before physical delivery would occur.[68] So, a utility could purchase a relatively large number of call options and close them financially. That is, if someone purchases a large number of call options it is not obligated to physically take any actual gas.[69]

Q. Do any of the utilities discuss how much gas could be hedged?

A. Yes, CenterPoint admits that "[h]ow much gas could be hedged under the $6.5M limit would depend on current market pricing for hedging instruments."[70]

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[67] A similar principle applies to natural gas <u>producers</u>. It is natural for them to sell <u>call</u> options because they have a built-in hedge based on the natural gas that they extract from the ground. This is likely why natural gas producers will agree, well in advance, to a "ceiling price" above the expected market price—they will be paid a small premium up-front that they get to keep while agreeing to potentially sell their gas at a higher price than what they would otherwise expect. The same principle applies to most, if not all, commodity producers.

[68] Smead Direct at 10.

[69] This is particularly true for options that are financially settled, but it is also true for physically settled options.

[70] CenterPoint Response to OAG Information Request 008 (attached as Schedule BPL-D-11).

Q. At what price can put options be sold?

A. It depends on a number of factors, including the strike price of the put. All else equal, puts with higher strike prices have a higher value than those with lower strike prices—that is, a $4.00 strike put will cost more than a put with a $3.00 strike price.

Q. At what strike prices can puts be sold?

A. They can be sold out-of-the money, at-the-money, and in-the-money.[71]

Q. Would you provide an example to explain those terms?

A. Yes. For example, assume the current price of natural gas is $4.00—in that case, puts with strike prices below $4.00 are "out-of-the-money" and those with strike prices above $4.00 are "in-the-money."

Q. Is it possible to collect more money after a put is sold?

A. Yes, it could be rolled up, even into-the-money, to collect more premium.

Q. How much premium could be collected?

A. It depends on market conditions and on a variety of other factors like how far they are rolled.

[71] New strike prices are added to accommodate market demand, usually up to once per day.

XI. RISKED REVENUE ENERGY ASSOCIATES ("R^2")

Q. Did CenterPoint provide any information regarding advice it received from a third party regarding its hedging activity?

A. Yes. CenterPoint provided some information from a consultant it hired which is named Risked Revenue Energy Associates (which also calls itself "R^2").[72]

Q. How did CenterPoint explain how it uses the recommendations from R^2?

A. CenterPoint explained the following in response to DOC Information Request 5:

> To determine the exact timing of hedge purchases, CenterPoint relies on advice from Risked Revenue Energy Associates and its proprietary hedging methodology "Trend, Location, and Control" or "TLC" model. TLC provides an objective and quantifiable snapshot of energy market prices that factor into hedging purchase decision.[73]

Q. What advice did R^2 provide to CenterPoint?

[HIGHLY CONFIDENTIAL TRADE SECRET INFORMATION BEGINS]

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[72] *See* Schedule BPL-D-6.
[73] *See* Schedule BPL-D-6.
[74] *See* Schedule BPL-D-6.

[HIGHLY CONFIDENTIAL TRADE SECRET INFORMATION ENDS]

Please see Sections V and VII above for further information to consider in the context of the recommendations from R^2 to CenterPoint—it suggests that a substantial disallowance would be reasonable.

Q. Were you able to find detailed information regarding R^2's "Trend, Location, and Control" or "TLC" methodology that CenterPoint mentioned in response to DOC Information Request 5?

A. Yes. R^2's founder and one of his longtime lieutenants recently co-authored a 200+ page book that explains that "effective hedging is not a decision, it is a process. [R^2] call[s] this Process Risk Management or PRM."[75] R^2's "TLC" is one of the main components of its PRM. The book explains that "[t]he three drivers of the market provide information that is so important that we borrowed an acronym to help readers remember them: TLC—trend, location, and control."[76]

Additionally, the book says:

> The beauty of PRM is that you don't do this once and assume you are safe. No, the world of commodities is dynamic, fast moving, and occasionally treacherous. Begin by getting the firm safe and then employ a process to monitor both your assumptions and market conditions to confirm that it remains safe.[77]

And

> Process Risk Management is an objective way to identify how to hedge at the appropriate time, in the appropriate amount, using the appropriate instruments based on the requirements of the hedger and the current conditions of the market.[78]

[75] WAYNE PENELLO & ANDREW P. FURMAN, RISK IS AN ASSET: TURNING COMMODITY PRICE UNCERTAINTY INTO A STRATEGIC ADVANTAGE 12 (ForbesBooks) (Kindle Edition).
[76] *Id.* at 123.
[77] *Id.* at 13.
[78] *Id.* at 26.

Q. Does the book provide an analogy using the weather?

A. Yes. It says:

> Most people say that the markets are a random walk; like the weather, they are unpredictable and uncertain. And so most people just assume that they should behave the same way toward the markets every day. That doesn't exactly make sense to us. The markets are a random walk, just like the weather. However, you shouldn't respond to the markets in the same way each day, just like you shouldn't waste the time and energy to bring an umbrella with you everywhere you go, no matter the weather conditions.[79]

And goes on to say:

> And in the cases of major shifts in weather patterns or sudden disasters such as tornadoes, hurricanes, or blizzards, your umbrella won't be enough to keep you safe, warm, and dry. Significant weather events happen. Fortunately, we do not have to face them very often.[80]

Q. Does the book explain how a company would determine whether it needs to hedge?

A Yes, it asks and answers that question as follows:

> What's the litmus test you should use to determine whether your company needs to hedge? If your commodity price exposure can threaten your profit margin, you will almost certainly need a hedge program.[81]

Q. Are the utilities' profit margins threatened due to "commodity price exposure?"

A. The four utilities in this docket likely believed that their profit margins were not threatened because they thought they would be able to eventually pass the cost on to their customers. In fact, internal correspondence from some of the utilities shows that they were operating under the assumption that any risk would be passed on to ratepayers—see Schedules BPL-D-13 and BPL-D-14 for internal emails that were sent during the event.[82]

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[79] *Id.* at 28.
[80] *Id.* at 29.
[81] *Id.* at 35.
[82] *See* Schedule BPL-D-13 (internal CenterPoint email from February 12, 2021 stating "this is fully recoverable as a pass through cost"); Schedule BPL-D-14 (internal MERC email from February 12, 2021 stating "increased prices
(Footnote Continued on Next Page)

Q. Did the book discuss the potential implications of not managing risk?

A. Yes, it said:

> In terms of managing risk for a business whose costs or revenue is highly exposed to fluctuating prices, if you are not confronting the brutal facts about higher cost potential or lower revenue potential, price risk will rear its ugly head at the worst possible time with the worst possible consequences. Conversely, the active management of risk on a continuing basis will nip problems in the bud.[83]

And went on:

> By actively managing risk, you keep risk decisions small and the subsequent decisions even smaller. For the car driver, keep your hands on the steering wheel and always keep your eyes on the road. For the business with commodity exposure, keep updating your risk and always confront the brutal facts.[84]

Q. Did the book discuss "midmonth" updates?

A. Yes, it suggested that midmonth updates may be prudent:

> Responding on a monthly time frame is usually frequent enough to be responsive to market changes, and it avoids reacting to temporary blips in pricing that reflect noise rather than trends. However, any time you are close to your risk threshold and prices jump, it may be prudent to update your risk map midmonth. You won't get it right all the time. No one can. But take solace knowing that if you do hedge and these hedge adjustments are not accompanied by a new trend, then you will have just a few poorly placed hedges that should have little impact on your overall budgetary performance. On the other hand, if prices persist negatively, then these hedges are likely to provide some of the protection needed to achieve success.[85]

(Footnote Continued from Previous Page)
are expected to be recovered through normal regulatory treatment from our LDC customers") (public version only). Both emails were produced in response to OAG Information Request 5.

[83] *Id.* at 38.

[84] *Id.* at 39.

[85] *Id.* at 79.

It also provided a related sports analogy regarding the imprudence of "stick[ing] with one strategy and us[ing] it all the time."

> To use another sports analogy, football teams get four downs to succeed. It's what they do in each down, and the result of each play, that influences what they will do on the next down. If the quarterback gets sacked on the first down, both the offensive and defensive teams will use that information to develop their strategies for the next down. Or if a team has first and goal at the eight-yard line, their first-down play will look vastly different compared to if they were sixty yards downfield. They don't simply assume that because the outcome of the plays is unpredictable, perhaps random, they should stick with one strategy and use it all the time.[86]

Q. Did the book discuss adjusting hedges to "remove the desired amount of risk" … "whether prices have moved lower or higher?"

A. Yes, to be specific the book said:

> If, however, a consumer wants to lower their High Case to reduce risk, that can be accomplished whether prices have moved lower or higher. The volume needed to achieve the reduction must be adjusted to compensate for current price, of course, but a hedge can be implemented that will still remove the desired amount of risk.[87]

[86] *Id.* at 111–12.
[87] *Id.* at 134–35.

Q. Did the book explain some of the services that R^2 provides to utility customers?

A. Yes. The book explains:

> [The utility] had three parties they ultimately needed to answer to: (1) shareholders, who wanted to be assured that their dividends would be paid; (2) ratepayers, who could not afford large increases in electricity rates; and (3) the government/public utility commission, who wanted to make sure that excessive costs were not being placed on ratepayers.

And eventually they:

> calculated the price of the maximum acceptable fuel cost and how much risk needed to be hedged away. Now the utility could monitor its risk as it related to the metric of success they were being evaluated by, explain to stakeholders why they were hedging, and hedge appropriately to defend the metric.[88]

Also, R^2 says that it "provides clients with thorough and timely information about their risk profile and specific hedge recommendations to achieve bottom-line goals."[89]

Q. Was R^2 providing services like that to the four utilities in this docket?

A. Based on the information CenterPoint provided, it is not clear whether R^2 was providing the exact same level of analysis described in the book, but it is clear that R^2 was providing some level of analysis.

Q. Did the book discuss both preparing for and reacting to rough seas when they inevitably arrive?

A. Yes, the book concludes by explaining that:

> Anyone can appear to be a good sailor when the seas are calm. It's how one handles the storms that separates the great sailors from others in the fleet. While the timing of storms may be impossible to predict, their magnitude is not. Good sailors are prepared for and keep an active look out for storms.[90]

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[88] *Id.* at 113.
[89] *Id.* at 217.
[90] *Id.* at 215.

Q. So, what does the book suggest?

A. It suggests that it would have been prudent for the utilities to have some hedges in place well ahead of time (such as the hedged swing supply that I discuss above) and that it would have been prudent to adjust hedges to remove excess risk as market conditions changed (such as the hedges I discussed in Sections V and VI above). That is, it would not have been necessary or prudent to fully hedge up to the maximum over the summer, for example—but, given the flexibility offered by not excessively hedging over the summer, adjusting the hedges would have been prudent to reflect changing market conditions.

XII. CONCLUSION

Q. What do you conclude?

A. My primary conclusion is that, if the Commission finds that the utilities should have both (1) negotiated collars into their swing contracts and (2) should not have been exposed to the risks of spot market prices, it should disallow the full $661,537,779 at issue in this case.[91,92]

Q. If the Commission does not fully agree with those two factors, do you have an alternative recommendation?

A. Yes. If, instead, the Commission finds that the type of swing contracts (without collars or protection against price spikes) were acceptable and the exposure to February's index-priced spot market was reasonable, the Commission should consider disallowances based on other hedges.

Q. What kinds of other hedges are you referring to?

A. They include both (1) the results of the actual hedges that were available to the utilities (which I explain above in Section VI, Actual Hedge Results) and (2) the potential hedges which I explain above in Section V, (Potential Hedges). As I explained in Section VI above, a reasonable disallowance based on the actual hedges would be in the range of approximately $71 million to $92 million. I am also pursuing additional hedging information and may provide more detailed recommendations in my surrebuttal testimony.

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[91] The impacted utilities calculated the following revised extraordinary gas costs: $408,755,953 for CenterPoint; $178,978,695 for Xcel; $64,975,882 for MERC; and $8,827,249 for Great Plains. *See* ORDER GRANTING VARIANCES AND AUTHORIZING MODIFIED COST RECOVERY SUBJECT TO PRUDENCE REVIEW, AND NOTICE OF AND ORDER FOR HEARING (Aug. 30, 2021).

[92] Greater Minnesota Gas explained that it was able to completely avoid any and all prices above $20, likely due, in part, to its hedging activity, and is not at risk of a potential disallowance in this docket.

My conclusions can be summarized as follows:

- Swing contract hedges combined with completely avoiding index-priced spot purchases could have saved $661 million.
- Actual hedges could have saved approximately $71 million to $92 million.
- I am pursuing additional information from the utilities and elsewhere to possibly provide more detailed hedging recommendations in future testimony.

Finally, the Commission could disallow a different dollar amount by concluding that the utilities could have engaged in some combination of hedges, but the total cannot exceed the maximum amount of potential disallowances at issue in this docket (approximately $661 million).

Q. Does this conclude your direct testimony?

A. Yes.

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PRICE QUOTATION	U.S. dollars and cents per MMBtu
TRADING HOURS	Sunday - Friday 6:00 p.m. - 5:00 p.m. (5:00 p.m. - 4:00 p.m. CT) with a 60-minute break each day beginning at 5:00 p.m. (4:00 p.m. CT)
PRODUCT CODE	**CME Globex:** KDB **CME ClearPort:** KD **Clearing:** KD
LISTED CONTRACTS	1 daily contract listed daily
TERMINATION OF TRADING	Trading terminates at the close of business on the contract date.
POSITION LIMITS	NYMEX Position Limits
EXCHANGE RULEBOOK	NYMEX 832
BLOCK MINIMUM	Block Minimum Thresholds
VENDOR CODES	Quote Vendor Symbols Listing
STRIKE PRICES STRIKE PRICE INTERVAL	Strike Price Listing and Exercise Procedures Table

EXERCISE STYLE	European
SETTLEMENT METHOD	Financially Settled
UNDERLYING	Henry Hub Natural Gas Futures

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Futures and Options

GLOBEX CODE	LAST	CHANGE	VOLUME
NGF2	3.796	+0.002 (+0.05%)	108,325

Add to portfolio

as of December 14 2021, 03:05pm CT

OVERVIEW QUOTES SETTLEMENTS VOLUME & OI TIME & SALE FUTURES OPTIONS

NATURAL GAS WEEKLY OPTIONS (AMERICAN) - CONTRACT SPECS

CONTRACT UNIT	10,000 MMBtu
MINIMUM PRICE FLUCTUATION	0.001 per MMBtu = $10.00
PRICE QUOTATION	U.S. dollars and cents per MMBtu
TRADING HOURS	**CME Globex:** Sunday 5:00 p.m. - Friday - 4:00 p.m. CT with a daily maintenance period from 4:00 p.m. – 5:00 p.m. CT **CME ClearPort:** Sunday 5:00 p.m. - Friday 4:00 p.m. CT with no reporting Monday - Thursday from 4:00 p.m. – 5:00 p.m. CT
PRODUCT CODE	**CME Globex:** ON1,ON2,ON3,ON4,ON5 **CME ClearPort:** ON1,ON2,ON3,ON4,ON5 **Clearing:** ON1,ON2,ON3,ON4,ON5
LISTED CONTRACTS	Weekly contracts listed for 4 consecutive weeks. No weekly contract listed if expiration would occur the same day as the corresponding monthly option expiration.
TERMINATION OF TRADING	Trading terminates on Friday of the contract week. If Friday is not a business day, trading terminates on the prior business day.
POSITION LIMITS	NYMEX Position Limits
EXCHANGE RULEBOOK	NYMEX 1012

BLOCK MINIMUM	Block Minimum Thresholds
STRIKE PRICES STRIKE PRICE INTERVAL	Strike Price Listing and Exercise Procedures Table
SETTLEMENT METHOD	Deliverable
UNDERLYING	Henry Hub Natural Gas Futures

CME OPEC Watch Tool
Stay up to date with the probabilities of certain outcomes of the next OPEC meeting using NYMEX WTI Crude Oil option prices.

Interactive Expiration Calendar
Use this calendar to find relevant product dates and CME Group holiday hours.

Option Settlement Tools
Anlayze settlement values for all CME Group options products, including both settlement prices and implied volatilities.

Open Interest Profile Tool
Analyze open interest and open interest change patterns for each expiration within the selected product.

Looking for more? Explore our additional resources

PRODUCTS

- Micro WTI Crude Oil futures
- CBL Nature-Based Global-Emissions Offset futures
- Henry Hub Natural Gas futures
- RBOB Gasoline futures
- Weekly energy options

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- Expiration Calendar

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- COMEX

English

FEEDBACK

← Natural Gas

View an Energy Product

Henry Hub Natural Gas

Futures and Options

GLOBEX CODE	LAST	CHANGE	VOLUME
NGF2	3.796	+0.002 (+0.05%)	108,325

Add to portfolio

as of December 14 2021, 03:05pm CT

OVERVIEW QUOTES SETTLEMENTS VOLUME & OI TIME & SALE FUTURES OPTIONS

NATURAL GAS SHORT-TERM OPTION - CONTRACT SPECS

CONTRACT UNIT	10,000 MMBtu
MINIMUM PRICE FLUCTUATION	**CME Globex:** 0.001 per MMBtu = $10.00 **CME ClearPort:** 0.0001 per MMBtu = $1.00
PRICE QUOTATION	U.S. dollars and cents per MMBtu
TRADING HOURS	Sunday - Friday 6:00 p.m. - 5:00 p.m. (5:00 p.m. - 4:00 p.m. CT) with a 60-minute break each day beginning at 5:00 p.m. (4:00 p.m. CT)
PRODUCT CODE	**CME Globex:** U01 **CME ClearPort:** U01 **Clearing:** U01
LISTED CONTRACTS	Daily contracts listed for the current day and the following four business days within a seven-calendar day period, unless that business day coincides with the expiration of a monthly Natural Gas Option in which case it is not listed.
TERMINATION OF TRADING	Termination of trading coincides with the ticker symbol symbol. For example, C25 N21 coincides with a termination of trading on July 25, 2021.
POSITION LIMITS	NYMEX Position Limits
EXCHANGE RULEBOOK	NYMEX 1066
BLOCK MINIMUM	Block Minimum Thresholds

VENDOR CODES	Quote Vendor Symbols Listing
STRIKE PRICES STRIKE PRICE INTERVAL	Strike Price Listing and Exercise Procedures Table
EXERCISE STYLE	European
SETTLEMENT METHOD	Financially Settled
UNDERLYING	Henry Hub Natural Gas Futures

CME OPEC Watch Tool →
Stay up to date with the probabilities of certain outcomes of the next OPEC meeting using NYMEX WTI Crude Oil option prices.

Interactive Expiration Calendar →
Use this calendar to find relevant product dates and CME Group holiday hours.

Option Settlement Tools →
Anlayze settlement values for all CME Group options products, including both settlement prices and implied volatilities.

Open Interest Profile Tool →
Analyze open interest and open interest change patterns for each expiration within the selected product.

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FEEDBACK

Weather Futures and Options

MANAGE RISK ASSOCIATED WITH FLUCTUATING GLOBAL TEMPERATURES

Overview

It is estimated that nearly 30 percent of the US economy is directly affected by the weather. In order to enable businesses to hedge the risk they face from atypical weather conditions – particularly as the onset of climate change precipitates extreme weather events – CME Group offers Weather futures and options. These products are financial tools that provide a means of transferring risk associated with adverse weather events. They are index-based products geared to average seasonal and monthly weather in 12 cities around the world – nine in the US, two in Europe, and one in Asia.

Key features:

- Access to unique tools for managing exposure to weather
- Stabilized cash flow for hedges participating in these markets
- Centralized clearing and counterparty credit guaranteed by CME Clearing
- Transparent prices on all weather futures and options

Market participants:

Participants in these markets include companies in a wide range of industries:

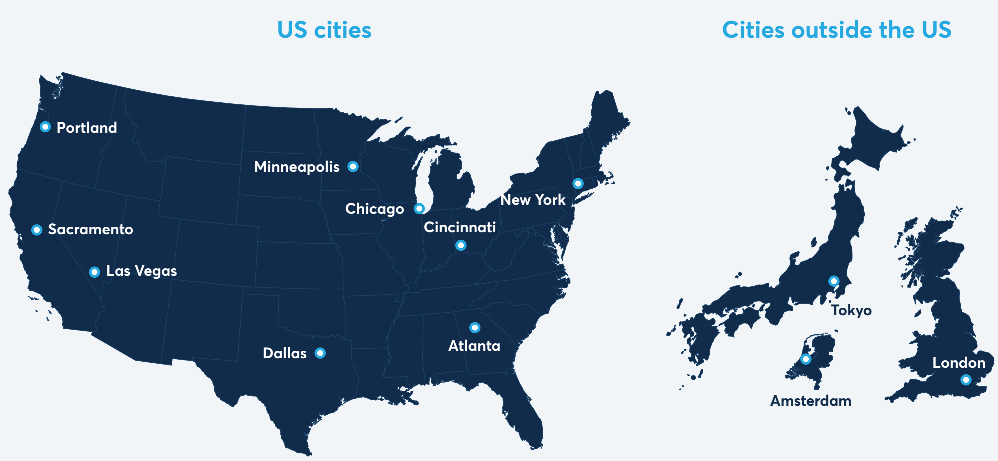
- Insurance and reinsurance companies
- Hedge funds
- Energy companies
- Food/agriculture industry
- Pension funds
- State governments
- Retailers
- Utility companies

Latest weather research white paper (Jan 2021)

Managing Climate Risk with CME Group Weather Futures & Options

Read more >

- **12 global price points**
- **Monthly and seasonal strip HDD/CDD/CAT futures and options**
- **Available for block trading on CME Clearport and electronically on CME Globex**
- **Block trade minimum of 20**



CME Group

How weather is traded at CME Group

Weather products quantify weather in terms of how much the temperature deviates from the monthly or seasonal average in a particular city, allowing market participants to trade the weather much like any other commodity index.

The value of a Weather future or option is determined by the value of the underlying weather index, measured in Heating Degree Days (HDD) or Cooling Degree Days (CDD) – the total number of degrees that the average outside air temperature falls or rises below or above the base temperature of 65°F (18°C for non-US cities). The European summer cooling month contracts and all Tokyo contracts are based on a Cumulative Average Temperature (CAT). Each monthly CAT index is simply the accumulation of daily average temperatures recorded in degrees Celsius over a calendar month

For example, if the average of a day's maximum and minimum temperature on a midnight-to-midnight basis is 55° F, that day's HDD is 10 and the CDD is zero. The original futures are based on the cumulative value of HDDs or CDDs during the term of the contract. Assume we are evaluating a monthly contract in which the month had 31 days and each day was like our example, with an average daily temperature of 55°F. Accordingly, the cumulative monthly HDD would equal 310 (10 HDDs x 31 days). Value at settlement for Weather contracts is determined by multiplying the cumulative HDD or CDD by the contract's tick size of $20. The final value of our example Weather futures contract would equal $6,200 (310 index points multiplied by $20).

Using Tokyo to illustrate to CAT index pricing, assume that the month had 30 days and the average daily temperature for each of the first 15 days was 10°C and the average daily temperature for each of the remaining 15 days was 20°C. Accordingly, the cumulative average temperature (CAT) would equal 450 (= (15 days x 10) + (15 days x 20)). The futures contract value would be identified by multiplying that figure by ¥2,500 (Japanese Yen). In this example, the cash value of the contract would be ¥1,125,000 (= ¥2,500 x 450).

HEATING (HDD) FUTURES AND OPTIONS

	CITY CODE	NOV-MAR STRIP	DEC-FEB STRIP
US			
ATLANTA	H1	H1X	H1Z
CHICAGO	H2	H2X	H2Z
CINCINNATI	H3	H3X	H3Z
DALLAS	H5	H5X	H5Z
LAS VEGAS	H0	H0X	H0Z
MINNEAPOLIS	HQ	HQX	HQZ
NEW YORK	H4	H4X	H4Z
PORTLAND	H7	H7X	H7Z
SACRAMENTO	HS	HSX	HSZ
EUROPE			
AMSTERDAM	D2	D2X	D2Z
LONDON	D0	D0X	D0Z
ASIA			
TOKYO*	G6	G6X	G6Z

COOLING (CDD) FUTURES AND OPTIONS

	CITY CODE	JUL-AUG STRIP	MAY-SEP STRIP
US			
ATLANTA	K1	K1K	K1N
CHICAGO	K2	K2K	K2N
CINCINNATI	K3	K3K	K3N
DALLAS	K5	K5K	K5N
LAS VEGAS	K0	K0K	K0N
MINNEAPOLIS	KQ	KQK	KQN
NEW YORK	K4	K4K	K4N
PORTLAND	K7	K7K	K7N
SACRAMENTO	KS	KSK	KSN
EUROPE			
AMSTERDAM*	G2	G2K	G2N
LONDON*	G0	G0K	G0N
ASIA			
TOKYO*	G6	G6K	G6N

**CAT Index used*

For more information on Weather futures and options, visit cmegroup.com/weather

cmegroup.com

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Source: Enverus

State of Minnesota
Minnesota Department of Commerce

Utility Information Request

Docket Number: G-008/M-21-138 - Cost Impacts/Extreme Weather — Date of Request: 11/2/2021

Requested From: CenterPoint Energy Minnesota Gas — Response Due: 11/10/2021

Analyst Requesting Information: Nancy Campbell

Type of Inquiry: Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
DOC 005 P - S	Topic: Hedging Reference(s): All Gas Utilities' Testimony The definitions provided in DOC Information Request No. 4 apply to this IR. a. Please provide any natural gas hedging and risk management strategy, policy, and procedures documents relied on for the utility's hedging plan for 2020-21 winter heating season. b. For long-term hedging and supply as well as specific requirements for each day of the Event, please provide gas supply reserve margin requirements on a quantified basis and related documentation. c. Please describe how the utility determined monthly baseload volumes for the winter 2020-21 heating season and provide associated documentation d. Please provide a narrative summary of gas system locational requirements, and how these locational requirements impact hedging and supply requirements. e. Please provide relevant regulatory filings associated with winter 2020-21 season hedging, planning, or arrangements (AAA, CD, etc.). Please include filings with Minnesota and federal agencies, commissions, and boards as well as non-governmental standard setting and reporting organizations.

Response By: Paula Grizzle
Title: Director, Gas Supply Portfolio Optimization
Department: Gas Purchasing
Telephone: 713-207-3389

f. Please provide the percentage breakdown of the utility's fixed price vs indexed for daily spot purchases since October 1, 2018 on a daily basis.

g. Please provide details surrounding any improvements or reforms taken in response to the 2017/2018 New Year's Event and/or the 2019 Polar Vortex Event.

Response:

Contains Highly Confidential Trade Secret Information:
CenterPoint Energy Minnesota Gas has designated information in attachments to this document as highly confidential trade secret. The information meets the definition of trade secret in Minn. Stat. § 13.37, subd. 1(b), as follows: (1) the information was supplied by CenterPoint Energy Minnesota Gas, the affected organization; (2) CenterPoint Energy Minnesota Gas has taken all reasonable efforts to maintain the secrecy of the information; and (3) the protected information contains gas pricing information which derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

a. See Exhibit___(PJG-D), Schedule 2, CenterPoint Energy's Minnesota 2020 Gas Procurement Plan and supporting documentation provided in Docket No. G008/M-19-699 (Jun. 19, 2020). This plan includes significant detail regarding planning objectives, procurement strategy, results from the prior plan year, contracting parameters, supply strategy, market outlooks, load forecasts, design day, and capacity services, dispatch modelling, supply resources, price volatility management, hedge implementation and hedging products, resource mix modeling, hedge product selection modeling, competitive bidding processes, summer and winter procurement strategies, and long-term planning.

To determine the exact timing of hedge purchases, CenterPoint relies on advice from Risked Revenue Energy Associates and its proprietary hedging methodology "Trend, Location, and Control" or "TLC" model. TLC provides an objective and quantifiable snapshot of energy market prices that factor into hedging purchase decision. See 200518 Opinion letter.pdf, 200630 Opinion letter.pdf, 200723 Opinion letter.pdf, 200819 Opinion letter.pdf, and 200916 Opinion letter.pdf for the opinions provided by Risked Revenue for CenterPoint Energy's 2020-2021 hedging. See also attached Risk Policy.pdf.

b. CenterPoint Energy's capacity reserve margin calculation is related to the Company's capacity demand entitlements, as reflected in the Company's annual demand entitlement filings. Information on the design day determination and associated reserve margin for the 2020-2021 heating season was provided in the Company's Request for Change in Demand Units filed July 1, 2020, in Docket No. G002/M-20-565. As described in the Direct Testimony of Ms. Paula Grizzle, baseload gas supply, including hedged baseload supplies, is determined based on the Company's monthly and daily requirements forecasts. Baseload and hedged baseload supplies are not determined based on the Company's design day forecast or capacity reserve margin.

c. Please see discussion in the Direct Testimony of Paula Grizzle, Exhibit ___(PJG-D), pages 6-7, 38-40, and Schedule 2, the Company's 2020-2021 Gas Procurement Plan, pages 9-10. Daily baseload volumes for each month are shown in Appendix D to the 2020-2021 Gas Procurement Plan. The monthly baseload volumes are based on the warmest forecast day within each winter month.

d. The locations at which a shipper has firm rights to put gas into a pipeline (i.e., receipt points) and take gas out of a pipeline (i.e., delivery points) are specified in its pipeline transportation contracts. As a result, a gas utility generally buys gas at locations that correspond to receipt points on its pipeline transportation contracts that have gas supplies available and uses its pipeline capacity to deliver the gas to its distribution system. Physical gas supply hedge contracts will also be purchased at some combination of these same receipt point locations since these hedged supplies will ultimately be delivered to the gas utility's distribution system. As specified in CenterPoint Energy's Minnesota 2020 Gas Procurement Plan (provided as PJG-D, Schedule 2) at pages 27-28, CenterPoint has firm receipt point capacity at 11 locations on Northern Natural and at one point on Viking.

See CenterPoint Energy's transportation contracts provided in response to CUB Information Request No. 2 for details regarding the delivery points and receipt points for each of the Company's interstate pipeline transportation contracts.

See Exhibit ___(PJG-D), Schedule 2, to the Direct Testimony of Ms. Paula Grizzle, at 29-31.

CenterPoint Energy holds long term contractual rights to firm transportation on two interstate pipelines that are used to transport gas commodity purchases to CenterPoint Energy town border stations. Maximum daily firm delivery capacity rights held on Northern, which connects directly to CenterPoint Energy, total 1,230,290 Dth/day in the winter months of November through March and 708,174 Dth/day in the summer months of April through October. This capacity is held at various receipt points into Northern which allows for flexibility in purchasing gas when loads are below entitlement levels; however, full entitlements at all points would be used on colder days of the winter and summer (attachment DOC 5 - NNG 20-21 Capacity.xlsx provides a summary of capacity by receipt point on Northern's system). The Northern receipt points where CenterPoint Energy holds a majority of its capacity are Ventura (interconnect with Northern Border Pipeline near Ventura, Iowa), and Demarcation (near Clifton, Kansas) which is the transfer point for gas coming north from Northern's producing area to serve Northern's market area. Demarcation also receives gas coming out of the Rocky Mountain region via Trailblazer Pipeline, with whom CenterPoint contracts with for upstream capacity, and Rockies Express Pipeline. The gas supply points of Ventura and Demarcation are more liquid than others on Northern and therefore are the key points where CenterPoint Energy incorporates flexibility into its gas purchasing

Maximum daily firm delivery capacity rights held on Viking, which connects to CenterPoint Energy through Minnesota Intrastate Pipeline Company ("MIPC"), total 76,809 Dth in both the winter and summer months. Gas to be transported on Viking must be purchased at Emerson, Manitoba (Canadian border), and moved to MIPC at Cambridge, Minnesota. CenterPoint Energy holds firm capacity rights on MIPC (an affiliate pipeline) of 100,000 Dth per day, which allows for transportation of Viking gas from Cambridge to CenterPoint Energy's system.

CenterPoint Energy also holds firm upstream capacity rights on NGPL, a pipeline not directly tied to CenterPoint Energy's system. This capacity is used for moving purchased gas supplies to storage pools for injection and for moving withdrawn storage gas to points of interconnect with Northern for ultimate delivery to CenterPoint Energy's system. At times when this capacity is not needed for moving storage gas, it can be used to buy lower priced gas on NGPL and move to Northern for ultimate delivery to CenterPoint Energy's system.

e. The relevant filings are listed below:

- Annual Automatic Adjustment Report – CenterPoint Energy

Resources Corp. d/b/a CenterPoint Energy Minnesota Gas, Docket No. G999/AA-21-114 (Sept. 1, 2021) (2020-2021 AAA Report).

- CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas Annual True-Up Report, Docket No. G008/AA-21-666 (Sept.1, 2021) (2020-2021 Annual True-Up Report).
- CenterPoint Energy's Request for Change in Demand Units, Docket No. G008/M-20-565 (Jul. 1, 2020) (2020-2021 Demand Entitlement).
- CenterPoint Energy's monthly Purchased Gas Adjustment Reports, Docket Nos. G008/AA-20-805 (November 2020), G008/AA-20-848 (December 2020), G008/AA-20-906 (January 2021), G008/AA-21-95 (February 2021), G008/AA-21-145 (March 2021).
- *In the Matter of the Petition of CenterPoint Energy Resources Corp. for Approval of an Extension of Rule Variances to Minnesota Rules to Recover the Costs of Certain Natural Gas Financial Instruments Through the Purchased Gas Adjustment,* Docket No. G008/M-19-699, Minnesota 2020 Gas Procurement Plan (Jun. 19, 2020); Minnesota 2021 Gas Procurement Plan (Sept. 30, 2021).

f. See Attachment DOC 5(f) Spot Deal Daily Pricing Percents for a daily count of fixed price and index spot purchases from 10/1/18 to 10/31/21. Days with fixed price spot purchases are highlighted for easy reference.

As discussed in the Direct Testimony of Mr. Jeffrey Toys at pages 9-10, when the Company purchases daily spot gas, it generally purchases Gas Daily Daily index-priced gas. Index-priced transactions reflect the forces of supply and demand in the market as they are an average of the reported prices at which transactions were executed. As a result, parties to index-priced transactions bear no price risk because the price reflects the average market price. Second, as such products trade in the morning, Gas Supply is able to secure the spot market supply it needs earlier in the day, avoiding the need to purchase gas for the next day as the markets are closing, and facing the risk of diminished supplies and higher prices. Fixed-price contracts are far more speculative than index-priced contracts as the price inherently only reflects one transaction.

g. See Docket No. E,G999/CI-19-160 for changes, including tariff modifications, implemented by CenterPoint Energy in response to the 2019 Polar Vortex. The Company's November 1, 2019, Compliance Filing summarizes process improvements and reinforcement projects undertaken and the Company's March 20, 2020, Compliance Filing provides redlined tariff changes implemented. In its November ,6, 2019 Order, the Commission:

- approved CenterPoint Energy's proposed changes to its interruptible

tariff, including clarifying language and a penalty increase for non-compliance with curtailment orders;
- required additional reporting in the annual September 1 AAA reports relative to customer curtailments; and
- required a compliance filing on reinforcement projects and progress in implementing various process improvements to address severe weather events.

The Company's November 1, 2020, Compliance Filing reported on completion of two reinforcement projects and CenterPoint Energy's progress in implementing process improvements relative to interruptible customers, including:

- contact information;
- seasonal energy management seminars; and
- resolution of curtailment non-compliance.

As a result of the 2019 polar vortex, CenterPoint Energy implemented a certification form for interruptible customers to ensure they have a functioning backup system, and the ability to discontinue use of all natural gas during the entire period of any curtailment.

The Company continuously reviews gas prices, however after the 2017/18 New Year's Event or the 2019 Polar Vortex Event, the Company still believed that the probability of gas price spikes was low and that the spikes experienced were anomalies. Therefore, the Company did not make any major changes to its Gas Purchase Plan in response to those events.

Supplemented 12/16/21:

Attached please find a corrected version of attachment Risk Policy.pdf corrected to reflect highly confidential trade secret designations.

Risk Policy

Date Approved: August 24, 2020

Legal Policies

Risk Policy

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

RISK POLICY

Revised & Approved: August 24, 2020

Date Approved: August 24, 2020

Risk Policy

[TRADE SECRET DATA BEGINS...

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Date Approved: August 24, 2020

CenterPoint Energy

Risk Policy

Date Approved: August 24, 2020

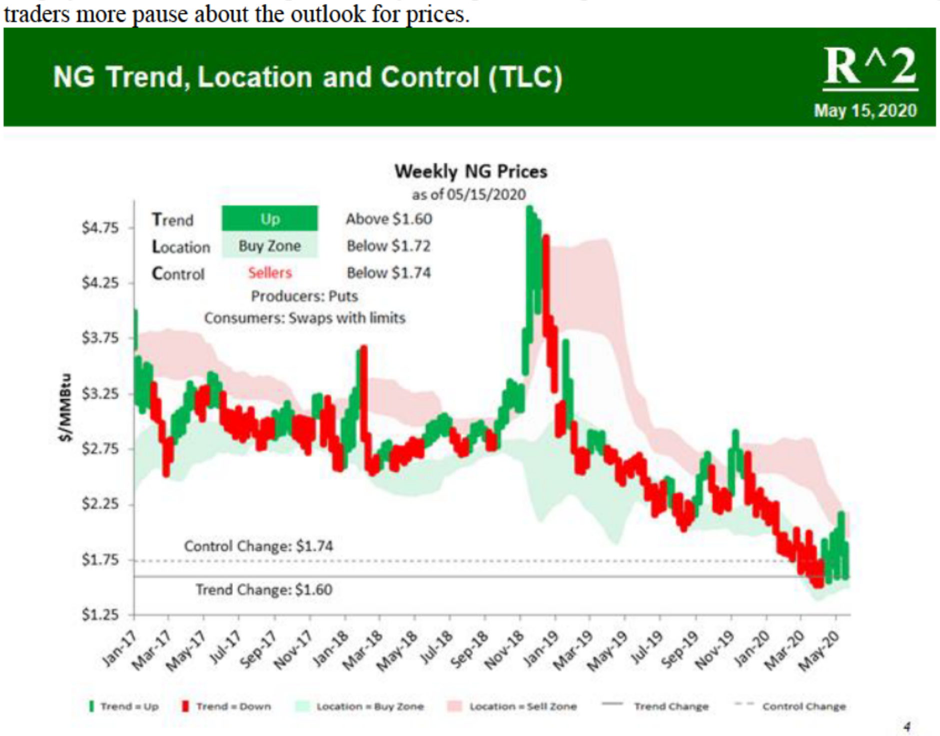
Date Approved: August 24, 2020

...TRADE SECRET DATA ENDS]

May 18, 2020

To whom it may concern,

Natural gas fell 18 cents in spot, but found support above recent lows. The winter contract months fell roughly half as much. The rapid recovery in oil prices along with the weaker LNG demand are giving gas traders more pause about the outlook for prices.



[HCTS Data Begins ...

We advised in the February 29 Risked Revenue Hedge Report the following:
NG is confirming the UP Trend for four consecutive weeks. NG is rallying into the sell zone above $2.04/MMBtu. [redacted]

...HCTS Data Ends]

R^2 analysis is a tool, designed to provide assistance to companies that hedge. The assumptions used in R^2 analysis provide a practical framework from which a successful hedge program can be developed and maintained. R^2, while mathematically rigorous, is not a substitute for logic, common sense or the fiduciary responsibilities that drive hedging or any other business decisions. The information contained in this report is taken from sources the author believes to be reliable, but is not guaranteed as to the accuracy or completeness thereof and is reported for information purposes only. The recommendations contained in this report represent the opinions of the author. Such opinions are subject to change without notice. The author may or may not trade in commodities discussed in this report, taking positions similar or opposite to the recommendations discussed herein. Commodity trading involves risk and is not for everyone.

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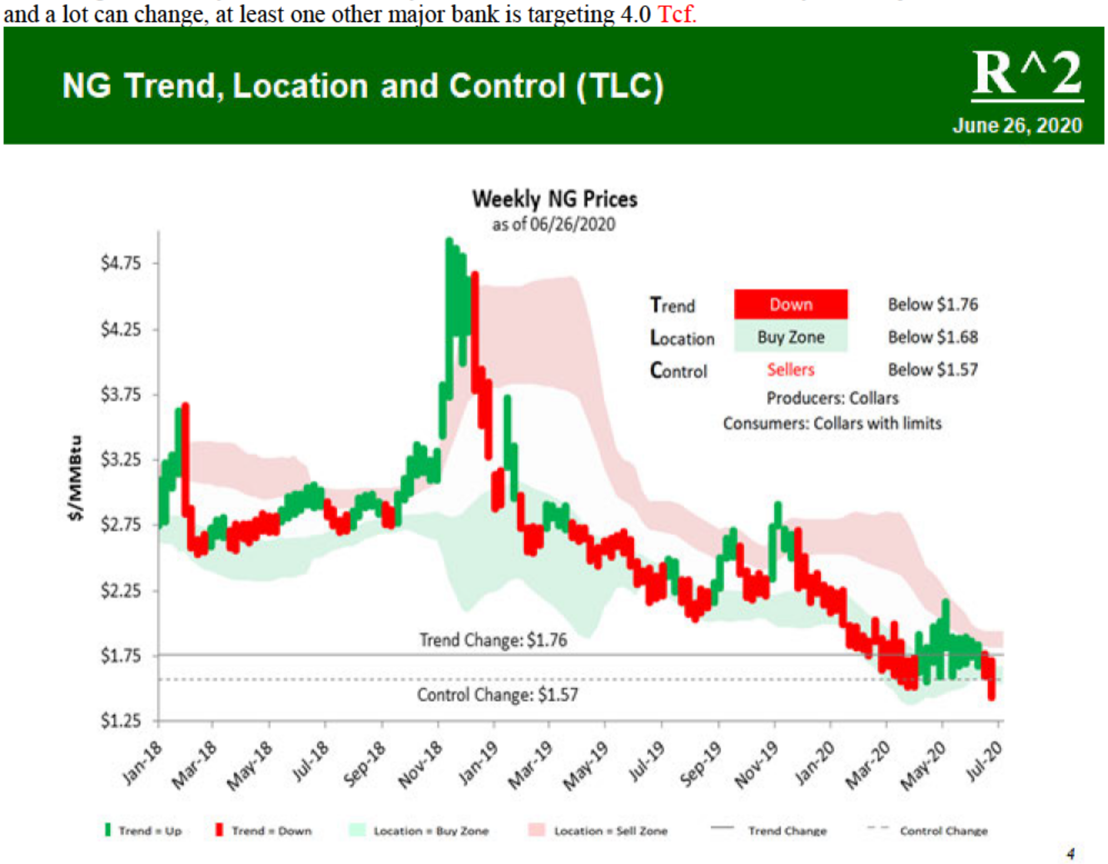
June 30, 2020

To whom it may concern,

Natural Gas fell 13 cents to $1.54, the lowest price since 1995. August is expected to see 40-45 cancelled cargoes of LNG exports, much greater than originally expected. This increases the possibility for storage congestion before the injection cycle wraps up in October. One prominent investment bank has suggested that storage levels may exceed 4.3 TCF by the end of the season. While it is early in the injection season, and a lot can change, at least one other major bank is targeting 4.0 Tcf.



[HCTS Data Begins... We advised in the May 31 Risked Revenue Hedge Report the following:
NG is continuing in it's UP Trend and is trading in a range inside the Neutral zone between $1.71 and $1.90. The shut-ins in US oil production has reduced associated NG production. [redacted]

...HCTS Data Ends]

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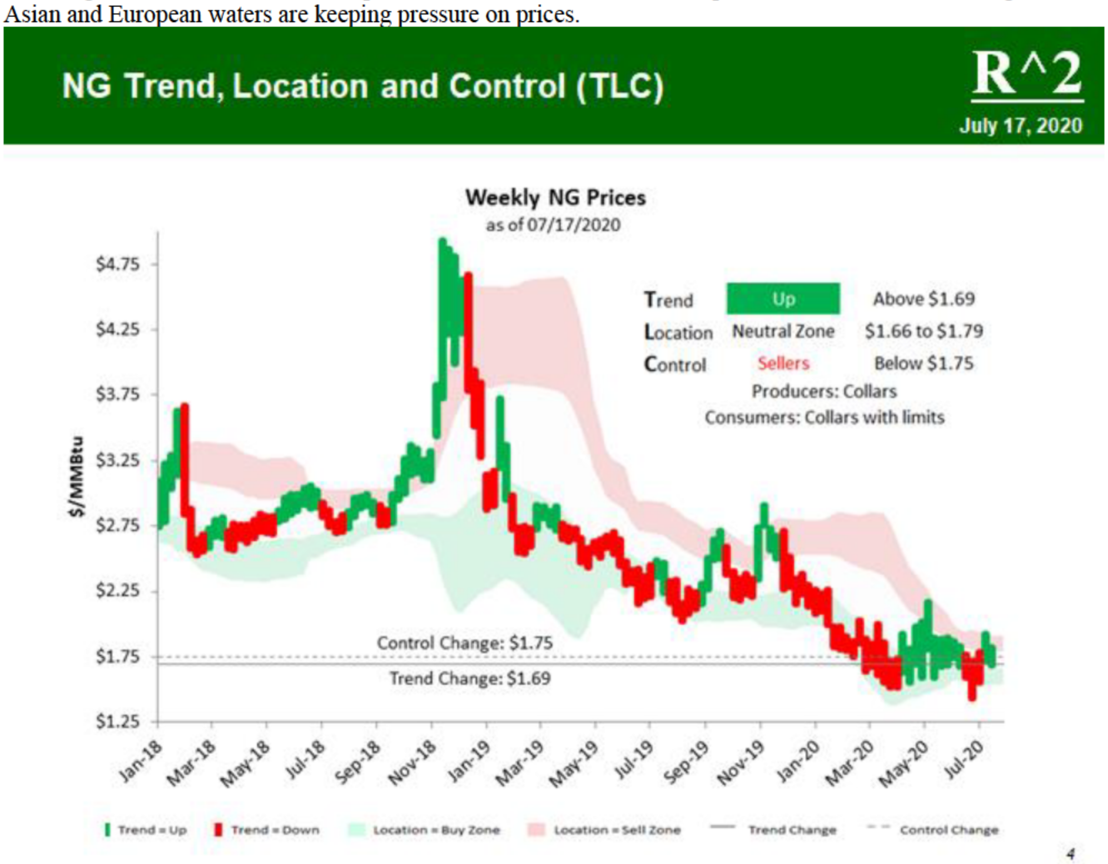
July 23, 2020

To whom it may concern,

Natural gas fell 9 cents. Warmer temperature forecasts moderated and reports of 30 LNG tankers idling in Asian and European waters are keeping pressure on prices.



[HCTS Data Begins...

We advised in the June30 Risked Revenue Hedge Report the following:
Natural Gas is trading sideways near the 5-year lows and has been closing inside the buy zone, offering a good buying opportunity. [redacted]

[redacted]

...HCTS Data Ends]

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August 19, 2020

To whom it may concern,

Natural Gas gained 12 cents on the heels of a Friday rally. Futures followed the cash market higher. With summer forecasts mostly finished, there was little news to drive the market. R^2 believes participants are focusing on record low rig counts, which will negatively impact 2021 production.

NG Trend, Location and Control (TLC)

R^2

August 14, 2020

[HCTS Data Begins...

We advised in the July 31Risked Revenue Hedge Report the following:

Natural Gas has broken out of the trading range from the past few months with warmer weather and lower production growth. [redacted]

[redacted]

... HCTS Data Ends]

R^2 analysis is a tool, designed to provide assistance to companies that hedge. The assumptions used in R^2 analysis provide a practical framework from which a successful hedge program can be developed and maintained. R^2, while mathematically rigorous, is not a substitute for logic, common sense or the fiduciary responsibilities that drive hedging or any other business decisions. The information contained in this report is taken from sources the author believes to be reliable, but is not guaranteed as to the accuracy or completeness thereof and is reported for information purposes only. The recommendations contained in this report represent the opinions of the author. Such opinions are subject to change without notice. The author may or may not trade in commodities discussed in this report, taking positions similar or opposite to the recommendations discussed herein. Commodity trading involves risk and is not for everyone.

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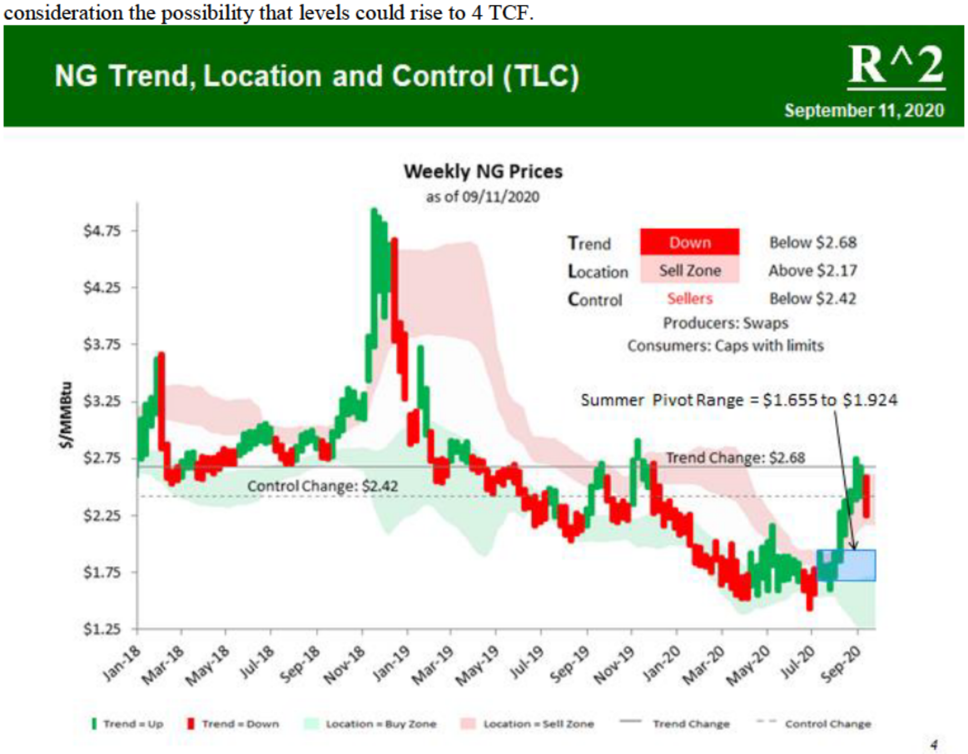
September 16, 2020

To whom it may concern,

Spot Natural Gas fell by 32 cents to $2.26, which changed the Trend to DOWN. Cal '21 fell just $0.03 to $2.963. It remains in an UP Trend, although Sellers have Control below $2.98. The power outage caused by Hurricane Laura at the Port of Lake Charles still has Cameron LNG exports idled. LNG exports out of Corpus Christi and Sabine are operating normally. The drop in exports has traders who had expected a 3.85 TCF endpoint for storage to consideration the possibility that levels could rise to 4 TCF.



We advised in the August 31 Risked Revenue Hedge Report the following:

[HCTS Data Begins...

CNP has until Oct 1, 2020 to finish its buy program for another 4.2 Bcf of gas. R^2 recommends having a plan for assuring that these volumes are transacted:

If spot gas closes above [redacted] finish the buy program.

If spot gas closes below [redacted] finish the buy program.

If spot remains rangebound, finish the program on the last day available.

Since spot closed last Friday at $2.26, [redacted] **The assumptions used in R^2 analysis provide a practical framework from which a successful hedge program can be developed and maintained. R^2, while mathematically rigorous, is not a substitute for logic, common sense or the fiduciary responsibilities that drive hedging or any other business decisions. The information contained in this report is taken from sources the author believes to be reliable, but is not guaranteed as to the accuracy or completeness thereof and is reported for information purposes only. The recommendations contained in this report represent the opinions of the author. Such opinions are subject to change without notice. The author may or may not trade in commodities discussed in this report, taking positions similar or opposite to the recommendations discussed herein. Commodity trading involves risk and is not for everyone.**

...HCTS Data Ends]

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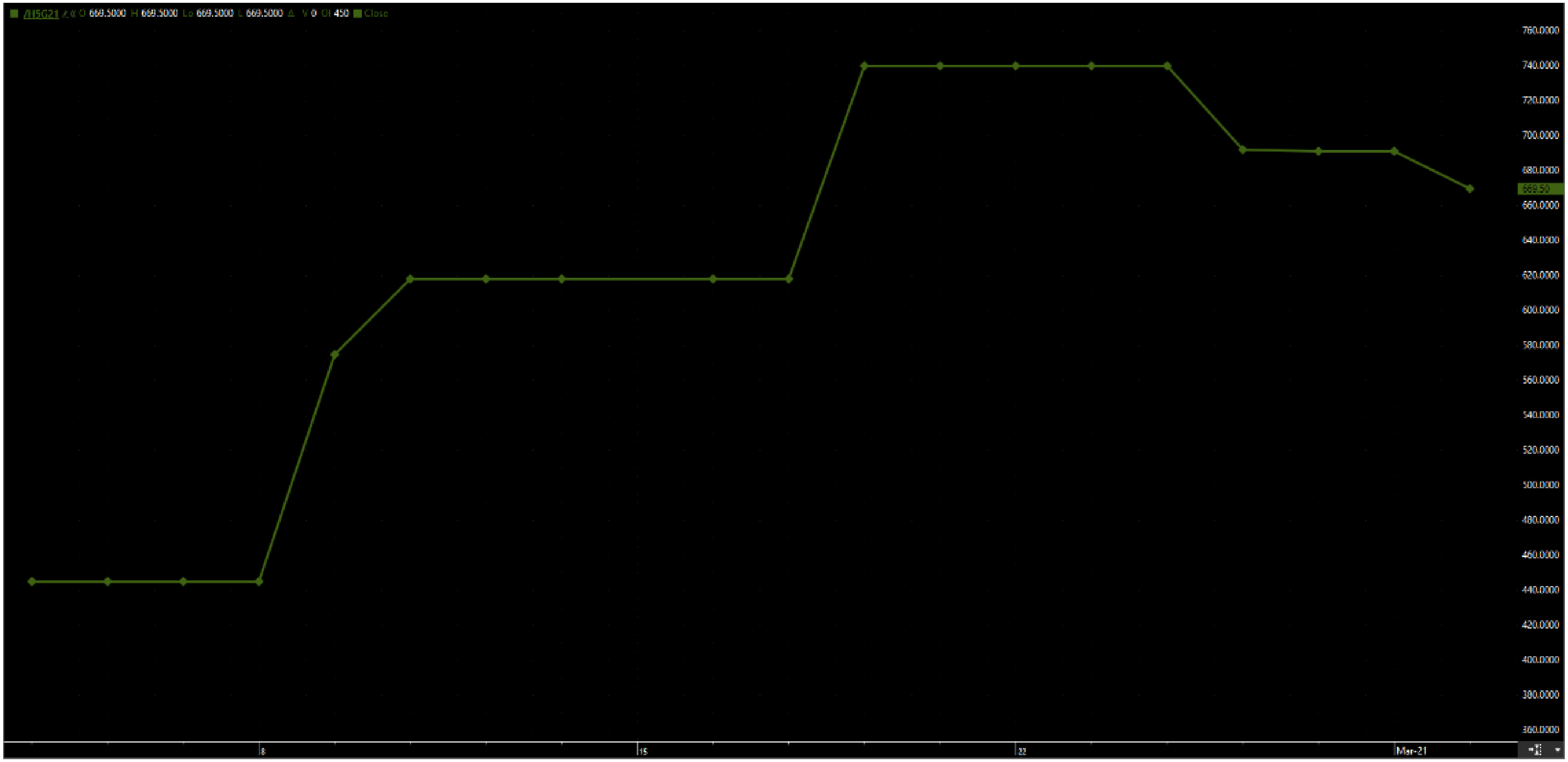
HIGHLY CONFIDENTIAL TRADE SECRET DATA HAS BEEN EXCISED

Source: Enverus



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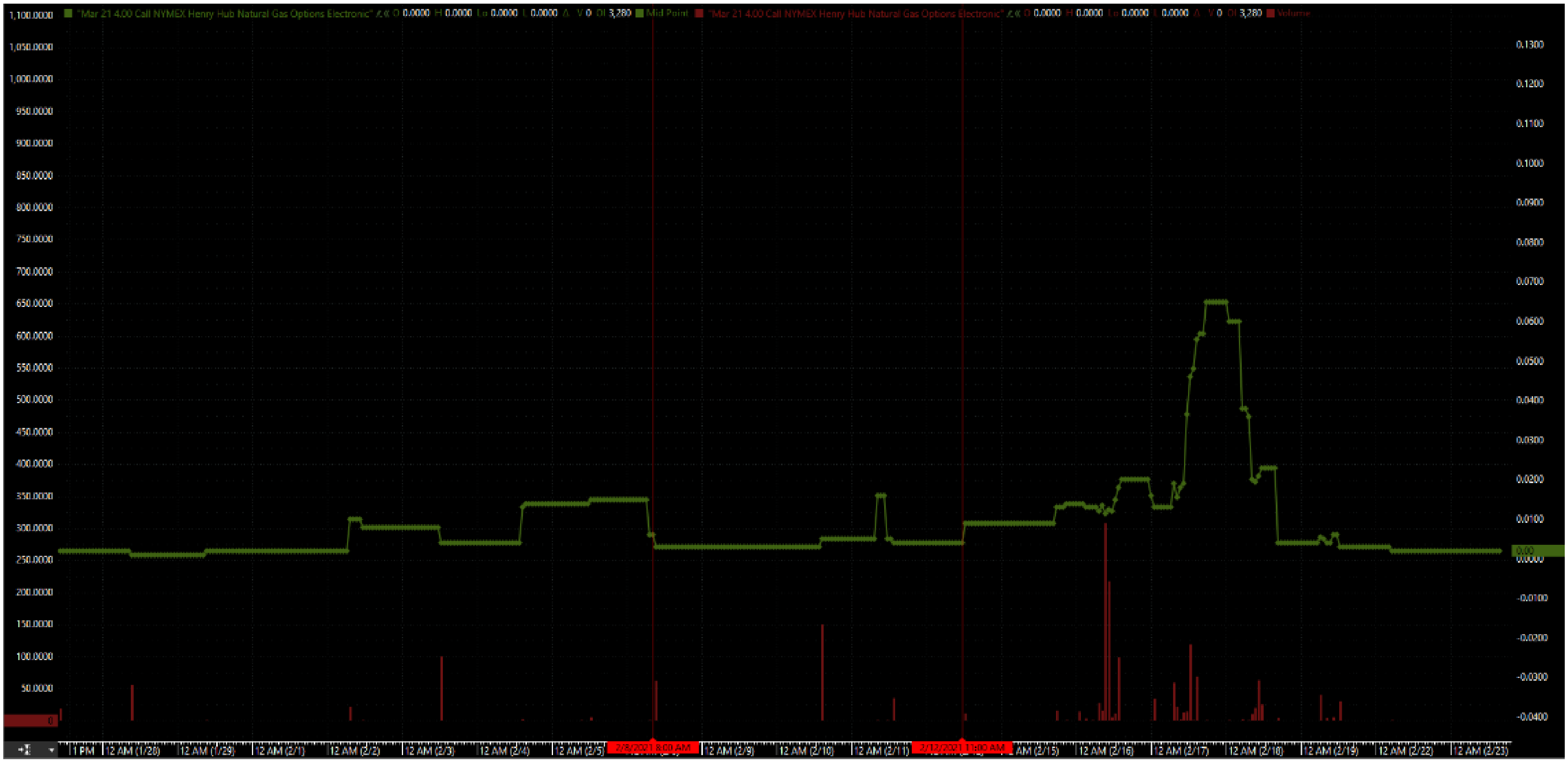
Source: Enverus



TRADE SECRET
IN ITS ENTIRETY

DOC **Request Number: 29**
Topic: Smead Direct
Reference(s): Smead Direct
All page and line numbers below refer to the Direct Testimony of Richard G. Smead filed on behalf of Joint Gas Utilities on October 22, 2021

DOC No. 29 a)

Page 23, lines 10-16, Mr. Smead states:

During Winter Storm Uri, which affected the entire midcontinent, extending to important supply areas in Oklahoma and Texas, the primary factors that acutely impacted market prices were loss of production in Texas and Oklahoma, tight pipeline tolerances, and uncertainty as to the stability of the flowing supply that had been scheduled. In the interstate market, the rigidity of the NAESB timeline and the pipeline-specific restrictions discussed in the next section also played a role.

Please reconcile the timing of loss of production versus gas prices spiking based on trading that took place on February 12th.

Response:

It is not clear what is meant by "reconcile the timing." However, as reported in the Federal Energy Regulatory Commission/National Electric Reliability Corporation staff report on Winter Storm Uri, released in final form on November 17, 2021, supply loss began as early as February 7, 2021. Prices rose somewhat in subsequent days, but the first spikes were reflected in transactions made on February 12 for supply over the four-day weekend. Genuinely catastrophic loss of supply occurred on Sunday, February 14. Thus, prices spiked before genuinely deep cuts in supply took place physically, having been set after the early morning index based trading on February 12, in contemplation of a supply collapse that occurred later in the four-day weekend.

Date: November 24, 2021

Prepared by: Richard G. Smead, Consultant to Joint Utilities

29 b) On page 33, lines 7-8, explaining the term “contract swing,” Mr. Smead states, “These contracts require the same volume for each day over a trading period such as a weekend or holiday.”

Please explain any options or possibility Mr. Smead is aware of to make non-ratable gas supply purchases over a weekend.

Response:

If a contract is already in place that allows non-ratable purchases, it would be available over a weekend, but such contracts usually involve a significant premium because of the unpredictability of revenue for the seller. For gas purchased on the daily market, but effective throughout a weekend, I am unaware of any approach other than ratable flow until the first business day after the weekend.

Date: November 24, 2021

Prepared by: Richard G. Smead, Consultant to Joint Utilities

c) Page 37, lines 6-10, Mr. Smead states:

As the Gas Day begins, even if conservation is observed in the early hours, there is no guarantee that it will continue in later hours, meaning that the LDC cannot reduce its daily nomination and release supply to sell in the market without reasonable certainty that lower consumption levels will continue during the day.

i. Please describe if firmer reductions in supply need (e.g. curtailment, peak shaving) would provide a means for a utility to release supply?

ii. Does the daily nomination and market process allow for a utility to purchase its needs at index in the early morning and then release or sell back some of those purchases later in the trading day?

Response:

i. As I interpret the DOC's use of the term, "reductions in supply need" do not provide a means for supply to be "released." Rather, they may be considered in determining the necessary nomination levels. However, such sources have limitations on how long they can run, and, in the case of storage there can be inventory-driven reductions in deliverability that will diminish its value for later demands. In both cases, the way such assets are used is extremely fact-intensive and reliant upon a particular utility's operational profile. Curtailment of interruptible loads can reduce the need for gas supply, but again, this is very fact intensive.

ii. Not in practical terms. First, there is no right to "sell back" purchased gas. I assume that by this phrase the question is asking if a utility could find a third-party purchaser. Second, as noted in my testimony, even if conservation is observed early, there is no guarantee it will continue, so that the earliest an attempt could be made to dispose of conserved supply would be in the third nomination cycle, nominated at 7:00 PM Central, for effectiveness at 10:00 PM Central. That cycle is subject to FERC's "no bump" rule, which restricts firm shippers from bumping nominated and scheduled interruptible service during the last standard intraday nomination cycle of the gas day. Thus, even if there were a willing buyer, that buyer could not change its firm nomination or secure additional lower-priority transportation if it meant forcing anyone off the system. If such a hypothetical buyer holds unused firm transportation capacity on the pipeline, if that capacity has been scheduled as interruptible service for other shippers for the day, the "no-bump" rule prohibits the firm shipper from taking the capacity back to move late-day purchases. Thus, there is simply no market for nighttime purchases, since they cannot be reliably taken by a purchaser.

Date: November 24, 2021

Prepared by: Richard G. Smead, Consultant to Joint Utilities

d) On page 44, lines 5-8, discussing Figure 5 – Weather Desk Predictions and Experience, on page 43, Mr. Smead concludes:

[A]s of the morning of February 12, when commitments were made that would define the available supply through February 16, a decision to commit to more natural gas supply than the weather forecast indicated was the correct one.

i. Do natural gas utilities commit to more supply than forecasts indicate?

ii. If the answer is yes, what are the protocols and parameters for doing so?

Response:

i. The decision to do so is extremely utility and fact specific. There is no "one size fits all" answer.

ii. Again, "protocols and parameters" for establishing a reserve margin are company-specific, part of each company's planning process. Generally, a reserve margin is established, especially during a strained operating condition, to address two potential issues: Weather-related demand in excess of forecasts, and the potential for supply cuts.

Date: November 24, 2021

Prepared by: Richard G. Smead, Consultant to Joint Utilities

e) On page 51, lines 12-16, Mr. Smead states:
These plans came to fruition as nominations were made on February 12 for the weekend. Pipeline nominations were due by 1:00 p.m. that day, but based on interviews with multiple purchasers in Minnesota, the common practice is to have supply committed and nominations tied down in the period from 7:00 a.m. to 10:00 a.m.

In the industry, while procuring supply, is it common practice to purchase all spot gas supply at an index practice?

Response:

Spot gas purchases are bilateral transactions, often executed on the Intercontinental Exchange (ICE) or by direct contact with suppliers. As shown in Schedule 4, 83 percent of all gas purchases on the spot market in 2020 were at index prices or based on index prices.

Date: November 24, 2021

Prepared by: Richard G. Smead, Consultant to Joint Utilities

f) On page 51, lines 24-26, Mr. Smead states: "LDCs sought to secure enough supply to have a reserve margin against supply cuts, pipeline issues, etc., and in particular, to avoid very severe pipeline penalties for overrunning their scheduled quantities."

i. How should gas utilities set reserve margins?

ii. What is the industry practice for establishing reserve margins?

iii. What is a typical reserve margin target?

Response:

i. There is no right way or wrong way. The level and character of a reserve margin is extremely utility- and fact-specific.

ii. To the best of my knowledge, there is no general industry practice, each company operates according to its own circumstances.

iii. I have no information on a "typical" reserve margin, in that such margin is the result of each utility's circumstances.

Date: November 24, 2021

Prepared by: Richard G. Smead, Consultant to Joint Utilities

g) On page 53, lines 24-25, Mr. Smead states:

LDCs sought to secure enough supply to have a reserve margin against supply cuts, pipeline issues, etc., and, to avoid very severe pipeline penalties for overrunning their scheduled quantities.

Please reconcile the prevalence of supply cuts and importance of reserve margins with the level of supply cuts experienced by the utilities.

Response:

My report addresses the backdrop against which the utilities were operating. The specific operational decisions of the utilities and their company-specific supply situations are outside the scope of my review and analysis.

Date: November 24, 2021

Prepared by: Richard G. Smead, Consultant to Joint Utilities

h) On page 55, lines 23-27, Mr. Smead states:

Moreover, the vast majority of the power generation in ERCOT is natural gas-fired generation owned by independent power producers, who drove natural gas prices up in a quest to capture extremely high ceiling prices for power in ERCOT--$9,000 per Megawatt-hour for four days.

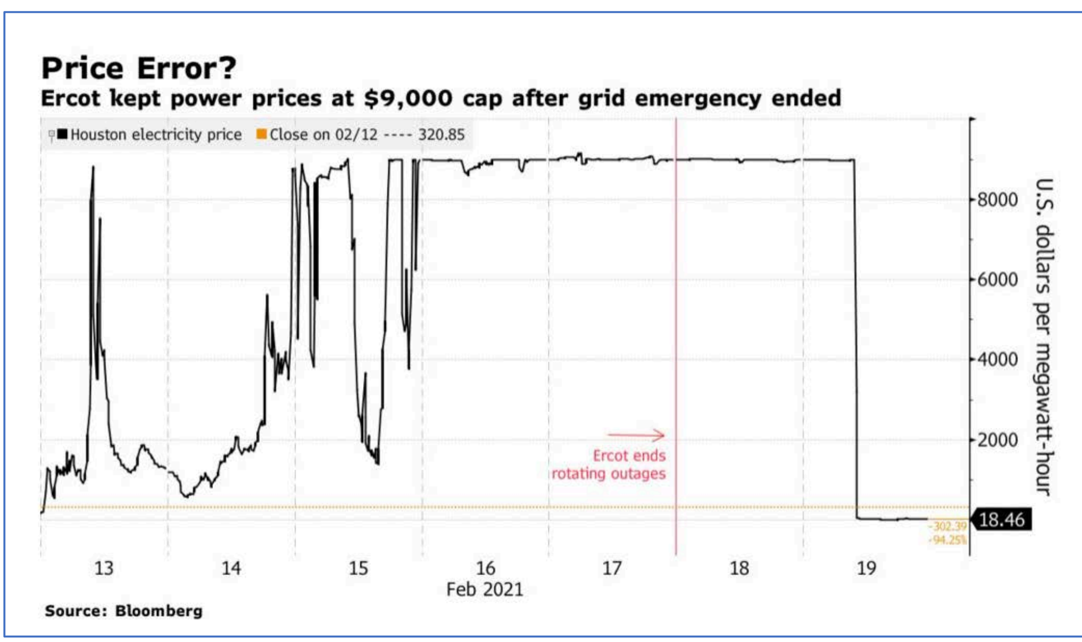
i. Please describe & explain how independent power producers in ERCOT drove up natural gas prices.

ii. Please reconcile the timing of the Minnesota gas utilities' purchases during the February Event and the actions by the independent power producers in ERCOT.

Response:

i. Independent power producers were willing to pay any price for natural gas that would still allow a major profit at the $9,000 per Megawatt-hour cap. For a 7,000 Heat Rate natural gas combined-cycle plant, $9,000 per Megawatt-hour equates to $1,285 per MMBtu for natural gas, making a gas price well in excess of $1,000 "in the money." Thus there was simply no meaningful economic limit on what a generator would pay for fuel in order to generate during the four days that ERCOT's price stayed at the limit.

ii. The Public Utility Commission of Texas ordered ERCOT to hold the price at the cap for four days, beginning February 15, extending beyond the end of rotating outages (please see chart below from Bloomberg).



Examination of the specific utilities' actual purchases is outside of the scope of my engagement.

Date: November 24, 2021

Prepared by: Richard G. Smead, Consultant to Joint Utilities

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-999/CI-21-135 - Gas Costs Investigation   Date of Request: 4/22/2021
Requested From: CenterPoint Energy Minnesota Gas   Response Due: 5/4/2021

Analyst Requesting Information: Peter Scholtz

Type of Inquiry: Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 008	**Reference: CenterPoint's April 9, 2021 filing at 5, footnote 4.** The Company mentions "an annual limit on net option premiums of $6.5 million, authorized continuation of put options in combination with call options to form a collar but disallowed any other use of put options." Given that the Company is allowed to implement costless collars or zero-cost collars, explain and quantify the theoretical limit on the quantity of natural gas that it could hedge given "an annual limit on net option premiums of $6.5 million." **Response:** The $6.5 million limit noted in the Commission's Orders on CenterPoint Energy's authorization to use hedging is related to net option premiums, excluding premiums or reservation fees paid for daily call gas. How much gas could be hedged under the $6.5M limit would depend on current market pricing for hedging instruments. CenterPoint Energy does not usually engage in financial hedging of the sort subject to the $6.5M limitation. CenterPoint attempts to solely use physical hedges and storage services to limit upward price movement for a part of its portfolio. Storage gas is gas purchased at market prices in the summer and injected into a storage cavern. In the winter, when CenterPoint Energy withdraws that gas from storage, it charges the cost of that gas through its Gas Supply Rate at the weighted average summer injection price, creating a 'natural' hedge since the price is 'fixed' when purchased. Hedged gas contracts are detailed in the Company's gas supply plan. One type of physical hedge that the company uses is a costless collar. A costless collar

Response By: Seth DeMerritt
Title: Manager, Regulatory Affairs
Department: Mng Smr Reg Svc Rev Req
Telephone: 612-321-4423

allows CenterPoint Energy to have a gas cost that floats with market prices within a banded range. A collar combines the ceiling and floor price. The premium for buying a call option (that is, receiving a ceiling price) is funded by the premium received when selling a put option (that is, receiving a floor price). When the premiums for those two products exactly offset each other, the resulting product is known as a costless collar.

The Commission's Hedging Order limits all hedged volumes, including physical hedges to 26 BCF per year or approximately 25% of planned winter throughput. Storage volumes are not limited by the Commission's Hedging Order, however to contract for more third-party storage CenterPoint Energy would need to ask for Commission approval via a demand filing. CenterPoint Energy would also need to identify additional storage that is deliverable to our system, which may be limited. Currently the Company has storage equal to about 25% of winter throughput.

The primary limiting factor in engaging in additional hedges on the Company's portfolio (greater than 50% of normal sales) is the need to 'do something' with excess gas on low demand days. Generally speaking, a warm winter month's sales volume can reduce expected sales by as much as 30% of a normal month, with specific warm days that are lower than the average by as much as 70%. Hedging more than the typical 50% normal level can cause additional limitations on the overall portfolio, forcing the utility into a position requiring the sale of excess/surplus contracted supply, typically at a loss.

Response By: Seth DeMerritt
Title: Manager, Regulatory Affairs
Department: Mng Smr Reg Svc Rev Req
Telephone: 612-321-4423

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-999/CI-21-135 - Gas Costs Investigation   Date of Request: 5/25/2021
Requested From: CenterPoint Energy Minnesota Gas   Response Due: 6/7/2021

Analyst Requesting Information: Peter Scholtz

Type of Inquiry: Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 008A	**Reference: CenterPoint Response to OAG IR 008 CPE.** 1. CenterPoint's response to OAG Information Request 008 mentions both "a 'natural' hedge" and a "physical hedge." Explain the difference between a natural hedge and a physical hedge. 2. If the counterparty exercises a put that CenterPoint sold, explain whether CenterPoint is obligated to physically purchase gas or if it is financially settled. Explain whether it is based on an index price, or a fixed strike price. 3. Explain why "CenterPoint Energy does not usually engage in financial hedging of the sort subject to the $6.5M limitation." Explain and Quantify the word "usually" as used in this context—explain how often the company engages in financial hedging of the sort subject to the $6.5M limitation. Quantify how near CenterPoint was to the $6.5M limit for the 2020-2021 heating season. 4. CenterPoint mentions "the need to 'do something' with excess gas on low demand days." Explain the extent to which there is a "need to 'do something' with excess gas" for financial hedges. **Response:** 1. Contract storage allows for the purchase of gas during summer months and withdrawal for system use during winter months at the average inventory value resulting in a natural price hedge. A physical hedge would be Call or a Costless Collar where CenterPoint would physically buy the gas.

Response By: Seth DeMerritt
Title: Manager, Regulatory Affairs
Department: Mng Smr Reg Svc Rev Req
Telephone: 612-321-4423

2. When CenterPoint uses physical hedges they physically purchase the gas. CenterPoint did not have any financial hedges during the plan year April 2020 to March 2021. The costless collar allows CenterPoint Energy to have a gas cost that floats with market within a banded range. A collar combines the ceiling and floor price. The premium for buying a call option (that is, receiving a ceiling price) is funded by the premium received when selling a put option (that is, receiving a floor price). When the premiums for those two products exactly offset each other, the resulting product is known as a costless collar.

3. CenterPoint Energy has not used financial hedges in any recent year, and therefore was not near the $6.5M limit for the 2020/2021 heating season, nor was there a need to do something with excess gas.

4. Because financial hedges do not involve the delivery of physical gas, there is no excess gas that would necessitate having to do something.

Response By: Seth DeMerritt
Title: Manager, Regulatory Affairs
Department: Mng Smr Reg Svc Rev Req
Telephone: 612-321-4423

From:	Doyle, Scott E [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=45599C5479B54988A2247B806F7525CE-00064900]
Sent:	2/12/2021 9:39:13 PM
To:	Lesar, David J [dave.lesar@centerpointenergy.com]; Wells, Jason [jason.wells@centerpointenergy.com]; Colvin, Kristie [kristie.colvin@centerpointenergy.com]; Ryan, Jason M [jason.ryan@centerpointenergy.com]
Subject:	Natural Gas Index Volatility Impact to our Supply Costs

We experienced significant price increases today as we locked in our marginal natural gas supply for the next four days.

this is fully recoverable as a pass through cost,

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This is a Holiday Weekend with Presidents Day on Monday. Gas traded in equal volumes for the entire 4 day period (Saturday – Tuesday). There was little to no gas available for a single day between Saturday and Tuesday.

Gas Price Indices will settle late tonight. I will report Saturday before noon the final prices to this group.

[redacted]

[redacted]

All LDC have sufficient physical gas to serve our customers.

[redacted]

Thank you - Sarah

From: Mead, Sarah R
Sent: Friday, February 12, 2021 10:24 AM
To: Lauber, Scott J <Scott.Lauber@wecenergygroup.com>; Klappa, Gale E <gale.klappa@wecenergygroup.com>; Krueger, Dan P <Dan.Krueger@wecenergygroup.com>; Jerome, Randall L <randall.jerome@wecenergygroup.com>; Metcalfe, Tom <Tom.Metcalfe@wecenergygroup.com>; Spicer, Paul J <paul.spicer@wecenergygroup.com>; Hinton, Torrence L <torrence.hinton@peoplesgasdelivery.com>
Cc: Fletcher, Kevin <Kevin.Fletcher@wecenergygroup.com>; Liu, Xia <Xia.Liu@wecenergygroup.com>; Garvin, Robert M <Robert.Garvin@wecenergygroup.com>; Eidukas, Theodore <Theodore.Eidukas@wecenergygroup.com>
Subject: RE: Gas Supply Cold Weather Update

Pricing Update 2/12/2021 in DTH:

Gas Prices are currently trading across our LDC's between [redacted] (MERC [redacted] More information will be available later today, however I do not think these are as high as we might see.
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.

[redacted]

Physical deliveries are NOT an issue in our markets.

Thank you - Sarah

From: Mead, Sarah R
Sent: Thursday, February 11, 2021 2:14 PM
To: Lauber, Scott J <Scott.Lauber@wecenergygroup.com>; Klappa, Gale E <gale.klappa@wecenergygroup.com>; Krueger, Dan P <Dan.Krueger@wecenergygroup.com>; Jerome, Randall L <randall.jerome@wecenergygroup.com>; Metcalfe, Tom <Tom.Metcalfe@wecenergygroup.com>; Spicer, Paul J <paul.spicer@wecenergygroup.com>; Hinton, Torrence L <torrence.hinton@peoplesgasdelivery.com>
Cc: Fletcher, Kevin <Kevin.Fletcher@wecenergygroup.com>; Liu, Xia <Xia.Liu@wecenergygroup.com>; Garvin, Robert M